Petroleum news

page 6 May ANS output down 0.6%, from April but up 12.4% year-over-year

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Chill out Glacier, Apollo; you're selling Badami at really bad time

GLACIER OIL AND GAS President Stephen Ratcliff has not yet responded to Petroleum News' mid-June query as to whether Glacier still has its Badami leases and infrastructure up for sale — not unusual in a situation involving business negotiations with third parties.

But three solid PN sources have confirmed the eastern North Slope asset is still up for sale — and one of them said Glacier has been "aggressively" marketing Badami, which is operated by Savant, a Glacier company.

All three sources agreed that now is the worst possible

see INSIDER page 11

Oil pops 50% in 2021, best half since US inventory plunge in 2009

Alaska North Slope crude moved higher by 14 cents June 30 to close at $75.24, while West Texas Intermediate jumped 49 cents to close at $73.47 and Brent lifted 37 cents to close at $75.13.

The month of June ended on an up note for oil prices, capping a remarkable recovery that saw oil turn in monthly and quarterly gains on the way to rising 50% so far in 2021, its best half since 2009.

U.S. commercial crude oil inventories — excluding the Strategic Petroleum Reserve — fell by 6.7 million barrels for the week ended June 25, the U.S Energy Information Administration said June 30, adding that at 452.3 million barrels, inventories stand about 6% below the five-year average for this time of year. It was

see OIL PRICES page 9

Augustine geothermal draws bid; state issues call for competitors

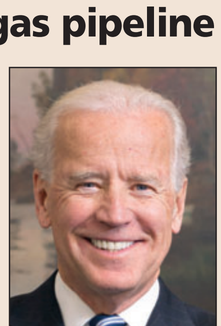
Alaska's Division of Oil and Gas has received a proposal for geothermal exploration on Augustine Island in Cook Inlet — the name of the individual or company, per state statute, has not yet been released.

Also according to state statute, on June 29, the division issued a call for public comments and competing proposals for geothermal exploration on and around Augustine Island with public comments and completed applications for proposed exploration due by 5 p.m. July 30.

The area includes all of Augustine Island, including some tidelands and adjacent waters within approximately 3 miles of the island, excluding nearshore tidelands of the mainland to the west. The area contains about 65,992 acres divided into 26

see AUGUSTINE BID page 11

After scuttling Keystone XL, Biden won't oppose Russian gas pipeline



JOE BIDEN

President Joe Biden made a lot of promises during his election campaign and immediately after his inauguration about rebuilding relationships with America's key allies.

For his closest and probably least troublesome friend — the Great White North — there are signs that the fence will need even more repairs than what Donald Trump left behind when he departed the White House.

What Canada now faces is picking up the pieces from Biden's decision to scuttle TC Energy's Keystone XL and his

see PIPELINE PARITY page 11

EXPLORATION & PRODUCTION

Advancing Alaska

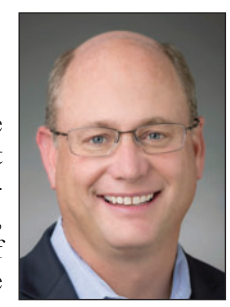
ConocoPhillips investing where it can; latest Slope discovery Coyote

By KAY CASHMAN

Petroleum News

Alaska got encouraging news in the June 30 ConocoPhillips market update, including the planned development of a new North Slope oil discovery, Coyote. It's on the western side of Kuparuk, and to the east of Nuna (see map in pdf or print version).

The big Willow development in the National Petroleum Reserve-Alaska has one more hurdle before the company moves to FID, or final investment decision, near the end of the year; and that is a district court decision expected in third quarter. Although appeals are possible,



NICK OLDS

ConocoPhillips Chairman and CEO Ryan Lance is confident the company will ultimately prevail.

Because of that final uncertainty, a capital allocation for Willow is not included in the updated 10-year plan presented June 30, but Lance made it clear the company had both the "flexibility and capacity to fund" the project should it advance.

Nick Olds, senior vice president of global operations, including Alaska, said the northernmost state "will continue to play an important role in our company for years to come. We have a

see CONOCO IN ALASKA page 12

UTILITIES

ERO regs issued

RCA publishes rules for organizations overseeing Alaska electrical systems

By ALAN BAILEY

For Petroleum News

Following a lengthy and complex regulatory development process, on June 29 the Regulatory Commission of Alaska published an order, issuing regulations for the operation of electric reliability organizations, or EROs, in Alaska. The regulations enable the implementation of Senate Bill 123, a statute passed in 2020 to enable the commission to regulate EROs.

The primary purpose is to enable the formation of an ERO for the Alaska Railbelt electrical system, to achieve more unified management and operation of the system. The Railbelt electric utilities are in the process of forming the Railbelt Reliability Council as an ERO for the Railbelt — presumably, now that regulations are in place, the RRC will be able to apply to the commission for a certificate, to enable the RRC to go into operation.

SB 123, and its supporting regulations, also give the RCA the authority to regulate the construction of new major generation and transmission facilities in the electricity grid, and to regulate integrated resource planning for the system.

see ERO REGS page 10

EXPLORATION & PRODUCTION

Fallout from fracking

Debate rumbles on over links between hydraulic fracturing and earthquakes

By GARY PARK

For Petroleum News

Just as the pace of exploration is accelerating in British Columbia's Montney region, which holds the key to success in Canadian LNG exports, the use of hydraulic fracturing to open up the gas formation has stirred a fresh round of debate.

A new study, by Alan Chapman, an independent researcher and formerly senior scientist with the B.C. Oil and Gas Commission, suggests more damaging earthquakes are likely to be triggered by fracking activities, based on a "fairly strong relationship between the cumulative underground water loading" which is tied to the injection of high-pressure fluids to fracture rocks and release oil and gas.

Chapman said his research suggests homes and infrastructure could be at risk from earthquakes triggered by fracking activities, partly stemming from inadequate safeguards.

Fracking has increasingly been associated with 436 earthquakes up to a magnitude of 4.6 in the Montney region over the 2013-19 period.

Earlier research has linked the pressure under which fluids are injected to earth movement.

Chapman's studies examined the total water volumes injected into wells within three miles of an earthquake epicenter and included the water build ups — sometimes from several different companies — with quake magnitudes of at least 3.0 which are

see FRACKING FALLOUT page 8

● PIPELINES & DOWNSTREAM

Hilcorp permits new Kenai field gas lines

New gathering lines will be larger than existing, provide increased deliverability, help meet peak Southcentral gas supply needs

By KRISTEN NELSON
Petroleum News

Hilcorp Alaska is permitting two new gas gathering flowlines in its Kenai Gas Field. The lines, a 20-inch medium pressure and a 24-inch low pressure line, will run between KGF pad 34-31 and KGF pad 14-6, alongside existing lines, a 12-inch low pressure line and a 16-inch high pressure line.

The Kenai gas field currently accounts for almost 20% of Cook Inlet natural gas production; Ninilchik, also a Hilcorp field, comes in second, accounting for more than 13%.

Hilcorp said the existing lines will continue to be used while the new flowlines are installed and will remain operational after the new flowline installation is complete.

"The purpose of the project is to provide system safeguards and to increase reliability to meet Southcentral Alaska's gas needs," the company said in an application filed with the Alaska Department of Environmental Conservation and public noticed by the department June 25.

Hilcorp cited "needle-peak" contractual demands for weeks of high deliverability during winter and said since it supplies the largest volume of gas in Southcentral it is the backstop in the event there was an issue at CINGSA, Cook Inlet Natural Gas Storage Alaska.

Debottlenecking KGF facilities

Hilcorp said the new gathering flowlines are the second phase of debottlenecking KGF facilities and said the new flowlines "will provide some critical spare capacity in the event of unplanned compressor maintenance during the winter." When there is an upset condition at KGF pad 34-31 — such as a compressor fails — "gas deliverability to the Kenai Peninsula is interrupted until the upset condition can be corrected," the company said, something which typically takes several days but could take as long as 28 days depending on the severity of the event.

"The last time a compressor failed was in the winter of 2020-2021, which led to pulling extremely hard from the gas storage wells and damage to one of the wells," Hilcorp said.

The company said the project is critical for gas deliverability to Southcentral because an upset during peak 2021-22 winter demand would risk similar gas storage well damage and a shortfall of a few days to weeks in meeting peak demand.

Hilcorp said the project will also allow it to pig and dewater the KGF gas lines, preventing water carryover into compressors.

All lines to be used

Hilcorp said the new flowlines will provide increased deliverability.

The existing 12-inch line will continue to be used for

see NEW GAS LINES page 8

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

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, MT7-03	ConocoPhillips
OIME 2000	141 (SCR/TD)	Standby	
	142 (SCR/TD)	Standby	
TSM 700	Arctic Fox #1	Standby	
ERD	26	Alpine, CD2-310	ConocoPhillips
Hilcorp Alaska LLC			
Rotary Drilling	Innovation	Milne Point, I Pad	Hilcorp Alaska LLC
Nabors Alaska Drilling			
AC Coil Hybrid	CDR-2 (CTD)	Deadhorse, Cold Stacked at Nabors Deadhorse Yard	Available
AC Coil	CDR-3 (CTD)	Kuparuk, Cold Stacked at 12 Acre Pad	ConocoPhillips
Ideco 900	3 (SCR/TD)	Deadhorse, Stacked	Available
Dreco 1000 UE	7-ES (SCR-TD)	Kuparuk, Cold Stacked	Oil Search
Mid-Continental U36A	3-S	Stacked	Available
Oilwell 700 E	4-ES (SCR)	Stacked	Available
Dreco 1000 UE	9-ES (SCR/TD)	Stacked	ConocoPhillips
Oilwell 2000 Hercules	14-E (SCR)	Deadhorse	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Stacked	Brooks Range Petroleum
Oilwell 2000 Canrig 1050E	27-E (SCR-TD)	Stacked	Glacier Oil & Gas
Oilwell 2000	33-E	Deadhorse	Available
Academy AC Electric CANRIG	99AC (AC-TD)	Stacked	Repsol
OIME 2000	245-E (SCR-ACTD)	12 Acre Pad, stacked	ENI
Academy AC electric CANRIG	105AC (AC-TD)	Stacked	Oil Search
Academy AC electric Heli-Rig	106AC (AC-TD)	Stacked	Great Bear Petroleum
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)	Deadhorse, stacked	Available
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

Doyon Drilling			
Sky top Brewster NE-12	15 (SCR/TD)	Spy Island, SP31-W7	ENI
Nabors Alaska Drilling			
OIME 1000	19AC (AC-TD)	Oooguruk, Stacked	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	Stacked	Hilcorp Alaska LLC
TSM-850	169	Beluga River Unit	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, stacked at Rig Tenders where pre mobilization work is being performed	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

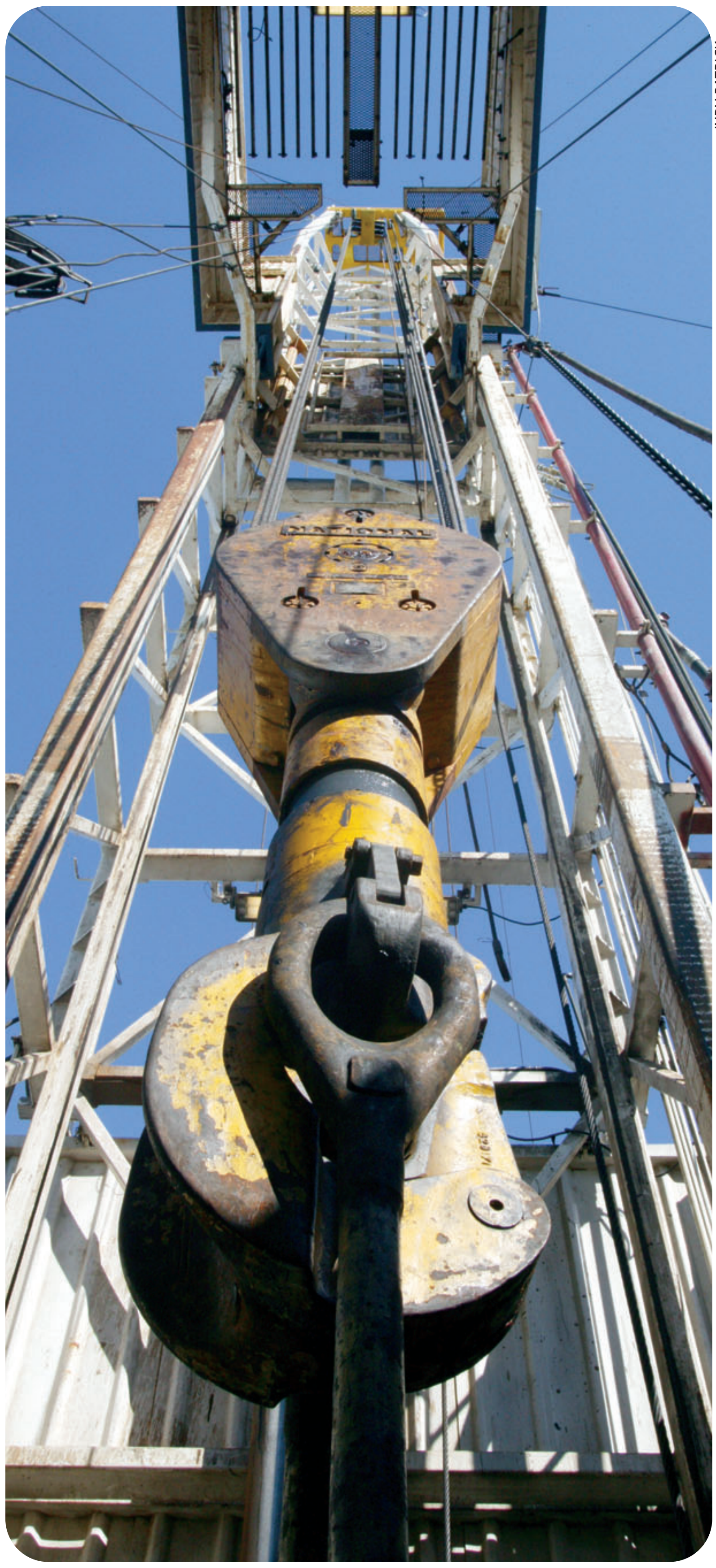
Canadian Beaufort Sea

SDC Drilling Inc.			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Available

The Alaska-Mackenzie Rig Report as of June 30, 2021.
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*

	June 25	June 18	Year Ago
United States	470	470	265
Canada	126	117	13
Gulf of Mexico	14	13	11

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

*Issued by Baker Hughes since 1944

● EXPLORATION & PRODUCTION

Hilcorp plans wells at Greater Point McIntyre

In proposed 2021 plan of development company tells state up to 4 wells may be drilled in 2021 POD at Lisburne, Pt McIntyre PAs

By KRISTEN NELSON
Petroleum News

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

Hilcorp took over as operator at Prudhoe July 1 of last year, after closing June 30 on the purchase of Standard Oil Co.'s stock in BP Exploration Alaska. BPXA had submitted the GPMA 2020 POD in late June of 2020.

PAs at Greater Point McIntyre

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

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

From April 1, 2020, through March 31 of this year, the GPMA PAs produced some 146 billion cubic feet of gas, 9.461 million barrels of oil, 1.362 million barrels of natural gas liquids and some 52 million barrels of water, Hilcorp said.

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

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

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

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

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

2020 POD

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

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

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

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

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

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

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

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

2021 POD

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

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

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

Long-range activities

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

•Evaluate and execute additional facility expansions;

•Evaluate development potential in Lisburne L4/L5 area;

•Evaluate development potential in Niakuk Kuparuk;

•Evaluate development potential at West Beach and North Prudhoe Bay; and

•Evaluate development potential of existing tract operations — NK-14B, NK-08B and P1-09. ●

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● UTILITIES

Moving ahead on EV charging stations

AEA has awarded funding for high speed charging stations on Alaska's road system while RCA opens docket for utilities' rate proposal

By ALAN BAILEY
For Petroleum News

Moves towards encouraging the use of electric vehicles on Alaska's roads are accelerating. On June 14 the Alaska Energy Authority announced that it is awarding nearly $1 million in grants for the installation of electric vehicle charging stations on the state's connected road system. And on June 9 the Regulatory Commission of Alaska opened a docket to consider a proposal by the Alaska Railbelt Electric utilities for addressing some tariff impediments to the provision of power for charging stations.

During a Commonwealth North Energy Policy Study Group meeting on June 18, Sean Skaling from Anchorage-based utility Chugach Electric Association presented data showing a steady growth in the purchase of electric vehicles in Alaska, with there now being more electric vehicles rather than hybrid vehicles in the state.

Electric vehicles, while relatively expensive to purchase, offer the benefits of much lower fuel and maintenance costs than internal combustion engine powered vehicles. The electric vehicles are quiet to drive and do not put emissions into the air. But long distance travel in electric vehicles depends on the availability of high speed charging stations along the travel route. The current absence of these high speed stations in Alaska presents an obstacle to electric vehicle use in the state.

Levels of charging stations

Essentially, there are three levels of charging system for electric vehicles. A level 1 arrangement, which charges very slowly, consists of a normal 120-volt outlet. Level 2, which can be installed in a house for domestic use, consists of a 240-volt outlet, analogous to the outlet for a clothes drier. A commercial level 3 fast charging station uses direct current rather than AC and operates at power ratings ranging from 50 kilowatts to 250 kilowatts.

Dimitri Shein, executive director of Alaska Electric Vehicle Association, told the Commonwealth North meeting that it typically takes six to eight hours to fully charge an empty car battery using a level 2 charger. On the other hand, a level 3 charger can charge a battery in minutes rather than hours, Shein said.

The AEA funding for charging stations comes from Alaska's portion of a settlement with Volkswagen over the company's fraudulent manipulation of emissions testing on its diesel vehicles a few years ago, and from the Department of Energy's State Energy Program. According to an AEA news release the agency is providing partial funding of up to $110,000 per site to entities building charging stations at nine sites on the road system. The funding will cover part of the cost of a total of 12 level 3 chargers and 11 level 2 chargers across those sites.

For example, charging stations at Cooper Landing and Soldotna will support drivers doing long distance trips on the Kenai Peninsula, while a charging station at Cantwell will support drivers using the Parks Highway. Shein commented that the number of fast charging stations planned still falls a bit short of the number needed to fully support electric vehicle use across Alaska's long distance road system — he suggested the formation of public-private partnerships with innovative companies for the construction of more charging stations.

People can use home level 2 chargers to charge their vehicles overnight, thus having sufficient driving range for daily use.

Tariff issues

Given that level 3 charging stations would be owned and operated by commercial companies, there are some issues that need to be resolved, associated with current electricity tariffs. Hence the new docket that the RCA has opened. All electric utility tariffs require RCA approval.

In particular, under current tariffs, a business entity that purchases electricity has to pay demand charges in addition to the charges for the amount of electricity that the business consumes. The demand charges become particularly high if a business imposes high loads on the system for relatively short periods of time. While these demand charges motivate businesses to spread their electricity loads out, to relieve stress on the electricity supply system, the characteristics of electric vehicle charging would likely result in high demand charges that would severely undermine the viability of charging station operation.

On the other hand, the increased electricity demand from electric vehicle use would be to the utilities' benefit, especially in an era when electricity demand is tending to fall because of the improved efficiency in electricity use.

Proposed rate structure

In their filing with the RCA the utilities proposed a electricity rate structure for commercial level 3 charging stations that would flatten the demand charges at relatively low levels, when charging station power demand is particularly concentrated over relatively short periods of time. The utilities have also asked the commission to resolve two other issues. The first of these issues is a provision in the current utilities' tariffs that prohibits a purchaser of electricity from a utility from reselling the electricity — clearly that provision would prevent a business from independently operating an electric vehicle charging station. The other issue relates to a need to clarify that an electric vehicle charging station would not be classified as a public utility that would be subject to RCA regulation.

The utilities originally floated their proposals in a May 19 filing in an RCA regulatory docket addressing issues relating to electric vehicle charging stations. As part of that docket the commission invited public comments on the proposals. The commission also asked the utilities to make a formal proposal, to trigger a formal response by the commission to the utilities' requests — hence the new regulatory docket that was initiated on June 9. Although there is a sense of urgency in dealing with regulatory issues relating to charging stations, the commission does have a legal mandate to invite and consider public comments on what is proposed. The commission has been receiving comments in both of the EV dockets.

Using EVs for local driving

Meanwhile, people are finding electric vehicles to be useful for local driving in Alaska. People can use home level 2 chargers to charge their vehicles overnight, thus having sufficient driving range for daily use. Shein commented that he uses his vehicle in this manner. Shaina Kilcoyne, energy and sustainability manager for the Municipality of Anchorage, told the Commonwealth North meeting that the resulting cost of charging an electric vehicle is less than half the cost of fueling an internal combustion engine.

Kilcoyne also said that the municipality is moving ahead with its own vehicle electrification program, as part of the municipality's climate action plan. The municipality partnered with Chugach Electric in the installation of one of the level 2 public charging stations in the municipality and is in the process of replacing fuel-hungry diesel garbage trucks and a medium-duty box truck with electric trucks. Apparently the Anchorage Police Department has purchased 20 new hybrid vehicles, with an expectation of a 45% fuel saving.

Beneficial opportunities

Skaling said that Chugach Electric has

see **EV CHARGING** page 6

GOVERNMENT

DEPARTMENT OF THE INTERIOR

Tommy Beaudreau sworn in at Interior

Tommy Beaudreau was sworn in as deputy secretary of the U.S. Department of the Interior by Interior Secretary Deb Haaland June 23.

Beaudreau, born in Colorado, was raised in Alaska and currently resides in Washington, D.C., with his wife and two children.

"I am honored to be back at the Department of the Interior as deputy secretary at this critical time for our country," said Beaudreau in a statement from Interior following his swearing in. "The Interior Department plays a key role in President Biden's economic, environmental, and racial justice agenda, and I am thrilled to join Secretary Haaland's team to delivery for the American people."

Beaudreau returns to Interior after serving for nearly seven years at the department during the Obama-Biden administration, including as the first director of the Bureau of Ocean Energy Management, acting assistant secretary for Land and Minerals Management and chief of staff to Secretary Sally Jewell.

An attorney, Beaudreau graduated from Service High School in Anchorage, earned a Bachelor of Arts in history from Yale and a law degree from Georgetown University Law Center. He was as associate and later a partner with the Fried Frank law firm in Washington, D.C. After serving in the Obama administration he became a partner at Latham & Watkins.

His nomination as deputy secretary was confirmed June 17 by an 88-9 vote in the U.S. Senate.

—PETROLEUM NEWS

● EXPLORATION & PRODUCTION

May ANS production down 0.6% from April

Crude, NGL total 487,672 bpd, down 2,853 bpd from May, but up 12.4% from a May '20 average of 433,840 bpd; Cook Inlet down 5%

By KRISTEN NELSON
Petroleum News

Alaska North Slope production averaged 487,672 barrels per day in May, down 0.58%, 2,853 bpd, from an April average of 490,525 bpd, but up 12.4% from a May 2020 average of 433,840 bpd.

The year-over-year increase reflects a return to normal activity from last year's COVID-19-related production decline.

The ANS volumes include an average of 434,569 bpd of crude, 89.1% of the total, and 53,102 bpd of natural gas liquids, 10.9% of the total volume. The crude average is down 0.6%, 2,567 bpd, from an April average of 437,136 bpd, and a 10.7% increase from a May 2020 average of 392,557 bpd, when crude represented 90.5% of total volume. The NGL volume reflects a drop of 0.5%, 287 bpd, from an April average of 53,389 bpd and a 28.6% increase from a May 2020 average of 41,283 bpd, 9.5% of total volume.

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

Prudhoe down 2.6%

Production from the Hilcorp North Slope-operated Prudhoe Bay, the Slope's largest field, averaged 261,449 bpd in May, down 2.6%, 7,090 bpd, from an April average of 268,538 bpd and up 6.6% from a May 2020 average of 245,333 bpd. Crude oil represented 81.3% of Prudhoe production in May, 212,582 bpd, down 3.2%, 7,100 bpd, from an April average of 219,683 bpd and up 2.7% from a May 2020 average of 206,982 bpd, 84.4% of total volume in that month. Prudhoe NGL production averaged 48,866 bpd in May, 18.7% of Prudhoe production (and 10% of Slope production), up marginally, 11 bpd, from an April average of 48,856 bpd and up 27.4% from a May 2020 average of 38,351, when NGLs represented 15.6% of Prudhoe production.

In addition to the primary reservoir, production volumes from Prudhoe include Aurora, Borealis, Lisburne, Midnight Sun, Niakuk, Polaris, Point McIntyre, Put River, Raven and Schrader Bluff.

The ConocoPhillips Alaska-operated Kuparuk River field, the Slope's second

Hilcorp Alaska's Milne Point field averaged 36,637 bpd in May, up 1,941 bpd, 5.6%, from an April average of 34,696 bpd and up 13% from a May 2020 average of 32,436 bpd.

largest, was also down month-over-month in May, averaging 90,855 bpd, down 834 bpd, 0.9%, from an April average of 91,690 bpd and up 38.5% from a May 2020 average of 65,607 bpd.

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

Hilcorp Alaska's Northstar field averaged 8,300 bpd in May, down 732 bpd, 8.1%, from an April average of 9,032 bpd and up 0.7% from a May 2020 average of 8,246 bpd. Northstar averaged 4,921 bpd of crude, 59.3% of the field's production, down 358 bpd, 6.8%, from an April average of 5,279 bpd and down 19.7% from a May 2020 average of 6,129 bpd, when crude represented 74.3% of the field's production. NGLs averaged 3,379 bpd, 40.7% of production, down 374 bpd, 10%, from an April average of 3,753 bpd and up 59.6% from a May 2020 average of 2,117 bpd, 25.7% of Northstar production in that month.

The Badami field, operated by Savant Alaska, a Glacier Oil & Gas company, averaged 1,143 bpd in May, down 164 bpd, 12.5%, from an April average of 1,307 bpd and up 3,951% from a May 2020 average of 28 bpd.

ConocoPhillips' Greater Mooses Tooth in the National Petroleum Reserve-Alaska averaged 2,449 bpd in May, down 157 bpd, 6%, from an April average of 2,606 bpd and down 44.8% from a May 2020 average of 4,433 bpd.

The Hilcorp-operated Endicott field averaged 6,542 bpd in May, down 64 bpd, 1%, from an April average of 6,606 bpd and down 0.5% from a May 2020 average of 6,574 bpd. Crude oil represented 86.9% of Endicott production, 5,685 bpd in May, down 141 bpd, 2.7%, from an April average of 5,826 bpd and down 1.3% from a May 2020 average of 5,760, when crude represented 87.6% of the field's production. NGL volumes averaged 857 bpd in May, 13.1% of Endicott production, up 77 bpd, 9.9%,

see **ANS OUTPUT** *page 7*

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EV CHARGING

been conducting research into electric vehicle and charging station use in its service area. There is a particularly large opportunity for commercial businesses with vehicle fleets, where a vehicle's daily milage is within the range of level 2 charging systems, he said.

And, if people are charging their vehicles overnight, that boosts electricity usage at a time when electricity demand is normally low, thus making more complete use of the electricity supply infrastructure. So, given the incentives to make maximum use of expensive electrical infrastructure, the increasing use of electric vehicles should put downward pressure on electricity rates.

"So, EVs really are good for everybody, whether you drive an electric vehicle or not," Skaling said. ●

Contact Alan Bailey at abailey@petroleumnews.com

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ANS OUTPUT

from an April average of 780 bpd and up 5.2% from a May 2020 average of 816 bpd, 12.4% of Endicott production in that month.

Point Thomson up 17.3%

The ExxonMobil Production-operated Point Thomson field averaged 9,350 bpd in May, up 17.3%, 1,381 bpd, from an April average of 7,970 bpd and down 2.8% from a May 2020 average of 9,618 bpd.

Eni's Oooguruk field averaged 6,856 bpd in May, up 831 bpd, 13.8%, from an April average of 6,026 bpd and up 8.3% from a May 2020 average of 6,331 bpd.

Eni's Nikaitchuq field averaged 17,250 bpd in May, up 1,229 bpd, 7.7%, from an April average of 16,021 bpd and down 4.9% from a May 2020 average of 18,144 bpd.

Hilcorp Alaska's Milne Point field averaged 36,637 bpd in May, up 1,941 bpd, 5.6%, from an April average of 34,696 bpd and up 13% from a May 2020 average of 32,436 bpd.

ConocoPhillips' Colville River averaged 46,838 bpd in May, up 1.8%, 806 bpd, from an April average of 46,032 and up 26.3% from a May 2020 average of 37,090 bpd. In addition to oil from the main Alpine pool, Colville production includes satellite production from Nanuq and Qannik.

Cook Inlet down 5%

Cook Inlet crude oil production averaged 8,857 bpd in May, down 5%, 463 bpd, from an April average of 9,321 bpd and down 23.4% from a May 2020 average of 11,563 bpd. With the exception of 88 bpd of NGLs from Swanson River, combined with crude in these numbers, all reported Cook Inlet volumes are crude oil.

Hilcorp's Beaver Creek averaged 202 bpd in May, down 6%, 13 bpd, from an April average of 215 bpd and up 37% from a May 2020 average of 147 bpd.

Hilcorp's Granite Pint averaged 2,664 bpd in May, down 45 bpd, 1.7%, from an April average of 2,709 bpd and down 14% from a May 2020 average of 3,096 bpd.

BlueCrest's Hansen field averaged 928 bpd in May, down 16 bpd, 1.7%, from an April average of 944 bpd and down 5.1% from a May 2020 average of 977 bpd.

Hilcorp's McArthur River, Cook Inlet's largest field, averaged 3,079 bpd in May, down 10.4%, 356 bpd, from an April average of 3,435 bpd and down 14.8% from a May 2020 average of 3,611 bpd.

Hilcorp's Middle Ground Shoal, shut-in since a leak in a fuel gas line discovered April 1, showed 13 bpd of crude production in May, down 51 bpd, 79.7%, from an April average of 64 bpd, and down 99% from a May 2020 average of 1,266 bpd. Hilcorp has applied to the Alaska Division of Oil and Gas to suspend operations at the field until the pipeline issue is resolved.

Hilcorp's Swanson River averaged 909 bpd (crude and NGLs) in May, down 71 bpd, 7.2%, from an April average of 979 bpd and up 2.9% from a May 2020 average of 883 bpd.

Hilcorp's Trading Bay averaged 1,063 bpd in May, down 15 bpd, 1.4%, from an April average of 1,078 bpd and down 8.2% from a May 2020 average of 1,158 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. ●

Contact Kristen Nelson at knelson@petroleumnews.com

Cook Inlet gas production down marginally

Cook Inlet natural gas production averaged 219,912 thousand cubic feet in May, down 1,047 mcf, 0.5%, from an April average of 220,959 mcf and up 10.8% from a May 2020 average of 198,445 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.

The inlet's nine largest fields accounted for 87.1% of natural gas production in May, down slightly from 87.8% in April but up from 81% in May 2020.

Hilcorp's Kenai field averaged 42,453 mcf per day in May, 19.3% of inlet production, down 5,501 mcf per day, 11.5%, from an April average of 47,954 mcf per day and up 30.7% from a May 2020 average of 32,489 mcf per day (16.4% of inlet production in that month).

Hilcorp's Ninilchik averaged 29,595 mcf per day in May, 13.5% of inlet production, up 938 mcf per day, 3.3%, from an April average of 28,658 mcf per day and down 2% from a May 2020 average of 30,207 mcf per day (15% of inlet production in that month).

Hilcorp's McArthur River averaged 25,781 mcf per day in May, 11.7% of inlet production, down 600 mcf per day, 2.3%, from an April average of 26,380 and up 8.9% from a May 2020 average of 23,684 mcf per day (11.9% of inlet production in that month).

The Hilcorp-operated Beluga River field averaged 21,158 mcf per day in May, 9.6% of inlet production, up 178 mcf per day, 0.9%, from an April average of 20,980 mcf per day, and up 19.6% from a May 2020 average of 17,692 (8.9% of inlet production in that month).

Hilcorp's Swanson River averaged 20,916 mcf per day in May, 9.5% of inlet production, up 1,953 mcf per day, 10.3%, from an April average of 18,963 mcf per day, and down 29.1% from a May 2020 average of 29,516 mcf (14.9% of inlet production in that month).

Furie's Kitchen Lights averaged 16,294 mcf per day in May, 7.4% of inlet production, up 873 mcf per day, 5.7%, from an April average of 15,421 mcf per day and up 18.8% from a May 2020 average of 13,715 mcf (6.9% of inlet production in that month).

Hilcorp's North Cook Inlet averaged 15,086 mcf per day in May, 6.9% of inlet production, up 1,153 mcf per day, 8.3%, from an April average of 13,933 mcf per day and up 15.1% from a May 2020 average of 13,110 mcf per day (6.6% of inlet production in that month).

Hilcorp's Ivan River averaged 10,182 mcf per day in May, 4.6% of inlet production, down 273 mcf per day, 2.6%, from an April average of 10,455 mcf per day and up 3,063.9% from a May 2020 average of 322 mcf per day (0.2% of inlet production in that month).

Hilcorp's Beaver Creek averaged 9,975 mcf per day in May, 4.5% of inlet production, down 1,189 mcf per day, 10.7%, from an April average of 11,164 mcf per day and down 1.3% from a May 2020 average of 10,104 mcf (5.1% of inlet production in

see **INLET PRODUCTION** *page 8*

LAND & LEASING

Final finding for North Slope Foothills

The Alaska Division of Oil and Gas has issued a final written finding of the director for proposed North Slope Foothills Areawide Oil and Gas lease sales 2021-30. Division Director Tom Stokes signed off on the finding, issued June 24, and Department of Natural Resources Commissioner Corri Feige signed as concurring.

Best interest findings are issued every 10 years; the division then issues annual calls for any substantial new information which has become available since issuance of the most recent best interest finding.

The division initiated the 10-year review for the North Slope Foothills areawide in May 2020; a preliminary best interest finding and request for public comments were issued this February with comments due April 26.

After weighing the facts and issues, the finding says, "The director finds that the potential benefits of lease sales outweigh the possible negative effects, and that the North Slope Foothills Areawide oil and gas lease sales will best serve the interests of the State of Alaska."

No bids were received in the most recent North Slope Foothills sale held earlier this year; there are just a handful of active leases shown in the foothills area map that is part of the BIF.

"Except for the Umiat oil accumulation, oil and gas discoveries to date within the Arctic Foothills physiographic region have been primarily dry gas trapped in anticlinal fold closures, identified from early surface geologic mapping and supported by two-dimensional reflection seismic surveys," the division said.

Major new oil finds are unlikely because formation outcrops and well data indicate source rocks in the Arctic Foothills "have likely reached advanced thermal maturity due to deep sediment burial," the division said. Geology, geophysics and exploration are sparsely distributed for the sale area, with the potential for conventional recoverable petroleum "relatively high for gas, and relatively low for oil."

—KRISTEN NELSON

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NEW GAS LINES

gas from Cannery Loop wells, the company said, and the existing 16-inch line will be used as needed for future projects in the Kenai field.

Hilcorp said it has plans within the next one or two years to "upgrade the main KGF gas sales line by installing a pig launcher/receiver, replacing valves, and upgrading/replacing the associated tie-in piping."

The 16-inch line will be used temporarily for sales gas while those upgrades are being done and will continue to serve as a backup flowline for the life of the field, the company said.

Hilcorp proposes completing the new lines prior to winter gas demand for the 2021-22 season "to avoid potential gas supply issues for Southcentral Alaska."

Flowline installation is planned to begin this summer, with the exact start depending on receipt of regulatory approval from the U.S. Army Corps of Engineers.

The company said it would monitor ground conditions for construction and begin work "when the ground is sufficiently dry to reduce impacts to wetland areas and allow safe access to equipment," anticipated to be in the August-September timeframe.

The company said regulatory authorizations may delay the project to the winter of 2021-22, but once begun, the project is expected to take up to 45 days.

The flowline route is some 5,600 feet between the two pads, the company said. ●

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FRACKING FALLOUT

sufficient to be felt on the surface.

One section of the Montney generated about 20 earthquakes when 1 million cubic meters of fluids were pumped underground and registered more than 160 events when injection grew to 3.5 million cubic meters.

Chapman, noting that many Montney sites have only four wells that could reach 30 wells as development moves to a peak.

Commission critical

The B.C. Oil and Gas Commission was critical of Chapman's peer-reviewed work which the agency's geological and engineering experts concluded was based on a "number of unproven assumptions or incomplete consideration of the factors cited."

The commission said the study failed to account for variation of rock strata, fault types and local stresses, calling the conclusions "speculation."

Regulations in British Columbia and Alberta are managing risk by requiring companies to reduce pumping pressure and volumes once light earthquakes are felt, but Chapman said four of the five biggest recent earthquakes in the Montney were not preceded by any warnings.

Researchers at the University of Calgary have concluded that fracturing fluids can cause slow slips on a fault line, leading to a sudden slip where conditions are unstable, triggering an earthquake.

That finding invalidated claims that earthquakes should not be possible given the type of rock stimulated by fracking.

In February 2020, the Fraser Institute, a public policy Canadian think-tank, challenged the risk claims.

"Seismic activity — which is typically very minor, causing no damage — related to fracking is not due to the practice per se, but rather to wastewater disposal methods which pumps water back into the ground. Research suggests that altering the depth and flow rate of the water injection can minimize the risk of seismic activity," the Fraser Institute said.

It also said there is no evidence that methane emissions from fracking are greater than what is emitted from conventional wells and that by making natural gas more abundant the process is cutting down on the amount of coal burned in electric power plants.

From beginnings in the early 1950s which went largely unobserved and unreported, the use of hydraulic fracturing in Canada is now a key contributor to oil and natural gas production in the four western provinces.

Changes in fracking

A report by the Petroleum Services Association of Canada, said "the science and technology of fracking have evolved over the past 60 years, becoming more productive, sophisticated and safer," turning into a "game changer" for the industry.

"Advances in the implementation of fracking have come from the collaboration among governments, industry, academics and others to share practices and learning gained from experience and research."

PSAC said the learning gained from experience and research has contributed to big advances, covering: public disclosure of frac fluids and access to data on the industry's use of water; more opportunity for public and Indigenous consultation and engagement; and the use of clean technology to reduce the use of water and energy, while generating less waste and decrease the environmental footprint.

Against this backdrop, the industry players doubt there will be any hasty moves by regulators or governments to ban the use of fracking. ●

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INLET PRODUCTION

that month).

Combined, the smaller Cook Inlet gas fields account for some 13% of inlet production.

Hilcorp's Cannery Loop averaged 5,568 mcf per day in May, up 13.1%, 646 mcf per day, from an April average of 4,923 mcf per day and up 6.6% from a May 2020 average of 5,223 mcf per day.

AIX's Kenai Loop averaged 4,816 mcf per day in May, down 17 mcf per day, 0.4%, from an April average of 4,834 mcf per day and up 10.4% from a May 2020 average of 4,362 mcf per day.

Hilcorp's Deep Creek averaged 4,242 mcf per day in May, down 80 mcf per day, 1.9%, from an April average of 4,322 mcf per day and up 6.6% from a May 2020 average of 3,980 mcf per day.

Hilcorp's Granite Point averaged 3,558 mcf per day in May, down 86 mcf per day, 2.4%, from an April average of 3,644 mcf per day and down 0.2% from a May 2020 average of 3,566 mcf per day.

Vision Operating's North Fork field averaged 3,264 mcf per day in May, up 6.1%, 187 mcf per day, from an April average of 3,077 mcf per day and down 6% from a May 2020 average of 3,472 mcf per day.

BlueCrest's Hansen field averaged 3,161 mcf per day in May, up 607 mcf per day, 23.8%, from an April average of 2,554 mcf per day and up 13.7% from a May 2020 average of 2,780 mcf per day.

Hilcorp's Trading Bay averaged 2,198 mcf per day in May, up 110 mcf per day, 5.3%, from an April average of 2,088 mcf per day and up 0.3% from a May 2020 average of 2,191 mcf per day.

Hilcorp's Lewis River averaged 1,092 mcf per day in May, down 19 mcf per day, 1.7%, from an April average of 1,111 mcf per day and up 0.8% from a May 2020 average of 1,083 mcf per day.

Amaroq's Nicolai Creek averaged 425 mcf per day in May, up 70 mcf per day, 19.8%, from an April average of 355 mcf per day and up 94% from a May 2020 average of 219 mcf per day.

Hilcorp's Nikolaevsk averaged 147 mcf per day in May, up marginally from an April average of 145 mcf per day and down 29.1% from a May 2020 average of 208 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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OIL PRICES

the sixth straight week of drawdowns, spurred by demand for motor vehicle fuel.

A June 30 Bloomberg report said that over the last four weeks total stockpiles, including the Strategic Petroleum Reserve, fell at a rate of 1.15 million barrels a day, the largest four-week decline on a rolling basis in EIA data going back to 1982.

ANS, WTI and Brent ended June just below the peak post-COVID levels set at the end of the previous week. On Friday June 25, ANS closed at $75.88, up 66 cents, WTI jumped 75 cents to $74.05 and Brent broke the $76 mark to close at $76.18 — up 62 cents.

But prices dropped sharply on concerns over COVID-19 case spikes in Europe and Asia as the new week began June 28, taking ANS and Brent below $75 and taking WTI below $73.

OPEC+ meets on production strategy

The indexes staged a modest recovery June 29 after optimistic remarks about the market from the Organization of the Petroleum Exporting Countries at its meeting of the Joint Technical Committee of the Declaration of Cooperation of OPEC and non-OPEC oil producing countries.

"The overall brighter picture in relation to the pandemic recovery efforts has led to significantly improved oil market conditions and prospects for future growth," OPEC Secretary General Mohammad Sanusi Barkindo told the committee.

The June OPEC Monthly Oil Market Report projected global oil demand to rise by 6 million barrels per day in 2021, while world economic growth is forecast at 5.5 % in the same period.

The joint technical committee meeting is the lead-in to the 31st Meeting of the Joint Ministerial Monitoring Committee scheduled for June 30, and the 18th OPEC and non-OPEC Ministerial Meeting scheduled for July 1, which will decide whether to increase production in August.

The most likely outcome, according to analysts, is for an increase of 500,000 bpd.

The JMMC was delayed however, to allow OPEC+ to allow more time for a compromise before the ministerial meeting, Bloomberg reported June 30.

Reportedly, OPEC+ power players Saudi Arabia and Russia were at odds in preliminary discussions, with the Saudis urging restraint, and the Russians calling for a more aggressive boost in supply.

In a similar standoff in December, the group decided on a modest increase in production.

Both meetings were rescheduled to be held on July 1.

In early trading ahead of the meetings, oil prices responded positively. At Petroleum News press time early July 1, WTI had vaulted 2.95% and Brent had gained 2.36%.

The ministerial meeting may consider extending the OPEC+ overall supply pact beyond April 2022, due to "significant uncertainties" and the risk of an oil glut next year, sources within the group told Reuters.

OPEC+ is moving towards adding approximately 2 million bpd of oil to the market between August and December, an OPEC+ source told Reuters, according to a July 1 report.

Cuts now stand at about 5.8 million bpd, down from more than 9 million bpd in May 2020.

Supply deficit seen

Despite OPEC+ concerns about a glut in 2022, many analysts are convinced that pent-up demand may overwhelm the ability of suppliers to close the gap.

"There's a sense that supply is more narrow, and it may not be enough to cover the pent-up demand; that's what's driving the current boost in price," Regina Mayor, global head of energy at KPMG, told CNBC's Trading Nation June 29.

"Most analysts are predicting that the world will return to over 100 million barrels per day of demand by at least the end of 2022 and we're seeing a surge in short-term demand in the U.S. and China," she said. "What's coming home to roost is the underinvestment that the sector has gone through — 30% lower than five years ago in terms of oil and gas investment and $250 billion of underinvestment in 2020 alone."

Goldman Sachs Commodities Research said more production is needed from OPEC+ to balance the market by 2022 as supply risk looms elsewhere, Reuters reported June 30.

Oil demand is likely to rise by an additional 2.2 million bpd by year-end, leaving a 5 million bpd supply shortfall — more than what Iran and shale producers can bring online, Goldman said.

"While a large new infection wave could slow the market rebalancing, we expect OPEC+ to remain tactical in its output hikes with downside risks to global supply elsewhere pointing to a more robust outlook for crude and the upstream sector than petroleum products and the downstream sector," Goldman said.

—STEVE SUTHERLIN

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Petroleum news — Oil Patch Bits

Coffman promotes Matt Stielstra to principal

Coffman Engineers Inc., a multidiscipline engineering firm, recently announced the promotion of Matt Stielstra, SE, to principal and structural department manager at the Anchorage office. Stielstra joins Will Veelman, a long-time principal, in structural leadership of the Anchorage office as Veelman continues his incredible Coffman career as a principal advisor and a member of Coffman's executive committee.

Stielstra received his Bachelor of Architectural Engineering from Oklahoma State University and his Master of Engineering in architectural engineering from Penn State University. He worked at an A/E firm in Springfield, Missouri, his first year after graduate school before moving back to his home state of Alaska and joining Coffman in the fall of 2008. He is a licensed civil engineer in Alaska, a licensed structural engineer in Alaska and Hawaii, and a licensed building systems engineer in Washington.

Stielstra has worked on an array of building and nonbuilding structures for industrial, oil and gas, commercial, and government clients. His notable recent projects include the facility design for one of Alaska's largest military developments for the F-35 program at Eielson Air Force Base.

He joins six other shareholder promotions company-wide, as well as a leadership change to our board of directors. To read more about Stielstra's accomplishments and other leaders promoted visit www.coffman.com/leadership/.

MATT STIELSTRA

Companies involved in Alaska's oil and gas industry

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

EXPLORATION & PRODUCTION

AOGCC OKs Hilcorp's Seaview No. 9

The Alaska Oil and Gas Conservation Commission has approved an application from Hilcorp Alaska for the Seaview No. 9 delineation well.

This will be the second well at the company's southern Kenai Peninsula Seaview gas field. Hilcorp is in the process of completing a gas line which will enable it to begin production from Seaview 8, the discovery well at the field.

The Seaview 9 well will be in an undefined gas pool within 1,500 feet of a property line where owners and landowners are not the same on both sides of the line, the commission said, and where more than one well will be drilled to and completed in the same pool in the same governmental section and completed closer than 3,000 feet to any well drilling to or capable of producing from the same pool.

The commission said the well is classified as an exploratory well because it is drilled to delineate a pool.

Hilcorp provided a list of tract ownership listing mineral owners, gross acreage and mineral interest percentage for each tract, and proposes an escrow account for 100% of production royalties allocated to non-participating owners/landowners and uncommitted tracts.

The Seaview 9 "targets unproven discontinuous and lenticular reservoirs" which cannot be reached by a well conforming to spacing requirements, the commission said.

As part of its order the commission addressed requirements for the escrow account, including a requirement that Hilcorp deposit, no later than the 30th day of each month, "an amount equal to the total of that non-participating owner's/landowner's interest percentage for those parcels multiplied by the production attributed to those parcels for the previous month multiplied by 0.125 (the royalty rate) multiplied by the prevailing value for Cook Inlet gas published for that quarter by the Alaska Department of Revenue."

Hilcorp is required to provide the commission a tract ownership schedule within 60 days listing all tracts within 1,500 feet of the Seaview 9 wellbore, and on or before Feb. 1 of each year, the company is required to provide the commission an updated tract ownership schedule and detailed accounting of the escrow account.

—KRISTEN NELSON

US rotary rig count unchanged at 470

The Baker Hughes U.S. rotary drilling rig count was 470 the week ending June 24, unchanged from the previous week and up by 205 from 265 a year ago.

When the count bottomed out at 244 in mid-August last year, it was not just the low for 2020, but the lowest the count has been since the Houston based oilfield services company began issuing weekly U.S. numbers in 1944.

> *Baker Hughes shows Alaska with four rigs active June 25, up one from the previous week and up one from a year ago, when the state's count stood at three.*

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 when it gained back 10 rigs.

The June 25 count includes 372 rigs targeting oil, down one from the previous week and up 184 from 188 a year ago, 98 rigs targeting gas, up by one from the previous week and up by 23 from 75 a year ago, and no miscellaneous rigs, unchanged from the previous week and down by two from a year ago.

Thirty of the rigs reported June 25 were drilling directional wells, 421 were drilling horizontal wells and 19 were drilling vertical wells.

Alaska rig count up by one

Alaska's rig count (4) was up by one from the previous week; California (6) was down by one.

Rig counts in all other states were unchanged from the previous week: Colorado (10), Louisiana (52), New Mexico (75), North Dakota (17), Ohio (9), Oklahoma (27), Pennsylvania (18), Texas (221), Utah (10, West Virginia (9) and Wyoming (10).

Baker Hughes shows Alaska with four rigs active June 25, up one from the previous week and up one from a year ago, when the state's count stood at three.

The rig count in the Permian, the most active basin in the country, was down by one from the previous week at 236 and up by 105 from a count of 131 a year ago.

—KRISTEN NELSON

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ERO REGS

The RRC has been planned to maintain and mandate reliability standards for the high voltage electrical system; administer rules for open access to the transmission grid; conduct Railbelt-wide system planning; and investigate the economic value of security constrained economic dispatch for all or part of the system. Economic dispatch involves the continuous use of the most cost effective power generation that is securely available.

SB 123, and its supporting regulations, also give the RCA the authority to regulate the construction of new major generation and transmission facilities in the electricity grid, and to regulate integrated resource planning for the system.

The overall objective is to minimize the cost of electricity for consumers while maintaining adequate levels of reliability in the electricity supplies. Another objective revolves around a desire to enable independent power producers, including the producers of renewable energy, to have equable access to the system.

With a statutory deadline of July 1 of this year for issuing the regulations, RCA has had to develop the new regulations in a compressed timeframe. Development of the nearly 100 pages of detailed regulations has been a major project for the commissioners and the RCA staff. Stakeholders in the electrical system, including the electricity utilities, have also had to devote significant amounts of time to the project.

Regs for the board structure

There have been a number of difficult issues relating to the new regulations. One particularly difficult issue has revolved around the need for a balanced or independent board of directors for the ERO. The concept is that the ERO should equably represent the interests of a range of stakeholders in the electrical system, including electricity providers and electricity consumers. While the electricity utilities have expertise in how the system operates, independent power producers, for example, seek fair access to the system. And electricity consumers have obvious interests in the system.

SB123 requires that the ERO board must be "independent," "balanced," or a "combination thereof." The handling of this issue is one of a number of areas in which the electric utilities have argued that the commission has been over prescriptive in its approach to developing the regulations. Less prescriptive regulations would involve the setting of some general parameters under which the commission would assess whether an ERO applicant meets the statutory requirements, rather than spelling out more explicitly how the ERO should be organized and should operate.

In the event, the commission has opted for fairly complex regulations defining how an ERO board can be approved as appropriately balanced or independent.

> *There have been a number of difficult issues relating to the new regulations. One particularly difficult issue has revolved around the need for a balanced or independent board of directors for the ERO. The concept is that the ERO should equably represent the interests of a range of stakeholders in the electrical system, including electricity providers and electricity consumers.*

The regulations depend on the identification of different classes of stakeholder in the system. A balanced board cannot have more than 50% of its directors from a single stakeholder class. Electricity providers and consumers require equal representation. And there must be an odd number of directors, to prevent hung votes. An independent board cannot have directors who are employed by an ERO or by a registered entity within the ERO-regulated electrical system.

Need for specificity

In their June 29 order the commissioners justified their approach to defining the board requirements, arguing that, given the lack of specific definitions in the SB 123 statutory language, an absence of adequate regulatory guidance could have led to a situation where the commission would be unable to deny certification to an ERO applicant that the commission did not view as having a balanced board structure. The commissioners also commented that several non-utility commenters had expressed support for the commission's approach to the regulations for ERO board composition.

Along similar lines, contention also arose over the extent to which the regulations should spell out the required contents of an integrated resource plan. However, in the June 29 order, the commissioners also pointed out that there are areas of the regulations that were streamlined in response to public comments.

Other complications

There were complications over dealing with the approval of large electrical facilities whose planning and development start before the approval of the first integrated resource plan for the system — initial IRP approval may not happen until several years after an ERO is certified. And figuring out acceptable rules for determining how transmission system costs need to be allocated to transmission system users required significant attention.

Another difficult question has revolved around whether an ERO is a public utility, requiring a traditional certificate of public convenience and necessity — SB 123 did not address this question. In the event, based on an assistant attorney general legal opinion, the commission has opted for a position that an ERO is not a utility and will be issued with an ERO certificate rather than a CPCN, a certificate of public convenience and necessity. As a consequence, the commission has had to adjust some of its existing regulations to take into account the regulation of EROs. In addition, the new ERO regulations have had to include specific procedures such as the tariff filing process for EROs, and to include language to accommodate situations under which specific regulations can be waived. ●

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INSIDER

time to be selling Badami: "Alaska is really unpopular with investors. What with the banks boycotting the state and fear of reprisal from Biden et al and all their green hysteria. But this just needs to run its course," one source said. "In my humble opinion, Apollo and Glacier need to chill out on their sale as they are selling into a super bad market. Oil could be $100 a barrel a year from now."

Another PN source pointed to the fact that "Armstrong and Oil Search have all that acreage south of Badami, which they expect to be drilling in the next year or two. That alone will increase Badami's value, especially if they find what they expect to. And so far, their track record on the North Slope is excellent," he said.

"And if they can snag Glacier's president, Stephen Ratcliff, who is a technical whizz, they can use Badami's infrastructure as a hub for the area," he continued, pointing to Badami's 38,500 barrel-a-day processing facility and multiple access points," which is almost exactly what the first broker of the Badami assets said in November — BMO Capital Markets Energy Group.


STEPHEN RATCLIFF

Note: Badami production has been slowly dropping, although some of it is a seasonal variation. Last fall it was producing about 1,400 barrels of oil per day; in April it was at 1,307 bpd and in May 1,143 bpd.

Another one of BMO's bullet points was the many access points, including "via barge landing and 5,500-foot airstrip." Another was the "70 mbo/d capacity Nutaaq pipeline owned and operated by Glacier (12" diameter, 25 miles long) that connects Point Thompson to Endicott."

BMO no longer has the property listed.

The next place Badami was listed, per one of the PN sources, was on Datasite.com under the site name Grizzly. That was a month ago, but it is no longer there, he said, and PN was unable to find it anywhere else.

"Maybe they took it off the market," he said, noting it was a buyers' market.

Most data rooms can only be entered with an invitation, so Glacier/Apollo could have set up a data room elsewhere. Or, of course, they could be in final negotiations with a solid buyer.

The word on the street a few weeks ago was they had a buyer, but no formal/public applications surfaced at the state level. Alaska's Division of Oil and Gas must approve new owners and lease transfers, even for simple stock transactions.

In the case of new owners, the primary controlling new entity must prove both its technical and financial wherewithal.

Stay tuned …

—KAY CASHMAN

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AUGUSTINE BID

tracts, ranging from 2,489 to 2,560 acres.

The division said the call will initiate the process to allow exploration for geothermal resources, "which could result in a disposal, by either a geothermal prospecting permit or a geothermal lease."

Past interest

There has been interest in this area in the past, and in 2013 the division issued a final finding for an Augustine Island geothermal lease sale. That sale was held in conjunction with the Cook Inlet areawide sale in June 2013. The state received a single bid, for tract 13, $1.02 per acre from Nicholas Van Wyck, $2,544.90 for the 2,495-acre tract.

In its finding for that sale the division discussed the history of Augustine Volcano, which, it said "has explosively erupted, sometimes ejecting very large fragments of magma thousands of feet into the atmosphere. Larger-sized volcanic debris, called blocks or bombs, typically strike near the vent of the volcano."

The Alaska Volcano Observatory has reported ash clouds from the 1976 and 1986 eruptions reaching high enough to damage aircraft, with five jetliners experiencing severe exterior abrasion in 1976 and in 1986 a DC-10 encountered an Augustine Volcano ash cloud on descent into Anchorage, and although it landed safety, the division said, air traffic was routed around the ash cloud for several days.

In its 2013 finding the agency said the geothermal energy potential at Augustine Island is indicated by the presence of the volcano, but said data is not yet available on the subsurface and geologic data related to geothermal potential of the volcano, with Alaska Volcano Observatory published field studies conducted on the island related to geohazards and volcanology of the volcano.

Challenge of transport

There are challenges in transporting geothermal energy, the division said in a 2013 director's finding, and "currently geothermal energy must be used or converted to electricity within a few miles of its recovery from the ground reservoir."

Augustine Island is far from the existing electrical power grid, with the nearest power plants some 150 miles away at Beluga and 112 miles at Nikiski.

That was in 2013.

But public interest in cleaner sources of energy continued to grow, including investments in technology for geothermal power.

The main problem facing renewable energy is that the biggest sources, wind and solar, are variable. While fossil fuel power plants can be constant or turned on and off on demand — wind and solar come and go with, well, the wind and sun.

Geothermal has the best chance of the renewables to be constant, reliable,

And the increased financial incentives for renewables that have come with the Biden administration have been a boon for geothermal investment, including technology research.

Thus, Augustine Island's geothermal potential might not go to waste because of its distance from the electrical grid. New technology might present a solution.

—PETROLEUM NEWS

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PIPELINE PARITY

failure, so far, to make his position clear on Enbridge's Line 3 and Line 5.

Nord Stream 2

Instead, he has mystified Canadians by expressing a willingness to drop actions on the Nord Stream 2 natural gas pipeline from Russia to Germany, while enthusiastically unveiling a multibillion-dollar domestic infrastructure program to upgrade roads, bridges and other transportation systems that will demand even greater sources of crude oil.

The curiosity surrounding Biden's view of Nord Stream 2 first surfaced in mid-May when U.S. Secretary of State Antony Blinken suggested it was in the "national interest of the United States" to waive pipeline sanctions against Russia while at the same time opposing "the completion of this project."

The sanctions had already been dismissed as toothless because they failed to restrict financing for the Russian pipeline.

The justification by the Biden administration that Nord Stream 2 was a "Russian geopolitical project intended to divide Europe and weaken European energy security" got sanctions relief when Washington felt it was unable to stop the nearly completed project and wanted to rebuild its friendship with Germany after four tense years under Trump.

Nord Stream v Keystone XL

U.S. Republicans were quick to attack Biden by drawing distinction between Nord Stream 2 and Keystone XL.

Sixty-eight Republicans in the House of Representatives slammed relief on the Russian pipeline in a letter that said: "Given your open hostility to domestic pipelines like Keystone XL, which was also a top priority for our Canadian allies, it is baffling that you are willing to green-light" Nord Stream 2.

James Coleman, professor of law at the Southern Methodist University in Dallas said it was "striking that the administration was willing to reward Russia to placate its German ally, but unwilling to budget on Keystone XL."

"The Keystone pipeline would enhance our energy security and create job opportunities for Americans. Lift these sanctions, prioritizes Russian energy over American energy and Russian jobs over American jobs."

James Coleman, professor of law at the Southern Methodist University in Dallas said it was "striking that the administration was willing to reward Russia to placate its German ally, but unwilling to budget on Keystone XL."

Lawrence Herman, a former Canadian diplomat, told the Financial Post it is fair to link Biden's policy with Nord Stream 2 and Keystone XL, noting that Canada will be materially harmed "if the U.S. fails to stand up and respect its binding obligations" on Keystone XL.

Coleman said "some have joked that Canada is the United States' strategic oil reserve, which is to say that oil is always there if the United States wants to approve a pipeline later."

Line 5

While this spat continues, the Line 5 plan to build a tunnel under the Straits of Mackinac in the face of strong opposition from Michigan Gov. Gretchen Whitmer, now faces a new setback with the U.S. Army Corps of Engineers opting to conduct an extensive review of Enbridge's project.

The USAEC has chosen to prepare an environmental impact statement, a more wide-ranging study than an environmental assessment.

The Army Corp's website says an impact statement is "the most thorough and comprehensive level of the National Environmental Policy Act documentation used to assist in making a decision."

An Army Corps permit is needed regardless of the permit issued by the Michigan Department of Environment, Great Lakes and Energy.

That review process is seen by Enbridge as pushing back the timeline for constructing a tunnel to carry 540,000 barrels per day and could take years to complete.

Enbridge said the company has already spent more than US$100 million on the project and "remains intensely focused on project permitting and the sustained and safe operation (of the existing) Line 5," which has never leaked into the Straits of Mackinac.

—GARY PARK

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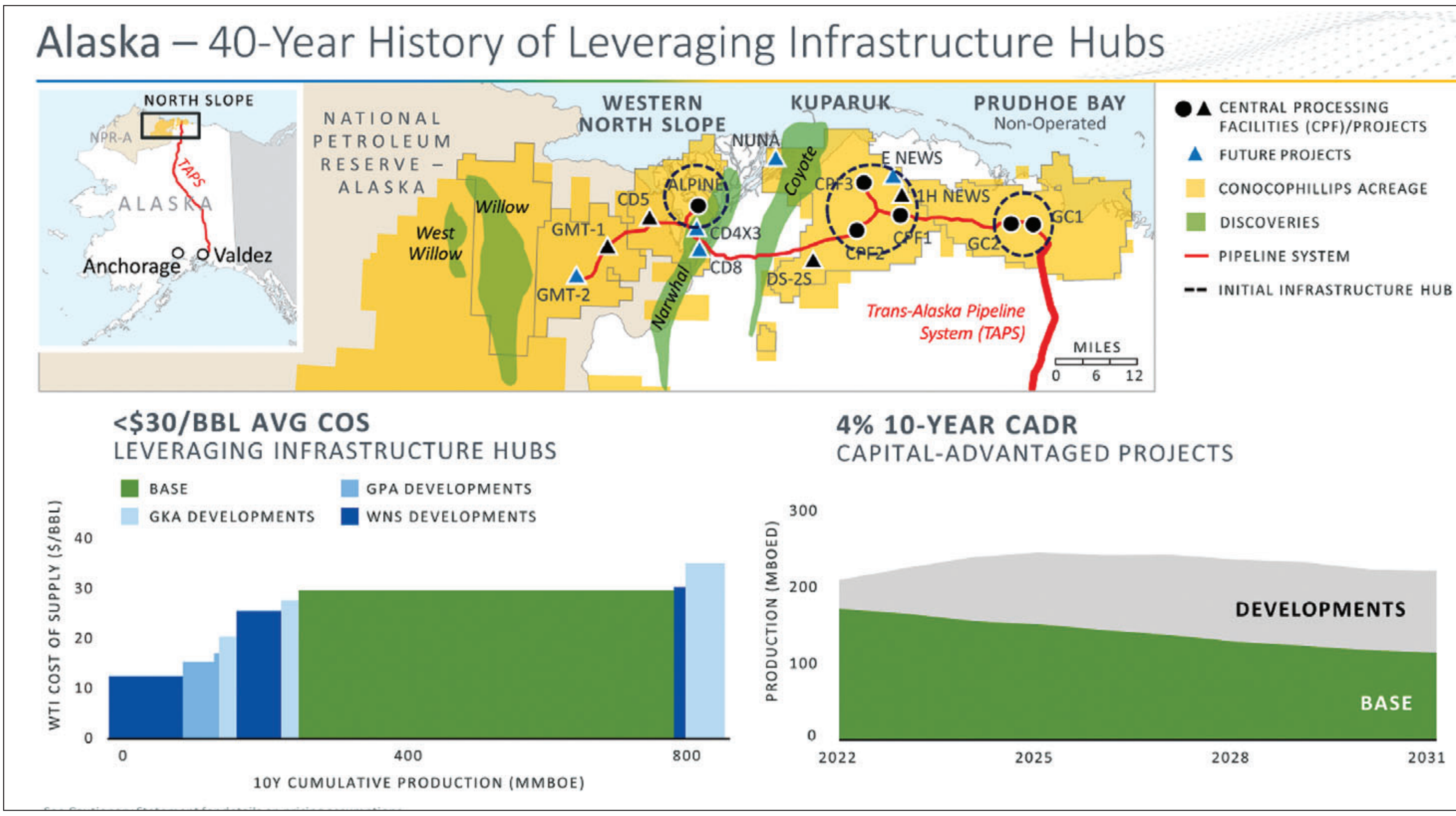

CONOCOPHILLIPS

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CONOCO IN ALASKA

proven 40-year history as a proven, responsible operator with relationships that run deep," noting that "Alaska consists as of a set of world class oilfield developments that leverage infrastructure hubs"; from east to west, they are currently Prudhoe, Kuparuk and Alpine. "Years after the development of these hubs, we continue to identify and invest in low cost of supply projects that are capital advantaged because of access to existing infrastructure," he said.

A company source told Petroleum News permitting work for the Coyote discovery has already begun.

ConocoPhillips also has a long track record of identifying new development opportunities that arise from technology advancements that have occurred on the North Slope in recent years, Olds said. "Technology such as extended reach drilling and coiled tubing drilling enable us to reach more resource from longer distances — and with a reduced footprint."

Today's plan, he said, "has an extensive inventory" of new developments, such as Nuna and Eastern News in the Kuparuk field, and Narwhal in the western North Slope area."

The company has its "bread and butter work" across the area as well, "including the recently discovered Coyote trend in Kuparuk and our extended reach drilling rig, or ERD program, in the western North Slope," Olds said.

"Over the next 10 years the Alaska fields are expected to deliver about 800 million BOEs of production at an average cost of supply of less than $30 a barrel on a WTI basis." He said ConocoPhillips expects these development programs will more than offset their base decline of more than 4%, which is a 2% improvement from the company's 2019 10-year plan. It allows ConocoPhillips to maintain production at more than 200 million barrels of oil equivalent per day in Alaska.


RYAN LANCE

Alpine case study

"Like all great Alaska fields … Alpine can be summed up in a simple statement: Big fields get bigger," Olds said.

Alpine was sanctioned more than 20 years ago, "approved as a 430 million BOE standalone development that included a single processing facility and two drill sites. Since then, cumulative production has been nearly 600 million BOEs or 30% beyond the initial estimates of recoverable oil," Olds said. "Currently we have identified, plans in hand, of expected yield of another 600 million BOEs of future production. That means our current estimate of ultimate recovery could be almost three times greater than our estimate at project approval."

Future inventory cost of supply has been estimated to be less than $30 per barrel on a WTI basis, he said, "reflecting that infrastructure advantage that makes these assets so attractive," Olds said.

Current project update

ConocoPhillips Great Mooses Tooth 2 is on schedule and under budget for startup later this year, Olds said. GMT-2 is projected to yield about 30,000 BOEs per day, which he said will restore rates to what they were about 10 years ago.

The extended reach drilling rig is now drilling the first Fiord West well from the existing CD-2 pad, which is about 7 miles to the north.

"This will test more than 45 million BOEs of resource from the existing CD-2 pad," Olds said. "It will be tied back to infrastructure and is scheduled for first oil later this year. This is what we call growth without new gravel."

Willow next hub

"We believe Willow could be the next great Alaska hub," Olds said.

"We've now completed our appraisal of Willow; a 12-well program that de-risked the resource," he said, noting that the information had been incorporated into the company's front-end engineering and design, or FEED.

"We've had several years to consider and evaluate various plans of development using our optimization models," Olds said, concluding that "the highest economic value will be achieved using a modularized central processing facility with a capacity of 180,000 barrels of oil a day and 250 million cubic feet per day of gas handling."

Field development will require approximately 200 wells, which will be drilled from only three drill sites to minimize the footprint and "enabling us to capture efficiencies," Olds said.

"On our current timeline, first oil occurs about 6 years after we make our

"Over the next 10 years the Alaska fields are expected to deliver about 800 million BOEs of production at an average cost of supply of less than $30 a barrel on a WTI basis." —Nick Olds

final investment decision, or FID, and we're on a path to have FID completed by year-end — if the litigation uncertainties are resolved."

"At 100% working interest, we estimate the project requires approximately $6 billion of capital to first production, including pre-drilling development wells," Olds said, estimating investment for the total plan of development will be approximately $8 billion to develop the recoverable resource, which is estimated at 600 million BOEs.

Willow is "very competitive" on a cost of supply basis in the mid-$30s per barrel, he said. "And we've identified up to 3 billion BOEs of nearby prospects and leads with similar characteristics that could leverage the Willow infrastructure."

Olds said ConocoPhillips has "every reason to believe Willow should and will be developed."

Q&A Willow

One of the first questions asked in the Q&A session was for more details about the "gate factors for Willow" before moving to FID. "How do you know the coast is clear before moving ahead with the project?"

"We hope this will be resolved later this year. You saw the Biden administration cleared up the review of the record of decision. That was a very … positive outcome," Olds said, noting the company expects the Alaska District Court to rule in third quarter. It has helped, he said, to have so much stakeholder support, such as from the North Slope Borough and the State of Alaska.

"I would add," Lance said, "that this isn't unusual for Alaska. Just about every major project up there has gone through this, so we know what's coming, we planned for it, and we know how to deal with it." ●

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