Petroleum news

Vol. 27, No. 29 • www.PetroleumNews.com | A weekly oil & gas newspaper based in Anchorage, Alaska | Week of July 17, 2022 • $2.50

page 3 EIA forecasts average $104/bbl Brent in '22, dropping to $94 in next year

FBI, MI5 warn against CCP; State, Hilcorp, ConocoPhillips talk LNG

ON JULY 6 AT MI5'S Thames House headquarters in London MI5 director Ken McCallum and FBI chief Christopher Wray warned of the threat posed by the Chinese Communist Party in their first ever joint speech.

The heads of Britain and America's intelligence agencies promised more investigations into China as they jointly warned that the world faces a "game changing challenge" from the CCP.

Wray warned that if China was to try to "forcibly take over Taiwan" it would "represent one of the most horrific business disruptions the world has ever seen.

see **INSIDER** *page 8*

Great Bear Pantheon spuds first Alaska North Slope production well

PATRICK GALVIN

Great Bear Pantheon spud its first production well on Alaska's North Slope the evening of July 6 using Nabors 105AC drill rig.

The Alkaid 2, a horizontal long-term test well, marks the company's possible transition from explorer to producer. If successful at Alkaid 2, Great Bear Pantheon will truck the produced oil to Pump Station approximately 20 miles north of Alkaid and sell the produced oil to a nearby North Slope facility.

The first horizontal wells drilled on the North Slope were

see **ALKAID 2** *page 12*

Pad work approved in advance of methane hydrate test at Prudhoe

Alaska's Division of Oil and Gas has authorized Arctic Slope Regional Corp. to make gravel improvements to the 7-11-12 pad in the Prudhoe Bay unit on the North Slope, in preparation for a program of methane hydrate production testing. On May 19 ASRC Consulting and Environmental Services LLC filed an application with the division for approval of the testing program. The gravel improvements at the 7-11-12 pad are one component of this program. The division has yet to issue any decisions on the remainder of ASRC's application, and the application itself is not yet publicly available.

However, the 7-11-12 pad was the site of a successful

see **METHANE HYDRATE** *page 11*

Tidal Energy revises Turnagain Arm plan, now focused on turbines

In a July 8 progress report to the Federal Energy Regulatory Commission, Anchorage based Tidal Energy Corp. told the commission that it is now pursuing a third design concept for its proposed tidal energy project near the entrance to the Turnagain Arm. The company has been pursuing a project that it says could use the major tidal currents flowing in and out of the arm to generate most of the electricity used by Alaska Railbelt electric utilities. TEC had applied to FERC for a preliminary permit for the project.

The original concept for the tidal power system involved the placement of two 8-mile tidal bridges or fences across the Arm, each holding multiple turbines with a total generation capacity of 1,000 megawatts. One bridge would have stretched west from Fire

see **TIDAL ENERGY** *page 10*

GOVERNMENT

Smaller Willow?

Scaled-back alternate in draft SEIS: one drill site cut, another deferred

By KRISTEN NELSON
Petroleum News

Could ConocoPhillips Alaska's Willow project be built on a smaller scale? In the draft supplemental environmental statement for the National Petroleum Reserve-Alaska development, released July 8, the U.S. Bureau of Land Management has included an alternative that — instead of the five drill sites ConocoPhillips proposed — has an initial three drill sites with a fourth drill site to be built later.

The draft supplemental environmental impact statement has 45-day public comment period which began with the July 15 Federal Register notice.

BLM said on its website that the timeline for the final supplemental EIS and record of decision "will rely largely on comments received during the public review of the Draft Supplemental EIS, as well as meaningful input from our cooperators and affected communities." The draft SEIS is out for public comment until Aug. 29.

> ***"Construction is typically assumed to start in either the winter 2022/2023 or winter 2023/2024," the agency said.***

BLM said the draft SEIS addresses deficiencies identified by the U.S. District Court for the District of Alaska in 2021 when it vacated a 2020 ROD approving Willow based on a 2020 final EIS.

see **WILLOW SCALE** *page 10*

LAND & LEASING

Nikaitchuq North axed

Eni, Shell allow OCS Beaufort leases with promising geology to terminate

By KAY CASHMAN
Petroleum News

The fate of the Nikaitchuq North Beaufort Sea prospect quietly became evident on July 6 when operator Eni US Operating Co. and leaseholder Eni Petroleum US filed the 15th plan of development for the central North Slope's Nikaitchuq unit, which is on state leases.

According to the POD filed with the state of Alaska's Division of Oil and Gas, the federal Nikaitchuq North prospect leases, which lie outside the Nikaitchuq unit, have terminated.

Prior to drilling its first Nikaitchuq North exploration well, Eni had acquired ADL 393175 in a state of Alaska Beaufort Sea lease sale in late 2016. Sandwiched between the state unit and the federal unit, it provided "some protection acreage, should there be any future development opportunities involving the Nikaitchuq North Exploration Project," the company explained in a development plan.

> ***"Due to Shell's decision to not participate in the drilling of the NN-02 well, Management decided to allow the SOO to expire in April 2022," Eni said.***

The company's proposed 15th POD for the Nikaitchuq unit that runs from Oct. 1 to Sept. 30,

see **NIKAITCHUQ NORTH** *page 9*

FINANCE & ECONOMY

Price gyrations pause

Rally fizzles, taking Brent below $100 as China lockdowns stifle demand

By STEVE SUTHERLIN
Petroleum News

Oil price volatility took a pause July 13 after a precipitous slide on the previous day. Alaska North Slope crude rose 57 cents to close at $103.05 per barrel, West Texas Intermediate rose 46 cents to close at $96.30 and Brent rose 8 cents to close at $99.57.

ANS dropped $7.31 July 12 to close at $102.48, while WTI plummeted $8.25 to close at $95.84 and Brent slid below the $100 mark — falling $7.61 to close at $99.49.

Chinese lockdowns aimed at containing COVID-19 outbreaks continued to take a bite out of demand, as did slowing economic activity elsewhere as pandemic stimulus measures are withdrawn and traders worry that aggressive rate hikes to stem inflation will further pummel demand.

> ***Russia's government could lose some $85 billion in oil and gas tax income in 2022 due to the significant discount to Urals blend crude, Rystad Energy said in a July 12 release.***

On the supply side, Russian oil has evaded Western sanctions over Putin's war on Ukraine to

see **OIL PRICES** *page 11*

● EXPLORATION & PRODUCTION

Hilcorp asks commingling at Beaver Creek

Fieldwide permission would allow maximizing natural gas production while reducing administrative burdens to company, AOGCC

By KRISTEN NELSON
Petroleum News

Hilcorp Alaska has requested that the Alaska Oil and Gas Conservation Commission allow downhole commingling of natural gas production from the Sterling, Beluga and Tyonek gas pools on a fieldwide basis at Beaver Creek.

The field is in the Kenai National Wildlife Refuge, east of Nikiski on the Kenai Peninsula.

Hilcorp's request is for an amendment of the existing conservation order for Beaver Creek to allow commingling between all gas pool within the unit.

The Beaver Creek unit, BCU, was formed by Marathon Oil Co. in 1967 and is now operated by Hilcorp, the company said in its July 1 application to AOGCC. There are four federal oil and gas leases, a total of 3,680 acres. The Bureau of Land Management and Cook Inlet Region Inc. own the mineral rights.

Hilcorp took over as operator in January 2013 and cumulative gas production since that date is 38,736.1 million cubic feet and cumulative oil production is 785,000 barrels, the company said, with gas production predominantly from the Sterling and Beluga formations with some gas from the Tyonek formation.

Twelve of 18 existing wells remain active. There are also two disposal wells, the company said.

Hilcorp has increased both oil and gas production from Beaver Creek. The most recent data available from AOGCC, for May, show that in just the last year, oil production at Beaver Creek was up 367% (May 2022 compared to May 2021) to 923 barrels per day, while natural gas production increased 52% over the same period to 15,144 thousand cubic feet per day.

Commingling request

Hilcorp said the proposed amendment to pool rules for Beaver Creek is "designed to prevent waste, further protect correlative rights, and improve the ultimate recovery of remaining hydrocarbons through BCU. Allowing for the commingling of downhole production will also help reduce the administrative burdens on both Hilcorp and AOGCC staff."

The company said its "objective is to maximize the recovery of remaining hydrocarbons from the field," and said it "cannot efficiently drill and produce the remaining reserves" under the rules of the existing conservation order.

"Requests for authorization to commingle production downhole are administratively burdensome and are currently unnecessary to protect correlative rights within the BCU," Hilcorp said.

The company has requested and received permission to commingle from three wells beginning in 2016 and said it anticipates commingling in two other wells, allowing it to "target smaller, un-drained portions of heterogeneous sand bodies that cannot produce on their own without commingling."

At the three gas wells online with commingled production, Hilcorp said, tubing pressures nearly identical to non-commingled wells, suggest "minimal pressure

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● FINANCE & ECONOMY

EIA forecasts '22 $104 average for Brent

US crude forecast to average 11.9 million bpd this year, a record 12.8 million bpd in 2023, breaking 12.3 million bpd 2019 record

By KRISTEN NELSON
Petroleum News

The spot price of Brent crude is expected to average $104 per barrel this year, dropping to $94 per barrel in 2023, the U.S. Energy Information Administration said in its latest Short-Term Energy Outlook, released July 12.

A bigger change is expected in the Henry Hub spot price for U.S. natural gas, now forecast to average $5.97 per million British thermal units during the second half of the year, down 44% from EIA's June forecast.

The Henry Hub price drop is based on an expected drop in U.S. liquefied natural gas exports, now forecast to average 10.5 billion cubic feet per day in the second half of the year, down 6% from the first half of the year, a 14% decrease in U.S. LNG exports from the agency's June forecast.

The revision in estimates is based on an outage at the Freeport LNG facility, now expected to last until late in the year. Freeport accounts for 17% of U.S. LNG export capacity, EIA said.

"With less LNG being exported in the second half of the year, more natural gas is likely to stay in the domestic market," said EIA Administrator Joe DeCarolis. "We expect lower U.S. natural gas prices for the rest of 2022 than we had previously forecast, but lower prices in 2022 led us to reduce our expectations for natural gas production."

Henry Hub averaged $6.07 per million Btu in the first half of 2022, increasing in each month from January through May, when it reached $8.14 per million Btu, EIA said, before declining to $7.07 per million Btu in June. After averaging $5.97 per million Btu in the second half of this year, the price is expected to average $4.76 per million Btu in 2023.

Natural gas

EIA estimates that U.S. LNG exports averaged 11.2 billion cubic feet per day in the first half of 2022, compared with 9.5 bcf per day in the first half of 2021, and are forecast to average 10.9 bcf per day for all of 2022 and 12.7 bcf per day in 2023. "We reduced our forecast for LNG exports in 2H22 as a result of the outage at the Freeport LNG export facility in Texas. Our forecast assumes the facility will return to near full operations in January 2023," EIA said.


JOE DECAROLIS

EIA said U.S. dry natural gas production is forecast to average 96.2 bcf per day this year, up 2.7 bcf per day, 3%, from 2021, increasing to almost 100 bcf per day in 2023.

"Increases in crude oil and domestic natural gas prices, as well as increases in the number of active oil and natural gas rigs, will contribute to an overall increase in drilling activity in 2022 and 2023 that will lead to production growth," EIA said, with the Haynesville region and Permian driving dry natural gas production, "supported by increased pipeline takeaway capacity in both regions and high oil production in the Permian Basin that results in greater levels of associated natural gas production."

U.S. natural gas consumption is expected to increase by 2.9 bcf per day, 3%, to average 85.9 bcf per day this year, falling to 85.4 bcf per day in 2023.

US LNG exports

Prior to the outage at the Freeport LNG facility, U.S. LNG exports averaged 11.2 bcf per day in the first half of the year and set a monthly record in March, averaging 11.7 bcf per day.

"U.S. LNG export capacity is continuing to expand this year with the addition of the Calcasieu Pass LNG export facility, which has been ramping up LNG production ahead of schedule and is expected to be fully operational by the third quarter of 2022," EIA said.

Continued growth in U.S. LNG exports in the first half of the year was driven by strong natural gas demand and high LNG prices in Europe and Asia, EIA said, with the U.S. exporting 71% of its LNG to Europe in the first five months of the year, compared to an annual average of 34% in 2021.

Asia has previously been the main destination for U.S. LNG, taking almost half of total exports in 2020 and 2021.

EIA said the European Union and the United Kingdom have imported record volumes of LNG since December 2021, "primarily to fill natural gas storage inventories, which were historically low from fall 2021 through spring 2022."

Last year the U.S. became the largest LNG supplier to the EU and United Kingdom, accounting for 26% of imports, with that volume continuing to grow in the first five months of this year.

US crude production

EIA forecasts U.S. crude oil production to average 11.9 million bpd in 2022 and 12.8 million bpd next year, surpassing the current record of 12.3 million bpd set in 2019. But there are barriers. "Although crude oil prices are high, economic headwinds including inflation, supply chain issues, and labor shortages, and less operator activity than we had forecast at the beginning of this year have limited production growth," the agency said.

Most drilling activity took place in the Permian this year, with favorable geology combined with technological and operational improvements making the Permian "one of the most prolific regions of U.S crude oil production," EIA said.

There is a downside posed by the increased production of associated natural gas in the region. "If natural gas pipeline constraints are not eased and the proposed 5.0 billion cubic feet per day of pipeline takeaway capacity out of the Permian Basin is not brought online by 2024, drilling activity in areas with high concentration of natural gas might be reduced," EIA said. The agency also cited capital development decisions by operators as critical for rig deployment and production. "Further, production could be less than our forecast if supply chain issues and input cost inflation persist through the forecast period."

EIA forecasts average annual Permian crude production at 5.3 million bpd this year and 5.7 million bpd in 2023.

In other areas which EIA notes in the forecast, it expects Gulf of Mexico crude production to average some 1.8 million bpd both this year and next, with seven new projects having come online last year and nine more projects are expected online this year.

The agency said Alaska's crude oil production is expected to stay near the 2021 level of 400,000 bpd in both 2022 and 2023. ●

Contact Kristen Nelson at knelson@petroleumnews.com

EXPLORATION & PRODUCTION

US rotary rig count back up by 2 to 752

The Baker Hughes' U.S. rotary drilling rig count was 752 on July 8, back up by two after dropping by three the previous week. The count was up by 273 from 479 a year ago.

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

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

Baker Hughes shows Alaska with eight rotary rigs active July 8, unchanged from the previous week and up by four from a year ago, when the state's rig count stood at four.

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

The July 8 count includes 597 rigs targeting oil, up by two from the previous week and up 219 from 378 a year ago, with 153 rigs targeting natural gas, unchanged from the previous week and up 52 from 101 a year ago, and two miscellaneous rigs, unchanged from the previous week and unchanged from a year ago.

Forty-three of the rigs reported July 8 were drilling directional wells, 682 were drilling horizontal wells and 27 were drilling vertical wells.

Alaska rig count unchanged

The rig counts in Louisiana (65) and Texas (361) were each up by one from the previous week.

Rig counts in all other states were unchanged week over week: Alaska (8), California (6), Colorado (19), New Mexico (112), North Dakota (35), Ohio (11), Oklahoma (60), Pennsylvania (24), Utah (13), West Virginia (14) and Wyoming (19).

Baker Hughes shows Alaska with eight rotary rigs active July 8, unchanged from the previous week and up by four from a year ago, when the state's rig count stood at four. Seven of the rigs in Alaska were onshore, one was offshore — also unchanged week over week.

The rig count in the Permian, the most active basin in the country, was up by one from the previous week at 350 and up by 113 from 237 a year ago.

—KRISTEN NELSON

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● EXPLORATON & PRODUCTION

Eni files 15th POD for Nikaitchuq unit

During first nine months of 14th POD that will end Sept. 30, Eni drills several wells, adds six-well shelter at Spy Island

By KAY CASHMAN
Petroleum News

The proposed 15th plan of development, or POD, for the Nikaitchuq unit was submitted to Alaska's Division of Oil and Gas on July 6 by Eni US Operating Co. Inc. as operator, on behalf of its affiliate Eni Petroleum US LLC, owner of 100% of the working interest in the North Slope Nikaitchuq unit.

During the first nine months of the 14th POD period, which runs from Oct. 1, 2021, through Sept. 30, Eni has already accomplished most of what it committed to, including the drilling of several wells and the commissioning and startup of an additional six-well shelter at its Spy Island Drillsite.

North of the Kuparuk River unit, the Nikaitchuq unit was formed in April 2004, with Eni joining the unit in 2005 and becoming 100% working interest in 2007. (Eni was brought to the North Slope by a Bill Armstrong company, which spearheaded drilling at Nikaitchuq.)

The unit's Schrader Bluff participating area was approved effective Jan. 1, 2011, and commenced sustained production on Jan. 31, 2011.

The existing unit area covers approximately 21,200 acres encompassing 11 state oil and gas leases. Production is from two drilling locations, the Spy Island Drillsite and the Oliktok Point pad.

Production is processed at the Oliktok Point pad, or OPP. Cumulative oil production from the Nikaitchuq unit was 71.2 million barrels through May 31, 2022.

The Nikaitchuq unit's operating agreement's automatic 10-year contraction had been extended by the division until Sept. 30 of this year.

Accomplished in 14th POD

During the first nine months of the 14th POD period, Eni reactivated the infill drilling program at the Spy Island Drillsite, or SID, with the addition of three water injection wells, of which two have been completed, SI02-SE6 and SI15-E1, and one, SI41-E3, is planned to be completed in August.

Two dual lateral oil producers, SP09-E2 and SP40-E4, and one additional lateral in existing oil producer SP03-NE2 L2 were completed. The SI15-E1, SP09-E2, SI41-E3, and SP40-E4 wells are associated with the northeast extension added to the original development plan.

To date, 56 development wells have been drilled and completed within the Nikaitchuq unit, including 31 oil producers (11 OPP, 20 SID) and 25 injector wells (eight OPP, 17 SID).

Additionally, dual lateral wellbores have been completed in 27 producer wells (eight OPP, 19 SID).

In the 14th POD period, one inactive development well, OP19-T1N, was drilled and completed to test the potential of the N sand development. Additionally, two disposal wells (one OPP, one SID) and three Ivishak water source wells (three OPP) are active in supporting operations.

Major capital projects included commissioning and startup of an additional six-well shelter at SID, allowing for additional drilling and production in 2022.

The electrical power sharing project was funded to interconnect the Oooguruk and Nikaitchuq power generation systems to allow more robust and efficient power sharing between the two Eni-operated fields. Engineering is in progress, with startup scheduled for summer 2024.

Eni also racked up several more accomplishments in the 14th POD period.

And finally, with the reduction of COVID-19 impacts, Eni's corporate office visited the site for several audits and assessments during the period. Notably, an energy assessment audit, operational assessment, biodiversity review and logistics audit were performed. Findings and recommendations will be implemented in the 15th POD period.

Reservoir management

Subsurface development of Nikaitchuq's Schrader Bluff participating area is ongoing with dedicated development wells in the Alaska Oil and Gas Conservation Commission-approved Nikaitchuq Schrader Bluff oil pool.

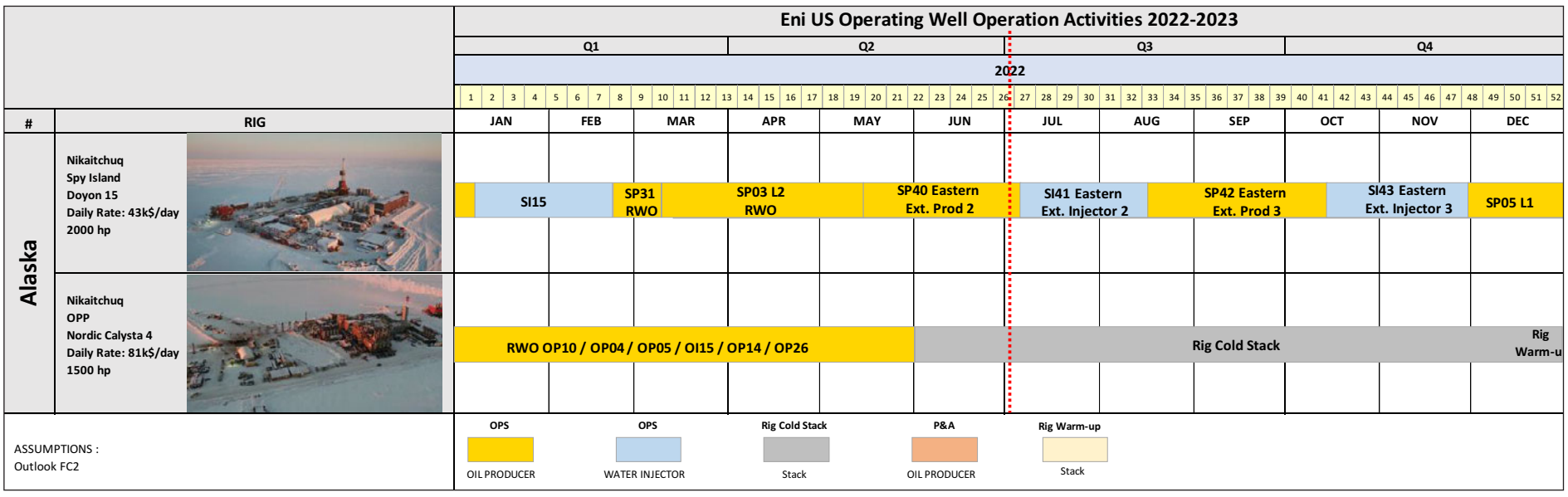
AOGCC issued pool rules for the reservoir and an area injection order authorizing the injection of fluids for enhanced oil recovery.

The primary recovery mechanism for the field is waterflooding. Producers and injectors have been drilled in side by side pairs and completed with horizontal drains in the OA sands.

Oil producer and water injector targets are defined based on historical producer-injector water flood responses, pressure trends, ESPs constraints and well integrity limits.

On Oct. 22, 2019, polymer injection was

see **NIKAITCHUQ UNIT** *page 5*



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NIKAITCHUQ UNIT

initiated in the Oliktok Point I-2 (OP-I2) well for a one-year test to determine the effectiveness of polymer injection for improving recovery.

The test was cut short after 154 days due to logistical issues resulting from the COVID-19 pandemic. The shortened test period resulted in inconclusive test results and the polymer injection pilot was shut down in March 2020 but resumed at OP-I2 well in April 2021 and extended until Dec. 31, 2022.

Depending on the results of this pilot test, a feasibility study will be carried out to evaluate a full field implementation and the required surface modifications of the existing network facilities.

Observed field oil production and water cut were in-line with Eni's reservoir model expectations. From Oct. 1, 2021, through May 31, 2022, oil production averaged 17,548 barrels of oil per day with 49,001 barrels of water per day (74% water cut) "and an average producing GOR of 147 SCF/STBO," Eni said.

Water injection during this period averaged 80,035 bpd with a monthly average and cumulative voidage replacement ratio of 1.16 and 1.17, respectively. During May oil production averaged 18,562 bpd.

15th POD facilities plans

During the Nikaitchuq unit's 15th POD period from Oct. 1 of this year through Sept. 30, 2023, Eni said it plans to perform routine maintenance and mechanical integrity inspection of piping, equipment, vessels, tanks, and other safety systems in the field.

The company has several planned minor facility upgrades at OPP and SID.

Efforts will continue on cleaning and replacing inlet heat exchanger bundles to maximize heat to the processing system. Actions will be based on the heat exchanger analysis performed in the 12th POD.

An alarm management and rationalization study will be completed to reduce nuisance alarms in the OPP control room.

The OPP control room relocation will be progressed in engineering design during this period to provide additional information to support an ultimate management decision. The intent is to ensure control room staff and infrastructure are located in a safe location.

As previously mentioned, the electrical power sharing project to interconnect the Nikaitchuq and Oooguruk power will continue to move forward.

Follow-up action items will be addressed from the several internal corporate audits and assessments performed in 2022. Notably an energy efficiency audit, operational assessment and logistics audit will likely result in recommendations to decrease greenhouse gas reduction, increase compliance with corporate operational guidelines and further ensure the safety of all workers, the environment and infrastructure.

15th POD period reservoir management

Reservoir management activities will continue in the Nikaitchuq unit's Schrader Bluff participating area, the objectives being as follows:

• Maximize daily volumes and value by optimizing hydrocarbon production.

• Minimize risk exposure to key producing wells and maintain well integrity.

• Continue the polymer injection test at OPP through end of this year.

• Tracer sampling and interpretation in the OP-I2 polymer pilot area.

• Proactively define and develop mitigation plans related to water production.

• Proactively acquire reservoir performance data critical to reservoir management and overall recoverable volumes determination.

• Ensure timely execution of reservoir surveillance plans, workovers, re-completions, and infill drilling.

• Update current reservoir simulations and studies to reproduce the field behavior.

• Find cost-effective solutions to optimize the production.

During the 15th POD period, Eni plans to work with the division to submit an application to expand the Schrader Bluff PA to be consistent with current and ongoing development plans.

Following completion of the expansion the Schrader Bluff PA "will better reflect tract participations consistent with ongoing production, costs and future development providing appropriate allocations of unitized substances produced and unit expenditures," the company said in its proposed 15th POD.

15th POD period drilling

The Nordic Calista Rig 4 is currently cold stacked. There are currently no plans for any new wells at OPP; however, it is anticipated the rig will be warmed up in January 2023 to conduct workovers, to be determined, in order to restore, sustain and increase Nikaitchuq production.

The Doyon 15 rig remains active at SID and plans are to drill three new wells and one lateral as summarized below:

• SP42-E2 (producer dual lateral) — start in August during the 14th POD and finish the well in October 2022.

• SI43-E3 injector) — planned to be drilled and completed in fourth quarter of this year to complete the northeast extension program.

• SP05-FN7 (second lateral) — tentatively planned to be added in fourth quarter of this year.

• Drilling of SI44-S5 (injector) — planned in first quarter of 2023 to replace OI15-S4 which has been suspended due to a mechanical failure during the March 2022 rig workover to replace the tubing.

Currently no workovers are planned on SID; Eni said in its July 6 POD application. However, the need for well interventions will be evaluated on an ongoing basis. ●

Editor's note: See related story on the fate of the Nikaitchuq North prospect in this issue of Petroleum News.

Contact Kay Cashman at publisher@petroleumnews.com

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BEAVER CREEK

differentials exist between the Sterling, Beluga, and Tyonek sands. Our most recent production survey in a commingled well (BCU 24 on 06/16/2022) shows that sands from both the Tyonek and Beluga reservoirs are clearly contributing, further supporting the idea that commingling does not put reserves from either pool at risk."

Hilcorp said all three wells currently approved for commingling "experienced a production increase when new sands were perforated and commingled, without observing any subsequent crossflow. Hilcorp expects to see a similar response in other BCU wells is commingling were to occur."

Hilcorp said commingling would allow it to "produce those BCU gas pools which otherwise would be bypassed due to the inability to sustain flow on their own. Allow the commingling will result in extending the productive life of the BCU and maximizing recovery of reserves."

AOGCC has tentatively scheduled a public hearing on the request for Aug. 18 at 10 a.m. in its Anchorage offices, with call-in available at 907-202-7104 conference ID 730 806 333#.

The commission said if a request for hearing is not filed by 4:30 p.m. July 29, the commission may issue an order without a hearing. ●

Contact Kristen Nelson at knelson@petroleumnews.com

GOVERNMENT

BOEM schedules 5-year plan meetings

The U.S. Department of the Interior's Bureau of Ocean Energy Management said the 90-day public comment period for the 2023-28 National Outer Continental Shelf Oil and Gas Leasing Program, and the draft programmatic environmental impact statement began July 8 when notice of availability was published in the Federal Register.

BOEM will host four live virtual open house meetings allowing the public to speak with BOEM staff about the 2023-28 proposed program.

The agency provided eastern daylight time for the meetings; Alaska daylight time is also shown:

•Tuesday, Aug. 23, 4-7 p.m. EDT (12-3 p.m. ADT);
•Thursday, Aug. 25, 5-8 p.m. EDT (1-4 p.m. ADT);
•Monday, Aug. 29, 7-10 p.m. EDT (3-6 p.m. ADT); and
•Wednesday, Aug. 31, 8-11 p.m. EDT (4-7 p.m. ADT).

To register for public meetings go to https://forms.gle/WqTN6z9YFTRUSsbH8.

Information on the 2023-28 proposed program, draft PEIS, virtual meetings and on how to submit comments is available at BOEM's website.

—PETROLEUM NEWS

● EXPLORATION & PRODUCTION

Eni considering 2 new wells at Oooguruk

Company's 16th plan of development, Oct. 1-Sept. 30, 2023, includes facilities, rig workovers, with potential new wells in mid-'23

By KRISTEN NELSON
Petroleum News

In a 16th plan of development for the Oooguruk unit, covering Oct. 1 through Sept. 30, 2023, Eni lists facilities work, rig workovers and potential new wells. "The proposed drilling schedule is subject to changes accordingly with global economic environment and company investment objectives," Eni said in the POD. The company is also evaluating two appraisal wells into the northern Nuiqsut reservoir.

The POD was submitted to the Alaska Department of Natural Resources' Division of Oil and Gas by the unit operator, Eni US Operating Co., on behalf of its affiliate Eni Petroleum US LLC, the 100% working interest owner at Oooguruk.

The Oooguruk unit

Eni said the unit was formed in 2003 with some 53,344 acres. Several leases on the southern end of the unit were removed effective July 1, 2019, and there are now approximately 35,285 acres in the unit in 16 leases.

Eni succeeded Caelus Natural Resources Alaska as operator effective Aug. 1, 2019.

There are three participating areas: Nuiqsut, Kuparuk and Torok, with production commingled on the surface and processed at the Kuparuk River unit. Production from Oct. 1, 2021, through May 31, 2022, averaged 5,532 barrels per day and cumulative oil production totaled 45.9 million through the end of May.

The automatic 10-year contraction of the unit was revised by DNR on May 6, 2021, delaying it through Sept. 30, 2022.

Oooguruk development is from an offshore manmade gravel island, the Oooguruk drill site just east of the Colville River Delta in Harrison Bay, with production delivered to the onshore Oooguruk tie-in pad via buried subsea flowline bundle and onshore flowlines, metered and then transferred to Kuparuk River unit facilities, operated by ConocoPhillips Alaska, for final processing and transportation to the sales line.

Existing wells

Eni said 42 wells have been drilled and completed at Oooguruk:

•Twenty-seven Oooguruk Nuiqsut participating area development wells;
•Five Oooguruk Kuparuk PA development wells;
•Three Oooguruk Torok PA development wells;
•Two Oooguruk Nuiqsut-Oooguruk Kuparuk dual completion wells;
•One Class I and II disposal well; and
•Four completions outside existing participating areas — two appraisal wells, a Kuparuk test well and the Sikumi 1 exploration well, all either plugged and abandoned or on long-term shut-in.

15th POD facilities work

Eni said during the 15th POD (Oct. 1, 2021-Sept. 30, 2022), engineering and operational efforts "were focused on optimizing and debottlenecking existing equipment, including separator control system performance, proportional fluid sampling maintenance to both the daily and monthly production fluid samples, and improving measurement system accuracy."

Routine maintenance was performed on three power generation turbines and two gas injection compressors at the OTP, Eni said, while minor capital projects included completion of Oooguruk drill site control room location and detailed design to relocate the Oooguruk tie-in pad control room.

Major capital projects included finalizing commissioning and startup of the seawater injection system booster pump at Oooguruk drill site.

"SWIS was started up in May 2020 allowing higher pressure and higher seawater injection rates at ODS," Eni said. "Since implementation, seawater supply has been consistently available at required volumes to optimize reservoir management."

Eni said startup of the Oooguruk drill site booster pump in the third quarter of

see **ENI WELLS** *page 7*

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ENI WELLS

2022 "will further increase injection pressures and rates in select wells."

The company competed and approved an engineering study to construct a 20 million cubic feet per day partial gas processing system at the Oooguruk tie-in pad "to mitigate gas processing constraints, reduce associated costs from KRU CPF-3, and unburden the CPF-3 gas compression system. Detailed engineering began in June 2021 and startup is forecast for late 2023."

Eni said the electrical power sharing project to interconnect the Oooguruk and Nikaitchuq power generation systems was approved. The project will allow more robust and efficient power sharing between the two Eni units. Detailed design is in progress and startup is forecast in 2024.

15th POD reservoir work

Eni said active development wells include 24 oil producers (18 Nuiqsut, four Kuparuk and two Torok), 13 injectors (10 Nuiqsut, two Kuparuk and one Torok) and one disposal well.

The original Oooguruk development plan called for ultimately using electric submersible pump completions to maximize drawdown and minimize gas lift associated Kuparuk River unit and hydraulic back-out effects, but all Oooguruk producing wells currently require gas lift, with gas lift capacity limited to 20 million cubic feet per day. Eni said high gas lift rate coupled with some 4 million to 12 million cubic feet per day combined Oooguruk formation gas "significantly increases the flowline pressure, reducing overall flowrates, and generates significant back-out rates at KRU, which is also primarily constrained by gas processing capacity."

Because of hydraulic effects and Kuparuk River back-out, "all OU wells cannot be produced concurrently using gas lift," Eni said, with an average of 12 of 22 available producing wells online in 2021 with total gas oil ratio determining which wells to produce.

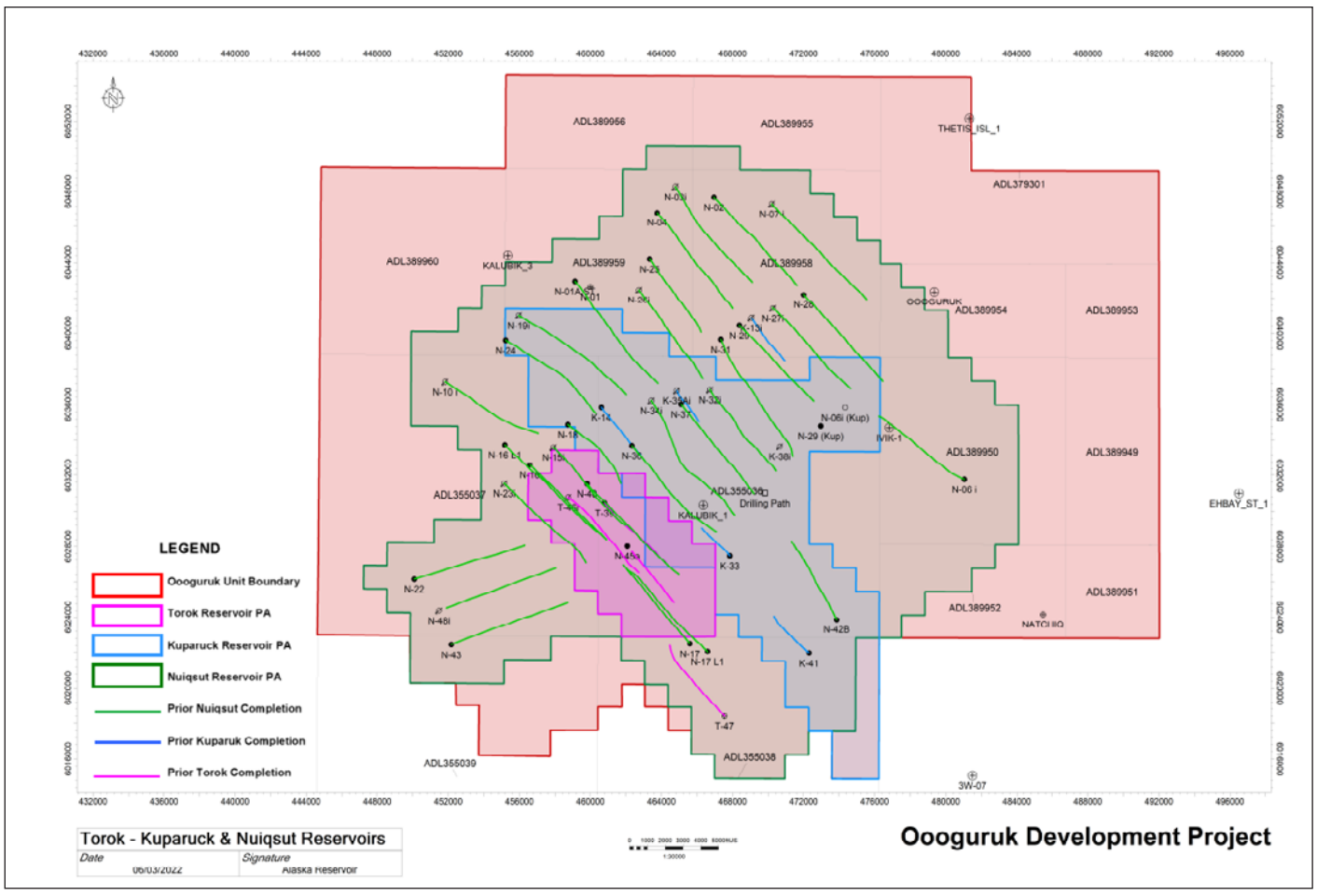
Eni said the main recovery mechanism for all three reservoirs at Oooguruk is waterflood with periodic miscible gas injection in the Nuiqsut. The seawater injection system, SWIS, which was started up in May 2020 has improved reservoir management by increasing uptime and supply pressure, improving throughput and voidage replacement at Oooguruk. Once the Oooguruk drill site booster pump goes into service, "water injection supply pressures can be boosted from 3,300 psi to 3,700 psi, where allowed, which will significantly increase injectivity and flood throughput in certain low injectivity wells." Eni said the Alaska Oil and Gas Conservation Commission has approved increasing the pressure limit to 3,700 psi for the Oooguruk Nuiqsut and Oooguruk Kuparuk oil pools, but the limit remains 2,800 psi in the Oooguruk Torok oil pool.

Oooguruk Torok PA

There are two producing wells in the Oooguruk Torok PA and one injection well.

Eni said there was no production from the OTPA during the 15th POD due to high gas-oil ratio required to produce the wells with gas lift and recurring tubing hydrate brockages in one of the wells.

There are plans and materials in place to install electric submersible pumps in both producing wells, reestablish OPTA production and then restore integrity in the tubing for a third well which has been shut-in since 2020 due to tubing to inner annulus pressure communication.



The company competed and approved an engineering study to construct a 20 million cubic feet per day partial gas processing system at the Oooguruk tie-in pad "to mitigate gas processing constraints, reduce associated costs from KRU CPF-3, and unburden the CPF-3 gas compression system. Detailed engineering began in June 2021 and startup is forecast for late 2023."

Oooguruk Kuparuk PA

The Oooguruk Kuparuk PA development includes seven wells. This area is a very mature flood, Eni said, and voidage replacement has been reduced over the last few years to minimize waterflood bypass while stabilizing reservoir pressure and the gas oil ratio.

"As a result, the producing Kuparuk water oil ratio and oil production had remained stable and ultimate recovery is expected to exceed expectations."

One well, ODSN-29 Kuparuk in the eastern Ivik fault block accounted for 88% of OKPA production in 2021, Eni said.

Oooguruk Nuiqsut PA

There are 29 wells in the Oooguruk Nuiqsut development area, 18 producers, 10 injectors and one long-term shut-in well.

During the 15th POD period, Eni said ONPA under-saturated water-alternating-gas reservoir management included "maximizing voidage replacement and managing producing gas oil ratios by cycling producing wells on and off production where possible operationally."

The cumulative voidage replacement ration through 2021 was 53%, consistent with the injector-to-producer ratio and the ONPA pattern layout. Flood throughput increased with continued consistent water injection and ample supply following implementation of the seawater injection system. The monthly voidage replacement ration ranged from 67% to 142% in 2021, averaging 98%, reducing the overall gas oil ratio and increasing area pressure, Eni said, resulting in stabilized or increased oil production and water production and reduced cycling. "Some of the water increases appear to be from unexpected connections which are being evaluated and monitored," the company said.

Rig workovers are planned during 2022 and 2023 to restore and improve production at three wells, with additional wells being considered.

"Future ONPA development plans include twelve additional Nuiqsut wells, eight from available well slots and four well slot reclaims," Eni said.

15th POD drilling

Rig mobilization, recommissioning of the rig support complex and workover planning were reinitiated during the 15th POD, and recompletion of the ODSN-06 was started on May 6. Additional rig activities planned to be completed by Sept. 30 include recompleting ODSN-02 with an ESP, replacing the failed ESP in ODSK-41 and replacing the failed ESP in ODSN-31, which has been shut-in since March 2021 due to a failed SSSV.

Well interventions and maintenance performed in the unit by June 16 included four coil tubing unit jobs and three e-line/slickline jobs.

16th POD proposed facilities work

In its 16th proposed POD, Eni said it will perform a minor three-day turnaround in the summer of 2023 allowing the mechanical tie-ins for the partial gas processing project to be installed. The company will continue engineering and operational efforts in optimizing and debottlenecking existing equipment, and is evaluating minor capital projects including relocating the Oooguruk tie-in pad control room, "installation of diesel pipeline corrosion coupons, improved diesel pipeline leak detection system, final upgrades to the ODS polar bear camera system, upgrades to the OTP compressor lubrication system and installation of a chemical injection system for the seawater injection pipeline."

Major capital projects, Eni said, include final engineering, fabrication and installation of the partial gas processing project to install 20 million cubic feet per day gas processing and compression equipment at the Oooguruk tie-in pad, a project which "will mitigate gas processing constraints and reduce associated costs from CPF-3." Startup for the project is scheduled for December 2023, during the 17th POD.

Another major capital project is the electrical power sharing project between Nikaitchuq and Oooguruk, "with engineering and fabrication occurring in this period. This will allow more robust and efficient power system sharing between the two development projects." This project is scheduled for startup in the summer of 2024, during the 17th POD period.

16th POD reservoir management, drilling

ENI plans to further optimize waterflood in the Oooguruk Kuparuk PA during the 16th POD and the under-saturated water-alternating gas flood in the Oooguruk Nuiqsut PA. It also plans to reestablish Oooguruk Torok enhanced recovery operations by repairing one well, ODST-46i, following workovers on two other wells — ODST-39 and ODST-45A.

A number of rig workovers are planned:

•ODSN-06 — workover to isolate Nuiqsut formation, perforate Kuparuk formation and initiate Kuparuk production.

•ODSN-02, ODST-39 and ODST-45A — recompletion with electric submersible pump (ESP).

•ODSK-41, ODSN-31 and ODSN-25 — ESP replacement.

Eni said it is considering additional workovers and timing of those listed may change "depending on funding and material availability."

Drilling activity is presently planned to restart in mid-2023 "targeting two new wells to be drilled in 2023 and to be fracture stimulated and put on production in 2024," Eni said, noting — as with the workovers — that the drilling plan is subject to change, in this case based on the "global economic environment and company investment objectives."

Eni said it is also evaluating two appraisal wells which would target the northern Nuiqsut reservoir. It said the wells, ERD-N01 and ERD N-02 are within the estimated 22,000-foot drilling radius of the Oooguruk drill site, with the primary objective of the wells to test productivity and oil quality in leases ADL 379301, ALD 389953 and ADL 389949. Those tracts are within the unit boundaries at Oooguruk, west and northwest of existing participating areas. ●

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EXPLORATION & PRODUCTION

Hilcorp plans to drill two new gas wells

Wells would be drilled from the Pearl pad, south of Ninilchik unit, where Pearl 2A has been tested, but is not yet on production

By KRISTEN NELSON
Petroleum News

Hilcorp Alaska has applied to the Alaska Oil and Gas Conservation Commission for spacing exceptions for the Pearl 8 and Pearl 9 wells. Spacing exceptions are required because the wells would drill, complete, test and produce in an undefined gas pool and the Ninilchik Beluga-Tyonek gas pool within 1,500 feet of a property line where owners and landowners are not the same on both sides of the line, AOGCC said in a public notice.

The commission has tentatively scheduled a public hearing for Aug. 9 at 10 a.m. in its Anchorage offices, with call-in participation at 907-202-7104 conference ID 837 155 757#. If a request for a hearing is not filed by 4:30 p.m. July 26, AOGCC said, it may issue an order without a hearing.

Pearl delineation wells

In its June 27 application, Hilcorp Alaska told the commission it is the sole working interest owner of the affected oil and gas leases and operator of the Ninilchik unit.

It is seeking permission to drill two grassroots wells, Pearl 8 and Pearl 9, in the Pearl undefined gas pool and the Ninilchik Beluga/Tyonek gas pool, within 1,500 feet of a property line where owners and landowners are not the same on both sides of the line and within 1,500 feet of the exterior boundary of the area of Conservation Order 701C.

A map provided with the application shows the Pearl 8 well running almost due north from the pad, which is just south of the unit boundary, while a map of the Pearl 9 well path shows it running northeast from the pad.

"The Pearl Prospect is located approximately 2.5 miles north of Ninilchik, Alaska and directly south and adjacent to the Ninilchik Unit/Field. At the time of this application, Pearl 2A has been tested, but is not capable of producing to sales," Hilcorp said. The closest producing well, the company said, is Paxton 5 in the Ninilchik unit northeast of Pearl 2A and Pearl 8.

Once Pearl 8 and Pearl 9 have been drilled and tested, "surface facilities will be installed to enable production from the Pearl 2A, Pearl 8 and Pearl 9," Hilcorp said.

Discontinuous channel sands

The company said it expects the productive sands in the Pearl 8 and Pearl 9 will be "discontinuous channel sands" in the Beluga and Tyonek formations in the undefined gas pool — outside the Ninilchik unit — and the Beluga/Tyonek pool in the unit, which could not be produced by wells conforming to applicable spacing restrictions.

Hilcorp said that following successful testing and completion of the new wells it plans to submit an application to adjust the Ninilchik unit to the Alaska Department of Natural Resources' Division of Oil and Gas "to include any lands reasonably estimated to be productive" or alternative, apply to form a separate unit and participating area.

There is complex ownership involved in the Pearl field, Hilcorp said, and it will allocate production in accordance with DNR's unit and participating area decision authority and AOGCC's applicable rules.

Ninilchik is currently the most prolific of the Cook Inlet gas fields, accounting for 15.6% of inlet gas production in May, the most recent month for which AOGCC production data is available. ●

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INSIDER

The FBI director also said the Chinese government is "set on stealing your technology, whatever it is that makes your industry tick, and using it to undercut your business and dominate your market."

McCallum and Wray accused China of deploying a global network of spies to hack and penetrate governments, businesses, and universities worldwide.

In USA Today's coverage of the joint FBI-MI5 press conference, it said the message the U.S. wants to send is: "There are no free lunches if you see an offer from … a Chinese business entity that seems too good to be true."

—KAY CASHMAN

Alaska in talks with Hilcorp, Conoco on LNG

ACCORDING TO A RECENT Bloomberg report, the state of Alaska is in talks with Hilcorp Energy and ConocoPhillips to secure natural gas for a project that would export liquefied natural gas to Asia.

Gov. Mike Dunleavy and Frank Richards, president of Alaska Gasline Development Corp., met with officials from both companies during a recent visit to Houston about securing feedgas for the Alaska LNG project, the governor told Bloomberg in an interview.

"While terms of the discussions were not disclosed, the project has a federal permit to make and export 20 million tons of liquefied natural gas per year," Bloomberg reported, noting "ConocoPhillips said it supports selling gas from the wellhead to the Alaska LNG project. Privately held Hilcorp didn't respond to a request for comment."

The feedgas talks follow a June trade mission to Japan where "Dunleavy and Richards met with company officials from JERA, Tokyo Gas, INPEX and other potential customers. The project has signed letters of intent with Asian buyers whose identities are protected by non-disclosure agreements, Richards said," per the Bloomberg report.

—KAY CASHMAN

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NIKAITCHUQ NORTH

2023, contained a brief plan of exploration for Nikaitchuq North.

First well spud

Eni spud the first Nikaitchuq North exploration well, NN-01, in late December 2017 from Spy Island Drillsite into the Harrison Bay Block 6423 OCS unit. The distance between the Spy Island Drillsite, or SID, and the federal unit is approximately 6 miles.

SID is a man-made gravel island in shallow state waters off Oliktok Point where the Nikaitchuq unit's onshore production and processing facilities are located.

ENI's plan in 2017 was to drill two ultra-extended reach wells over a two-year period. Drilling restrictions designed to protect the environment allowed Eni to drill vertically only during frozen ice conditions and the open water season (between July 15 and Sept. 15); the lateral portion of a well could only be drilled during frozen ice conditions.

After some stops and restarts due to restricted drilling periods and drilling problems, NN-01 reached a vertical depth of 8,131 feet and a measured depth of 30,010 feet, shy of its 35,000-foot MD target.

The well was officially suspended by Eni because of drilling "complications."

Shell won't participate

Eni anticipated continuing the drilling of the NN-01 well in early February 2020, but instead announced it would not finish drilling NN-01 or sidetrack it; rather it would try again in second quarter 2020 with a new well, NN-02.

One of the reasons Eni gave for stepping out north of the Nikaitchuq unit to test the Nikaitchuq North prospect was it wanted new oil to take advantage of significant spare capacity in the standalone Nikaitchuq unit production facility, which can handle 40,000 barrels per day and could easily be expanded to 50,000 bpd, according to Eni.

However, Eni's 50% working interest partner (Shell) elected to go non-consent, meaning it would not participate and pay its share of the cost of drilling and testing the NN-02 well.

Eni applied for and received from the U.S. Bureau of Safety and Environmental Enforcement a suspension of operations, or SOO, for two years until April 2, 2022.

"Due to Shell's decision to not participate in the drilling of the NN-02 well, Management decided to allow the SOO to expire in April 2022," Eni said in its proposed Nikaitchuq unit POD. "As a result of the SOO expiry the Federal Unit (Harrison Bay Block 6423 Unit) and corresponding leases have terminated."

NN-02 would have had a vertical depth of 8,329 feet and a measured depth of 38,173 feet. Proposed sidetracks would measure about 1,000 feet, Eni said in 2020.

Spare processing capacity

One of the reasons Eni gave for stepping out north of the Nikaitchuq unit to test the Nikaitchuq North prospect was it wanted new oil to take advantage of significant spare capacity in the standalone Nikaitchuq unit production facility, which can handle 40,000 barrels per day and could easily be expanded to 50,000 bpd, according to Eni.

May production from the Nikaitchuq unit averaged 18,574 bpd in May, up 540 bpd, 3%, from an April average of 18,034 and up 7.7% from a May 2021 average of 17,250 bpd.

Geological target

Prior to Eni allowing its federal leases and unit to terminate, the U.S. Bureau of Ocean Energy Management, or BOEM, said Eni's NN-02 well would be "targeting the same seismic anomaly" as the first well, NN-01.

Like the first ultra-extended reach well, NN-02 was to be an S-shape wellbore into the target reservoir.

In the public portion of the paperwork Eni filed with the state and feds, geological information about the Nikaitchuq North target reservoir was not released.

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

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

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

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

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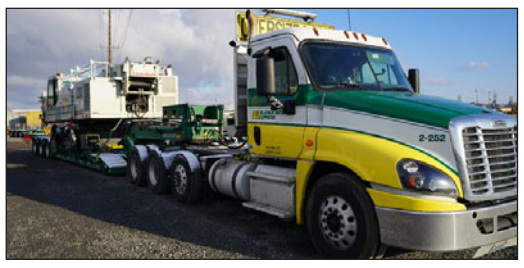
Petroleum news

Oil Patch Bits

Alaska West Express receives safe truck fleet award

As reported by Lynden News July 7, ConocoPhillips and the Alaska Trucking Association presented Alaska West Express with the 2021 Alaska Safe Truck Fleet of the Year Award in the highway division. The award recognizes the hard work and focus on health and safety that all Alaska West Express employees have demonstrated over the past year. "It is an honor and very humbling to be around a team of individuals that strive to be the best at what we do every day," says Tyler Bones, Alaska West Express director of HSSE. "It is always special when the hard work of our employees and contractors are recognized. Alaska West operated 4.6 million miles accident free in 2021. Considering the challenging operating conditions on the Dalton Highway, this is a remarkable achievement."



ALASKA WEST EXPRESS

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TIDAL ENERGY

Island, while the other would have been placed at least 5 miles from the first.

In April 2021 Christopher D.L. Lee, president and CEO of TEC, filed a revised permit application with FERC, saying that after corresponding "with dozens of experts in many different disciplines related to this hydropower project" he had concluded that the tidal bridge concept would not pass the environmental assessment for the permit, "due to its sheer size, footprint and impact on its environment."

Alternative proposals

Instead TEC was proposing the construction of six tidal barrage-style power stations, each about half a mile long and 300 feet wide. In total the power stations would hold 242 turbine generators, with a total peak output of 2,420 megawatts. An alternative, should the barrage proposal not pass environmental muster, would be the installation of three fields of individual tidal turbine generators, with layouts rather like those of solar energy farms. TEC also proposed the construction of an electrolysis plant in Anchorage, for the production of green hydrogen from any excess tidal power.

In his July 8 progress report Lee said that TEC has now determined that the tidal barrage design proposed in 2021 is "too environmentally invasive to pass muster with the many regulatory agencies tasked with the licensing the project." TEC is now focused on the tidal field concept, using turbines that could be seafloor or surface based, depending on a determination of an appropriate engineering solution. Part of the design concept involves the placement of turbine fields, positioned several miles apart to soften the impact of the turning tidal currents on the total power output.

In whatever configuration the arrays of turbines in the tidal fields are constructed, the result would be a gigawatt scaled tidal energy project, able to fully power the two Southcentral Alaska grids that it is nestled between, as well as to use excess energy to produce green hydrogen, Lee told the commission.

Lee said that his company has reviewed available technologies for marine turbine power generators and has identified three companies that offer turbines capable of generating power at megawatt scale. Two of these companies have signed memoranda of understandings for feasibility analyses and resource assessments for the proposed Turnagain Arm siting, Lee said. TEC has also met with other companies that specialize in smaller scale turbine systems, he said.

Lee also told the commission that the TEC team has met with the Alaska congressional delegation, and with representatives from the Railbelt electric utilities, the Alaska Energy Authority, the Denali Commission, the Alaska Power Authority, the Renewable Energy Alaska Project, the University of Alaska Fairbanks, Alaska Center for Energy and Power, Cook Inlet Keepers and Cook Inlet Region Inc.

"There do not seem to be any objections to the idea of the project," Lee told the commission.

—ALAN BAILEY

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WILLOW SCALE

Changes in 2022 draft SEIS

The 2020 EIS contained four alternatives — including a no action alternative and ConocoPhillips' proposal.

In the 2022 draft SEIS there are five alternatives — again including a no action alternative. The additional alternative scales back the project by eliminating one of the drill sites proposed by ConocoPhillips and delaying action on another drill site.

BLM said since publication of the final EIS in 2020, ConocoPhillips has continued with permitting and detailed engineering and some components of the project have undergone further refinement. The agency said the SEIS incorporates a number of updates to the project.

Updates include changes in airstrips, updating to mine site footprints and revisions to the estimated oil and gas production schedule "based on additional characterization of the target reservoir and further engineering refinement."

BLM also said specific dates have been replaced by references to year 1, year 2, etc., allowing flexibility in the project start date to account for unforeseen delays.

"Construction is typically assumed to start in either the winter 2022/2023 or winter 2023/2024," the agency said.

Under Alternative A, the no action alternative, the project would not be constructed. Oil and gas exploration would continue.

Alternative B

Alternative B, the proponent's project, would extend an all-season gravel road from Greater Mooses Tooth 2 southwest toward Willow and gravel roads would connect all facilities, including the Willow processing facility, Willow operations center, airstrip and five drill sites — Bear Tooth 1, 2, 3, 4 and 5.

There would be 484 acres of gravel fill, a constructed freshwater reservoir, four valve pads, four pipeline pads, two water source access pads, eight road turnouts with subsistence access ramps, horizontal directional drilling pipeline pads at the Colville River and as many as three boat ramps for subsistence use. There are 37.4 miles of gravel road and seven bridges, with infield pipelines connecting individual rill sites to the WPF and export-import pipelines connecting the WPF to existing North Slope infrastructure. Diesel would be piped to Alpine and trucked to the project area.

All alternatives require sealift module delivery.

Alternative C

Alternative C has disconnected infield roads. It would include the gravel access road between GMT2 and Willow, but there would not be a gravel road between the WPF and Bear Tooth 1.

BT1, BT2 and BT4 would be connected by gravel road, as in Alternative B, for a total of 35.4 miles of gravel roads with six bridges.

WPF, South Willow operations center and the primary airstrip would be about a mile east of their locations in Alternative B, closer to the eastern Bear Tooth unit boundary.

A second airstrip, storage and staging, and WOC would be near BT2 to accommodate personnel and materials transported between the South WOC and North WOC and BT1/BT2/BT4. A 3.6-mile long annual ice road would allow for movement of large equipment and consumable materials to BT1/BT2/BT4. Infield pipelines would connect all drill sites to the WPF.

The gravel footprint would be 545.9 acres, with four valve pads, four pipeline pads, three water source access pads, eight road turnouts with subsistence access ramps, HDD pipeline pads at the Colville River, one boat ramp and expansion of the gravel pad at Kuparuk CPF2.

Alternative D

Alternative D would co-locate the WPF and BT3, construct four additional drill sites, the WOC, pipeline and valve pads, a constructed freshwater reserve, two water source aces road and pads, gravel roads connecting project facilities, six bridges, an airstrip, a staging pad near GMT2, a boat ramp and expansion of existing gravel pads at Alpine drill site 1 and Kuparuk CPF2. Total gravel footprint would be 482.7 acres.

There would not be al all-season gravel road to GMT1 but gravel roads would connect drill sites with other Willow facilities; there would be an annual 12.5 mile ice road between GMT2 and WPF.

Alternative D would minimize the project footprint and fill, reduce the number of bridges and "lessen the length of linear infrastructure on the landscape to decrease effects to caribou movement and subsistence."

Alternative E

There would be only four drill sites under the new alternative, E, with BT4 eliminated and BT5 deferred. The alternative includes the WPF, the WOC, four valve pads, four pipeline pads, five water source access pads, gravel roads connecting the project to GMT2 and all drill sites to the WPF, an airstrip and three subsistence use boat ramps.

BT2 would be relocated north of Fish Creek "to gain access to a portion of the target reservoir that would otherwise be captured by BT4."

BT5 would be relocated some 1.8 miles to the northeast to avoid two yellow-billed loon buffer setbacks.

BT1 and BT2 would be some 100 feet longer to accommodate additional wells, allowing access to "portions of the resource that would otherwise be accessed from BT4 and the alternate BT2 location."

BLM said Alternative E was developed "to reduce surface impacts, in response to the District Court's remand decision."

BT5 would not be authorized in the Willow master development plan record of decision, BLM said, "it would require a separate future decision."

BT5 construction would start at the earliest in year 7, providing overlap with other construction and the beginning of drilling.

"If BT5 construction is deferred beyond Year 7, BT5 impacts would be delayed, resulting in extended temporal impacts," BLM said, although impacts to surface resources would be lessened because there would be less overall project activity. ●

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METHANE HYDRATE

methane hydrate test well, completed in early 2019. The drilling came as part of a research project conducted by a partnership between the U.S. Department of Energy's National Energy Technology Laboratory; Japan Oil, Gas and Metals National Corp.; the U.S. Geological Survey and Petrotechnical Resources of Alaska. BP, then operator of the Prudhoe Bay unit, oversaw the drilling. ASRC is also involved in the program.

The division says it understands that ASRC is finalizing an agreement with Hilcorp North Slope, now Prudhoe Bay operator, for conducting a methane hydrate test program within the impacted lease area.

Further drilling planned

After the test well was completed in 2019, subsequent permit applications filed with the division by ASRC indicated an intent to drill further wells in the winter of 2021-22, to be followed by a hydrate production test program in 2021 or 2022. The concept was to drill two additional wells: a methane hydrate production well and a monitoring well, for determining the subsurface response to the production. The well that had already been drilled would become a second monitoring well.

According to information published by NETL, the test well completed in early 2019 penetrated two highly saturated methane hydrate reservoirs. The deeper of these reservoirs appeared particularly suitable for production testing, while the shallower reservoir could provide additional research opportunities.

And in April 2019 ASRC Energy Services Alaska applied to Alaska's Division of Mining, Land and Water for the use of gravel pads across the region between the Colville and Canning Rivers for subsurface temperature monitoring in connection with the methane hydrate test program.

However, no further drilling for the test program has happened. Although the research partnership has not issued any status report on the program, the drilling plans may have been impacted by the hiatus in North Slope drilling as a consequence of the COVID pandemic.

A huge potential resource

Methane hydrate is a solid in which molecules of methane, the primary component of natural gas, are concentrated inside a lattice of water molecules. Huge quantities of the material, which remains stable within a certain range of relatively high pressures and low temperatures, are known to exist around the base of the permafrost under the North Slope.

Gas can be released from hydrates through some combination of elevating the temperature or reducing the pressure of the hydrate resource. Although there have been demonstrations of short-term hydrate production, no one has yet conducted a sustained production test of the type envisaged on the North Slope.

There is international interest in the feasibility of producing natural gas from hydrates — hence the North Slope project. Assuming that production is technically possible, the commercial practicalities of producing gas in this manner on the North Slope would also depend on numerous factors, including some means of shipping the gas to market or of using the gas in some other way.

—ALAN BAILEY

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OIL PRICES

find willing buyers in China, India and South America.

The falling prices may be a temporary phenomenon, according to Chevron CEO Michael Wirth.

Supply is tight, and the risks remain skewed towards the upside, Wirth said at the CNBC Evolve Global Summit July 13.

"What I would say is that the tightness in supply hasn't gone away, and so to the extent that we were to see China reopen fully — and we're still seeing some COVID restrictions there — see air travel return fully, there are some up legs in demand that could start to really pull hard on that supply again," he said.

A rally from the previous week that took ANS above $110 began to unwind July 11, as ANS fell 68 cents to close at $109.79, WTI fell 70 cents to close at $104.09 and Brent rose 8 cents to close at $107.10.

ANS rose $2.81 July 8 to close at $110.47, while WTI rose $2.06 to close at $104.79 and Brent rose $2.37 to close at $107.02.

On July 7, ANS jumped $4.13 to close at $107.66, WTI leapt $4.20 to close at $102.73 and Brent lifted $3.96 to close at $104.65.

Despite the price volatility, from Wednesday-to-Wednesday ANS closed on July 13 just 47 cents lower than its closing price of $103.52 set on July 6.

The price gains July 13 came despite a report released the same day by the U.S. Energy Information Administration that for the week ending July 8, commercial crude oil inventories — excluding the Strategic Petroleum Reserve — increased by 3.3 million barrels from the previous week. At 427.1 million barrels, inventories were 5% below the five-year average for the time of year.

Total motor gasoline inventories jumped as well, by 5.8 million barrels to stand at 5% below the five-year average for the time of year.

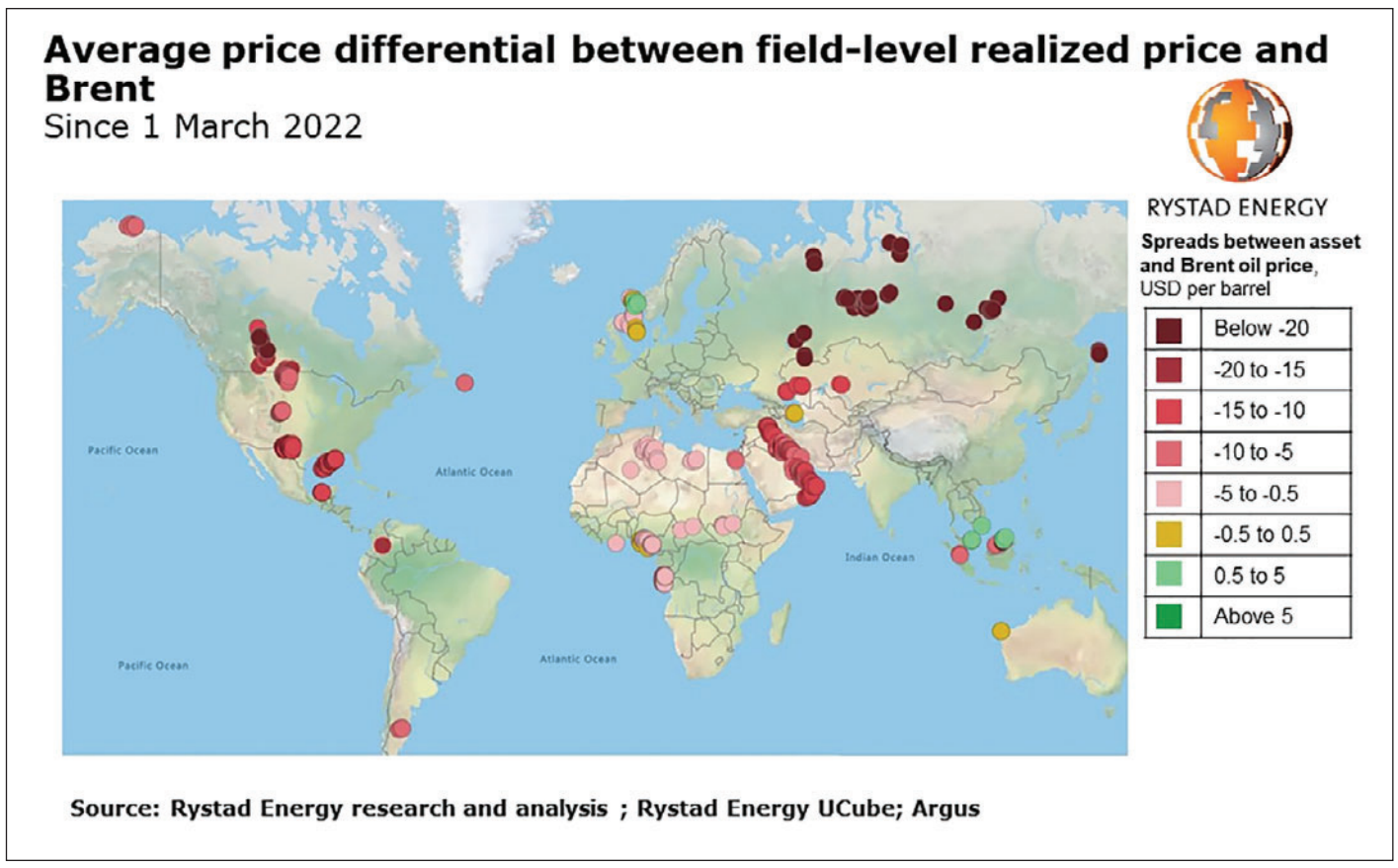
Crude in the Strategic Petroleum Reserve fell 6.9 million barrels on the week from 492.0 million barrels to 485.1 million barrels, the EIA said.

WTI and Brent continued to rally modestly in early trading July 14, but as Petroleum News went to press, both indexes erased the gains and were trading in the red.

Russia oil tax income hit by discounts

Russian oil may be finding buyers, but the Russian government is taking a hit on tax revenue.

Russia's government could lose some $85 billion in oil and gas tax income in 2022 due to the significant discount to Urals blend crude, Rystad Energy said in a July 12 release.



Crude in the Strategic Petroleum Reserve fell 6.9 million barrels on the week from 492.0 million barrels to 485.1 million barrels, the EIA said.

The Urals blend — Russia's key oil reference — has been trading at around $30-$40 per barrel lower than Brent since April, Rystad said.

"The steep discount on Urals shows that some of the sanctions imposed on Russia are having an impact and are reducing potential oil and gas income to the Russian government," Rystad said.

Rystad said that although Brent surged past $100 per barrel following Russia's invasion of Ukraine in late February, not all producers are benefitting equally from the sustained high crude prices as the war rages on.

Price differentials between Brent and other crude streams have widened considerably, and Brent is currently trading at a premium to almost all other crude streams, it said.

For Russia, Rystad estimated that the total government income for 2022 would be around $295 billion if all oil assets realized the Brent oil price.

"By using an average fixed spread of $40 per barrel between the realized price and Brent, we estimate that the tax income is reduced by $85 billion over the whole year, an almost 30% reduction compared to the 'no spread' case," Rystad said.

The consultancy estimates that the Russian government will earn around $210 billion in oil and gas tax income this year.

"We could potentially start to see the impacts of Western sanctions on Russian oil and gas revenues," said Daria Melnik, Rystad senior analyst. "The steep discount on Urals is costing the Russian government, while providing cheaper energy to some Asian economies."

"While the sanctions are likely to hit revenues, oil production has remained higher than expected, demonstrating that Russia's upstream sector has adapted quickly to sanctions on sales," Melnik said. ●

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ALKAID 2

drilled by BP Exploration (Alaska) starting in the 1990s, and the technology has been used ever since on the Slope.

Pantheon Resources is an AIM listed oil and gas company with 100% working interest in all of its oil projects spanning 153,000 acres adjacent and near to the Dalton Highway and Trans Alaska Pipeline System, or TAPS, which are the main transportation highway and export pipeline. Pantheon's acreage is operated by affiliate Great Bear Pantheon.

Patrick Galvin, formerly commissioner of the Alaska Department of Revenue, is chief commercial officer and general counsel for Great Bear Pantheon.

PAT GALVIN, GREAT BEAR PANTHEON

Nabors 105AC is drilling Great Bear Pantheon's Alkaid 2 well.

Phased development

Because of its close proximity to the 800-mile trans-Alaska oil pipeline and the Dalton Highway, Pantheon said the Alkaid accumulation is ideal for a phased development, which would minimize upfront capital expenditure and allow for future capital needs to be partly funded through production revenues, yielding higher internal rates of return.

"As our first horizontal well, Alkaid 2 is an important operation for Pantheon. The long-term production test through the horizontal section will define the resource and aid the understanding and future development potential of Alkaid. But most importantly, if successful, it will begin generating revenue for the company," said Jay Cheatham, CEO of Pantheon Resources.

While the company believes the best well design to exploit the Alkaid anomaly would involve 8,000-plus foot lateral sections, in this first well Great Bear Pantheon will adopt a more conservative approach with a shorter lateral to minimize operational risk.

According to a July 7 Pantheon press release the Alkaid 2 well will assess three "impactful objectives" over multiple formations:

1. Production testing a proven oil formation encountered in Alkaid 1, which is approximately 4.5 miles from Alkaid 2.

2. Exploring the deeper potential for oil in that zone.

3. Appraising an extension of oil discovered in the Shelf Margin Deltaic, or SMD, at Alkaid 1 and Talitha 1.

Resource estimates

Pantheon's resource estimates for the Alkaid horizon are as follows:

• Oil in place 900 million barrels of oil.

• Recoverable resource: 90-135 million barrels.

Alkaid 1 tested an average of 108 barrels of oil per day via a small "through-tubing single frac," which perforated 6 feet of the 240 foot net pay interval, Pantheon said.

Alkaid 2 will test this same zone through a long horizontal section accessing several thousand feet of oil bearing section.

Exploration potential

According to Pantheon's July 7 release Alkaid 2 has significant exploratory potential immediately below the total depth at Alkaid 1. As part of the current drilling program Great Bear Pantheon intends to evaluate the extent of this deeper oil column.

Alkaid 1 was terminated within the oil zone at a time when regional flooding of the Dalton Highway occurred. Based on seismic and other analytical analysis, the company believes the Alkaid horizon's oil zone is substantially thicker than drilled to date, offering the potential for additional resource growth.

Appraisal of SMD

Great Bear Pantheon's recent oil discovery at Talitha A in the Shelf Margin Deltaic formation has "upgraded the potential for the SMD to produce oil at the Greater Alkaid location, as well as at the Talitha project," Pantheon said.

The company estimates the SMD contains 2.6 billion barrels oil in place and a contingent resource of 404 million barrels.

In a success case, the Pantheon believes a large portion of this resource could be developed from the Dalton Highway which would represent a considerable near term development opportunity, especially if combined with the deeper oil zone utilizing the same production infrastructure.

"We have discovered a lot of oil on the ANS across our Theta West, Talitha and Greater Alkaid projects which are estimated by management to contain over 23 billion barrels of oil in place and over 2.3 billion barrels of recoverable resource in those horizons that have flowed oil, and Alkaid 2 could add to these estimates," Bob Rosenthal, technical director for Pantheon, was quoted as saying in the July 7 release.

—KAY CASHMAN

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