Petroleum news

page 4 ANS output 398,003 bpd in June, down from almost 515,000 in Jan.

Vol. 25, No. 31 • www.PetroleumNews.com *A weekly oil & gas newspaper based in Anchorage, Alaska* Week of August 2, 2020 • $2.50

Oil Search reports strong second quarter; liquidity rises to $1.67B

KEIRAN WULFF

Oil Search released strong second quarter results on July 21, with operated oil production up 14% to 7.29 million barrels of oil equivalent since first quarter, at the highest level since the 2018 Papua New Guinea Highlands earthquake.

Revenue was down 26% between the first and second quarters because the average price of oil in the first half of the year dropped 53%.

But following decisive steps taken in March to reduce 2020 capital expenditure by approximately 40%, Oil Search further

see **OIL SEARCH** *page 9*

Chugach Electric files for power pool; condition of ML&P purchase

Anchorage-based utility Chugach Electric Association has filed a tariff advice with the Regulatory Commission of Alaska, requesting commission approval of the formation of a tight power pool with Matanuska Electric Association. Often termed security constrained economic dispatch, the concept behind the power pool is to share the continuous use of the most cost effective power generation, thus reducing the cost of electricity for consumers.

As one of the conditions for regulatory approval of Chugach Electric's planned purchase of Municipal Light & Power the commission requires Chugach Electric to establish economic dispatch with MEA — the commission sees the operation of a tight pool as a factor in ensuring that the elec-

see **POWER POOL** *page 10*

Armstrong North Fork 3D & Doyon well data to be released

The Alaska Department of Natural Resources, Division of Oil and Gas published a notice July 28 announcing the upcoming release of exploration seismic and well information, specifically PGS Onshore's 2010 southern Kenia Peninsula North Fork 3D seismic survey and Doyon Ltd.'s Nenana basin Totchaket 1 well data.

The division said it would make the information available to the public no less than 30 days following the notice.

Discovered in 1965

The history of the North Fork field goes back to 1965 when

see **WELL DATA** *page 8*

Cost of bad bets: Alberta savings pensions funds, 'quarter from hell'

It was launched in 1976 full of hope that Alberta would build a piggybank "to save for the future, strengthen or diversify our economy and improve the quality of life for Albertans."

Labelled as the Alberta Heritage Savings Trust Fund, AHSTF, it was designed to capture surplus oil and natural gas revenues and give the province some financial security against a day when the fossil fuel industry started to wind down ... such as right now.

The slide from the mountain top, where Alberta governments were able to gaze with pride at their debt-free status and mandatory deficit-free budgets, started 10 years ago and is now at the point where Alberta's debt is fast approaching C$100 billion, with the COVID-19-driven deficit expected to easily surpass C$20 billion in 2020-2021.

see **SAVINGS FUND** *page 7*

FINANCE & ECONOMY

Summer price doldrums

Oil prices may slip on supply increases before demand rallies in December

By STEVE SUTHERLIN

Petroleum News

> *"We doubt that the market can take the additional production volumes from OPEC+ from August without negative consequences for oil prices."*
> *—Bjornar Tonhaugen, Rystad head of oil market research*

Oil prices have been in the doldrums: a low $40s trading range for most of the summer.

After a wild and crazy spring, Alaska North Slope crude and Brent prices crossed above the $40 line June 5. ANS crude led Brent for most of the period, stayed over $40, flirted with $45 several times, but never made it above the $44.75 it posted on July 22.

Brent and West Texas Intermediate also traded in a tight holding pattern during June and July.

Price volatility is the lifeblood of oil traders, and the lack of it has sent traders to the sidelines this summer, awaiting more robust price action.

In a tug of war between the historic growth of oil consumption — which will resume eventually — and the COVID-19 related destruction of demand, a standoff has occurred. As long as coronavirus clouds threaten, that dance might continue.

Of course, a trading range can break in the next 15 minutes, as we know. The price will change; that is

see **OIL PRICES** *page 12*

EXPLORATION & PRODUCTION

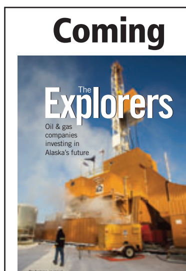
Exploration not forte, but …

Hilcorp appears to be advancing Whiskey Gulch, Lower Cook Inlet exploration

By KAY CASHMAN

Petroleum News

Coming



August 2020

Hilcorp is best known for employing modern tools to increase output from mature oil and gas fields, giving fields past their prime the attention they need to continue producing at optimum levels.

Hilcorp's modern exploration toolbox is seldom pulled off the shelf but with the company's strategy of having little middle management, its individual asset teams have creative license to chase ideas, an approach that paid off in late 2018 with a natural gas discovery in the Seaview No. 8 discovery well in the southern Kenai Peninsula.

Near Anchor Point, Seaview is slated to go online in late 2020.

Among other things, Hilcorp's exploration tool chest includes airborne gravity gradiometric and magnetic surveys, along with geologic field surveys, drainage anomaly studies and seismic surveys to home in on more optimized well locations in its search for more gas to serve Cook Inlet area markets.

Hilcorp has also been doing preliminary exploration in the lower Cook Inlet and on the west side of Cook Inlet on the Iniskin Peninsula, looking at the oil and gas potential of those areas.

Two things could upset the pace of the compa-

see **HILCORP EXPLORATION** *page 11*

EXPLORATION & PRODUCTION

Wary mood in Canada

Kenney holds out signs of hope; Suncor, Cenovus leaders don't see quick recovery

By GARY PARK

For Petroleum News

JASON KENNEY

Alberta Premier Jason Kenney is predicting that when the global economy rebounds from COVID-19 "we are going to see something of a supply shortage."

Two of his province's largest oil sands producers — Suncor Energy and Cenovus Energy — both believe the outlook is starting to improve, though most upstream companies are barely able to break even when oil nudges US$40 a barrel.

Kenney bases his hopes on the cancellation of exploration and development drilling that he is counting on to apply upward pressure on commodity prices.

"That will be a great opportunity for Alberta especially as we make progress on pipelines," he said.

Not everyone agrees with his view of pipelines, except for completion of the Trans Mountain expansion, which will add a net addition of 590,000 barrels per day when it comes on stream by late 2022.

But Kenney is alone in believing that Keystone XL will be completed, which could be tied less to reality and more to his desperate commitment of C$7 billion for the 830,000-bpd system to the Texas Gulf Coast.

see **WARY MOOD** *page 10*

● EXPLORATION & PRODUCTION

Hilcorp plans drilling at Beaver Creek

At Birch Hill plan is for a road to allow plugging and abandoning the field's single gas well, which hasn't produced since 1965

By KRISTEN NELSON

Petroleum News

Hilcorp Alaska has current plans of development and operations submitted to the U.S. Bureau of Land Management for two small fields in the Kenai National Wildlife Refuge, one of which is in production, while the other hasn't produced since 1965.

The producing field, Beaver Creek, averaged 108 barrels per day of oil in June, the most recent month for which Alaska Oil and Gas Conservation Commission data are available, and 9,851 thousand cubic feet per day of natural gas, accounting for less than 1% of Cook Inlet oil production and just over 5% of Cook Inlet natural gas production. Beaver Creek, discovered by Marathon Oil in 1972 and in production since 1973, is southwest of the Swanson River field on the Kenai Peninsula.

Birch Hill, discovered by ARCO Alaska in 1965, is north of Swanson River. It had its only production in June 1965, when over a period of 12 days it produced a total of 65,331 mcf of natural gas from the field's single well, which AOGCC records show as suspended.

Beaver Creek

In Hilcorp Alaska's POD submittal to BLM for Beaver Creek, reporting on work during the 2019 POD period, April 1, 2019, through March 31, 2020, the company listed necessary routine repairs and replacement of facilities as required to maintain and increase field production, "including converting a gas separator to an oil separator, piping modifications to accommodate oil well drilling," installation of a new generator on Pad 4, completion of overhaul of a gas sales compressor, wastewater pump maintenance, fire and gas upgrades on Pad 3 and Pad 4, and installation of an oil LACT (lease automatic custody transfer) meter.

Cumulative production during the 2019 POD period was 2,741 million standard cubic feet of natural gas and 131,500 barrels of oil.

Hilcorp reported drilling a sidetrack to the BCU-04 well during the 2019 POD and perforating three wells.

AOGCC records for June 2020 show one active oil well at the field and seven active gas wells.

For the 2020 POD period, Hilcorp said necessary routine repairs and replacement of facilities would include work necessary to accommodate drilling of gas wells, which may include piping and/or electrical instrumentation.

The company said it anticipates drilling one new sidetrack project, BCU-19RD, during the 2020 POD period, and working over BCU-04RD. Hilcorp said that well failed mechanically in August 2019. AOGCC records for July 2019 show the BCU-04RD producing a total of 10,429 barrels, almost half of the 23,399 barrels the field produced in that month (755 barrels per day).

Birch Hill

At Birch Hill, the issue is work required to plug and abandon the field's single well, although Hilcorp said it also continues to work with Cook Inlet Region Inc., which holds a 20% working interest in Birch Hill, to determine if there is interest from other parties in developing oil and gas resources in the Birch Hill area.

Hilcorp said it and CIRI have had two meetings "with an interested oil and gas company" on the possibility of Birch Hill development, and while the level of interest is

see BEAVER CREEK *page 5*

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Alaska-Mackenzie Rig Report

The Alaska-Mackenzie Rig Report as of July 29, 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

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, L-61	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
Kuukpik Drilling	5	Deadhorse	Available
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)	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

BP			
Top Drive, supersized	Liberty rig	Inactive	BP
Doyon Drilling			
Sky top Brewster NE-12	15 (SCR/TD)	Standby	
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

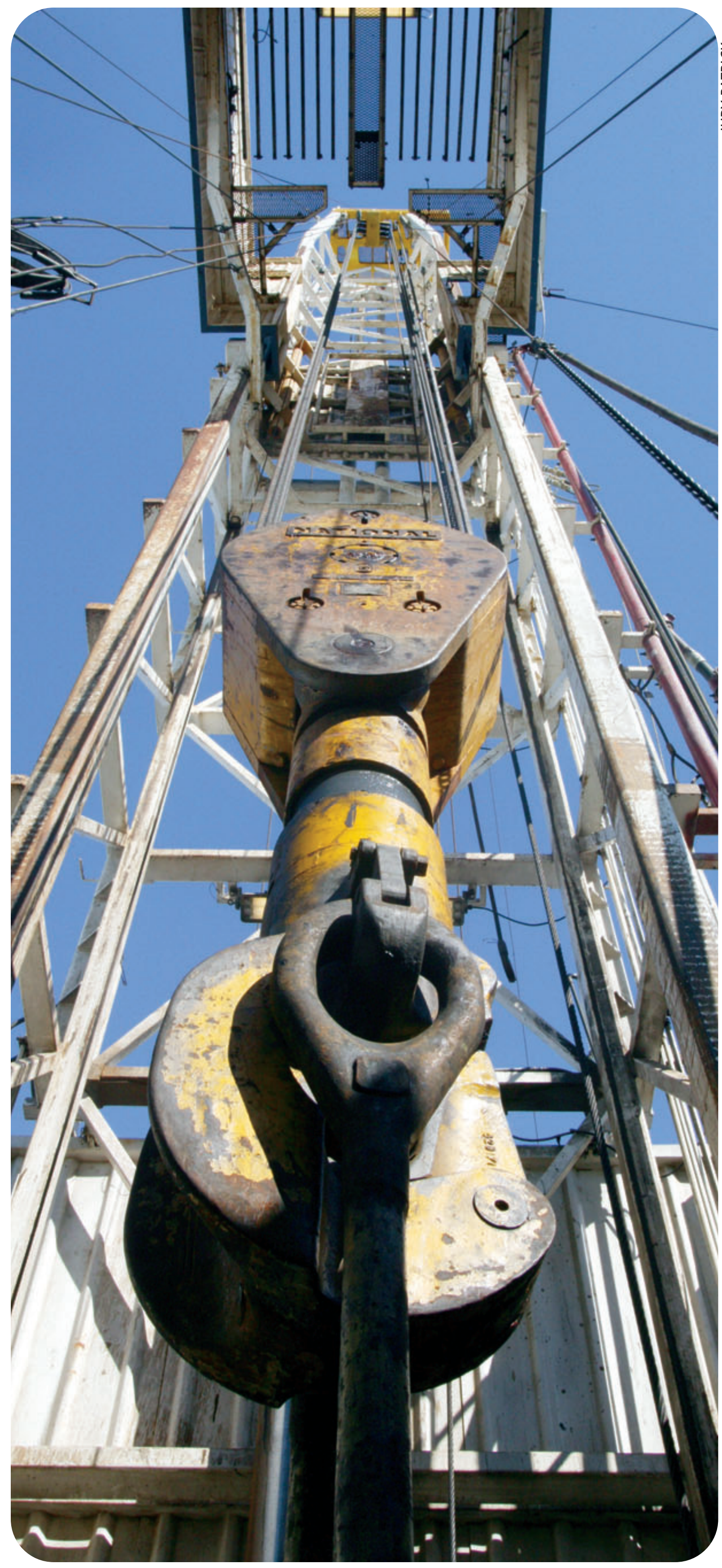
Cook Inlet Basin – Offshore

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



JUDY PATRICK

Baker Hughes North America rotary rig counts*

	July 24	July 17	Year Ago
United States	251	253	946
Canada	42	32	127
Gulf of Mexico	12	12	23

Highest/Lowest		
US/Highest	4530	December 1981
US/Lowest	251	July 2020

*Issued by Baker Hughes since 1944

● EXPLORATION & PRODUCTION

ANS averaged 398,003 bpd in June, down 8%

Steepest drops at Kuparuk, Colville, with Conoco's announced 100,000 bpd cut in Alaska; increases elsewhere, largest at Prudhoe

By KRISTEN NELSON

Petroleum News

Alaska North Slope crude oil production took a steep dive in June. After starting the year averaging almost 515,000 barrels per day, the June average was below 400,000 bpd, the lowest level this year, although cumulative field data posted for the current month by the Alaska Department of Revenue show volumes beginning to increase in July.

Detailed breakdowns in this story are from data provided by the Alaska Oil and Gas Conservation Commission, which reports production by well and field on a month-delay basis — and also breaks out natural gas liquids production from crude oil.

Cook Inlet crude oil production averaged 11,635 bpd in June, up 0.6%, 72 bpd, from a May average of 11,563 bpd but down 12.7% from a June 2019 average of 13,325 bpd.

ANS production averaged 398,003 barrels per day in June, down 8.3%, 35,837 bpd, from a May average of 433,840 bpd and down 18.6% from a June 2019 average of 489,144 bpd.

ANS crude averaged 349,339 bpd in June, down 11%, 43,218 bpd, from a May average of 392,557 bpd and down 20.9% from a June 2019 average of 441,437 bpd. ANS NGLs, on the other hand, averaged 48,663 bpd in June, an increase of 17.9%, 7,380 bpd, from a May average of 41,283 bpd, and up 2% from a June 2019 average of 47,706 bpd.

Month-over-month declines

The strongest impact on June production was from a 100,000-bpd cut in Alaska production by ConocoPhillips in response to a drop in demand due to COVID-19 and the resulting steep drop in oil prices. Ramp down for the ConocoPhillips cuts began in May and the company said June 30 that it expected to begin restoring Alaska production in July.

The largest month-over-month ANS volume drop was at the ConocoPhillips Alaska-operated Kuparuk River field, which averaged 38,747 bpd in June, down 40.9%, 26,861 bpd, from a May average of 65,607 bpd, and down 62% from a June 2019 average of 101,878 bpd. (ConocoPhillips holds some 94.7% of the working interest at Kuparuk; Chevron holds 4.95%; ExxonMobil holds less than 1%.)

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

The largest month-over-month percentage drop was at ConocoPhillips' Colville River field, which averaged 18,505 bpd in June, down 50.1%, 18,584 bpd, from a May average of 37,090 bod, and down 63.8% from a June 2019 average of 51,136 bpd.

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

ConocoPhillips' Greater Mooses Tooth in the National Petroleum Reserve-Alaska averaged 3,182 bpd in June, down 28.2%, 1,251 bpd, from a May average of 4,433 bpd, and down 72.3% from a June 2019 average of 11,496.

The ExxonMobil Production-operated Point Thomson field averaged 9,440 bpd in June, down 1.9%, 178 bpd, from a May average of 9,618 bpd, but up 95.7% from a June 2019 average of 4,823 bpd.

NGL impact at Prudhoe

The largest volume month-over-month increase was at the Prudhoe Bay field. Since July 1 operated by Hilcorp, in June Prudhoe was still being operated by BP Exploration (Alaska).

Combined production at Prudhoe in June was 251,505 bpd, up 2.5%, 6,172 bpd, from a May average of 245,333 bpd and up 2.1% from a June 2019 average of 246,265 bpd.

That increase, however, was from natural gas liquids.

Crude oil production at Prudhoe averaged 206,225 bpd in June, down marginally (0.4%, 757 bpd) from a May average of 206,982 bpd, although up 2.6% from a June 2019 average of 201,073 bpd.

NGL production at Prudhoe averaged

see **ANS PRODUCTION** page 5

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ANS PRODUCTION

45,280 bpd in June, up 18.1%, 6,929 bpd, from a May average of 38,351 and up 0.2% from a June 2019 average of 45,192 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.

Month-over-month increases

The largest percentage month-over-month production increase was at Eni's Oooguruk field, which averaged 8,256 bpd in June, up 30.4%, 1,924 bpd, from a May average of 6,331 bpd and up 8.5% from a June 2019 average of 7,611 bpd.

The Hilcorp-operated Endicott field averaged 7,286 bpd in June, up 10.8%, 712 bpd, from a May average of 6,574 bpd, but down marginally from a June 2019 average of 7,289 bpd. Crude oil production at Endicott averaged 6,364 bpd in June, up 10.5%, 605 bpd, from a May average of 5,760 bpd, but down 2.3% from a June 2019 average of 6,512 bpd. NGL production at Endicott averaged 922 bpd in June, up 13.1%, 107 bpd, from a May average of 815 bpd and up 18.6% from a June 2019 average of 777 bpd.

Eni's Nikaitchuq averaged 19,923 bpd in June, up 9.8%, 1,779 bpd, from a May average of 18,144 bpd, and up 2.7% from a June 2019 average of 13,394 bpd.

The Hilcorp-operated Northstar field averaged 8,373 bpd in June, up 1.5%, 127 bpd, from a May average of 8,246

The largest percentage month-over-month production increase was at Eni's Oooguruk field, which averaged 8,256 bpd in June, up 30.4%, 1,924 bpd, from a May average of 6,331 bpd and up 8.5% from a June 2019 average of 7,611 bpd.

but down 1% from a June 2019 average of 8,457. Like the much larger Prudhoe, Northstar had a drop in crude production, offset by NGLs. The field averaged 5,911 bpd of crude in June, down 3.6%, 218 bpd, from a May average of 6,129 bpd, and down 12% from a June 2019 average of 6,720 bpd. NGL production at Northstar averaged 2,462 bpd in June, up 16.3%, 345 bpd, from a May average of 2,117 bpd and up 41.7% from a June 2019 average of 1,737 bpd.

The Hilcorp-operated Milne Point field averaged 32,786 bpd in June, up 1.1%, 351 bpd, from a May average of 32,435 bpd, and up 12.3% from a June 2019 average of 29,198 bpd.

Production was suspended at Badami, operated by Glacier Oil & Gas Corp.'s Savant Alaska, in May and the field had no production in June.

Cook Inlet up marginally

Cook Inlet crude oil production averaged 11,635 bpd in June, up 0.6%, 72 bpd, from a May average of 11,563 bpd but down 12.7% from a June 2019 average of 13,325 bpd.

Operations have been suspended at two fields, Redoubt Shoal and West McArthur River, both operated by Glacier's Cook Inlet Energy, and they had no production in June.

Three fields had month-over-month production declines.

Hilcorp's Beaver Creek, the inlet's smallest oil field, averaged 108 bpd in June, down 26.6%, 39 bpd, from a May average of 147 bpd and down 68.7% from a June 2019 average of 345 bpd.

Hilcorp's Swanson River averaged 841 bpd in June, down 4.8%, 42 bpd, from a May average of 883 bpd, and down 12.7% from a June 2019 average of 963 bpd.

Hilcorp's Middle Ground Shoal averaged 1,258 bpd in June, down 0.7%, 8 bpd, from a May average of 1,266 bpd and down 3.4% from a June 2019 average of 1,302 bpd.

The remaining four fields all had month-over-month production increases.

Hilcorp's McArthur River field, the inlet's largest, averaged 3,957 bpd in June, up 9.6%, 345 bpd, from a May average of 3,611 bpd, but down 14.5% from a June 2019 average of 4,628 bpd.

Hilcorp's Granite Point averaged 3,113 bpd in June, up 0.6%, 17 bpd, from a May average of 3,096 bpd, and up 28.6% from a June 2019 average of 2,420 bpd.

Hilcorp's Trading Bay field averaged 1,365 bpd in June, up 17.9%, 207 bpd, from a May average of 1,158 bpd and up 92.2% from a June 2019 average of 710 bpd.

BlueCrest's Hansen field, the Cosmopolitan project, averaged 994 bpd in June, up 1.7%, 16 bpd, from a May average of 977 bpd, but down 32.4% from a June 2019 average of 1,469 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.

Cook Inlet natural gas production will be in the Aug. 9 issue of Petroleum News. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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BEAVER CREEK

unclear, "Hilcorp and CIRI plan to continue looking and evaluating potential partners."

P&A at Birch Hill requires road access, although Hilcorp said it had evaluated using a helicopter.

During the 2019 POD period (April 1, 2019, through March 31, 2020), Hilcorp evaluated the option of constructing a gravel road to Birch Hill from the north, following an existing trail. The company said that route is entirely on Tyonek Native Corp. lands within the Kenai Wildlife Refuge.

The option the company previously proposed was a snow road and gravel road from the south, coming from a Swanson River pad. Hilcorp said it conducted environmental studies and economic analysis, as well as risk analysis, and determined the route from the south was no longer a preferred or viable option.

Hilcorp said it met with BLM and CIRI to discuss the northern road access to Birch Hill on TNC lands, and said that in addition to having less environmental and wetlands impact, that route is "significantly shorter, and involves less complicated land ownership and restrictions on said lands, compared to the currently approved road coming in from the south from Swanson River."

The north road, however, is dependent on the Kenai Peninsula Borough's Kenai Spur Highway extension project, and on coordination with TNC on road construction on their land and "transferring the constructed road to TNC after Hilcorp P&A's the BHU 22-25 well and padsite." ●

Contact Kristen Nelson at knelson@petroleumnews.com

● UTILITIES

REAP clarifies ERO governance position

Rose comments that REAP does not see a need to enforce board independence but wants a board structure that ensures fair decisions

By ALAN BAILEY
For Petroleum News

On July 22 Chris Rose, executive director of Renewable Energy Alaska Project, filed comments with the Regulatory Commission of Alaska, clarifying REAP's position on the governance of an electric reliability organization, or ERO. Rose wrote that a filing that he had made in June had been incorrectly interpreted as meaning that REAP wants the commission to enforce the independence of an ERO board of directors.

During this year's legislative session the state Legislature passed Senate Bill 123, a bill enabling RCA to regulate an ERO. The RCA has opened three dockets for developing regulations to implement SB 123. The primary purpose of an ERO is to ensure a coordinated approach to the management and operation of an interconnected electrical system.

At the end of last year the six Alaska Railbelt utilities issued a memorandum of understanding for the formation of the Railbelt Reliability Council, or RRC, which would operate as an ERO for the Railbelt.

Questions over governance

One of the more contentious aspects of the regulatory requirements relates to the extent to which the ERO board should have to be independent from the utilities that operate the electrical system. On the one hand, the utilities have significant expertise in the operation of the system. On the other hand, independent power producers and other stakeholders in the system want a say in how the system is operated. The RRC MOU specified a 13-member board, with a director from each of the utilities, six non-utility directors, and the RRC CEO as the 13th member.

SB 123 allows considerable flexibility over board membership, with the statute requiring a board "formed as an independent board; a balanced stakeholder board; or a combination independent and balanced stakeholder board."

In his new filing Rose wrote that his June filing had not intended to indicate that REAP wants the RCA to mandate an independent ERO board. Nor did REAP call for any of the utilities to be eliminated from the ERO board, Rose wrote. The critical issue is to achieve balance by ensuring that no one stakeholder or group of stakeholders with the same interests can dominate board decision making, he wrote.

Rose, who was recently selected as a member of the RRC implementation committee, expressed his appreciation at opportunities for REAP to comment on the RRC MOU, and at the utilities' accomplishment in agreeing on a form of ERO. However, he also expressed concern about the low level of non-utility involvement in the MOU process. ●

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● GOVERNMENT

AOGCC rules against French on waste

By KRISTEN NELSON
Petroleum News

In a July 28 order the Alaska Oil and Gas Conservation Commission ruled against Hollis French, formerly the commission's chair, on a claim that waste occurred as a result of gas escaping when the DS02-03B well failed in April 2017.

"Shortly after the failure, AOGCC determined the gas which escaped was not waste under 20 AAC 25.235(d)(5)(B). French was an AOGCC commissioner at the time," the commission said in its order.

French had petitioned the commission in 2019 to hold a hearing on a complaint of waste from the North Slope well, a petition the commission denied on the basis that circumstances surrounding release of gas from the well were the subject of an ongoing investigation.

French appealed to Alaska Superior Court which ordered the commission to hold the requested hearing.

At the June 23 hearing, French said he didn't think there was any doubt that there was an uncontrolled gas release at the well.

Venting gas

A situation report from the Alaska Department of Environmental Conservation said the venting of gas from the well was discovered in the morning of April 14, 2017, with a team from well control contractor Boots and Coots able to place a plug in the damaged piping April 16, allowing fluid to be pumped into the well April 17 killing it.

In its July 28 order the commission said French argued at the June 23 hearing that the failure at DS02-03B "created a dangerous situation. French further stated that his waste petition was premised solely on his view that gas escaping into the air constitutes waste as a matter of strict liability. French's claim is contrary to the language of the AOGCC's enabling act, AS 31.05.170(15)(H), and its regulations, 20 AAC 25.235(d)(5)(B). As a result, French has failed to demonstrate waste occurred."

At the hearing French said he and the commission have different views on the commission's boundary of jurisdiction.

French was appointed to the commission by Gov. Bill Walker in 2016 and dismissed by Gov. Mike Dunleavy in 2019. Dunleavy cited neglect of duty and said a hearing officer found "substantial evidence to show an 'overall pattern' of absenteeism and that it was 'more norm than … exception'" and substantial evidence that French did not perform routine work, which then fell to others,

The hearing officer found that "Commissioner French was persistent and energetic in pursuing his view that the jurisdiction of the AOGCC was being interpreted more narrowly than he believed that the enabling statutes intended." ●

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EXPLORATION & PRODUCTION

US rig count down by 2 more, now at 251

The number of active oil and gas drilling rigs in the U.S. continues to drop, with the Baker Hughes' weekly U.S. rig count for July 24 down two from the previous week to 251 and down 695 from 945 a year ago.

Each week in the last 12 the count has set a new record for low number of rigs, 374 rigs on May 8 of this year; 339 rigs on May 15; 318 on May 22; 301 on May 29; 284 on June 5; 279 on June 12; 266 on June 19; 265 on June 26; 263 on July 2; 258 on July 10; 253 on July 17; and 251 for the current week. The Houston oilfield services company has issued a weekly rig count since 1944. Prior to this year, the low was 404 rigs in May 2016.

Baker Hughes said 181 rigs targeted oil, up one from the previous week and down 595 from a year ago, while 68 targeted gas, down three from the previous week and down 101 from a year ago. There were two miscellaneous rigs active, unchanged from the previous week and up by one from a year ago.

Twenty-two of the holes were directional, 215 were horizontal and 14 were vertical.

New Mexico (51) was up by a single rig from the previous week.

Rig counts were unchanged for Alaska (3), California (4), Colorado (5), Louisiana (30), North Dakota (10), Ohio (6), Oklahoma (10) and Wyoming (1).

Pennsylvania (20), Texas (103) and West Virginia (5) were each down by one rig from the previous week.

Baker Hughes shows Alaska with three active rigs July 24, down by six from a year ago.

The rig count in the nation's most active basin, the Permian (126), was up by two rigs from the previous week, and down by 317 from a count of 443 a year ago.

Baker Hughes has issued weekly rig counts for the U.S. and Canada since 1944 and began issuing international rig counts in 1975.

The U.S. rig count peaked at 4,530 in 1981. This week's count of 251 is a new low, surpassing lows set in the previous 11 weeks. Prior to that the previous low was 404 rigs in May 2016.

—KRISTEN NELSON

NATURAL GAS

FERC denies AKLNG rehearing requests

The Federal Energy Regulatory Commission has denied rehearing requests on the authorization it issued May 21 for the Alaska Gasline Development Corp. to construct the Alaska LNG project.

FERC received requests for rehearing from the Matanuska-Susitna Borough and from the Center for Biological Diversity and Earthjustice on behalf of Chickaloon Village Traditional Council, Northern Alaska Environmental Center and the Sierra Club (see story in June 28 issue of Petroleum News).

The Matanuska-Susitna Borough request was dated June 19; the Center for Biological Diversity request June 22.

In a July 22 notice, FERC said in the absence of a commission action on requests for rehearing within 30 days from the date the requests were filed, the requests "may be deemed denied."

—KRISTEN NELSON

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SAVINGS FUND

The only reminder to Albertans of once-heady days is the sight of rail grain cars, emblazoned with the AHSTF logo, headed for export terminals on the Pacific Coast.

Slush fund for governments

Otherwise the AHSTF has become a slush fund for financially strapped governments to raid, with income from fund investments contributing C$44.5 billion over recent years for programs including health care, education and job-creating infrastructure.

Since 1980 non-renewable resources have generated far in excess of C$200 billion, but the fund has slipped in value to C$16.3 billion, ending the 2019-20 fiscal year with a loss of 5.1% and a decline in value of 10.4%.

It was disclosed in mid-July that the portfolio had hit its lowest point in eight years, partly the result of a risky investment strategy by the Alberta Investment Management Corp., AIMCo, that cost the fund C$411 million in the last fiscal year. Global market losses also contributed to the setback.

"You don't have to apologize for being hard on us," said a rueful AIMCo Chief Executive Officer Kevin Uebelein. "This latest quarter was one from hell and we deserve to be whacked around.

Public pension fund also down

Earlier this year, the Alberta government's public pension fund lost C$4 billion of its C$50 billion portfolio value volatility trades, leading to the government replacing AIMCo Chairman Richard Bird with Mark Wiseman, former head of the Canada Pension Plan Investment Board, and prompting an external review.

Alberta Finance Minister Travis Toews said Wiseman "brings deep experience in large fund management."

AIMCo currently manages the investment of 31 funds, including major public sector worker pension funds.

In a report on AIMCo's performance, reviewers said risk governance and culture at AIMCo were "unsatisfactory" and that employees were too slow in raising concerns about the investment strategy to managers or the board.

University of Calgary economics professor Trevor Tombe warned the government may have to decide whether to withdraw more of the principal from the fund, permanently depleting its value, or run a larger fiscal deficit to make up the difference.

Given that government borrowing is relatively cheap, he said there could be a case for the government to run an even deeper deficit and keep more money in the AHSTF.

—GARY PARK

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WELL DATA

Chevron predecessor Standard Oil Company of California encountered gas in two zones in the Tyonek formation while drilling the North Fork Unit No. 41-35 well as part of an oil exploration program. There was no interest in natural gas development at the time, so the field lay undeveloped for many years, during which time ownership of the unit changed hands several times.

Armstrong Cook Inlet, an affiliate of Denver-based Armstrong Oil and Gas, acquired the unit in 2007, subsequently re-entering the 41-35 well, contracting with PGS for a 20 square mile 3D seismic survey and drilling several new wells.

Anchor Point Energy, the midstream company formed by Armstrong and its partners at North Fork, subsequently built a 12-mile pipeline to Anchor Point on the Kenai Peninsula coast, to hook up with another gas line that Enstar Natural Gas Co. constructed south from the existing pipeline infrastructure, which eventually was extended into Homer.

Armstrong brought the field online in 2011.

Lenticular sands

Ed Kerr, then-Armstrong's vice president of land and business development, said the 3D seismic acquired by PGS in 2010 "greatly improved the regional structural definition of the four-way anticlinal North Fork closure."

The trick at North Fork was to find productive patches within the sandstones.

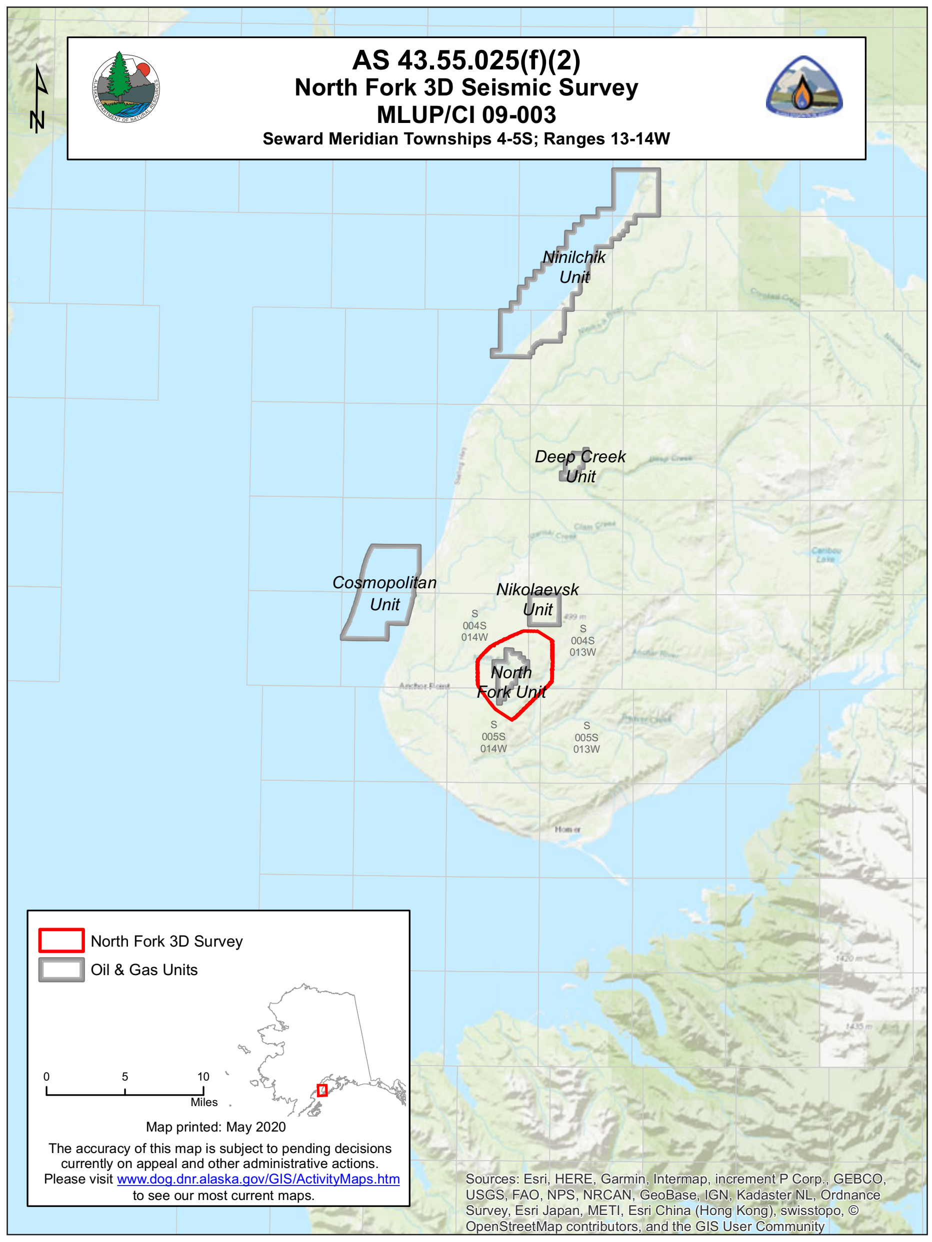
"Depositionally, these are lenticular sands, so they come and go," Kerr told Petroleum News at the time, referring to layers of sands and mud. "We're drilling through a package of sands."

Additionally, and in part because of the seismic results, the state agreed to expand the North Fork unit and its Gas Pool No. 1 participating area to the west.

North Fork became increasingly important as an anchor development for the southern Kenai Peninsula, a region at the time that had many known but undeveloped prospects.

In early 2014, Miller Energy Resources of Tennessee announced it purchased the North Fork field from Armstrong in a $65 million deal. Miller subsidiary Cook Inlet Energy was to operate the field.

Petroleum News has reported on Doyon's search for oil and gas in the Nenana basin since the Native regional corporation for Interior Alaska partnered with others in 2004, took over as operator in 2009, and drilled what would prove to be its last well, Totchaket 1, in summer 2018.



Drilled in the northern part of the basin on the east side of the Tanana River about 20 miles north of the town of Nenana, the Totchaket 1 well was drilled with Nabors rig 105 to a vertical depth of 11,225 feet.

It encountered multiple gas shows but did not find commercial amounts of oil or gas, Doyon partner Cook Inlet Region Inc. reported following drilling and testing.

CIRI said that, based on drilling results so far, it continued to view the Nenana basin as holding considerable resources.

All in all, five wells were drilled — three in the basin's central saddle, and two wells in the deeper more northerly part of the basin, above the presumed oil and gas kitchen.

Doyon's exploration, encouraged by pervasive evidence of oil and gas throughout the program, was carefully planned and executed, targeting potential traps identified from 2D and 3D seismic and related data (gravity, magnetics, lake-bed geochemical survey, etc.).

But in 2019 Doyon decided to halt the program, allowing its 20 state leases (approximately 100,000 acres) in the area to expire, with the last of the group terminating in June of that year.

Aaron Schutt, Doyon president and CEO, confirmed this in an email to PN on April 15, 2019: "Doyon is not pursuing further work in the Nenana basin at this time. As with all investments, a time comes when you have to make a decision to go forward or not. Following Totchaket 1, we decided not to continue."

A Doyon shareholder who asked not to be identified told PN at the time, "our geoscientists were pursuing an idea we had for the area. … We've given it a good try, but … perhaps someone with a new idea will come in and see what they can find."

Doyon's focus, he said, was returning to a more typical approach, that of a lessor, referring to the subsurface rights the Native regional corporation holds for approximately 400,000 acres in the Nenana basin.

Time-equivalent Kenai Group

The Nenana basin is located close to the Parks Highway, to the southwest of Fairbanks. Doyon had been particularly focused on making an oil discovery, although the basin is also highly prospective for natural gas, per the division.

Doyon had indicated that, given the convenient location of the Totchaket project site, a development could be viable at an oil price of around $50 per barrel, even with a relatively small discovery of perhaps 40 million to 60 million barrels.

If a workable oil resource had been discovered, production could have begun around 2023 to 2025, or perhaps earlier if oil were to be shipped by truck or rail to the oil refinery at North Pole, or to a trans-Alaska oil pipeline pump station.

One of several Alaska basins formed by the pulling apart of the Earth's crust, the Nenana basin is filled with a huge thickness of non-marine Tertiary sediments. Coal seams and shales within the rock sequence have the potential to source both oil and gas, depending on the extent to which they are heated at depth. There are sands with excellent hydrocarbon reservoir potential, interlayered with shales that could form hydrocarbon traps.

In broad terms, the basin has a northeast to southwest trending hourglass shape, with a deep basin in the north and a central saddle in the narrower, central part of the basin, immediately west of the town of Nenana. The depths reached in the northerly section of the basin are thought to be sufficient to have raised the temperatures in the potential source rocks to levels conducive to oil formation.

"The prospective sedimentary section … consists of sands, gravels, conglomerates, shales and coals … thought to be time-equivalent to the productive Kenai Group in the Cook Inlet (basin)," the division said.

—KAY CASHMAN

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OIL SEARCH

strengthened its balance sheet in April by raising approximately $700 million through an equity issue.

The company also reduced its debt during second quarter, the culmination of all these actions resulting in increased total liquidity by the end of June to $1.67 billion — $831.4 million in cash and $835.6 million in undrawn credit facilities.

The mixed bag of second quarter results follows unpresented disruptions to the global oil and gas industry, caused by the coronavirus pandemic.

Alaska spend drops by $80M

The 40% reduction in capital expenditure totaled $270-$315 million, with Alaska representing only about $80 million of that, Anchorage-based Amy Burnett, Oil Search's manager of U.S. media and communications, told Petroleum News July 27.

"The majority of our investment budget for the year was allocated to the winter exploration and construction programs," she said. "In addition to construction work to finish the winter gravel project, summer work will include some hydrology studies and standard post-season surveying and cleanup activities to ensure there is no damage or litter remaining from the winter program."

No more North Slope exploration wells are planned until market conditions improve, Oil Search said.

Upgraded resource potential

Adding to the company's good news, was the completion of a "very successful" two-well (plus sidetrack) winter exploration season on Alaska's North Slope in second quarter, which Oil Search said, "upgraded resource potential" close to the proposed central processing facilities for the Pikka unit development.

The well drilled close to those facilities was Mitquq 1 with the Mitquq 1 ST1, which is 5.6 miles east. The well encountered a net pay zone of 172 feet with a gas cap of 29 feet in the Nanushuk formation. On test, it flowed at a stabilized rate of 1,730 barrels of oil per day from a single stimulated zone.

Oil Search said high quality oil in a deeper Alpine reservoir at Mitquq was also discovered but not tested.

The Stirrup 1 exploration well, approximately 7.5 miles west of the 2017 Horseshoe 1 discovery well and 22 miles southwest of the proposed Pikka development, encountered an oil column in the Nanushuk reservoir with net pay of 75 feet. On test, Stirrup 1 flowed at a stabilized rate of 3,520 bopd from a single stimulated zone.

Stirrup is a direct analogue to the Horseshoe 1 Nanushuk discovery and as such the company has said it could underpin a possible standalone Horseshoe development. Or, it could represent a low cost tie-back option to Pikka.

Flow tests in both wells included a cleanup, flow period and a pressure buildup prior to the final test to assess well deliverability.

"These results have materially upgraded the ultimate prospectivity and optionality of our Alaskan portfolio and are being integrated into asset appraisal and development plans," Oil Search Managing Director Keiran Wulff said July 21. "Value engineering and optimization studies, aimed at reducing upfront capital expenditure and ensuring that the Pikka development is cost competitive and commercially viable in a lower price environment, are progressing well."

Oil Search, he said, is now focusing on "completing the Strategic Review, which will help redefine our long-term strategy," taking into account market developments, shareholder expectations and revised commodity price forecasts.

"Our aims are to simplify and de-risk existing operations, maintain balance sheet strength, prioritize capital expenditure and develop clear pathways to maximize shareholder value. We look forward to updating the market on the outcome of the review in the fourth quarter of 2020," Wulff said.

—KAY CASHMAN

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Petroleum news

Oil Patch Bits

C&R Pipe and Steel expands its equipment and inventory

C & R Pipe and Steel in Fairbanks, Alaska, said recently that it has been working towards better serving the oilfield industry by expanding its inventory and obtaining high end equipment.

The company said it has recently added a Messer MetalMaster 2.0 to its arsenal of equipment. The addition of this high-end CNC cutting table allows C & R Pipe and Steel to process plate up to 1 5/8-inch in high definition giving precision cutting when it comes to cutting holes in a true hole diameter.

The machine is high-performance with cutting at 114 feet per minute with the utmost accuracy, whether while cutting with plasma, or with oxyfuel. The Hypertherm Powermax 125 plasma torch, on the cutting table, can cut steel, aluminum, or stainless plates.

This machine will allow C & R Pipe and Steel a great advantage when it comes to processing plate in the interior for the oilfield industry. It was a welcomed addition to the vast inventory of C & R Pipe and Steel's yard.

For more information visit http://crpipeandsteel.com/.

COURTESY C&R PIPE AND STEEL

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WARY MOOD

Hesitancy on recovery

The leaders of Suncor and Cenovus, two of the Canadian industry's most trusted voices, are hesitant about committing to a recovery strategy.

"I'm wary to say the worst is behind us," said Cenovus Chief Executive Officer Alex Pourbaix, after reporting his company posted a net loss in the second quarter of C$235 million, compared with earnings of C$1.8 billion a year earlier.

He bluntly declared that Cenovus is "not counting on a big demand recovery to save our bacon."

"We're on the road to recovery from the low point of the downturn in April, though we expect commodity price volatility for the foreseeable future."

For now, he said Cenovus has applied itself to driving down costs and capital spending, even if the price environment improves.

Pourbaix said Cenovus was supported by its ability to store crude that helped it escape the worst of the spring price collapse, combined with seizing the opportunity to buy up production credits from other producers at "very low cost."

However, Cenovus shut in 60,000 bpd in April, although it pumped an average 400,000 bpd in the second quarter, up 8% from the same period in 2019.

Adding to debt

Cenovus and Suncor both added to their short- and long-term debts in the first half of 2020, contributing to a long-term debt of C$8 billion for Cenovus at the end of June.

Suncor's short-term debt rose to C$3 billion at the end of June, up C$900 million from the end of 2019, while its long-term debt climbed to C$16 billion from C$12.9 billion over the same period. The company posted a net loss of C$614 million in the second quarter compared with net earnings of C$2.7 billion a year earlier.

"We knew that the second quarter would be challenging ... certainly the most challenging in our modern history," said Suncor Chief Executive Officer Mark Little.

But he and other Suncor executives doubted the company will take on more debt through the second half of 2020, although Little was unwilling to commit to a strategy amid volatility in crude markets.

Crude-by-rail exports down

Reduced oil demand and a sharp easing of pipeline congestion has landed heavily on Canada's railroads, with crude-by-rail exports plunging to their lowest levels in four years in May.

The shipments were down 63% in May from April at 156,242 bpd, a stunning descent from an all-time high of 411,991 bpd in February.

The slump in oil demand in the United States forced Canadian shut-ins of about 1 million bpd, while Enbridge, operator of the Mainline (the largest pipeline network in North America), said throughout on that system was down 400,000 bpd in April, compared with a normal first-quarter average of 2.84 million bpd.

The joint price and demand nosedive contributed to a fall in Canadian production to 4.4 million bpd in May, the lowest output since mid-2016 when wildfires in northeastern Alberta crippled oil sands operations. ●

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POWER POOL

tricity ratepayers are compensated for the amount that the price that Chugach Electric pays for ML&P exceeds ML&P's book value.

The proposed power pool will only go into effect if Chugach Electric completes its purchase of ML&P. And the pooling agreement requires approval from the MEA and Chugach Electric boards.

Chugach Electric, ML&P and MEA had previously proposed a power pooling agreement in January 2017. However, that agreement was placed on hold, pending the proposed purchase of ML&P by Chugach Electric.

The key component of the tight power pool is the operation of a central function for managing the dispatch of power across both utilities, and to manage transactions involving the sale and purchase of energy with entities outside the power pool.

A variety of power plants

The utilities own and operate a combination of new, efficient generation plants, and older less efficient units. In particular Chugach Electric and ML&P jointly operate the Southcentral Power Project, a modern combined cycle, gas fired power plant in Anchorage. ML&P operates its modern Plant 2A combined cycle, gas fired plant, also in Anchorage. MEA has the Eklutna Generation Station, a modern power plant that uses gas-fueled reciprocating engines for power generation.

The utilities also obtain hydropower from Bradley Lake on the Kenai Peninsula and from the Eklutna hydroelectric power plant, just north of Anchorage. Chugach Electric purchases wind power from the Fire Island Wind Project, offshore Anchorage. MEA also uses some other hydropower and some solar power.

Presumably the ML&P acquisition would, in itself, result in the economic dispatch of power generation within the consolidated utility. However, the power pool with MEA would reduce the overall cost of fuel gas for the utilities by maximizing the optimum use of the more modern and efficient gas-fired units. Power pooling would also reduce operations and maintenance costs. Under the terms of the agreement, the utilities would equally share the net cost savings from the power pooling. And neither utility would charge the other for the transmission of power involved in pooling transactions across their networks.

Chugach Electric told the commission that the power pooling agreement will likely result in annual cost saving across the utilities of $4 million to $6 million. For Chugach Electric that would translate to a net operating cost reduction of $1.8 million to $2.8 million, a cost savings equivalent to an electricity rate reduction of 0.5 to 0.7%. Chugach Electric would incur an upfront implementation cost of about $300 million for establishing the power pool arrangements.

The utility is asking the RCA for approval in time to enable pooling transactions to begin no later than April 30, 2021 — that would be six months after the anticipated close of the ML&P acquisition on October 30, 2020.

Implementation period

An 18-month implementation period for the power pooling would start upon close of the ML&P purchase. Testing of the power pool arrangements would take place during the first six months of this period. The power pooling would then go into operation, with the remainder of the implementation period providing opportunities to further refine the pooled operations, agree on the combined load balancing area boundaries, and finalize dispatch and settlement arrangements for the pooled operations.

Given inherent uncertainties in the ultimate financial impacts of the pooling arrangements, the utilities plan to continuously monitor the efficiencies and cost savings achieved, with the possibility of modifying the pooling agreement to address any issues that may arise. Ultimately, if adequate benefits cannot be achieved, either utility can cancel the agreement. The utilities also reserve the right to terminate the agreement if the RCA seeks to impose conditions on the agreement that are unacceptable to the utilities.

—ALAN BAILEY

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HILCORP EXPLORATION

ny's exploration plans: Covid-19 restrictions and the challenge of securing funds for oil and gas exploration and development.

Seeking partners

Both Hilcorp and the Alaska Department of Natural Resources had booths at NAPE in early February 2020, before the oil price crash and before much was known about the coronavirus. DNR Commissioner Corri Feige, who spent time at Hilcorp's booth discussing the company's Cook Inlet and North Slope prospects, talked to Petroleum News after the annual prospect conference and expo.

Among other things, "We talked about as cold as this winter has been they have been producing all out so they're very excited about new Cook Inlet gas prospects," she said, as well as "the new prospects they have down in the southern waters in Lower Cook Inlet."

Feige said Hilcorp officials are "feeling very bullish about both oil and gas down there. They were actively talking to people visiting their booth about it."

On hand in the Hilcorp booth were four geoscientists and landmen knowledgeable about opportunities in Alaska: Kevin Tabler, Jim Shine, Dave Buthman and Steve Dietz.

"We've seen a shale mania craze at the last several NAPEs, but now we are seeing a shift. Companies are looking for ways to balance their portfolios … to get conventionals back in the mix … and Alaska has an abundance of those," Feige said.

Looking at Hilcorp's various agency filings, the company's next Cook Inlet basin exploration well will most likely be onshore near Anchor Point at Whiskey Gulch, but the company has other more distant opportunities, such as the Iniskin Peninsula, outer continental shelf leases in Lower Cook Inlet and the 1002 area of the Arctic National Wildlife Refuge where the KIC well and Native leases it shares with Chevron give Hilcorp valuable insights on the area's potential.

Iniskin Peninsula

With a huge geologic anticline clearly visible from the air and associated surface oil seeps, the Iniskin Peninsula across Cook Inlet from Kachemak Bay seems an obvious target for oil exploration. But, since wells drilled in the early 1900s, in the 1930s and in the 1950s failed to make a commercial oil discovery in the area, the peninsula has remained dormant from the perspective of petroleum exploration.

Until, that is, 2013 when Hilcorp signaled its interest by shooting a 2D seismic survey there, a survey that for the first time revealed some information about the Iniskin Peninsula's subsurface structure and stratigraphy.

On May 23, 2017, during the Association of American Petroleum Geologists Pacific Region annual conference, Hilcorp geologist David Buthman said the company is encouraged by what it has seen on the peninsula and would be interested in drilling an exploration well there in the future.

The drilling conducted in the '30s and '50s had reached depths of 8,775 to 11,231 feet in the "up-plunge" or higher section of the anticline on the peninsula. Although oil was encountered, the flow rates were deemed to be too low for viable development, Buthman said. But modern development techniques open the area's possibilities of development, he said, noting the large thicknesses of the rock units with oil potential compensate for the poor rock permeability.

STEVE SUTHERLIN

Rig 169 at Seaview Pad during the drilling of the Seaview No. 8 discovery well, which was completed in December 2018 to a vertical depth of 10,148 feet.

55,000-acre prospect

The Iniskin prospect consists of a 55,000-acre structural closure, with two potential oil and gas reservoirs, 1,292 feet and 300 feet thick, in the Middle Red Glacier formation, part of the Jurassic Tuxedni group that sourced most of the oil in the Cook Inlet oil fields. These are mudrocks within the thermal window in which oil may be generated — they could provide tight oil targets.

The rocks have fractures that follow characteristic orientations and could transport fluids. And the nature of the rocks seems similar to the Wolfcamp shale, a tight oil source in the Permian basin of Texas, Buthman said. In addition, there are known to be numerous oil-saturated, low permeability, low porosity sandstones in the region of the Iniskin Peninsula that could make other targets.

Volcanic breccia and sandstones within the Lower Red Glacier formation also appear to provide highly prospective conventional targets.

Offset crest

Moreover, Hilcorp's seismic data on the Iniskin Peninsula indicate that the anticline on the peninsula has a surface crest offset to the west relative to the crest of the deeper structure. Consequently, the wells that were drilled into the structure many years ago missed that deeper crest, Buthman said.

He also commented that live oil was observed in eight of the seismic shot holes that were drilled on the crest of the surface structure in conjunction with Hilcorp's seismic survey.

Asked about the prospects of further investigation, Buthman said drilling on the peninsula should be straightforward but that moving the equipment and personnel to the remote location, negotiating the Cook Inlet tides at the landing point with a barge, would be difficult.

Survey approved

Of seemingly more interest to Hilcorp is its nearby acreage in the federal waters of the Lower Cook Inlet, southwest of Kachemak Bay

On May 1, 2020, the Bureau of Ocean Energy Management announced that it had issued a permit allowing Hilcorp to conduct a geohazard site clearance survey the area. The approximately 88 square-mile survey area covers portions of 11 of 14 OCS leases that Hilcorp obtained in a June 2017 federal OCS lease sale. A geohazard survey of this type is an essential prerequisite to the drilling of offshore exploration wells. Federal regulations require a hazard evaluation to be conducted over the entire area within about 1.5 miles of a well site.

BOEM said that Hilcorp expects to begin the surveying in late summer 2020 and that the survey operations must be completed by Oct. 31, 2020. The exact length of the survey timeframe will depend on the weather and on any schedule adjustments needed to accommodate the protection of marine mammals, the agency said.

A geohazard survey vessel will conduct the operation, with data being collected using equipment mounted on and towed behind the vessel. In addition to using shallow seismic equipment such as sidescan sonar, Hilcorp anticipates collecting water and seabed sediment samples, while also collecting cores from the seabed, BOEM's approval document said.

Trained observers on the vessel will monitor for marine mammals, to ensure that appropriate measures can be taken to avoid wildlife disturbance.

Environmental assessments

BOEM said that it had originally conducted an analysis of the potential environmental impacts of Hilcorp's likely activities, including the geohazard survey, when preparing an environmental impact statement for the 2017 Lower Cook Inlet lease sale. The agency determined that this analysis was sufficient to enable approval of Hilcorp's survey permit application without further review.

In July 2019, the National Marine Fisheries Service issued a letter of authorization for the unintended disturbance by Hilcorp of marine mammals during the company's anticipated oil and gas activities throughout the Cook Inlet over the following five years. Those activities include conducting a 3D seismic survey in the Lower Cook Inlet in 2019 or 2020; conducting an OCS geohazard survey in the Lower Cook Inlet in 2020 or 2021; and drilling two to four exploratory wells between February and November in 2020 through 2022.

Each well would take 40 to 60 days to complete and would require a jack-up rig, the letter of authorization said. The newly approved plan for the geohazard survey encompasses five potential well locations.

Seismic, jack-up

Hilcorp conducted its planned offshore 3D seismic survey during the summer of 2019.

In March 2019, Buthman said Hilcorp was working to bring the Seadrill West Epsilon jack-up rig to Cook Inlet for the drilling. There are two jack-up drilling rigs currently stationed in the Cook Inlet region: the Spartan 151 and Randolph Yost. But both rigs are apparently limited to maximum water depths of 150 feet.

Mike Dunn, Hilcorp development manager, said that the West Epsilon rig can drill to subsurface depths of 25,591 feet in water depths up to about 393 feet.

Highly prospective

Although some distance south of most of the producing Cook Inlet oil and gas fields, the area of the planned drilling is north of the Augustine-Seldovia arch, a geologic structure to the south of which the thick Tertiary rock sequence hosting the producing fields of the region thins out.

The successful Cosmopolitan oil field lies under the nearshore waters of the Inlet immediately to the northeast, near where Hilcorp is planning to develop its new Seaview gas field. Underneath the Tertiary sequence lies a thick sequence of Mesozoic strata that also have known oil potential.

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HILCORP EXPLORATION

Buthman said Hilcorp is particularly interested in what it refers to as the Blackbill prospect, an oil prospect penetrated by ARCO's Raven No. 1 well in 1982. The prospect, about halfway across the inlet, due west of the town of Homer, contains a known oil resource in a Cretaceous reservoir within the Mesozoic sequence, Buthman indicated. He said that Hilcorp's 2019 3D seismic survey had revealed a 65,000-acre, four-way closure with the oil discovery at the top.

Anchor Point gas fever

While Hilcorp employs a host of modern high tech and traditional exploration techniques, its study of drainage anomalies on the Kenai Peninsula led the way to the Anchor Point area.

The Swanson River field discovery by Richfield in the late 1950s is credited with sparking the modern oil industry in Alaska, which in turn built the case for statehood.

Soldotna Creek wraps around the main producing part of the Swanson River field, Buthman said in a March 17, 2020, presentation.

"It's hard to avoid seeing the importance of drainage anomalies when you see this," Buthman said. "A full half of the production of Swanson River has come from this circular drainage anomaly."

Happy Valley has a nosing drainage anomaly where Deep Creek flows that reveals a surface expression of the structure, he said.

"The discovery we just made at Seaview, you see the same sort of thing with the Anchor River," he said. "We don't have outcrops there, but we still see the same nosing."

Over the last few years, Hilcorp has been securing mineral rights around the Anchor River from the state as well as from private mineral holders and public entities.

The company has drilled several stratigraphic test wells at Whiskey Gulch on the southern Kenai Peninsula just north of Anchor Point, including some in June 2020.

Petroleum News sources indicate Hilcorp is in the process of finalizing a location to drill its first Whiskey Gulch exploration well; something the company is hoping to do in 2021. Hilcorp would not confirm that information.

ANWR 1002 area

Through its 2020 purchase of all BP's upstream oil and gas assets in Alaska, Hilcorp has unique access to valuable geological data regarding the ANWR 1002 area, which is a 1.57-million acre strip of coastline that was set aside because of its petroleum potential by Congress in 1980 when the 19 million-acre wildlife refuge was created.

Operator Chevron and BP were 50-50 partners in the KIC No. 1 well, which was drilled in the mid-1980s and remains the only well in the 1002 area. The well was drilled over two winter seasons to a depth of 15,193 feet at a cost of more than $40 million. It is on 92,000 acres of Native land within the 1002 area that the partners leased from Arctic Slope Regional Corp., which owns the subsurface oil and gas mineral rights, with the village corporation in the area, Kaktovik Inupiat Corp., owning the surface; hence the well name KIC.

The BP acquisition also means Hilcorp is part of a consortium of companies that have access to 2D seismic data in ANWR, along with Chevron, Anadarko, ConocoPhillips, ExxonMobil, Hess, Marathon, Murphy, Oxy, Shell and Total.

In addition to BP, Chevron and ASRC, a handful of state of Alaska geoscientists have been able to see KIC well data.

When BP and Chevron renewed the 92,000-acre Native lease in 1999, Neil Ritson, then-exploration vice president for BP in Alaska, was quoted as saying, "ANWR offers the greatest potential for a world-class oil discovery on the North Slope."

Quoted in the same press release Dave Birsa, then Chevron's exploration manager for Alaska, said what state geoscientists have continued to echo: "The ANWR coastal plain … is on trend with the prolific oil fields of the central North Slope and has significant geological potential." ●

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OIL PRICES

what oil prices do. An unexpected event can impact prices very quickly, and radically, as we've seen this spring. After such a season of calm, perhaps a squall is overdue.

If prices begin to move in a meaningful way, there likely will be volatility, especially in the short term, as the markets shake off lethargy.

No lack of market forces

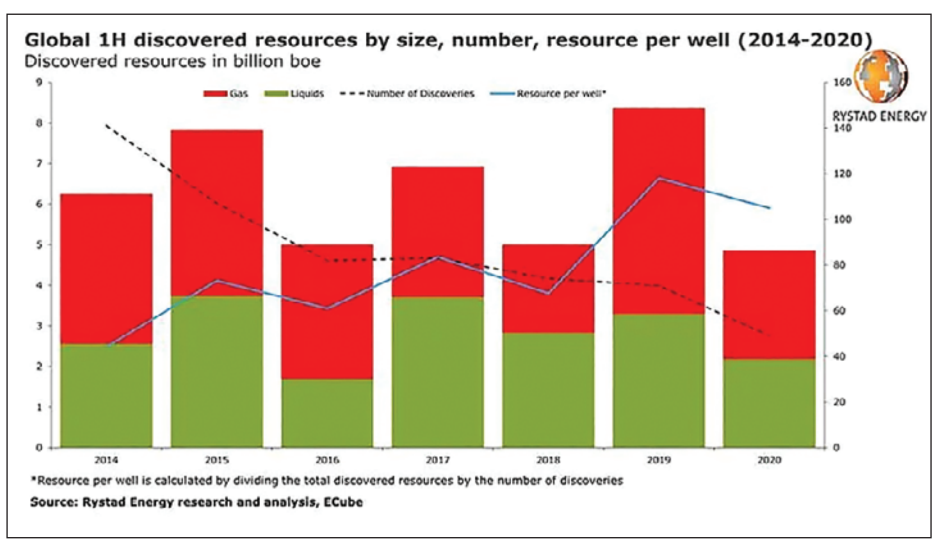
The calm price atmosphere may not, however, signal a lack of forces buffeting the markets, but rather a plethora of countervailing forces imposing on the price action.

The Organization of the Petroleum Exporting Countries has been active in 2020, with Russia and a few other cooperating countries flooding the markets in March, and later instituting a record 9.7 million barrel per day production restraint in May, June and July. OPEC plans to ease up on the production cuts in August, with the expectation that demand will improve.

In the United States, much unconventional production has become uneconomic at lower prices, putting the lid on new drilling and completions in the shale patch. Marginal conventional production has been shut in.

Petroleum inventories have waxed and waned.

Oil companies worldwide have slashed capex spending, and projects have been delayed or scrapped, not only due to low prices but due to coronavirus restrictions in the workplace as well.



*Resource per well is calculated by dividing the total discovered resources by the number of discoveries
Source: Rystad Energy research and analysis, ECube

On the demand side coronavirus restrictions have gutted the market for transportation fuels.

And the coronavirus itself has been a persistent foe. Just as human activity begins to ramp back up, COVID-19 flares up and spreads. New governmental restrictions and fears of the illness continue to keep oil demand in check.

COVID-19 has no cure or vaccine, but the medical community is learning more about how to treat it, some treatments have been successful and optimism is high for new medicines and new vaccines.

Given the depressed price level found now, higher seems like the logical path for prices. Even as non-oil powered transportation is adopted, pent-up demand around the world for a middle-class lifestyle remains a long-term tailwind for oil prices.

When will the doldrums end?

Most traders see higher oil prices in the future. The burning question, as always, is 'when?'

A new Rystad Energy analysis predicts that a partial return of curtailed OPEC+ oil production beginning in August will create a new four-month supply glut of around 170 million barrels that won't be balanced by demand until December.

"The analysis is based on the assumption that oil demand will not rebound as quickly as previously thought due to the persistent expansion of the COVID-19 pandemic in key markets, or what we call a mild second wave of the virus," Rystad said in a July 28 release.

The set-up for the OPEC+ production increase seems favorable.

Early in 2020 global oil production was high compared to market demand, but in June global stocks saw some relief of 2.2 million bpd of implied oil inventory draws, Rystad said, adding that July is also "set to end with demand surprisingly exceeding supply by 1.9 million bpd."

But total liquids demand levels from August to October will stay flat at around 90.5 million bpd, before rising to 92.9 million bpd in November and 94.6 million bpd in December, Rystad said.

Global oil supply reached an "astonishing low" of 86.4 million bpd in June, and will finish July at approximately 88.2 million bpd, Rystad said. The increase from OPEC+ and the reactivation of other global shut-in production is forecast to push supply to 91.2 million bpd in August, 92.5 million bpd in September, 92.9 million bpd in October and 93.3 million bpd in November, before closing at 93.4 million bpd in December.

"We doubt that the market can take the additional production volumes from OPEC+ from August without negative consequences for oil prices," said Bjornar Tonhaugen, Rystad head of oil market research.

But perhaps the doldrums will persist until prices rise at Christmas. OPEC's market monitoring committee will be reassessing the market on a monthly basis. ●

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