Petroleum news

page 5 October ANS production up 4% at 501,688 bpd; Cook inlet down 1%

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NMFS declines request to delist ringed seal by state, NSB, ASRC

In a 90-day finding over a petition to delist the Arctic ringed seal as threatened under the terms of the Endangered Species Act, the National Marine Fisheries Service has upheld its listing of the seals. The State of Alaska, the North Slope Borough, the Arctic Slope Regional Corp. and the Inupiat Community of the Arctic Slope launched the petition in 2019. NMFS originally listed the seals in 2012.

Dependent on sea ice

The ringed seal is one of several Arctic animal species that depend on an Arctic sea ice habitat and that may, therefore, be at risk because of sea ice loss as a result of climate change. However, there is controversy regarding the reliability of

see **SEAL LISTING** page 10

AOGCC adopts changes to its bonding regulations as proposed

At a Dec. 2 public meeting the Alaska Oil and Gas Conservation Commission unanimously adopted changes to its bonding regulations proposed in an Oct. 15 public notice.

The changes are to regulations the commission adopted in 2019; it held a public hearing on the proposed changes Nov. 4 (see story in Nov. 8 issue of PN).

Changes include amounts of required bonding for fewer wells: $400,000 each for one to five wells; $2 million for six to 20 wells plus $250,000 per well for each well above five; and $6 million for 21 to 40 wells (see story in Oct. 25 issue of PN).

The changes allow a decrease if an operator has other

see **BONDING REGS** page 7

Ending oil sands 'overlap'; Suncor to take over Syncrude operations

The latest page has been turned in the decades-long evolution of Alberta's oil sands, which started with various methods to extract raw bitumen from vast deposits and upgrade the substance into synthetic crude for refining into a basket of energy fuels.

In 1963 Sun Oil invested C$250 million to establish the Great Canadian Oil Sands, GCOS, project in what some critics within the oil industry said was a "daring venture into an unknown field" and the "biggest gamble in history."

Undaunted, J. Howard Pew, then Sun Oil's chairman and president, said he was "convinced this venture will succeed (and become the) means of opening up reserves to meet the needs of the North American continent for generations to come."

His confidence has largely been validated despite a series of

see **SUNCOR TAKEOVER** page 10

RCA accepts state, CIPL tariff settlement and new rate of $8.57

The Regulatory Commission of Alaska has accepted a November settlement agreement between the State of Alaska and Cook Inlet Pipe Line LLC.

Cook Inlet Pipe Line LLC, CIPL, is a limited liability company managed by its members and is 100% held by Harvest Alaska LLC, a part of Hilcorp's midstream company.

Under an existing settlement agreement, in November 2019 CIPL filed a rate increase from $5.61 per barrel to $8.57 per barrel for shipment of crude oil from Granite Point or Trading Bay to the connection with the Swanson River Oil Pipeline.

The state filed a formal complaint and petition to intervene in December 2019.

The commission said it suspended the new rate and established

see **CIPL TARIFF** page 10

FINANCE & ECONOMY

OPEC+ eyes 2021 plan

Production increase from cartel will create massive glut, Rystad says

By **STEVE SUTHERLIN**
Petroleum News

The Organization of the Petroleum Exporting Countries gathered in a virtual meeting Nov. 30 and was scheduled to meet Dec. 1 with its affiliated producing countries including Russia to decide the fate of the group's scheduled Jan. 1 production increase of 2 million barrels per day.

Analysts and traders widely expected the extended group — known as OPEC+ — to roll over existing production cuts of 7.7 million bpd, due to a spike in worldwide COVID-19 cases which caused a slower recovery of oil demand than that projected by OPEC when cuts were implemented in the spring during the first wave of the pandemic.

Despite announcements in recent weeks of three promising vaccines for the virus, OPEC now anticipates that a meaningful demand recovery from the pandemic will not occur until mid-year 2021.

Despite announcements in recent weeks of three promising vaccines for the virus, OPEC now anticipates that a meaningful demand recovery from the pandemic will not occur until mid-year 2021.

Saudi Arabia had recommended a three-month extension to the existing level of cuts.

The Dec. 1 meeting was instead rescheduled for

see **OIL PRICES** page 11

NATURAL GAS

On the hydrogen highway

Alberta, Saskatchewan eye future as hydrogen powers; Canada moves to net-zero

By **GARY PARK**
For Petroleum News

Alberta and Saskatchewan are quietly making strides towards capturing a slice of the anticipated multi-billion dollar a year global hydrogen market.

Of Canada's combined gas output of 16.6 billion cubic feet per day — making it the fourth largest gas producer in the world — Alberta contributes 71% 11.8 bcf/d, while Saskatchewan adds a modest 2% or 332 million cubic feet per day, leaving British Columbia to cover the remaining 27% or 4.48 bcf/d.

As of now it's the two Prairie provinces that are viewing hydrogen as a key plank in their natural

Transition Chief Executive Officer Dan Wicklum said a hydrogen-based energy system could enable countries around the world to set and meet net-zero carbon targets.

gas strategies, joining Australia, China, Germany, Saudi Arabia, South Korea and the United Kingdom.

They are eager to exploit the potential of hydrogen, which produces water vapor rather than carbon dioxide when it combusts in combination with oxygen, to reduce their CO2 emissions.

see **HYDROGEN HIGHWAY** page 9

EXPLORATION & PRODUCTION

Alpine clocks 20 years

ConocoPhillips Alaska still investing, still pulling oil, from North Slope field

By **KAY CASHMAN**
Petroleum News

On Nov. 16, 2000, ConocoPhillips Alaska predecessor Phillips Alaska announced it had begun moving oil from the North Slope Alpine field west of Kuparuk and adjacent to the National Petroleum Reserve-Alaska.

An earlier predecessor, ARCO Alaska, discovered Alpine in 1994 and delineated it in subsequent winter drilling seasons.

Successor ConocoPhillips Alaska continues to operate Alpine, which is part of the Colville River unit.

In 1996 Alpine was deemed a commercial-grade discovery. In the years that followed a main drilling and production pad was completed and pipelines built between Alpine and the Kuparuk oil field. Gravel was also laid for a secondary drilling pad and a road between the two pads.

Once the Alpine field went online in late 2000, work in 2001 included pipelines between the pads, completion of a bridge on the road between the pads and installation of modules on the secondary pad, which became operational that summer.

Phillips said that as of Nov. 16, 2000, 30 wells — 16 production and 14 injection — had been completed at the first Alpine drill site. The company also said the entire Alpine development called

see **ALPINE AT 20** page 8

● EXPLORATION & PRODUCTION

State approves Milne Point unit 39th POD

Hilcorp's annual plan of development for North Slope unit includes up to 17 new wells, 20 well workovers, 6 major facility projects

By KAY CASHMAN

Petroleum News

Hilcorp Alaska's 39th plan of development for the North Slope Milne Point unit filed on Oct. 14 was approved by Alaska's Division of Oil and Gas on Nov. 25. In the POD period of Jan. 13, 2021, through Jan. 12, 2022, the company anticipates drilling up to 17 new wells, completing as many as 20 well workovers with the ASRI rig, and undertaking six major facility projects, including polymer facility installation and startups at Moose Pad, I Pad and E Pad, as well as a fuel gas compressor installation and startup and a G Pad replacement test separator installation.

The 50,000-acre Milne Point unit was formed in September 1979. Hilcorp, a privately held independent, acquired a 50% working interest in the oil field in November 2014 from major BP Exploration (Alaska) and took over operatorship. Today, Hilcorp holds a 100% working interest in Milne Point.

Drilling candidates

The 17 new wells that Hilcorp expects to drill are 14 I Pad Schrader Bluff wells (six injectors, eight producers) and three J Pad Schrader Bluff wells (two injectors, one producer).

Other 39th POD projects might include, but are not limited to, B Pad gas injection compressor installation and startup; V-5304 grid replacement; S Pad test separator replacement; S Pad polymer engineering and procurement; Solar Titan 130 power generator engineering and procurement; and diesel tank to slop oil tank conversion.

In the future the company will also be evaluating drilling opportunities on undeveloped acreage in the northwest of the unit, particularly in the net profit share leases, as well as previously developed acreage from I, H and S pads in the Schrader Bluff participating area.

Also in the future Hilcorp will be likely be continuing expansion of polymer injection into the Schrader Bluff reservoir in horizontal well patterns beyond current polymer injection pilots at J and L pads, as well as evaluating continued performance from Ugnu horizontal producing well S-203 to help decide on a future Ugnu development strategy.

Infill drilling opportunities in the Kuparuk sands via conventional and coiled tubing drilling will also be considered in the future.

Field production

Since inception, approximately 370 million barrels of oil have been produced from Milne Point.

Known for rejuvenating aging oil and gas fields that have long been in decline and maintaining or growing production, Hilcorp pursued that strategy at the Milne Point unit.

When the company took over as operator in November 2014, the unit was producing 18,400 barrels of oil per day.

From Jan. 1 through Aug. 31 of this year the average

see **MILNE POINT** *page 4*

contents

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ON THE COVER

ALTERNATIVE ENERGY

ENVIRONMENT & SAFETY

EXPLORATION & PRODUCTION

GOVERNMENT

Alaska-Mackenzie Rig Report

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

Alaska Rig Status

North Slope - Onshore

Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Milne Point, I-40	Hilcorp Alaska LLC
Dreco 1000 UE	16 (SCR/TD)	Standby	
Dreco D2000 Uebd	19 (SCR/TD)	Standby	
AC Mobile	25	Standby	
OIME 2000	141 (SCR/TD)	Standby	
	142 (SCR/TD)	Standby	
TSM 700	Arctic Fox #1	Standby	
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	BP
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)	Deadhorse, stacked	Available
Ideco 900	3 (SCR/TD)	Talitha A	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

BP			
Top Drive, supersized	Liberty rig	Inactive	BP
Doyon Drilling			
Sky top Brewster NE-12	15 (SCR/TD)	Spy Island, Start Up	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
All American Oilfield LLC			
IDECO H-37	AAO 111	Stacked in the Peak yard	Available
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

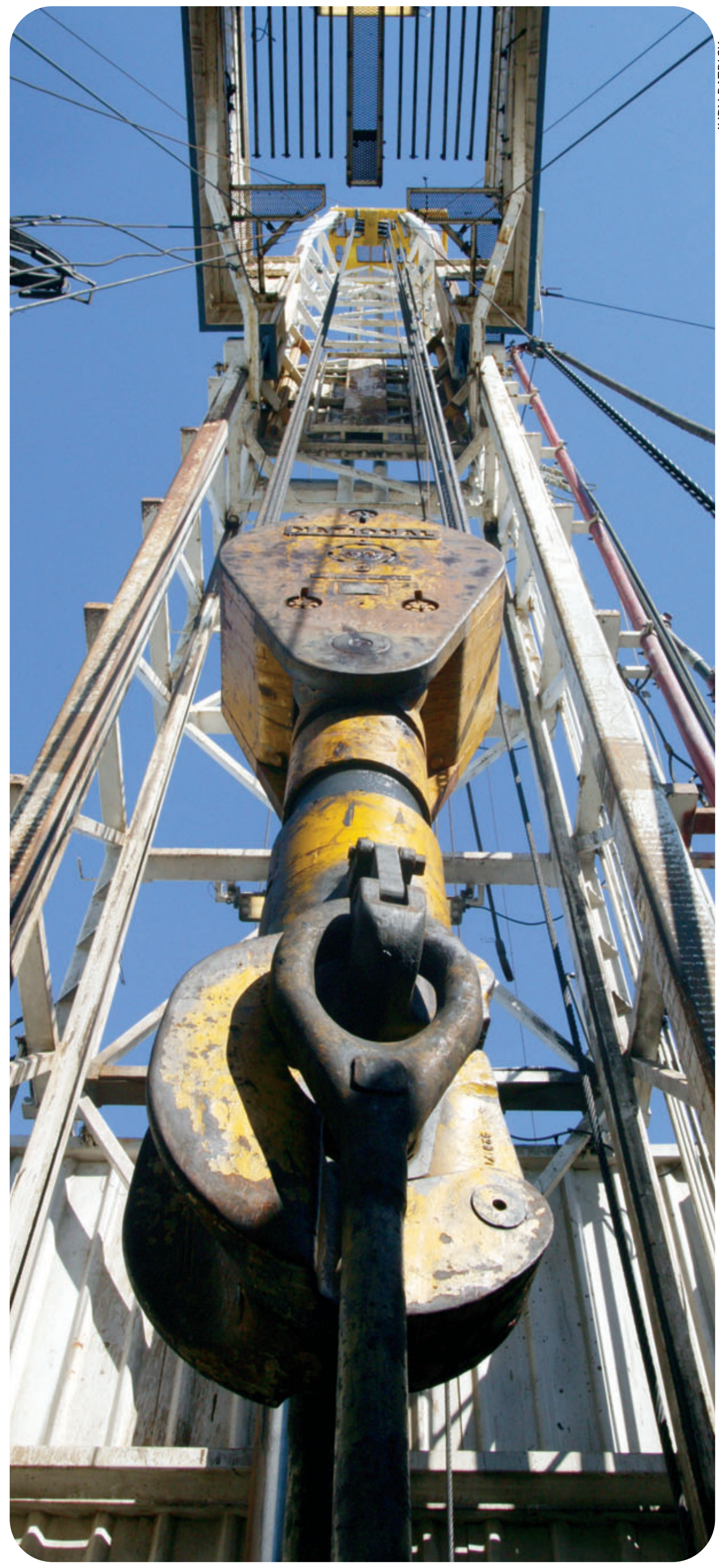
Canadian Beaufort Sea

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

The Alaska-Mackenzie Rig Report as of December 2, 2020. 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*

	Nov. 25	Nov. 20	Year Ago
United States	320	310	802
Canada	102	101	126
Gulf of Mexico	12	12	22

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

*Issued by Baker Hughes since 1944

ENVIRONMENT & SAFETY

State gets EPA Fairbanks air quality grant

The U.S. Environmental Protection Agency has awarded a $14.7 million Targeted Air Shed grant to the Alaska Department of Environmental Conservation to help the Fairbanks North Star Borough improve air quality in the borough's non-attainment area.

The grant was developed to help reduce air pollution in communities with the highest levels of fine particulate matter and ozone ambient air concentrations in the nation.

The state and borough said wood smoke is the main source of fine particulate matter pollution in the borough, and funded projects will help reduce these fine particulate emissions over the five-year life of the grant.

EPA said the borough will use the grant to continue a woodstove changeout and conversion program with a goal of converting more wood burning appliances to liquid or gas-fueled heating appliances. The agency said wood smoke contributes 60% to 80% of fine particle pollution levels measured in the FNSB.

"The state, local leaders and the community are making progress and air quality is improving," said EPA Region 10 Administrator Chris Hladick. "This round of EPA's Targeted Airshed Grant funding will further boost the community's efforts to reduce wood smoke pollution and improve air quality in the Borough."

"Through appropriate wood stove replacement realized through this grant and our continued cooperative efforts outlined in our State Implementation Plan, we look forward to reaching attainment by 2024," said DEC Commissioner Jason Brune.

The largest project to be funded will be the Wood Stove Change Out Program in the FNSB, assisting local residents to remove or replace higher polluting devices 25 years or older by 2024.

The FNSB will administer the program and document benefits.

"The Targeted Air Shed Grant award will give our community a fighting chance to come into compliance with the EPA PM2.5 air quality standards," said FNSB Mayor Bryce Ward. "The funding will allow us to continue to provide the wood stove change out program and manage vendor capacity to complete the woodstove exchanges."

—KRISTEN NELSON

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● EXPLORATION & PRODUCTION

Glacier Oil & Gas updates Badami POD

By KRISTEN NELSON
Petroleum News

Glacier Oil and Gas, parent company of Badami-operator Savant Alaska, has submitted a second proposed 17th plan of development for Badami, covering Oct. 7 through July 15, 2021.

The Alaska Department of Natural Resources' Division of Oil and Gas approved a suspension of operations for Badami in June, requiring that a new updated second 17th POD for Badami be submitted within 60 days of restart of production at the field. As part of the suspension approval, the division suspended a decision on the 17th POD which had been submitted in March and extended the 16th POD for the term of suspension.

When the company submitted its suspension application it said: "The present global condition of low crude oil prices, combined with a lack of demand, obligates Glacier to act as a prudent operator and suspend operations until demand and market price have sufficiently recovered to justify the resumption of production operations."

The company returned the field to operations in October.

In a review of work done, Glacier said it completed geological and geophysical evaluation of new Killian prospects using well log data from the B1-07 and existing seismic data. The company also completed G&G evaluation of new Badami sands prospects in the unit and completed an engineering project covering additional infrastructure which would be needed to support Badami East Pad operations. The company is continuing permitting for the Badami East Pad. "Once construction is complete it would become the surface drilling pad for additional Killian prospect wells on the Eastern side of the Badami Unit," the company said.

During the suspension, Glacier "completed a full facility turnaround that included cleaning maintenance, inspection and recertification work on the facility." The company "also conducted a major logistic operation to resupply essentials like fuel and chemicals to Badami for restart operations after remaining several months in warm standby." During 24 days of operations after Savant restarted the Badami pad in October, the field yielded more than 2,000 barrels per day, the company said.

In its updated POD the company said it will continue to work with DNR to resolve its request for expansion of the Badami unit, which the division partially approved in 2013, a decision which Savant has appealed. The company said it has met with DNR regarding the appeal and will continue to work with DNR to resolve the matter.

"As economic conditions warrant," the company said, it "intends to further the planning development activities for the new Badami and Killian sand prospects" and planning for prospects outside the participating area at Badami. It will also continue compliance work on the Badami East Pad, and will "further engineering work related to infrastructure, tie-in and additional processing requirements for the new Badami East Pad."

As Petroleum News reported in November, Glacier has put the Badami field up for sale, with a Nov. 16 divestiture notice by BMO Capital Markets Energy Group saying it had been retained by Glacier to represent the company in its sale of the Badami unit. ●

Contact Kristen Nelson at knelson@petroleumnews.com

GOVERNMENT

State allows North Slope snowmobile use

The Alaska Department of Natural Resources' Division of Mining, Land and Water said Nov. 30 that snow conditions within the North Slope Oil Production District "are adequate for snowmobile use," an opening which applies only to operators with valid off-road vehicle travel permits for state-owned North Slope lands.

Off-road travel, however, is not yet allowed.

The division said Nov. 24 that all tundra opening areas were closed for off-road travel, as only one monitoring station has recorded minus 5 degrees C for soil temperature at 30 centimeters depth.

For off-road travel the state looks at conditions in four areas: eastern coastal, western coastal, lower foothills and upper foothills.

In the coastal areas the target is 6 inches of snow and soil temperature of minus 5 degrees C at 30 centimeters depth. For the foothills, the temperature target is the same, but the snow depth target is 9 inches.

For snowmobile travel, the division said operators do not need to request approval, and for the remainder of the 2020-21 winter season, and said, "permit holders may designate environmental staff to approve of the use of snowmobiles without contacting the DMLW Northern Regional Land Office."

The division noted that any snowmobile use must be reported "on tundra travel completion reports for the season."

—KRISTEN NELSON

continued from page 2

MILNE POINT

daily production rate from Milne Point was 32,407 bpd. In September the unit averaged 33,038 bpd, down 0.1%, 31 bpd, from an August average of 33,069, but up 5.9% from a September 2019 average of 31,192 bpd.

Milne Point consists of the Kuparuk reservoir in the Kuparuk participating area, the Schrader Bluff reservoir in the Schrader Bluff PA and the Sag River reservoir in the Sag River PA.

Additionally, the unit includes the following tract operations: C-15A, S-90, C-23, K-33, MPS-37, MPS-39, MPS-41, MPS-43, B-30, C-46 and S-203.●

Contact Kay Cashman at publisher@petroleumnews.com

● EXPLORATION & PRODUCTION

October ANS production up 4%, 19,494 bpd

Slope crude, NGLs averaged 501,688 bpd, compared to 482,194 bpd in September; Cook Inlet at 11,348 bpd, down 1% from September

By **KRISTEN NELSON**
Petroleum News

Alaska North Slope production, combined crude oil and natural gas liquids, averaged 501,688 barrels per day in October, up 4%, 19,494 bpd, from a September average of 482,194, but down 1.4% from an October 2019 average of 508,751 bpd.

North Slope crude averaged 448,012 bpd in October, up 4.1%, 17,761 bpd, from a September average of 430,251 bpd but down 2.9% from an October 2019 average of 461,170 bpd.

ANS NGLs averaged 53,676 bpd in October, up 3.3%, 1,733 bpd, from a September average of 51,942 and up 12.8% from an October 2019 average of 47,581.

The ANS crude/NGL split was 89.3%/10.7% this October and 90.7%/9.3% last October.

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

The largest month-over-month volume increase was at the ConocoPhillips Alaska-operated Colville River unit, which averaged 50,923 bpd in October, up 22.8%, 9,451, from a September average of 41,473, but down 12.5% from an October 2019 average of 58,189 bpd.

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

Prudhoe

The Hilcorp-operated Prudhoe Bay field, the Slope's largest, averaged 266,089 bpd in October, up 2.5%, 6,395 bpd, from a September average of 259,593, and also up, by 4.6%, from an October 2019 average of 254,432 bpd.

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.

Prudhoe is one of three North Slope fields to produce NGLs.

Crude production at Prudhoe averaged 216,757 bpd in October, up 2.1%, 4,525 bpd, from a September average of 212,232 bpd, and up 3.3% from an October 2019 average of 209,781 bpd. NGLs at Prudhoe averaged 49,331 bpd in October, up 3.9% from a September average of 47,461 bpd and up 10.5% from an October 2019 average of 44,650.

The Prudhoe crude/NGL split was 81.5%/18.5% this October and 82.4%/17.6% last October.

Others with increases

At Milne Point, where Hilcorp has been steadily increasing production, volumes averaged 35,304 bpd in October, up 2,266 bpd, 6.9%, from a September average of 33,038 bpd and up 19.4% from an October 2019 average of 29,571.

The Point Thomson field, operated by ExxonMobil Production, averaged 9,096 bpd in October, up 21.2%, 1,590 bpd, from a September average of 7,505 and up 89.1% from an October 2019 average of 4,810.

At Badami, operated by Savant Alaska, a Glacier Oil & Gas company, production averaged 1,543 bpd in October, up by that amount from September, when the field was shut-in. Production at Badami was suspended in early May and the field had no production June through September. Volumes were up, by 4.1%, from October 2019 when the field averaged 1,481 bpd.

ConocoPhillips' Greater Mooses Tooth in the National Petroleum Reserve-Alaska averaged 3,287 bpd in October, up 79.9%, 1,459 bpd, from a September average of 1,828 bpd, but down 56.1% from an October 2019 average of 7,481 bpd.

Eni's Oooguruk averaged 7,665 bpd in October, up 34 bpd, less than half a percent, from 7,631 in September but down 7.4% from an October 2019 average of 8,276 bpd.

Month-over-month decreases

The ConocoPhillips-operated Kuparuk River field averaged 96,080 bpd in

see **ANS PRODUCTION** *page 6*

Cook Inlet natural gas production up 5%

Cook Inlet natural gas production averaged 230,289 thousand cubic feet per day in October, up 5.2%, 7,757 mcf per day, from a September average of 233,532 mcf per day and up 2% from an October 2019 average of 225,728 mcf per day.

Data are 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.

Twenty-two fields in Cook Inlet, 20 currently online, have produced gas in the last year, with eight fields accounting for 86% of gas production, 197,838 mcf per day in October.

Hilcorp's Kenai gas field produced 44,739 mcf per day in October, 19.4% of total inlet production. The field's October average was up 12.3%, 4,895 mcf, from a September average of 39,845 mcf and up 30.4% from an October 2019 average of 34,317 mcf.

Hilcorp's McArthur River averaged 32,412 mcf per day in October, up 10%, 2,954 mcf per day, from a September average of 29,458 mcf per day and up 46.5% from an October 2019 average of 22,119 mcf per day. The field accounted for 14% of inlet production in October.

see **COOK INLET GAS** *page 6*

continued from page 5

ANS PRODUCTION

October, down 2.7%, 2,639 bpd, from a September average of 98,719 and down 11% from an October 2019 average of 107,921 bpd.

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

The Hilcorp-operated Endicott field averaged 6,547 bpd in October, down 6.6%, 460 bpd, from a September average of 7,006 and down 12.4% from an October 2019 average of 7,473 bpd. Endicott produces both crude oil and NGLs and crude from the field averaged 5,713 bpd in October, down 4.3%, 254 bpd, from a September average of 5,967 bpd and down 13% from an October 2019 average of 6,564 bpd. NGL production averaged 833 bpd in October, down 206 bpd, 19.8%, from a September average of 1,039 and down 8.4% from an October 2019 average of 909 bpd. The crude/NGL ratio at Endicott was 87.3%/12.7% this October, little changed from 87.8%/12.2% in October 2019.

Northstar, also operated by Hilcorp, averaged 8,864 bpd of combined crude and NGLs in October, down 1.5%, 132 bpd, from a September average of 8,996 bpd and down 3.4% from an October 2019 average of 9,172 bpd. The field's crude average was 5,353 bpd in October, down 3.6%, 201 bpd, from a September average of 5,554 bpd and down 25.1% from an October 2019 average of 7,150 bpd. NGL production averaged 3,511 bpd in October, up 2%, 69 bpd, from a September average of 3,442 and up 73.7% from an October 2019 average of 2,022 bpd. The crude/NGL ratio at Northstar was 60.4%/39.6% in October, a substantial change from the 78%/22% ratio in October 2019.

Eni's Nikaitchuq averaged 16,291 bpd in October, down marginally, 13 bpd, from a September average of 16,304 and down 18.3% from an October 2019 average of 19,946 bpd.

Cook Inlet down 1.1%

Crude oil production from Cook Inlet averaged 11,348 bpd in October, down 1.1%, 115 bpd, from a September average of 11,483 bpd and down 16.6% from an October 2019 average of 13,613 bpd.

Hilcorp's Beaver Creek averaged 149 bpd, down 18.4%, 34 bpd, from a September average of 183 bpd and down 36.5% from an October 2019 average of 235 bpd.

Hilcorp's Granite Point averaged 2,977 bpd in October, down 0.9%, 28 bpd, from a September average of 3,005 but up 23.9% from an October 2019 average of 2,403 bpd.

BlueCrest's Hansen averaged 1,035 bpd, down 0.9%, 10 bpd, from a September average of 1,045 bpd and down 16.9% from an October 2019 average of 1,246 bpd.

Hilcorp's McArthur River field, Cook Inlet's largest, averaged 3,892 bpd in October, down 1.1%, 41 bpd, from a September average of 3,933 bpd and down 13% from an October 2019 average of 4,472 bpd.

Hilcorp's Middle Ground Shoal averaged 1,255 bpd in October, up 8.1%, 102 bpd, from a September average of 1,161 bpd but down 5.3% from an October 2019 average of 1,325 bpd.

Hilcorp's Swanson River averaged 797 bpd in October, down 4.2%, 36 bpd, from a September average of 833 bpd and down 5.2% from an October 2019 average of 841 bpd.

Hilcorp's Trading Bay averaged 1,242 bpd in October, down 6.1%, 69 bpd, from a September average of 1,323 bpd and down 13.4% from an October 2019 average of 1,435 bpd.

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

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continued from page 5

COOK INLET GAS

Ninilchik, another Hilcorp field, accounted for 11.8% of production, averaging 27,250 mcf per day in October, down 6.8%, 1,990 mcf per day from a September average of 29,241 mcf per day, and down 22.5% from an October 2019 average of 35,167 mcf per day.

The Beluga River field, operated by Hilcorp (Chugach Electric Association holds the majority interest in leases at Beluga), accounted for 11.4% of Cook Inlet gas production, averaging 26,222 mcf per day in October, up 20.8%, 4,509 mcf per day, from a September average of 21,713 mcf per day and up 17.3% from an October 2019 average of 22,363 mcf per day.

Hilcorp's Swanson River field, 9.8% of production volumes, averaged 22,573 mcf per day in October, down 4.3%, 1,013 mcf per day, from a September average of 23,585 mcf per day and down 42.4% from an October 2019 average of 39,219 mcf per day.

Hilcorp's North Cook Inlet, 7.5% of October production, averaged 17,340 mcf per day, down 3.1%, 551 mcf per day, from a September average of 17,891 mcf per day but up 24.4% from an October 2019 average of 13,940 mcf per day.

Kitchen Lights, operated by HEX's Furie Operating Alaska, accounted for 6.1% of October production, averaging 14,114 mcf per day, down 4.3%, 635 mcf per day, from a September average of 14,749 mcf per day, and down 12% from an October 2019 average of 16,037 mcf per day.

Hilcorp's Beaver Creek, 5.7% of October production, averaged 13,188 mcf per day, down 19.4%, 3,182 mcf per day, from a September average of 16,370 mcf per day but up 88.7% from an October 2019 average of 6,990 mcf per day.

Combined production from the remaining 12 fields producing in October accounted for 14% of Cook Inlet gas volumes.

The AIX-operated Kenai Loop field averaged 5,065 mcf per day in October, up 10%, 461 mcf per day, from a September average of 4,604 mcf per day but down 6.8% from an October 2019 average of 5,433 mcf per day.

Hilcorp's Cannery Loop averaged 4,872 mcf per day in October, up 1%, 49 mcf per day, from a September average of 4,823 mcf per day but down 41.1% from an October 2019 average of 8,266 mcf per day.

Hilcorp's Ivan River averaged 4,538 mcf per day in October, up 89.4%, 2,142 mcf per day, from a September average of 2,396 mcf per day and up 1,072.8% from an October 2019 average of 387 mcf per day.

Hilcorp's Granite Point averaged 3,766 mcf per day, up 2.9%, 105 mcf per day, from a September average of 3,661 mcf per day, and up 43.3% from an October 2019 average of 2,629 mcf per day.

Hilcorp's Deep Creek averaged 3,714 mcf per day in October, up 7.5%, 259 mcf per day, from a September average of 3,455 mcf per day but down 17% from an October 2019 average of 4,472 mcf per day.

The North Fork field, acquired by Gardes Holdings in September, averaged 3,216 mcf per day in October, down 2.4%, 80 mcf per day, from a September average of 3,296 mcf per day and down 14.3% from an October 2019 average of 3,752 mcf per day.

BlueCrest's Hansen field averaged 2,871 mcf per day, down 5.9%, 181 mcf per day, from a September average of 3,052 mcf per day and down 46.5% from an October 2019 average of 5,365 mcf per day.

Hilcorp's Trading Bay averaged 2,475 mcf per day in October, up 0.8%, 19 mcf per day, from a September average of 2,456 mcf per day, but down 19.9% from an October 2019 average of 3,088 mcf per day.

Hilcorp's Nikolaevsk averaged 362 mcf per day in October, down 2.6%, 10 mcf per day, from a September average of 372 mcf per day and down 22.3% from an October 2019 average of 466 mcf per day.

Hilcorp's Middle Ground Shoal averaged 263 mcf per day in October, up 13%, 30 mcf per day, from a September average of 233 mcf per day but down 12.1% from an October 2019 average of 299 mcf per day.

Amaroq's Nicolai Creek averaged 251 mcf per day in October, down 5.5%, 15 mcf per day, from a September average of 266 mcf per day; AOGCC records show no production from the field in October 2019.

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

—KRISTEN NELSON

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GOVERNMENT

CINGSA latest to ask for bond reduction

The Alaska Oil and Gas Conservation Commission has denied another request for bond reduction based on the existence of a dismantlement, removal and restoration bond with the Alaska Department of Natural Resources.

The latest petition for a reduction in bonding amount came in October from Cook Inlet Natural Gas Storage Alaska, CINGSA.

CINGSA has five permitted wellheads at its Kenai Peninsula gas storage facility.

The commission notified CINGSA in July 2019 that based on its five wellheads, its bonding requirement would increase to $2 million under AOGCC's new bonding regulations. CINGSA had a $200,000 bond in place, so the commission required an additional $1.8 million.

In its request for reconsideration of its bond amount, CINGSA said it has increased its $200,000 bond: in 2019, to $700,000; in July of this year, to $1 million; and in August of this year, to $1.2 million.

CINGSA proposes to increase its bond to $1.5 million in August 2022, "at which point, provided this request for reconsideration is granted, it will have fulfilled its AOGCC-related bonding requirements," the company said.

In a Nov. 30 decision the commission denied the request for reconsideration, saying that the $500,000 DR&R bond with DNR is a bond to return DNR's leases to a condition acceptable to that agency.

"As of the date of this order, no evidence has been offered that any of the DNR bond is exclusively dedicated to the costs to properly plug and abandon CINGSA's wells. CINGSA's bonding amounts will not be reduced by the amount of the DNR DR&R bond."

The commission acknowledged that CINGS currently has bonding with AOGCC at $1.2 million and said "CINGSA's revised bond required an additional $800,000."

—KRISTEN NELSON

continued from page 1

BONDING REGS

bonds in place dedicated to plugging and abandonment and for bonds in place with the U.S. Environmental Protection Agency for P&A of disposal wells.

Terms for installment payments are also extended.

"Amaroq continues to be supportive of AOGCC's efforts to adopt regulations on bonding that give consideration to unique circumstances facing each operator," G. Scott Pfoff, president of Amaroq Resources, told the commission in Nov. 19 written comments.

Pfoff said the proposed changes fail to recognize the Alaska Department of Natural Resources dismantlement, removal and restoration agreement that requires an operator to fund the estimated cost of both surface reclamation and plugging and abandonment of wells, and asked the commission "to find a way to coordinate its bonding requirements with the DNR in such a way as to avoid duplicative financial coverage for plugging and abandonment."

Pfoff said spreading out annual payments on the increased bonding costs from 4 to 7 years has only marginal benefits for Amaroq as the minimum first installment is $500,000. "Amaroq's ability to make the first installment would be questionable," he said.

In Nov. 20 comments, Patrick N. Bergt, regulatory and legal affairs manager for the Alaska Oil and Gas Association, said "AOGA commends AOGCC for its efforts to update and modernize the bonding requirements" and supports proposed changes.

"Adding a category for 6-20 wells in the permitted wellheads bond amount table will work to increase opportunity in Alaska and, together with the proposed changes to the payment schedule, helps smaller operators shoulder financial burdens resulting from recent developments in the global oil and gas markets."

Bergt said AOGA supports reductions when the operator has a bond in place with the landowner dedicated exclusively to plugging and abandonment, but said AOGA suggests a further modification so that the requirement is that the operator have a "bond, cash deposit, or other

In Nov. 20 comments, Patrick N. Bergt, regulatory and legal affairs manager for the Alaska Oil and Gas Association, said "AOGA commends AOGCC for its efforts to update and modernize the bonding requirements" and supports proposed changes.

acceptable form of security in place with the landowner, or other affected party" dedicated to P&A.

The commission also received comments Nov. 20 from Tim Jones, land manager for Oil Search (Alaska).

"As a lease holder and operator on the North Slope, OSA supports clear and reasonable bonding requirements," Jones said.

In October 2018, OSA provided comments to the previously proposed changes, and Jones said the company is encouraged "that AOGCC is proposing revisions that are consistent with changes suggested in OSA's October 2018 comments," namely increasing or decreasing a bonding obligation based on "engineering, geotechnical, environmental, or location conditions," on a "bond or other security required by a landowner" and on "bonding or other security required by the U.S. Environmental Protection Agency to address disposal wells."

The commission received comments from Furie Operating Alaska/HEX at its Nov. 4 hearing and in a Nov. 2 letter.

Rick Dusenbery, the company's chief operating officer, said in the letter that while the company supports the additions to the section on reasons it may increase or decrease bonding amounts, and the extension of the payment period for additional bonding, "we still feel that this level of bonding is counterproductive to exploration and development in the Cook Inlet during these economically distressed times."

The letter also requested bonding reduction based on other bonds or securities in place, including DNR's DR&R bonding.

—KRISTEN NELSON

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ALTERNATIVE ENERGY

Next steps for Makushin geothermal project

Ounalashka Corp. and Chena Power are moving ahead with a project to develop a geothermal energy system, to obtain electrical power from the Makushin Volcano on Unalaska Island. The idea is to establish a local, renewable source of electricity for the island, including the City of Unalaska. Ounalashka Corp. is the Alaska Native village corporation for Unalaska. Chena Power installed and operates the Chena Hot Springs geothermal power plant in the Alaska Interior.

Ounalashka and Chena have announced that they have selected Power Engineers, an international renewable energy company based in Hailey, Idaho, as the engineering company for the project. Electric Power Systems of Anchorage, Alaska, will assist in assessing whether the existing Unalaska power grid is strong and resilient enough handle the anticipated power output from the Makushin facility. The assessment will identify any necessary infrastructure improvements and associated costs.

In addition, Ounalashka and Chena have commissioned a cost-benefit analysis for the conversion of Unalaska homes and businesses to the use of electrically powered heat pumps for the heating of buildings. The evaluation project will include the conversion of some selected buildings to heat pump use at no cost to the owners.

The development of the 18 to 30 megawatt geothermal plant will involve the installation of roads, pads and facilities. A buried transmission line will transport power to the City of Unalaska power grid. The developers envisage the drilling of three production wells and two injection wells to depths of about 2,000 feet.

—ALAN BAILEY

EXPLORATION & PRODUCTION

US drilling rig count up by 10 to 320

The Baker Hughes U.S. rotary drilling rig count increased by 10 to 320 on Nov. 25, a count early in the week due to Thanksgiving. The count had dropped by two the week ending Nov. 20, only the second such reversal in a gradual increase that began in mid-August. The count is still down substantially from a year ago, by 482 from 802.

When the count hit 244 the week of Aug. 14, it was not just the low for 2020, but the lowest it has been since the Houston based oilfield services company began issuing a weekly U.S. rig count in 1944.

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

At the beginning of the year the count was in the low 790s, 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 Nov. 25 count includes 241 rigs targeting oil, up 10 from the previous week but down 427 from a year ago, 77 rigs targeting gas, up one from the previous week but down 54 from a year ago and two miscellaneous rigs, down one from the previous week and down one from a year ago.

Twenty-two of the holes were directional, 283 were horizontal and 15 were vertical.

Alaska count unchanged

There were three-rig gains recorded in three states: California (7), New Mexico (58) and Texas (147).

Colorado (5) and Louisiana (39) were each up by one rig.

Rig counts were unchanged in the remaining states: Alaska (3), North Dakota (11), Ohio (4), Oklahoma (13), Pennsylvania (20), Utah (3), West Virginia (7) and Wyoming (2).

Baker Hughes shows Alaska with three active rigs Nov. 25, unchanged from the previous week but down by four from a year ago.

The rig count in the Permian, the most active basin in the country, was up by five from the previous week at 161, but down 244 from a count of 405 a year ago.

—KRISTEN NELSON

continued from page 1

ALPINE AT 20

for two drill sites and more than 112 horizontal wells.

Ryan Lance, Phillips Alaska's vice president for the western North Slope (today he is chairman and CEO of parent ConocoPhillips) told Petroleum News Nov. 16 that the company circulated diesel through the system to warm it up "over the last four or five days, and when we were ready to go and had the final safety system checks, we opened up the wells yesterday."

Lance said production started with nine wells and a production level of 35,000 to 40,000 barrels a day. About 31,000 barrels would be required to fill the line, so it would take about 20 hours for the first oil to reach Kuparuk, probably about dinner time Nov. 16, he said.

"I sell crude at Kuparuk," Lance said, "so my cash register starts ringing when it gets to Kuparuk."

The rest of the existing production wells were brought on quickly, with oil production ramping up before year-end to 80,000 barrels of oil per day.

At the time Phillips estimated the gross recoverable reserves from Alpine at 429 million barrels.

Phillips Petroleum Co. Chairman and Chief Executive Officer Jim Mulva called Alpine key to Phillips' Alaska operations.

Alpine was the farthest west producing field on the North Slope at the time and the first significant commercial oil production on lands conveyed to an Alaska Native corporation pursuant to the terms of the Alaska Native Claims Settlement Act.

"Under the terms of ANCSA," Jacob Adams, then president of Arctic Slope Regional Corp., said at the time, "70% of the net revenues realized by ASRC are distributed among all regional corporations in Alaska, who in turn share one-half of their receipts with the village corporations and their at-large shareholders."

PETROLEUM NEWS ARCHIVE

The Alpine field pictured here approximately a year after startup.

The companies said that Alpine field construction took three years and 6 million manhours. Total cost would be more than $1 billion, of which the companies said $800 million has been spent with Alaska contractors.

The field included both state and Kuukpik Village Corp. lands. The royalty interest was owned by the state of Alaska, the Kuukpik Village Corp. and by ASRC.

Both Kuukpik and ASRC would, and continue to, receive royalty shares from Alpine production. Residents of Nuiqsut also get gas from the field for village power generation.

Production setbacks

Twenty years later there are five drilling pads in the Colville River unit. In addition to oil from the main/largest Alpine pool, Colville production includes satellite output from Fiord, Nanuq and Qannik.

Because drilling in the unit was halted for much of 2020 due to COVID concerns and is not expected to restart until mid-December these recent production numbers can be expected to increase in 2021: The Colville River unit averaged 41,473 bpd in September, down 23.6% from a September 2019 average of 54,271 bpd.

ConocoPhillips completed initial development drilling at Alpine in November 2005 from the CD1 and CD2 pads and switched to peripheral opportunities. The startup of the CD5 pad in late 2015 provided additional opportunities to produce from the pool.

The Alpine pool includes two participating areas: Alpine and Nanuq Kuparuk. The Alpine participating area is currently being developed from 156 wells — 82 producers, 72 injectors, and two disposal wells in the Ivishak. The Nanuq Kuparuk participating area is currently being developed from 13 wells — six producers and seven injectors.

In the coming year, the company is planning (dependent on budget approval from corporate in Houston since these plans were announced earlier in 2020) an undefined coiled tubing drilling program at the Alpine field using laterals to target areas between existing producers. The company is also planning a rotary program at Alpine including three producers and six injectors.

Alpine plans

In the coming year, the company is planning (dependent on budget approval from corporate in Houston since these plans were announced earlier in 2020) an undefined coiled tubing drilling program at the Alpine field using laterals to target areas between existing producers. The company is also planning a rotary program at Alpine including three producers and six injectors.

Within the Nanuq Kuparuk sand, ConocoPhillips is planning to use an extended reach drilling rig in early 2021 to access opportunities to the west of the CD5-316 well — again, this could be delayed a year.

Oil production is declining at the pool. The Alpine participating area produced 34,900 barrels of oil per day in 2019, down from 37,100 bpd in 2018. The Nanuq Kuparuk participating area produced 10,000 bpd in 2019, down from 12,600 bpd in 2018. The combined pool has produced 504.4 million barrels of oil cumulative since startup. ●

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In ConocoPhillips' words

On its website ConocoPhillips describes its Alpine field operations as follows:

The Alpine Field, located approximately 34 miles west of Kuparuk, is one of the largest conventional onshore oil fields developed in North America in the past 25 years.

Alpine is a model for future oil developments as directional drilling and other innovations minimize its environmental footprint.

In 2019, net crude oil production was 27 MBOED (million barrels oil equivalent per day).

Alpine West CD5, a drill site that extends the Alpine reservoir into the NPR-A, achieved first production in 2015. The original project scope was completed in 2016

ConocoPhillips has substantially advanced the state of drilling technology at CD5. Favorable results have led to continued drilling and approval of two subsequent projects to expand CD5 up to its full 43-well slot capacity. The company has drilled Alaska's 10 longest wells there, with one measuring over 33,000 feet in horizontal distance.

continued from page 1

HYDROGEN HIGHWAY

If they can made headway on the commercial front, Alberta and Saskatchewan may eventually find a way out of their current reliance on oil, especially heavy crude, and respond to the prod they received earlier in November from newly announced Canadian government legislation that mandates net-zero carbon emissions by 2050 which will include rolling five year targets starting in 2025.

Alberta's Industrial Heartland

In Alberta, an industrial corridor known as the Industrial Heartland north of Edmonton has the potential to become Canada's first hydrogen production hub by taking a "leadership role in the transition to a net-zero hydrogen economy" said a report issued by University of Calgary researchers and the Transition Accelerator, a think-tank funded by several family foundations and governments.

The report, which estimates the domestic and international hydrogen markets have the potential to be worth C$100 billion a year or more, said the potential in Alberta is mirrored by five hydrogen facilities in the Edmonton region that produce hydrogen.

Transition Chief Executive Officer Dan Wicklum said a hydrogen-based energy system could enable countries around the world to set and meet net-zero carbon targets.

Alberta's Associate Minister of Natural Gas Dale Nally said multiple projects in Western Canada could drive the growth of hydrogen, including two approved pipelines that are designed to connect natural gas fields with LNG export ventures that could be repurposed to export hydrogen.

He said the resulting jobs and royalties "could be a game changer for Albertans."

The Alberta vision involves taking a portion of the province's natural gas (made of CH_4, four hydrogens and one carbon) and stripping out the one carbon, leaving an emissions free energy fuel.

The challenge then is to ensure the carbon element never enters the atmosphere to become an active greenhouse gas.

That can be achieved by sequestering the gas as CO_2 in deep underground reservoirs or caverns or using the carbon as an input in another industrial process.

Saskatchewan leads in carbon capture

Saskatchewan is already a world leader in the commercial capture and storage of carbon, by extracting hydrogen from abandoned oil wells and by repurposing oil fields to produce close to zero-emissions fuel.

Proton Technologies Chief Executive Officer Grant Strem said that oil will always be needed as a chemical feedstock, but "as an energy product I think it will be priced out of the market in the five to 10 years."

He said vast underground energy reserves have uniquely positioned Canada to become a global leader in clean energy production through his company's carbon traction process.

Saskatchewan is also making an initial hydrogen move through a pilot project that could supply "10% of the world's energy needs in the form of exported hydrogen by 2040," Strem said.

Question on Proton technology

Taking a more cautious view, the Alberta-based think tank Pembina Institute said that although promising, the Proton technology has yet to be fully tested.

"To be validated as a zero-carbon technology, the (Proton method) would have to go through a full life-cycle assessment of environmental and social benefits and risk," said Pembina senior fossil fuels analyst Benjamin Israel.

That injection of realism aside, Alberta is pinning its hopes of winning over skeptical investors through the use of low-carbon hydrogen and hydrogen-derived fuels along with International Energy Agency support for other technologies to reach net-zero emission goals such as electrification of heating and transport, bi-energy and carbon capture.

Positive hydrogen view

Even Alberta Premier Jason Kenney, who is tough to move off his long-held positions, has been more subtle in his views of hydrogen's potential.

He told members of his governing United Conservative Party that Alberta must "find a way forward for our industry where we won't stick our head in the ground and pretend that the aspirations behind (the Paris climate-change agreement) are not hugely influential in how capital is allocated and how market access decisions are made."

The next national step will be the appointment of a 15-member panel to advise the federal government on the best ways to reach the net-zero goal in 2050.

Earlier this year the administration of Prime Minister Justin Trudeau set the ball rolling by calling on resource companies to provide "credible" net-zero plans as part of their applications to build new projects.

But it has yet to be established how committed Trudeau is achieving net-zero after decades of Canada failing to meet climate targets, including missing its 2012 target under the Kyoto Accord by more than 100 million metric tons and looking at an even greater deficit by the end of this year. ●

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Petroleum news Oil Patch Bits

Lynden Air Cargo welcomes N410LC

As reported by Lynden News Nov. 24, another L100 Hercules joined the Lynden Air Cargo fleet this fall. After a major overhaul and conformity heavy check, N410LC was delivered to Anchorage in October. "The aircraft was purchased in Africa from Safair in 2017," explains Ethan Bradford, vice president of technical operations. "Our dedicated maintenance, quality control, records, contract vendors and other Lynden Air Cargo personnel have spent many thousands of hours getting it ready to serve our customers." Oct. 8 was N410LC's functional test flight out of Singapore.

The addition of N410LC brings Lynden's fleet to 14. "We operate nine Hercules aircraft; one is a parts plane and four are on lease back to Safair," Bradford explains.

COURTESY LYNDEN

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

SUNCOR TAKEOVER

setbacks from plant breakdowns, to fires, freeze-ups, power shortages, management and ownership turmoil and labor showdowns.

GCOS was eventually renamed Syncrude Canada, a consortium that is owned 59% by Suncor Energy, 25% by Imperial Oil (which is 69.6% owned by ExxonMobil) and the balance by two Chinese government owned entities — Sinopec Oil Sands Partnership with a 9% stake and China National Offshore Oil Corp. with 7%.

Over the last 40 years, it has grown output from 45,000 barrels per day to 350,000 bpd from shallow deposits which are upgraded from bitumen into high quality light (32 degrees API) sweet synthetic crude for refining into various fuels.

Suncor to take over operations

Now Syncrude is poised to turn over the controls of its day-to-day mining and upgrading operations from Imperial to Suncor by the end of 2021 in a bid to cut C$300 million from annual operating costs, reducing them to US$23 (C$30) a barrel.

It's a change Suncor Chief Executive Officer Mark Little said "presents a strategic opportunity for Syncrude and the joint-venture partners."

He said Syncrude currently has "some degree of duplicate management structure" compared with Suncor and "is getting so convoluted."

The joint owners agree Suncor should remove some of that excess but would not disclose how many of the Syncrude consortium's 4,600 jobs would be affected.

In October, Suncor set in motion a cost-cutting initiative within its own ranks to reduce its workforce by 15%, or an estimated 2,000 jobs.

Switching the operator role at Syncrude is a sign of the evolution of the oil sands mining sector from a high-cost venture with risky, unproven technology to one that is more proven and predictable, said Joseph Doucet, dean of the Alberta School of Business at the University of Alberta.

National Bank analyst Travis Wood said in a report that Suncor believes it can drive average utilization rates to 90%, compared with a five-year average of 80%, with only six quarters of the last 20 exceeding the 90% target.

He said the cost target would represent a major change compared with Syncrude's five-year average of C$39 per barrel.

—GARY PARK

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continued from page 1

SEAL LISTING

long-term climate forecasts, and hence the ice-loss predictions used in listing decisions. People also question what the actual impacts of sea ice loss on the impacted species will turn out to be.

Opponents of the ringed seal listing argue that the listing will have negative impacts on Alaska's economy and the subsistence economy of Alaska Natives.

The listing has already been challenged through the courts. In 2016 the federal District Court in Alaska upheld three appeals against the listing, saying that the current seal population was healthy and that it was unreasonable to speculate on conditions that may exist 80 to 100 years into the future. However, in 2018 the U.S. Court of Appeals for the 9th Circuit overturned the District Court decision, saying that the NMFS view that the seals are likely to become endangered was reasonable and was supported by the record presented to the courts.

New data since listing

The petition that triggered the new 90-day filing argued that an analysis of new data that have become available in the last six years, coupled with a re-analysis of previous data, have indicated that there is a continuing abundant population of Arctic ringed seals; that there is no evidence of any decline in the health of the animals, despite the shrinkage of the sea ice habitat; and that the best available scientific evidence demonstrates that the seals are resilient to changing habitat conditions.

However, in rejecting the petition, NMFS has argued that recent research findings remain consistent with the data used in support of its 2012 listing decision. For example, although more recent climate change projections have differed from the projections used in making the decision, the decision considered the uncertainties in those projections. And, although a recent study has indicated that observed changes in sea ice extent and duration have not resulted in corresponding drops in seal population or health, the original listing finding did not assume that the long-term impacts of climate change on the seals would be detectable in the near future, NFMS argued. Moreover, the observed declines in habitat cited in the petition do not represent the anticipated impacts of the climate warming across the 21st century, NMFS said.

Other factors relating to the listing, challenged by the petition but upheld by NMFS, include the potential for increased seal predation as the sea ice extent shrinks; questions regarding the extent to which global efforts to reduce greenhouse gas emissions may impact global warming; and views on the potential impacts on the seals from manmade factors such as commercial fishing, as the climate warms.

State expresses disappointment

In a Nov. 25 press release, the State of Alaska expressed its disappointment with the NMFS finding.

"Ongoing research, along with traditional knowledge compiled since the listing shows no evidence of declines in ringed seal populations," said Alaska Department of Fish and Game Commissioner Doug Vincent-Lang. "The seals are handling current environmental changes well. ESA listings should be reserved for imperiled species. It is difficult to believe that a species with a healthy, robust population that numbers in the millions can be considered threatened with extinction."

The state says that the extent of the proposed critical habitat for the seals would encompass an area greater than the extent of the states of California, Oregon and Washington combined, including the coastlines of the Chukchi, Beaufort and northern Bering Seas.

—ALAN BAILEY

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continued from page 1

CIPL TARIFF

a temporary rate equal to the filed rate and granted intervention by the state.

RCA said the original settlement agreement dates to 2001 and has been amended five times.

On Nov. 17 the parties, CIPL and the state, filed a stipulation resolving all disputed issues, RCA said. The parties also filed to have the docket closed and for expedited consideration of the stipulation, because the original settlement agreement was set to expire Nov. 30, with new rates needing to be filed no later than Dec. 1 to go into effect Jan. 1, 2021, as required by the new settlement agreement.

RCA said the parties agreed that the 2020 rate, calculated under the 2020 settlement, will be $8.57 per barrel. The commission accepted the agreement between the state and CIPL, accepted the $8.57 pr barrel rate for the period beginning Jan. 1, 2020, and closed the docket, effective Nov. 25.

On Dec. 1 CIPL filed an increase from $8.57 per barrel to $12.57 per barrel with an effective date of Jan. 1, 2021.

There are no unaffiliated shippers on the CIPL.

In their Nov. 17 stipulation, the parties said Cook Inlet Energy was a party to the previous settlement agreement but has closed its facilities on the west side of the inlet and is no longer a shipper.

The parties said the new settlement updates the terms of the original settlement "to a more modern form of agreement." The new settlement reduces the life of the line from 2038 to 2034, "as a result of the loss of CIE's volume of shipments through the pipeline and the substantial and ongoing reduction in oil prices."

The parties said the new agreement also lowers amounts for the rate of return on equity and cost of debt, revises calculation of the tax allowance and treatment of decommissioned assets.

—KRISTEN NELSON

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continued from page 1

OIL PRICES

Dec. 3 when it became apparent that some members harbored objections to continuing the cuts into the new year without modifications.

The United Arab Emirates agreed that an extension of supply cuts was needed, but it demanded that participating countries adhere to the cuts and compensate for previous excess output, Reuters reported Dec. 1 citing multiple sources.

Russia — blaming a harsh winter season — fell short of its agreed cuts of 2 million bpd, with cumulative overproduction since May of 530,000 bpd.

Iraq had a cumulative overproduction of 610,000 bpd over the same period.

Iraq's Deputy Prime Minister Ali Allawi reportedly said during a virtual conference prior to the Dec. 1 meeting that he is no longer willing to accept a "one size fits all" approach to production cuts and wants considerations such as per capita income and sovereign wealth funds to factor into production quotas for individual members, according to a report by Al Jazeera.

OPEC+ member Kazakhstan also indicated it would like to increase production going into the new year.

Iran and Venezuela are exempt from OPEC+ cuts because U.S. sanctions and internal political strife have depressed oil production in those countries.

Libya has also been exempted from the cuts, but with the country swiftly ramping up its oil production to 1 million bpd following a landmark ceasefire deal among warring groups, it may be asked to participate at some point.

The price of OPEC basket of thirteen crudes stood at $46.72 per barrel Dec. 2, compared with $46.43 the previous day, according to OPEC Secretariat calculations.

Major oil benchmarks closed lower on Dec. 1. Alaska North Slope Crude fell 75 cents to close at $46.56, West Texas Intermediate slid 79 cents to close at $44.55, and Brent lost 17 cents to close at $47.42.

On Dec. 2, ANS rose 65 cents to close at $47.21, WTI rose 73 cents to $45.28, and Brent closed at $48.25, up 83 cents.

Production increase may create glut

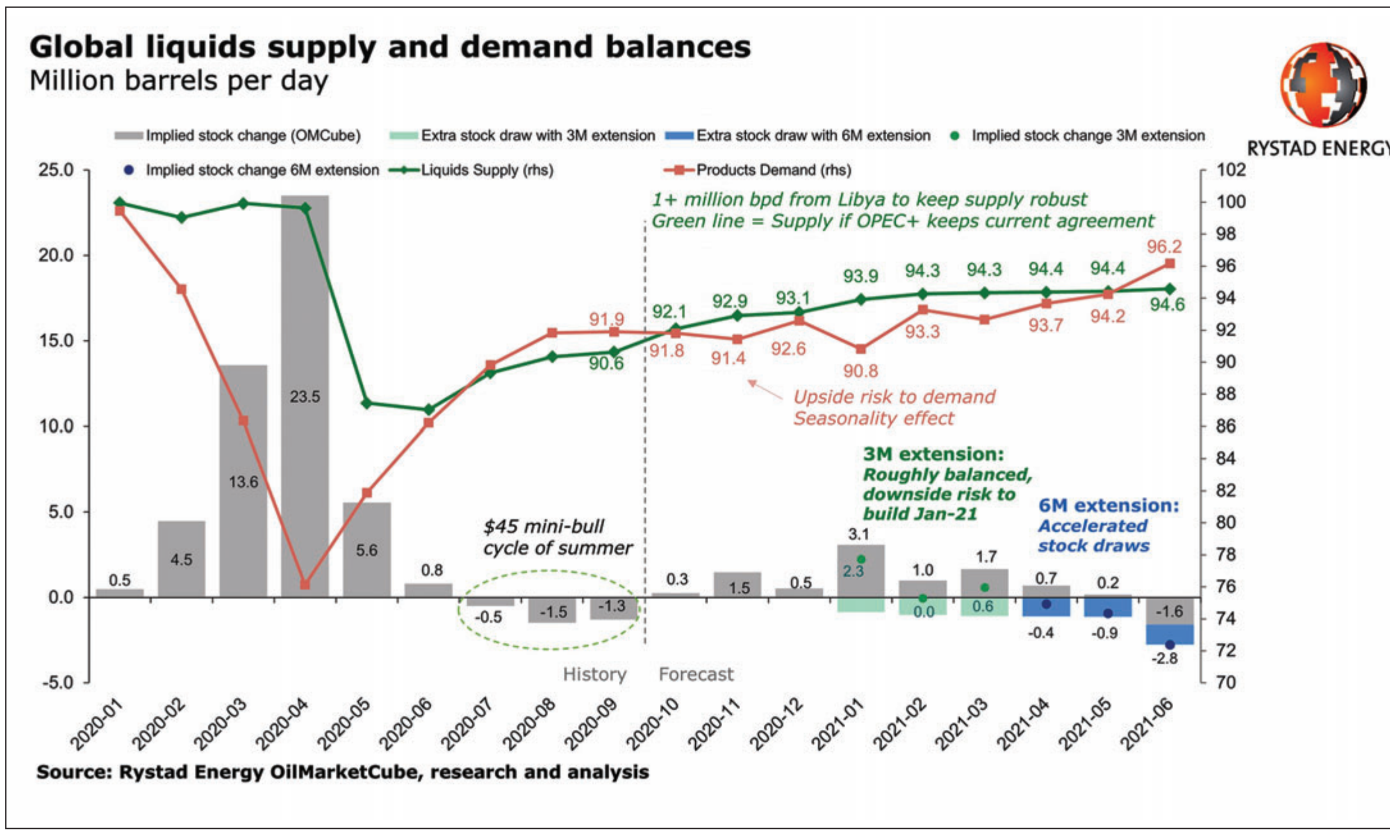
OPEC+ originally agreed to a historic reduction of 9.7 million bpd and was able to pare the reductions back to 7.7 million bpd during the summer lull in COVID cases. Oil prices recovered from devastating April lows and have largely occupied a price channel ranging from $40 to $45 per barrel for the latter half of the year.

But if OPEC+ increases oil output as planned from January, the world will face a new 200 million-barrel surplus through May, Rystad Energy said in a. Nov. 30 report.

Should OPEC+ fail to amend its existing deal, January will bring the largest monthly glut since April, with an average daily surplus of 3.1 million barrels, Rystad said. Smaller surpluses will likely continue through May, before finally starting to shrink from June forward.

Rystad modeled a possible decision by OPEC+ to postpone its production increase and calculated the effect on global oil balances of three-month and six-month extension scenarios.

If OPEC+ postpones its planned January production increase by three months, there will still be consecutive monthly surpluses through May, but the total size will be limited to about 115 million barrels, Rystad said. But if OPEC+ extends the status quo for six months, surpluses will end after March, leaving a smaller, three-month glut of just 90 million barrels, which will be erased by the end of June due to deficits beginning in April.



Rystad expects the second wave of Covid-19 cases to continue to surge through the end of 2020 and have a residual effect on oil demand in 2021, causing a slow recovery.

"We believe keeping the current agreement in place — which calls for raising target production by 1.9 million bpd from January 2021 — could send Brent back down to $40 per barrel or lower," said Bjornar Tonhaugen, Rystad head of oil markets. "A three-month extension would only provide marginal support to prices but would help to establish $50 as a sturdier floor, while a six-month extension could help to meaningfully deplete the storage overhang and supercharge prices into the mid-$50s."

Rystad expects the second wave of Covid-19 cases to continue to surge through the end of 2020 and have a residual effect on oil demand in 2021, causing a slow recovery.

"At present, we expect demand for total liquids will not surpass 93 million bpd before year-end 2020," it said.

If OPEC+ maintains current production, the primary benefactor will be "the most flexible marginal supply source on the market — shale," Rystad said.

"The past few months demonstrated that $40 Brent was enough to slow oil production growth prospects in the U.S. shale patch, but at the same time it was clearly not a high enough price environment to allow players to thrive, as evidenced by the increase in consolidation and bankruptcy activity," it said.

"The breakup of the OPEC+ deal in March 2020, when participants failed to agree on an additional 1.5 million bpd of cuts, sparked a full collapse in oil prices with a drop of $10 per barrel from the time the decision was made public until markets opened the following Monday," Tonhaugen said. "These were of course special circumstances, but a vote of no confidence from OPEC+ this week would surely be crushing for oil prices, though perhaps to a milder degree this time."

In its calculations, Rystad did not include any material positive effect by vaccines on oil demand in the first half of 2021 because the roll-out of vaccination campaigns remains uncertain. It assumes a slow and gradual roll-out before lockdowns lift and behaviors change in the wider population. ●

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