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page 3 April ANS production down 1.9% from March; inlet crude down 13%

Conoco drilling at GMT2 in NPR-A with first production by year end

ConocoPhillips Alaska spud its first development well at Greater Mooses Tooth 2 in the National Petroleum Reserve-Alaska on April 27, the company told the Alaska Oil and Gas Conservation Commission May 25 in a hearing on an application for pool rules for the Rendezvous oil pool at GMT2.

Production engineer Dana Glessner said the first development well at GMT2 was spud April 27, following two construction seasons, with final installation of facilities and pipelines this year and first production and injection expected in the fourth quarter.

Rendezvous is ConocoPhillips' second development in the Greater Mooses Tooth unit, 8 miles southwest of the initial development at GMT1, the Lookout oil pool, she said.

Exploration drilling occurred in the area in 2000-04 with

see **GMT2 DRILLING** page 9

88 Energy releases more Merlin 1 well data; ELKO gets more shares

ERIK OPSTAD

In a May 25 operations update, 88 Energy Ltd. said costs associated with this past winter's Merlin 1 North Slope exploration well "have now been largely finalized," with the company's share of the costs estimated to be US$9 million, "inclusive of wireline costs and additional costs associated with operational issues during the wireline program."

Along with a partial cash payment, the lead contractor on Merlin 1, ELKO International LLC, is being issued 345 million new ordinary 88E

see **WELL DATA** page 11

LNG takes another blow in BC as Kitimat project looks for buyers

The once head-spinning pioneering days of LNG development in British Columbia, when former Premier Christy Clark touted as many as 20 projects and predicted three large scale ventures would be onstream by 2020, have turned into a head numbing experience.

Virtually all of the proposed schemes carrying combined investments of well over C$100 billion have disappeared almost as fast as they surfaced.

That leaves the C$40 billion Shell-led LNG Canada, which has four Asian partners, and is moving ahead with construction of its terminal, while a TC Energy pipeline from northeastern British Columbia gas fields is proceeding. The anticipated startup

see **KITIMAT PROJECT** page 8

Piling on: IEA adds to Canadian upstream anti-fossil fuel problems

Canadian petroleum producers have been getting increasingly dumped on for their environmental performance despite success in curbing greenhouse gas emissions and setting aggressive net-zero targets.

The word in Calgary office towers is that lenders are rapidly divesting themselves of stakes in upstream operators and refusing to answer the call for help from small companies which have been pushed to the brink of oblivion.

Compounding the industry troubles, insurance companies, under mounting pressure from environmentalists and First Nations, are turning down applications to renew policies of pipeline builders such Trans Mountain and Coastal GasLink and to provide coverage for expansion and greenfield projects.

see **PILING ON** page 10

EXPLORATION & PRODUCTION

An Alaska venture

HEX Cook Inlet moving ahead with re-invigorating Kitchen Lights gas field

By ALAN BAILEY

For Petroleum News

JOHN HENDRIX

Having completed its purchase of Furie Operating Alaska and on July 1 taken over operatorship of the Kitchen Lights gas field in Cook Inlet, HEX Cook Inlet LLC is forging ahead with re-invigorating the field, John Hendrix, CEO and president of HEX, told the board of the Alaska Industrial Development and Export Authority on May 19.

Hendrix emphasized his company's focus on establishing HEX as an Alaska company — the company now has 21 employees who are Alaska residents and just two employees from out of state. Prior to the takeover, Furie had just one full-time Alaska employee, Hendrix said.

The Kitchen Lights field produces gas through the Julius R offshore production platform, delivering the gas to onshore processing facilities on the Kenai Peninsula through a 15-mile subsea gas pipeline.

HEX is 100% owned by Alaskans and is the only Alaska oil and gas company operating in the state, Hendrix said. Although HEX has retained Furie Operating Alaska as the legal name of the company operating the field, Furie, and its associated companies, are now wholly owned by HEX.

see **KITCHEN LIGHTS** page 7

FINANCE & ECONOMY

China stokes demand

New China tax sets crude buyers on hunt to replace feedstock hit by levies

By STEVE SUTHERLIN

Petroleum News

Alaska North Slope crude gained 17 cents May 26 to close at $67.94, while West Texas Intermediate added 14 cents to close at $66.21 and Brent added 22 cents to close at $68.87. The day marked the fourth trading day in a row of gains for the indexes as they broke upward from a savage three-day swoon that saw Brent testing the $70 mark May 18 before reversing to close at $67.42 for a loss of 75 cents on the day.

Prices continued sharply downward May 19 and May 20, a drop which analysts attributed to jitters over surging COVID-19 cases in Asia, as well as inflation concerns on the United States.

ANS sunk to a close of $64.12 May 20, before decisively snapping the downtrend May 21 with a rise of $1.41 to close at $65.53, while WTI gained $1.53 to $63.58 and Brent gained $1.33 to $66.44.

The rise followed a report of planned tax adjustments in China expected to boost its crude imports and raise refinery run rates across the nation.

From mid-June, China will introduce a levy on inbound flows of three oil-related items — bitumen mix, light-cycle oil and mixed aromatics — that are used to make low-quality fuels or processed in refineries, Bloomberg reported May 20. The prospect of costlier products sent Chinese buyers after barrels of suitable crudes to make

see **OIL PRICES** page 12

GREEN ENERGY

Surf's up for GeoAlaska

Part 1: Craig gets Northwest Mount Spurr geothermal exploration license

By KAY CASHMAN

Petroleum News

PAUL CRAIG

1 2 SERIES

The potential for new zero carbon geothermal energy development in Alaska has surfaced again, this time with a long-time oil and gas investor/entrepreneur, Anchorage-based Dr. Paul Craig.

On May 24 the Alaska Department of Natural Resources' Division of Oil and Gas issued the Northwest Mount Spurr two-year geothermal prospecting permit to GeoAlaska LLC, 100% owned by Craig. His permit, or license, covers three state tracts on 6,376 acres northwest of Trading Bay and approximately 40 miles west of Tyonek on the southern flank of Mount Spurr, an active volcano to the west of upper Cook Inlet, about 80 miles west of Anchorage.

The two-year permit can be extended for a third year if GeoAlaska has been unable to discover a viable geothermal resource despite reasonable diligence in conducting exploration activities. And then it can be rolled into a state geothermal lease, which is like an oil and gas lease in that it can be extended if the acreage is in production.

"I haven't switched industries. For 28 years I have been in the energy industry," Craig told

see **SPURR GEOTHERMAL** page 7

● EXPLORATION & PRODUCTION

Hilcorp files with DEC for jack-up use

By KRISTEN NELSON

Petroleum News

Hilcorp Alaska has applied to the Alaska Department of Environmental Conservation for supplemental development drilling at its Tyonek Platform in northern Cook Inlet using the Spartan 151 mobile offshore drilling unit or a similar MODU.

DEC said in a notice of review for an Alaskan Pollutant Discharge Elimination preliminary draft individual permit that the company is applying for oil and gas drilling activity related wastewater discharges at the Tyonek Platform from drilling intended to increase gas production at the facility.

On May 20 the Alaska Department of Natural Resources' Division of Oil and Gas approved Hilcorp's 2021 plan of development for the North Cook Inlet unit, which produces from the Tyonek platform. In the 2021 period, the division said, the company plans to complete sidetracks of up to three shut-in wells, in addition to recompleting wells, doing well clean outs and adding perforations.

Longer-term sidetrack drilling is also planned beyond the 2021 POD period, the division said.

The 2021 POD covers July 1 of this year through June 30, 2022.

In its POD the company told the division four sidetrack prospects were identified in a field study at the unit but said some of those prospects probably won't be drilled in the 2021 POD period.

Hilcorp told the division it "plans further review of gas potential in the Beluga and Sterling accessible via RWO or sidetracks of existing wells," with as many as three sidetracks targeting the Beluga and Sterling proposed for the 2021 POD period.

Spartan or other MODU

DEC said that while the permit has been developed based on characterizations of wastewater from the Spartan 151 jack-up, it would allow discharges from an alternative MODU "so long as the discharge characteristics would not represent a material and substantial alteration or addition to the permitted discharges that would require different permit conditions."

Discharges in the permit include graywater, blowout preventer fluid, noncontact cooling water, uncontaminated ballast water and excess cement slurry.

DEC said the project involves moving the Spartan 151 jack-up to the site and cantilevering it over the existing Tyonek production platform.

Because the Spartan 151 will be physically located over the platform, DEC said associated discharges are considered to be from the platform and applicable to the existing authorization.

There are four necessary discharges not currently authorized — blowout preventer fluid, noncontact cooling water, uncontaminated ballast water and excess cement slurry — and because graywater from the Spartan 151 will be from a separate treatment unit, a graywater discharge permit is also required.

The project is expected to be completed during the 2021 drilling season, DEC said.

North Cook Inlet is one of the larger gas fields in the Cook Inlet basin, producing an average 13,933 thousand cubic feet per day, 6.3% of inlet natural gas production in April, the most recent month for which production data is available from the Alaska Oil and Gas Conservation Commission. The field was discovered by Pan American in 1962 and developed by Phillips later in the 1960s to provide natural gas for the liquefied natural gas plant Phillips and Marathon built at Nikiski.

Phillips merged with Conoco in 2001 and ConocoPhillips sold the North Cook Inlet unit to Hilcorp Alaska in 2016. ●

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● EXPLORATION & PRODUCTION

April ANS production down 1.9% from March

Milne Point, Point Thomson only North Slope fields with month-over-month increases; April Cook Inlet crude down 13% from March

By KRISTEN NELSON
Petroleum News

Alaska North Slope production averaged 490,525 barrels per day in April, down 1.9%, 9,577 bpd, from a March average of 500,082 bpd and down 1.6% from an April 2020 average of 498,422 bpd.

ANS crude averaged 437,136 bpd in April, 89.1% of ANS production, down 1.3%, 5,642 bpd, from an April average of 442,778 bpd and down 2.6% from an April 2020 average of 448,849 bpd.

North Slope natural gas liquids averaged 53,389 bpd in April, 10.9% of ANS production, down 6.8%, 3,916 bpd, from a March average of 57,305 bpd but up 7.7% from an April 2020 average of 49,573 bpd. ANS NGLs are produced from just three fields — Endicott, Northstar and Prudhoe Bay.

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

Milne, Point Thomson up

The largest per-barrel increase was at Hilcorp Alaska's Milne Point field, which averaged 34,696 bpd in April, up 5.6%, 1,852 bpd, from a March average of 32,845 bpd and up year-over-year, gaining 5.8% from an April 2020 average of 32,794.

Hilcorp has been working hard to increase production at this field since 2014, when it purchased a 50% working interest from BP and took over as operator. Hilcorp acquired the remainder of BP's interest in the field as part of its 2019 purchase of BP's Alaska assets, a sale which closed July 1.

The ExxonMobil Production Co.-operated Point Thomson field averaged 7,970 bpd in April, up 16.4%, 1,123 bpd, from a March average of 6,847 bpd but down 14.1% from an April 2020 average of 9,278 bpd. Facilities at the field are rated at 10,000 bpd, but the company has struggled to keep production at the high-pressure condensate field at that level.

Prudhoe, Kuparuk have largest declines

The biggest per-barrel decline was at Hilcorp North Slope-operated Prudhoe Bay, the Slope's largest field, which averaged 268,538 bpd in April, down 5,046 bpd, 1.8%, from a March average of 273,584, but up 3.2% from an April 2020 average of 260,289 bpd.

Prudhoe production is 81.8% crude and 18.2% NGLs, with crude averaging 219,683 bpd in April, down 0.6%, 1,308 bpd from a March average of 220,991 bpd and up 2.4% from an April 2020 average of 214,644 bpd and NGLs averaging 48,856 bpd in April, down 7.1%, 3,738 bpd, from a March average of 53,593 bpd and up 7% from an April 2020 average of 45,645 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.

Production at the ConocoPhillips Alaska-operated Kuparuk River field averaged 91,690 bpd in April, down 2.4%, 2,282 bpd, from a March average of 93,972 bpd and down 6% from an April 2020 average of 97,555 bpd.

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

Eni's Nikaitchuq field averaged 16,021 bpd in April, down 10.3%, 1,843 bpd, from a March average of 17,864 bpd and down 9.7% from an April 2020 average of 17,737 bpd.

ConocoPhillips' Colville River field averaged 46,032 bpd in April, down 1,658 bpd, 3.5%, from a March average of 47,691 bpd and down 9.5% from an April 2020 average of 50,854 bpd.

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

Eni's Oooguruk averaged 6,026 bpd in April, down 888 bpd, 12.8%, from a March average of 6,913 bpd and down 20.3% from an April 2020 average of 7,562 bpd.

ConocoPhillips' Greater Mooses Tooth in the National Petroleum Reserve-Alaska averaged 2,606 bpd in April, down 13.7%, 415 bpd, from a March average of 3,021 bpd and down 44.5% from an April 2020 average of 4,699 bpd.

The Hilcorp-operated Northstar field averaged 9,032 bpd in April, down 251 bpd, 2.7%, from a March average of 9,283 bpd and down 0.4% from an April 2020 average of 9,071 bpd. Crude oil from the field averaged 58.5% of production, 5,279 bpd in April, down 2.8%, 149 bpd, from a March average of 5,428 bpd and down 13.7% from an April 2020 average of 6,118 bpd. Northstar NGLs were 41.6% of April production at 3,753 bpd, down 2.6%, 101 bpd, from a March average of 3,854 bpd and up 27.1% from an April 2020 average of 2,953 bpd.

The Hilcorp-operated Endicott field averaged 6,606 bpd in April, down 1.2%, 78 bpd, from a March average of 6,685 bpd and down 12.4% from an April 2020 average of 7,543 bpd. Crude oil in April was 88.2% of Endicott production, averaging 5,826 bpd, down from 5,828 bpd in March and down 11.3% from an April 2020 average of 6,569 bpd. NGLs were 11.8% of production at 780 bpd, down 9%, 77 bpd, from a March average of 857 bpd and down 19.9% from an April 2020 average of 974 bpd.

Badami, operated by Savant Alaska, a Glacier Oil and Gas company, averaged 1,307 bpd in April, down 71 bpd, 5.2%, from a March average of 1,378 bpd and down 0.1% from an April 2020 average of 1,308 bpd.

Cook Inlet down 12.6%

April Cook Inlet crude and NGL production averaged 9,321 bpd, down 1,341 bpd, 12.6%, from a March average of 10,662 bpd and down 33% from an April 2020 average of 13,906 bpd.

see **ANS PRODUCTION** *page 5*

Cook Inlet gas down 4.3%

Natural gas production from Cook Inlet averaged 220,959 thousand cubic feet per day in April, down 9,897 mcf per day, 4.3%, from a March average of 230,855 mcf per day but up 8% from an April 2020 average of 204,584 mcf per day.

The inlet production drop was driven by lower production from seven of the largest nine fields, which averaged a combined 193,908 mcf per day in April, down 5.2% from a March total of 204,589 mcf per day. Those fields accounted for 87.8% of inlet gas production in April, compared to 88.6% in March.

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

The largest month-over-month drop was at Hilcorp's Kenai gas field, accounting for 21.7% of production, which averaged 47,954 mcf per day in April, down 8.6%, 4,510 mcf per day, from a March average of 52,465 mcf per day but up 43.7% from an April 2020 average of 33,368 mcf per day.

The Hilcorp-operated Beluga River field averaged 20,980 mcf per day in April, 9.5% of inlet production, down 2,787 mcf per day, 11.7%, from a March average of 23,767 mcf per day but up 15.3% from an April 2020 average of 18,204 mcf per day.

Hilcorp's Ninilchik field averaged 28,658 mcf per day in April, 13% of inlet production, down 1,690 mcf per day, 5.6%, from a March average of 30,348 mcf per day, and down 16.5% from an April 2020 average of 34,313 mcf per day.

Hilcorp's Swanson River averaged 18,963 mcf per day in April, 8.6% of inlet production, down 1,055 mcf per day, 5.3%, from a March average of 20,019 mcf per day and down 40.9% from an April 2020 average of 32,067 mcf per day.

Hilcorp's North Cook Inlet averaged 13,933 mcf per day in April, 6.3% of inlet production, down 6.8%, 1,016 mcf per day, from a March average of 14,949 mcf per day but up 8.5% from an April 2020 average of 12,839 mcf per day.

Hilcorp's McArthur River averaged 26,380 mcf per day in April, 11.9% of inlet production, down 437 mcf per day, 1.6%, from a March average of 26,817 mcf per day but up 26.7% from an April 2020 average of 20,819 mcf per day.

Hilcorp's Ivan River averaged 10,466 mcf per day in April, 4.7% of inlet production, down 377 mcf per day, 3.5%, from a March average of 10,832 mcf per day, but up 2,919.2% from an April 2020 average of 346 mcf per day.

Two of the nine largest producers had month-over-month increases.

see **INLET GAS** *page 5*

EXPLORATION & PRODUCTION

Weekly US rotary rig count up by 2 at 455

The Baker Hughes U.S. rotary drilling rig count, 455 on May 21, was up by two from 453 the previous week and up by 137 from a count of 318 a year ago.

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

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

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

Baker Hughes shows Alaska with four rigs active May 21, unchanged from the previous week and up by one from a year ago, when the state's count stood at three.

The May 21 count includes 356 rigs targeting oil, up by four from the previous week and up by 119 from 237 a year ago, 99 rigs targeting gas, down by one from the previous week and up by 20 from 79 a year ago, and no miscellaneous rigs, down by one from the previous week and down by two from a year ago.

Twenty-eight of the rigs reported May 21 were drilling directional wells, 412 were drilling horizontal wells and 15 were drilling vertical wells.

Alaska rig count unchanged

The Oklahoma rig count (26) was up by four from the previous week and New Mexico (72) was up by two.

Louisiana (53) and Texas (214) were each down by two rigs from the previous week.

Counts in all other states were unchanged from the previous week: Alaska (4), California (6), Colorado (10), North Dakota (16), Ohio (10), Pennsylvania (19), Utah (9), West Virginia (11) and Wyoming (4).

Baker Hughes shows Alaska with four rigs active May 21, unchanged from the previous week and up by one from a year ago, when the state's count stood at three.

The rig count in the Permian, the most active basin in the country, was unchanged from the previous week at 231 and up by 69 from a count of 162 a year ago.

—KRISTEN NELSON

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● EXPLORATION & PRODUCTION

Hilcorp applies for Seaview pool rules

By KRISTEN NELSON
Petroleum News

Hilcorp Alaska has applied to the Alaska Oil and Gas Conservation Commission for pool rules for its Seaview gas field on the southern Kenai Peninsula, discovered in 2019 with drilling of the Seaview No. 8 well.

The company has also applied for a spacing exception to allow it to drill a second well at the field since pool rules aren't yet in place.

In its April 26 application for a spacing exception to allow it to drill the Seaview No. 9, Hilcorp said the well would be drilled from the Seaview pad on privately owned property within the field, which is near Anchor Point, with drilling operations expected to begin around June 15.

Hilcorp said Seaview No. 9 would be a grassroots delineation well some 1.5 miles south of Anchor Point within the Seaview field, targeting potential gas-bearing sands in the Beluga and Tyonek formations.

Without pool rules, commission regulations require, among other things, that a well can be open for production within 1,500 feet of a property line only if the owner is the same on both sides of the line.

Seaview is in an area of the Kenai Peninsula which was homesteaded at a time when both surface and subsurface rights went to the homesteader. Properties initially homesteaded were sold in individual parcels, resulting in much of the land in the Seaview unit having subsurface ownership in private hands, although land leased by the State of Alaska for oil and gas development is also part of the unit.

Pool rules

In the May 20 pool rules hearing the company told the commission the Beluga and Tyonek formations are the main gas source at the field and said the company is planning just the single well site with two additional wells.

In a geologic report submitted prior to the hearing Hilcorp recommended that pool rules define the Seaview gas pool "as the interval from the Top of the Beluga to the base of the Tyonek."

The Seaview No. 8, which Hilcorp drilled in 2018 and completed in 2019, reached a measured depth of 10,621 feet, and that gas discovery is the bulk of the discussion for Seaview pool rules, the company said. The Sterling, Beluga and Tyonek formations are generally accepted, the company said in the geologic report, to be "part of a self-sourcing natural gas petroleum system — that is, the substantial Tertiary coal measures of the Sterling, Beluga and Tyonek formations generate dry methane gas that migrates into, and is trapped within, adjacent sandstone reservoirs."

The geologic report and an accompanying reservoir report both say that economic production will require commingling gas from Beluga and Tyonek sands and the reservoir report also says that since the gas-bearing sands are discontinuous and there will be commingling of sands within wellbores, "it will be difficult to accurately measure depletion and recovery of individual sands." ●

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GOVERNMENT

NM rules to curb emissions take effect

New Mexico's new rules to limit most venting and flaring in the oilfield as a way to reduce methane emissions are now in effect.

State officials are billing the rules, published May 25 in the New Mexico Register, as some of the strongest gas capture requirements in the nation. Unlike other states, New Mexico's rules also apply to the midstream sector, which collects natural gas from wells for processing. It took nearly two years to develop the rules. Virtual public hearings were held and state regulators heard from environmental advocates and technical experts from the industry.

The first phase of implementation begins in October with data collection and reporting to identify natural gas losses at every stage of the process. With this information, regulators will then require operators — from those that manage pipelines to smaller wells and other infrastructure — to capture more gas each year.

The target is capturing 98% of all natural gas waste by the end of 2026. If operators fail, regulators can deny drilling permits.

The rules are one part of a two-pronged approach by the state to address climate change. Still pending are rules being drafted by the Environment Department that would target oilfield equipment that emits methane, volatile organic compounds and nitrogen oxides.

—ASSOCIATED PRESS

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ANS PRODUCTION

Furie's Kitchen Lights averaged 15,421 mcf per day in April, 7% of inlet production, up 759 mcf per day, 5.2%, from a March average of 14,662 mcf per day and up 11.8% from an April 2020 average of 13,790 mcf per day.

Hilcorp's Beaver Creek averaged 11,164 mcf per day in April, 5% of inlet production, up 432 mcf per day, 4%, from a March average of 10,732 mcf per day and up 22.1% from an April 2020 average of 9,145 mcf per day.

Inlet's smaller gas producers

Of the inlet's 10 smaller producers, excluding Hilcorp's Middle Ground Shoal, which had no production following an April 1 fuel line leak, half had month-over-month increases and half had decreases.

In descending order by April production, Hilcorp's Cannery Loop averaged 4,923 mcf per day in April, 2.2% of inlet production, down 203 mcf per day, 4%, from a March average of 5,126 mcf per day but up 10.2% from an April 2020 average of 4,460 mcf per day.

AIX's Kenai Loop averaged 4,834 mcf per day, 2.2% of inlet production, up 20 mcf per day, 0.4%, from a March average of 4,814 mcf per day and down 7.6% from an April 2020 average of 5,230 mcf per day.

Hilcorp's Deep Creek averaged 4,322 mcf per day in April, 2% of inlet production, up 1,310 mcf per day, 43.5%, from a March average of 3,012 mcf per day and up 6.1% from an April 2020 average of 4,074 mcf per day.

Hilcorp's Granite Point averaged 3,644 mcf per day in April, 1.7% of inlet production, down 29 mcf per day, 0.8%, from a March average of 3,673 mcf per day and up 3.4% from an April 2020 average of 3,524 mcf per day.

BlueCrest's Hansen averaged 2,554 mcf per day in April, 1.2% of inlet production, up 183 mcf per day, 7.7%, from a March average of 2,371 mcf per day but down 26% from an April 2020 average of 3,453 mcf per day.

The North Fork field, operated by Vision Operating (formerly Gardes Holdings), averaged 3,077 mcf per day in April, 1.4% of inlet production, up 32 mcf per day, 1.1%, from a March average of 3,045 mcf per day, but down 14.4% from an April 2020 average of 3,593 mcf per day.

Hilcorp's Trading Bay averaged 2,088 mcf per day in April, 0.9% of inlet production, down 92 mcf per day, 4.2%, from a March average of 2,180 mcf per day and down 33.1% from an April 2020 average of 3,121 mcf per day.

Hilcorp's Lewis River averaged 1,111 mcf per day in April, 0.5% of inlet production, up 15 mcf per day, 1.3%, from a March average of 1,096 mcf per day and up 0.5% from an April 2020 average of 1,105 mcf per day.

Amaroq's Nicolai Creek averaged 355 mcf per day, 0.2% of inlet production, down 41 mcf per day, 10.3%, from a March average of 395 mcf per day but up 36.4% from an April 2020 average of 260 mcf per day.

Hilcorp's Nikolaevsk averaged 145 mcf per day in April, 0.1% of inlet production, down 190 mcf per day, 56.8%, from a March average of 335 mcf per day and down 22.8% from an April 2020 average of 187 mcf per day.

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

—KRISTEN NELSON

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INLET GAS

The drop in Cook Inlet production is almost entirely due to a 94.8% month-over-month drop in production from Hilcorp's Middle Ground Shoal following a fuel gas leak reported April 1 from a line connecting the Middle Ground Shoal A Platform with the MGS onshore facilities.

The company reported only one day of production from Middle Ground Shoal in April, averaging out to 64 bpd over the month, hence the drop of 94.8% from a March average of 1,226 bpd and a comparable drop of 94.8% from an April 2020 average of 1,229 bpd.

Month-over-month per-barrel changes at other Cook Inlet fields were all small by comparison.

Hilcorp's Beaver Creek averaged 215 bpd in April, down 34 bpd, 13.6%, from a March average of 249 bpd and up 31.8% from an April 2020 average of 2020.

Hilcorp's Granite Point averaged 2,709 bpd in April, down 2.8%, 78 bpd, from a March average of 2,787 bpd and down 16.1% from an April 2020 average of 3,230 bpd.

BlueCrest's Hansen field averaged 944 bpd in April, up 30 bpd, 3.3%, from a March average of 914 bpd and down 7.3% from an April 2020 average of 1,018 bpd.

Hilcorp's McArthur River, Cook Inlet's largest field, averaged 3,435 bpd in April, basically unchanged from a 3,437-bpd average in March and down 12.6% from an April 2020 average of 3,928 bpd.

Hilcorp's Swanson River averaged 979 bpd combined crude and NGLs in April, down 9 bpd, 1%, from a March average of 988 bpd and up 8.3% from an April 2020 average of 904 bpd.

Hilcorp's Trading Bay averaged 1,078 bpd in April, up 1.6%, 17 bpd, from a March average of 1,061 bpd and down 22.1% from an April 2020 average of 1,383 bpd.

With the exception of a small volume of NGLs from Swanson River, 124 bpd in April, all of Cook Inlet production is crude.

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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UTILITIES

RCA OKs CINGSA formula rate mechanism

The Regulatory Commission of Alaska has approved a formula rate mechanism whereby Cook Inlet Natural Gas Storage Alaska can make annual adjustments to the rates that it charges its customers for the storage of natural gas.

The newly approved mechanism arises from an order that the commission issued in 2018. In that order the commission expressed concern that, because CINGSA's rate base was depreciating rapidly, the company's rates were becoming misaligned with the rate base — the use of a formula rate mechanism would benefit CINGSA's customers through the use of annually updated data. The rate base, the value of a utility's assets, is a key factor in determining how much a utility charges its customers. Normally there is a multi-year lag between the tariffs that utilities file.

In the event, CINGSA proposed a formula rate mechanism involving annual adjustments to several of the factors, including the rate base, that determine the utility's rates. Following an investigation, all of CINGSA's customers except Homer Electric Association agreed to a modified version of the proposed formula. HEA objected on the grounds that the ability to annually change several parameters that determine the storage rates would reduce CINGSA's incentives to reduce its costs. However, parties to the stipulation argued that an entity questioning CINGSA's cost efficiency could request the commission to investigate.

CINGSA plays a vital role for Cook Inlet gas and electric utilities by storing excess produced gas during times of low gas demand, for use during periods of high demand, especially during the winter. Without gas storage it would not be possible to maintain adequate gas supplies for heating buildings and generating electricity during Southcentral Alaska winters. The cost of gas storage, resulting from CINGSA's rates, is factored into the rates that the utilities charge their customers.

—ALAN BAILEY

● PIPELINES & DOWNSTREAM

Judge: line can stay open pending review

By DAVE KOLPACK & JAMES MACPHERSON

Associated Press

A federal judge ruled May 21 that the Dakota Access oil pipeline may continue operating while the U.S. Army Corps of Engineers conducts an extensive environmental review.

U.S. District Judge James Boasberg made his decision after attorneys for the pipeline's Texas-based owner, Energy Transfer, argued that shuttering the pipeline would be a major economic blow to several entities, including North Dakota, and the Mandan, Hidatsa and Arikara Nation tribe, in the heart of the state's oil patch.

Boasberg said the Standing Rock Sioux had to "demonstrate a likelihood of irreparable injury" from the pipeline's continued operation for him to rule in their favor.

'Daunting hurdle'

The tribe, he said, has "not cleared that daunting hurdle."

Attorneys for the Standing Rock Sioux and other tribes say the pipeline is operating illegally without a federal permit granting easement to cross beneath Lake Oahe, a Missouri River reservoir near the Standing Rock reservation that is maintained by the Corps. They said preventing financial loss should not come at the expense of the other tribes, "especially when the law has not been followed."

"The Court acknowledges the Tribes' plight, as well as their understandable frustration with a political process in which they all too often seem to come up just short. If they are to win their desired relief, however, it must come from that process, as judges may travel only as far as the law takes them and no further. Here, the law is clear, and it instructs that the Court deny Plaintiffs' request for an injunction." Boasberg wrote.

The Standing Rock tribe, which draws its water from the Missouri River, says it fears pollution. The company has said the pipeline is safe.

"We believe the Dakota Access Pipeline is too dangerous to operate and should be shuttered while environmental and safety implications are studied — but despite our best efforts, today's injunction was not granted," Jan Hasselman, the EarthJustice attorney representing Standing Rock and other tribes, said in a statement.

The pipeline was the subject of months of sometimes violent protests in 2016 and 2017, during its construction.

The $3.8 billion, 1,172-mile pipeline began operating in 2017 and environmental groups, encouraged by some of President Joe Biden's recent moves on climate change and fossil fuels, were hoping he would step in and shut down the pipeline. But the Biden administration left it up to Boasberg, even after the judge asked the Corps to state an opinion on paper, if it had one.

Boasberg on May 21 also denied the state of North Dakota's motion to intervene. State Attorney General Wayne Stenehjem had said the Corps has abandoned its lead role in defending its decision to grant an easement for crossing the river and that the agency can no longer "adequately represent" North Dakota's interests.

Further study ordered in 2020

In April 2020, Boasberg ordered further environmental study after determining the Corps had not adequately considered how an oil spill under the Missouri River might affect Standing Rock's fishing and hunting rights, or whether it might disproportionately affect the tribal community. A federal panel later upheld the judge's ruling but did not go as far as shutting down the pipeline.

Energy Transfer estimated it would cost $24 million to empty the pipeline and preserve the structure and said maintenance of the line would cost $67.5 million every year it is inoperable.

Former President Barack Obama's administration originally rejected permits for the project, and the Corps prepared to conduct a full environmental review. In February 2017, after Donald Trump took office, the agency scrapped the review and granted permits, concluding that running the pipeline under the Missouri River posed no significant environmental issues. ●

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KITCHEN LIGHTS

In addition to Hendrix, the HEX management team consists of Chief Operating Officer Rick Dusenbery, Chief Financial Officer Kevin Hemenway, and Chief Geologist Alex Tworow.

HEX purchased Furie out of bankruptcy with AIDEA funding assistance in the form of a $7.5 million loan. The total purchase price was $34 million, Hendrix said. Hendrix emphasized his company's success in repaying the loan.

"I'm proud to say that we've paid back in the last 10 months 33% of the principal on the note," Hendrix told the AIDEA board.

Dealing with hydrates

One of the reasons for Furie's bankruptcy was a lengthy closure of the field in 2019 because of hydrate blockages in the subsea pipeline and in the onshore facility — hydrate formation resulted from the freezing of a combination of water and gas in the line. To prevent a recurrence of this type of problem, HEX has been aggressively pigging the pipeline and has established a protocol for monitoring the line for hydrate issues. In fact, the company did observe a hydrate related pressure increase in the line at one point in the past winter — the company shut the pipeline down for less than 24 hours to successfully rectify the situation, Hendrix said.

HEX has also installed a water processing facility on the Julius R platform. And in April the Alaska Department of Environmental Conservation issued a permit, allowing HEX to discharge clean wastewater from the platform. The primary purpose of the water processing is to enable gas production from the Sterling formation reservoir in the Kitchen Lights field — current production comes just from the Beluga formation. HEX now plans to conduct some testing of Sterling production.

HEX COOK INLET LLC

The Julius R platform offshore in the Cook Inlet produces gas from the Kitchen Lights field.

Operational improvements

HEX has also been reviewing the operation of the onshore processing facility, assessing the safety of the system and installing duplicated technology for blocking and bleeding the system. The company has also fixed some mis-positioning of sensors and gauges used to feed data into the control and data acquisition system for the facility. In addition the company encourages its field operators to find ways of improving operating efficiency.

"That's where we want to be, when people start owning and bringing things forward," Hendrix said.

The company has been able to reduce some of its costs by converting some unused wells previously drilled in the Kitchen Lights unit from a suspended to a plugged and abandoned status. That has eliminated about $350,000 per year in liability insurance associated with the company's contingency plan, Hendrix said. The company is also saving money by placing needed equipment on the platform, rather than repeatedly incurring the costs involved in shipping the equipment to and from the platform, he said.

Excess capacity

Hendrix commented that one of the economic challenges in operating the Kitchen Lights field results from the fact that the field facilities were designed and built to handle much larger volumes of gas than the field is currently producing. The underutilization of equipment such as gas compressors adds to the unit cost of the gas, he said. On the other hand, the company has no immediate plans for further drilling at Kitchen Lights — a new well, costing perhaps $15 million to $20 million, would draw down the company's capital. Drilling at the Julius R platform involves the hiring of a jack-up drilling rig.

The platform can accommodate up to six wells and is currently producing from four wells.

On the other hand, HEX does have available some gas that is additional to gas that the company currently has committed under contract. One particular interest is finding ways whereby this gas might be used to manufacture products in Alaska, rather than simply selling raw gas, Hendrix said.

Alaska benefits

And Hendrix emphasized the benefits that his company brings to Alaska, both in terms of local employment and in state revenues. The company pays royalties on its production to the state and others, in addition to property taxes. However, the company is challenging the level of the state property taxes, arguing that the state is significantly over valuing the company's properties. If Hex had not purchased the property, the state would have faced the loss of royalties and an abandonment liability of about $16 million, Hendrix commented.

Hendrix expressed his pride in his company's focus on benefits to Alaska, including the company's environmental stewardship. The company also supports the local Kenai Peninsula through charitable giving and sponsorships.

But Hendrix also expressed caution that, although there are further opportunities for his company, it is important for the company to first consolidate its base.

"We've got a good management team. We've got a good reservoir. And we're going to continue to try to build with what we've got," he said. ●

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SPURR GEOTHERMAL

Petroleum News in a May 26 interview.

"The scientific data regarding the atmospheric impact of Alaska's oil industry is hands down more environmentally friendly when compared with other oil fields elsewhere in the world," he said. "GeoAlaska is trying to move Alaska's energy industry one step forward into the future by creating a source of green electrical energy that has a zero-carbon footprint on the environment. We are not anti-oil. We are not anti-natural gas. We are pro-business and pro-energy, but we want to do it in a way that creates a sustainable future for our children and our grandchildren; for generations to come."

Craig said "GeoAlaska perceives Mount Spurr as the most propitious location at which to develop an Alaskan-owned and operated geothermal energy company."

The "we" in many of Craig's statements is inclusive of Erik Anderson, a consultant and innovator, who first brought Mount Spurr to his attention.

Anderson has an option to buy a minority interest in GeoAlaska in the future, having earned that option through "sweat equity," Craig said.

Enter Erik Anderson

Anderson approached Craig about two years ago. He had been working with Raser Power Systems, an Alaska limited liability corporation that was owned by Salt Lake City-based Cryq Energy, which was recently acquired by a subsidiary of geothermal energy giant Macquarie Infrastructure of Australia.

"Raser applied for a Mount Spurr exploration permit with the division, and was granted it about two months ago, but they didn't apply for the location that Erik thought was most promising. Instead, Raser applied for the surface expression geothermal hot springs at the base of Mount Spurr. Erik was encouraging Raser to think more about where the reservoir would be that was the source for those springs," Craig said.

"Erik had heard about my oil patch entrepreneurship and decided to approach me. He explained that there were some very attractive geothermal properties that were not applied for. As he educated me, the more I learned, the more I thought he had a good idea. And so, through GeoAlaska LLC we applied for 10 square miles north and west of Raser's selected acreage."

GeoAlaska's acreage "linearly follows the Capps Glacier fault and the North Bench fault," Craig said.

"North Bench fault is sufficiently close to the Crater Peak magma conduit, that a well at sufficient depth could encounter thermally charged water. The BTUs of geothermal energy that may be discovered could be substantial," he said.

Anderson, Craig said, describes himself as an earth scientist.

"Erik is brilliant mathematically and geologically. He is … highly educated, knowledgeable and is experienced in geothermal. He's well-connected with geothermal experts worldwide. He's the one, for example, who brought GeothermEX, a Schlumberger company, to my attention," he said.

"Erik has a background in hydrology.

see **SPURR GEOTHERMAL** *page 8*

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KITIMAT PROJECT

date is 2025.

Otherwise, the only apparent survivor is the C$1.6 billion electric-powered Woodfibre LNG project which is expected to make a final investment decision this fall, buoyed by its recent sales agreement with BOP.

A handful of other players with plans in the tentative stages have yet to declare their intentions.

Kitimat LNG

The scrapheap has just been expanded as the Chevron-Woodside joint venture for the C$32 billion Kitimat LNG has folded after several years of shuffling the partners and stalling on a final investment decision.

In April, Chevron said it would stop funding feasibility work on the project. That decision came 18 months after putting its assets up for sale and writing off C$2.2 billion as an asset impairment.

On May 18, Australia's Woodside announced plans to divest its 50% of the project. It had already made a $720 million write down in 2019.

There are no obvious candidates to make offers in the wake of an exodus from British Columbia's LNG sector that has included Malaysia's Petronas and ExxonMobil, two global LNG players who have been discouraged by long and contentious regulatory processes and heated opposition from environmentalists and some First Nations.

Key gas producers such as Encana (now Ovintiv), EOG Resources and Apache have also bailed out as lead players in LNG development.

Keeping Liard Basin assets

Woodside Chief Operations Officer Meg O'Neill said her company would retain its Liard Basin gas assets, straddling the British Columbia-Alberta border, the planned source of feedstock for Kitimat LNG.

She said the upstream position in the basin would give Woodside a "low-cost option to investigate potential future natural gas, ammonia and hydrogen opportunities in British Columbia."

O'Neill said Woodside had hoped to develop new LNG supplies for Asian markets later this decade but has decided instead to refocus funds on "opportunities that will deliver nearer-term shareholder value."

David Austin, an attorney who concentrates on the energy sector, told Global News the Kitimat LNG announcement is a "big deal … there aren't many active players left on the development side of the LNG industry in British Columbia."

He said Kitimat LNG may be a casualty of advances in the renewable energy sector and the development of larger batteries to store the electricity they produce.

"Potential purchasers of LNG don't want to commit to long-term contracts," especially as the cost of renewable generated electricity such as wind and power has dropped by 80% to 90% over the last decade, Austin said.

The setback to Kitimat LNG has upset a First Nations partnership representing 16 aboriginal communities in northern British Columbia.

Mark Podlasly, chair of the partnership, said his group "stands ready to support the right buyers who will treat us as a genuine partner and recognize the unique value that we can bring to the table."

—GARY PARK

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SPURR GEOTHERMAL

He has worked on various geothermal projects. … For example, he has had experience working on a very successful geothermal exploration program at Nevis in the Caribbean. And he worked on the geothermal program at DNR a few years ago and is now working as an independent consultant."

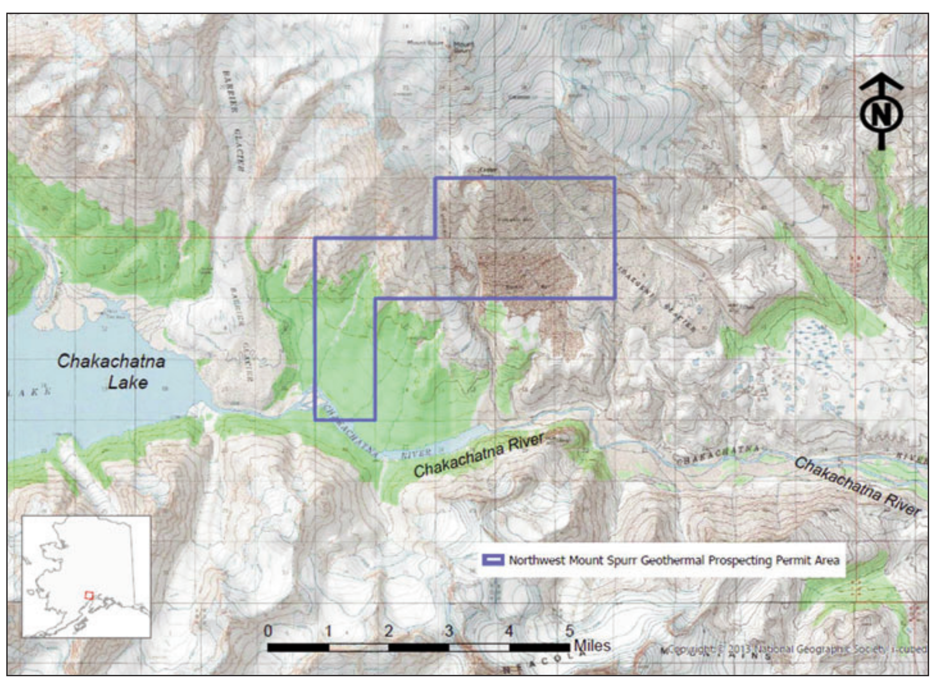
There are several other notable consultants that Anderson has brought to GeoAlaska: "Those consultants have been very helpful in terms of analyzing data and planning for exploration, financing, etc.," Craig said.

Quantitative Frontier LLC is a consulting firm owned by Anderson. On Jan. 30, 2020, when it appeared no 3D seismic was going to be acquired before the first ANWR 1004 area lease sale, Quantitative released a report titled Land Valuation by Simulated Exploration of a Probabilistic Model of the Undiscovered Oil Accumulations in the ANWR 1002 Area.

"As I said, Erik is brilliant," Craig said, who himself holds a PhD in neuropsychology.

Financing first

One of the first things on Craig's agenda now that he has the exploration license is to find financing for the project. He has been running the operation out of his "back pocket, so to speak."



ALASKA'S DIVISION OF OIL & GAS

GeoAlaska LLC's geothermal exploration permit area.

"We have multiple interested parties. We're just trying to figure out which path or paths to pursue that is in the best interest of all concerned," Craig said.

Although he didn't go into detail about what those options are, the obvious possibilities are entering into a drill-to-earn agreement, partnering with a company that has the capacity to raise the financing, and/or accessing federal programs that may help with financing or green-energy tax incentive programs that might help make the project more economically attractive to financiers.

"I like a surfing metaphor that describes our perfect timing for getting into geothermal," he said. "We started almost two years ago. It feels analogous to deciding to go surfing and heading out before sunrise while the water was still calm, and then waiting for dawn when the waves will arrive."

"Well … Surf's up! We could not have known the things that would happen in last two years. The Clean Energy Act of 2020 was two or more years in the making. Trump signed it in December 2020 when it was integrated in the Cares Act. Thirty pages of that bill was dedicated to geothermal. Then chair of the Senate Energy Committee, Lisa Murkowski, was pushing it — she and her staff, helped write those 30 pages," Craig said.

Putting it into the grid

"We will be working to tie the electricity we hope to produce into the Railbelt electrical grid," he said.

GeoAlaska already has a letter of intent with a potential and "very credible" power purchaser.

"We have a letter of understanding with a potential consumer of significant quantities of electricity. They would like their efforts to be as green as GeoAlaska wants those efforts to be. Zero carbon footprint," Craig said, noting the power purchaser is a public company with a strong balance sheet.

"They would be delighted to purchase our electricity if it can be reasonably priced," Craig said.

It is too early in the game to release the name of the potential buyer, he said.

Brand new drill rig

GeoAlaska already has identified a drilling rig — brand new and built in Alaska.

"It's a newly constructed rig. It has been designed consistent with AOGCC's requirements for drilling rigs. And the beauty of it is that it's state of the art and it's heli-portable. No component weighs more than 4,000 pounds. And it fits together like a big Lego set. It's elegant and beautiful," Craig said, noting the rig is "a remarkably well-designed piece of equipment."

The designer and builder is Anchorage-based Alaska Drilling & Completions LLC. Tim Flynn is the company's chief operating officer.

A member spotlight published by The Alliance in July 2019 said the drilling company was formed in November 2015 with the intent of providing the best-in-class drilling and completion engineering and project support services required for Alaska oil and gas exploration, appraisal and/or development campaigns.

"The company has been founded on the premise that diligent pre-planning along with sound engineering design are the keys to executing a successful project that is on schedule and on budget. The two founders of the company; Tim Flynn and David Ross, are both degreed petroleum engineers with a combined total of 60 years working in both the service and operator sectors of the oil and gas industry."

"I like a surfing metaphor that describes our perfect timing for getting into geothermal," Craig said. "We started almost two years ago. It feels analogous to deciding to go surfing and heading out before sunrise while the water was still calm, and then waiting for dawn when the waves will arrive."

Their experience includes 38 years supporting development projects and remote exploration campaigns in the Cook Inlet and on the North Slope.

Drilling to 3,000 feet

Like the rig, the drilling program GeoAlaska is designing, Craig said, will meet Alaska Oil and Gas Conservation Commission standards as well as all other regulatory requirements.

"Our exploration plan at this time is to drill to about 3,000 feet. We should hit water well before that depth. Contrary to oil and gas exploration, we're targeting fractured rock that is usually found along fault lines," he said.

Alaska Drilling & Completions "is well aware there is a risk of loss of mud when drilling into fractured rock, so we may be doing continuous coring. …. We'll certainly be selecting a drilling program that meets all of AOGCC's requirements, including using a blowout preventer that is temperature-rated for the geothermal targets we'll be drilling."

Craig quipped, "This is the first time in my life that I started a business with the hope of getting into hot water!"

More on the drilling program in the second part of this story — and more on the tremendous amount of science collected by Craig and Anderson for the project.

"We're not going into this blind," Craig said. ●

See Part 2 in the June 6 edition of Petroleum News, which will be available online late in the day Thursday, June 3.

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GMT2 DRILLING

Rendezvous 2 drilled and flow tested in 2008, followed by Rendezvous 3 in 2014.

Development in southern area

There are nine wells in the pool which are plugged and abandoned (Altamura 1, Carbon 1, Moose's Tooth C, Rendezvous 2, Rendezvous A, Spark DD-9, Spark 1, Spark 1A and Spark 4) and two suspended wells (Rendezvous 3 and Scout 1).

Although there is a gas cap at the Greater Mooses Tooth unit north of the Rendezvous oil pool, Glessner said, identified when the Spark wells were drilled, development focus is on the oil.

There are 36 initial wells planned, 18 producers and 18 injectors, with production, like that from GMT1, routed to the Alpine central facilities for final processing. A potential 12 additional wells are extended reach drilling targets.

Doyon 25 is being used for the 36-well program; Doyon 26 would be used for extended reach targets, Glessner said.

The initial 36-well development plan is horizontal wells with lateral lengths in the reservoir from 10,000 to 18,000 feet, with the northern wells to be drilled under the gas cap.

Development will be with enriched water alternating gas flood, she said, as at other Alpine reservoirs.

Geology

Development geologist Garrett Timmerman said Rendezvous is a stratigraphic trap with the Alpine sand interval, C and D, contained by Miluveach shale above and Kingak shale below, and oil sourced from the Lower Kingak.

The northern wells in the development, Timmerman said, will be drilled underneath the gas cap and terminated before intersecting the gas.

The Rendezvous 2 well is in the core of the development area, he said, with the pool interval from 8,229 to 8,393 feet measured depth.

ConocoPhillips would like both Alpine C and Alpine D to be considered for the pool, Timmerman said.

API gravity at Rendezvous is 37.2 degrees. The reservoir is a little tighter than Alpine, he said, with a little lower permeability and porosity.

Original oil in place is estimated to be 300 million to 460 million barrels, with primary recovery estimated at 20%, a range of 60 million to 92 million barrels, Versteeg said.

Within the Rendezvous pool, rock quality tends to be a little better to the north.

Glessner said they planned to begin injection with seawater and switch to produced water as that becomes available.

Estimated recovery

Reservoir engineer Joe Versteeg, discussing fluid properties, said they expected a very efficient flood.

Original oil in place is estimated to be 300 million to 460 million barrels, with primary recovery estimated at 20%, a range of 60 million to 92 million barrels, Versteeg said.

Primary recovery plus enriched water alternating gas, EWAG, flood is estimated at 35-60% of OOIP, 105 million to 276 million barrels, with original gas in place estimated at 1.7 trillion to 2.8 trillion cubic feet, with an estimated yield range of 30 to 60 barrels per million standard cubic feet.

He said production is projected out to 2050 or so, describing it as a long life, low permeability reservoir with low throughput.

The company is looking at the gas, he said, but no gas development plan has matured.

This is an oil rim only development, designed to minimize gas coning and manage the gas-oil-ratio. Versteeg said the goal is to drill the northern row of wells under the gas cap to maximize the physical offset and also to maximize injection with a target ratio of 1.0 between injection and withdrawal.

The plan is to have a couple of injectors on to start production, with gas injection to occur after six to 12 months. He said they wanted a good slug of water before beginning gas injection.

Oil production will be in a range of 20,000 to 45,000 barrels per day, with the cap on peak production the onsite production separator. He said they expected a pretty slow flood, so a slow ramp up in water production.

From the injection side they are projecting a range of 20,000 to 50,000 barrels of water per day and 20 million to 70 million cubic feet of gas.

Versteeg said projected production at GMT2 was so much lower than Alpine because of the separator constraint and the lower permeability environment than at Alpine.

Drilling plan

Drilling engineer Nina Anderson said the program for 36 horizontal wells is a similar drilling program to that at CD5. The key focus is maintaining hole conditions and wellbore stability because of the shales in the area, she said.

The initial 36 wells will be drilled with a 16-inch surface hole, she said, although 20-inch surface hole will be required for the ERD wells.

Timmerman said the thickness of the shale package in the area causes the concern with hole stability.

Metering, fluids

Glessner said AOGCC approved the GMT2 production measurement and allocation system in late 2018. She said GMT2, like GMT1, will have both a test separator and production separator on site, with production metered after three-phase separation on the drill site before transport and commingling with GMT1 and other Colville River unit pools.

In September ConocoPhillips applied to AOGCC for final measurement approval of the fiscal allocation metering system for GMT2.

Water and gas for Rendezvous pool injection will come from the Alpine central facility, and gas will be measured before leaving the Colville River unit, with gas and water injection at GMT2 also measured at each individual injector.

She said the company expects Rendezvous production to be fully compatible with Lookout, GMT1, and other Colville River pools.

Rendezvous is a close analog to the Alpine pool with both sharing a similar geologic history and the same oil charge source from the Lower Kingak.

Glessner said drilling of the initial 36 wells is expected to be completed by the end of 2024.

—KRISTEN NELSON

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PILING ON

The culmination of these efforts to put the industry in a chokehold culminated in mid-May when the International Energy Agency called for an end to spending on new developments to boost oil and natural gas supplies.

An IEA study laid out 400 “milestone” recommendations it said the world would need to pass if it hoped to achieve net-zero greenhouse gas emissions by 2050 and make a dramatic shift from reliance on fossil fuels to a global economy dominated by renewable resources.

The Paris-based IEA — rated by Alberta Energy Minister Sonya Savage as an organization dominated by “activists” — said the path to net-zero requires rapid exploitation of renewables, the establishment of carbon capture, utilization and storage projects and increased use of hydrogen.

Some recovery projected

But Alberta Premier Jason Kenney noted the IEA study still concedes that global consumption of oil will soon recover to 72 million barrels per day (down from a pre-pandemic peak of 100 million bpd) and remain at that level for several decades.

“That oil has got to come from somewhere and it has to come from new development,” he said.

“The (IEA is) suggesting that will come from OPEC rather than from western countries. I think that is the worst possible outcome.”

Wrapping himself in a patriotic flag, Kenney said he wants “the best, last barrel of oil to come from Alberta.”

What causes some serious head scratching is the IEA’s apparent about face on its World Energy Report last fall which predicted oil demand could rebound to 100 million bpd within five years, then stabilize at 104 million bpd in 2040.

Less than a year later, the IEA’s new blueprint now targets 72 million BPD by 2030 and 24 million bpd by 2050, with prices sagging to US$24 a barrel in 2050.

Allan Fogwill, chief executive officer of the Canadian Energy Research Institute, questioned whether it is realistic for the IEA to expect everyone will scramble aboard its freshly repainted wagon.

At best, he said the IEA had laid out a pathway “for some of the decisions they have to make.”

Jackie Forrest, executive director of the ARC Energy Research Institute, said one of the toughest challenges for the IEA will be to persuade governments and consumers to accept the need for a “real change” in demand habits.

The industry is more inclined to accept a projection last year by the federal government’s Canada Energy Regulator which estimated oil production in Canada will rise by 18% to 5.8 million bpd by 2039, before declining modestly over the following decade.

New technologies, efficiencies

What frustrates industry leaders in Canada is the refusal by global policy-makers to acknowledge the deployment of new technologies and efficiencies that the Canadian Energy Center estimates lowered greenhouse gas emissions per C$1 billion of Gross Domestic Product by 30% over the 2000-18 period.

IHS Markit has calculated there could be GHG reductio ns in Canada of up to 27% in steam-assisted operations in the oil sands and 20% in mined oil sands.

Among the latest goals set in Alberta, the province’s two leading utilities — TransAlta and Atco — are accelerating their efforts to eliminate coal-fired power plants.

TransAlta is on track to end the use of coal at its five Alberta plants which can generate almost 4,000 megawatts.

Under its new Chief Executive Officer John Kousinioris, the company has approved a new wind farm in Alberta and is examining the potential of a carbon capture and storage strategy as part of its “rapid energy transition as it tries to anticipate where things are going.”

Meanwhile, Atco has teamed up with oil sands giant Suncor Energy in a “multi-billion-dollar project” to produce more than 300,000 metric tons a year of hydrogen and capture more than 90% of the carbon dioxide produced from the energy required to make hydrogen.

Suncor Chief Executive Officer Mark Little said Canada is poised to become a “big player in clean hydrogen globally and I think (this partnership) is the first big step forward.”

Among those in the industry scouring the horizon for signs of hope, some has surfaced from the federal government’s Canada Pension Plant Investment Board, which has C$475 billion of assets under management.

It established a Sustainable Energy Group in April to invest C$18 billion in renewable conventional energy and new technology, while Bloomberg estimates UD$15 trillion will need to be invested in new power capacity over the next 30 years, a lift for the natural gas sector among others.

In addition, the Norwegian-based research firm Rystad Energy estimates that upstream investment is not about to collapse.

It rates the top spending levels for 2021 at US$88 billion in the United States, US$41 billion in Russia and US$38 billion in China, with those three jurisdictions driving more spending growth over the years to 2025, while Saudi Arabia, Brazil and Angola are expected to post the biggest absolute gains this year. Canada is expected to come in at sixth place this year at US$16.8 billion.

Rystad forecasts Norway, the United States and Canada will lead supply growth among non-OPEC producers, respectively adding 900,000 bpd, 700,000 bpd and 300,000 bpd over the 2019-25 period.

—GARY PARK

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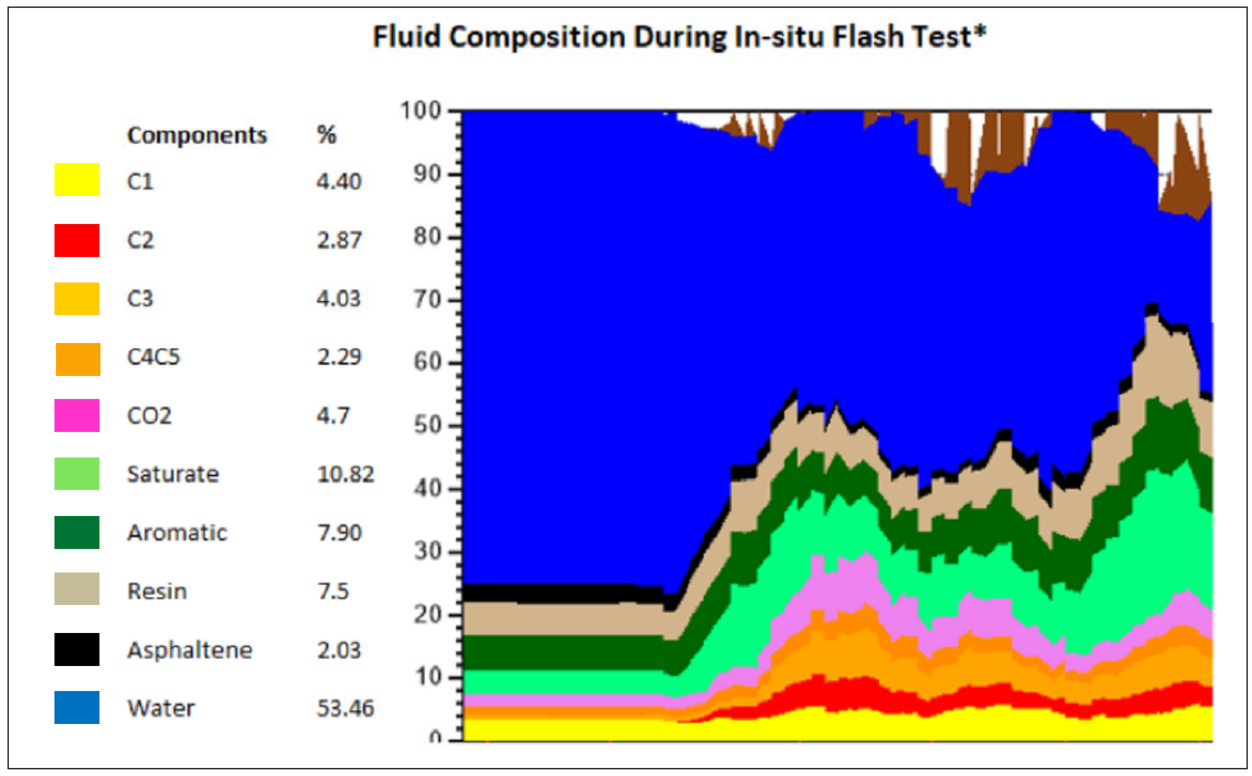
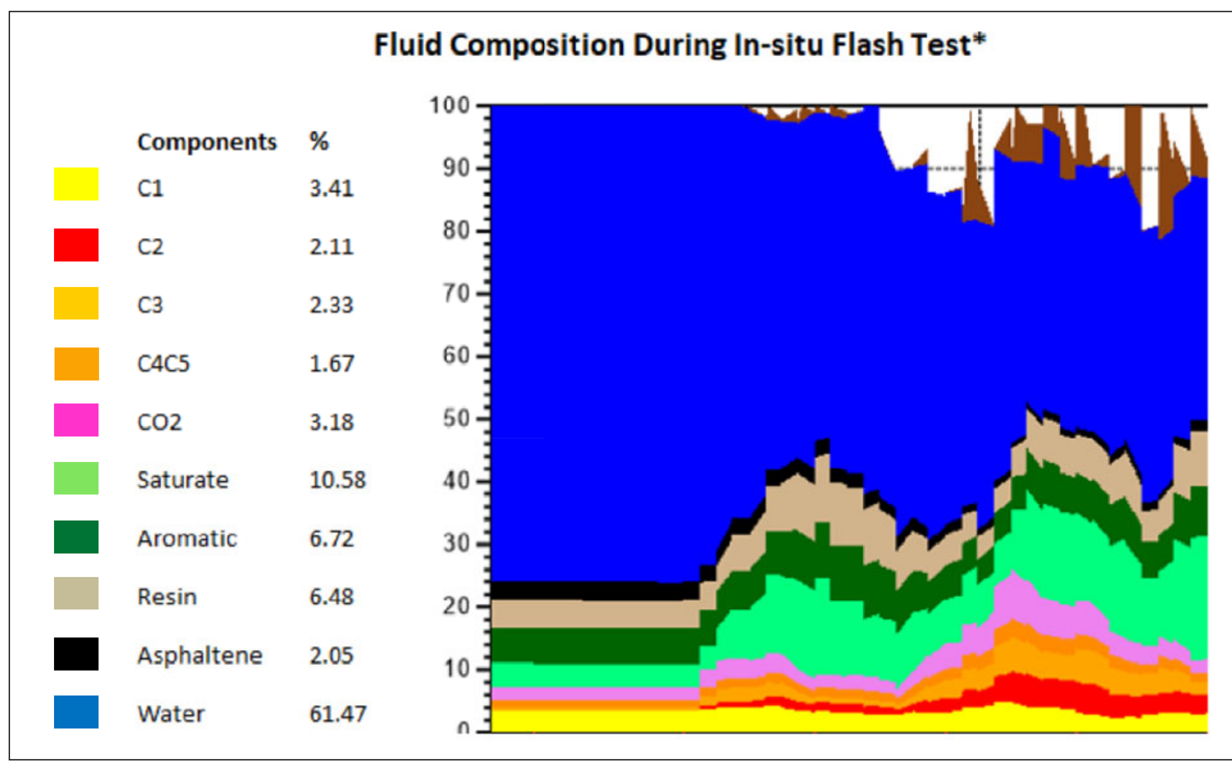
WELL DATA





Independent Resource Assessment#

Project Peregrine: Alaska North Slope	Unrisked Net Entitlement to 88E Prospective Oil Resources (MMstb)				
Prospects (Probabilistic Calculations)	Low (1U)	Best (2U)	High (3U)	Mean	COS
Merlin (Nanushuk)	41	270	1,463	645	37%
Harrier (Nanushuk)	48	207	940	417	24%
Harrier Deep (Torok)	42	267	1,336	574	20%
Prospects Total				1,636	

shares at a value of 25 cents each. This is on top of the 360 million shares ELKO was issued in late March at 18 cents per share.

ELKO, an Anchorage-based limited liability corporation, is owned by long-time Alaska geologist Erik Opstad.

The deal, 88E said, "will ensure the Company is left in a strong financial position ahead of next winter's exploration program."

Two other highlights of the operations update, which was signed by 88E's new Managing Director Ashley Gilbert, included:

• Encouraging evidence of oil in down hole samples being investigated in laboratory.

• Additional fluorescence recorded at previously unidentified depths.

Before getting into the latest well information released by the company, 88E also said that none of the information they have or are "aware of" materially affects the company's previous market announcements of prospective resources or reserves in the Merlin and Harrier Nanushuk prospects that are part of 88E subsidiary Emerald House's Peregrine project on 195,000 acres of leased land in the eastern National Petroleum Reserve-Alaska (see chart in the pdf and print versions of this story). So, the Merlin prospect's mean unrisked prospective oil resource remains at 645 million barrels.

The information gleaned from tests to date simply helps confirm the presence of a significant oil discovery.

RDT review in

88E said that it recently received and finalized its review of the report related to the downhole sampling program undertaken during the logging of Merlin 1 using Halliburton's Reservoir Description Tool, or RDT. As previously reported by 88E, observations from an optical fluid analysis sensor had indicated the likely presence of oil in the formation fluid across several of the depths that were sampled.

As part of standard procedure, the pressure in the sample chambers was decreased to see changes to the quantum and composition of the fluids at closer to normal surface conditions (known as a "flash test"). Observations from a more accurate optical sensor were then made — this data was in raw format and only verbal comments had been received by 88E — which indicated an increased fraction of resins and asphaltenes, something that can only be associated with the presence of oil, 88E reported.

The raw data has since been processed and presented in a final report from the RDT logging run. These results are shown below (see fluid composition flash tests graphs in the pdf and print versions of this story) for two of the samples where the pressure was taken to below 100 psi (atmospheric pressure is ~15 psi).

It is important to note, 88E said, that while the percentages of hydrocarbon in the two graphs reach up to ~70% of the sample, which would be indicative of a discovery, the results are deemed qualitative, and the margin of error is uncertain. This means "further investigation is required to validate the actual percentage of hydrocarbon in the samples," the company said.

The ratios of hydrocarbon indicate that the liquid present is highly "likely to be oil rather than condensate, which also bodes well from a thermal maturity perspective regionally," 88E said.

These horizons had previously been "deemed to contain mostly water and this remains a possibility."

Regardless of the final percentages of hydrocarbon vs water in these samples, which will be known in coming weeks, 88E said, the presence of oil is highly encouraging particularly given that the two most prospective horizons were not able to be sampled due to operational issues.

On April 6, 88E said it was too late in the season to initiate flow testing operations, but Merlin 1 "may be re-entered in the future … in order to drill a sidetrack and conduct a flow test."

The company also said that next winter it might go back to Peregrine to drill the Harrier 1 exploration well.

In 88E's first quarter report released on April 20, the company said the Nanushuk formation, which contained the primary targets for the Merlin 1 well, was encountered ~600' low to prognosis and was interpreted to be ~500' thicker than that encountered in the wells drilled in ConocoPhillips' Willow oil field to the north of the Peregrine project.

More on fluorescence

In its May 25 operations update 88E said that while preparing the Merlin 1 sidewall cores for further testing, white and UV light photography was used because if oil is present, then fluorescence will be evident under the UV light. Multiple horizons were identified as having oil present during drilling via observation of fluorescence under UV light and using solvent (or cut) to determine whether oil would leach out from the samples.

Subsequently, observations in the lab of the sidewall cores indicated they "are largely confirmatory" of the previous analyses, "however, several horizons have shown evidence of oil, which were not previously identified. These horizons, in addition to those already known to contain oil, will be the focus of further work."

Some of this work includes nuclear magnetic resonance imagery to determine the ratios of free oil and water present as well as porosity; and Dean Stark, which extracts the oil and water from the sample to determine saturations.

88E said the results from these analyses will be known within the next few weeks.

Notably 18 of the most prospective samples were not included in those sent for lab analyses; rather, the company said they "have been set aside for special analysis related to any oil extracted."

Supervised by Staley

In compliance with the requirements of the ASX Listing Rules Chapter 5 and the AIM Rules for Companies, the technical information and resource reporting contained in 88E's May 25 operations update was prepared by, or under the supervision of, Dr. Stephen Staley, who is a non-executive director of 88E.

Staley has more than 35 years of experience in the petroleum industry, is a Fellow of the Geological Society of London, and a geologist/geophysicist who has experience that is relevant to the style and nature of the oil prospects under consideration and to the activities described in the operations update, 88E said.

Staley has reviewed the information and supporting documentation referred to in the update and considers the resource and reserve estimates to be "fairly represented and consents to its release in the form and context in which it appears."

88E said his academic qualifications and industry memberships comply with the criteria for "competence" under clause 3.1 of the Valmin Code 2015."

Staley's years of management and technical experience were in the European, African and Asian oil, gas and power sectors, including with Conoco and BP.

More recently he was founding managing director of upstream startups Fastnet Oil & Gas plc and Independent Resources plc. He was also non-executive director of Cove Energy plc.

Staley holds a BSc (Hons.) in geophysics from Edinburgh University, a PhD in petroleum geology from Sheffield University and an MBA from Warwick University.

—KAY CASHMAN

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OIL PRICES

replacements.

Spot differentials for Middle Eastern and Russian crude hit a multi-month high, and time spreads for Dubai crude strengthened on expectations China will continue its oil-purchasing spree, Bloomberg said, adding that the spreads are a "key gauge of the supply-demand balance."

ANS continued to surge $2.14 higher May 24 to close at $67.67, while WTI jumped $2.47 to $66.05 and Brent popped $2.02 to close at $68.46.

The three indexes moved modestly higher May 25.

Dutch verdict chills drilling

A Dutch court ordered Royal Dutch Shell Plc to curtail its emissions more rapidly than planned, delivering a chill on investment in oil drilling that could spread across the industry.

The court told Shell to slash emissions by 45% by 2030 from 2019 levels, rejecting Shell's pledged reductions in greenhouse gas emissions of 20% by 2030 — reaching net-zero by 2050.

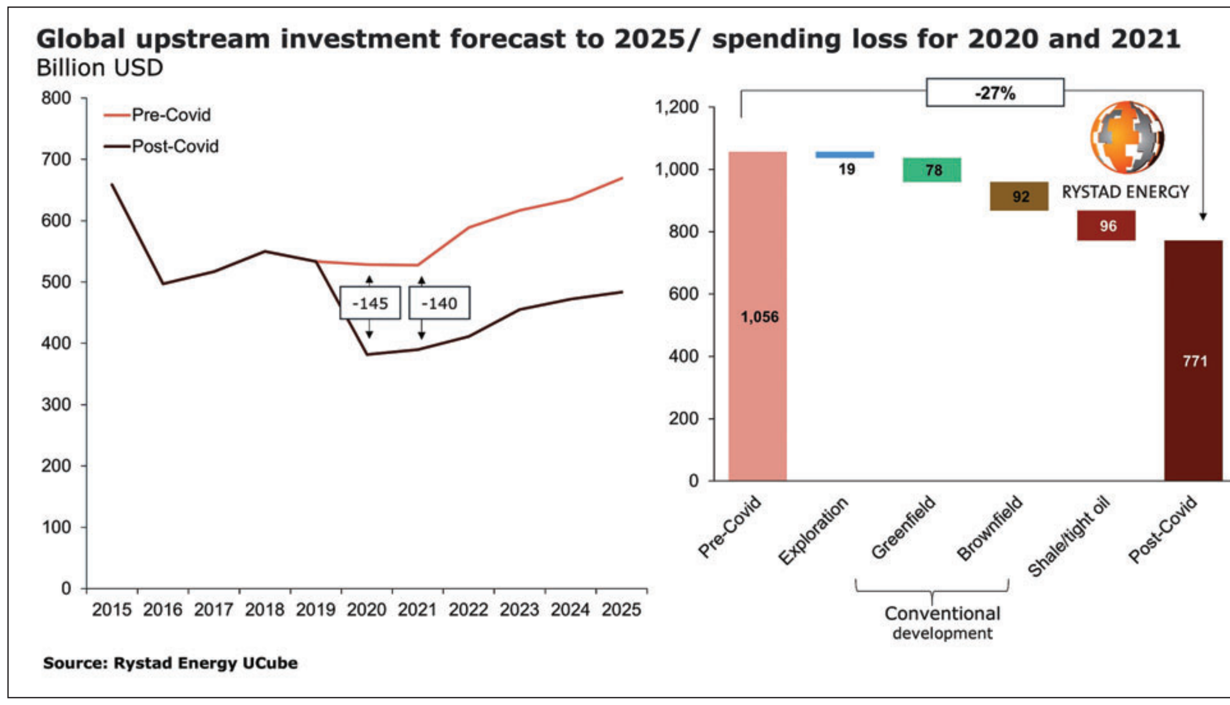
The landmark Dutch verdict "could trigger what some experts say is a coming wave of climate-related litigation with ramifications far beyond the Netherlands," Law360 said.

Legal experts said the impact of the decision will be amplified because the court relied on global human rights standards and international instruments on climate change to arrive at its decision, according to a May 26 CNN report.

"I can imagine this will inspire a series of other cases against companies, especially those active in the oil extraction industries like Shell," said Eric De Brabandere, an international dispute settlement professor at Leiden University in the Netherlands. "It is a groundbreaking decision, it's really a landmark."

The case was heard in The Hague, home of Shell's headquarters.

Shell can appeal the ruling, something the company said it expects to do, but the judge said the more ambitious target for the company will remain in effect while the appeals process plays out, NPR said in a May 26 report.



Pandemic depresses upstream investment

COVID-19 placed a pall on upstream investments, whacking away $285 billion of spending in the first two years of the downturn, according to a May 12 Rystad Energy report. The shale sector was most affected, with conventional exploration and investments in mature assets suffering the least.

In February 2020, Rystad estimated global upstream investments for the year would near $530 billion — mirroring 2019 levels — and that 2021 investments would remain in line with 2020 levels.

E&P companies slashed 2020 investment budgets to protect cash flow, and the spending trend was not reversed in 2021, when prices rose, Rystad said.

Compared to pre-pandemic estimates for 2020 and 2021, Rystad observed that spending fell by $145 billion last year and will end up losing $140 billion by the end of this year, implying that COVID-19 eliminated 27% of planned investments.

Upstream spending was $382 billion in 2020 and is forecast to marginally grow to $390 billion this year, Rystad said.

Although spending will start growing from 2022 it will not return to the pre-pandemic level of $530 billion, the consultancy said. Growth will be limited, and investments will only inch up annually to just over $480 billion in 2025, when the report's forecast ends.

Over the period of 2020 and 2021, shale/tight oil investments are most affected, losing $96 billion of previously expected spending, or 39% for the sector, Rystad said, adding that exploration spending is expected to drop by $19 billion, or 22% below the previous forecast.

Greenfield investment in new conventional projects will fall by $78 billion, or 28%, while brownfield investment in existing conventional projects will fall by $92 billion, or 20%, the consultancy said.

"Since shale/tight oil is both the segment with the highest decline in activity and the supply source in greatest need of continuous reinvestment to keep production growing, the immediate impact on output from this sector has been significant," said Espen Erlingsen, Rystad head of upstream research. ●

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