Petroleum news

page 4 Yeager named interim president at Alyeska Pipeline, replacing McCown

Vol. 27, No. 6 • www.PetroleumNews.com A weekly oil & gas newspaper based in Anchorage, Alaska Week of February 6, 2022 • $2.50

Nottingham named director of Alaska's Division of Oil and Gas

DEREK NOTTINGHAM

As of Feb. 1, Derek Nottingham, who has been serving as petroleum economist for the Alaska Department of Revenue, took office as the new director of Alaska's Division of Oil and Gas.

An experienced reservoir engineer, Nottingham received a bachelor's and master's degree focused in Petroleum Engineering from Louisiana State University.

Prior to working for DOR, he was employed by BP for 11-plus years, most recently from February 2015 to April 2020 as reservoir development area team lead for BP at Prudhoe Bay. Nottingham led the

see **NEW DIRECTOR** page 10

Hilcorp conducts geohazard survey in federal waters of Cook Inlet

According to information on the Bureau of Ocean Energy Management website, Hilcorp Alaska completed its planned geohazard survey in federal leases in Cook Inlet last year. Hilcorp has not responded to requests from Petroleum News for information about the survey. The company presumably carried out the survey during the summer months, when the waters of the inlet would have been free of sea ice.

The surveying had been planned to encompass four lease blocks about halfway across the inlet, to the west of Kachemak Bay. Hilcorp sees the potential to drill up to four exploratory wells in federal lands in the lower Cook Inlet — federal regulations require a geohazards evaluation in the

see **GEOHAZARD SURVEY** page 7

State has Marathon, Petro Star RIK findings out for comment

The Alaska Department of Natural Resources, Division of Oil and Gas, has issued preliminary best interest findings and determinations for two proposed sales of North Slope royalty oil, one to Marathon Petroleum Supply and Trading Company LLC and one to Petro Star Inc. The documents are available at https://dog.dnr.alaska.gov/Library/. Deadline for comments is 4:30 p.m. March 2.

Both contracts were negotiated by the DNR commissioner on behalf of the state.

Under its oil and gas leases, the state may take its royalty either in value or in kind. With royalty in kind, RIV, the state's royalty oil is marketed by the lessee along with its own

see **RIK FINDINGS** page 10

Cook Inlet Energy submits PODs for Redoubt, West McArthur River

Cook Inlet Energy, a Glacier Oil and Gas company, submitted plans of development for its Redoubt and West McArthur River units to the Alaska Division of Oil and Gas Feb. 1.

Production from the Cook Inlet units was suspended from May 2020 through September 2021 (at Redoubt) and through October 2021 (for West McArthur River) due to unfavorable economic conditions.

The company said it completed an extensive restart program on the west side of Cook Inlet from July to October 2021, bringing online assets that were previously cold stacked, including wells in both the Redoubt and West McArthur River units.

At Redoubt, the 21st POD shows four wells in production, all

see **DEVELOPMENT PLANS** page 7

EXPLORATION & PRODUCTION

Exploration status

Number of Alaska North Slope winter wells still uncertain, 2 for sure, maybe 3

By KAY CASHMAN

Petroleum News

The Alaska faces of Eni, 88 Energy and Pantheon, from left to right, Robert Province, Erik Opstad and Pat Galvin.

88 Energy and Great Bear Pantheon are moving forward with their winter North Slope wells. Great Bear has already spud Theta West 1 and 88 Energy has finished its 111-mile snow road between KRU 2P and the Merlin 2 well location.

A third company, Eni US Operating, a subsidiary of Italian multinational Eni S.p.A., hasn't yet made its intentions public about an offshore exploration well planned north of its Nikaitchuq unit for April.

In its 14th plan of development for the Nikaitchuq unit, which runs from Oct. 1 through Sept. 30, 2022, operator Eni told Alaska's Division of Oil and Gas that facility upgrades will be completed to support a second Nikaitchuq North

see **EXPLORATION STATUS** page 11

FINANCE & ECONOMY

ANS stays above $90

Bullish for ANS: Los Angeles moves to eliminate oil and gas wells in the city

By STEVE SUTHERLIN

Petroleum News

Alaska North Slope crude fell 3 cents Feb. 2, closing at $90.54 per barrel in a trading week that saw a high close of $91.08 Jan. 31 and a low of $90.25 Jan. 27.

West Texas Intermediate and Brent rose Feb. 2 — WTI up 6 cents to close at $88.29 and Brent up 31 cents to $89.47. Brent hit a high close of $91.21 Jan. 31, but it lost $2.05 to close at $89.16 Feb. 1.

Oil staged its largest January gain in at least 30 years, posting a 17% gain over the month, but was little changed after the most recent week of trading. ANS stood at $90.51 per barrel on Jan. 26, 3 cents shy of the Feb. 2 price.

> *"Oil and gas production in the United States is a great geopolitical asset." —oil historian Daniel Yergin*

U.S. commercial crude oil inventories — excluding those in the Strategic Petroleum Reserve — fell by 1 million barrels from the week ending Jan. 28, according to the U.S. Energy Information Administration. At 415.1 million barrels, U.S. crude oil inventories stand 9% below the five-year average for the time of year.

In early trading Feb. 3, as Petroleum News went to press, WTI and Brent were trading slightly

see **OIL PRICES** page 8

NATURAL GAS

Study: AK LNG competes

Wood Mackenzie looks at updated project, compares it favorably to GOM projects

By KRISTEN NELSON

Petroleum News

A study by Wood Mackenzie for the Alaska Gasline Development Corp. concludes that the Alaska LNG project, with improvements over the past 5 years which reduced the cost of supply by 43%, is now competitively positioned ahead of U.S. Gulf Coast LNG projects with a window for the project's LNG in the world market by 2028.

AGDC released the study Jan. 31. It is available online at AGDC.us.

In a Jan. 31 statement AGDC said over the past 5 years it has obtained federal project authorization, reduced project construction costs by 12% and implemented a project financing structure using third party tolling.

> *LNG demand growth remains robust beyond 2050, Wood Mackenzie said, with Japanese spot prices of $8 per unit expected, above the $6.70 Alaska cost of supply.*

AGDC said Wood Mackenzie calculates that those changes, along with a reduction in the expected cost to purchase natural gas, reduce the project's cost of supply to Asia to $6.70 per million British thermal units.

"The new potential cost of supply falls below

see **LNG STUDY** page 9

● UTILITIES

EV charging station rates proposed

Railbelt and Juneau utilities apply to RCA for approval of electricity fees for commercial high speed charging stations

By **ALAN BAILEY**
For Petroleum News

Electric utilities on the Alaska Railbelt electrical system and in Juneau have applied to the Regulatory Commission of Alaska for approval of electricity rates for high speed charging stations for electric vehicles. A program sponsored by the Alaska Energy Authority is underway to implement a series of commercial high speed charging stations along the Alaska highway system — the availability of these stations is seen as critical to the use of electric vehicles for long distance travel in Alaska. However, the current fees for the provision of electricity for commercial use may undermine the commercial viability of the charging stations. Hence the filing of the new charging station rate structures.

Demand charges

The essential problem with the existing commercial electricity rates relates to what are referred to as demand charges. These charges involve fees linked to the maximum rate of electricity usage, to encourage commercial electricity users to appropriately manage their electricity demand profiles. But, because electric vehicles have a particular demand profile involving high demand peaks when vehicles are being charged but low demand at other times, the utilities have argued that the existing demand charges would render the power supplies for the charging stations to be unrealistically expensive.

Chugach Electric Association is proposing load factors that apply to commercial rates equivalent to the rates charged for residential customers, with the resulting charging station rates then equaling the rates charged for residential use.

The use of demand charges responds to the requirement that high rates of peak demand require matching supply capacity in the electricity system.

Two other issues also needed to be resolved. One problem arises from the fact that the existing electric utility tariffs prohibit purchasers of electricity from a utility from reselling the electricity: Clearly the commercial operator of a charging station would be reselling electricity to its customers. The other issue relates to the question of whether the operator of a commercial charging station would be viewed as a utility, subject to RCA regulation.

RCA approval of rate structure

In October the RCA approved a general charging station rate structure proposed by the Railbelt utilities involving a demand charge formula using a charging station load factor that each utility would specify in its tariff. The commission also ordered utilities to state whether they would allow charging station operators to resell electricity. And the commission clarified that charging stations are not public utilities. The commission required the filing of revised electricity supply tariffs incorporating the new charging station rate structures by Jan. 24. The approved rate would apply on an inception basis, subject to potential approved change, for up to 10 years, while the utilities gather information on actual charging station usage.

Utility tariff filings

In their new tariff filings, each utility has proposed a charging station load factor, based on its assessment of charging station usage in its service area. That has enabled the utility to determine a charging station electricity rate, assuming that the load from the charging station remains below the proposed load factor. If, however, the actual load exceeds the load factor, the resulting electricity rate would be higher.

Matanuska Electric Association, for example, has proposed a 5% load factor, with a resulting rate of $0.30243 per kilowatt hour. However, if a charging station operator thinks that its charging stations will exceed

see **CHARGING RATES** *page 5*

contents

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

Alaska-Mackenzie Rig Report

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

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
All American Oilfield LLC			
IDECO H-37	AAO 111	Deadhorse, Stacked in Cruz Yard	Available
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Standby	Hilcorp Alaska LLC
Dreco 1000 UE	16 (SCR/TD)	Standby	
Dreco D2000 Uebd	19 (SCR/TD)	Standby	
AC Mobile	25	Alpine, MT7-96	ConocoPhillips
OIME 2000	141 (SCR/TD)	Standby	
	142 (SCR/TD)	Alpine, WD-30	ConocoPhillips
TSM 700	Arctic Fox #1	Start Up, waiting for mobilization to Merlin 2	Emerald House
ERD	26	Alpine, CD2-310	ConocoPhillips
Hilcorp Alaska LLC			
Rotary Drilling	Innovation	Milne Point, S Pad	Hilcorp Alaska LLC
Nabors Alaska Drilling			
AC Coil Hybrid	CDR-2 (CTD)	Prudhoe Bay	Hilcorp Alaska LLC
AC Coil	CDR-3 (CTD)	Kuparuk	ConocoPhillips
Ideco 900	3 (SCR/TD)	Deadhorse, Stacked	Available
Dreco 1000 UE	7-ES (SCR-TD)	Kuparuk	ConocoPhillips
Mid-Continental U36A	3-S	Stacked	Available
Oilwell 700 E	4-ES (SCR)	Stacked	Available
Dreco 1000 UE	9-ES (SCR/TD)	Stacked	Available
Oilwell 2000 Hercules	14-E (SCR)	Deadhorse	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
Oilwell 2000	33-E	Deadhorse	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)	Deadhorse, stacked	Available
Ideco 900	3 (SCR/TD)	West Theta	Great Bear Pantheon
Rig Master 1500AC	4 (AC/TD)	Oliktok Point	ENI
Parker Drilling Arctic Operating LLC			
NOV ADS-10SD	272	Deadhorse, Stacked	Available
NOV ADS-10SD	273	Deadhorse, Stacked	Available

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Sky top Brewster NE-12	15 (SCR/TD)	Spy Island, SI15-E1	ENI
Nabors Alaska Drilling			
OIME 1000	19AC (AC-TD)	Oooguruk, Stacked	ENI

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
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	Stacked	Hilcorp Alaska LLC
TSM-850	169	Seaview	Hilcorp Alaska LLC

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
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
Furie Operating Alaska			
Randolf Yost jack-up		Nikiski, OSK dock	Available
Glacier Oil & Gas			
National 1320	35	Osprey Platform, activated	Glacier Oil & Gas

Mackenzie Rig Status

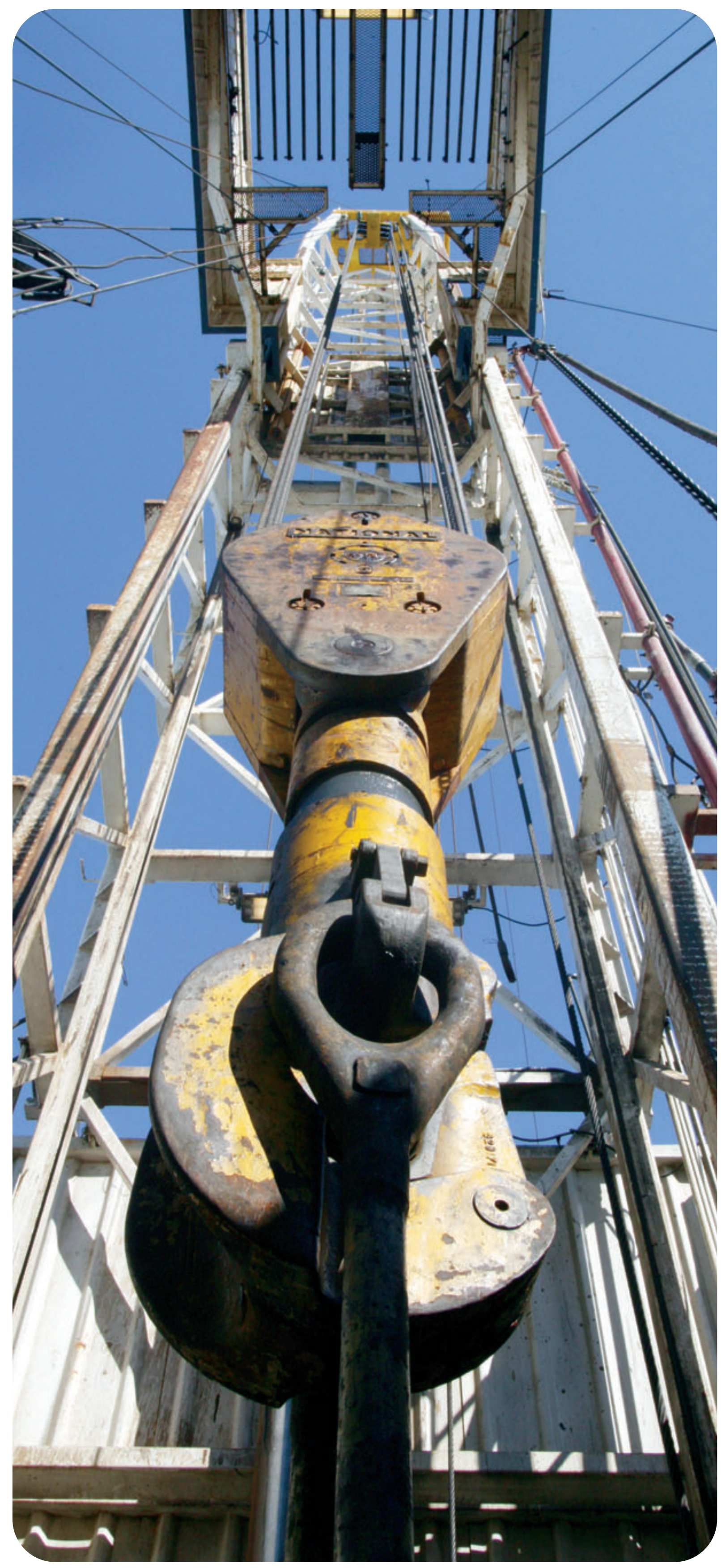
Canadian Beaufort Sea

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
SDC Drilling Inc.			
SDC Mobile Offshore Drilling Unit Rig #2		Set down at Roland Bay	Available

The Alaska-Mackenzie Rig Report as of February 2, 2022.
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*

	Jan. 28	Jan. 21	Year Ago
United States	610	604	384
Canada	217	212	174
Gulf of Mexico	18	18	16

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

*Issued by Baker Hughes since 1944

PIPELINES & DOWNSTREAM

Yeager named interim president at Alyeska

Alyeska Pipeline Service Co. said Brigham McCown, who has been the president, left the company Jan. 31.

"Alyeska and the TAPS Owners want to thank him for his two years of leading Alyeska and wish him the best in his future endeavors," the company said in a statement.


DANIKA YEAGER

Danika Yeager, who joined Alyeska as vice president of operations and maintenance in 2021, has been named interim president.

Alyeska said Yeager has "decades of midstream leadership," with experience in operations; health, safety and environment; regulatory compliance; commercial; and joint venture owner relations.

Prior to joining Alyeska, Yeager held positions of increasing responsibility at Colonial Pipeline Co. and Enterprise Products Co., and led development of a $1.2 billion crude export terminal with Lone Star Ports LLC in Corpus Christi, Texas.

Yeager earned a bachelor of arts from Mary Washington College in Virginia, a master of science from the University of South Carolina and a master of business administration from Richmond College in London, England.

"The continued safe and reliable operation of the Trans Alaska Pipeline System (TAPS) is Alyeska's top priority," the company said, adding, "Alyeska and the TAPS Owners have confidence that Ms. Yeager will effectively guide the organization forward as we work towards a permanent appointment."

Alyeska, which operates the trans-Alaska oil pipeline and the Valdez Marine Terminal on behalf of the owner companies, has more than 700 employees; the company said there are also hundreds of contractors also working at any given time.

Owners of Alyeska Pipeline Service Co. are Harvest Alaska LLC, 49.1069%; ConocoPhillips Transportation Alaska Inc., 29.6102%; and ExxonMobil Pipeline Co., 21.2829%.

—KRISTEN NELSON

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
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
907.522.9469
circulation@petroleumnews.com

ADVERTISING
Susan Crane • 907.770.5592
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. 27, No. 6 • Week of February 6, 2022

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

Hilcorp applying to drill Pearl 2A well

Exploration gas well would be drilled from south of Ninilchik unit; spacing exception required; hearing tentatively scheduled

By KRISTEN NELSON
Petroleum News

Hilcorp Alaska has applied to the Alaska Oil and Gas Conservation Commission for a spacing exception to drill the Pearl 2A well into an undefined gas pool and the Ninilchik Beluga/Tyonek gas pool.

In a Jan. 26 application to the commission Hilcorp said it plans to spud on or around March 22 from the Pearl Pad south of the Ninilchik unit.

A map submitted with the application shows the proposed bottomhole for the exploration well almost due north of the pad, under Cook Inlet.

Pearl 1 was an exploration well drilled by Chevron USA Inc. in 2002 and described in AOGCC records as a single completion gas well which is plugged and abandoned.

Hilcorp drilled seven Pearl stratigraphic tests in 2017, two of which are now being used as water supply wells; the other five were plugged and abandoned. Six of the stratigraphic tests had true vertical depths of 600 feet; one had a depth of 540 feet.

All the previous Pearl wells had wellhead locations in township 1 south, range 14 west, Seward Meridian, in sections 13, 23, 24 or 26.

Hilcorp said the well path of the Pearl 2A is on three private oil and gas leases and state lease ADL 384372, with the bottomhole on the state lease within the area of Conservation Order 701Cd.

The spacing exception is necessary because the Pearl 2A will be drilled within 1,500 feet of a property line where owners and landowners are not the same on both sides of the line and within 1,500 feet of the exterior boundary of the affected area of Conservation Order 701C.

Testing southern extent of Ninilchik

Hilcorp said Pearl 2A is some 2.5 miles north of Ninilchik within the Pearl prospect, also known as the Pearl field, south and adjacent to the Ninilchik unit.

"Pearl 2A will be the first Hilcorp exploration well drilled around the southern extent of the existing Ninilchik Unit/Field," the company said in its application. Pearl 1 and Ninilchik Unit 1, previous exploration wells, were drilled more than 3,000 feet to the southeast and did not have commercial oil or gas discoveries.

Hilcorp said the closest producing gas well to the Pearl 2A target is Paxton 5, in the Ninilchik unit, which is northeast of Pearl 2A.

"Hilcorp anticipates that the productive sands in Pearl 2A will be discontinuous channel sands in the Beluga and Tyonek Formations within both the Undefined Gas Pool and the Beluga/Tyonek Pool that cannot be produced by wells conforming to applicable spacing restrictions," the company said.

Hilcorp, the Ninilchik unit operator, owns 100% working interest in the affected lands offshore included in ADL 3384372.

Unit extension if successful

Following successful completion of Pearl 2A, and prior to bringing the well online, Hilcorp said it plans to apply to the Alaska Department of Natural Resources, Division of Oil and Gas, to adjust the Ninilchik unit and the corresponding participating area to include any lands reasonably estimated to be productive, or alternatively, form a new unit and PA.

Since there are complex ownerships in the Pearl field, Hilcorp said it plans to allocate production in accordance with DNR's unit and PA decision and said production from Pearl 2A will begin only when a PA including Pearl 2A is approved by the state. A copy of that decision and PA allocation schedule will be provided to AOGCC before production begins, Hilcorp said. The company told the commission in its application that it "believes the correlative rights of all owners, landowners, and operators will be protected under the existing oil and gas leases in place and the proposed conditions of this application."

Hilcorp said it proposes to allocate royalties to all leased owners/landowners based on tract allocation percentage, mineral ownership and lease royalty shown on the approved PA allocation schedule. The company will establish and maintain an interest-bearing escrow account for non-participating owners/landowners and will deposit amounts equal to the total of non-participat-

see PEARL 2A WELL page 5

FINANCE & ECONOMY

Exxon restructures divisions, centralizes

Exxon Mobil is restructuring its business into three divisions and moving its headquarters 250 miles south from Irving, Texas, to its campus north of Houston.

The oil giant said Jan. 31 it will combine its chemical and refining operations, while centralizing its technology and engineering and other support services. It will also consolidate its exploration and drilling operations.

Exxon, whose sales for the year are expected to be close to $300 billion, says the reorganization will be effective April 1 and the move south will be complete sometime in the middle of 2023.

The company said its move to Houston will enhance its collaboration and integration.

"We greatly value our long history in Irving and appreciate the strong ties we have developed in the North Texas community," CEO Darren Woods said. "Closer collaboration and the new streamlined business model will enable the company to grow shareholder value and position ExxonMobil for success through the energy transition."

Shares of Exxon Mobil Corp. have surged about 25% this year in tandem with the rising price of crude, up about 17% per barrel in 2022.

—ASSOCIATED PRESS

EXPLORATION & PRODUCTION

US rotary drilling rig count now 610, up 6

Baker Hughes' U.S. rotary drilling rig count was 610 the week ending Jan. 28, a gain of six rigs over the previous week and up by 226 from a count of 384 a year ago.

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

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

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

The Jan. 28 count includes 495 rigs targeting oil, up by four from the previous week and up 200 from 295 a year ago, with 115 rigs targeting gas, up by two from the previous week and up 27 from 88 a year ago, and no miscellaneous rigs, unchanged from the previous week and down by one from a year ago.

Thirty-six of the rigs reported Jan. 28 were drilling directional wells, 553 were drilling horizontal wells and 21 were drilling vertical wells.

Alaska rig count unchanged

Texas (284) was up by four rigs from the previous week, while Louisiana (57), Oklahoma (51) and Pennsylvania (23) were each up by a single rig.

New Mexico (94) was down by a single rig.

Rig counts in all other states were unchanged week over week: Alaska (6), California (8), Colorado (12), North Dakota (27), Ohio (11), Utah (10), West Virginia (11) and Wyoming (15).

Baker Hughes shows Alaska with six rigs active Jan. 28, unchanged from the previous week and up by two from a year ago, when the state's rig count stood at four.

The rig count in the Permian, the most active basin in the country, was up by one from the previous week at 293 and up by 101 from 192 a year ago.

—KRISTEN NELSON

continued from page 2

CHARGING RATES

this load factor, the operator has the option to use instead the standard rate structure for commercial electricity use.

Golden Valley Electric Association has also proposed a load factor of 5% and a resulting electricity rate of $0.65480 per kilowatt hour.

Chugach Electric to match residential rates

Chugach Electric Association is proposing load factors that apply to commercial rates equivalent to the rates charged for residential customers, with the resulting charging station rates then equaling the rates charged for residential use. The load factors and rates are different between the utility's north district and its south district: The north and south districts relate to Chugach Electric's purchase of Municipal Light & Power in 2020.

If the load factor for a commercial electric vehicle charging station remains below the load factor in the relevant district, the electricity rate for the charging station would be $0.13508 per kilowatt hour in the south district and $0.15274 per kilowatt hour in the north district. The maximum applicable load factor would range from 34% to 41%, depending on the district and on whether the charging station operator is obtaining its power from the high-voltage electrical system or from the lower voltage distribution system.

If the load factor for a commercial electric vehicle charging station remains below the load factor in the relevant district, the electricity rate for the charging station would be $0.13508 per kilowatt hour in the south district and $0.15274 per kilowatt hour in the north district

Homer Electric Association is proposing a load factor of 15%, with an electricity rate of $0.16441 per kilowatt hour for load factors below this rate. The normal commercial rate would apply to loads above the 15% factor.

Juneau utility Alaska Electric Light and Power Company is proposing a load factor of 10% coupled with different electricity rates for the operation of high speed charging stations by residential, small commercial and large commercial customers. Rates would range from $0.1383 to $0.2489 per kilowatt hour, depending on the class of customer and on whether the electricity is consumed during the peak season for electricity demand from November to May. ●

Contact Alan Bailey at abailey@petroleumnews.com

continued from page 4

PEARL 2A WELL

ing owners/landowners interest percentage for parcels multiplied by production attributed to the parcels for the previous month times the 12.5% royalty rate times the prevailing value for Cook Inlet gas published by the Alaska Department of Revenue, thus protecting correlative rights of all affected owners, landowners and operators.

The company said it anticipates perforating, testing and producing Pearl 2A in all potential gas bearing sands between 1,500 and 8,460 feet measured depth.

The commission has tentatively scheduled a public hearing for March 1 at 10 a.m. if it receives written request by 4:30 p.m. Feb. 18 indicating a significant degree of public interest. The commission said if a request for hearing is not timely field, it may consider issuing an order without a hearing.

Information on the tentative hearing will be posted on the commission's Events webpage after Feb. 18. ●

Contact Kristen Nelson at knelson@petroleumnews.com

● LAND & LEASING

Federal judge throws out Gulf lease sale

By MATTHEW DALY

Associated Press

A federal court has rejected a plan to lease millions of acres in the Gulf of Mexico for offshore oil drilling, saying the Biden administration did not adequately take into account the lease sale's effect on planet-warming greenhouse gas emissions, violating a bedrock environmental law.

The decision by U.S. District Judge Rudolph Contreras in Washington on Jan. 27 sends the proposed lease sale back to the Interior Department to decide next steps. The judge said it was up to Interior to decide whether to go forward with the sale after a revised review, scrap it or take other steps.

Environmental groups hailed the decision and said the ruling gave President Joe Biden a chance to follow through on a campaign promise to stop offshore leasing in federal waters. The decision was released on the one-year anniversary of a federal leasing moratorium Biden ordered as part of his efforts to combat climate change.

Energy companies including Shell, BP, Chevron and ExxonMobil offered a combined $192 million for drilling rights on federal oil and gas reserves in the Gulf of Mexico in November.

"We are pleased that the court invalidated Interior's illegal lease sale," said Brettny Hardy, a senior attorney for Earthjustice, one of the environmental groups that challenged the sale.

"This administration must meet this critical moment and honor the campaign promises President Biden made by stopping offshore leasing once and for all," Hardy added. "We simply cannot continue to make investments in the fossil fuel industry to the peril of our communities and increasingly warming planet."

Interior reviewing decision

A spokeswoman for Interior Secretary Deb Haaland said the agency was reviewing the decision.

The administration was "compelled to proceed with Lease Sale 257" following a court ruling in Louisiana, spokeswoman Melissa Schwartz said.

Interior has "documented serious deficiencies in the federal oil and gas program," Schwartz said, and Haaland has recommended an overhaul of the nation's oil and gas leasing program to limit areas available for energy development and raise costs for energy companies to drill on public land and water.

"Especially in the face of the climate crisis, we need to take the time to make significant and long overdue programmatic reforms," Schwartz said. "Our public lands and waters must be protected for generations to come."

Companies bid on leases

Energy companies including Shell, BP, Chevron and ExxonMobil offered a combined $192 million for drilling rights on federal oil and gas reserves in the Gulf of Mexico in November.

The Interior Department auction came after attorneys general from Republican states led by Louisiana successfully challenged a suspension on sales that Biden imposed when he took office.

Companies bid on 308 tracts totaling nearly 2,700 square miles. It marked the largest acreage and second-highest bid total since Gulf-wide bidding resumed in 2017.

The auction was conducted even as Biden has tried to cajole other world leaders into strengthening efforts against global warming, including at United Nations climate talks in Scotland in early November. While Biden has taken a number of actions on climate change, he has faced resistance in Congress, and a sweeping $2 trillion social and environmental spending package remains stalled. The so-called "Build Back Better" plan contains $550 billion in spending and tax credits aimed at promoting clean energy.

In his 68-page ruling, Contreras said Interior failed to consider the greenhouse gas emissions that would result from the lease sale, violating the National Environmental Policy Act, a bedrock environmental law.

"Barreling full-steam ahead with blinders on was simply not a reasonable action for BOEM to have taken here," he said, referring to Interior's Bureau of Ocean Energy Management.

Environmental reviews of the lease auction — conducted under former President Donald Trump and affirmed under Biden — reached the unlikely conclusion that extracting and burning more oil and gas from the Gulf would result in fewer climate-changing emissions than leaving it.

Similar claims in two other cases, in Alaska, were rejected by federal courts after challenges from environmentalists.

Federal officials have since changed their emissions modeling methods but said it was too late to use that approach for the November auction.

Industry slams decision

The National Ocean Industries Association, which represents the offshore industry, slammed the ruling and called U.S. oil and gas production crucial to curbing inflation and strengthening national security.

"The U.S. offshore region is vital to American energy security, and continued leases are essential in keeping energy flowing from this strategic national asset," said Erik Milito, the group's president. "Uncertainty around the future of the U.S. federal offshore leasing program" would benefit Russia and other adversaries, he said.

The administration has proposed another round of oil and gas sales in Wyoming, Colorado, Montana and other states. Interior Department officials proceeded despite concluding that burning the fuels could lead to billions of dollars in potential future climate damage.

Emissions from burning and extracting fossil fuels from public lands and waters account for about a quarter of U.S. carbon dioxide emissions, according to the U.S. Geological Survey.

A report issued by Haaland in November stopped short of recommending an end to oil and gas leasing on public lands, as many environmental groups have urged. But officials said the report would lead to a more responsible leasing process that provides a better return to U.S. taxpayers. ●

continued from page 1

DEVELOPMENT PLANS

from the Hemlock participating area, two wells in service for waterflood, one well in service as a class 1 disposal well and two wells shut-in, one due to water load and one due to ESP failure. For the period of 2021 that Redoubt was in production (beginning partway through September), total volumes were 91,576 barrels of oil, 260,495 barrels of water and 18,766 thousand cubic feet of gas.

Redoubt produces from the Osprey Platform, the most southerly in Cook Inlet.

For the 21st POD, covering May 1, 2022, through April 30, 2023, the company said it "plans to implement cost-effective solutions to handle increasing water cuts from existing wells within the unit through proper water disposal," and to decrease the amount of produced water from West McArthur River that is being injected at Redoubt.

It is keeping its options open for development of the northern and southern fault block and said it "will seek partners to reduce the risk factors associated with drilling as economic conditions improve."

Various work is planned, including optimization of pressures and rates for waterflood and disposal of produced water and, pending approvals, a flow test on RU-9 in the southern fault block, shut-in due to a failed electronic submersible pump. An inline inspection is planned on subsea pipelines connecting the Osprey Platform with the Kustatan production facility. The company plans to upgrade fire and gas systems on the platform and analyze multibeam surveys done in 2021 on the subsea pipelines "and engage in appropriate remediation work if necessary."

West McArthur River

The 30th POD for the West McArthur River unit covers May 1, 2022, through April 30, 2023.

There are two producing wells at West McArthur, both producing from the Area No. 1 PA. One well is a class 1 disposal well.

Three wells are plugged and abandoned. Five wells are shut-in, two with failed jet pumps; two with failed ESPs; and one an unsuccessful gas completion.

Production at the field, from October resumption through the end of 2021, was 21,334 barrels of oil 207,633 barrels of water and 3,846 thousand cubic feet of gas.

For the 30th POD, the company said it "will implement cost-effective solutions to handle increasing water cuts from existing wells within the unit through proper water disposal."

It plans to "keep Sabre prospect open for development," and said it will seek partners to reduce the risk.

The company said it would complete detailed engineering on the free water knock out project to enhance production from high water cut wells and it plans to replace failed ESPs on WMRU-2B and Sword 1, depending on rig availability, logistics and economics.

To implement the free water knock project, the company said it plans to repurpose existing equipment at West McArthur, depending on "results and economics stemming from the detailed engineering work."

Both PODs are signed by David Pascal, chief operating officer.

—KRISTEN NELSON

Contact Kristen Nelson at knelson@petroleumnews.com

continued from page 1

GEOHAZARD SURVEY

vicinity of a planned well site before drilling can begin.

In addition to obtaining a BOEM permit for the drilling, Hilcorp obtained letters of authorization from the National Marine Fisheries Service and the U.S. Fish and Wildlife Service for the incidental take of whales and sea otters.

Hilcorp has previously indicated an intention to bring a jack-up drilling rig to Cook Inlet, to conduct some exploratory offshore drilling. The company appears particularly interested in testing the Blackbill prospect, discovered about halfway across the inlet by ARCO's Raven No. 1 well in 1982. In 2019 Hilcorp conducted an offshore 3D seismic survey that provided some new insights into this prospect: The Cretaceous reservoir that holds the discovered oil is associated with a 65,000-acre, four-way closure in the rock strata.

The area that Hilcorp is exploring lies north of the Augustine-Seldovia Arch, a geologic structure to the south of which the Tertiary strata hosting the producing Cook Inlet oil and gas fields thin out. However, the Cretaceous rocks associated with the Blackbill prospect are part of the older Mesozoic sequence that underlies the Tertiary.

—ALAN BAILEY

Contact Alan Bailey at abailey@petroleumnews.com

Alaska Department of Natural Resources, Division of Oil and Gas, Notice of Preliminary Best Interest Finding and Determination for a proposed sale of North Slope Royalty Oil to Marathon Petroleum Supply and Trading Company LLC.

The Division of Oil and Gas is seeking comments regarding the Commissioner's "Preliminary Best Interest Finding and Determination for the Sale of Alaska North Slope Royalty Oil to Marathon Petroleum Supply and Trading Company LLC." The Department of Natural Resources proposes to sell approximately 10,000 to 15,000 barrels per day of the State's North Slope royalty in-kind oil to Marathon Petroleum Supply and Trading Company LLC for processing at its refinery at Nikiski, in the Kenai Peninsula Borough. The deadline for comments on this Preliminary Best Interest Finding and Determination is 4:30 PM AST, March 2, 2022.

The Commissioner of the Department of Natural Resources proposes to sell royalty oil from the State oil and gas leases on the North Slope under a three-year contract. Deliveries of royalty oil under this proposed contract will have an estimated starting date of August 1, 2022 and continue until July 31, 2025. The price provision in the proposed contract is based on a formula that relies on accepted industry price reporting services and resembles the formulas used to calculate value of royalty oil paid to the State by the North Slope producers. The Commissioner's Preliminary Best Interest Finding and Determination includes a draft of the sales contract, provides an analysis of its specific provisions, and how it will serve the best interests of the state under the criteria set out in AS 38.05.183 and AS 38.06.070.

The public can access this document at: https://dog.dnr.alaska.gov/Library/

These findings are preliminary; and final conclusions have not been reached. Comments received from the public and from the Royalty Board will be used to determine whether the proposed sales contract is in the state's best interest. If the Commissioner determines that the proposed sale is in the state's best interest and if the Royalty Board recommends that the sale go forward, a bill will be introduced in the legislature to approve the contract.

Comments should be emailed to: sean.clifton@alaska.gov

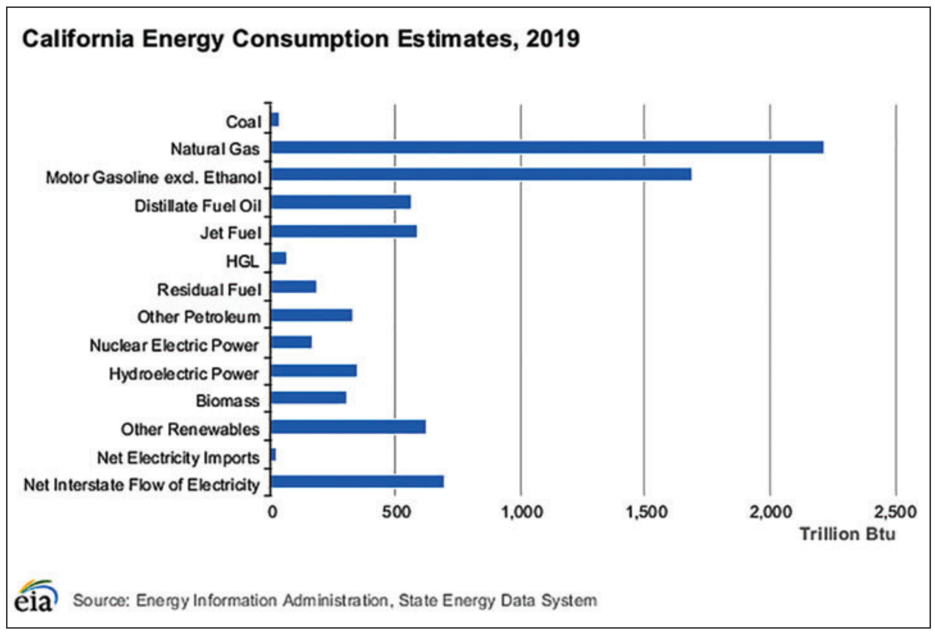
Or mailed to:

Division of Oil and Gas
C/O RIK Public Comments
550 W. 7th Avenue, Suite 1100
Anchorage, Alaska 99501-3563
Phone: (907) 269-8800

PUB 2/6/2022 AO 22DR-10-042

continued from page 1

OIL PRICES



lower, at $87.66 and $88.95, respectively.

On Feb. 2, ANS held a $1.07 premium over Brent, reflecting a continuing tight market for Pacific oil cargoes due to Asian buying.

In Europe, even as natural gas shortages loom, fuel oil is limited by regulation as to the part it can play in alleviating energy shortages in a fragile supply situation for natural gas. In Asia, however, the regulatory structure is more accommodating to the burning of oil to displace scarce and increasingly expensive natural gas for power generation.

Industrial activity has been a strong driver of oil demand in China, but factories there are shut-in for the Chinese New Year celebration over the first week of February, with closures extending before and after the official holiday.

Normally, transportation fuel demand spikes on the New Year holiday, as throngs travel to meet family and friends to celebrate, but this year travel is slowed due to numerous lockdowns as China pursues a zero-COVID policy.

LA ban augurs reduced West Coast competition

North Slope crude is sold, and prices are set on the West Coast. In a classic case of the law of supply and demand, strong Asian demand is bullish for ANS pricing, as it soaks up Pacific cargoes that might compete with ANS in California.

Now, new laws may mop up locally supplied oil that competes with ANS in West Coast markets.

The Los Angeles City Council voted unanimously Jan. 26 to ban new oil and gas wells and to phase out existing wells in the city over a period of 5 years.

On Feb. 2, the Los Angeles City Council directed the city attorney to draft an ordinance to enforce the ban, change zoning laws to make drilling illegal and study how to legally phase out existing wells, FOX Business reported.

California Independent Petroleum Association CEO Rock Zierman told FOX that the measure would raise gasoline prices, eliminate jobs, and make the region more dependent on foreign oil at a time when tensions are brewing.

California consumes 1.8 million barrels of oil per day — three quarters of which comes from out of state, according to Californians for Energy Independence.

California stood as the seventh-largest producer of crude oil among the 50 states in 2019, and, as of January 2020, it ranked third in oil refining capacity, according to the EIA, which added that foreign suppliers — led by Saudi Arabia, Iraq, Ecuador, and Colombia — supplied more than half of the crude oil refined in California in 2019.

At the end of 2019, the state's crude oil reserves stood at 2,213 million barrels, the EIA said.

California is the largest consumer of jet fuel and motor gasoline among all 50 states, and it accounted for 17% of the nation's jet fuel consumption and 11% of motor gasoline consumption in 2019, the EIA said. It is the second-largest consumer of all petroleum products combined, accounting for 10% of the U.S. total.

California's per capita energy consumption, however, is the fourth-lowest due in part to its mild climate and its energy efficiency programs, the EIA said.

OPEC+ rubber stamps production increase

The Organization of the Petroleum Exporting Countries and its allied oil producing nations, known as OPEC+ have decided to proceed with a planned 400,000 bpd oil production increase in March, OPEC said in a Feb. 2 release.

The group is phasing out a production curtailment of 10 million bpd put in place at the beginning of the coronavirus pandemic in April 2020.

In opening remarks Feb. 1 to the Joint Technical Committee of the Declaration of Cooperation, OPEC Secretary General Mohammad Sanusi Barkindo said that the measured, nimble, and facts-based approach of OPEC+ "continues to reinforce a sense of stability and reassurance to the market."

"I commend the DoC producers for their ongoing resilience in constantly adapting to the volatile oil market dynamics that we have witnessed throughout this pandemic and continue to see now," Barkindo said. "This highly effective DoC framework has stood the test of time and continues to be regarded as an industry-leading instrument for global energy cooperation."

Oil historian Daniel Yergin told Bloomberg Television Feb. 2 that he believes OPEC had "no choice" but to increase output, but that the group will not be able to reach the new proposed target.

Yergin said that escalation in U.S.-Russia tensions over Ukraine could propel oil prices to $100 per barrel, and that increased tension could trigger "a panicky reaction in the market."

U.S. shale drillers are increasing output, however, serving as a great stabilizer in the market, he said.

"Oil and gas production in the United States is a great geopolitical asset," Yergin said.

The total completed lateral footage of wells in the Permian Basin is expected to hit a record high of 50 million feet in 2022, versus the 2021 total of 45.8 million feet and the pre-COVID-19 levels of 47.5 million feet in 2019, Rystad Energy said in a Jan. 28 release.

In 2020, total lateral footage in the basin dropped to 32.5 million feet due to pandemic-reduced activity, the consultancy said.

Due to a surge in lateral well length, the average productivity of new wells in the Permian is set to hit a record high in 2022, Rystad said. New wells are expected to break the 1,000 barrels of oil equivalent per day threshold in 2022 for the first time on record, rising from 974 boepd achieved in 2021.

"The Permian is now entering a three-mile lateral era," said Artem Abramov, Rystad head of shale research. "Such long wells were viewed as inferior for their high finding and development costs in some deeper zones just a few years ago, but modern equipment and completion methods allow extended reach wells to spread across the entire basin." ●

continued from page 1

LNG STUDY

the expected price from Gulf Coast projects targeting the same Asian markets," AGDC said.

"We are closer now, more than ever, to realizing the decades-old dream of bringing our natural gas off the North Slope for the benefit of Alaskans and worldwide markets," said Gov. Mike Dunleavy.

AGDC President Frank Richards said: "As our work continues to transition Alaska LNG to a privately led project team, this economic analysis demonstrates that Alaska LNG can deliver LNG at competitive prices."

Demand growth robust

Wood Mackenzie said AGDC has acted on the recommendations in the 2016 study it did for AGDC, BP and Exxon, reducing the cost of Alaska LNG delivered to Japan from US$11.70 per million Btu to US$6.70 per million Btu.

Debt financing reduces the cost of supply by some 29%, with the total delivered cost of supply down by 43%.

LNG demand growth remains robust beyond 2050, Wood Mackenzie said, with Japanese spot prices of $8 per unit expected, above the $6.70 Alaska cost of supply.

The research firm found that within 6 years, LNG demand will outstrip supply, strengthening the need for new projects.

In its cost reductions Wood Mackenzie did not include the $26 billion federal loan guarantee in the infrastructure legislation, or tax reforms which it said would bring Alaska in line with other domestic jurisdictions.

2016 study

The 2016 Wood Mackenzie analysis concluded the Alaska project required changes like those listed in the current report.

Wood Mackenzie said the 2016 study: "Established the base cost of supply for Alaska LNG and defined the target range for a competitive cost of supply" for the Alaska project, identifying options to reduce the projects cost of supply.

"LNG demand remains robust under all scenarios to 2050, despite gas demand peaking in 2040, due to declining indigenous production in key demand regions," Wood Mackenzie said, with the strong demand expected to create a supply gap beginning in 2028 requiring new projects.

Cost of supply

Wood Mackenzie said AGDC provided a new price for raw gas from Prudhoe Bay and Point Thomson of $1 per million Btu. There is no commodity price link, and price escalation of 2% per year is assumed. When fuel gas is added, the raw gas cost becomes $1.15 per million Btu, the study said.

The cost of supply is most sensitive to capital costs and property tax, Wood Mackenzie said, and Alaska's property tax is 2% compared to an average of about 0.2% for Louisiana (0%) and Texas (0.5%). If Alaska property tax were reduced to 0.2% it would reduce the cost of supply by some 50 cents per million Btu, the report said.

The federal loan guarantee is limited to 80% of total capital costs, including construction. It would provide a guarantee that, should the borrower default, the federal government will cover the debt obligation, "and may be expected to de-risk the project for both lenders and participants," Wood Mackenzie said, helping reduce the interest rate and the hurdle rate.

Changes from 2016 reducing the cost of the Alaska LNG project include: 70% debt funded third-party tolling structure; reduction of capital costs from US$45 billion to US$38.7 billion; and reduction of feed gas prices from $2.09 per million Btu to $1.15.

Shipping costs, however, have increased from 60 cents per million Btu to 76 cents.

Industry changes

Wood Mackenzie said about 60% of LNG contracts in the last 10 years have been oil linked, but it expects long-term contracting for Japan to continue softening "in the face of energy transition uncertainties and greater confidence in the trading capabilities of the major players."

The carbon footprint is of increasing importance, Wood Mackenzie said, with capture and sequestration of CO2 from feedstock gas on the North Slope expected to position the Alaska LNG project well with both buyers and regulators, particularly when compared to Lower 48 competitors where emissions are generally higher.

A chart comparing cost of supply for delivery into North Asia shows the projected Alaska LNG cost of $7.60 per million Btu, with low end Gulf of Mexico projects approaching $8 and high-end Gulf projects at more than $8. ●

Contact Kristen Nelson at knelson@petroleumnews.com

Petroleum news

Oil Patch Bits

ChampionX announces next generation pump system

As reported on championx.com Jan. 27, ChampionX Corp. announced that UNBRIDLED ESP Systems has introduced the HIGH RISE series pump line, which is engineered to significantly improve electrical submersible pumping system performance and longevity while also meaningfully reducing the carbon footprint of ESP operations.

HIGH RISE pumps feature patented Oculus technology, which allows the pumps to achieve up to 33% greater lift per unit length of pump. Higher lift per stage means fewer components in the well and faster installs to minimize rig time while also reducing the overall carbon footprint of an ESP system. The HIGH RISE pump series also covers an extended production range from 200 to 7,500 barrels per day.

"The Oculus technology feature in our HIGH RISE pumps allow operators to achieve their production targets with significantly less iron in the well, which helps reduce the carbon footprint of an ESP installation. Based on internal calculations of our manufacturing processes and EPA data, HIGH RISE pumps reduce carbon emissions by one ton per install and use on average 20% less heavy metals," said Ryan Rasmussen, vice president and managing director of ChampionX's UNBRIDLED ESP Systems.

ESPs are designed to handle the high initial production rates common in unconventional wells and to achieve the necessary pressure draw down to maximize reserve recovery. However, the continuously changing operating conditions — like rapidly declining production rates and gas slugs in the fluid stream — that are typical in unconventional plays have a heavy impact on ESP performance. The HIGH RISE series pumps are designed to address those issues and to assure consistent quality.

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 1

RIK FINDINGS

oil, and the state receives the value of its royalty share. With RIK, the state assumes ownership of the oil and the DNR commissioner disposes of it through either a competitive or non-competitive sale.

From November 1979 through November 2021 the state disposed of 967 million barrels through RIK sales, some 46% of North Slope royalty oil, the finding said. The state has sold its royalty oil to in-state refineries and occasionally has auctioned its royalty oil to Lower 48 customers.

The finding said that since 1986 the state has disposed of its RIK oil through negotiated non-competitive sales.

Marathon

The preliminary best interest finding and determination for the royalty in kind, RIK, sale to Marathon said the contract has a term of three years.

"The sale of royalty oil under the proposed contract will help meet the in-state need for crude and help facilitate continued operations of Marathon's Kenai refinery, which has been operating since 1969, with the attendant benefits to Alaskans," the finding says.

Meeting in-state need for crude and benefitting Alaskans "are paramount in the State's decision to sell royalty in-kind to Marathon through the contract."

A third concern in negotiating the contract was to avoid interruptions to delivery of RIK oil to in-state refineries.

The next step is to seek legislative approval and review of the Royalty Oil and Gas Development Board for the contract.

The volume of oil the state receives depends on the value of oil produced and the proposed Marathon contract calls for delivery of between 10,000 barrels per day and 15,000 bpd between Aug. 1, 2022, and July 31, 2025.

Meeting in-state need for crude and benefitting Alaskans "are paramount in the State's decision to sell royalty in-kind to Marathon through the contract." A third concern in negotiating the contract was to avoid interruptions to delivery of RIK oil to in-state refineries.

The finding said that based on average forecast volumes, between 48,000 bpd and 66,000 bpd are expected to be available, so Marathon's nomination under the proposed contract could represent between 15% and 31% of the state's North Slope royalty oil.

Marathon's current RIK contract obligates the state to deliver between 10,000 bpd and 15,000 bpd between Aug. 1, 2021, and July 31, 2022.

Key considerations

The finding said there are three key considerations for the state in considering how much RIK oil to sell.

The state wants to keep a small percentage in RIK "due to higher royalty values for certain leases, and to obtain pricing and other information from in-value dispositions for comparison purposes."

The state limits its RIK contracts to 95% of its North Slope royalty oil.

A second consideration is that expected royalty production is based on a forecast, and, the finding said, even the best forecast will probably be incorrect. "Historically, the State has experienced periods where production forecasts from which the royalty forecast is derived have been optimistic, with realized production often falling below forecasted levels."

The third condition is seasonal variation in North Slope production, with production peaking in the winter and reaching its lowest levels in the summer. "This seasonality is part of the consideration when negotiating nomination ranges with refineries," the finding said.

The state receives more revenue from RIK sales than from RIV sales, the finding said, and while that isn't the only criteria used in evaluating the best interest of the state, the state does have a duty to generate as much revenue as it can from its royalty oil.

State refineries

The finding said there are five active refineries in the state, operated by four organizations — Hilcorp, ConocoPhillips, Petro Star and Marathon.

Three of the refineries produce refined petroleum for the consumer market — Marathon's Kenai refinery, Petro Star's North Pole refinery and Petro Star's Valdez refinery. All three refine Alaska crude and provide refined petroleum products to the Alaska market.

The Petro Star refineries exclusively refine ANS drawn from the trans-Alaska oil pipeline.

The North Pole refinery has a maximum throughput capacity of 22,000 bpd; Valdez has a maximum throughput capacity of 60,000 bpd.

The Petro Star refineries produce some 65% jet fuel. The remaining output is ultra-low sulfur diesel, asphalt and heating oil.

Marathon's Kenai refinery is not tied to the trans-Alaska oil pipeline. Some feedstock arrives over water, and can come from the Valdez Marine Terminal, Cook Inlet or the world market. The finding said the Kenai refinery only receives non-Alaska crude on an infrequent basis, with some 90% of its input in recent years from the North Slope or Cook Inlet.

Because the Marathon refinery is not connected to the trans-Alaska oil pipeline, it cannot re-inject unprocessed portions of the crude back into the pipeline, so those portions not refined into salable product, the heavy ends, "must be loaded onto a ship and transported to another Marathon facility (or sold to a third party) for further processing. Furthermore, unlike the Petro Star North Pole and Valdez refiners, which fuel the refineries with the crude extracted from TAPS, Marathon fuels its refinery with natural gas from Cook Inlet," the finding said.

Most of the refined product from Marathon's Kenai refinery is consumed in Alaska, with jet fuel going via pipeline to Anchorage, where the majority of that jet fuel consumed at Ted Stevens Anchorage International Airport. The finding noted that the Kenai refinery does retain the ability to ship refined product out of the state.

RIK and Alaska commercial refining

All four commercial refineries in Alaska — the three operating and a fourth refinery that closed in 2014 — have had RIK contracts at various points, the finding said.

"Three of these four refineries refined royalty oil, while a royalty contract backstopped financing for the fourth."

The state has supplied RIK to the Kenai refinery sporadically beginning in 1980, with the refinery purchasing a total of 262.4 million barrels under nine RIK contracts.

"DNR believes the proposed RIK contract with Marathon is important to meeting in-state demand for crude and to facilitating the continued operation of the Kenai Refinery, with the attendant positive implications on the economy of the state," the finding said.

Petro Star contract

The proposed Petro Star contract is for five years with Arctic Slope Regional Corp., which owns Petro Star, as guarantor. Petro Star has two refineries. The North Pole refinery was built in 1985 and the Valdez refinery was completed in 1993.

The proposed contract with Petro Star is for 12,500 bpd between Jan. 1, 2023, and Dec. 31, 2024, and between 12,500 and 10,000 bpd between Jan. 1, 2025, and Dec. 31, 2027.

Of the state's forecast RIK of between 48,000 and 67,000 bpd, the Petro Star nominations represent between 19% and 22%.

The state has sold RIK to Petro Star sporadically since 1986, supplying the two refineries some 27 million barrels of North Slope RIK over that period.

The finding said a 1992 contract with the Petro Star Valdez Joint Venture was a 10-year contract to supply the proposed Valdez refinery with up to 30,000 bpd. "With this contract in hand, the joint venture secured the needed financing and constructed the Valdez refinery." The finding said the contract helped the JV secure financing because it demonstrated "guaranteed access to an on-going supply of feedstock."

The Valdez refinery never took possession of an RIK under that contract, securing its supply from the private market.

—KRISTEN NELSON

Contact Kristen Nelson at knelson@petroleumnews.com

continued from page 1

NEW DIRECTOR

Gathering Center 2 reservoir development team from 2018 to 2020 and the Flow Station 2 reservoir development team from 2015 to 2018.

He was responsible for leading geoscientists, reservoir engineers and petroleum engineers in continued flood management, drilling programs and workover programs in those areas of the Prudhoe Bay field.

From March 2013 to January 2015 Nottingham was reservoir management team lead, heading a group of reservoir engineers and geoscientists responsible for progressing development plans for the Prudhoe Bay Ivishak waterflood and the Sag River reservoirs in Prudhoe Bay.

From January 2009 to March 2013 he worked for BP as a reservoir engineer where he was responsible for flood management, production forecasting, and development planning for the Sag River reservoir (2010-2013) and the Eileen West End Ivishak reservoir (2008-2010).

Before that Nottingham worked for Chevron for a little over six years, most recently as a reservoir engineer for the company's Cook Inlet assets, and prior to that as an asset development engineer in the Gulf of Mexico Shelf.

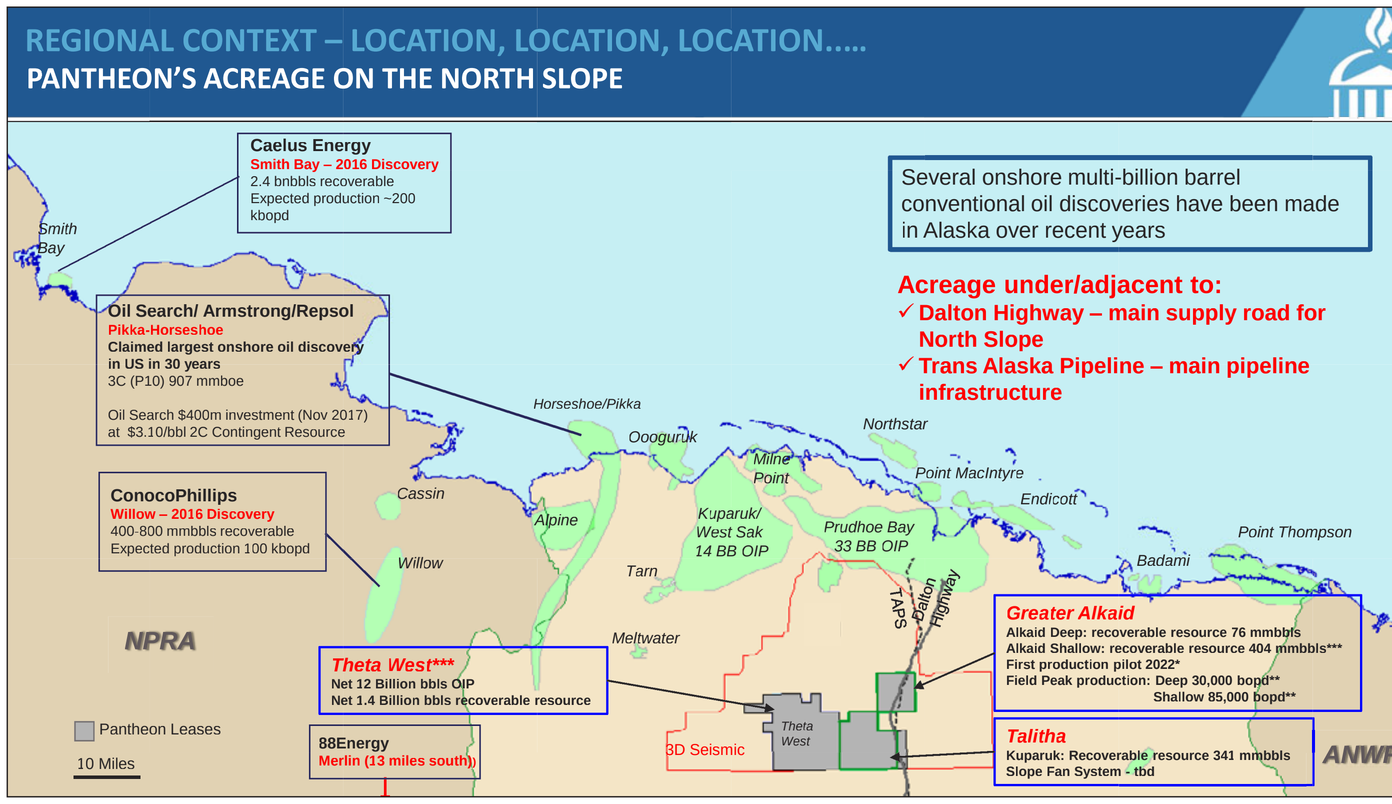
Nottingham replaced Tom Stokes who retired from the division in January.

—KAY CASHMAN

Contact Kay Cashman at publisher@petroleumnews.com

continued from page 1

EXPLORATION STATUS



extended reach exploration well in second quarter 2022.

NN-02 was supposed to be drilled unless Eni requested an extension from the feds, which is did for two years. That extension runs out in April.

As of Feb. 1, no extension request had been filed.

Similar to NN-01 well

The Alaska Beaufort Sea prospect is in a 13-lease federal OCS unit, Harrison Bay block 6423, which is approximately 6 miles from the Spy Island Drillsite, or SID, in the state Nikaitchuq unit.

SID is a man-made, land-based gravel island, constructed in shallow (6 to 8 feet) coastal waters, approximately 3 miles north of Oliktok Point. SID is 100% owned and operated by Eni and supports the drilling and production from Eni's Nikaitchuq unit.

The second Nikaitchuq North well will be similar to the first ultra-extended reach well, NN-01, in that it will be an S-shape wellbore into the target reservoir.

In Eni's 13th plan of development for the Nikaitchuq unit the company told the division that it will do facility upgrades to support the NN-02 well, including a new six-slot well containment shelter and associated well conductors. The work was supposed to be done during the 13th POD period from Oct. 1, 2020, through Sept. 30, 2021.

Geological target speculation

The seismic anomaly — the target of both Nikaitchuq North wells — was identified from 3D seismic. But in the public portion of the paperwork Eni filed with the state and feds, geological information about the Nikaitchuq North was not released.

However, Eni left hints elsewhere; specifically, in its oil discharge prevention and contingency plan application that appeared to be based on tapping the Jurassic Alpine sands, which would certainly qualify as an anomaly in the area.

Whatever the case, the 25,957 barrels per day in the contingency plan application could not be referring to the heavy Schrader Bluff oil produced from the Nikaitchuq unit that is known to extend a long way north because that oil can't flow unassisted.

Also, the measured depth and angle of the well suggest one of the Jurassic sands.

A previous Nikaitchuq unit operator, Kerr-McGee and partner Armstrong, talked about the possibility of testing the Jurassic Nuiqsut sandstone and the Triassic Sag River sandstone to the north.

Merlin 2 still on track

Farther west in the National Petroleum Reserve-Alaska, 88 Energy is moving ahead with its plans to drill Merlin 2 in its Peregrine Project. It will be using the Arctic Fox drilling rig and the company is still on track to spud its well in late February.

A third company, Eni US Operating, a subsidiary of Italian multinational Eni S.p.A., hasn't yet made its intentions public about an offshore exploration well planned north of its Nikaitchuq unit for April.

88 Energy is also continuing its polar bear monitoring, although the Merlin 2 drill site is more than 100 miles from the coast, so outside the normal range of the bears.

88 Energy told investors that Merlin 2 will be drilled east and downdip of Merlin 1, "in an area expected to display thicker reservoir sections along with higher permeability and porosity."

The Merlin 2 drill site is to the southeast of Merlin 1 and closer to the shelf break.

Merlin 2's total depth is expected to reach 8,000 feet, and "is targeting 652 million barrels of oil, in the highly prospective N18, N19 and N20 targets that were encountered in the successful Merlin 1 exploration well," which was drilled in Project Peregrine in March 2021 to a depth of 5,267 feet.

Merlin 1, 88 Energy said, "demonstrated the presence of oil in these multiple stacked sequences within the Brookian Nanushuk formation."

Project Peregrine encompasses approximately 195,000 contiguous acres in NPR-A. 88 Energy has a 100% working interest in the project.

Merlin 1 results

The Merlin 1 exploration well was spud in March 2021 with drilling operations completed in April 2021.

Interpretation of results was completed in August with post-well evaluation "successfully demonstrating the presence of oil in N20, N19 and N18 targets, with 41 feet of net log pay across the three reservoir intervals noted and geochemical analysis determining the oil to have an estimated API gravity between mid-30 to low-40 API," 88 Energy said.

Pantheon also testing Talitha A

London-based Pantheon Resources said Jan. 24 that it spud its Alaska North Slope Theta West 1 well on Jan. 21 using the Nordic Calista Rig 3, as planned. Pantheon's Alaska subsidiary Great Bear Pantheon holds a 100% interest in the well.

Prior to moving 8-1/2 miles west to the Theta West well location, the rig completed preparations for testing operations at the Talitha A well which included a plugging operation in the Kuparuk formation, which won't be tested this year.

Theta West targets

Theta West 1 is targeting two primary targets:

1. the Upper Basin Floor Fan.
2. the Lower Basin Floor Fan.

These combined horizons, Pantheon estimates, hold 12.1 billion barrels of oil in place with an approximate 1.4 billion barrels of recoverable resource.

The top of the formation is expected at a depth of about 7,600 feet.

Pantheon said the plan is to drill to target depth, estimated at 9,200 feet, case the hole, and begin testing operations on both the Lower Basin Floor Fan and Upper Basin Floor Fan.

Vertical test wells

Both the Theta West 1 and Talitha A are vertical test wells.

Pantheon said the objective of winter drilling and testing at Theta West and testing at Talitha is to determine reservoir deliverability — not about maximizing flow rates, as future production wells will be drilled horizontally, not vertically.

Pantheon wants to establish/prove the movability and quality of the oil.

Talitha A testing operations commenced over the weekend of Jan. 22 and 23, and are starting from the lowest formation, the Lower Basin Floor Fan, before proceeding sequentially to the two shallower Slope Fans (which will be tested together) and the Shelf Margin Deltaic horizons.

A coiled tubing unit used for flow testing operations will mobilize to the location after fracking is finished.

Talitha A, which was drilled in 2021, encountered five independent oil horizons, including Kuparuk at the deepest level.

The company had a lot of problems in the Kuparuk zone last winter, but Pantheon executives said they think they understand now what went wrong. But with 2 billion barrels to test in the horizons above the Kuparuk, they have elected to drill a well sometime in the future to test the Kuparuk, likely choosing a better location for doing so.

Pantheon said independent "Volatiles Analysis" undertaken by Advanced Hydrocarbon Stratigraphy/Baker Hughes took 416 cuttings during the drilling of Talitha A over a 3,700 foot section covering the five horizons, with each and every sample confirming the presence of oil. ●

Contact Kay Cashman at publisher@petroleumnews.com