Petroleum news

Vol. 28, No. 10 • www.PetroleumNews.com | A weekly oil & gas newspaper based in Anchorage, Alaska | Week of March 5, 2023 • $2.50

page 4 ANS January production up over last month by 0.5%; up year-over-year

88 Energy's Toolik River unit approved 'in part' by Alaska DNR

DEREK NOTTINGHAM

The North Slope Toolik River unit proposed by 88 Energy's operator Accumulate Energy Alaska was approved "in part" on Feb. 27 by Alaska's Division of Oil and Gas; "in part" meaning that instead of the 82,846 acres requested by Accumulate, 59,942 acres were included in the new unit.

The leases approved for inclusion in the Toolik River unit, or TRU, cover the western and central Project Phoenix lease area. They are as follows: ADLs 392296-392315, 392540, 392541, 392756, 392759, 392770, 392771, 392773, 392779-392785, 393078-393080, 393087, 393089, 393090, 393131 and 393133. Many of these leases were close to expiring but the unit approval with a unit plan of exploration extended the leases beyond their primary term through to February 2028.

Leases excluded from the TRU are on the eastern side of the approved leases and include the following: ADLs 393081, 393083, 393085, 393086, 393088, 393091, 393132, 393134 and 393139-393146.

see TOOLIK RIVER page 8

Harvest applies for easement for LNG plant on existing Slope pad

Harvest Alaska has applied to the Alaska Department of Natural Resources for an easement for the construction of a North Slope liquefied natural gas plant on part of an existing gravel pad adjacent the Spine Road, about one mile southeast of Trans-Alaska Pipeline's Pump Station 1.

As previously reported by Petroleum News, Harvest has signed a contract with Fairbanks-based Interior Gas Utility to manufacture LNG for IGU, using North Slope natural gas supplied by Hilcorp Alaska. IGU will truck the LNG from the North Slope to its LNG storage facilities in central Fairbanks and North Pole, thus shifting its entire gas supply arrangements from the Cook Inlet to the North Slope. Harvest is Hilcorp's midstream affiliate that owns and operates pipelines in Alaska.

The Interior Energy Project

IGU's gas supply business evolved through the Interior Energy Project, an Alaska Industrial Development and Export

see LNG PLANT page 10

Geothermal bill heard in House Energy; CCUS in Resources

Gov. Mike Dunleavy's bill to update the state's geothermal statutes, House Bill 74, had its first legislative hearing in the House Special Committee on Energy on Feb. 28. The bill was scheduled for a second hearing in that committee March 2.

The governor's carbon storage bill, HB 50, has been heard numerous times in House Resources. A committee substitute was adopted March 1 with committee amendments on the bill due March 7.

Companion bills in the Senate had not been scheduled for hearings when this issue of Petroleum News went to press.

The geothermal bill, HB 74, was referred to Energy, Resources and Finance. The CCUS bill had Resources and Finance referrals — both Senate bills had Resources and Finance referrals in that body.

CCUS

The governor's carbon storage bills are designed to set the

see DUNLEAVY BILLS page 9

GEOTHERMAL ENERGY

Ignis enters Alaska

Partners with GeoAlaska to explore for and deliver geothermal energy

By KAY CASHMAN
Petroleum News

On March 1, Ignis H2 Energy Inc., a global leader in connecting advanced technologies to establish reliable baseload energy from geothermal resources, and GeoAlaska LLC, a geothermal focused exploration and development company based in Anchorage, announced a new partnership to explore for and produce reliable baseload energy from geothermal resources in Alaska.

"Alaska is blessed with an abundance of natural resources that can be responsibly exploited in order to deliver power, for the benefit of all Alaskans," Richard Calleri, CEO and owner of Ignis, said.

"Currently, geothermal resources in Alaska are under-developed and provide little or no contribution to the state energy mix. Our aim, supported by our sister company Geolog is to work with GeoAlaska to explore for and generate reliable, carbon zero baseload energy, that is sustainably produced and sensitive to local ESG policies and practices," he said.

Paul L. Craig, CEO and majority owner of GeoAlaska added, "GeoAlaska is excited to have this opportunity to partner with Ignis who will bring valuable experience in geothermal exploration and production and assist GeoAlaska with

see GEOTHERMAL ENERGY page 11

FINANCE & ECONOMY

ANS retakes the $80s

Spring-loaded: recovering China oil demand will collide with tight supply

By STEVE SUTHERLIN
Petroleum News

Alaska North Slope crude climbed 69 cents higher March 1, closing at $80.90 per barrel, while West Texas Intermediate rose 64 cents to close at $77.69 and Brent edged up 42 cents to close at $84.31.

ANS regained the $80 range Feb. 28, up $1.05 to close at $80.21, while WTI jumped $1.37 to close at $77.05 and Brent jumped $1.44 to close at $83.89.

Higher prices were supported by factory reports out of China that suggested that the country's rebound from COVID-19 restrictions was picking up steam.

"We created new supply not though investment but through China contracting through lockdowns."
—Jeff Currie, Goldman Sachs

ANS had fallen to $77.48 — its second lowest close of February — on Wednesday Feb. 22, but one week later its March 1 close of $80.90 took it $3.42 higher.

Despite the fluctuation, ANS remained in a narrow trading band established in late 2022 that has seen it trading within several dollars plus or minus the $80 mark — a period of relative stability for the

see OIL PRICES page 10

EXPLORATION & PRODUCTION

Hickory 1 plan approved

88 Energy's North Slope exploration drilling ops to begin in late February

By KAY CASHMAN
Petroleum News

88 Energy Ltd.'s Alaska operator, Accumulate Energy Alaska Inc., received approval Feb. 23 from Alaska's Division of Oil and Gas for its lease plan of operations to carry out the Hickory 1 Exploration Well Project about 30 miles south of Deadhorse on the North Slope.

The project area is on state lands; none of which are jointly managed.

After state land is leased for oil and gas development, projects follow a phased progression. These phases include exploration, development and transportation.

The Division of Oil and Gas, which is part of the Alaska Department of Natural Resources, or DNR, continually examines effects of oil and gas activities as projects transition through each phase.

Before the next phase of a project may proceed, the division must provide notice to the public and the opportunity to comment before issuing a decision. Accumulate's proposed operations would begin the exploration phase for oil and gas lease ADL 392314.

Hickory 1 project components are the pad and well, which will be located at meridian, township, range and section Umiat, T005N, R014E, Sec 19.

The four Hickory 1project milestones are as follows:

1. Mobilize drill rig (start date 2/25/2023, end date 3/8/2023).

see HICKORY 1 PLAN page 11

● ENVIRONMENT & SAFETY

Foggy Island drill site to be remediated

Plan filed for BP America Production lists corrective action including removal of foam board insulation, P&A of exploration well

By KRISTEN NELSON
Petroleum News

In 1975, Amoco Production Co. built an 8-acre pad and drilled the Foggy Island Bay State 1 exploration well in the Sagavanirktok River delta adjacent to the Beaufort Sea some 20 mile northeast of Deadhorse. In 1998, Amoco merged with BP, and BP America Production is in the process of remediating the site to meet Alaska Department of Environmental Conservation regulations.

A temporary land use permit application filed by ERM Alaska on behalf of BP describes the work to be performed, including plugging and abandoning the well.

ERM said the gravel pad is just outside the eastern boundary of the Prudhoe Bay unit and outside the southern boundary of the Duck Island unit.

An ice road will be required, estimated at 1.1 miles.

What's on the pad

Erm said the gravel pad is some 800 feet by 200 feet and appears to be some 3 feet thick compared to the surrounding tundra, with the pad surface level and no evidence of retention of surface water.

There is a capped drilling waste reserve pit to the southeast of the wellhead. The pit was filled with gravel and leveled in 1983. When a site assessment was done in 1989, "slight depressions were noticed in the cap, but no standing water was observed."

There were four fuel storage areas on the western corner of the pad which were filled with gravel and leveled in 1989.

There is an associated cellar drain pit, burn pit, sewage pit and incinerator pad, all of which were filled and graded in 1983.

A 2013 assessment found the condition of the site similar to that found in 1989, with the gravel pad remaining relatively debris free, sparse vegetation growth, and no hydrocarbon staining or standing water visible on the pad surface.

Work planned

Ice road construction was expected to occur in January, followed by construction of an ice pad around the existing Foggy Island Bay gravel pad in early 2023, allowing for material and equipment staging and to allow equipment to maneuver.

The exploration well was to be properly plugged and abandoned. The Alaska Oil and Gas Conservation Commission issued a drilling permit in early February to BP America Production for a re-entry of the Foggy Island Bay State 1 well.

In addition to saying the well will be properly plugged and abandoned, the site rehabilitation plan says the corrective action plan includes cutting off "the casing of the existing exploration well at least 3 feet below tundra grade."

Work includes loosening and removing sand/gravel above the existing foam board and segregating clean versus contaminated soil.

The foam board insulation is to be removed and hauled offsite for landfill disposal.

ERM said the layer of foam board was believed to be some 6 inches thick at the time of installation. It extends beneath the entire gravel pad at a depth of some 1.4 feet below the current surface. Borings taken in 2013 show the foam has compressed to some 1-2 inches thick.

Uncontaminated and minimally contaminated soil from the reserve and burn pits is to be removed and used as backfill in the pit areas.

Contaminated soil from the pit areas and the lined fuel storage areas is to be excavated and transported "offsite for proper disposal at the Grind and Inject facility."

Confirmation soil samples will be collected for field screening and laboratory analysis.

Once cleanup levels are achieved, excavated areas will be backfilled and graded and top dressed with 3-5 inches of organic-rich overburden.

This summer, debris from winter activities will be picked up and initial revegetation activities will begin, with revegetation monitoring expected to continue for up to 10 years. ●

Contact Kristen Nelson at knelson@petroleumnews.com

contents

Alaska-Mackenzie Rig Report

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status

Alaska Rig Status

North Slope - Onshore

All American Oilfield LLC			
IDECO H-37	AAO 111	Stacked in MagTec's Yard	Available
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Milne Point, MPU B-37	Hilcorp Alaska LLC
Dreco 1000 UE	16 (SCR/TD)	Standby	Available
Dreco D2000 Uebd	19 (SCR/TD)	Kuparuk, 3S-704	ConocoPhillips
AC Mobile	25	Alpine, MT7-97	ConocoPhillips
OIME 2000	141 (SCR/TD)	Standby	Available
	142 (SCR/TD)	Alpine, CD3-303	ConocoPhillips
TSM 700	Arctic Fox #1	Standby	ConocoPhillips
ERD	26	Alpine, CD2-361	ConocoPhillips
Hilcorp Alaska LLC			
Rotary Drilling	Innovation	Prudhoe Bay, Z Pad	Hilcorp Alaska LLC
Nabors Alaska Drilling			
AC Coil Hybrid	CDR-2 (CTD)	Prudhoe Bay, L4 Pad	Hilcorp Alaska LLC
AC Coil	CDR-3 (CTD)	Kuparuk	ConocoPhillips
Dreco 1000 UE	7-ES (SCR-TD)	Kuparuk	ConocoPhillips
Dreco 1000 UE	9-ES (SCR/TD)	Stacked	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Stacked	Brooks Range Petroleum
Emsco Electro-hoist			
Oilwell 2000 Canrig 1050E	27-E (SCR-TD)	Stacked	Available
Academy AC Electric CANRIG	99AC (AC-TD)	Stacked	Available
OIME 2000	245-E (SCR-ACTD)	12 Acre Pad, stacked	Available
Academy AC electric CANRIG	105AC (AC-TD)	Stacked	Available
Academy AC electric Heli-Rig	106AC (AC-TD)	Stacked	Available
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Deadhorse	Available
Superior 700 UE	2 (SCR/CTD/TD)	Hickory 1 well	Accumulate Energy Alaska
Ideco 900	3 (SCR/TD)	Deadhorse	ASRC
Rig Master 1500AC	4 (AC/TD)	Oliktok Point	ENI
Parker Drilling Arctic Operating LLC			
NOV ADS-10SD	272	Deadhorse Yard, undergoing maintenance/upgrades	Santos
NOV ADS-10SD	273	Deadhorse, Stacked	Available

North Slope - Offshore

Doyon Drilling			
Sky top Brewster NE-12	15 (SCR/TD)	Spy Island SP42-NE4	ENI
Nabors Alaska Drilling			
OIME 1000	19AC (AC-TD)	Oooguruk	ENI

Cook Inlet Basin – Onshore

BlueCrest Alaska Operating LLC			
Land Rig	BlueCrest Rig #1	Stacked	BlueCrest Alaska Operating LLC
Glacier Oil & Gas	Rig 37	West McArthur River Unit Workover	Glacier Oil & Gas
Hilcorp Alaska LLC			
TSM-850	147	Beluga River Unit, F Pad	Hilcorp Alaska LLC
TSM-850	169	Pearl Pad	Hilcorp Alaska LLC

Cook Inlet Basin – Offshore

Hilcorp Alaska LLC			
National 110	C (TD)	Platform C, Stacked	Hilcorp Alaska LLC
	Rig 51	Steelhead Platform, Stacked	Hilcorp Alaska LLC
	Rig 56	Monopod A-13, stacked	Hilcorp Alaska LLC
Nordic Calista Services			
Land Rig	36 (TD)	Kenai, stacked	Available
Spartan Drilling			
Baker Marine ILC-Skidoff, jack-up		Spartan 151, Tyonek Platform	Hilcorp Alaska LLC
Glacier Oil & Gas			
National 1320	35	Osprey Platform, activated	Glacier Oil & Gas

Mackenzie Rig Status

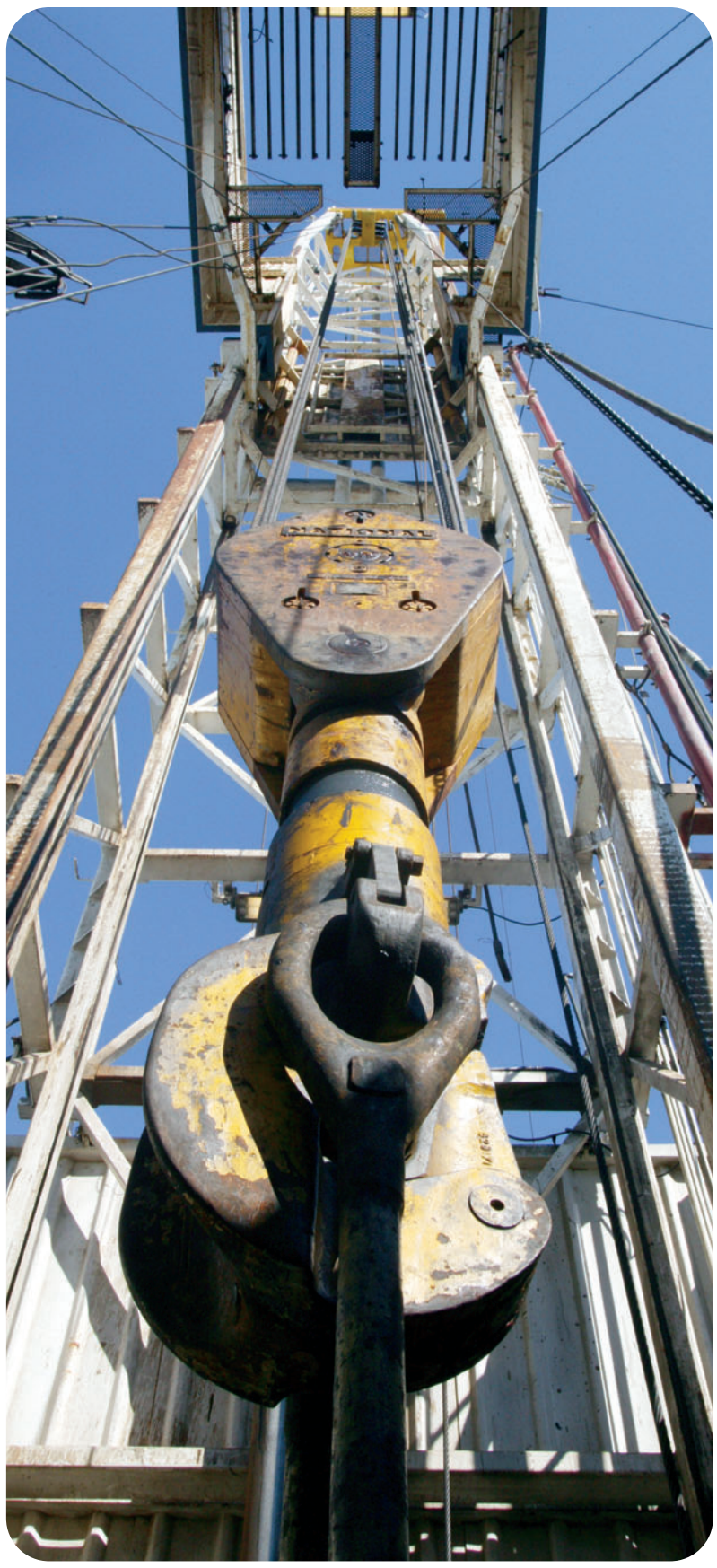
Canadian Beaufort Sea

SDC Drilling Inc.		
SDC Mobile Offshore Drilling Unit Rig #2	Set down at Roland Bay	Available

The Alaska-Mackenzie Rig Report as of March 1, 2023. Active drilling companies only listed.

TD = rigs equipped with top drive units WO = workover operations
CT = coiled tubing operation SCR = electric rig

This rig report was prepared by Marti Reeve



JUDY PATRICK

Baker Hughes North America rotary rig counts*

	Feb. 24	Feb.17	Year Ago
United States	753	760	650
Canada	244	248	224
Gulf of Mexico	17	17	12

Highest/Lowest		
US/Highest	4530	December 1981
US/Lowest	244	August 2020

*Issued by Baker Hughes since 1944

EXPLORATION & PRODUCTION

Slope January production edges up 0.5%

Average is 500,747 bpd, up from 498,184 bpd in December, led by 4,167 bpd Greater Mooses Tooth increase; Prudhoe up by 1,190 bpd

Cook Inlet gas up year-over-year

January natural gas production from Cook Inlet averaged 225,202 thousand cubic feet per day, down 238 mcf, 0.1%, from a December average of 225,440 mcf per day, but up 10.5% from a January 2022 average of 203,701 mcf per day.

This data is from the Alaska Oil and Gas Conservation Commission, which reports production on a month-delay basis. For natural gas AOGCC reports measurements in thousands of cubic feet, mcf.

Inlet gas production is dominated by six fields, each accounting for more than 5% of total volume: Ninilchik, North Cook Inlet, Beluga River, Kenai, McArthur River and Kitchen Lights. Collectively the fields accounted for 79% of production in January.

Hilcorp Alaska's Ninilchik averaged 50,155 mcf per day in January, 22.3% of inlet production, up 2,006 mcf per day, 4.2%, from a December average of 48,149 mcf per day and up 69.7% from a January 2022 average of 29,556 mcf per day.

Hilcorp's North Cook Inlet averaged 38,886 mcf per day in January, 17.3% of inlet production, down 1,090 mcf per day, 2.7%, from a December average of 39,977 mcf per day but up 29.2% from a January 2022 average of 30,093 mcf per day.

The Hilcorp-operated Beluga River field averaged 38,050 mcf per day in January, 16.9% of inlet production, down 1,973 mcf per day, 4.9%, from a December average of 40,023 mcf per day and up 11.9% from a January 2022 average of 34,011 mcf per day.

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By KRISTEN NELSON
Petroleum News

Alaska North Slope production averaged 500,747 barrels per day in January, up 2,563 bpd, 0.5%, from a December average of 498,184 bpd, but down 0.1% from a January 2022 average of 501,328 bpd.

Crude oil accounted for 87.8% of ANS January production, an average of 439,735 bpd, up 1,829 bpd, 0.4%, from a November average of 437,906 bpd but down 0.1% from a January 2022 average of 440,304 bpd.

ANS natural gas liquids averaged 61,012 bpd, 12.2% of January production, up 734 bpd, 1.2%, from a December average of 60,278 bpd and down marginally from a January 2022 average of 61,025 bpd.

Production data come from the Alaska Oil and Gas Conservation Commission which reports production by field and well on a month delay basis.

Month-over-month increases

The largest month-over-month increase, 4,167 bpd, 32.8%, was at ConocoPhillips Alaska's Greater Mooses Tooth in the National Petroleum Reserve-Alaska. This appears to be a return to a more normal production level, following a December production drop of 17.8%.

GMT production has increased substantially since a second pad at that field, GMT2, came online in mid-November 2021. During most of 2021, GMT averaged less than 3,500 bpd. The field's production peaked in May 2022 at an average of 20,349 bpd, 91% of that volume from the new pad, GMT2.

Production in November averaged 15,456 bpd, 87.3% from GMT2, dropping to 12,698 bpd in December, 82.3% from GMT2. In January, production averaged 16,866 bpd, 86.9% from GMT2.

Combined crude and NGLs from the Hilcorp North Slope-operated Prudhoe Bay field averaged 281,681 bpd, up 1,190 bpd, 0.4%, from a December average of 280,492 bpd and up 2% from a January 2022 average of 276,266 bpd.

Prudhoe crude averaged 224,633 bpd in January, 79.75% of the volume, up 617 bpd, 0.3%, from a December average of 224,016 bpd and up 2.1% from a January 2022 average of 220,000 bpd. Prudhoe NGL production averaged 57,048 bpd, 20.25% of the total, up 573 bpd, 1%, from a December average of 56,475 bpd and up 1.4% from a January 2022 average of 56,266 bpd.

Production volumes from Prudhoe include satellite production from Aurora, Borealis, Lisburne, Midnight Sun, Niakuk, Polaris, Point McIntyre, Put River, Raven and Schrader Bluff.

ConocoPhillips Alaska-operated Kuparuk River averaged 82,511 bpd in January, up 738 bpd, 0.9%, from a December average of 81,773 bpd and down 5.1% from a January 2022 average of 86,960 bpd.

In addition to the main Kuparuk pool, Kuparuk produces from satellites at Tabasco and Tarn, and from West Sak.

Hilcorp Alaska's Endicott averaged 6,613 bpd in January, up 0.1%, 5 bpd, from a December average of 6,608 bpd and down 4.7% from a January 2022 average of 6,942 bpd. Crude accounted for 88.2% of the field's production, 5,831 bpd, down 6 bpd, 0.1%, from a December average of 5,837 bpd and up 0.2% from a January 2022 average of 5,823 bpd. NGLs were11.8% of volume, averaging 782 bpd, up 11 bpd, 1.5%, from a December average of 770 bpd and down 30.2% from a January 2022 average of 1,119 bpd.

Month-over-month declines

The largest per-barrel month-over-month decline was at ConocoPhillips' Colville River, which averaged 35,806 bpd in January, down 2,048 bpd, 5.4%, from a December average of 37,854 bpd and down 11.2% from a January 2022 average of 40,328 bpd.

In addition to oil from the main Alpine pool, Colville includes production from the Nanuq and Qannik oil pools.

Hilcorp Alaska-operated Point Thomson averaged 7,288 bpd in January, down 940 bpd, 11.4%, from a December average of 8,228 bpd and down 20.1% from a January 2022 average of 9,120 bpd.

Eni's Oooguruk averaged 6,553 bpd in January, down 272 bpd, 4%, from a December average of 6,825 bpd but up 13.9% from a January 2022 average of 5,752 bpd.

Hilcorp Alaska's Milne Point averaged 39,114 bpd in January, down 216 bpd, 0.6%, from a December average of

see **ANS OUTPUT** *page 5*

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ANS OUTPUT

39,329 bpd but up 5.5% from a January 2022 average of 37,084 bpd.

Hilcorp's Northstar averaged 6,924 bpd in January, down 46 bpd, 0.7%, from a December average of 6,969 bpd and down 17.1% from a January 2022 average of 8,348 bpd. Crude was 54% of the field's January production, averaging 3,741 bpd, down 195 bpd, 5%, from a December average of 3,937 bpd and down 20.5% from a January 2022 average of 4,709 bpd. NGLs were 46% of Northstar's January production, averaging 3,182 bpd, up 149 bpd, 4.9%, from a December average of 3,033 bpd and down 12.6% from a January 2022 average of 3,639 bpd.

Eni's Nikaitchuq averaged 16,889 bpd in January, down 15 bpd, 0.1%, from a December average of 16,904 bpd and up 0.5% from a January 2022 average of 36,811 bpd.

Savant's Badami averaged 503 bpd in January, down marginally, 1 bpd, 0.2%, from a December average of 504 bpd and down 52.4% from a January 2022 average of 1,055 bpd. Savant is a Glacier Oil and Gas company.

Cook Inlet down 0.3%

Cook Inlet production averaged 8,762 bpd in January, down 30 bpd, 0.3%, from a December average of 8,792 bpd and down 6.7% from a January 2022 average of 9,387 bpd.

The Cook Inlet volumes are 99% crude, with 1%, all at Swanson River, from NGLs.

The inlet's largest producer, Hilcorp's McArthur River, averaged 2,879 bpd in January, 33% of inlet production, up 27 bpd, 0.9%, from a December average of 2,852 bpd and up 11.5% from a January 2022 average of 2,582 bpd.

Hilcorp's Granite Point averaged 2,274 bpd in January, 26% of inlet production, down 73 bpd, 3.1%, from a December average of 2,348 bpd and down 10.9% from a January 2022 average of 2,552 bpd.

Hilcorp's Trading Bay averaged 822 bpd in January, 9.4% of inlet production, up 120 bpd, 17.1%, from a December average of 702 bpd and down 10.2% from a January 2022 average of 915 bpd.

BlueCrest's Hansen averaged 736 bpd in January, 8.4% of inlet production, down 8 bpd, 1.1%, from a December average of 744 bpd and down 10.3% from a January 2022 average of 820 bpd.

Hilcorp's Swanson River averaged 726 bpd in January (635 bpd of crude and 91 bpd of NGLs), 8.3% of inlet production, down 20 bpd, 2.7%, from a December average of 746 bpd and up 12.4% from a January 2022 average of 647 bpd.

Hilcorp's Beaver Creek averaged 507 bpd in January, 5.8% of inlet production, up 1 bpd, 0.2%, from a December average of 506 bpd and down 9.6% from a January 2022 average of 561 bpd.

Cook Inlet Energy's Redoubt Shoal averaged 457 bpd in January, 5.2% of inlet production, down 64 bpd, 12.2%, from a December average of 521 bpd and down 55.4% from a January 2022 average of 1,025 bpd. CIE is a Glacier Oil and Gas company.

CIE's West McArthur River averaged 360 bpd in January, 4.1% of inlet production, down 28 bpd, 7.3%, from a December average of 388 bpd but up 26.4% from a January 2022 average of 285 bpd.

ANS crude oil production peaked in 1988 at 2.1 million bpd; Cook Inlet crude oil production peaked in 1970 at more than 227,000 bpd. ●

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INLET GAS

Hilcorp's Kenai field averaged 23,079 mcf per day in January, 10.3% of inlet production, down 332 mcf per day, 1.4%, from a December average of 23,411 mcf per day and down 17.2% from a January 2022 average of 27,856 mcf per day.

Hilcorp's McArthur River averaged 15,672 mcf per day in January, 7% of inlet production, down 624 mcf per day, 3.8%, from a December average of 16,296 mcf per day and down 21% from a January 2022 average of 19,826 mcf per day.

Furie's Kitchen Lights averaged 12,181 mcf per day in January, 5.4% of inlet production, up 750 mcf per day, 6.6%, from a December average of 11,431 mcf per day and up 1.1% from a January 2022 average of 12,052 mcf per day.

Fifteen smaller producing fields accounted for 21% of inlet production in January.

Hilcorp's Beaver Creek averaged 8,950 mcf per day in January, down 1,243 mcf per day, 12.2%, from a December average of 10,193 mcf per day and up 11.4% from a January 2022 average of 8,034 mcf per day.

Hilcorp's Swanson River averaged 8,447 mcf per day in January, up 2,712 mcf per day, 47.3%, from a December average of 5,735 mcf per day and down 36% from a January 2022 average of 13,199 mcf per day.

Hilcorp's Ivan River averaged 6,937 mcf per day in January, down 414 mcf per day, 5.6%, from a December average of 7,351 mcf per day and up 38.3% from a January 2022 average of 5,016 mcf per day.

Hilcorp's Cannery Loop averaged 6,408 mcf per day in January, down 97 mcf per day, 1.5%, from a December average of 6,505 mcf per day and up 51.3% from a January 2022 average of 4,236 mcf per day.

Hilcorp's Deep Creek averaged 4,117 mcf per day in January, down 139 mcf per day, 3.3%, from a December average of 4,256 mcf per day and up 27.9% from a January 2022 average of 3,220 mcf per day.

Hilcorp's Granite Point averaged 3,325 mcf per day in January, down 1 mcf, 0.02%, from a December average of 3,326 mcf per day and down 6.3% from a January 2022 average of 3,549 mcf per day.

Vision Operating's North Fork averaged 2,977 mcf per day, down 91 mcf per day, 3%, from a December average of 3,068 mcf per day and down 11.8% from a January 2022 average of 3,376 mcf per day.

AIX's Kenai Loop averaged 2,415 mcf per day in January, up 326 mcf per day, 15.6%, from a December average of 2,089 mcf per day and down 39.1% from a January 2022 average of 3,966 mcf per day.

BlueCrest's Hansen averaged 1,602 mcf per day in January, down 149 mcf per day, 8.5%, from a December average of 1,751 mcf per day and down 19.6% from a January 2022 average of 1,992 mcf per day.

Hilcorp's Trading Bay averaged 1,018 mcf per day in January, up 247 mcf per day, 32%, from a December average of 771 mcf per day and down 34.4% from a January 2022 average of 1,552 mcf per day.

Hilcorp's Lewis River averaged 374 mcf per day in January, down 118 mcf per day, 24.1%, from a December average of 492 mcf per day and down 62.7% from a January 2022 average of 1,003 mcf per day.

Hilcorp's Nikolaevsk averaged 224 mcf per day in January, down 15 mcf per day, 6.4%, from a December average of 239 mcf per day and down 23.9% from a January 2022 average of 294 mcf per day.

Amaroq's Nicolai Creek averaged 157 mcf per day in January, down 9 mcf per day, 5.5%, from a December average of 167 mcf per day and down 10.2% from a January 2022 average of 175 mcf per day.

Cook Inlet Energy's Redoubt Shoal averaged 130 mcf per day in January, up 5 mcf per day, 3.7%, from a December average of 125 mcf per day and down 44.1% from a January 2022 average of 232 mcf per day. CIE is a Glacier Oil and Gas company.

CIE's West McArthur River averaged 98 mcf per day in January, up 12 mcf per day, 14.1%, from a December average of 86 mcf per day and up 56.8% from a January 2022 average of 63 mcf per day.

Cook Inlet natural gas production peaked in the mid-1990s at more than 850,000 mcf per day.

—KRISTEN NELSON

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EXPLORATION & PRODUCTION

State approves expansion of 12-acre pad

The Alaska Department of Natural Resources' Division of Oil and Gas has approved a request from ConocoPhillips Alaska to expand the 12-acre pad in the Kuparuk River unit.

The Feb. 23 approval is for a unit plan of operations amendment application dated Dec. 19.

The company plans to expand the pad by placing some 18,500 cubic yards of clean gravel fill onto 2.6 acres of tundra, expanding pad on its western side, the division said, to provide additional laydown space for staging and storage of drilling rigs, equipment piping and other materials associated with an increase in North Slope activity.

The work, to be done from the existing gravel pad, is scheduled to begin in April.

DNR's Division of Mining, Land and Water inquired whether the Nabors Alaska Drilling rig 245E would be temporarily displaced by the work. The division provided ConocoPhillips' response which was that the Nabors 245E rig would remain on the pad during and after construction, there are no plans to move the rig off the pad and it is anticipated it will remain on site for the foreseeable future.

—PETROLEUM NEWS

US rotary drill rig count down 7 to 753

The Baker Hughes' U.S. rotary drilling rig count was down by seven rigs the week ending Feb. 24 to 753 and up 103 from a count of 650 for the same period a year ago. The count has dropped in five of the past eight weeks, down from 779 at the end of December after reaching a high for 2022 of 784 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 Feb. 24 count includes 600 rigs targeting oil, down seven from the previous week and up 78 from 522 a year ago, with 151 rigs targeting natural gas, unchanged from the previous week and up 24 from 127 a year ago, and two miscellaneous rigs, unchanged from the previous week and up by one from a year ago.

Forty-four of the rigs reported Feb. 24 were drilling directional wells, 693 were drilling horizontal wells and 16 were drilling vertical wells.

Alaska rig count unchanged

Pennsylvania (25) was up by three rigs from the previous week.

West Virginia (12) was down three rigs.

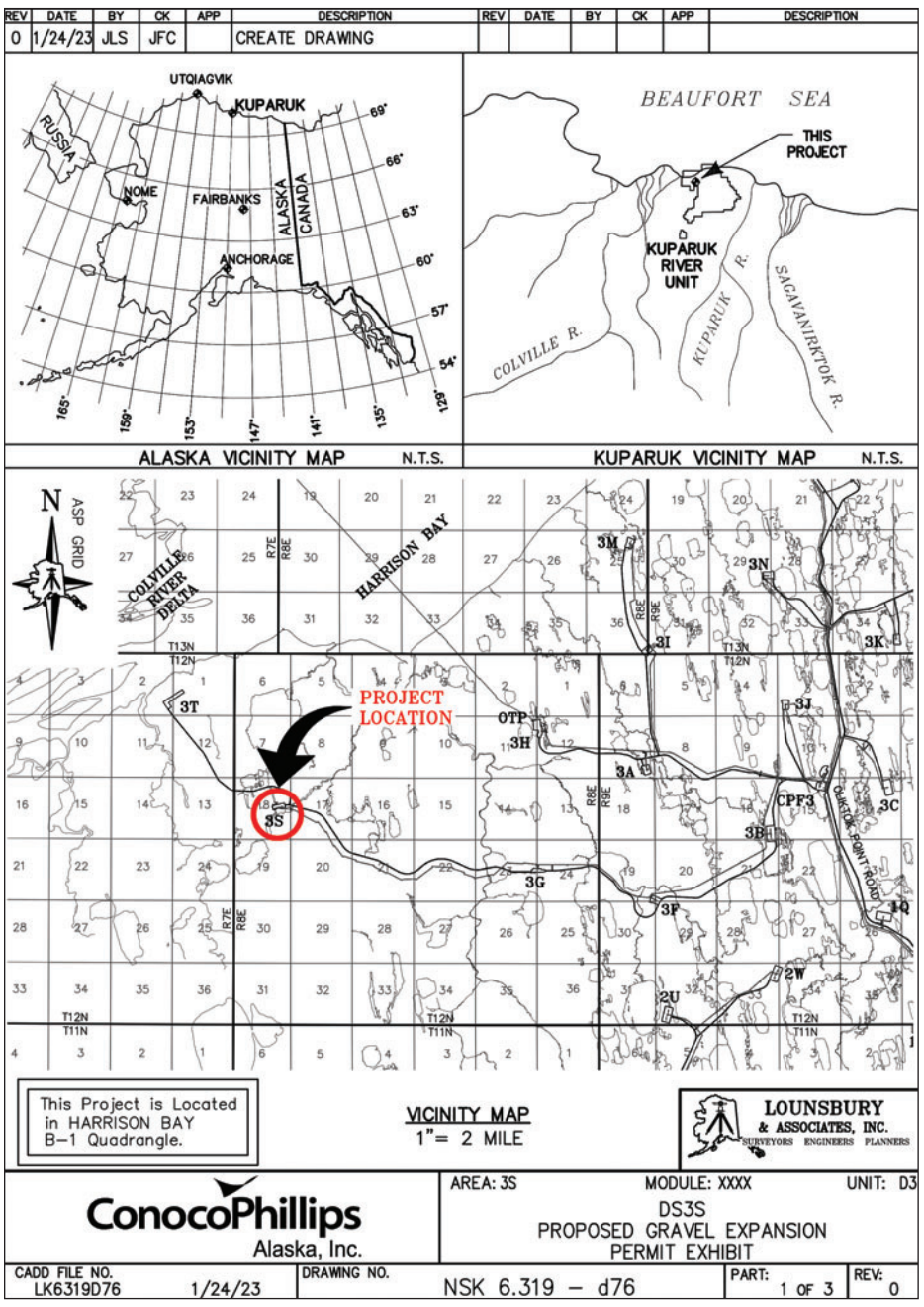
California (2), New Mexico (106) and Oklahoma (62) were each down by two rigs week over week, while Colorado (17) was down a single rig.

Rig counts in other states were unchanged from the previous week: Alaska (7), Louisiana (64), North Dakota (41), Ohio (14), Texas (370), Utah (11) and Wyoming (18).

Baker Hughes shows Alaska with seven rotary rigs active Feb. 24, unchanged from the previous week and down by one from a year ago, when the state's rig count stood at eight. All seven of the Alaska rigs were onshore, unchanged from the previous week. There were no offshore rigs active in the state.

The rig count in the Permian, the most active basin in the country, was up by one rig from the previous week at 353 and up by 44 from 309 a year ago.

—KRISTEN NELSON



● EXPLORATION & PRODUCTION

Conoco to expand 3S drillsite at Kuparuk

By KRISTEN NELSON
Petroleum News

ConocoPhillips Alaska has applied to expand drillsite 3S in the Kuparuk River unit and drill 16 new wells.

In its Feb. 7 application ConocoPhillips said it is proposing to expand the existing DS 3S gravel pad by placing some 65,000 cubic yards of clean gravel fill onto 7.75 acres of tundra. The company is also requesting approval to install 16 new wells.

In addition to the wells, space is required for the drilling rig, equipment, piping, vertical support members "and other materials associated with the Coyote development," the company said.

The Alaska Department of Natural Resources Division of Oil and Gas issued a public notice Feb. 23 for the unit plan of operations amendment application for the work. Comments on the application are due March 23.

An illustration of the proposed work shows the pad being expanded primarily on the eastern end, with some expansion on the southern side of the pad. Sixteen wells are proposed to be added at the pad and the illustration has Doyon 142 named in the expansion area, presumably the rig the company plans to use, or an indication of that or a similar rig.

In related permitting, the company received approval from the Alaska Oil and Gas Conservation Commission on Jan. 4 for a three-year enhanced oil recovery pilot at the Coyote reservoir, which is on the western edge of the Kuparuk River unit.

In its approval the commission said the Nanushuk formation was first discovered near the proposed pilot project area in the 1965-66 Sinclair Colville 1 well, some 3 miles south-southwest of 3S pad. Phillips Alaska's Palm 1 2001 exploration well, drilled from what is now the 3S pad, encountered oil shows in Nanushuk sandstones, the commission said, and also noted that seven development and service wells drilled to deeper reservoirs have penetrated the Coyote interval in or near the planned project area.

An illustration of the proposed work shows the pad being expanded primarily on the eastern end, with some expansion on the southern side of the pad. Sixteen wells are proposed to be added at the pad and the illustration has Doyon 142 named in the expansion area, presumably the rig the company plans to use, or an indication of that or a similar rig.

The 3S-24B, a 2021 exploratory redrill, penetrated and tested the Coyote interval, AOGCC said.

In its application to the division, ConocoPhillips said the proposed start for gravel work is March 15, with the work proposed to be completed by the end of the year.

Wells are proposed to be drilled beginning March 15, with drilling continuing through the end of 2025.●

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● UTILITIES

Division of O&G approves CINGSA 2023 POD

Cook Inlet Natural Gas Storage Alaska will add pig launcher, receiver, to meet PHMSA requirements for piping at the facilities

By KRISTEN NELSON
Petroleum News

The Alaska Division of Oil and Gas has approved the 2023 plan of development for Cook Inlet Natural Gas Storage Alaska's gas storage lease ADL 391627.

In the POD, submitted Jan. 31, CINGSA said 2022 was the facility's 11th calendar year of operation. CINGSA converted the nearly depleted Sterling C1 and C2 sands into an underground gas storage reservoir, drilling five injection/withdrawal service wells during 2011. Work to perforate and complete the five wells began at the end of January 2012, with all wells completed by the third week of February.

CINGSA said Sterling C produced some 23 billion cubic feet of natural gas prior to being shut-in in 2012 and was estimated to have originally contained 26.5 bcf of gas in place.

Compression station facilities are east of the intersection of Beaver Loop Road and Bridge Access Road on property purchased by CINGSA. The well facilities are between Boat Launch Road and Bridge Access Road on property owned by the state and leased to CINGSA.

Storage injection began with free flow of gas in April 2012, with injection with compression beginning later in that month. CINGSA said initial injection capacity was below expectations, which was determined to be caused by near-wellbore completion damage. The re-perforation of all five wells corrected the situation, significantly improving injection/withdrawal capacity "and after eight storage cycles, performance on average is now consistent with design capacity."

CINGSA said it operates the storage reservoir under a contracted maximum total storage volume of 18 bcf, 11 bcf of working gas and 7 bcf of base gas, with its contracts allowing it to inject some 68% of the reservoir's initial gas-in-place.

2022 activities

CINGSA said normal maintenance and operations in 2022 included semiannual shut-ins in April and September.

To meet requirements of the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, CINGSA constructed a small gravel pad on the plant site to prepare for pipeline inspection gauge — pig — launch operations, with piping construction for the pig launcher also completed.

During 2022, CINGSA injected some 6.2 bcf, the division said, and withdrew some 4.7 bcf. CINGSA's POD shows injections peaking in June and July and withdrawals peaking in January.

2023 proposed activities

CINGSA said that in 2023 it will be adding pig launcher and receiver to meet PHMSA requirements for the pipeline between the well pad and the facility, including expanding the well pad by some 15,000 square feet within the existing leased area to accommodate safe installation and operation of the pig receiver construction which will take place in phases over two years to meet permitting requirements. Completion of the pipe modifications and pig launcher is anticipated by December 2023. ●

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● THIS MONTH IN HISTORY

Geologists discuss Foothills geology

20 years ago this month: Div. of Geological & Geophysical Surveys geologists making some exciting discoveries near the Haul Road

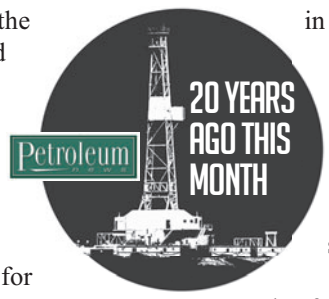
Editor's note: This story appeared in the March 9, 2003, issue of Petroleum News Alaska.

By ALAN BAILEY
Petroleum News

A team of geologists working near the Haul Road on the north side of the Brooks Range is piecing together the detailed geology of some of the rocks that underlie much of the North Slope. The investigations are yielding new information about potential oil and gas source rocks and reservoirs.

"What we're trying to do ... is collect baseline geological data in the Foothills belt, north of the Brooks Range, south of the NPR-A (National Petroleum Reserve-Alaska), that are important for understanding the oil and gas resources of the area," Dave LePain, NPR-A-Foothills program leader in the Division of Geological and Geophysical Surveys, told Petroleum News Alaska.

LePain leads a team consisting of Rocky Reifenstuhl, Ellen Harris and Paige Peapples of the Alaska Division of Geological and Geophysical Surveys and Gil Mull of the Alaska Division of Oil and Gas — Mull was one of the geologists who discovered the Prudhoe Bay field back in the 1960s. This core team is collaborating with several other geologists.



Industry provides much of the funding for the program.

"Our operational support ... and most of our analytical budget ... comes from an industry consortium that we've developed over the past five, six, seven years," LePain said.

Mapping and stratigraphy

The program involves detailed geological mapping combined with investigations of the rock stratigraphy.

"We usually map in the area where we're doing the detailed stratigraphic studies — the two kind of go hand in hand," LePain said.

And the study takes a particular interest in rocks that show potential economic value.

"We focus in on selected stratigraphic units that have economic significance, either as reservoirs or as source rocks," he said.

Geological mapping by the DGGS team also feeds into a federal program called StateMap, in which the U.S. Geological Survey is assembling detailed maps through state agencies. The StateMap program enables some federal funds to be applied to the mapping component of the DGGS work.

"Every year we submit a project proposal and a budget to the StateMap committee ... for funding," LePain said. DGGS alternates between energy and mineral related StateMap projects in successive years.

see **HISTORY** *page 8*

continued from page 7

HISTORY

"All of the energy state maps have been up on the North Slope and over the last five years or so they've all been in the area that the NPR-A-Foothills program is working," he said. "So we use StateMap moneys and our industry consortium moneys to try to leverage each other."

The Foothills belt

The study area sits in the Foothills belt of the Brooks Range, where rocks that lie under the North Slope become exposed at the surface.

Uplift and overthrusting of the Brooks Range more than 100 million years ago loaded and depressed the earth's crust to the north, forming the so-called Colville Basin that extends east to west under the North Slope. Erosion of the newly formed mountains dumped huge quantities of sand, silt and other debris into this basin over an extensive time period.

Later movement in the Brooks Range pushed the rock strata up to the surface along the north front of the mountains. As a result, the Foothills area affords excellent surface access to strata that are buried underground elsewhere. By detailed investigation of the surface exposures, the study team can provide valuable insights into the geology for people doing seismic exploration.

"What we're looking at is basically the outcrop equivalents of the units that occur in the subsurface to the north," LePain said. "... by looking at them in outcrop you're able to get information that you can't get when you're limited to just the subsurface ... so by providing outcrop details to the industry groups that are up there actively exploring, they can integrate that outcrop data set with their subsurface data and come up with a much better understanding."

Oil-stained sands near the Haul Road

The team of geologists has found widespread outcrops of oil-stained Lower Cretaceous sandstones in the area west from the Haul Road to Chandler Lake. In that area, deepwater sands grade upward into shallow water or non-marine sands. Many of these sands exhibit excellent reservoir potential — some U.S. Geological Survey geologists have even suggested that the oil staining provides evidence of a breached, pre-existing oilfield.

"You've got these deepwater sands and shallow marine sands that have good indications of hydrocarbons having been in them in the past, so these are definitely potential reservoir rocks in the subsurface to the north," LePain said.

And there's an abundance of shales which could provide a rich source of hydrocarbons.

"Gil Mull's ... taken the lead on the source rock part of the stratigraphic study, focusing in on ... a unit that we call the Otuk formation," he said.

The Otuk formation, a deepwater deposit exposed just west of the trans-Alaska pipeline, a short distance north of the Brooks Range front, contains organic-rich shales and shaly limestones.

GIL MULL

DAVE LEPAIN

"Some of these have upwards of 10 to 15% total organic carbon, so they're rich marine source rocks and they're correlative with the Shublik," LePain said.

The Shublik is a stratigraphic unit that people recognize in the subsurface geology throughout the North Slope and that forms the source rock for much of the oil in the Prudhoe Bay area, he said.

Although people generally think that the thermal history of the rocks in the Foothills belt favors gas generation, Mull's analyses of the Otuk rocks reveals intriguing evidence of the formation of oil.

"For a long time the Foothills belt was largely regarded as a gas province. ... Gil's work on these Otuk exposures suggests that that's probably the case," LePain said. "But some of his geochemical results are showing that there might be more oil potential than was originally recognized — that's very economically significant."

Oil indications east of the Haul Road

The area east of the Haul Road between the Sagavanirktok and Ivishak Rivers is yielding some equally interesting finds. The rocks in this area post-date the rocks to the west and generally exhibit the depositional features of deeper water.

"The Colville Basin, north of the Brooks Range, was filled from west to east, so the older rocks are in the central part of the basin and the western part," LePain said. "As you go east, the rocks get younger and you get a predominance of the deep water facies."

The NPR-A-Foothills team has found a well-exposed 3,900-meter rock sequence on an unnamed drainage east of the Haul Road — the geologists are trying to correlate this sequence back to the detailed stratigraphy that they have established to the west. The fossils in the eastern sequence indicate an Upper Cretaceous age.

And there's ample indication of oil formation in these younger rocks.

"There's oil-stained sands in the base of that section ... and then there's also some brown paper shales that are probably correlative with the Hue shale gamma ray zone," LePain said. The Hue shale gamma ray zone is a very prominent North Slope subsurface log marker that people think to be an important hydrocarbon source rock.

Indeed, the paper shales that the team has discovered contain substantial organic material and may have generated oil that can be detected in an adjacent layer of a type volcanic rock called a tuff.

"(There are) volcanic tuffs in the same part of the section and they just reek of oil," LePain said, "... you break them open and they smell like the floor of a gas station."

Assessing the reservoir potential

Following some initial funding from the Division of Oil and Gas for laboratory work, the team has supplemented its fieldwork with tests on rock samples, to determine the reservoir potential of the various sandstones in the study area. The lab tests measure the porosity and permeability of the samples — the porosity determines how much fluid the rock can hold, while the permeability provides a measure of how easily fluids can flow through the rocks.

"So now what we do routinely when we're out in the field is we collect the samples from selected sand units and then we send off a limited suite for laboratory analysis," LePain said.

Team member Rocky Reifenstuhl has been assembling the results of the tests and also looking at microscope slides of the rocks, to determine the internal features that give rise to the porosity and permeability.

LePain pointed out that weathering can make porosity and permeability measurements of surface exposed rocks misleading. However, he believes that the results of the lab tests yield generally useful information for assessing the reservoir potential at depth.

Future direction

So how will the NPR-A-Foothills program progress in the future?

When the program started about four years ago the team planned to investigate the surface geology all the way from the Haul Road to the DeLong Mountains at the far western end of the Brooks Range. However, the discoveries in the rock outcrops in the area near the Haul Road have caused the team to focus on that area rather than moving further west.

"We've kind of become bogged down in the eastern part of that whole trend in the Chandler Lake, Sag River area, because there's so much geology there of economic significance," LePain said. "... each year as we think about the upcoming field season we can't really justify moving further out to the west, because there's so much left to be done."

With the program now entering the fifth year of what was initially a five-year plan, the project team will need to assess the future direction. The program could move west, as originally envisaged. However, economic interest in the geology east of the Haul Road and the possibility of the coastal plain of the Arctic National Wildlife Refuge opening for exploration could favor an eastward move.

So, future direction will depend in part on where industry exploration goes — the program team will seek input from its sponsoring industry consortium and the Division of Oil and Gas.

Meanwhile the NPR-A-Foothills team continues to extend the knowledge of rocks that may turn out to be critical in future oil and gas discoveries. ●

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TOOLIK RIVER

The Hickory 1 well will be drilled into approved lease 392324 this month (see related page 1 story titled "Hickory 1 plan approved").

Division of Oil and Gas Director Derek Nottingham said in his decision that "the approved TRU area includes the reservoirs that have been proven through drilling and testing; additional delineation work, however, will determine commercial viability. Leases outside the approved TRU acreage were not included due to a lack of data to support the existence of a potential hydrocarbon accumulation."

One of the approved leases, 392301, contains the Icewine 1 and 2 wells previously drilled by Accumulate and adjacent to both the trans-Alaska pipeline and the Dalton Highway.

In a Feb. 28 ASX release, 88 Energy said that "unitization of the leases in the Toolik River unit provides an efficient, integrated approach to exploration, delineation, and development of the numerous identified and potential reservoirs."

Accumulate Energy's plan of exploration filed with the Division of Oil and Gas includes a program of drilling and non-drilling activities as follows:

• The non-drilling activities will focus on conducting a further review and analysis of the Franklin Bluffs 3D data, including completion of amplitude-variation-with-offset analysis (AVO analysis) and simultaneous seismic inversion (SSI or inversion), to assist in defining further "sweet spots" for each play and determine optimal drilling locations for future exploration and appraisal wells, as well as to further mature the conventional prospectivity of the TRU acreage.

• Drilling activities include the Hickory1 vertical exploration well this winter and performing a flow test, subject to well results, during the 2023/2024 season.

• Subject to success of the Hickory 1 exploration well, the company will consider mobilizing a rig to the Franklin Bluffs pad and re-entering the Icewine 1 well to potentially conduct a short-term production test — or drilling and flow testing a new delineation appraisal well in a subsequent season.

• Subject to obtaining positive results from the flow tests and exploration program, plans also include drilling a horizontal production test well with an extended flow test program.

• Subject to the successful flow test of Hickory 1, non-drilling activities may also include the acquisition, processing and interpretation of new 2D seismic over the eastern portion of the Project Phoenix acreage.

Gilbert pleased

"We are pleased that the DNR has approved the Toolik River unit covering the western and central leases of the Project Phoenix acreage and our plan of exploration. This is a further demonstration of the strong support that 88 Energy, and the broader industry, enjoys from the State of Alaska," 88 Energy Managing Director, Ashley Gilbert, said in the Feb. 28 ASX release.

The new TRU lies directly adjacent to the southern border of Great Bear Pantheon's Talitha unit, approximately 27 miles south of the Prudhoe Bay unit.

The approved TRU is effective as of the date of the director's decision, Feb. 27.

—KAY CASHMAN

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DUNLEAVY BILLS

framework for the state to lease its pore space for carbon storage, collecting revenues for both leasing the pore space and for storage fees.

In presentations to House Resources the week of Feb. 19, there was concern from members about the upfront costs to the state — a fiscal note from the Department of Natural Resources Division of Oil and Gas covered the addition of two positions, a storage geologist I/II position to evaluate and characterize carbon storage resources in the state and an economist II/III/IV position to conduct research on commercial and fiscal storage terms and long-term liability issues.

And a fiscal note from the Alaska Oil and Gas Conservation Commission showed more than $1 million to cover that agency's costs.

At the Feb. 27 hearing, DNR, represented by Deputy Commissioner John Crowther and Aaron O'Quinn, leasing section manager in the division, said that there would be a revised fiscal note from DNR to accompany the committee substitute showing no additional costs. They said the licensing program could be integrated with existing leasing IT infrastructure and handled by existing subject-matter expertise.

Primacy issue

The committee had at one point suggested it might defer allowing AOGCC to pursue the Class VI well primacy from EPA, although it had heard testimony that having state primacy for Class VI wells was an important consideration for industry because of more timely response from state regulators.

AOGCC provided a Jan. 31 letter of intent to the U.S. Environmental Protection Agency, notifying EPA that AOGCC intended to participate in the UIC Class VI grant program, which provides funds for states applying to assume Class VI well primacy. The committee was told AOGCC's initial costs are expected to be recoverable from the EPA grant program.

For a growing program, costs would be offset by regulatory charges or licensing fees.

The committee substitute did not drop pursuing Class VI primacy.

CCUS opportunities

Also in the Feb. 27 hearing, DNR listed opportunities for CCUS beyond leasing and injection revenues, including extending the life of existing royalty revenues by providing opportunities to operators for decarbonization, with additional revenue opportunities through enhanced oil recovery and royalty-like payments for use of the state's pore space.

The department also noted CCUS would build on, preserve and possibly grow the in-place industry workforce.

Geothermal

The governor's geothermal bill was presented to House Energy Feb. 28 by DNR's Crowther and O'Quinn.

The goal of HB 74 is to modernize the state's geothermal exploration program by aligning geothermal leasing with the state's oil and gas exploration license program. Under HB 74 companies would also have more time to identify and prove the resource, with the exploration license being convertible to leases.

The length of the initial license term would increase from the current 2 years to 5 years, with conversion to leases through completion of a work commitment expressed in dollars, and annual reporting and performance objectives.

Geothermal leases would be for 10 years, with a 5-year extension possible. Leases under production would run for the term of production.

Holders of current geothermal prospecting permits could convert those to geothermal exploration licenses.

Currently the DNR commissioner has an opportunity after 20 years to renegotiate rental and royalty rates and that would be repealed, allowing companies more certainty for long-term investments in geothermal projects.

HB 74 also increases the maximum acreage a lessee may hold from 51,200 acres to 100,000 acres, reflecting the fact that geothermal systems can underlie very large areas.

And rental fees would be set by regulation, rather than by statute, enabling the division to respond to market changes.

HB 74 also modernizes unitization statutes for geothermal to match the model the state uses for oil and gas, allowing the DNR commissioner to compel unitization; establish, change or revoke drilling, producing and royalty requirements of leases as part of the unit agreement; and making leases and unit agreements subject to current and future statutes and regulations.

HB 74 was on House Energy's schedule for March 2, after this issue of Petroleum News goes to press.

—KRISTEN NELSON

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Petroleum news

Oil Patch Bits

Alaska West Express delivers cat stat

As reported by Lynden News Feb. 27, in January Alaska West Express was called upon to respond to a natural disaster. An Alaska Railroad freight train was heading into Anchorage early on the morning of Jan. 17 when it ran into avalanche debris on the track. There were no injuries, but the impact derailed two locomotives, partially derailed a third and held up 7,000 tons of freight. The avalanche occurred the previous night, covering the track near Turnagain Arm with tons of snow and debris.

"The Alaska Railroad came knocking on our door at 5:30 a.m.," said Alex Clifford, Alaska West Express Anchorage service center manager. "Dave Heston was in the office and ready to help. They needed to get a 117,000-pound Cat 345B excavator moved from Anchorage to the avalanche site, which was about 3 miles south of Girdwood." Dave called one of Alaska West Express' long-time drivers, Aaron Smith, and told him about the situation. Aaron drove in from his home in Wasilla, hooked up the lowboy by 7 a.m. and delivered the equipment approximately five hours later so the railroad could dig the engines out. Workers had to clear a spot for him to fit the truck and lowboy in the snow. The oversized excavator is modified with larger tracks for flotation and a huge snow bucket.

ALASKA WEST EXPRESS

"We couldn't get a train down to offload the Alaska Marine Lines rail barge in Whittier until the avalanche was cleaned up," Alex explains. Lynden's rail barges arrive in Whittier once a week from Seattle loaded with freight bound for different points in Alaska. The track was repaired on Jan. 24 and rail service was restored later that week allowing for offloading of the rail barge a few days later.

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LNG PLANT

Authority sponsored project with the objective of bringing affordable natural gas to the Fairbanks region. The original concept behind the IEP had been to manufacture LNG for Fairbanks from North Slope natural gas. However, following engineering work for the LNG project it became clear by the end of 2014 that the project was not viable — the project costs would have resulted in gas prices too high for gas consumers. Instead, an existing facility near Point Mackenzie has been used to manufacture LNG from Cook Inlet gas, with the LNG being shipped by truck to Fairbanks.

But following concerns about the reliability of future Cook Inlet gas supplies, in January IGU signed contracts with Hilcorp and Harvest for the future supply of North Slope manufactured LNG. The resulting cost of gas for Fairbanks consumers would be similar to the cost of gas derived from the Cook Inlet.

The gravel pad

As part of the original IEP concept of producing LNG on the North Slope, AIDEA did sponsor the construction of a gravel pad on the Slope for the siting of an LNG plant. It is that same pad that Harvest now plans to use to locate its LNG plant. In 2019 AIDEA entered into a purchase and sale agreement to transfer a lease with the pad and access road to Ahtna Petrochemical Products LLC. And in March 2022 Ahtna assigned the lease to Alyeschem LLC. Alyeschem plans to construct a petrochemical plant on the gravel pad to produce methanol.

But the planned methanol plant will not require the whole gravel pad — the concept now is that Harvest's LNG plant and Alyeschem will each use part of the pad, while sharing some of the pad for common uses such as pad access. The two companies are negotiating a purchase and sales agreement to address gravel ownership and shared use of the pad.

LNG manufactured in the new plant will either be loaded directly into trucks for shipment to Fairbanks or will be diverted into storage tanks for later shipment. The facility will have a 150,000 gallons per day production capacity. The liquefaction process will result in the generation of some natural gas liquids, which will be separated and returned to Hilcorp. Initial LNG storage capacity will depend on the practicalities of shipping a suitable storage tank to the site. Ultimately, the facility will likely have two 75,000-gallon storage tanks.

IGU will separately pay Hilcorp for the natural gas supply and Harvest for the LNG manufacturing.

Harvest anticipates starting work on preparing the gravel pad in July of this year. Following pipeline construction, installation of the LNG facility would begin in March 2024. The company expects commissioning of the facility to be completed by the end of October 2024.

—ALAN BAILEY

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OIL PRICES

traditionally volatile commodity.

The recent placidity of markets stands in contrast to the wildly whipsawing action that has gripped prices since early 2020 when oil cratered to a negative price level on a demand collapse only to surge a year ago as Russia invaded Ukraine, taking ANS into the high $120s.

U.S. inventory builds of late have helped moderate oil prices despite China's reopening, and this week is no exception although the build was below analyst expectations.

U.S. commercial crude oil inventories for the week ending Feb. 24 — excluding Strategic Petroleum Reserve supplies — rose 1.2 million barrels from the previous week, the U.S. Energy Information Administration said in its March 1 report. At 480.2 million barrels, inventories stand 9% above the five-year average for the time of year.

Total motor gasoline inventories fell 0.9 million barrels for the period, however, to 5% below the five-year average for the time of year.

The indexes fell Feb. 27. ANS slipped 64 cents to close at $79.16, WTI fell 64 cents to close at $75.68 and Brent fell 71 cents to close at $82.45.

ANS gained 76 cents Feb. 24 to close at $79.80, as WTI gained 93 cents to close at $76.32 and Brent gained 95 cents to close at $83.16.

ANS jumped $1.56 Feb. 23 to close at $79.04, while WTI jumped $1.44 to close at $75.39 and Brent jumped $1.61 to close at $82.21.

Spring-loaded situation

Recent market stability aside, a growing cadre of analysts see a resurgence in Chinese demand on the horizon that will collide with an oil market that has little ability to supply more barrels quickly due to underinvestment in new exploration and development.

Jeff Currie, Goldman Sachs global head of commodities research, said he expects crude will surge above $100 per barrel in the fourth quarter, adding that his confidence in an oil price spike during the next 12 to 18 months is "quite high."

The "big event" affecting oil supplies last year was not Russia, it was China, Currie said in a "Bloomberg Surveillance Early Edition" interview March 1.

"Global oil demand contracted 2% in the fourth quarter of last year; that's a recession in my book," Currie said. "That created the spare capacity in oil, metals … everything, and that manufacturing data that came out this morning says we're starting to reverse that."

"We created new supply not though investment but through China contracting through lockdowns," he said. "Now as China comes back, we're going to lose that spare capacity and we're going to be back to the same problems we had before, but even much worse because we haven't invested."

Currie said energy security, reliability, and energy affordability are all now back on the agenda.

"The ability to get from one year to the next, given how scarce supply is, is really the focus," he said.

BofA Global Research expects Brent to average $88 per barrel in 2023, it said in a new report, Rigzone reported Feb. 28.

"Coupled with limited U.S. shale supply growth and OPEC's tight grip on the market, we now expect the reopening of China to result in Brent crude oil prices averaging $88 per barrel in 2023, down from $100 per barrel prior, and $90 per barrel in 2024," BofA Global Research said.

Oil prices should see support from increased capital discipline across the global oil industry and thinning spare capacity, it said in the report.

In a separate report Feb. 21, JP Morgan said its prediction that Brent will average $90 in 2023 remains unchanged.

The Russian factor

Dislocations rising from Russia's invasion of Ukraine continue, but the effects on markets are subsiding.

"It is the most significant set of market dislocations and distortions in energy markets generally speaking that I ever recall," Ed Morse, Citi global head of commodity research said, per a Feb. 24 Yahoo Finance report.

"It has, from a markets' perspective, created two markets, a transparent market, and a non-transparent market," he said.

"In a roundabout way, the December 5, 2022, price caps that were imposed on Russian crude oil exports are working," Andy Lipow of Lipow Oil Associates said in a note. "The E.U. and USA and others are not buying from Russia; that leaves Russia with a limited number of customers; those customers are demanding lower prices."

Russian crude oil was simply reshuffled from old customers in Europe to new customers in Asia, Lipow said. ●

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HICKORY 1 PLAN

2. Drill and evaluate Hickory 1 (start date 3/1/2023, end date 4/5/2023).

3. Demobilize drill rig, camp and support operations (start date 4/5/2023, end date 4/30/2023).

4. Clean up, remediate ice infrastructure — pad and road areas (7/1/2023, end date 8/20/23).

In a Feb. 27 ASX release 88 Energy said that Hickory 1 ice pad construction is nearing completion and that pre-spud operations are on schedule.

The company also said that mobilization of the Nordic Calista rig and operations equipment would begin "shortly."

Deepest zone Kuparuk

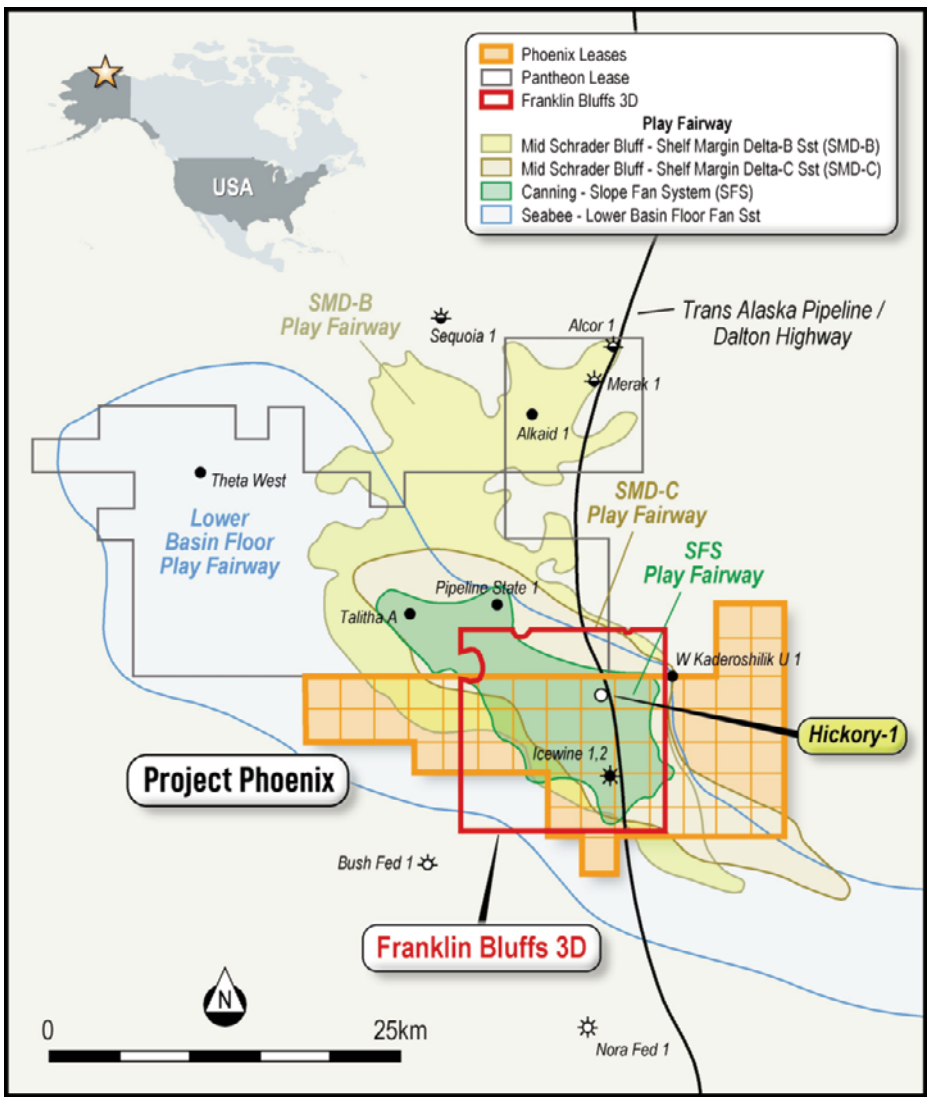
As mentioned, Hickory 1 will be approximately 30 miles south of the Deadhorse. The pad will be located 400 feet west of the Dalton Highway, approximately 0.3 miles south of Milepost 382.

The well will be situated on a 600-foot by 600-foot ice pad, for a total of 8.26 acres, and connected to the Dalton Highway by a 500-foot-long ice road.

The ice pad and road are expected to be built 2 to 3 feet thick. The road is expected to be roughly 500 feet in length and 35 feet in width, for a total of approximately 0.4 acres. The total ice footprint will be approximately 8.66 acres.

The final configuration of the road and pad may be slightly modified to account for on-site conditions.

The Hickory 1 plan is derived from relevant drilling and geological data obtained from seismic data, as well as from historical offset wells in the surrounding area.



88 ENERGY

Using the Nordic Calista Rig-2 the Hickory 1 well will be drilled to a vertical depth of 12,500 feet through various hydrocarbon zones of interest, with the deepest zone being the Kuparuk sands.

In the Feb. 27 release 88 Energy was more specific, saying: "The well is designed to appraise up to six conventional reservoir targets within the SMD, SFS, BFF and KUP reservoirs and 647 million barrels of oil and is permitted to a total depth of up to 12,500 feet. The primary targets for the well are the 3 SMD reservoirs (SMD-A, B and C), with the SFS and BFF reservoirs considered secondary targets. The Kuparuk reservoir is a tertiary target and will be drilled subject to time remaining in the season, borehole conditions and other technical considerations."

The formations will be logged and sidewall cores may be taken in specific zones of interest as needed. At the end of the project the Hickory 1 well will be plugged and abandoned or suspended in accordance with Alaska Oil and Gas Conservation Commission requirements.

The Feb. 27 release said flow testing of the Hickory 1 well is planned to be undertaken during the 2023/24 winter season, subject to well results. "This will provide ample time, subsequent to drilling of the well, to optimize the flow test program, design, permitting and implementation."

Temporary structures

All structures required to complete the Hickory 1 project will be temporary. Facilities located on the drill ice pad to support the project will include a camp, storage and laydown areas, communication tower and connexes, and maintenance shops.

The camp will be equipped with offices, a medic/camp clinic, bathroom facilities, dining area, kitchen and food storage facilities, recreation area, and laundry facilities.

During the public notice period in December and early January no comments were received.

A status report for the activities conducted under the division's approval must be filed on May 1 and Nov. 1 each year, from the date the approval was issued and until a final completion report is filed with the division. ●

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GEOTHERMAL ENERGY

its ultimate goal of producing net zero-carbon baseload power at competitive rates for the benefit of all Alaskans."

Craig said that "working hand in hand with Ignis, GeoAlaska believes we can accomplish that goal."

In its March 1 release, Ignis said it is focused on evaluating and advancing technologies that lead to a sustainable energy path. The company is "currently assessing and evaluating geothermal opportunities based on their technical, resource sustainability and financial risks with a view to quickly becoming a geothermal power producer in multiple countries."

Within this role, Ignis is partnering with companies that offer "step change innovations to improve reliability, cost, and efficiency in geothermal energy delivery."

The end goal for Ignis? 100% Green Hydrogen production from geothermal.

GeoAlaska is an Alaska based geothermal exploration company that currently holds exploration permits in the Cook Inlet region of Alaska with a focus on Augustine Island and Mount Spurr, both situated along the west shore of the Cook Inlet, with potential for connection to the Alaska Railbelt power grid.

For more information about Ignis Energy go to www.ignisenergy.com. Geolog can be found at www.Geolog.com.

Recent articles about GeoAlaska can be found in Petroleum News story archive www.petroleumnews.com. ●

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MARCUS OESTERBERG

An artistic rendering of a geothermal power plant on Augustine Island.