Petroleum news

page 3 EIA drops Brent forecast 7% to $79; US crude to average 12.53M bpd

Vol. 28, No. 20 • www.PetroleumNews.com   A weekly oil & gas newspaper based in Anchorage, Alaska   Week of May 14, 2023 • $2.50

Legislature confirms Dunleavy's department heads, AOGCC's Huber

The Alaska State Legislature has confirmed all of Gov. Mike Dunleavy's appointees to lead state departments, as well as Brett Huber Sr., chair of the Alaska Oil and Gas Conservation Commission.

GOV. MIKE DUNLEAVY

The confirmed cabinet level department heads include Department of Natural Resources Commissioner John Boyle and Department of Revenue Commissioner Adam Crum.

Boyle moved to Alaska in 2010 after receiving a Juris Doctorate from J. Ruben Clark Law School at Brigham Young University. He was assistant North Slope Borough attorney in Utqiaġvik and then chief advisor to the major and director of the NSB's government and external affairs department. He joined BP as director of government affairs in 2018 and then joined Oil Search as government affairs manager.

Crum, who served as commissioner of the Department of Health and Social Services starting in 2018, has a Master of Science in Public Health from Johns Hopkins University, and

see CABINET CONFIRMATIONS page 11

Slope LNG plant moving forward; Harvest has acquired gravel pad

Steps are moving ahead to develop a new liquefied natural gas plant on the North Slope for the supply of LNG to Fairbanks based Interior Gas Utility, IGU general manager Dan Britton told the IGU board on May 2. IGU supplies gas to customers in the Fairbanks region from LNG storage tanks in Fairbanks and North Pole.

As previously reported by Petroleum News, IGU is moving its gas supplies from the Cook Inlet to the North Slope, because of concerns about the adequacy of future Cook Inlet gas availability. Hilcorp Alaska's midstream affiliate Harvest Alaska has committed to build the LNG plant. Hilcorp will supply North Slope gas to the plant and IGU will truck the LNG to its storage facilities in Fairbanks and North Pole. Currently IGU's LNG comes from its Titan LNG plant near Point Mackenzie on Cook Inlet.

Britton told the board that Harvest has now completed the purchase of the gravel pad area that is earmarked for the LNG

see LNG PLANT page 11

Hilcorp revises POD for Seaview; CMB test planned for Seaview 9

Hilcorp Alaska submitted a revised fourth plan of development for its Seaview unit on the southern Kenai Peninsula, clarifying its plans for the small gas field.

The original 2023 POD 2023 was submitted May 1 (see story in May 7 issue of Petroleum News); the revised POD was submitted May 8.

In the revised 2023 POD, sent to the Alaska Department of Natural Resources' Division of Oil and Gas, the company said it had, as planned, moved the compressor at Seaview Pad 1 to another of its pads.

In the previous plan, for 2022, the company said it planned to move the existing compressor at Seaview to the Cannery Loop unit because of increased natural gas production at Cannery Loop and said it would evaluate a smaller compressor for Seaview.

In the original 2023 POD the company said it did not replace the Seaview compressor "because the smaller compressor is not needed at this time."

see SEAVIEW POD page 11

FINANCE & ECONOMY

Tax tops income

ConocoPhillips Alaska reports $416M in Q1 income, incurs $46M in taxes

By KAY CASHMAN

Petroleum News

ConocoPhillips Alaska reported net income of $416 million for the first quarter of 2023. During the quarter, the company incurred an estimated $464 million in taxes and royalties, which includes $320 million to the state of Alaska and $144 million to the federal government.

EREC ISAACSON

Additionally, in the first quarter of 2023, ConocoPhillips Alaska, which has operated in the state for more than 50 years, invested $406 million in its operations in the state.

"ConocoPhillips Alaska spent $1.1 billion in 2022, and in 2023, is projected to increase capital spend as the Willow project has commenced construction. Alaska's existing fiscal regime (SB21) is clearly working to promote new and ongoing investment," Erec Isaacson, president, ConocoPhillips Alaska, was quoted as saying in a May 4 press release.

"We remain committed to investing in projects on the North Slope that will deliver new barrels and contribute significantly to the state's economy through job growth and revenue generation," he said.

see CONOCO REVENUE page 11

FINANCE & ECONOMY

Recovery… of sorts

Oil rebounds from bank failure contagion fears; ANS at premium to Brent

By STEVE SUTHERLIN

Petroleum News

After marching higher for four trading days, Alaska North Slope crude took a breather May 10, inching down 79 cents to close at $77.63 per barrel. West Texas Intermediate was down $1.15 on the day to close at $72.56 and Brent shed $1.03 to close at $76.41.

The May 10 price movement was in line with a jump in U.S. commercial crude supplies reported by the Energy Information Administration.

ANS had been on a roll since plunging dramatically to just above $70 on May 3 as traders succumbed to demand destruction fears as another U.S. bank failure raised the specter of contagion in financial markets.

"If we don't see companies and countries investing, we could see a shortage in the future." —Suhail Al Mazrouei, United Arab Emirates energy minister

From Wednesday to Wednesday, ANS gained $7.29 from its May 3 close of $70.34 to reach $77.63 May 10.

ANS leapt $2.20 May 9 to close at $78.42, while WTI rose 55 cents to close at $73.71 and

see OIL PRICES page 9

FINANCE & ECONOMY

Producers on SB 114

Hilcorp, ExxonMobil, ConocoPhillips testify in Senate Finance on tax increases

By KRISTEN NELSON

Petroleum News

The Senate Finance Committee heard from oil companies May 5 as it considers Senate Bill 114, part of which would impact Hilcorp, and potentially other independent oil and gas producers and transporters in the state, while other portions of the bill would impact all North Slope producers.

LUKE SAUGIER

The bill would tax companies not organized as corporations at a 9.4% rate, aimed at companies organized as partnerships and limited liability companies. Hilcorp is an LLC.

The bill would also change how the state's production tax is structured, impacting all North Slope producers, the largest of which are ConocoPhillips Alaska, ExxonMobil Production Co. and Hilcorp.

The bill originally included a provision ring fencing North Slope fields, requiring allowable deductions for capital and operating expenditures to be taken against only the unit in which they were occurred.

That provision was eliminated, but the proposal still limits tax benefits of allowable deductions with per-barrel credits tied to capital spend.

The bill, by Senate Rules, is being heard only in Senate Finance.

see SB 114 TESTIMONY page 10

NATURAL GAS

AGDC updates legislators, talks budget

Running out of funds from original appropriation, seeks general funds, also authority to accept $4 million in federal receipts

By KRISTEN NELSON
Petroleum News

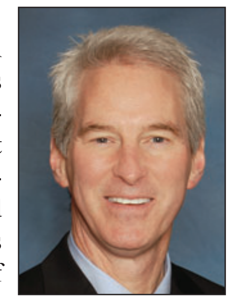
The Alaska Gasline Development Corp. updated legislators May 3 on the status of the Alaska LNG Project and on budget requests, including allowing AGDC to accept up to $4 million in federal receipts.

Frank Richards, AGDC President, said in presentations to the Senate Finance Committee and the House Finance Committee that Goldman Sachs is under agreement with AGDC to raise investment capital for Alaska LNG, with some $150 million in development capital targeted to get to a final investment decision.

That money would cover third party FEED costs, project management, legal/commercial and 8 Star Alaska overhead. AGDC is an independent, public corporation owned by the state and created by the Legislature. It is the current owner and developer of the Alaska LNG Project.

8 Star Alaska was created by AGDC and would manage Alaska LNG through the final investment decision. It will be managed by private investors with AGDC as a minority owner.

The $4 million in federal receipts, secured by Sen. Lisa Murkowski for the project, would make up part of the $150 million, Richards said, but requires $2.5 million in matching funds from the state.


FRANK RICHARDS

Regarding the monies which have supported and support its ongoing activities, AGDC originally received multi-year funding, but Richards said that original appropriation will be running out and without approval of general funds to continue, AGDC would lay off its staff, move out of its offices and box up the project.

The transition

Richards said AGDC's role is to transition the project to private investors, retaining a minority, 25%, interest, which will keep open the option for the state to invest in the project.

AGDC is transitioning Alaska LNG assets to 8 Star, Richards said.

What AGDC has for sale is a 75% equity ownership in 8 Star Alaska in exchange for taking the project to a final investment decision.

In its presentation, AGDC said Alaska LNG has the best economics of any North American project; has major federal and state permits and authorizations; has beneficial equity terms; and has local support.

Highlights of the AGDC equity offering include majority ownership and control of Alaska LNG in exchange for funding development costs to FID; commitment to more Alaska LNG forward on fast timeline; preferential in-state gas supply; and opportunity for Alaska to invest.

8 Star

8 Star will manage Alaska LNG through FID.

It will be managed by private investors with AGDC as a minority owner and will be the project manager and retain oversight of all three aspects of the project through to FID.

Ownership of 8 Star will likely consist of a lead party with other strategic partners taking minority stakes.

At final investment decision, 8 Star will raise construction capital for each of the three project subcomponents: the Arctic Carbon Capture facility on the North Slope; the 800-mile pipeline from the North Slope to Nikiski; and the LNG facility at Nikiski.

Alaska utilities

Richards said AGDC has offered agreements to Alaska utilities that will ensure the utilities receive gas

see AGDC UPDATE page 10

contents

Petroleum News | Alaska's source for oil and gas news

● LAND & LEASING

BLM further delays ANWR lease sale DEIS

Agency now expects to publish draft version of the supplemental EIS for lease sale program in the third quarter of this year

By ALAN BAILEY
For Petroleum News

The Bureau of Land Management has further delayed the completion of a draft supplemental environmental impact statement for its Arctic National Wildlife Refuge coastal plain oil and gas leasing program, according to recent filings in several court cases in federal District Court in Alaska. The court cases are challenging the legality of the lease sale program but are on hold, pending the outcome of the supplemental EIS — the findings of the supplemental EIS could render the court cases moot.

The court filings say that BLM now anticipates releasing the DEIS in the third quarter of this year. Originally the agency had planned to publish the DEIS in June 2022, with the final supplementary EIS being published in April 2023, followed by a record of decision in June 2023. However, the completion of the DEIS has been delayed several times and, until this most recent court filing, had been anticipated for the second quarter of this year. Essentially, the development of the DEIS is now running more than a year behind the original schedule.

Approved by Congress

As part of the Tax Cuts and Jobs Act of 2017 the U.S. Congress approved the conducting of lease sales in the 1002 area of the ANWR coastal plain, with BLM being required to hold at least two areawide lease sales in the 1002 area by December 2024. The first of the lease sales was conducted on Jan. 6, 2021, with the Alaska Industrial Development and Export Authority, Knik Arm Services and Regenerate Alaska obtaining leases in the sale. Multiple lawsuits challenging the lease sale program were initiated in District Court by environmental organizations, the Gwich'in Native people and several U.S. states. These are the lawsuits that are currently on hold.

In separate legal action, the Alaska Industrial Development and Export Agency, the state of Alaska and several other plaintiffs have challenged a June 2021 decision by the Department of the Interior to suspend all lease related activities in the ANWR coastal plain, pending a rework of the lease sale program EIS. That court case has yet to be resolved. Meanwhile, Knik Arm Services and Regenerate Alaska have relinquished their ANWR leases. ●

Contact Alan Bailey at abailey@petroleumnews.com

● FINANCE & ECONOMY

EIA drops '23 Brent forecast by 7% to $79

Agency cites concerns over weakening global economic conditions, perceived banking sector risk, persistent inflation as factors

By KRISTEN NELSON
Petroleum News

The U.S. Energy Information Administration has dropped its Brent spot oil price forecast from $85 per barrel for 2023 in April, to $79 per barrel, down 7.5%, in its May Short-Term Energy Forecast, issued May 9. EIA dropped its 2024 Brent forecast from $81 per barrel to $74 per barrel, down 8.3%. The Brent spot price averaged $101 per barrel in 2022.

JOE DECAROLIS

The agency said the Brent spot price fell from an average of $85 per barrel in April to close at $73 per barrel May 4.

The Organization of Oil Exporting Countries and partner companies, OPEC+, said at the beginning of April that they would cut crude oil production by 1.2 million barrels per day through the end of 2023. That move, EIA said, increased oil prices because it would tighten suppliers. "However, ongoing considerations about weakening lobal economic conditions, perceived risk around the global banking sector, and persistent inflation outweighed the initial increase in oil prices and have led to lower prices."

EIA said there are some downside risks in the demand for liquid fuels through the end of 2024, and said it expects "the seasonal rise in oil consumption and a drop in OPEC crude oil production to put some upward pressure on crude oil prices in the coming months."

EIA is forecasting an increase in global liquid fuels consumption of 1.6 million bpd this year and 1.7 million bpd in 2024, with most of that expected growth in non-OECD Asia, led by China and India.

The agency expects this growth in demand to bring the global oil market into balance between the third quarter of this year and the first quarter of 2024, pushing the Brent price back to between $75 and $80 per barrel.

Beginning in the second quarter of 2024, EIA said it expects "consistent global oil inventory builds over the rest of the forecast period as global oil production outpaces global oil demand, putting downward pressure on oil prices," with global inventories forecast to grow by 300,000 bpd in 2024, leading to a Brent average of $74 per barrel in 2024, down $7 per barrel from the agency's April forecast.

Production

U.S. crude oil production averaged 11.89 million bpd last year and is forecast to average 12.53 million bpd this year and 12.65 million bpd in 2024.

EIA said global liquid fuels production is forecast to increase by 1.5 million bpd this year compared to 2022, "primarily because of growth from non-OPEC producers."

While production from Russia is forecast to fall by 300,000 bpd this year, other non-OPEC liquid fuels production is forecast to increase by 2.2 million bpd this year and by an additional 1.1 million bpd next year. Russian production is forecast to decline from 10.9 million bpd in 2022 to 10.6 million bpd this year and 10.5 million bpd in 2024.

Total OPEC crude oil output is forecast to fall by 300,000 bpd this year, largely due to the April 3 OPEC+ production cut announcement. In addition to reduced OPEC production due to the announced cuts, EIA said "recent disruptions to crude oil exports in Iraq and a force majeure limiting crude oil exports in Nigeria have also reduced our near-term OPEC forecast in 2023."

Total OPEC liquid fuels production is forecast to increase by 600,000 bpd in 2024 "driven by the end of the current OPEC+ production cuts in 2023."

Natural gas

The Henry Hub price for natural gas is forecast at $2.91 per million British thermal units this year, EIA said, rising to $3.72 in 2024. The 2022 Henry Hub price averaged $6.42 per million Btu. The price is forecast to average $2.35 per million Btu in May and rise to some $3 per million Btu in July and August when power demand peaks.

The agency is forecasting that this summer will see the second-highest U.S. natural gas consumption for electricity, surpassing a record set last summer.

"The increasing share of renewables in the U.S. generation mix is a major feature of our electricity forecast this summer and through 2024," said EIA Administrator Joe DeCarolis. "As electricity providers generate more electricity from renewable sources, we see electricity generated from coal decline over the next year and a half. We expect that the United States will generate less electricity from coal this year than in any year this century."

The agency expects retail electricity costs will remain higher than before the COVID-19 pandemic and said even if households consume less electricity this summer, their bills are likely to be similar to or slightly higher than last summer.

"Our forecast for the consumption of electricity and for the amount Americans pay for electricity this summer is highly dependent on weather," DeCarolis said. "If this summer turns out to be warmer than we expect, we will see more demand for air conditioning, greater electricity use, and higher bills."

EIA said its forecast for U.S. natural gas consumption for electricity this summer is an average of 38 billion cubic feet per day, behind 39 bcf per day last summer. ●

Contact Kristen Nelson at knelson@petroleumnews.com

EXPLORATION & PRODUCTION

Upper foothills closed to off-road travel

The Alaska Department of Natural Resources' Division of Mining, Land & Water, said conditions in the upper foothills are no longer suitable for off-road travel. The area closed May 5 and off-road travel in progress was required to be completed within 72 hours.

While never officially opened for winter off-road travel, conditions for off-road travel were met in some locations of the upper foothills, the division said. However, with widespread deterioration of the snowpack and large areas of visible vegetation, even with air temperatures predicted to be below freezing, the sun is continuing to compromise the snowpack.

The division said the lower foothills, eastern coastal and western coastal areas remain open.

Unless otherwise authorized, summer off-road travel may begin July 15, with summer off-road travel applying "only to holders of valid permits who obtain specific approval and is limited to those vehicles approved by DMLW for summer off-road travel," the division said.

—PETROLEUM NEWS

Petroleum news
www.PetroleumNews.com

Kay Cashman	PUBLISHER & FOUNDER
Mary Mack	CEO & GENERAL MANAGER
Kristen Nelson	EDITOR-IN-CHIEF
Susan Crane	ADVERTISING DIRECTOR
Heather Yates	BOOKKEEPER
Marti Reeve	SPECIAL PUBLICATIONS DIRECTOR
Steven Merritt	PRODUCTION DIRECTOR
Alan Bailey	CONTRIBUTING WRITER
Eric Lidji	CONTRIBUTING WRITER
Gary Park	CONTRIBUTING WRITER (CANADA)
Steve Sutherlin	CONTRIBUTING WRITER
Allen Baker	CONTRIBUTING WRITER
Judy Patrick Photography	CONTRACT PHOTOGRAPHER
Forrest Crane	CONTRACT PHOTOGRAPHER
Renee Garbutt	CIRCULATION MANAGER

ADDRESS
P.O. Box 231647
Anchorage, AK 99523-1647

NEWS
907.522.9469
publisher@petroleumnews.com

CIRCULATION
281.978.2771
circulation@petroleumnews.com

ADVERTISING
Susan Crane • 907-250-9769
scrane@petroleumnews.com

Petroleum News and its supplement, Petroleum Directory, are owned by Petroleum Newspapers of Alaska LLC. The newspaper is published weekly. Several of the individuals listed above work for independent companies that contract services to Petroleum Newspapers of Alaska LLC or are freelance writers.

OWNER: Petroleum Newspapers of Alaska LLC (PNA)
Petroleum News (ISSN 1544-3612) • Vol. 28, No. 20 • Week of May 14, 2023

Published weekly. Address: P.O. Box 231647 Anchorage, AK 99523-1647
Subscription prices in U.S. — $118.00 1 year, $216.00 2 years
Canada — $206.00 1 year, $375.00 2 years
Overseas (sent air mail) — $240.00 1 year, $436.00 2 years

"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News, P.O. Box 231647 Anchorage, AK 99523-1647.

● EXPLORATION & PRODUCTION

US rotary rig count drops by 7 to 748

Texas down by 9 from previous week; the April international rig count, excluding North America, was 947, up 17 rigs from March

By KRISTEN NELSON
Petroleum News

The Baker Hughes' U.S. rotary drilling rig count was down by seven the week ending May 5 to 748, and up 43 from a count of 705 for the same period a year ago. This is the largest weekly drop since Feb. 24 — a week which also saw a seven-rig drop.

The count dropped in four of the past eight weeks, with the current count up from 754 eight weeks ago but down from a high so far this year of 771 on Jan. 20. The high for 2022 was a count of 784 rigs at the beginning of December.

When the count dropped to 244 in mid-August 2020, it was the lowest the domestic rotary rig count had 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 prior to the COVID-19 pandemic, 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 5 count includes 588 rigs targeting oil, down by three from the previous week and up 31 from 557 a year ago, with 157 rigs targeting natural gas, down four from the previous week and up 11 from 146 a year ago, and three miscellaneous rigs, unchanged from the previous week and up by one from a year ago.

Fifty-one of the rigs reported May 5 were drilling directional wells, 676 were drilling horizontal wells and 21 were drilling vertical wells.

Alaska rig count unchanged

California (3), Louisiana (61) and Oklahoma (54) were each up by one rig from the previous week.

Texas (368) was down by nine rigs week over week and North Dakota (38) was down by one.

Rig counts in other states were unchanged from the previous week: Alaska (9), Colorado (19), New Mexico (107), Ohio (11), Pennsylvania (26), Utah (13), West Virginia (16) and Wyoming (18).

Baker Hughes shows Alaska with nine rotary rigs active May 5, unchanged from the previous week and up by one from a year ago when eight rigs were active. Eight of the Alaska rigs were onshore, unchanged from the previous week, and one was working offshore, also unchanged from the previous week.

The rig count in the Permian, the most active basin in the country, was down by six from the previous week at 356 and up by 21 from 335 a year ago.

International rig count up 17 to 947

Baker Hughes' international rig count for April, issued May 5, is up by 17 rigs from March at 947 rigs, with land rigs up by 18 to 720 and offshore rigs down one to 227. Compared to the April 2022 count, 815, this April's international count is up by 141 rigs, with land rigs up by 105 and offshore rigs up by 36.

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

The Middle East accounts for the most rigs in the international totals, 337 in April, followed by Asia Pacific with 219, Latin America with 178, Europe with 120 and Africa with 93.

The U.S. rig count averaged 752 in April, down by one from March, and up by 62 from April 2022, while the Canadian count for April averaged 109, down 87 from March and up by two from April 2022.

Worldwide the rig count was 1,808 in April, down 71 from 1,879 in March and up by 205 from 1,603 last April. ●

Contact Kristen Nelson at knelson@petroleumnews.com

EXPLORATION & PRODUCTION

Squeezing oil from Kuparuk unit

ConocoPhillips Alaska's plans of development optimize use of existing infrastructure, thus minimize environmental impacts

By KAY CASHMAN

Petroleum News

On May 3 ConocoPhillips Alaska submitted its update to the Kuparuk River unit Plan of Development, or POD, to the Alaska Department of Natural Resources' Division of Oil and Gas as required by a letter from the state of Alaska dated April 11, 1986. It said the company had to file an annual update to the Kuparuk River unit POD by July 1 of each year for approval by Aug. 1.

The updates are submitted by unit operator ConocoPhillips Alaska Inc., or CPAI.

In addition to the Kuparuk unit POD and the Kuparuk participating area, more reservoirs — Meltwater, Tarn, Tabasco, and West Sak — have been developed within the Kuparuk River unit. Annual PODs must be submitted separately for each reservoir, or participating area.

The effective plan period for the unit and participating area submittals is Aug. 1, 2023, through July 31, 2024, also referred to as the 2023-24 POD period.

CPAI said that the basis for all the PODs is "consistent with the current business climate. Changes in business conditions, applications of new technologies, new insights into reservoir performance or other changes may alter the timing, scope, or feasibility of one or more components" of a plan.

Previous Kuparuk PA activities

Notable activities completed within the Kuparuk participating area over the preceding POD period are:

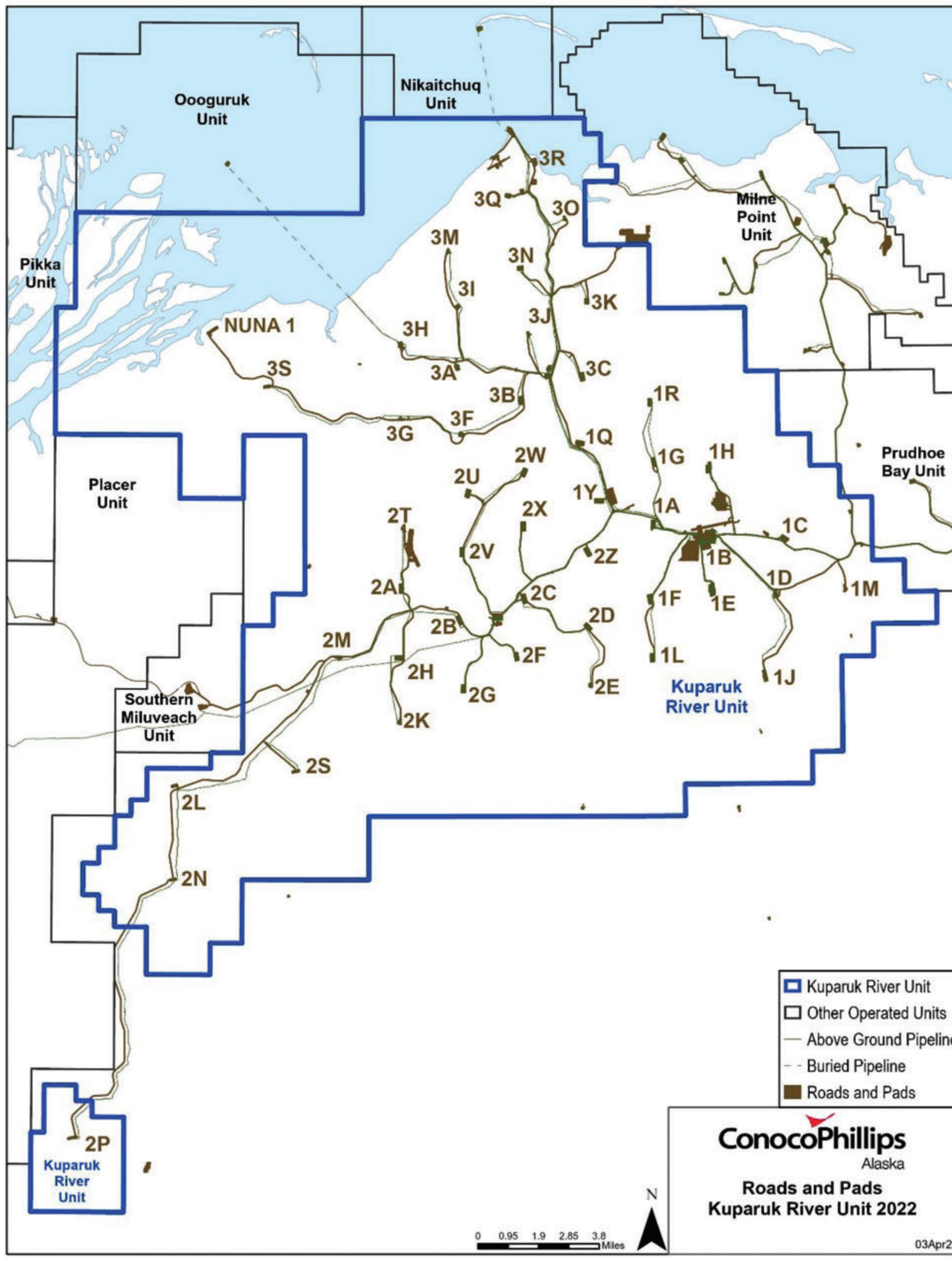
- Drilling and completion of two rotary exploration wells into the Brookian-age Coyote (Nanushuk) reservoir from DS-3S.
- Drilling and completion of two rotary wells into the Torok (Moraine) reservoir from DS-3S.
- Drilling and completion of 10 CTD wells adding approximately 0.9 MBOPD gross oil in 2023.
- Completion of 19 workovers restoring ~5.8 MBOPD in 2022.

The 2023-24 POD differs from the previous year's plan in that it does not include a continual CTD program. The CTD rig was suspended in January. CPAI said it is currently evaluating when and if the program will be restarted in the Kuparuk River unit. Additionally, a second workover rig was added to the plan starting in Q2 2023.

Kuparuk reservoir depletion

CPAI said depletion options for the Kuparuk participating area are:

- Delineate and optimize development of remaining areas of competitive oil accumulation such as the peripheral areas.
- Evaluate and economically optimize water flood where incremental rate and recovery justify the process.
- Management of excess water volumes e.g. via water shut-offs, particularly in commingled A and C sand completions.
- Management of lean gas volumes.



Kuparuk PA drilling

CPAI's development drilling strategy for the Kuparuk reservoir is to target high value locations.

For example, existing wells that are currently shut-in due to mechanical problems or low production rates may be sidetracked to new bottom-hole locations.

A single horizontal well in the Kuparuk reservoir, 3H-36, was drilled in Q2 2023. No additional wells are planned.

Rotary drilling in the Torok (Moraine) reservoir resumed in Q3 of 2022 with the injector/producer pair.

CPAI continues to monitor the existing Torok (Moraine) horizontal producer/injector well pairs at DS-3S to determine long-term deliverability and waterflood performance

see KUPARUK UNIT page 6

continued from page 5

KUPARUK UNIT

of the reservoir.

It is the intention of CPAI to apply for a separate participating area for the Torok (Moraine) reservoir and to apply for a separate PA for the Coyote (Nanushuk) reservoir.

Enhanced oil recovery

In regard to enhanced oil recovery (EOR), enriched gas water−alternating−gas (EWAG) was the main enhanced oil recovery process for the Kuparuk River unit in 2022.

In September of 2018, natural gas liquids (NGLs) imports from Prudhoe Bay were brought back into Kuparuk for the first time since 2014 and continued until September of 2021.

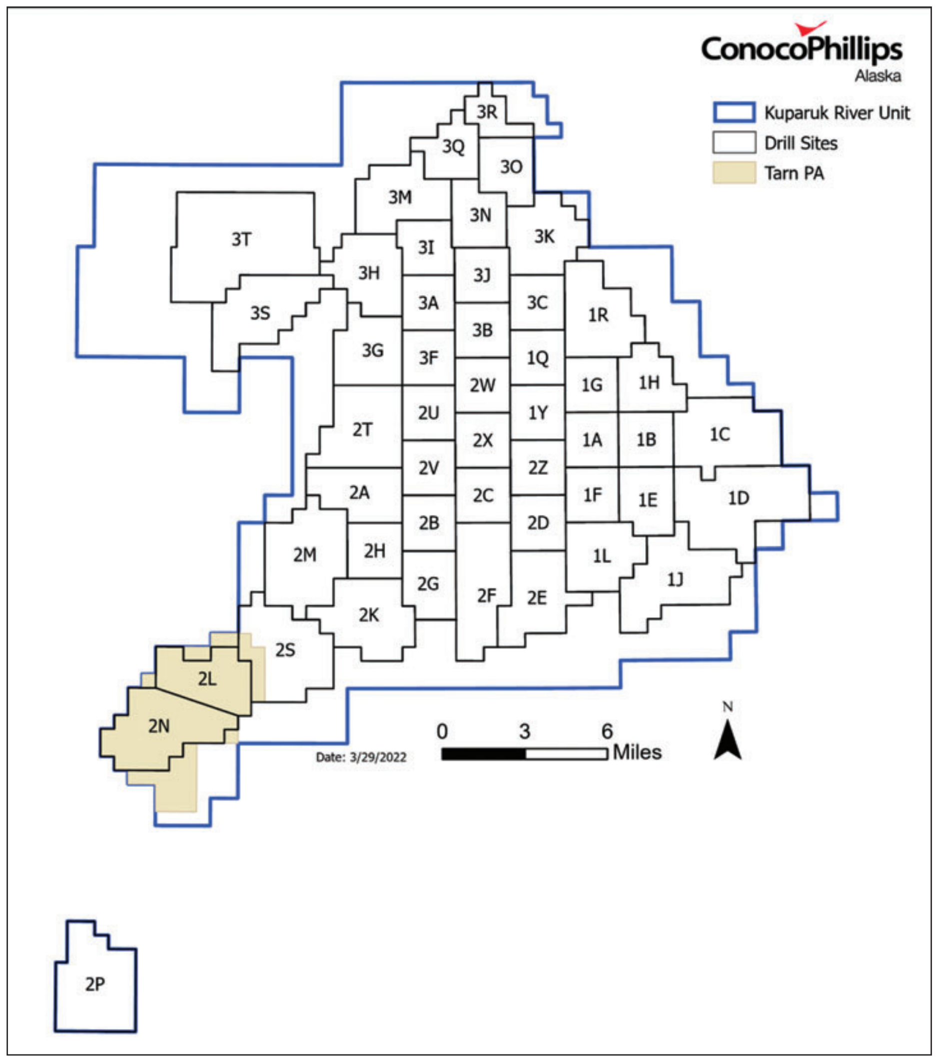
With the cessation of Prudhoe Bay NGL imports, only Kuparuk indigenous NGLs were blended for gas enrichment. This marked the transition from a miscible water alternating gas (MWAG) process to an enriched water alternating gas (EWAG) tertiary gas injection flood starting in 2021.

In total, 65 injectors and 24 drill sites received enriched gas injectant between January and December of 2022. The Kuparuk River unit manufactures enriched gas injectant at two of its Central Processing Facilities (CPFs).

Enriched injectant (EI) is manufactured by blending together produced lean gas (LG) and the Kuparuk NGLs.

Only indigenous NGLs were used for enhanced recovery programs in 2022.

The tertiary flood at Kuparuk has historically prioritized immature, efficient patterns to maximize EOR benefit. However, as the Greater Kuparuk Area (GKA) produced gas continues to decline, the gas injection strategy now prioritizes mature patterns with minimal gas trapping to maximize return gas.



Since the conversion back to natural gas imports in 3Q 2021, CPAI maintains the option to either segregate lean and enriched injection systems or blend a non-miscible "enriched" gas stream across all drill sites.

Studies have shown oil rate benefits from injecting lean gas in previously MI-flooded areas, however CPAI does not have specific timing for a potential lean gas chase through the Kuparuk reservoir.

Facilities, infrastructure

When evaluating future development opportunities and optimizing current production, CPAI said it is continuously analyzing impacts on existing Kuparuk facilities and infrastructure.

In regard to turbine capacity for power generation, the unit keeps its full generation capacity available via one Frame 5, one Frame 6 and 15 Ruston machines. This capacity is utilized for supporting field rotating/heat equipment, along with a certain amount of "spinning reserve" to manage fluctuations and any unplanned downtime on the machines.

Similarly for water injection, the Kuparuk River unit maintains its full water injection turbine capacity to manage effective voidage across the unit.

Turnarounds & maintenance

Turnarounds are planned for CPF1 (primary separator inspection) and CPF3 (fuel gas and pipeline tie-ins) in the summer of 2024.

CPAI continues to perform routine maintenance and execution of smaller scale projects to ensure the integrity of the Kuparuk River unit facilities and infrastructure.

This includes employing a corrosion team that continues with regular inspections and reviews of pipeline integrity.

Replacement activity planning remains in place with regular review meetings to examine newly acquired data and to make decisions on revisions to the pipeline renewal program including coatings, replacements, repairs, repurposing and consolidations.

CPAI said electronic equipment used at Kuparuk is becoming obsolete at an increasing rate as manufacturers introduce new equipment and no longer wish to support older equipment.

As such, process control systems among other systems will continue to be upgraded and automated as current equipment becomes obsolete and no longer maintainable. The fire and gas systems have been upgraded at the CPFs and the seawater treatment plant, with drill site upgrades ongoing.

Kuparuk PA status update

As of Dec. 31, 2022, the Kuparuk reservoir is developed from 46 drill sites.

The Kuparuk field had 758 active wells in 2022 — 400 producers and 358 injectors.

In 2022 the Kuparuk participating area averaged 57.19 MBOPD of crude and 106.17 MMSCFD of natural gas. The average water production rate was 516.8 MBWPD.

Meltwater participating area

No development wells were drilled at Meltwater during the previous plan period.

All wells were shut-in with continuous monitoring of OA pressures until such time as the wells are plugged and abandoned.

All pipelines to and from 2P drill site have been temporarily abandoned in place.

No further exploration/delineation is planned in the Cairn or Bermuda sand intervals at this time.

Extensive analyses of Meltwater operations, production, and associated impacts were undertaken in 2020-2021. Based on these analyses, CPAI indefinitely shut-in Meltwater (DS-2P) in order to eliminate backout impacts to the rest of CPF2 production.

Detailed plans for drill site abandonment are progressing, including development of approved procedures to plug and abandon the wells at 2P.

Tabasco 2022-23 period

Summarized below are notable occurrences at the Tabasco PA in the 2022-23 period:

- No development wells were drilled.
- The cumulative year-end 2022 injection-withdrawal ratio (I/W) is estimated at 0.9 based on current formation volume factors.
- 2T-208 has been worked over and the current completion has a bigger ESP. This allows the well to produce more oil at lower water cut. In addition, the 2T-203 ESP has been sped up and 2T-218 ESP has been slowed down. These changes have also lowered water cut and increased oil production rate.

2023-24 POD plans

There are no significant differences

see **KUPARUK UNIT** *page 7*

continued from page 6

KUPARUK UNIT

between the 2022-23 and 2023-24 POD period plans for Tabasco.

No further exploration/delineation or development drilling is planned.

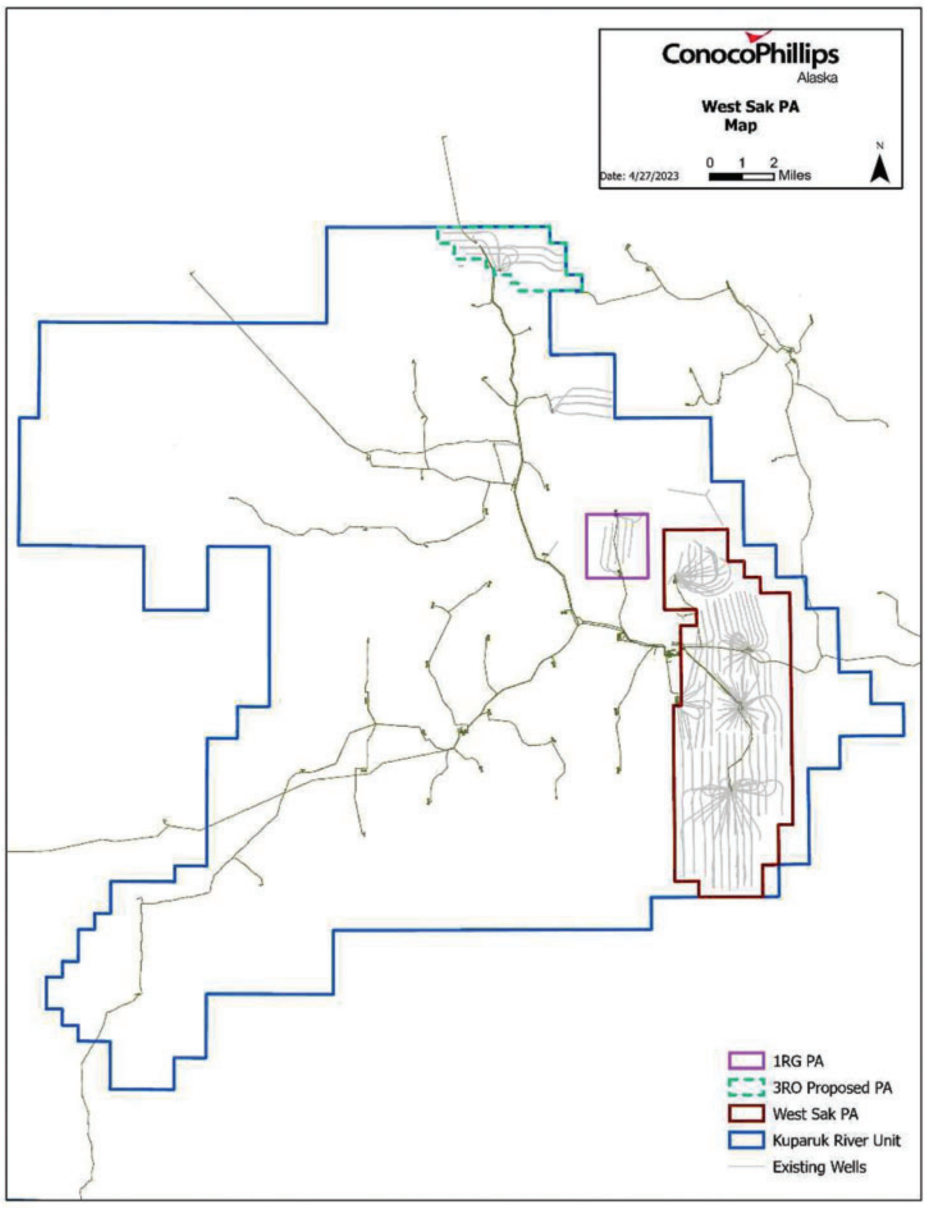
Tabasco injection-withdrawal ratios are monitored to maintain an instantaneous value of approximately 0.9.

Waterflood operations will continue to be optimized in 2023-24 with plans to continue the drawdown in the producers to minimize water cut. The reservoir management strategy is predicated upon injecting water deep into the central canyon and producing from the periphery. These high permeability facies are prevalent in the central canyon injectors but not in the peripheral wells. The gravity slumping of the injected water combined with recovery higher up in the structure leads to a gravity stable waterflood.

This has been key in keeping Tabasco water cut under control and has improved overall oil recovery.

As of Dec. 31, 2022, the Tabasco field had seven active wells in 2022 — five producers and two injectors.

The 2022 average oil production rate was 1.2 MBOPD. The average 2022 gas production rate was 0.2 MMSCFD and the average water production rate was 16.0 MBWPD.



Tarn 2022-23 activities

The notable occurrences at the Tarn participating area in the 2022-23 POD period were as follows:

• No development wells were drilled.

• A few wells developed annular communication problems and are on the rig workover schedule.

• The producer 2N-329 was shut in due to high water cut. The well will be recompleted with new perforations added to shallower Bermuda to evaluate whether production with lower cut can be obtained.

• Routine paraffin scrapes and hot diesel flushes were conducted throughout 2022 on many Tarn wells to maintain production.

• The cumulative year-end 2022 injection-withdrawal ratio (I/W) is estimated at 1.15.

Tarn 2023-24 POD period

There are no significant differences in the activities planned for the 2023-24 POD period as compared to the 2022-23 period.

No drilling of any kind is planned.

Due to well integrity issues caused by jet pump power fluids in the past, the majority of Tarn wells have been converted to gas lift.

In addition, usage of miscible gas containing NGL as the lift gas helps in mitigating paraffin deposition. It is expected that these regular mitigation measures will continue to be applied throughout the 2023-24 plan period.

Tarn status and outlook

Tarn continues to exhibit high water cut as the area approaches maturity. Recompletions will be performed where possible to isolate higher water cut intervals.

Despite Tarn producing from the same reservoir as Meltwater, it does not have the same depositional setting and subsequent production challenges that Meltwater faces. Accordingly, CPAI will continue to look for strategies that add value to the Tarn field.

In the near term, plans are already in place to recomplete Tarn wells by adding new perforations or through isolation of high water cut zones. The feasibility of fracking or re-fracking Tarn wells is also being considered.

In the long term, CPAI recognizes that there is potential to further develop Tarn through new well drilling.

As a first step of that process, a new full field model for Tarn is in the process of being history matched. An initial history match has been completed; however more work needs to be done to complete the process.

Once complete, the full field model will be used to identify drilling opportunities and associated economics, and subsequently compare them with other opportunities in the GKA.

As of Dec. 31, 2022, the Tarn field had 57 active wells at two drill sites (DS) 2L and 2N — 35 producers and 22 injectors.

Tarn PA average oil production rate in 2022 was 4.0 MBOPD; and average gas production rate was 6.9 MMSCFD, with average water production rate 7.7 MBWPD.

West Sak PA previous

Summarized below are notable occurrences at West Sak in 2022:

ï Two new Matrix Bypass Events (MBE) developed in the patterns 1J-102/1J-159 and1J-170/1J-166.

ï Three MBE remediation treatments were attempted in injectors 1C-127, 1J-136 and 1E-102 to reestablish water injection support and pattern sweep. These treatments are gel jobs pumped to remediate their respective MBEs. The status of these treatments remains under evaluation, CPAI said.

Going back further, in 2014, AOGCC approved Viscosity Reducing Water-Alternating Gas (VRWAG) injection as an enhanced oil recovery process for the West Sak oil pool.

In 2022 gas was injected only in 1C-154. There are no further plans to inject gas in West Sak due to lack of miscible injectant in the field.

Lean gas injection can lead to rapid breakthrough of gas in West Sak which can lead to enhanced sand production and subsequent MBEs.

CPAI continues to monitor the five West Sak CTD wells (two producers, three injectors) within the 1RG PA.

The 2022 West Sak participating area POD premised drilling two CTD sidetrack wells and completing a remedial screen in Q4 of 2022.

The CTD sidetracks were not executed due to the suspension of the CTD program; the remedial screen was completed in early 2023. Additionally, three rotary West Sak wells and a water source well have been delayed since the previous plan was submitted.

These wells are now planned for the current plan period.

CPAI plans to resume rotary drilling within the West Sak participating area beginning in Q2 2023 with a core area development program at DS-1C. This program includes one water source well in the water leg of the Ugnu reservoir, one producer and two injectors.

Additionally, CPAI plans to begin drilling 1H NEWS Phase 2 in Q2 2024. This program will include two dual-lateral producers and two dual lateral injectors.

Facility upgrades

Drill sites 1B, 1C, 1D, 1.E, 1G, 1H, 1J, 3K and 3R currently have West Sak/NEWS production.

New developments at existing drill sites in the West Sak/NEWS area may require facilities upgrades such as the addition of heaters, electrical upgrades, and pipelines.

These additional facility requirements add to the economic challenge of further West Sak/NEWS development in the current business environment.

West Sak PA status

The West Sak field is developed from 10 drill sites: 1B, 1C, 1D, 1E, 1G, 1H, 1J, 1R, 3K and 3R.

As of Dec. 31, 2022, West Sak had 118 active wells in 2022 — 58 producers and 62 injectors.

West Sak participating area and Northeast West Sak participating area combined average metrics for 2022:

— Average oil production rate 18.13 MBOPD.

— Average formation gas production rate 9.08 MMSCFD.

— Average water production rate 26.77 MBWPD. ●

Contact Kay Cashman at publisher@petroleumnews.com

● THIS MONTH IN HISTORY

Pioneer gives Alaska top billing in plans

20 years ago this month: Northwest Kuparuk's geologic age, permeability, porosity similar to Alpine with Jurassic-aged sands

Editor's note: This story appeared in the May 4, 2003, issue of Petroleum News Alaska.

By KRISTEN NELSON
Petroleum News

Alaska is number one on Pioneer Natural Resources' "pipeline of opportunities" list for 2004-2006, the company told analysts April 29, 2003.

Alaska made the list because preliminary well results from the independent's Northwest Kuparuk prospect off Alaska's North Slope show oil-bearing Jurassic-aged sands very similar in geologic age, permeability and porosity to those in the prolific, onshore Alpine field to the southwest.

In the area from north of the Kuparuk River unit, including Northwest Kuparuk in Harrison Bay, going south and west through the Alpine field and into the National Petroleum Reserve-Alaska there are a series of three upper Jurassic-aged sandstones that are known to contain what Alaska Division of Oil and Gas Director Mark Myers refers to as "staggering amounts of oil."

Pioneer has applied to the state of Alaska to establish the Ooguruk unit covering its Northwest Kuparuk prospect and in that application the company said its plan of exploration "incorporates current engineering work under way to meet a possible winter 2004/2005 fast-track production start-up."

Pioneer drilled three exploration wells at Northwest Kuparuk this winter, saying March 31 that it had encountered two thick, oil-bearing, Jurassic-aged sand sections.

In late March, Myers did not know which Jurassic sands Pioneer had encountered, but said the issue would be finding reservoir quality, not finding oil. If the sands were similar in age, permeability and porosity to those at the Alpine field, he said, that would be "good news" because other upper Jurassic sands could be more difficult to produce.

At the April 29 meeting with analysts, in which Pioneer officials talked about first-quarter results, company Chairman and CEO Scott Sheffield said the Jurassic formation tested at the Northwest Kuparuk prospect was very similar in geologic age to the Alpine field and had "very similar permeability and porosities" to Alpine.

Sheffield also said the well test looked good; that he was "encouraged by the early evaluation work we've done to establish commerciality" at Northwest Kuparuk.

Pioneer, which elected to test just one of the three wells because the wells were similar, will be releasing results in three or four weeks, he said.

SCOTT SHEFFIELD

KEN SHEFFIELD

Opportunity for growth

Sheffield said the company is aiming for five-year compound annual production growth of some 12% and long-term growth at 10%. He said that Alaska is among the company's opportunities for growth.

Of nine projects listed, Sheffield said a lot of the potential is in the 2005-2006 timeframe, although "some of these will come on in 2004."

Pioneer has applied to the state of Alaska to establish the Ooguruk unit covering its Northwest Kuparuk prospect and in that application the company said its plan of exploration "incorporates current engineering work under way to meet a possible winter 2004/2005 fast-track production start-up."

"What's positive here is the fact that we are only six miles away from unused capacity at Kuparuk," Sheffield said, referring to the ConocoPhillips Alaska-operated Kuparuk River unit.

The Kuparuk field is the second largest oil field in North America behind the North Slope's Prudhoe Bay field. It is produced largely from the Kuparuk C sands, which had been Pioneer's number one target at Northwest Kuparuk. The company said March 31 that although it had found Kuparuk C sands filled with oil, those sands "were too thin to be considered commercial."

Depths also reported

Pioneer has also reported the depths of its Beaufort Sea winter exploration wells to the state. The Ooguruk, a vertical hole, was completed March 29. It had a measured depth and true vertical depth of 6,900 feet. The Natchiq, completed March 31, had a measured depth of 7,500 feet and a true vertical depth of 6,740 feet. The Ivik, completed April 9, had a measured depth of 6,943 feet and a true vertical depth of 6,942.

The wells were drilled from ice islands in shallow water northwest of the Kuparuk River unit.

Pioneer has a 70% working interest in the Northwest Kuparuk prospect and is the operator. Armstrong Resources, which assembled the acreage, holds the remaining 30%. ●

continued from page 1

OIL PRICES

Brent rose 43 cents to close at $77.44.

May 9 price action was significant in that ANS swapped places with Brent in the price hierarchy, opening a 98-cent price differential above Brent, which had held the lead for months. The lead widened on May 10.

The brief ANS lead may hint that Asian crude buying is sopping up Pacific cargoes in competition with the U.S. West Coast where most ANS is sold, or a sign that West Coast demand is stronger relative to Europe.

As China and India have of late been feasting on cheap Russian crude since the advent of Western sanctions and price caps on Russian oil put in place due to Russia's invasion of Ukraine, the differential might suggest that supplies from Russia have fallen.

At this point it is difficult to call a trend, but if the differential proves to be more than a volatility anomaly over a few trading sessions it may illustrate a shift in world markets — which have been in disarray since the invasion. Before the war prompted a moratorium on U.S. purchases, seaborne Russian oil competed with ANS on the West Coast, supplying some 7% of the market.

On May 8, ANS gained $1.65 to close at $76.21, as WTI gained $1.82 to close at $73.16 and Brent gained $1.71 to close at $77.07.

ANS leapt $2.64 May 5 to close at $74.56, as WTI vaulted $2.78 to close at $71.24 and Brent vaulted $2.80 to close at $75.30.

ANS rose $1.58 May 4, while WTI fell 4 cents to close at $68.56 and Brent edged up 17 cents to close at $72.50.

U.S. commercial crude oil inventories for the week ending May 5 — excluding the Strategic Petroleum Reserve — increased by 3.0 million barrels from the previous week, the EIA said. At 462.6 million barrels, the inventories stood 1% below the five-year average for the time of year.

Commercial inventories up, SPR down

Despite the pop in U.S. crude inventories reported May 10, WTI and Brent were priced modestly higher in early trading May 11 as Petroleum News went to press.

U.S. commercial crude oil inventories for the week ending May 5 — excluding the Strategic Petroleum Reserve — increased by 3.0 million barrels from the previous week, the EIA said. At 462.6 million barrels, the inventories stood 1% below the five-year average for the time of year.

Analysts had expected a small drawdown instead.

Total motor gasoline inventories decreased by 3.2 million barrels for the period to a level 7% below the five-year average for the time of year, the EIA said.

The SPR fell also, down 2.9 million barrels to 362.0 million barrels May 5, from 364.9 million barrels April 28. The reserve stood at 543.0 million barrels on May 6, 2022.

On May 8, two Republicans — Sen. John Barrasso and Rep. Cathy McMorris Rodgers — asked the Government Accountability Office to evaluate the Department of Energy's management of the SPR after the Biden administration sold 250 million barrels from the reserve last year, according to a Reuters report.

"DOE's mismanagement of the SPR has undermined America's energy security, leaving the nation more vulnerable to energy supply disruptions, and increasing the ability for OPEC and Russia to use energy as a geopolitical weapon," Barrasso and McMorris Rogers wrote in a letter to the GAO, adding that the sales may have done structural damage to the reserve's pipelines and caverns, compromising its energy security mission.

The Biden administration said in April that the sales did not damage the SPR.

No OPEC+ supply cut looms, minister says

Suhail Al Mazrouei, United Arab Emirates energy minister said another production cut by the Organization of the Petroleum Exporting Countries and its allied exporting countries soon is unlikely, according to a Bloomberg report.

OPEC+ made a surprise production cut in April, but prices have fallen since.

"I'm not that worried about the very, very short term," Al Mazrouei told reporters in Abu Dhabi May 9. "Let's wait. This is not a prediction that I can give now or a decision, this is a collective decision."

OPEC+ is planning an in-person meeting at its Vienna headquarters in June to discuss production. UAE is the third-largest producer in the group.

Al Mazrouei said the bigger risk to supply was the weak level of investment over the coming years.

"If we don't see companies and countries investing, we could see a shortage in the future," he said. ●

Contact Steve Sutherlin at ssutherlin@petroleumnews.com

Oil Patch Bits

Airgas awarded of Newsweek's Most Trustworthy Companies

Airgas, an Air Liquide company, said May 8 that it has been included on Newsweek's list of America's Most Trustworthy Companies 2023. This prestigious award is presented by Newsweek and Statista Inc., the world-leading statistics portal and industry ranking provider. The awards list was announced on March 29 and can be viewed on Newsweek's website.

America's Most Trustworthy Companies 2023 were identified in an independent survey based on a vast sample of approximately 25,000 U.S. residents who rated companies they know in terms of three touchpoints of trust. A total of 95,000 evaluations were submitted. All companies headquartered in the U.S. with a revenue over $500 million were considered in the study.

The top 700 most trustworthy companies across 23 industries have been chosen based on a holistic approach to evaluating trust. The three main public pillars of trust were considered: customer trust, investor trust and employee trust.

Airgas is pleased to be recognized on Newsweek's list of America's Most Trustworthy Companies 2023.

Marcelo Fioranelli, Airgas chief executive officer, commented: "This recognition by Newsweek represents exactly what Airgas wants to be for our customers, associates, and in the communities we serve. Our associates' continuous hard work and dedication to gain and retain our customers' trust has contributed to this recognition from Newsweek, which we are very honored to receive."

Companies involved in Alaska's oil and gas industry

All of the companies listed above advertise on a regular basis with Petroleum News

continued from page 2

AGDC UPDATE

supply on preferential terms. The agreements are with 8 Star Alaska and will bind future investors.

Key terms are:

•Alaska utilities will be provided natural gas from the project on priority terms to supply residential, commercial and small industrial customers.

•The price will be no higher than that paid by the LNG facility for its natural gas supply.

•In the event of an interruption, Alaska utilities will be prioritized over LNG.

•Gas supplies would be up to 500 million cubic feet per day, more than two times current in-state usage.

•Utilities would be able to adjust take-or-pay commitments in response to changes in demand or new renewable sources of energy.

Producer agreements

Richards said potential investors in the project have said gas supply terms are needed prior to investing development capital, and securing agreements is a top priority for AGDC.

Some potential buyers are considering equity offtake, with an investment in the project at FID in exchange for LNG supplied at cost.

The need for gas supply terms has been communicated to the North Slope producers, with both Department of Revenue Commissioner Adam Crum and Department of Natural Resources Commissioner John Boyle joining meetings to stress to producers the importance of the project to the state. Goldman Sachs has also joined meetings to discuss the views of investors on the importance of gas supply.

AGDC has transmitted gas supply precedent agreements to the producers.

•8 Star is the buyer so agreements would be binding on future investors.

•The precedent agreements establish price, term, volume and commitment to buy and sell gas.

•Prior to FID fully termed gas supply agreements would be negotiated by the private project developer.

•There has been a mixed level of engagement from the producers.

LNG sales agreements

AGDC said active negotiations are underway with multiple LNG offtakers/buyers, with negotiations fairly advanced and ongoing price discussions. Potential buyers include traditional Asian utilities, LNG traders and oil and gas companies, with all buyers credit worthy and large-scale market participants.

AGDC said the project offers a combination of prices: Brent-linked, Henry Hub, JKM and fixed price; with a 20-year term with an aggregate price floor covering system tolls and debt service.

Some potential buyers are considering equity offtake, with an investment in the project at FID in exchange for LNG supplied at cost.

AGDC said it is in discussions for 125% of project capacity, with all conversations under confidentiality agreements. ●

Contact Kristen Nelson at knelson@petroleumnews.com

continued from page 1

SB 114 TESTIMONY

Hilcorp

Luke Saugier, Hilcorp's senior vice president Alaska, said Hilcorp came to Cook Inlet in 2012, at a time when Southcentral Alaska was facing the prospects of brownouts and has invested more than $1 billion, drilling some 90 new wells, repairing more than 400 wells, bringing in new drilling rigs and innovative technologies.

On the North Slope, Hilcorp acquired Endicott, Northstar and part of Milne Point in 2014, Saugier said. Hilcorp took over as Milne operator in 2015 and has invested more than $1 million at that field, drilling more than 100 new wells, with 20 planned this year, and taking production from 18,400 barrels per day in 2014 to more than 41,000 bpd today, Saugier said, and with continued investment is expecting to see production near 60,000 bpd in the next four to five years.

In 2020, Hilcorp acquired BP's remaining Alaska assets and took over as operator at Prudhoe Bay.

Saugier showed a slide, based on the Department of Revenue's fall 2019 forecast, which showed a projected decline at Prudhoe of about 2% a year. Since taking over as Prudhoe operator, Saugier said, Hilcorp has worked closely with its partners in the field and stopped the production decline, with two consecutive years of production increases.

Hilcorp compared the 2019 forecast with Revenue's 2022 fall forecast, with the 2022 forecast showing the two-year increase in production at Prudhoe and what Saugier called the Hilcorp wedge — the difference between the two forecasts through 2028, 70 million barrels in 2023 and 100 million barrels in 2025.

Those production increases, he said, are from drilling new wells, fixing old wells and repairing and expanding oil production facilities.

Hilcorp's 2023 budget for Alaska is its largest ever in the state, which now represents nearly 60% of Hilcorp overall, Saugier said.

Saugier said Hilcorp's investment and work has resulted in significantly more oil in the pipeline, more natural gas and billions more to the state.

The future

Hilcorp's 2023 budget for Alaska is its largest ever in the state, which now represents nearly 60% of Hilcorp overall, Saugier said.

Over the next five years the company expects to invest roughly $1 billion or more in Cook Inlet on capital projects including exploration drilling, drilling new wells in existing fields and installing new offshore platforms, he said.

In 2023 the company expects to spend several hundred million dollars in Cook Inlet, drill nearly 20 new wells, operate four rigs — all to produce additional natural gas.

He noted the company was the only bidder in the two most recent Cook Inlet lease sales and said it is the only company to drill new gas wells in Cook Inlet in the last four years.

Hilcorp is also working with the Railbelt utilities to find solutions to gas supply challenges, he said, including big new capital investments, new commercial arrangements, new platforms, working to advance North Slope natural gas options and exploring repurposing existing infrastructure for generation of renewable energy.

On the North Slope, the company plans investment in new wells, fixing old wells, expanding facilities and optimizing production.

It has a new pad at Milne Point, Raven, which is expected to produce 10-15,000 bpd, another rig for the North Slope and plans for additional rigs and hopes to have at least six rigs operating on the North Slope.

Hilcorp's view

Saugier said the tax proposals give the company "great concern." Hilcorp is a privately owned family business and is organized the same everywhere it operates, he said, and was organized as a limited liability company when it came to the state, something regulators understood when they approved transferring leases to the company.

If the tax changes are passed, he said, Hilcorp would be forced to scale back, especially in Cook Inlet, but Prudhoe Bay would also be impacted, as Hilcorp would have less capital to invest in the state. He also noted the continued uncertainty resulting from changes of rules after billions have been invested.

He said the change in corporate income tax would not level the playing field, as proponents of the change have argued, but would tilt the field against small independent companies, negatively impacting the small, nimble companies operating in Cook Inlet.

He said Hilcorp would end up paying more than companies organized as corporations because of how the bill is structured.

ExxonMobil

Todd Griffith, president of ExxonMobil Production Alaska, told the committee that there are strong headwinds to investment in the Arctic, with litigation more prevalent, and said SB 114 is a fundamental change which would add to economic headwinds.

Griffith also objected to the process for SB 114, noting that when SB 21 was being considered it had some 50 hearings in three committees just in the Senate. He called SB 114 a change in policy focused solely on revenue, said it would undermine investor confidence and would stop momentum in the industry and make the state less competitive for investment.

SB 21 has led to increased production, Griffith said,

see **SB 114 TESTIMONY** *page 11*

continued from page 1

LNG PLANT

plant and has obtained an easement from the Department of Natural Resources for the plant and an associated pipeline. The company is conducting work on engineering and design. It is also ramping up the management team for the construction project.

"They appear to be on track," Britton said.

Meanwhile, IGU is taking steps to establish the trucking operation that will be needed for shipping the LNG to Fairbanks. In April the utility issued a request for proposals for LNG road transport trailers and is now evaluating responses to the RFP. The utility is also working on a request for bids to conduct the North Slope trucking, Britton said.

—ALAN BAILEY

Contact Alan Bailey
at abailey@petroleumnews.com

continued from page 1

CONOCO REVENUE

Since 2007, ConocoPhillips Alaska has incurred more than $43 billion in taxes and royalties to the state of Alaska and the federal government. Of that amount, about $33 billion went directly to the state. In that same period, ConocoPhillips Alaska's earnings were approximately $25 billion, the company said.

Corporate earnings

Parent ConocoPhillips saw its corporate earnings halved to $2.9 billion in the first quarter, compared with the $5.8 billion in the same period in 2022, as lower oil and gas prices impacted earnings.

Chief executive Ryan Lance said the results highlighted several moves towards additional growth in oil and gas and in the liquefied natural gas sector.

These moves included acquisition of a 30% equity interest in the Port Arthur LNG joint venture upon final investment decision for Phase 1 development; beginning construction on the Willow oil and gas project in Alaska after receiving approvals from the feds for a scaled down development plan with three core pads instead of the five originally requested; and assuming upstream operatorship of Australia's APLNG project. ●

Contact Kay Cashman
at publisher@petroleumnews.com

continued from page 1

SEAVIEW POD

In the revised 2023 POD the company said it had moved the Seaview compressor to another of its pads, and "did not replace the compressor at Seaview Pad No. 1 as planned due to other compression opportunities taking precedence at this time."

In the 2022 POD the company said it was evaluating additional perforations at the Seaview 9 well, plans which remained the same in the 2023 POD.

The revised 2023 POD said: "Hilcorp is targeting CBM injectivity test on Seaview No. 9 during the 2023 POD period which could include perforating and testing the coal bed methane opportunities."

Seaview 9 was drilled in 2021.

The only producing well at Seaview, Seaview No. 8, was drilled in 2018. That well produced gas from June 2021 through part of August last year but is currently shown as shut-in for the months since on Alaska Oil and Gas Conservation Commission records through March, the most recent month for which AOGCC production data is available.

In its original 2023 POD, Hilcorp said that during calendar year 2022 Seaview produced 63 million cubic feet of natural gas. This compares to total 2021 calendar year production, reported by the company in its 2022 plan proposal, of 146.9 million cubic feet.

The company did not discuss production volumes in the revised 2023 POD.

—KRISTEN NELSON

Contact Kristen Nelson
at knelson@petroleumnews.com

continued from page 1

CABINET CONFIRMATIONS

has served as a board member for groups like the Salvation Army and MyHouse. He was previously executive vice president of his family's company, Northern Industrial Training.

Huber moved to Alaska in 1984 from Colorado and early in his career designed and installed geomembranes for North Slope and Kenai Peninsula oil and gas operations. He worked for the Alaska Legislature on oil and gas, land, fish and wildlife issues, and served as Dunleavy's policy advisor and communications director.

"Thank you to the Legislature for approving all my (cabinet level) appointees today in a joint session," said Dunleavy in a May 9 statement. "These dedicated Alaskans will serve our state with pride. I have enjoyed working alongside each of them, and I know they will continue to prioritize helping Alaskans and doing what is best for our great state. Thank you, commissioners, for your commitment."

—PETROLEUM NEWS

continued from page 10

SB 114 TESTIMONY

and urged the committee to look for ways to incentivize investment. SB 114, he said, aids those who oppose investment in Alaska and would force companies to reevaluate investments in Alaska.

As for the change in corporate income tax, Griffith said that singles out oil and gas independents. He called for due diligence in analyzing the bills and said there could be unintended consequences, with long-term effects for a short-term solution.

ConocoPhillips Alaska

Barry Romberg, VP, commercial and Alaska midstream, and Walt Bass, VP, finance and IT, testified for ConocoPhillips, and focused on investments since the 2013 transition between ACES and SB 21, arguing that based on North Slope developments, SB 21 is working.

The passage of SB 21 in 2013 made the state more competitive in attracting investment, the men said, resulting in more production.

They noted that since SB 21 was passed ConocoPhillips produced first oil at GMT1 in 2018 and at GMT2 in 2021; at Fiord West Kuparuk the company drilled a record setting well with a new extended reach drilling rig; and progressed work at Nuna and Coyote.

Hilcorp, meanwhile, increased production at Prudhoe Bay and Milne Point.

Final investment decision was reached by Santos at Pikka and potential FID at Willow.

Seventy-one industry exploration wells have been drilled since 2013.

And all of that as the Brent spot oil price had a number of peaks and valleys.

They called out Willow as an SB 21 success story.

As to where investment could go if Alaska became less competitive, ConocoPhillips said unconventional fields in North America are Alaska's competition, with tens of thousands of drilling opportunities, lower costs, closeness to market, easier permitting and "stable, competitive fiscal policies."

ConocoPhillips said SB 114 would result in a significant increase in the cost of doing business in a state where it is already expensive to operate. The $3 per barrel tax credit reduction — with no reduction in the 35% base rate — is a significant tax increase, they said.

The corporate income tax change, they said, would double tax any flow through a partnership.

They noted fiscal stability as a critical part of decision making for long-term investments and called for Alaska to remain competitive "as the world moves toward energy transition." ●

Contact Kristen Nelson
at knelson@petroleumnews.com