Petroleum news

Vol. 27, No. 20 • www.PetroleumNews.com *A weekly oil & gas newspaper based in Anchorage, Alaska* Week of May 15, 2022 • $2.50

page 2 EIA: crude price to remain above $100, record US production in 2023

Alaska fits Conoco's GHG goal; Isaacson praises fiscal regime

EREC ISAACSON

In conjunction with ConocoPhillips' first quarter 2022 company-wide earnings presentation on May 5, ConocoPhillips Alaska reported a net income of $584 million for first quarter, whereas its parent reported company-wide net income of $5.76 billion.

During the quarter, ConocoPhillips Alaska incurred an estimated $702 million in taxes and royalties, which includes $524 million to the state of Alaska and $178 million to the federal government.

In first quarter ConocoPhillips Alaska said it invested capital

see **CONOCO EARNINGS** *page 8*

AOGCC OKs pool rules for Beluga River; Hilcorp plans more drilling

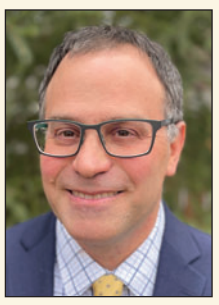
The Beluga River gas field on the west side of Cook Inlet has been in production since 1968 under various operators, none of whom, until this year, requested that the Alaska Oil and Gas Conservation Commission establish pool rules.

Hilcorp Alaska, the current operator at Beluga, requested in March that the commission define a new gas pool, the Sterling-Beluga gas pool, within the Beluga River unit and requested rules for development and operation of that pool. (See stories in March 20 and April 17 issues of Petroleum News.)

In its May 5 order, establishing the Sterling-Beluga gas pool at the Beluga River unit, and setting out pool rules, the

see **BELUGA RIVER** *page 9*

Cohn named Bureau of Land Management Alaska director



STEVEN COHN

Steven Cohn, a veteran public land manager, has been named the new director of the Alaska State Office of the Bureau of Land Management.

"Steve brings 27 years of professional and academic natural resource management experience to his new role," BLM Director Tracy Stone-Manning said in announcing the appointment. "He is a highly skilled and respected policy expert on Alaska public land and resources issues and his expertise will benefit the BLM and Alaska constituencies we serve."

see **NEW DIRECTOR** *page 10*

AEA files for Dixon Diversion to increase Bradley Lake output

CURTIS THAYER

The state is proceeding with plans to further increase output from the Bradley Lake hydroelectric facility on the Kenai Peninsula, following the 2020 completion of the Battle Creek diversion project, which increased output by about 10%.

In late April the Alaska Energy Authority, in partnership with the Railbelt facilities, filed a license amendment with the Federal Energy Regulatory Commission in what AEA called an initial step in pursuing the Dixon Diversion.

Bradley Lake, the largest hydroelectric plant in Alaska, a

see **DIVERSION PLAN** *page 8*

LAND & LEASING

Lease sale uproar

Interior Department confirms no Cook Inlet sale, appeals panel hears arguments

By KAY CASHMAN
Petroleum News

The Interior Department confirmed Wednesday, May 11, that it will not hold three offshore oil and gas lease sales — one in Alaska's Cook Inlet and two in the Gulf of Mexico.

The confirmation from Interior comes at a time when U.S. gasoline prices have reached record highs.

That said, a near halt in oil and gas leasing on and offshore by the Biden administration is old news.

As reported in the May 1 issue of Petroleum News, Interior's Bureau of Ocean Energy Management has been conducting offshore federal lease sales under its 2017-2022 program. Under the 2017-2022 program BOEM had planned a Cook Inlet lease sale for October 2021.

However, in early February 2021 the Biden

U.S. District Judge Terry Doughty found that states which challenged the order were likely to prove the Interior Department violated the Administrative Policy Act by acting without "any rational explanation."

see **SALE UPROAR** *page 11*

FINANCE & ECONOMY

Prices bounce back

US fuel inventory drawdown counteracts China COVID-19 lockdown fears

By STEVE SUTHERLIN
Petroleum News

Alaska North Slope crude surged $5.44 May 11 to close at $111.79 per barrel, while West Texas Intermediate vaulted $5.95 to close at $107.51, and Brent gained $5.05 to close at $107.51.

The gains coincided with a report that U.S. fuel inventories plunged as the busy summer driving approached. Total motor gasoline inventories decreased by 3.6 million barrels for the week ending May 6, settling 5% below the five-year average for the time of year, the Energy Information Administration reported May 11. Distillate fuel inventories decreased by 0.9 million barrels for the period, ending at 23% below the five-year average for the time of year.

May 11 price action was a reversal of an asset sell off that began Monday May 9, taking U.S. and international stocks sharply lower, along with cryptocurrencies, gold, silver and other commodities. U.S. equity markets were spooked by concerns

Rapid inflation in the U.S. oil patch is crimping CAPEX budgets for oil producers, just as the industry is attempting to ramp up production to meet recovering demand.

see **OIL PRICES** *page 11*

ENVIRONMENT & SAFETY

CD1 leak causes traced

ConocoPhillips provides analysis of March 4 gas release to regulators, Congress

By KRISTEN NELSON
Petroleum News

ConocoPhillips Alaska has determined two causal factors and four conditions which led to the natural gas release at the Colville River unit CD1 pad on March 4 and to initial releases from multiple wells across the pad.

The company provided its final report on the natural gas release at CD1 to the Alaska Oil and Gas Conservation Commission on May 3. On May 10, the company answered questions from Congress on the incident.

ConocoPhillips said in its report to the commission that gas from what was later determined to be the C10-Halo interval in the WD-03 disposal well,

"By March 8, ConocoPhillips had secured the location, determined the most probable gas source, and established a controlled flow path for the gas up the outer annulus of the WD-03 well into the Alpine Central Facility," the company said in its May 10 letter.

then being drilled at CD1, was observed March 4 as "intermittent, low pressure natural gas releases at CD1-05, which is approximately 450 feet away from WD-03."

On March 4 the release was reported to

see **GAS RELEASE** *page 10*

● FINANCE & ECONOMY

EIA sees oil price remaining above $100

US oil production forecast to average 11.9 million bpd this year, up 0.7 million from 2021, increasing to +12.8 million in 2023

By KRISTEN NELSON
Petroleum News

The U.S. Energy Information Administration is forecasting that the price of crude oil will remain above $100 this year and that U.S. crude oil production will average 11.9 million barrels per day in 2022 and more than 12.8 million bpd in 2023, surpassing the average annual record of 12.3 million bpd from 2019.

The agency continues to stress the uncertainty in its forecasts, something it emphasized in releasing its May Short-Term Energy Outlook on May 10.

"A high level of uncertainty remains in our outlooks," said EIA Administrator Joe DeCarolis, "but we have consistently forecast that elevated crude oil prices would help drive record-level annual U.S. oil production levels in 2023. Low global oil inventories coupled with continued high demand for gasoline, diesel, and other petroleum products means that increased production likely won't have much impact on prices in the short term."

Other highlights of the May forecast include an increase in the amount of U.S. electricity generation coming from solar and wind power this summer, 11.1% compared to 9.6% last summer.

"High natural gas prices, limited coal supply, the increased solar and wind capacity mean that renewables should play a larger role in the U.S. electricity mix this summer and throughout the year," DeCarolis said.


JOE DECAROLIS

The price of Henry Hub natural gas is also of note — forecast to average $8.59 per million British thermal units in the second half of the year, up 88% from the second half of 2021. EIA said this is a significant revision from previous forecasts, largely because it has "updated its power generation modeling to better account for evolving constraints in the coal market."

EIA's forecast for coal production is a 3% increase for 2022 from 2021, compared to a 7% increase in the April forecast, and part of the reason the agency is forecasting higher natural gas prices.

"Currently low coal supplies and limited capacity to increase domestic coal production mean that natural gas will remain in high demand for electricity generation, contributing to the higher natural gas prices in our forecast," DeCarolis said.

Brent crude

EIA said Brent crude averaged $105 per barrel in April, down $13 per barrel from March, but still above $100 per barrel following Russia's full-scale invasion of Ukraine.

Sanctions on Russia and independent corporate actions contributed to falling oil production in Russia "and continue to create significant market uncertainties about the potential for further oil supply disruptions," events occurring against what EIA said is a backdrop of low oil inventories and upward price pressures.

The agency expects Brent to average $107 per barrel in the second quarter of this year and $103 in the second half of the year, falling to an average of $97 per barrel in 2023.

U.S. crude production is forecast to average 11.9 million bpd this year, up 0.7 million bpd from 2021, and forecast to average more than 12.8 million bpd in 2023, surpassing the previous 12.3 million bpd record set in 2019.

Natural gas

The Henry Hub natural gas spot price averaged $6.59 per million Btu in April, up from a March average of $4.90 and well above the April 2021 average of $2.66 per million Btu.

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contents

● EXPLORATION & PRODUCTION

US drilling rig count up by 7 to 705

By KRISTEN NELSON
Petroleum News

The Baker Hughes' U.S. rotary drilling rig count topped 700 on May 6, up by seven to 705 from the previous week and up by 257 from 448 a year ago, the first time the count has been above 700 since April 2020.

When the count dropped to 244 in mid-August 2020 it was the lowest the domestic rotary rig count has been since the Houston based oilfield services company began issuing weekly U.S. numbers in 1944.

Prior to 2020, the low was 404 rigs in May 2016. The count peaked at 4,530 in 1981.

The count was in the low 790s at the beginning of 2020, where it remained through mid-March, when it began to fall, dropping below what had been the historic low in early May with a count of 374 and continuing to drop through the third week of August 2020 when it gained back 10 rigs.

The May 6 count includes 557 rigs targeting oil, up by five from the previous week and up 213 from 344 a year ago, with 146 rigs targeting gas, up by two from the previous week and up 43 from 144 a year ago, and two miscellaneous rigs, unchanged from the previous week and up by one from a year ago.

Thirty-four of the rigs reported May 6 were drilling directional wells, 646 were drilling horizontal wells and 25 were drilling vertical wells.

Alaska rig count down by one

Louisiana (62) was up by four rigs from a week ago.

Oklahoma (53) and Pennsylvania (25) were each up by two rigs week over week.

New Mexico (98) was up by one rig.

Alaska (8) and Texas (344) were each down a rig.

Rig counts in all other states were unchanged week over week: California (7), Colorado (15), Kansas (1), North Dakota (35), Ohio (12), Utah (12), West Virginia (14) and Wyoming (15).

Baker Hughes shows Alaska with eight rotary rigs active May 6, down by one from the previous week and up by five from a year ago, when the state's rig count stood at three.

The rig count in the Permian, the most active basin in the country, was unchanged from the previous week at 335 and up by 106 from 229 a year ago.

International rig count down 9 at 806

Baker Hughes began providing a monthly international rig 1975. The international count excludes North America which is included in the company's worldwide figures.

The international count for April, issued May 6, is down by nine from March to 806 rigs, Baker Hughes said, with land rigs down six to 615 and offshore rigs down three to 191. The April international count is up by 111 rigs from the comparable count in 2021, 695, with land rigs up by 85 and offshore rigs up by 26.

The Middle East accounts for the most rigs in the international totals, 300 in April, followed by Asia Pacific with 184, Latin America with 163, Europe with 81 and Africa with 78.

The U.S. rig count averaged 690 in April, up 29 from a March average of 661, and up by 254 from April 2021, while the Canadian count for April averaged 107, down 78 from a March average of 185 and up by 49 from April 2021. Worldwide the rig count was 1,603 in April, down 58 from 1,661 in March and up by 414 from 1,189 last April. ●

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● GOVERNMENT

CINGSA asks amendment of injection order

Alaska Oil and Gas Conservation Commission required gas detection at Inlet Fish Producers Cannery Loop plant when storage approved

By KRISTEN NELSON
Petroleum News

In 2010, when Cook Inlet Natural Gas Storage Alaska, CINGSA, requested a storage injection order for the facility from the Alaska Oil and Gas Conservation Commission, Inlet Fish, then owned by Vincent Goddard, opposed issuance of the order.

As related in a Feb. 22, 2022, letter to the commission, Moira Smith, vice president and general counsel for CINGSA, Goddard told the commission he was concerned about potential gas leakage from a well drilled by Unocal in 1964, KU 13-08, which, he said, was located somewhere on his property and needed to be re-entered, capped and sealed.

Smith said that in 2010 "CINGSA provided Inlet Fish with certain documents that demonstrated that KU 13-08 had been capped and properly plugged and abandoned in 1964, shortly after its completion; that the hole had been 'dry' at the time of completion, making it unlikely that the pocket into which it was completed would come in subsequent communication with natural gas; and that there was no evidence to support the assertion that the KU 13-08 wellbore would become an avenue for the communication of natural gas in the future."

At a hearing held in 2010 Goddard testified, Smith told the commission, that Inlet Fish's primary concern was for the health and safety of its plant operations and staff.

When the commission issued the storage injection order, rule 3 directed CINGSA to "install, operate and maintain a gas detection and alarm system in all buildings located within 50 feet of the surface location of well KU 13-08, unless prohibited from doing so by either the owner or lessee of the land upon which KU 13-08 is located."

CINGSA is requesting that the commission exercise its discretion to administratively waive compliance with rule 3.

Gas monitoring equipment

Smith said CINGSA installed gas monitoring equipment in the summer of 2012, as required in the order, and since then, "has worked diligently and in good faith to comply with the mandate in Rule 3 that it maintain gas detection equipment at Inlet Fish's plant."

The equipment has never alarmed due to gas detection, Smith said, but "has alarmed numerous times over the years — most frequently, when Inlet Fish employees disconnect power to the building which houses the equipment."

The equipment cannot operate without power, tripping an alarm when power is lost, requiring CINGSA to respond.

Smith said both CINGSA and AOGCC have directed Inlet Fish to maintain power to the gas detection equipment, but winterization procedures at the plant "apparently consist of shutting off power to the buildings, including the gas detection equipment, at the end of each fishing season."

Smith said while CINGSA responds immediately, it takes time for Inlet Fish to grant access to its facility. CINGSA employees responding to alarms at the plant "often report that Inlet Fish employees can be found inside the buildings, ignoring the alarming device and unaware of its purpose," indicating, Smith said, that the company and its employees do not have an ongoing concern for natural gas safety at the plant.

Most recently, in January of this year, CINGSA attempted to coordinate with Inlet Fish's local contact to make repairs to the equipment, and when access was gained, CINGSA found "the doors were knocked off the hinges, the walkways were not maintained, and that there was limited ingress and egress in the event of emergencies."

CINGSA has suggested an alternate method to ensure there is no gas seepage — surveying the area around the well twice a year, which, Smith said, is consistent with industry maintenance practices and is how CINGSA operates on its property.

The company contacted Inlet Fish with this proposal and discovered it "had been sold once again — this time, to E&E Foods."

"Based on its actions and communications with CINGSA, it appears Inlet Fish's concerns about its proximity to CINGSA's operations and the plugged and abandoned well on its property have been alleviated," Smith said.

The commission has tentatively scheduled a hearing for June 14. It said requests for the tentatively scheduled hearing to be held need to be received, in writing, by 4:30 p.m. May 25. ●

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● EXPLORERS' PREVIEW

Hilcorp plays it safe and takes risks

Company expands infrastructure at existing assets in Cook Inlet while pursuing future wildcats in Southcentral and Interior Alaska

By ERIC LIDJI
For Petroleum News

You can plot exploration plays along a spectrum, and the plays in Hilcorp Alaska LLC's portfolio exist at opposite ends of that spectrum, with very little in the middle.

At one end are infrastructure-led plays. These plays use existing production as an anchor for exploration activities. They are relatively cost-effective, low-risk and sustainable.

Over the past few years, Hilcorp has been undertaking these infrastructure-led projects around its onshore developments on the Kenai Peninsula, leading to new developments.

At the other end of the spectrum are wildcats in undeveloped basins. These are far from infrastructure and short on pre-existing information. They can be risky and uncertain. But if they succeed, they can open vast reserves for future exploration and development.

While Hilcorp has generally focused on maximizing existing production through well work and step out projects, it often keeps a few of those wildcat projects on the side.

(Editor's note: The company is not involved in exploration on the North Slope where it operates mature assets including Prudhoe Bay and several smaller fields.)

Cook Inlet

After years spent reviving fields at its many existing developments across the Cook Inlet basin, Hilcorp has increasingly been bringing its perspective to exploration opportunities.

The company has a system. First it drills several quick and shallow stratigraphic test wells, and then it uses the results to guide a small number of traditional exploration wells.

For example: Seaview.

Hilcorp acquired an aerial gravity and magnetics survey over the southern Kenai Peninsula prospect in 2015 and shot 20.54 miles of 2D seismic in 2016. In the summer of 2017, it drilled seven shallow stratigraphic test wells at the prospect. Using that data, the company completed the 10,148-foot Seaview No. 8 exploration well in late 2018.

The results justified development. Following a slight delay resulting from pipeline construction, Hilcorp brought the Seaview field into production in June 2021.

Shortly after completing its Seaview exploration campaign in late 2018, Hilcorp moved a bit to the north to pursue the Whiskey Gulch prospect on private land north of Anchor Point. (Oil patch veterans may remember the unrelated Whiskey Gulch unit formed on the North Slope by Brooks Range Petroleum Corp. in 2005 and terminated in late 2006.)

"The team is very excited about this one," Hilcorp Alaska Kenai team lead Jennifer Starck said in February 2021, at an Alliance Kenai digital luncheon. "The thing that's most exciting about this one is… it's all on roads, with a very known, feasible connect point for Enstar, which gets that gas right off to market quickly; that being said, you're still talking about two to three years between right of way, installation, and permitting."

The Alaska Oil and Gas Conservation Commission issued permits in late 2019 for Hilcorp to drill five stratigraphic test wells at the prospect: Whiskey Gulch 1-B, Whiskey Gulch 2, Whiskey Gulch 3, Whiskey Gulch 7 and Whiskey Gulch 10. In November 2019, Hilcorp drilled four of the five permitted wells — all but Whiskey Gulch 3. The shallow test wells were only about 600 feet deep.

The following year, the AOGCC issued seven additional permits for Whiskey Gulch stratigraphic test wells: Whiskey Gulch 4, Whiskey Gulch 5A, Whiskey Gulch 6, Whiskey Gulch 9A, Whiskey Gulch 11, Whiskey Gulch 12 and Whiskey Gulch 13. In July 2020, the company completed all seven, as well as the earlier Whiskey Gulch 3.

With two seasons of stratigraphic testing completed, Hilcorp transitioned to traditional exploration at Whiskey Gulch. The company proposed a two-well exploration program.

In planning documents, Hilcorp proposed building a 2.75-acre gravel pad on private surface lands at the end of Cape Ninilchik Avenue to support drilling. Construction would begin in mid-March, with drilling in June, with testing through early September.

The 10,000-foot Whiskey Gulch No. 1 well would target oil and gas to the southeast of the pad. The 8,491-foot Whiskey Gulch No. 14 well would target gas to the northeast.

Hilcorp spud Whiskey Gulch No. 1 in August 2021 but has yet to publicly announce results. The company received its final permits for Whiskey Gulch No. 14 in January 2022, but the well had not yet been drilled by April 2022, according to AOGCC records.

In permitting documents for Whiskey Gulch No. 14, Hilcorp said that analysis of Whiskey Gulch No. 1 and wells from surrounding fields "suggests that the Whiskey Gulch Undefined Gas Pool consists of a series of thin, discontinuous, stacked channel sands with a low

see **EXPLORERS PREVIEW** *page 6*

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EIA OUTLOOK

EIA said it expects Henry Hub to average $7.83 per million Btu in the second quarter and to average $8.59 in the second half of the year, reflecting an expectation that natural gas storage levels will remain lower than the five-year average this summer.

"Lower-than-average storage levels partly result from limited opportunities for natural gas-to-coal switching for power generation, which we forecast will keep the demand for natural gas for power generation high despite high prices," the agency said.

If summer temperatures are hotter than expected and electricity demand is greater, the price of natural gas could rise significantly above forecast levels.

EIA also expects U.S. liquefied natural gas exports will remain high during the summer.

It forecasts a drop in Henry Hub to $4.74 per million Btu in 2023, reflecting the agency's "expectation that the rate of natural gas production will increase next year while LNG export and demand growth slow, contributing to higher storage levels in 2023 than in 2022."

LNG

U.S. LNG exports averaged 11.6 billion cubic feet per day in April, slightly below the peak of almost 12 bcf per day set in March, and exports are forecast to average 12.1 bcf per day from May through August. EIA said this is slightly lower than its previous forecast and "reflects our assumption of slightly lower LNG demand in Asia and Europe this summer compared with our previous assumption, in part because of sustained high natural gas prices."

U.S. LNG exports are forecast to average 12 bcf per day this year, up 23% from 2021.

EIA said LNG export growth in recent years has been driven by capacity expansions, but the agency said it does not expect any new export facilities to come online in the forecast period and expects LNG export growth to slow to 5% in 2023, with exports averaging 12.6 bcf per day for the year. ●

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Congratulations

Congratulations ConocoPhillips!

Congratulations ConocoPhillips Alaska on the test results from your Coyote prospect well west of the Kuparuk field.

As reported in the May 8 issue of Petroleum News, the well results were very successful and exceeded your expectations.

Erec Isaacson

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EXPLORERS PREVIEW

net-to-gross ratio," requiring tighter spacing that other fields.

Given the complexity of land ownership in the southern Kenai Peninsula, Hilcorp would almost certainly need to apply for a participating area to develop Whiskey Gulch.

Following the Whiskey Gulch program, Hilcorp turned to Happy Creek.

In September 2021, the company received seven AOGCC permits for stratigraphic test wells, south of its Ninilchik unit: Happy Creek No. 1, Happy Creek No. 4, Happy Creek No. 5, Happy Creek No. 6, Happy Creek No. 8, Happy Creek No. 9 and Happy Creek No. 10. The company had not dilled any wells by April 2022, according to the AOGCC.

Yukon Flats

Yukon Flats is one of Alaska's perpetual "maybes."

Doyon Ltd. owns about 1.6 million acres of subsurface lands in the Yukon Flats area north of Fairbanks. The Alaska Native corporation for the Interior region spent years negotiating a land swap in the region with the U.S. Fish and Wildlife Service, which oversees the 10-million-acre Yukon Flats National Wildlife Refuge. When those negotiations failed, Doyon revisited the acreage and came to reconsider its potential.

In December 2019, Doyon and Hilcorp signed an agreement, creating a multi-year framework for the company to conduct exploration activities on the Yukon Flat acreage.

The program called for an airborne gravity survey in 2020 and 2021 to gather information to support a future seismic survey in the area around Birch Creek in 2022 and 2023.

With favorable results, the joint venture would conduct exploration drilling.

Even with the restrictions and uncertainly of the pandemic, Hilcorp was able to conduct the airborne gravity survey in the summer of 2020 and acquire the data it wanted.

In mid-June 2021, the AOGCC issued permits for Hilcorp to drill 15 stratigraphic test wells in the basin: Birch Creek No. 1, No. SE1, No. 3, No. 4, No. 5 and No. 6, Canvasback No. 1 through No. 6, and Saloon Island No. 1XX, No. 2. Between June 23 and July 23, the company completed all but Saloon Island No. 1XX and No. 3XX.

The Birch Creek wells were clustered at 16N/10-11E and 17N/7-8E. The Canvasback wells were at 18N/7-8E. The Saloon Island wells were at 18N/12-13E and 19N/12E.

According to Doyon, all 15 wells were drilled last summer to about 250 feet.

Texaco conducted a 2D seismic survey in the Yukon Flats region in the 1970s. Louisiana Land and Exploration conducted exploration in the adjacent Kandik area in the 1970s.

Exxon was pursuing an exploration program in the Yukon Flats region in the late 1980s in partnership with Amoco, but the Exxon Valdez oil spill in March 1989 prompted the company to withdraw from all wildcat exploration in the state, including Yukon Flats.

Exxon had been targeting source rocks near the Birch Creek, Beaver and Fort Yukon blocks in the central part of the Yukon Flats basin. "Exxon negotiated on a concurrent basis (1) an exploration lease option agreement with Doyon for oil and gas rights, (2) separate surface use agreements with the three villages, and (3) a surface use agreement with Doyon for its surface acreage which ended up mirroring the village agreements on commercial terms," Doyon Ltd. CEO Aaron Schutt told the Resource Development Council in September 2020. In the winter of 1988-89, "Exxon gathered approximately 280 miles of 2D helicopter supported Poulter type seismic along several widely spaced lines. Between 20-30 percent of the data was gathered on federal refuge lands."

Doyon returned to the region between 2008 and 2012, conducting a 2D seismic program near Stevens Village at the far western edge of the Yukon Flats basin. A 3D seismic survey, conducted in the winter of 2012 and 2013, was the last exploration in the area.

The land swap negotiations delayed progress for five years. In the meantime, a new USGS gravity survey indicated the presence of a series of sub-basins starting around 8,000 feet. Some of these sub-basins were close to the trans-Alaska oil pipeline.

Petrotechnical Resources of Alaska later estimated the possible existence of 300 million to 1 billion barrels of oil and perhaps 1 trillion cubic feet of natural gas in the basin — essentially an Alpine-sized field located much closer to people and to infrastructure.

Iniskin and Blackbill

Among the lower priority projects in the Hilcorp portfolio are the Iniskin Peninsula and a project in the federal waters of the lower Cook Inlet outer continental shelf.

The peninsula sits across Cook Inlet from Kachemak Bay, and it is one of those classic Alaska prospects: known to contain oil but hampered by logistical challenges.

Hilcorp revisited the prospect in the 2010s, believing that modern technology could address the low rate of oil flow that hampered exploration in the 1900s, 1930 and 1950s.

The company conducted a 2D seismic survey over the area in 2013. The survey provided the first information about subsurface structure and stratigraphy. The results suggested that previous exploration might have overlooked a deeper crest of an anticline in the area.

The next step would be an exploration well, which the company has yet to announce, although it acquired two tracts in the area in a 2020 lease sale. The physical remoteness of the area would make it challenging to bring both equipment and personnel to the site.

"We don't like the reservoir, nobody does," Hilcorp Senior Geologist Dave Buthman told Petroleum News, "but what we like is you've got about 9,000 feet of source rock there, right along the Bruin Bay fault in a similar structural position to the largest oil field in the basin which is McArthur River, which made about 650 million barrels of oil so far."

Hilcorp acquired 14 leases in the outer continental shelf of Cook Inlet in a federal lease sale in June 2017. The company conducted a 3D seismic survey over the leases in 2019 and a geohazard survey in 2021. The program initially included plans for two-to-four exploration wells between 2020 and 2022. The company had not yet drilled those wells by early 2022, perhaps in part due to the economic disruptions of the past few years.

In discussing the project, Hilcorp expressed an interest in bringing the Seadrill West Epsilon jack-up rig to Cook Inlet. The rig is capable of drilling deeper wells than either the Spartan 151 or Randolph Yost jack-up rigs, which are currently in the region.

The proposed Blackbill program would target an oil reservoir encountered by ARCO's Raven No. 1 well in 1982. The location is due west of Homer, halfway across Cook Inlet. ●

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LAND & LEASING

Accumulate gets lease rental reductions

Alaska's Division of O&G grants rent reductions on North Slope due to work, including drilling wells, seismic, done by independent

By KAY CASHMAN
Petroleum News

On Jan. 16, Alaska's Division of Oil and Gas accepted two applications for lease rental reductions from Houston, Texas-based Accumulate Energy Alaska, essentially a subsidiary of 88 Energy Ltd. The applications were filed by Accumulate on behalf of the working interest owners, or WIOs, for the leases, which include Accumulate and Burgundy Xploration.

When an application for multiple leases is filed, the leases must all have the same effective date, primary term and rental rate structure, which is the reason two separate applications were filed.

Sustained production has not begun on any of the leases.

On May 6, the division approved the rental reductions requested in both applications

In its May 6 approval, the division said the WIOs exercised reasonable diligence to explore and develop the leases during the primary term, justifying reducing rent from $250 per acre to $10 per acre or fraction of an acre for years eight, nine and 10.

Leases south of Talitha

One of the applications was for 12 state leases south of the Great Bear Pantheon-operated Talitha unit in an area where Accumulate has drilled two Icewine project wells (see map in the pdf and print versions of this story).

All the leases have a July 1, 2015, effective date with a 10-year primary term.

The 12 leases, which consist of 17,115.00 non-contiguous acres, are approximately 27 miles southwest of Prudhoe Bay, along the Dalton Highway. The leases are as follows ADL 392756, 392759, 392770, 392771, 392773, 392779, 392780, 392781, 392782, 392783, 392784 and 392785.

In years 1-7, the lease rental charge was $10 per acre.

Accumulate asked the division for a reduction in years 8 to 10, dropping the price to $10 per acre from the $250 per acre that was the amount that would otherwise have been charged.

The division can reduce the rental amount if the WIOs can show they have exercised reasonable diligence to explore and develop the leases during the primary term.

Accumulate listed the following activities as part of the due diligence:

• Toolik/Kuparuk 2D seismic was acquired in 2016, reprocessed, and new interpretation performed on lands that encompass the leases and adjacent acreage during the primary term, noting the work completed on the leases has added to the WIOs understanding of prospective reservoir targets on the leases.

• Because of the completed work, the WIOs drilled two wells on acreage directly adjacent to the leases. The Icewine 1 well (PTD 215167) was completed on Jan. 1, 2016. The Icewine 2 well (PTD 217033) was completed on June 18, 2017, with a flow test performed during the primary term on acreage adjacent to the leases.

•This well work continues to inform new phases of development for the leases.

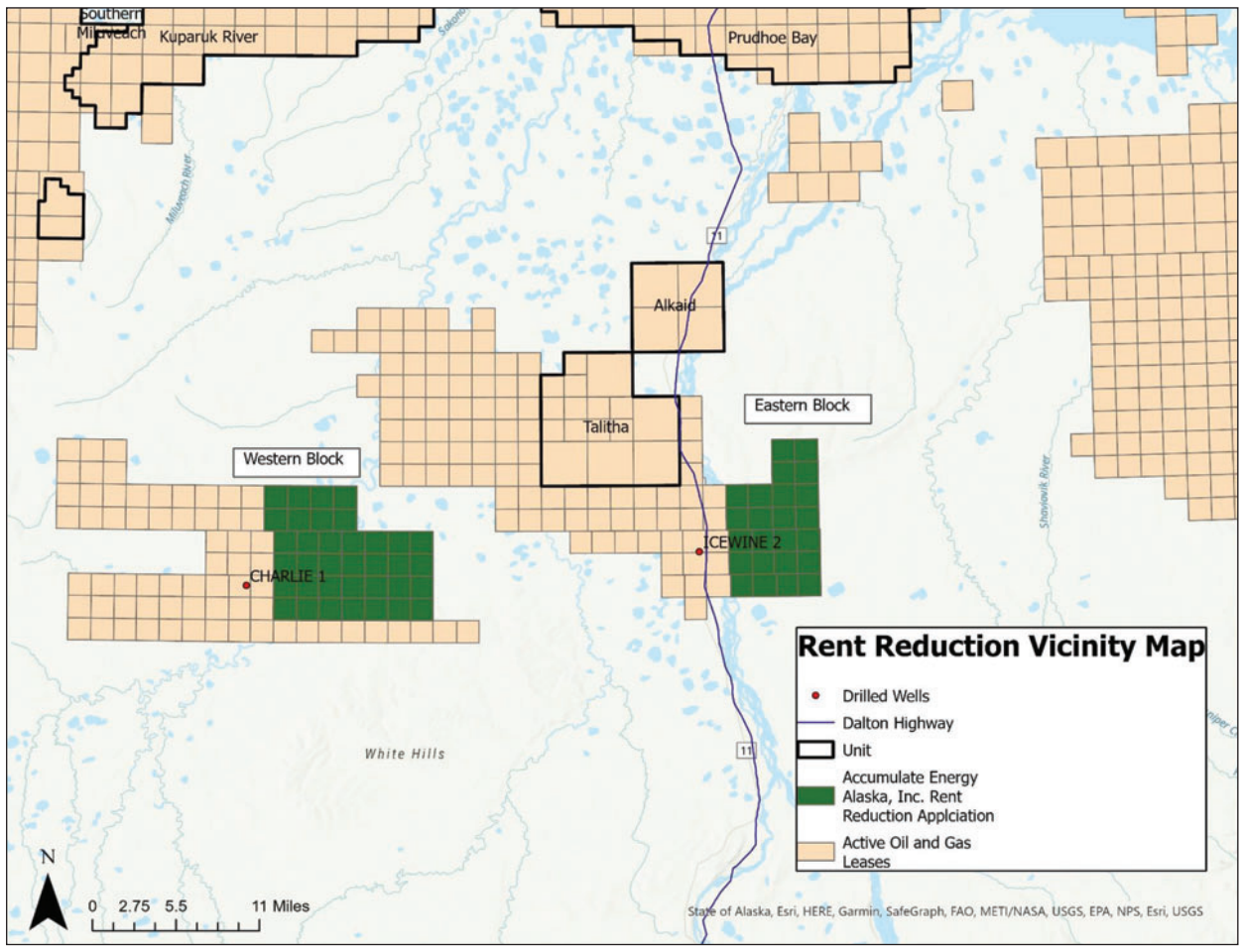
In its May 6 approval, the division said the WIOs exercised reasonable diligence to explore and develop the leases during the primary term, justifying reducing rent from $250 per acre to $10 per acre or fraction of an acre for years eight, nine and 10.

60 leases in 2 blocks

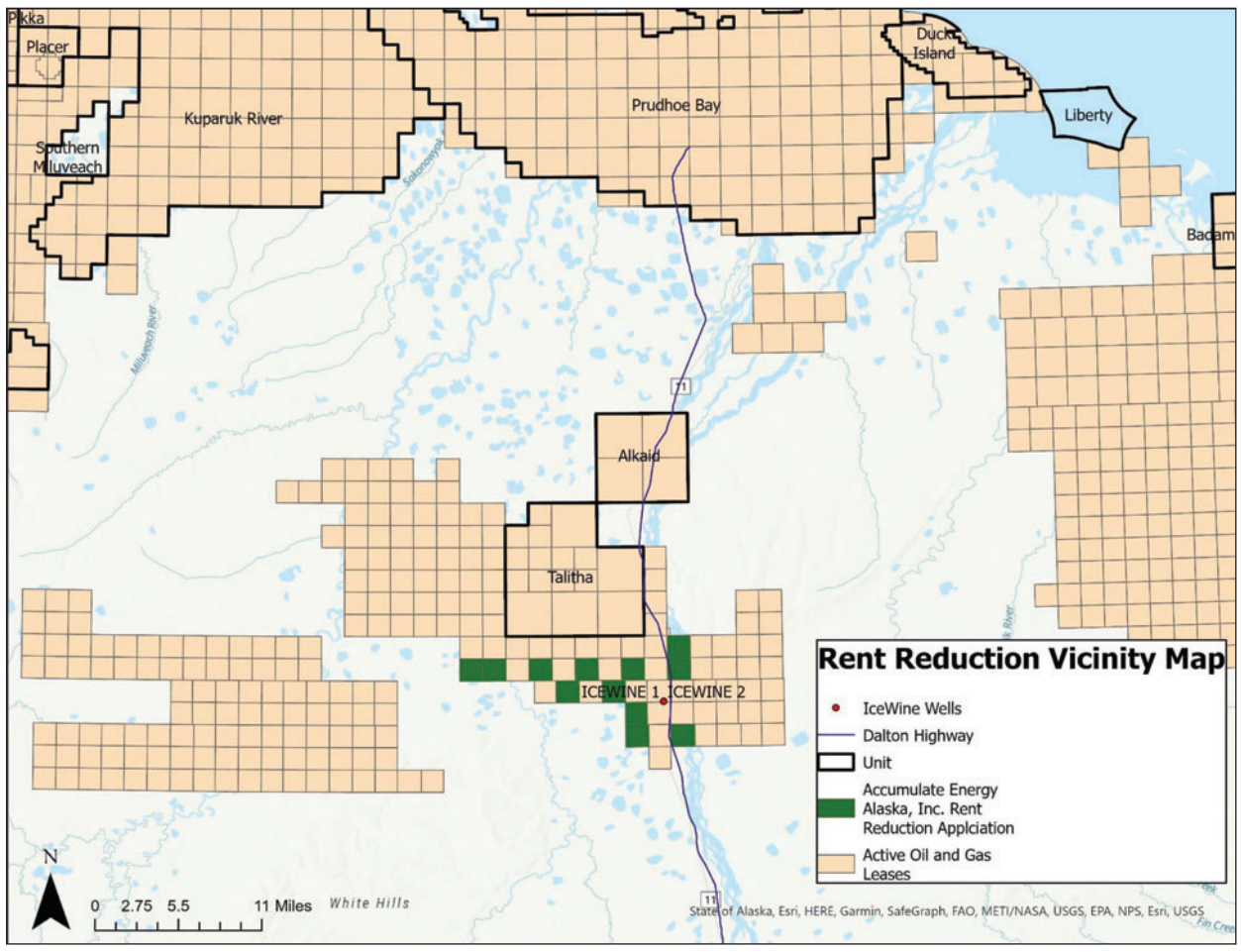
The 60 leases in the other application consist of two separate blocks encompassing approximately 85,442 acres (see map in the pdf and print versions of this story).

The Eastern Block consists of 24 leases comprising 34,262 contiguous acres approximately 24 miles southwest of and east of the Dalton Highway. It contains the company's Icewine 2 well.

The Western Block consists of 51,180 contiguous acres approximately 37 miles southwest of Prudhoe Bay, and approximately 18 miles west of the Dalton Highway. It contains the company's Charlie 1 well.



ACCUMULATE ENERGY ALASKA



The Western Block consists of 51,180 contiguous acres approximately 37 miles southwest of Prudhoe Bay, and approximately 18 miles west of the Dalton Highway. It contains the company's Charlie 1 well.

All 60 leases have a June 1, 2015, effective date with an eight-year primary term.

In years one-six, the lease rental charged was $10 per acre. Accumulate asked the division to reduce the rental rate to $10 from $100 per acre in year seven and $250 in year eight.

The work performed for the two blocks is listed as follows:

• The Toolik/Kuparuk 2D seismic was acquired in 2016, reprocessed, and new interpretation performed on lands that encompass the leases and adjacent acreage during the primary term.

• The Icewine 3D seismic survey was acquired in 2018, with processing and interpretation completed in 2018 on lands that encompass the leases and adjacent acreage during the primary term.

• The work completed on the leases has added to the WIOs understanding of prospective reservoir targets on the leases.

• Because of the completed work, the WIOs drilled two wells on acreage adjacent to the leases — Icewine 2 well completed on June 18, 2017, with a flow test performed during the primary term on acreage adjacent to the Eastern Block.

• The Charlie 1 well (PTD 22001) was completed on April 15, 2020, on acreage adjacent to the Western Block during the primary term of the leases.

• Well work continues to inform new phases of development for the leases.

In its May 6 approval, the division said the WIOs exercised reasonable diligence to explore and develop the leases during the primary term, justifying reducing rent from $100 to $10 for year seven and from $250 to $10 in year eight. ●

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CONOCO EARNINGS

of $253 million in the state and is on track to invest approximately $1 billion in Alaska for the entire year, which is about the same as its capital spend in 2021.

Houston-based parent ConocoPhillips said May 5 it expects to increase its company-wide capital spend from $7.2 billion to $7.8 billion. About half of the increase will be spent on "extra activity" its Lower 48 operations, with the balance going toward inflationary costs.

ConocoPhillips Chairman and CEO Ryan Lance spoke of the company's ambition to be "Paris aligned and net zero by 2050 with respect to the emissions produced as a company," noting that Alaska projects such as Willow fit that goal.

In reference to 2022 capital spending in Alaska, Erec Isaacson, president of ConocoPhillips Alaska, said "this investment in Alaska will bring new projects online and add new barrels of oil to the trans-Alaska pipeline"

The state of Alaska's "existing fiscal regime continues to generate revenue for Alaska and promotes a stable environment for ongoing investment," Isaacson added.

Since 2007, ConocoPhillips Alaska has incurred over $40 billion in taxes and royalties to the state of Alaska and the federal government. Of that amount, about $31 billion went directly to the state.

In that same period, ConocoPhillips Alaska's earnings were approximately $23 billion.

Not a 'cliff transition'

In the Houston-based parent's May 5 company-wide presentation, Lance spoke of the energy transition, saying he doesn't think it's going to be "a cliff transition. It's going to be a drawn out one and the pace of that — the slope of that curve — is pretty unknown. So the way you react to that is have the lowest cost of supply barrels that you can supply whatever that transition demand is going to look like and make sure that they're giving an adequate and competitive return. And I think we're well set up to go do that."

Lance said ConocoPhillips monitors four or five different "scenarios internally to the company, most of those suggest that there's going to be a need for oil and gas long past 2050."

But ConocoPhillips has to "supply that sustainably. We have to supply that with a low GHG intensity going to net zero by 2050," he said, "but we also have to supply low cost of barrels."

So, oil and gas is "going to be around a long time," with "medium- and longer-cycle projects," Lance said, "going to be needed in this industry. We just have to assure ourselves that they're competitive on a cost of supply basis and then they have a competitive GHG intensity as well."

"Projects like Willow and Alaska fit that mode. They're well under a $40 cost of supply. They are less than $10 a kilogram per barrel of CO2 intensity. So they fit well within what the world is going to need in order to ratably and reliably supply energy to a growing world where energy demand is going to be increasing over time," Lance said.

"We have to figure out how to do that more sustainably," he said.

Technology has been at the heart of ConocoPhillips Alaska's greening of its oil fields on the North Slope.

"The implementation of technology, such as coiled tubing and extended reach drilling, allows for development to avoid or minimize impacts to the environment. We are always seeking new and better ways to responsibly deliver Alaska's energy potential," Isaacson wrote in a recent editorial.

—KAY CASHMAN

Editor's note: ConocoPhillips has six operating segments, which are primarily defined by geographic region: Alaska; Lower 48; Canada; Europe, Middle East and North Africa; Asia Pacific; and Other International. Approximately 30% of its portfolio is natural gas.

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EXPLORATION & PRODUCTION

Lower Foothills closed to tundra travel

The Lower Foothills tundra opening area was closed to offroad tundra travel May 6.

The Alaska Department of Natural Resources' Division of Mining, Land and Water said the Lower Foothills tundra opening area "is no longer suitable for offroad travel. Snowpack deterioration is widespread, evident by large swaths of visible vegetation."

While snow cover appears capable of supporting offroad travel in some areas, it is "highly variable across the region" and with warm air temperatures and sunny skies, the snowpack will continue to deteriorate, the division said.

The Upper Foothills tundra opening was closed to offroad travel April 20.

The division said the Eastern Coastal and Western Coastal areas remain open to offroad tundra travel.

Because snow may be adequate for travel in some areas, the division said DNR "may consider granting travel extensions on a case-by-case basis," with any exceptions requiring prior approval by an authorized representative.

Summer offroad travel may begin at 6 a.m., July 15, "unless otherwise notified," the division said, and applies only to holders of valid permits who obtain specific project approval and is further limited to vehicles approved by the division for summer offroad travel.

Specific area information and an area map are available online: http://dnr.alaska.gov/mlw/tundratravel/.

—KRISTEN NELSON

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DIVERSION PLAN

MIKE DUNLEAVY

TONY IZZO

120-megawatt facility, generates 10% of the annual electric energy used by Railbelt electric utilities, providing some of the lowest-cost power in the state.

"Similar to Battle Creek, the Dixon Diversion would divert water from the East Fork of the Martin River into the Bradley Lake reservoir," AEA said May 4, and could increase power output at Bradley Lake by almost 50%.

AEA said the project timeline includes 5 years of studies and permitting, followed by 5 years of construction. Estimated cost of construction is between $400 million and $600 million, with no source of construction funding yet determined.

Renewal investment

"I am planning for the near-term rapid growth of renewables on the Railbelt," said Gov. Mike Dunleavy in the May 4 release. "The Dixon Diversion has the potential to be the largest renewable investment within the Railbelt since the Bradley Lake Hydroelectric Project was built 30 years ago. Natural gas prices have only risen while the cost of renewable energy has plummeted, and Alaska needs to consider where it will be 20 years from now. The Dixon Diversion is a big step towards energy independence," the governor said.

"We and our Railbelt utility partners are also planning to upgrade transmission and energy storage capacity and to improve reliability and resiliency," said AEA Executive Director Curtis Thayer. "These improvements will facilitate and increase the benefit from new renewable generation on the Railbelt, such as the Dixon Diversion."

Tony Izzo, CEO of Matanuska Electric Association and chair of the Bradley Lake Project Management Committee, acknowledged the governor's "vision and leadership on this important topic."

"The Bradley Lake Project Management Committee works to ensure the reliable operation of the biggest renewable asset in Alaska," Izzo said. "Alaskan leaders and visionaries of the 1950s and 60s recognized the power generation potential of this glacier fed lake. Because of their vision and expertise, ratepayers benefit from the low-cost power of Bradley Lake hydro today. With the Governor's support, we are working to diversity our energy mix, including clean, renewable energy for future Alaskans."

The Railbelt utilities include Chugach Electric Association, Golden Valley Electric Association, Homer Electric Association, Matanuska Electric Association and the City of Seward.

Initial consultation document

The FERC filing is an initial consultation document for a license amendment.

"The purpose of the amendment is to gain authorization to divert water from the Dixon Glacier to generate additional power," AEA said in its April 27 FERC filing.

AEA said it is investigating the feasibility of developing the outflow from the Dixon Glacier of the East Fork of the Martin River for additional water supply to increase power generation, and will "seek FERC authorization for the construction, operation, and maintenance of a new diversion system at the toe of Dixon Glacier that would divert flows from the East Fork of the Martin River," increasing hydropower at Bradley Lake and/or developing a new Martin River powerhouse.

There are alternatives in the filing, but, AEA said, "under any alternative the proposed action would include potential modification of Bradley Lake Dam and construction of a new diversion that would result in a significant change in the normal maximum surface area or elevation of Bradley Lake."

A joint agency and public meeting for the Dixon Diversion Project will be held June 14 from 5-7 p.m. at the Aspen Suites Hotel in Homer followed by an agency site visit on June 15.

AEA said it held an informal outreach meeting Feb. 8 with representatives invited from the Alaska Department of Fish and Game, Alaska Department of Natural Resources, the Kenai National Wildlife Refuge, National Marine Fisheries Service and the U.S. Forest Service.

—KRISTEN NELSON

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BELUGA RIVER

commission said some two-thirds of the 8,227.1 acres covered in the order are onshore with the remainder offshore along the western side of the Cook Inlet basin.

Owners of the Beluga River unit and the area covered by the order are Hilcorp and Chugach Electric Association, while landowners are the Alaska Department of Natural Resources, the U.S. Bureau of Land Management, Cook Inlet Region Inc., Chugach Electric and S&E Foster Properties LLC.

The commission said ownership at the unit changes with depth. From the surface down to 7,000 feet, Hilcorp owns one-third working interest and Chugach Electric two-thirds working interest, while below 7,000 feet, Chugach owns 100 percent working interest.

"The proposed pool only includes lands above the 7,000-foot depth," the commission said.

Beluga discovery

The commission said the Sterling-Beluga gas pool "was unexpectedly discovered by Standard Oil Company of California's" Beluga River 1 exploratory well (renamed BRU 212-35), drilled to 16,429 feet measured and true vertical depth. That company was searching for oil in a deeper objective near the center of the present-day unit, and that well "provided the first indication that large quantities of gas had accumulated in the area," the commission said. On April 28, 1962, while circulating at 3,249 feet MD after drilling a portion of the upper Sterling, "the well blew out, spewing mud, sand, rocks, water, and methane gas at an estimated rate of about 50 million cubic feet per day for more than nine hours."

In December of 1962, after the company had drilled, completed and tested the well, "Standard Oil announced a 'significant gas discovery' in the BRU and reported that BR 1 tested 4.3 million cubic feet per day from about 4,800 feet MD." In December 1962 the well was completed and shut in.

Four additional wells were drilled between 1962 and 1964 to delineate the field, and between December 1963 and May 1964, one of the four, BRU 212-25, "flowed a reported cumulative total of nearly 150.5 million cubic feet of gas from upper Sterling perforations between 3,437 and 4,111 feet MD," the commission said.

Regular gas production began at Beluga River in 1968 and for February 2022, "production totaled slightly more than 950 million cubic feet of gas from 15 wells, an average daily rate of about 34.1 million cubic feet," with cumulative production from the field through February 1.39 trillion cubic feet, the commission said.

In addition to the 15 producing wells, two disposal wells are active, one Class I and one Class II.

Sterling-Beluga gas pool

The Sterling-Beluga gas pool as defined in the order is the accumulation correlating with the interval in BRU 224-13 from 3,345 feet MD to 7,000 feet MD.

The commission said this is some 3,650 "true vertical feet of Tertiary-aged sediments deposited by braided and meandering rivers and streams that are assigned to the Sterling and Beluga Formarions (in descending stratigraphic order)."

The Sterling reservoir sands are up to 200 feet thick, with broad lateral continuity and typically with excellent reservoir quality, 20% to 30% porosity, 100 to 2,000 millidarcy permeability and little cementation.

The underlying Beluga sands are generally much thinner, 3 feet to 50 feet thick, "laterally discontinuous, isolated, lens-shaped bodies deposited by smaller reivers and streams," with generally lower reservoir quality — 10% to 20% porosity, 1 to 200 millidarcy permeability and often moderate cementation.

"To date," the commission said, "much of the production from the field has come from Sterling sands. The generally thinner, less continuous, and more isolated overall nature of the remaining untapped Sterling and Beluga reservoirs is the basis for Hilcorp's request for unrestricted well spacing in those portions of the proposed SBGP that lie more than 1,500 feet from the exterior boundary of the Affected Area" — the area covered by the order.

There are more than 100 individual sands within the proposed Sterling-Beluga gas pool "with various drive mechanisms and gas and water contacts (or lowest known gas when a water contact has not been detected)," the commission said.

Development plans

The commission said Hilcorp is proposing to drill four additional wells. The company drilled three wells at Beluga in 2020, requiring spacing exceptions because of the lack of pool rules.

Hilcorp ran repeat formation testers on two of the three 2020 wells, the commission said, and found sand bodies at original reservoir pressure within 1,000 feet of active wells, demonstrating "that there is still significant potential for finding untapped gas accumulations which cannot be produced from existing wells due to the discontinuous nature of the sands."

The commission said that in addition to the new wells, Hilcorp plans to workover existing wells to extend the life of the field and increase ultimate recovery. :As is typical for gas field developments in the Cook Inlet Basin, Hilcorp plans to develop from the bottom up in the wells, opening and isolating sands as necessary to achieve economically viable production," with may involving having multiple sand bodies open at the same time to achieve adequate production rates.

"The proposed pool is nearly 4,000 feet thick and a pore pressure fracture gradient chart provided by Hilcorp indicates that the potential exists for pressure from deeper sands to cause fractures to form in shallower sands if too thick of an interval is open for production at the same time in the same well."

In its conclusions the commission said that because of the risk of fracture, limitations are necessary on the thickness of intervals that can be open for production at the same time "to ensure that shallower zones are not fractured by production from deeper formations should the well be shut in and crossflow occur."

Pool rules appropriate

The commission said pool rules are appropriate, noting that Beluga River "is a very mature field that has been successfully developed in accordance with statewide relations, other than a plethora of spacing exceptions, for nearly 40 years. As such, the proposed SBGP will benefit from pool rules in order to ensure continued successful development."

Well spacing not restricted by internal property boundaries or minimum distances between wells "will increase flexibility in placing wells, facilitate more efficient resource recovery" and will not promote waste, jeopardize correlative rights nor be an increased risk to freshwater aquifers.

The commission said there are some 45 shallow water wells within and near the Beluga River unit, with reported depths from 20 to 295 feet. Since surfacing casing is set and cemented at Beluga River unit wells at depths from 1,982 to 3,386 feet, shallow drinking water wells and shallow aquifers are protected.

—KRISTEN NELSON

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GAS RELEASE

AOGCC and an incident management team activated.

ConocoPhillips clarified the timeline in response to questions from members of Congress.

"It took four days from when the natural gas release was first observed to identify the C10-Halo subsurface interval at the WD-03 waste disposal well as a potential source and to capture the flow and route it to facilities," the company said.

"By March 8, ConocoPhillips had secured the location, determined the most probable gas source, and established a controlled flow path for the gas up the outer annulus of the WD-03 well into the Alpine Central Facility," the company said in its May 10 letter.

The company told the commission April 1 that an estimated 7.2 million cubic feet of natural gas was not captured and said it believes most of that gas escaped to the atmosphere between March 4 and March 8. On March 8 "gas flow was routed through the WD-03 outer annulus" into the Alpine Central Facility.

In its May 3 final report to AOGCC ConocoPhillips said an estimated 24 million cubic feet was recovered, based on metering data from the flow directed to the ACF from the WD-03 outer annulus from March 8 through March 29, when source control was achieved and WD-03 stopped producing gas after circulation of kill weight fluid.

Causal factors

ConocoPhillips identified two causal factors.

In its letter to Congress, the company said its incident investigation report to AOGCC identified two causal factors, "neither of which relate to well design. The investigation team determined that (1) the cause of the natural gas release was a surface casing shoe in WD-03 that broke down when pressure limits were exceeded during freeze protect operations and that (2) subsequent pressure increases in the WD-03 outer annulus were not recognized or address, which could have led to more immediate investigation or remedial action."

"Pressure limits were exceeded while performing Annular Leak-Off Test, LOT, and Freeze Protect operations on the 13 3/8" x 7 5/8" annulus," the company told the commission.

A maximum test pressure of 14.9 ppg, pounds per gallon, is specified for the LOT and freeze protect operation, but "actual WD-03 Annular LOT results were 17.2 ppg."

That excessive pressure during the annular LOT and freeze protect operations on Feb. 27 "most likely broke down the casing shoe and provided an initial pathway for gas migration around the outside of the WD-03 surface casing," the company said, and the subsequent injection of some 300 barrels of water to displace the mud in the outer annulus as part of the freeze protection "likely expanded the pathway."

The second causal factor, ConocoPhillips told the commission, was that the pressure increases during post-annular Lot and freeze protect operations were not recognized. "The pressure increases in WD-03's OA from March 1 to March 3 were not recognized and/or addressed and, accordingly, did not lead to investigation or remedial action during that period. The volume of gas released from the C10/Halo in WD-03 could have been reduced if actions to address the elevated OA pressures had been taken earlier."

ConocoPhillips told the commission there was also a potential missed indicator. "A well in proximity to WD-03's well path potentially had indications of gas from shallower zones than the Qannik. Further review into the source of this gas may have informed WD-03 well planning."

CD1-48 was identified on the pre-drill anti-collision review "as a well proximity risk to the planned WD-03 well path." While the Qannik interval was cemented off in CD1-48, "efforts to bleed off pressure within the CD1-48 OA were unsuccessful, indicating a potential source of gas shallower than the Qannik formation. Further review of the source of this gas might have informed WD-03 well planning," the company said.

Cementing wells

In its letter of the members of Congress, ConocoPhillips said the WD-03 was "constructed in accordance with regulatory requirements, including cementing and casing regulations."

It is standard industry practice in Alaska — consistent with regulations — "not to fully cement wells. Keeping the outer annulus of the intermediate section of a well uncemented allows for freeze protection and well diagnostics to be carried out during the life of the well, which enhances well integrity."

Wells crossing intervals deemed significant hydrocarbon zones or "abnormally geo-pressured strata" require cement isolation, the company said, but the C10-Halo interval was determined not to be a significant hydrocarbon zone and not abnormally geo-pressured in the area of the WD-03.

Conditions

In its final report to the commission, ConocoPhillips said: "Based on historical evaluation methods used to successfully drill 49 other CD1 wells, the C10/Halo at the WD-03 well path was determined not to be a 'significant hydrocarbon zone' or 'abnormally geo-pressured strata' during pre-drill planning and/or during drilling operations," so no cement isolation was deemed necessary.

"While cement bond/USIT logs are not typically run to evaluate surface casing cement in production and injection wells, the USIT log run in WD-03 provided some relevant data related to identifying a potential gas migration pathway," the company told AOGCC.

Another condition cited by the company relates to freeze protection.

"Displacing water with diesel in WD-03's OA for freeze protection purposes reduced the hydrostatic pressure in the OA, causing it to become hydrostatically underbalanced relative to the C10/Halo pore pressure," ConocoPhillips said.

While the diesel was necessary for freeze protection, the displacement allowed "gas to flow out of the C10/Halo and into the WD-03 OA."

There is a permafrost thaw bulb under the CD1 pad, the company said, "that provides little to no resistance, both vertically and horizontally, for any gas that escaped from the WD-03 wellbore due to the compromised surface casing shoe and that also reached the base of the permafrost. The condition manifested as surface releases hundreds of feet from WD-03 along the well row and across the CD1 pad." ●

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NEW DIRECTOR

BLM said in a May 6 release that Cohn is returning to BLM from The Nature Conservancy where he has been Alaska state director since 2018.

Cohn began his federal service career with BLM as a presidential management fellow, and before he left in 2018 he was BLM Alaska deputy state director for resources. Other assignments during his tenure with BLM include acting Utah associate state director, division chief for the National Landscape Conservation System and acting branch chief, Planning and NEPA. He has also served at BLM's Hassayampa field office in Phoenix, Arizona, and as assistant field manager in Prineville, Oregon, and Tucson, Arizona.

Cohn holds a bachelor's degree in government from Harvard University and advanced degrees from the University of California at Berkeley College of Natural Resources. He lives with his family in Anchorage and enjoys fishing, hiking and paddling rivers in remote sections of the state. He replaces Tom Heinlein, who served as acting director and will return to his permanent role as BLM Anchorage district manager.

The agency said that as BLM Alaska state director Cohn will be responsible for overseeing management of 70 million surface acres and 220 million acres of federal subsurface mineral estate. He will oversee 650 permanent staff and some 200 seasonal employees who help manage public land uses and resources including the Federal Subsistence Management Program, the Alaska Land Transfer Program, the National Petroleum Reserve-Alaska and oversight of the Trans-Alaska Pipeline System.

Cohn will rejoin BLM by the end of May.

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SALE UPROAR

administration, as part of its strategy to pause federal oil and gas leasing, cancelled the public comment process for the lease sale's Environmental Impact Statement, or EIS.

Subsequently, in response to the June 2021 injunction by the Louisiana District court, BOEM announced that it would continue with preparations for a Cook Inlet lease sale. On Dec. 13 the agency closed the public comment period for a draft EIS for the lease sale. BOEM has not yet announced a timeframe for conducting the sale.

Nor has the agency announced its next five-year lease sale program.

The current five-year leasing program will lapse at the end of June. Interior cannot hold any new oil and gas lease sales until it has completed a replacement plan. But though the federal government is legally obligated to prepare one, the administration has not released its proposal — nor have officials said when it might be coming.

Lack of industry interest

Interior also doesn't have enough time left to hold the three remaining offshore oil and gas lease sales scheduled under the current plan.

In a statement shared first with CBS News, the Department of the Interior cited a "lack of industry interest in leasing in the area" for the decision to "not move forward" with the Cook Inlet lease sale.

Steve Milloy, a former Trump-Pence EPA transition member and founder of JunkScience.com, told FOX Business on May 11: "I blame Biden for all lack of production. He has scared away investment."

In Alaska, Milloy said, "the greens scared off virtually everyone. It's expensive to explore and drill, and the greens made it pretty clear, they were going to make it even more difficult."

Frank Macchiarola, senior vice president of policy, economics and regulatory affairs at the American Petroleum Institute, told FOX Business in a statement: "Unfortunately, this is becoming a pattern. The administration talks about the need for more supply and acts to restrict it. As geopolitical volatility and global energy prices continue to rise, we again urge the administration to end the uncertainty and immediately act on a new five-year program for federal offshore leasing."

Court action

On May 10 a federal attorney argued in front of a 5th U.S. Circuit Court of Appeals panel that Biden legally called for suspending oil and gas lease sales while considering their effect on climate change.

The current offshore lease sale plan states specifically that the U.S. Secretary of the Interior "may reduce or cancel lease offerings on account of climate change," Department of Justice attorney Andrew B. Bernie told the panel.

Land-based sales "were not postponed by the executive order. They were postponed because of a need to comply with NEPA" — the National Environmental Policy Act, he said.

Arguing for 13 states that challenged Biden's January 2021 order, Louisiana Deputy Solicitor General Joseph Scott St. John said laws passed in response to the 1970s oil crisis require lease sales.

The Biden administration failed to "grapple with prior analyses" of the planned sales to give a valid reason for postponing or canceling them, he said.

Judges James L. Dennis, Patrick E. Higginbotham and James E. Graves Jr. did not indicate when they will rule.

Louisiana is joined in the lawsuit by Alabama, Alaska, Arkansas, Georgia, Mississippi, Missouri, Montana, Nebraska, Oklahoma, Texas, Utah and West Virginia.

The state challenge to Biden's order has not yet gone to trial but a federal judge blocked the order in a preliminary injunction, writing that since the laws did not state the president could suspend oil lease sales, only Congress could do so.

Bernie said, "It is routine for individual lease sales or proposed lease sales not to be held for various reasons." The federal brief said nine five-year leasing plans have been approved and all had fewer sales than originally scheduled.

"We don't know why prior lease sales were withdrawn," St. John responded. "Presumably there was some kind of rationale. That was not the case here."

U.S. District Judge Terry Doughty found that states which challenged the order were likely to prove the Interior Department violated the Administrative Policy Act by acting without "any rational explanation."

Some sales in June

After Doughty ruled for the states, the Interior Department held an offshore lease sale, which a federal judge in Washington canceled. Four onshore lease sales are scheduled in June — in Nevada on June 14; New Mexico, Oklahoma and Colorado on June 16; Wyoming on June 22 and Utah, Montana and North Dakota on June 28.

However, the administration scaled back the amount of land originally on offer and raised royalty rates 50% from 12.5% to 18.75%. That's the amount usually charged for desirable deep water offshore leases, while those in less than 656 feet (200 meters) of water are charged the 12.5% minimum.

Biden has come under pressure to increase U.S. crude production as fuel prices spike as Russian oil is taken off the market. From within his own party, the president faces calls to do more to curb emissions from fossil fuels. ●

—Associated Press contributed to this story

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OIL PRICES

over how aggressively the Federal Reserve would raise interest rates to calm inflation.

China's economy weighed on oil prices after a May 9 New York Times report that growth in the country's exports slowed significantly in April, according to customs data.

Li Keqiang, the Chinese premier, warned over the weekend that the current state of the nation's jobs market was "complicated and grave," the Times said.

Oil prices have been kept in check by demand fears arising from a COVID-19 lockdown in Shanghai affecting millions of workers, which has snarled manufacturing in the area and reduced demand for fuels.

Beijing has reported an increase in COVID-19 cases as well, raising concerns that the Chinese government would put the nation's capital under similar lockdowns under its strict zero COVID policies.

The Straits Times reported May 9 that Beijing is tightening curbs across the city, ordering millions of people to work from home and stay within their districts, in what city residents are saying amounts to a de facto lockdown.

Beijing has reported dozens of cases each day, with 915 cases reported since April 22 when a cluster was detected at a Chaoyang district school, it said. Non-essential businesses such as cinemas, museums, and karaoke parlors; all schools except universities; and some parks were ordered to close.

Oil prices fell approximately 9% over the two trading days leading up to May 11.

ANS slid $6.44 May 9 to close at $109.84, as WTI dropped $6.68 to close at $103.09, and Brent slid $6.45 to close at $105.94.

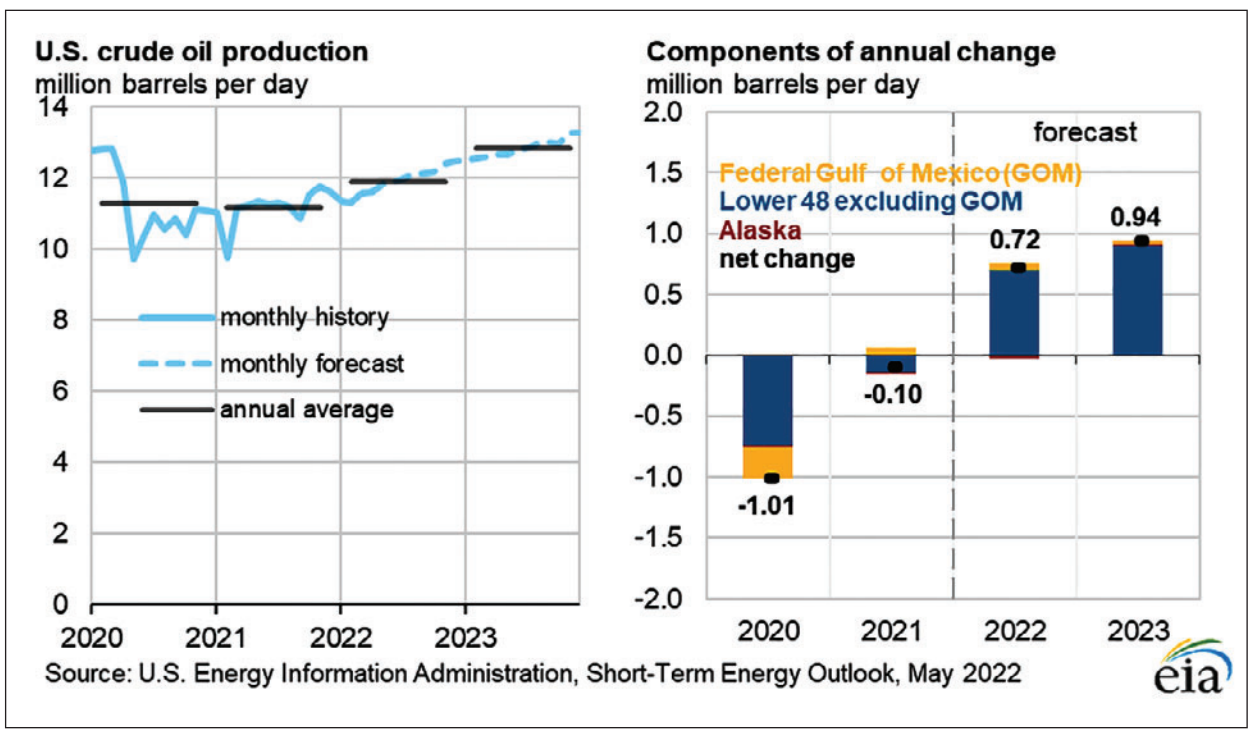
The losses continued May 10 as ANS fell $3.49 to close at $106.35, WTI fell $3.33 to close at $99.76, and Brent fell $3.48 to close at $102.46.

Oil closed Friday May 6 at a six-week high as members of the European Union moved closer to banning Russian oil imports by the end of the year in response to Russia's military aggression in Ukraine.

On May 6, ANS gained $1.39 to close at $116.26, WTI gained $1.51 to close at $109.77, and Brent gained $1.49 to close at $112.39.

ANS rose 64 cents May 5 to close at $114.89, as WTI rose 45 cents to close at $108.26, and Brent rose 76 cents to close at $110.90.

As Petroleum News went to press early May 12, WTI and Brent traded more than 1% lower than their May 11 closing prices.



High oilfield costs may hinder production

Rapid inflation in the U.S. oil patch is crimping CAPEX budgets for oil producers, just as the industry is attempting to ramp up production to meet recovering demand.

The EIA ratcheted down its forecasts for U.S. oil production by 0.8% to 11.9 million barrels per day in 2022 and 12.85 million bpd in 2023, in the face of its estimates that global petroleum demand will increase by 730,000 bpd to 20.51 million bpd in 2022.

Domestic crude oil production for the week ending May 6 fell 100,000 barrels to 11.8 million. Lower 48 production was unchanged, but Alaska production dropped slightly.

Drillers said they are experiencing spiraling prices on everything from rigs and workers to diesel fuel and frac sand, Bloomberg reported May 5. CEOs are being forced to increase annual spending plans to preserve crude and natural gas output targets.

The market for new equipment and skilled workers to man rigs and truck equipment across the oil fields has quickly tightened after years of limited investment, according to a May 2 Economist report.

"There is starting to be a little bit of a competition for (fracking) fleet," said Chris Wright, chief executive of Liberty Oilfield Services. "Not everyone that wants a fleet or wants an extra fleet today, frankly, is going to get one."

Meanwhile, investment advisor Bryan Rich suggests that inflation is likely heading higher, despite cooler CPI numbers reported May 11, and oil is at the crux of the disparity.

The 8.3% 12-month change in prices for April was cooler than the 8.5% inflation in the March report, but oil had a lot to do with the cooler number, Rich said in Pro Perspectives May 11.

"If we look at the change in price of crude from February to March, it was 18%; from March to April, crude prices were down 6%," Rich said, adding, "Not so coincidently, Biden announced a record release of oil from the U.S. Strategic Petroleum Reserve on March 31."

Rich said oil prices were manipulated lower, but now have returned to pre-SPR announcement levels.

"This oil price driver of inflation isn't going anywhere," he said. "And with the strong ex-food-and-energy inflation number this morning, we should expect higher inflation prints from here." ●

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