Petroleum news

Vol. 25, No. 43 • www.PetroleumNews.com A weekly oil & gas newspaper based in Anchorage, Alaska Week of October 25, 2020 • $2.50

page 2 With 200 installed, rural Alaska leads way for microgrid systems

More competition for O&G capital for Alaska from L 48 shale plays

ALASKA'S LARGEST OIL PRODUCER ConocoPhillips' planned acquisition of Concho Resources in a $9.7 billion all-stock deal gives the big independent more investment opportunities in Lower 48 and Canada unconventional plays, a region that already competes with the North Slope for capital.

Not to suggest ConocoPhillips is going anywhere, but in October 2014 Alaska lost Pioneer Natural Resources to the lure of the Lower 48 shale fields. For that matter, as BP Exploration was preparing to leave Alaska it expanded its Lower 48 unconventional holdings with a $10.5 billion acquisition of BHP's American

see INSIDER page 8

AOGCC denies reconsideration; ACC challenging constitutionality

The Alaska Oil and Gas Conservation has denied a request for reconsideration of its new bonding requirements by Alaskan Crude Corp.

ACC is challenging the constitutionality of the increase in bonding amounts as well as what it argues are regulations exceeding AOGCC's statutory authority.

In an Oct. 15 decision the commission upheld a $1.2 million bonding requirement for the company.

ACC is operator of record for three wells; it has a $200,000 AOGCC bond in place, and the remaining $1 million is due in two annual $500,000 payments.

This is the final AOGCC order on the matter. ACC has 30 days to appeal the commission's order to Alaska Superior Court.

see AOGCC DENIAL page 9

Alberta poised to test market with auctions, higher minimum bids

SONYA SAVAGE

Through the 1990s and the first decade of this century, the Alberta government feasted on the sale of oil and natural gas exploration rights at its twice-monthly auctions, times when raking in anything less than C$2 billion a year was a source of worry.

Those days are long gone and never likely to return.

During a protracted period of bearish commodity prices, compounded by the negative impact of COVID-19 on capital spending, Alberta

see AUCTION TESTS page 4

Alberta looks to diversify energy industry with geothermal, hydrogen

The Alberta government has set its sights on the New Energy Age by promising geothermal regulations this fall and targeting global hydrogen exports by 2040 to resuscitate its natural gas industry.

Geothermal technology — which is well advanced in the United States, Indonesia, the Philippines, Turkey, New Zealand and Iceland — harnesses natural heat energy generated beneath the Earth's crust, with heat pumps extracting steam or hot water to surface level.

Three types of geothermal power currently process the energy source — dry steam power, flash steam power stations and binary cycle power stations.

The constant and predictable availability of geothermal

see ENERGY DIVERSITY page 10

FINANCE & ECONOMY

Oil price lift off

US air travel gains altitude; coming supply constraints hike price forecast

By STEVE SUTHERLIN

Petroleum News

Jet fuel demand may climb higher as U.S. passenger numbers lifted above the 1 million mark for a single day, according to Transportation Security Administration passenger screening numbers. The agency cleared 1,031,505 passengers for takeoff Oct. 18.

The TSA said 6.1 million people passed U.S. airport checkpoints between Oct. 12 and Oct. 18 — the highest weekly traveler volume it reported since the pandemic sent passenger counts into a tailspin in March.

Daily screenings plunged below 100,000 passengers on April 14, a 96% reduction from 2019. While Oct. 18 numbers — the highest since March 16 — are a ten-fold improvement from the low for 2020, that passenger count is less than half of the 2.6 million that passed TSA checkpoints Oct. 18, 2019.

The TSA numbers nonetheless offer a bit of blue sky to the outlook for oil prices. The recovery in jet fuel demand has lagged behind that of other transportation fuels since the pandemic began.

On the supply side, this year's decline in North American light tight oil production is likely to con-

see OIL PRICES page 11

EXPLORATION & PRODUCTION

Pikka on track for 2025

Oil Search continues evaluating last winter's Mitquq and Stirrup discoveries

By KAY CASHMAN

Petroleum News

Oil Search's summer campaign on Alaska's North Slope has ended with all work planned for the first phase of the three-phase Pikka development completed, providing year-round access to the project, the company said Oct. 20 in its third quarter report.

The summer program involved finishing the following:

- Nanushuk access road to first drilling pad (ND-B road).
- Nanushuk operations pad.
- Nanushuk process facility pad.
- Bridge installation across the Miluveach River.

Further appraisal drilling of the Mitquq and Stirrup trends will be required to confirm the size and extent of these discoveries, with results to date continuing to support the potential development of Mitquq as a satellite to Pikka and Stirrup as a potential stand-alone development."

In an Aug. 25 interview with Petroleum News, Oil Search Managing Director Keiran Wulff said the company is now focused on developing Pikka's big Nanushuk reservoir (and smaller

see PIKKA ON TRACK page 7

GOVERNMENT

Some bonding reductions

AOGCC to amend regs, reducing some bond amounts, include some exemptions

By KRISTEN NELSON

Petroleum News

The Alaska Oil and Gas Conservation Commission is proposing changes to its bonding regulations which would amend the permitted wellheads bond amount table and allow a reduction in the requisite bond amount if an operator has a bond in place with the landowner dedicated exclusively to plugging and abandonment.

The commission adopted new bonding requirements in May 2019 after a lengthy series of hearings, reflecting its concern that companies could abandon wells, leaving the landowner, typically the State of Alaska, to pick up the cost for plugging and abandonment.

The proposed changes to the wellheads bond amount table are for 40 or fewer permitted wellheads.

Prior to May 2019, the commission's bonding requirement to secure plugging and abandonment had been $100,000 for a single well and $200,000 for multiple wells. The May 2019 changes raised that to $400,000 for one to 10 permitted wellheads; $6 million for 11-40 wells; $10 million for 41-100 wells; $20 million for 101-1,000 wells; and $30 million for more than 1,000 wells.

The changes the commission is proposing are

see BONDING REDUCTIONS page 10

ALTERNATIVE ENERGY

Leading the way for microgrid systems

Rural Alaska communities implementing cutting edge renewable energy and integration systems in effort to reduce diesel dependency

By **ALAN BAILEY**
For Petroleum News

While the Alaska Railbelt has ready access to natural gas for power generation, rural communities in the state have long had to rely on the use of expensive and erratically priced diesel fuel to meet their electricity production needs. For a number of years the rural communities have been implementing renewable energy systems in an effort to displace the use of diesel with more predictably priced and affordable generation systems. The consequent need to integrate several different power sources, each with varying generation characteristics, into single microgrids for village electricity supplies has placed rural Alaska at the cutting edge of these microgrid and renewable energy integration technologies, officials engaged in rural power supplies told a meeting of Commonwealth North on Oct. 14.

Early adoption in rural Alaska

Rural Alaska investigates and adopts new technologies well in advance of the Railbelt and major grids worldwide, often by decades, said Rob Roys, deployment director for Launch Alaska, an organization that facilitates the implementation of renewable energy and other environmentally

see **MICROGRID SYSTEMS** *page 3*

KOTZEBUE ELECTRIC ASSOCIATION

Kotzebue Electric Association's solar and wind farm. Advanced technology integrates wind and solar energy with diesel generation and battery storage to reduce diesel consumption.

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MICROGRID SYSTEMS

friendly systems in Alaska. Rural electric utilities began incorporating utility scale wind technology into their grids as early as 1997, Roys said. By comparison, wind farms linked into the Railbelt grid did not appear until 2012 and 2013, he said.

The implementation of utility scale solar has surged in the last two year, both in rural Alaska and on the Railbelt.

Golden Valley Electric Association, on the Railbelt grid, was an early pioneer in the use of energy storage to save any excess energy as a backup power source. In 2003 the utility implemented a 26-megawatt battery energy storage system, the largest system of its type in the world at the time. Chugach Electric Association later implemented a hybrid flywheel and battery energy system. Alaska Telecom Association is currently constructing a 46-megawatt storage system, Roys said.

But the rural utilities have been more aggressive in implementing energy storage. And there are now more than a dozen utility storage systems throughout the state, Roys said.

Increasing complexity

The combination of storage with an increasing variety of power source technologies has magnified the complexity of the rural electrical systems, with hydropower, solar power, wind power in various combinations having to be integrated and connected to dispatchable electrical loads in some of the most sophisticated power systems in the world. Expertise from Alaska in the advanced algorithms required for these systems is now being exported around the globe, Roys said.

For example, Kodiak has combined 31 megawatts of hydropower with 9 megawatts of wind generation, 3 megawatts of battery storage and 2 megawatts of flywheel energy storage into an electricity supply system that can operate annually with more than 99% renewable energy, Roys said.

And with more than 200 microgrids operating in the state and an installed capacity exceeding 800 megawatts, Alaska has the largest installed base of microgrids in the world, he said.

"In rural Alaska the ability to operate with no diesel online is the new standard for operations," Roys said.

Northwest Arctic Borough's vision

Ingemar Mathiasson, energy manager for Northwest Arctic Borough, emphasized the importance of reducing rural Alaska's dependence on diesel fuel. The borough has formed an energy steering committee that is developing a vision for the energy future for the region. The target is that 50% of energy for heating and electricity supplies will come from local sources by 2050. Part of the objective is to address climate change through the reduction of carbon dioxide emissions. Currently the borough is on track to achieve a 10% reduction in diesel fuel imports in 2020, Mathiasson said.

Projects include a solar farm in Kotzebue, a solar array in Ambler and an Ambler biomass project.

A pilot project in Kobuk and Ambler is assessing the practicalities of using reversible heat pumps for heating and cooling houses — an electrically powered heat pump, a kind of reverse air conditioner, can provide heat more efficiently than a conventional electric stove. The electricity supplies for the pumps are assisted by direct connection to solar arrays that can offset power from the grid, Mathiasson said. Despite the cold climate, it appears that people can use the heat pumps through to December, before having to switch back to conventional oil stoves, he said.

A project in Ambler, designed to assess the potential to reduce energy needs through energy efficiency and funded by the borough's Village Improvement Fund, involves the installation of LED lighting, solar panels and heat pumps for all 70 households in the village.

Regional utility energy projects in five other communities involve the installation of various combinations of wind power, solar power and battery storage, Mathiasson said.

KEA energy transition

Matt Bergan, wind farm project engineer for Kotzebue Electric Association, described KEA's efforts to transition from diesel power to renewables, to minimize diesel use. KEA is the hub utility for 3,200 people and 11 villages in the Northwest Arctic Borough, he said.

KEA began operating a hybrid wind and diesel system in 1997 — 15 to 25% of the utility's annual energy now comes from wind, Bergan said.

The original wind farm consisted of 19 wind turbines. However, the utility has recently replaced eight of these turbines with a solar array. Two of the turbines are large, modern units. The plan going forward is to install two or three more large turbines and complete the replacement of older, smaller turbines with solar power. A community scale battery supports the system.

The utility is able to additionally save some diesel power by selling electric heat from excess wind power to the local hospital.

Bergan sees 50% of power generation capacity as being the upper limit of renewable energy usage. Increasing renewable usage beyond that level would be cost prohibitive, he said.

Asked about the feasibility of bringing in alternative fuels to diesel, Mathiasson said that the Northwest Arctic Borough had investigated the logistics of shipping in natural gas or propane but had found this to be financially and logistically impractical using the shallow rivers of the region. ●

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EXPLORATION & PRODUCTION

US rotary rig count jumps up by 13 to 282

The Baker Hughes U.S. rotary rig count was at 282 for the week ending Oct. 16, up by 13 from 269 the previous week — the largest increase the count has seen since it turned around in mid-August from a low for the year. The count is still down substantially from a year ago, by 569 from 851.

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

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

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

This week's count includes 205 rigs targeting oil, up 12 from the previous week and down 508 from a year ago, 74 rigs targeting gas, up one from the previous week and down 63 from a year ago and three miscellaneous rigs, unchanged from the previous week and up two from a year ago.

Twenty-one of the holes were directional, 240 were horizontal and 21 were vertical.

The rig count for Texas (123), which has the most active rigs in the country, was up by seven from the previous week, but down 300 from a year ago.

Utah (3) was up by three rigs from the previous week, when it had no active rigs. Oklahoma (14) and Wyoming (3) were each up by two rigs. North Dakota (11) and West Virginia (8) were each up by one rig.

Colorado (4) was down by one rig from the previous week; Louisiana (38) was down by two rigs.

Rig counts were unchanged in the remaining states: Alaska (2), California (4), New Mexico (45), Ohio (6) and Pennsylvania (18).

Baker Hughes shows Alaska with two active rigs Oct. 17, unchanged from the previous week and down by six from a year ago.

The rig count in the Permian, the most active basin in the country, was unchanged from the previous week at 130, but down 292 from a count of 422 a year ago.

—KRISTEN NELSON

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Petroleum News and its supplement, Petroleum Directory, are owned by Petroleum Newspapers of Alaska LLC. The newspaper is published weekly. Several of the individuals listed above work for independent companies that contract services to Petroleum Newspapers of Alaska LLC or are freelance writers.

OWNER: Petroleum Newspapers of Alaska LLC (PNA)
Petroleum News (ISSN 1544-3612) • Vol. 25, No. 43 • Week of October 25, 2020
Published weekly. Address: 5441 Old Seward, #3, Anchorage, AK 99518
(Please mail ALL correspondence to:
P.O. Box 231647 Anchorage, AK 99523-1647)
Subscription prices in U.S. — $118.00 1 year, $216.00 2 years
Canada — $206.00 1 year, $375.00 2 years
Overseas (sent air mail) — $240.00 1 year, $436.00 2 years
"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News, P.O. Box 231647 Anchorage, AK 99523-1647.

PIPELINES & DOWNSTREAM

New move to shut down Dakota Access

Native American tribes opposed to the Dakota Access Pipeline once again have asked a federal judge to stop the flow of oil while the legal battle over the line's future plays out.

The Standing Rock Sioux and other tribes succeeded on their first attempt, only to have an appeals court overturn U.S. District Judge James Boasberg's shutdown order earlier this year. Now, they're asking the judge to clarify his earlier ruling to satisfy the appellate judges and then to again order the line to cease operations, the Bismarck Tribune reported.

The tribes argue that potential harm to their water supply outweighs any economic impacts of shutting down the line, which has been moving North Dakota oil to Illinois for more than three years.

"The Tribes are irreparably harmed by the ongoing operation of the pipeline, through the exposure to catastrophic risk, through the ongoing trauma of the government's refusal to comply with the law, and through undermining the Tribes' sovereign governmental role to protect their members and respond to potential disasters," attorneys Jan Hasselman and Nicole Ducheneaux wrote in an Oct. 16 filing.

Tribes fear a spill into the Missouri River just north of the Standing Rock Reservation would pollute their water supply. Pipeline operator Energy Transfer and the Army Corps of Engineers both maintain the pipeline is safe. Prolonged protests in 2016 and 2017 drew thousands of people to camps near the river crossing and resulted in hundreds of arrests.

U.S. Department of Justice spokeswoman Danielle Nichols declined to comment Oct. 19 on the tribes' filing. The Corps and Energy Transfer have until Nov. 20 to file a formal response.

Boasberg, who is overseeing the four-year-old lawsuit filed by the tribes, ordered an extensive environmental study last spring because he felt previous, less-extensive environmental analysis by the Corps left lingering questions.

Boasberg in July revoked the easement that allows for the river crossing and ordered the pipeline shut down until its environmental soundness was proven. A federal appeals court allowed oil to keep flowing, however, ruling that Boasberg hadn't justified a shutdown. That same appeals court is now determining whether to uphold his decision regarding the study.

Tribes are asking Boasberg to issue an injunction to shut down the pipeline while the legal fight plays out.

—ASSOCIATED PRESS

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AUCTION TESTS

held only six lease and license auctions in the first three months of this year, raising a meagre C$26 million.

"We were in an absolute crisis," said Energy Minister Sonya Savage, commenting on the government's decision to cancel land sales since early April to prevent the disposal of exploration prospects for little to no value.

"We didn't know how low (the auctions would fall). There was no question that no one was going to be bringing on new drilling," she said.

Auctions by end of year

But Savage confirmed to the Financial Post that Alberta is now poised to resume auctions by the end of 2020, despite questions about whether the government can fetch reasonable values for its rights.

She said upstream companies have been urging the province "to open land sales up otherwise the capital (investment in exploration) will be going elsewhere."

Savage said the auction process will take steps to ensure the land isn't sold too cheaply.

If returns from the six auctions held so far this year were adjusted to cover a full year, they would fall short of the 2019 returns of C$119 million, the low point since data was first collected in 1977, compared with a record C$3.5 billion in 2011 when oil sands rights were in high demand.

Higher minimum bid

To prevent bargain-basement sales, the government plans to implement a higher minimum bid.

Government documents obtained by the Financial Post show the government has considered minimum bids of C$50 per hectare (2.471 acres), compared with the current minimum bid of C$2.50.

In 2019, 59% of all land parcels sold in Alberta for less than C$50, compared with only 16% in Saskatchewan and 32% in British Columbia.

But the industry is not happy with Alberta's move to raise minimum bids.

Ben Brunnen, vice president of fiscal and economic policy at the Canadian Association of Petroleum Producers, urged the government to "proceed with caution."

He said that "for just about any bidding process, there's always an assumption that there would be another bidder. That competition for bidding has generally led to relatively healthy bid prices for land, despite where the minimum bid sits."

—GARY PARK

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● THE PRODUCERS MAGAZINE PREVIEW

Eni operates neighboring ANS units

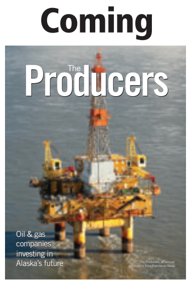
Italian company hesitant to resume drilling at nearshore Oooguruk and Nikaitchuq units, plans to continue maintenance work

By ERIC LIDJI
For Petroleum News

The fates of the Nikaitchuq and Oooguruk units have long been intertwined.

Both prospects were discovered during related exploration efforts at the turn of the 21st century. In the years since, operators of both units have faced similar challenges, arising from the complications of working on nearshore prospects in the Arctic Ocean. The solutions brought to bear at one unit have often informed decision making at the other.

Coming



November 2020

But the units are now more intertwined than at any point in their producing lives. After being a minority partner at Oooguruk for its entire existence as a producing field, Eni US Operating Co. Inc. is wrapping up its first year as the operator of the neighboring unit.

Oooguruk

In its first year as operator of Oooguruk, the American subsidiary of the Italian major Eni Petroleum was hampered by a series of external factors, mostly arising from the impact of the coronavirus pandemic on the Alaska oil industry, and the North Slope in particular.

The company subsequently cold-stacked Doyon Rig 15 and Nordic Calista Rig 4 but is evaluating electrical submersible pump replacements projects (at Nikaitchuq) in early 2021.

The proration of the trans-Alaska oil pipeline and the curtailment of the gas handling capacity at the Kuparuk River unit created secondary problems at Oooguruk. The unit produced 8,700 barrels of oil per day in March 2020 and just 6,300 bpd in May 2020.

Prompted by those infrastructure challenges and by the broader economic conditions of falling oil prices and declining demand, Eni deferred its original plans to conduct several workover projects in 2020 in advance of resuming the drilling of new wells at the unit in 2021. The company instead performed 15 maintenance and repair projects on 10 wells.

The company also undertook a range of other maintenance activities, including a gas debottlenecking project responsible for "several hundred" barrels per day of production.

Even with economic conditions now improving, Eni is hesitant to resume activities. The company is not planning drilling or workover projects for the coming development year, running through

see PRODUCERS PREVIEW page 6

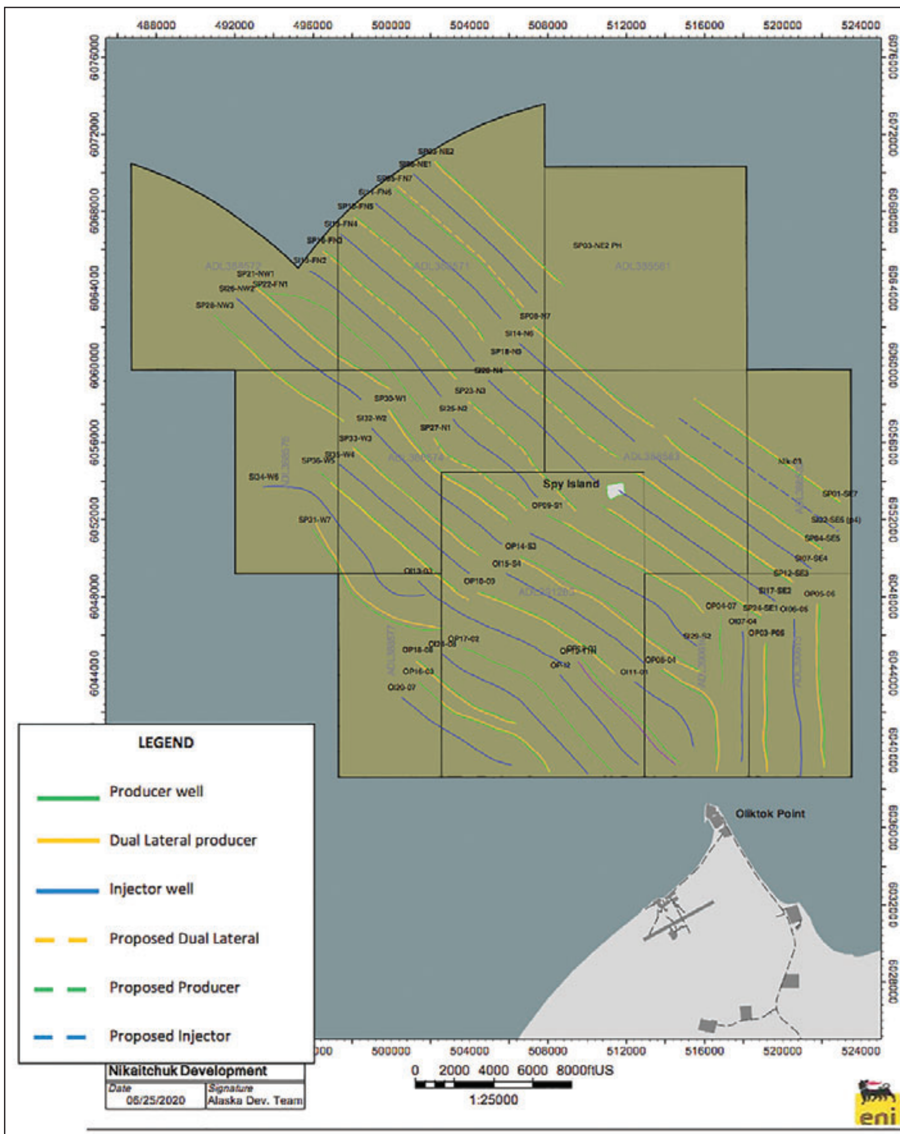
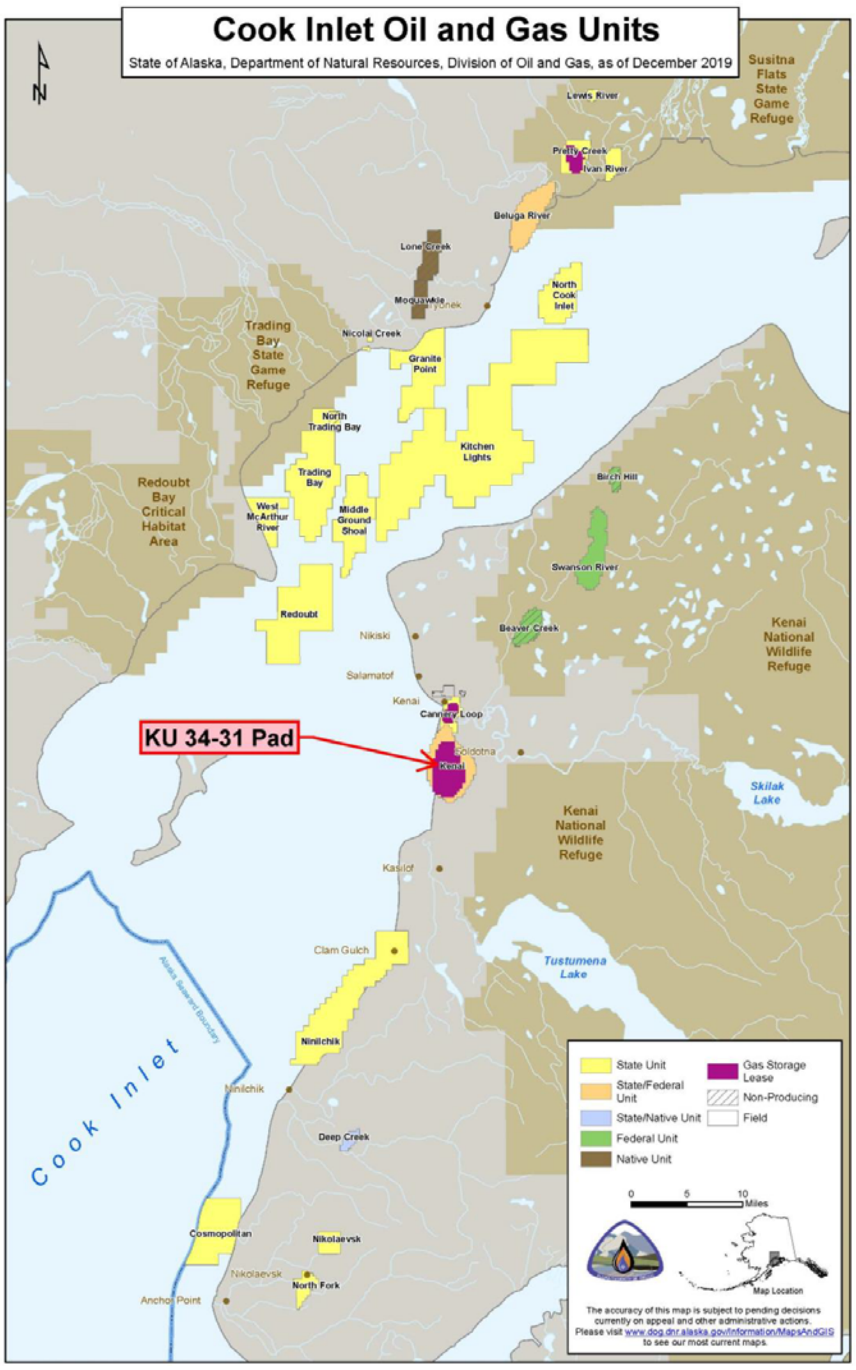


Figure 1. Proposed Nikaitchuq Unit development activity through July 2020

ENI US OPERATING CO. INC.

EXPLORATION & PRODUCTION



Hilcorp drilling storage well in Kenai unit

On Oct. 16, Alaska's Division of Oil and Gas approved an amendment Hilcorp Alaska applied for Sept. 15 to the Kenai unit's plan of operations. The project involves drilling a new Sterling pool 6 gas storage well from the existing KU 34-31 gravel pad and building associated infrastructure, including a well cellar and conductor, flowline, and electrical instrumentation.

The KU 34-31 pad is approximately 6 miles south of the city of Kenai on the Kenai Peninsula in southcentral Alaska.

The federally managed Kenai Gas Field is on private surface lands in the

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PRODUCERS PREVIEW

September 2021, although it is planning two well maintenance projects.

Further down the road, the company is evaluating two appraisal wells — ERD-N01 and ERD-N02 — on leases outside existing participating areas. The program would test the productivity and quality of oil on three leases beyond the reach of existing drilling but within the technical limitations of drilling technology from its offshore drilling pad.

Some of the challenges at Oooguruk this year are an extreme version of an ongoing challenge at the unit. The lack of independent infrastructure at the unit has forced previous operators to rely on infrastructure operated by neighboring ConocoPhillips.

ARCO Alaska Inc. discovered Oooguruk in 1992, and independent Armstrong Oil & Gas Inc. delineated the "Northwest Kuparuk" prospect in the early 2000s. Through a series of deals, Texas-based Pioneer Natural Resources Alaska LLC acquired a 70% interest and became operator of the unit, with Eni acquiring the remaining 30% interest.

After just five years of work, Pioneer brought the nearshore Oooguruk unit into production in June 2008, becoming the first independent producer on the North Slope.

In late 2013, after optimizing completion techniques at the unit and expanding the resource with a large discovery to the south called the Nuna prospect, Pioneer sold the Oooguruk unit to the independent company Caelus Natural Resources Alaska LLC.

Caelus was a smaller company with a history of short-term projects. The company announced major plans and even sanctioned the Nuna project. But when prices dropped in 2016, the company suspended regular operations and deferred development work. The company eventually sold its stake in Oooguruk to its partner Eni Petroleum in mid-2019.

Pioneer made a strategic decision to use facilities at the Kuparuk River unit rather than bear the expense of building independent facilities at Oooguruk. It occasionally struggled with the lack of control created by that decision, as did Caelus in its years as operator.

Eni recently launched a study to gauge the feasibility of installing partial gas processing facilities at the Oooguruk Tie-in Pad to avoid those Kuparuk River unit constraints. The company also launched a study looking at the possibility of connecting the power generation systems at Oooguruk and Nikaitchuq, to improve efficiency at both units.

After being a minority partner at Oooguruk for its entire existence as a producing field, Eni US Operating Co. Inc. is wrapping up its first year as the operator of the neighboring unit.

Oooguruk produces from three horizons: the Oooguruk-Kuparuk participating area, the Oooguruk-Nuiqsut participating area, and the Oooguruk-Torok participating area.

The unit produced 3,023,150 barrels of oil (approximately 8,282 barrels per day) in 2019 and 1,476,908 barrels (approximately 8,114 barrels per day) in the first half of 2020.

Nikaitchuq

Eni completed some of its work plan at Nikaitchuq early in the development year.

Before suspending operations, the company drilled the SP03-NE2 producer and the dual-lateral producers SP03-NE2 L1 and SP10-FN1 L1 from the Spy Island drilling site.

The original three-well program planned for the unit included a different slate of wells: the SP03-FN6 producer and the SI02-SE6 and SI06-FN8 water injection wells.

The SP03-NE2 project began with the SP03-NE2 PH pilot hole to the northwest to evaluate the prospect. Positive results led to an expansion of drilling plans for the area.

The workover campaign included projects at the SP12-SE3 producer, SP04-SE5 producer and SD37-DSP01 disposal well at the Spy Island drill site and the OP05-06 producer, OP17-02 producer and OP22-WW03 water well at the Oliktok Point drilling pad.

The company subsequently cold-stacked Doyon Rig 15 and Nordic Calista Rig 4 but is evaluating electrical submersible pump replacements projects in early 2021.

As with some other companies, the suspension of drilling activities allowed Eni to complete some maintenance activities that would have required a temporary shutdown.

Even so, the company is planning a summer 2021 turnaround at Nikaitchuq to coincide with a planned turnaround at the Kuparuk River Unit Central Processing Facility 2.

But the shutdown of regional infrastructure impacted Nikaitchuq production.

The unit produced 19,400 barrels per day between September 2019 and May 2020 but only 17,100 barrels per day during the month when throughput on the trans-Alaska oil pipeline was prorated. Production returned to 20,000 barrels per day in early June.

Eni also added six well slots to one of its drilling pads to accommodate the proposed NN02 exploratory well and as many as four additional Nikaitchuq wells. The company delayed the project after partner Shell declined to participate in the project. Eni subsequently received permission from federal authorities to suspend operations for two years, until April 2022.

In its plan for the current development year, running through September 2021, the company proposed no new drilling

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PIKKA ON TRACK

stacked accumulations) through the phased approach that will reduce upfront development costs and allow cash flow from Phase 1 oil production with a single drill site to fund the subsequent two phases.

The new approach will establish a strong foundation for the development of not only the Pikka unit, but also for prospective nearby acreage, the company said.

Capital spending down

Oil Search expects a reduction in even more costs than it estimated March 18 or this past August.

As of March 18, when the COVID-19 pandemic prompted a closure of exploration and development activities on the North Slope, Oil Search projected its 2020 capital spend in Alaska for exploration, evaluation and development would be between $260-300 million, down from earlier expectations of $340-380 million. As of Sept. 30, the company's full year guidance had dropped to $225-250 million.

The reduction is largely due to the rephrasing of front-end engineering design activities for Pikka, plus a concerted effort to reduce costs by Oil Search and its vendors.

Oil Search continues to work to get development costs down. Having already reduced costs to match an oil price in the low $40s, the company is looking to get them below $40 per barrel before relaunching its partial divestment (15%) in a formal sell-down sometime in 2021.

No more layoffs in Alaska

Oil Search does not have any exploration wells planned for the upcoming 2020-21 North Slope winter drilling season due to uncertain market conditions. Although the company halted its plans for limited early production of Pikka in 2022, choosing instead to concentrate on three-phase development that would begin production in 2025, Alaska has fared comparatively well in terms of layoffs compared to other areas within the company's portfolio.

The latest round of dismissals announced by Wulff on July 1 did not involve any Alaska workers.

PHOTO COURTESY OIL SEARCH

Oil Search's summer work program included bridge installation across the Miluveach River.

However, some Oil Search workers were laid off in March and April.

"While seasonal contractors associated with our winter drilling and exploration programs represent the majority (of those March and April layoffs), we have reduced full-time (Alaska) employees by about 15%," which brought the local total to 150 individuals, company spokeswoman Amy Burnett told Petroleum News July 1.

On Oct. 20, Burnett said Alaska employee numbers have remained at 150.

Mitquq, Stirrup evaluation

Meanwhile, on Sept. 30 Wulff noted that the Oil Search Alaska team, in cooperation with the company's key stakeholders, has continued to make excellent progress on the value and capital optimization studies for Pikka's new three-phase design.

"These changes will make the project resilient at lower oil prices and easier to finance, whilst ensuring the project can be expanded efficiently without compromising full value," Wulff said.

Oil Search has not yet released the amount of oil each phase is expected to produce, likely due in part to the fact it is still evaluating the results of last winter's exploration drilling.

Originally, Pikka was expected to produce 130,000-135,000 barrels of oil per day at its peak.

During third quarter, Oil Search continued to assess the results of its Mitquq and Stirrup discoveries. In combination with the latest seismic data, the results have provided an improved understanding of the geology and potential productivity of the Nanushuk play, the company said Sept. 30: "Further appraisal drilling of the Mitquq and Stirrup trends will be required to confirm the size and extent of these discoveries, with results to date continuing to support the potential development of Mitquq as a satellite to Pikka and Stirrup as a potential stand-alone development."

A final investment decision on Pikka is "currently forecast for the end of 2021," Oil Search said Sept. 30. ●

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PRODUCERS PREVIEW

and said it would perform workovers as needed.

"Eni reports the global COVID-19 pandemic and subsequent global oil demand and price impact has temporarily curtailed planned drilling activity in the 2020 (Plan of Development)," Eni wrote. "Actual activities may change as conditions improve."

Nikaitchuq produced 6,772,787 barrels of oil (approximately 18,555 bpd) in 2019, compared to 3,489,408 barrels (approximately 19,172 bpd) in the first half of 2020.

Eni acquired the Nikaitchuq leases through purchases in 2005 and 2007, sanctioned a $1.45 billion development program in January 2008, and brought the unit into production in early 2011. The company completed its initial onshore Oliktok Point pad drilling program in 2012 and shifted to continuous drilling at the offshore Spy Island drill site. ●

Editor's note: See full story in The Producers magazine, being released in November by Petroleum News.

Moody's gives deal thumbs up

Moody's Investor Service said Oct. 19 that ConocoPhillips' acquisition of Concho Resources is "credit positive (COP A3 stable.)"

"Concho's large-scale Permian operations will significantly enhance COP's scale, diversification, and portfolio durability while simultaneously improving capital flexibility and cost efficiency," Moody's reported.

However, the transaction "comes at a time of low oil prices and heightened uncertainty around global economic and oil demand recovery. The greater exposure to shale assets will also increase COP's relatively low (production) decline rate."

ConocoPhillips will need to "close the transaction, execute from an operational standpoint, and achieve the planned cost synergies," the investor service said.

Concho's large production and reserves base as well as its extensive drilling experience in the Permian basin "will immediately transform COP into a leading Permian basin producer. Concho produced 320,000 barrels of oil equivalent per day in the second quarter of 2020 and had 1 billion of proved reserves (75% developed) at the end of 2019. The combined company will have over 400,000 boe/d of Permian basin production significantly increasing COP's overall unconventional production, representing almost one half of future companywide production from about a third of total production today," Moody's said, adding that the acquisition "is consistent with COP's long-term strategy of maintaining a sustainable asset base with low cost of supply, strong organic growth potential and manageable ESG risks." (ESG stands for environmental, social and governance.)

ConocoPhillips will be paying "about $18/boe of PD reserves and $42,000 per flowing boe, which we view to be reasonable in today's price environment. We estimate Concho's breakeven cost to be around $30/boe. Concho's 550,000 low-cost, oil-weighted, and mostly contiguous net leasehold acreage in the Delaware basin and Midland basin will provide COP a deep drilling inventory allowing significant capital and operational flexibility."

The "contemplated combination synergies should also improve COP's cost and return metrics over time," Moody's said.

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INSIDER

shale assets.

Of course, Houston-based ConocoPhillips is already an "unconventional powerhouse," as it was recently described by Upstream. Absorption of the much smaller Midland, Texas-based Concho will give ConocoPhillips a huge footprint in the Delaware and Midland portions of the Permian basin, as well as solid positions in the Eagle Ford and Bakken in the Lower 48 and the Montney in Canada.


RYAN LANCE

The deal, announced Oct. 19 and expected to close in first quarter 2021, will make ConocoPhillips the largest independent oil and gas company in terms of daily production, Houston Business Journal reported.

The agreement calls for Concho shareholders to receive 1.46 shares of ConocoPhillips common stock for each share of Concho, which represents a 15% premium to closing prices on Oct. 13, per the companies. ConocoPhillips shareholders will own about 79% of the combined company, with Concho shareholders holding the other 21%.

The combined enterprise value is expected to be approximately $60 billion — its pro forma net debt was $12 billion as of June 30.

By 2022 the companies said the combined company is expected to realize $500 million in annual cost and capital savings, thanks in part to lower administrative expenses and a reduction in its global exploration program.

The combined company will have pro forma production of more than 1.5 million barrels of oil equivalent per day.

After the acquisition closes, Concho Chairman and CEO Tim Leach will join ConocoPhillips' board of directors and become an executive vice president of ConocoPhillips and president of the company's Lower 48 business. He will report directly to ConocoPhillips Chairman and CEO Ryan Lance.

"Concho is a tremendous fit with ConocoPhillips," Lance said. "Together, ConocoPhillips and Concho will have

Absorption of the much smaller Concho will give ConocoPhillips a huge footprint in the Delaware and Midland portions of the Permian basin, as well as solid positions in the Eagle Ford and Bakken in the Lower 48 and the Montney in Canada.

unmatched scale and quality across the important value drivers in our business: an enviable low cost of supply asset base, a strong balance sheet, a disciplined capital allocation approach … and great people. Importantly, the transaction meets our long-stated and clear criteria for mergers and acquisitions because it is completely consistent with our financial and operational framework."

Sector consolidation is "both necessary and inevitable," Lance told analysts after the announcement. "We both believe our industry needs solutions that address the lack of scale, poor returns and, increasingly, the challenges and opportunities of environmental, social and governance matters."

Roughly half of the combined company's production would be from the Lower 48, with 15% coming from Alaska and the remaining 35% from international assets (ConocoPhillips is active in 16 countries).

The company intends to return more than 30% of its cash generated from operations to shareholders through regular dividends and other distributions, consistent with ConocoPhillips's current targets.

Lance said those payouts help distinguish ConocoPhillips from rival oil and gas companies.

"You've got to deliver financial returns in this business," he said.

In its summary of the transaction's benefits, ConocoPhillips said: "Massive, diversified and low cost of supply resource base provides years of high-value investments: The combined company will hold approximately 23 billion barrels of oil equivalent resources with an average cost of supply of below $30 per barrel WTI."

—KAY CASHMAN

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AOGCC DENIAL

Revised bonding

The commission revised its bonding requirements for plugging and abandoning wells in May 2019 and advised existing operators of record of additional bonding amounts required under the new regulations.

Alaskan Crude Corp., the operator of record for the Burglin 33-1, Katalla KS-01 and Mike Pelch 1 wells, was advised by the commission that its existing $200,000 statewide P&A bond was being increased to $1.2 million ($400,000 per well), with the additional $1 million due in two annual $500,000 installments.

Alaskan Crude's attorney James B. Gottstein requested reconsideration in a July 25, 2019, letter, objecting to the increase.

He told the commission it was not legal under the Alaska Constitution "to increase the bonding/security requirements for existing permit holders," calling the increased bonding an illegal ex post facto law as applied to the three existing wells.

"Second," Gottstein said, "the new regulations go beyond the scope of the authorizing statute."

The commission's statutory authority, he said, quoting statute, allows it to require "the furnishing of a reasonable bond with sufficient surety conditions for the performance of the duty to plug each dry or abandoned well or the repair of wells causing waste."

The new regulation, he said, quoting the commission's regulations, requires "security to ensure that each well is drilled, operated, maintained, repaired, and abandoned and each location is cleared in accordance with this chapter."

"It is apparent the new regulations go far beyond the statutory authority of allowing bonds to be required to 'plug each dry or abandoned well or the repair of wells causing waste,'" Gottstein said.

January hearing

In a Jan. 22, 2020, letter to the commission — the day prior to a Jan. 23 reconsideration hearing — Gottstein reiterated the ex post facto argument from his July 23, 2019, letter, as well as the assertion that the new regulations exceed the agency's statutory authority.

At the Jan. 23 hearing, Gottstein told the commissioners there is another problem: you can't, he said, really tell what the new regulation means.

Referring to the language of the new regulations, he asked if the bond providing security to ensure that wells are drilled, operated, maintained in accordance with the regulations means that any deviation would result in the bond being seized? He noted that the commission's regulations require that every well must have a sign identifying it in a conspicuous place — if that is violated, would be bond be seized, he asked?

What does it mean that the well must be operated in accordance with the commission's regulations — does any deviation trigger a seizure of the bond, he asked.

Future plans for wells

At the Jan. 23 hearing the commission asked the company to provide future plans for the three wells.

Gottstein said in a Feb. 19 letter that the Burglin well is on a Department of Natural Resources lease, ADL 318613, which was terminated in 1990. He said the Burglin well then became property of DNR and Alaskan Crude had no more responsibility.

He said that while the commission's regulations provide that someone having the right to drill and produce oil and gas must P&A wells before expiration of rights in the property, "it does not appear the Commission had the authority to promulgate such a regulation."

He said the Burglin "well is a valuable DNR asset and it is believed was a significant factor in DNR's ability to lease the property at least twice since ADL 318613 expired. Alaskan Crude does not believe it has authority to enter on the property to plug the well, in any event," he said. "To my knowledge, DNR has not requested that their suspended well be plugged and abandoned, or specified how DNR plans to pay for the plugging and abandonment of their well that is in suspended status."

Gottstein said the Katalla well was not drilled on a DNR lease. It is the property of the landowner and Alaskan Crude does not have authority to enter the property or plug the well, he said.

The Pelch well is also on private property, Gottstein said. "It has a permit and permission to be re-entered and reworked so plugging and abandoning that well is premature."

Gottstein also noted that Alaskan Crude filed for bankruptcy in 1990. "It is my understand that all three wells were drilled prior to this," he said. Alaskan Crude Corp. "as currently constituted is a completely different entity than the Alaskan Crude Corporation that drilled the wells and had the plugging and abandoning requirement," Gottstein said.

He requested that the record be kept open until he returned to the state and could examine the bankruptcy file. He subsequently asked the commission to make bankruptcy paperwork available; the commission said in its Oct. 15 decision that any bankruptcy paperwork in its files would be available online.

see **AOGCC DENIAL** *page 11*

Petroleum news

Oil Patch Bits

Jeff Raun joins EXP to strengthen Alaska presence

EXP, a global leader in engineering, architecture, design and consulting, said Oct. 16 that it is excited to welcome Jeff Raun as senior environmental project manager, based in EXP's Anchorage office. Raun has more than 15 years of experience serving in environmental and regulatory roles. Most recently, Raun held various positions at ExxonMobil, where he worked on international oil and gas projects, conducting global exploration activities. In his new position, Raun will be responsible for managing and developing environmental permitting and regulatory compliance projects in and outside of Alaska and advancing strategies to support EXP's low carbon energy transition and developing sustainable regulatory strategies.

"EXP's role in Alaska is focused on delivering services to improve the resiliency of our client's resource projects. We are very excited to welcome Jeff to the team, enhancing our efforts to consistently exceed client expectations. Jeff brings the expertise, leadership and global knowledge to advance environmental solutions for complex projects and help drive EXP's sustainable initiatives."

EXP has been a part of the North American energy industry, including Alaska, for over 40 years. Led by Vice President Chris Humphrey, the EXP team has been delivering effective environmental and regulatory permitting services for oil and gas projects in Alaska, including the ongoing Alaska LNG project.

JEFF RAUN

Companies involved in Alaska's oil and gas industry

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

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BONDING REDUCTIONS

for 40 or fewer permitted wellheads.

For one to five wells, the new bonding requirement is $400,000 per well; for six to 20 wells, $2 million plus an additional $250,000 for each well above five; for 21 to 40 wells, $6 million.

Bonding amounts for more than 40 wells remain unchanged.

Increases adopted in 2019

The per-well impact of the increase in bonding which the commission adopted in May 2019 is greatest for operators with the fewest number of wells, and that continues to be true under the proposed changes.

With the proposed changes, the required bonding for an operator with one to five permitted wellheads continues to be $400,000 per well.

With six wells, at the $2 million plus $250,000 per well requirement, the average drops to $325,000 per well, and the average bonding for 20 permitted wells drops to $287,500 per well.

The original bonding requirement of $6 million for 11 to 40 wells averaged $545,455 for 11 wells, dropping to an average of $500,000 each for 12 wells and an average of $150,000 each for 40 wells.

Under the proposed change, which for 21-40 wells is $6 million, the required bonding averages $285,714 for 21 wells, dropping to $150,000 for 40 wells — the same average as the bonding amount for 40 wells as the 2019 regulations.

The bonding for more than 40 wells is unchanged: at $10 million for 41-100 wells, the bonding cost is an average of $243,902 each for 41 wells, dropping to an average of $100,000 per well for 100 wells.

The required $20 million in bonding for 101 to 1,000 wells averages $198,000 per well at 101 wells, dropping to $20,000 per well at 1,000 wells.

The $30 million in bonding required for more than 1,000 wells averages $29,970 per well for well number 1,001 and drops from there $15,000 per well at 2,000 wells.

Existing bonds

The commission's bonding regulations say it may increase or decrease bonding based on engineering, geotechnical, environmental or location conditions which warrant adjustment.

It proposes to add two other conditions: "a bond and, if required, security that is exclusively dedicated to the plugging and abandonment of a well or wells" in place with the landowner or a bond or security in place with the U.S. Environmental Protection Agency which is dedicated to P&A of disposal wells.

These changes reflect decisions the commission made earlier in the year.

In responding to an appeal from AIX Energy for a reduction in bonding, the commission reduced required bonding based on a $950,000 certificate of deposit in place with the Mental Health Trust Land Office which is dedicated to P&A of AIX's four wells.

The Trust Land Office is the landowner at the Kenai Loop field where AIX's wells are located. In its AIX decision the commission denied the company's request for a reduction in bonding based on a bond with the Alaska Department of Natural Resources for dismantlement, removal and restoration, saying the $500,000 DNR bond "is for the DR&R of the surface of DNR's leases to a condition acceptable to DNR. No evidence was offered that any of that bond is irrevocably restricted to the costs to properly P&A AIX's wells."

In a decision reducing bonding required from Cook Inlet Energy the commission said that reduction was based on a $324,000 bond in place with the U.S. Environmental Protection Agency dedicated to P&A of two disposal wells.

Hearing scheduled

The commission is also extending the time for installment payments on increased bonding amounts from 4 years to 7 years.

A hearing is scheduled on the proposed changes for Nov. 4 at the commission's Anchorage offices. The hearing is scheduled from 10 a.m. to 2 p.m. and may be extended to accommodate those present before 10:30 a.m. who did not have an opportunity to comment.

If COVID-19 necessitates that the hearing be held telephonically, phone lines will be available at 9:45 a.m., at 1-800-315-6338, code 14331.

Written comments may be submitted at the hearing; the commission will also accept written comments through Nov. 20 at 4:30 p.m., by mail, fax or electronic mail at aogcc.customer.svc@alaska.gov.

The notice and proposed regulation changes are available at: https://www.commerce.alaska.gov/web/aogcc/Events.aspx. ●

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ENERGY DIVERSITY

power, along with its relatively low cost and small carbon footprint make it an attractive power source as part of the green energy transition.

Energy Minister Sonya Savage said geothermal legislation will ensure Alberta has the regulatory and investment climate to make it competitive with other jurisdictions.

The government said geothermal presents a way to repurpose inactive oil and gas wells for heat and power production, aided by the fact that oil rigs are flexible enough to be used in geothermal drilling, boosted by Alberta's geothermal-friendly geology.

But Savage emphasized that a geothermal policy does not mean oil and gas is fading fast, noting that energy forecasts have fossil fuels continuing to dominate the world energy mix for 30 years.

She said that developing Alberta's full geothermal potential also "feeds into the narrative that Alberta is taking greenhouse emissions reduction seriously."

Savage said a guiding set of regulations will offer investors a predictable regime instead of current approvals on a case-by-case basis.

Bailey Schwarz, a lead engineer at Alberta-based Eavor Technologies, said it is rewarding to see that drilling technologies "designed for the more traditional energy sector might find a home in a green and clean solution."

Energy Futures, a partnership of government, industry and academia, has been working on advancing geothermal production in Western Canada for five years.

Juli Rohl, a geologist with Energy Futures, said the partnership is working on a project to understand how an Alberta First Nation can repurpose inactive gas wells to heat a greenhouse and help provide economic and food security for its community.

Hydrogen export more distant

The export goals for hydrogen are more distant, but much grander than geothermal, although the initial steps are limited to building a string of 20 small-scale projects and investments of C$58 million.

Beyond that plan, the Alberta government hopes to reduce carbon emissions by 1 million metric tons a year, or the equivalent of removing 750,000 cars from the road.

"Unlocking innovation across our natural gas sector will create jobs while helping the industry become more efficient," said Associate Minister of Natural Gas Dale Nally.

He said that by 2050 Alberta estimates hydrogen could be a US$3.5 trillion global industry, but the Hydrogen Council, a global corporate group, has lowered its sights to US$2.5 billion over the same period.

Alberta Premier Jason Kenney said Calgary-based utility Atco plans to build a pilot project that will convert natural gas and hydrogen into a source of home heating.

Within a decade, he said Alberta could have at least two large LNG projects exporting energy, be a continental leader for plastics recycling and host large-scale hydrogen production facilities, creating tens of thousands of jobs in the process

"A lot of this is just getting government out of the way, speeding up approvals and creating investor certainty," he said. "Most of what we're talking about actually won't cost the taxpayers a dime."

Atco Chief Executive Officer Nancy Southern said the immediate challenge involves scaling up commercial hydrogen production and delivering natural gas from carbon capture — a process she said is "still five to six years away."

"We do have to crack the carbon capture nut on a commercial level. But we're very, very close," she said.

NDP also looking at hydrogen

The New Democratic Party, soundly defeated by Kenney's United Conservative Party in 2019, is exploring the feasibility of a hydrogen pipeline costing about C$350 million as part of a plan to grow the province's participation in the energy source.

NDP leader Rachel Notley rolled out 11 proposals including government loan guarantees for pipeline infrastructure, production hubs and commercial applications, as well as royalty credits to attract large hydrogen projects.

That includes the creation of a task force to build a case for exporting hydrogen to markets in South Korea, Japan and California.

Notley said the NDP aims at taking advantage of a "generational economic shift" by producing what is known as blue hydrogen — using natural gas and existing carbon capture and storage facilities — to start exports in 2040.

She said the Kenney government's plan is too vague and fails to offer any industry incentives, unlike Australia and Germany.

A spokesman welcomed "ideas from others," but said it was hard not to note that Notley, while she was premier from 2015 to 2019, "did nothing" on the development of hydrogen.

—GARY PARK

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STORAGE WELL

Cook Inlet basin. The new gas storage well and its related infrastructure will support continued natural gas storage for the field.

The new well will be drilled into state of Alaska oil and gas storage lease ADL 390821.

Drilling activities are expected to begin around Oct. 18, with tie-in and construction work completed by approximately Dec. 11, 2020.

All activities will be done on the pad and will tie into existing gas storage infrastructure.

The division, which is part of the Alaska Department of Natural Resources, provided a review and comment opportunity for the activities considered for authorization under its Oct. 16 decision. The following agencies were notified on Sept. 16 for comment on the plan: Alaska Department of Environmental Conservation; Alaska Department of Fish and Game; DNR's Division of Mining, Land & Water, U.S. Army Corps of Engineers and Bureau of Land Management.

The comment deadline was 4:30 p.m. Alaska Time on Sept. 30. No comments were received.

The approval expires on Oct. 16, 2023, if work on the project has not started.

—KAY CASHMAN

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OIL PRICES

tinue into 2021, according to a Rystad Energy forecast for shale oil, gas production and capital investments released Oct. 21.

Activity levels and output in key contributing shale plays are "anticipated to show notable decline" in 2020 and 2021 as well, Rystad said.

"Since the downturn that prevailed between 2014 and 2016, LTO production in the region has revamped with a new force, able to adjust to a depressed price environment through high grading of acreage and considerable cost and productivity improvements," Rystad said.

In 2019, oil output reached 8.6 million barrels per day, representing a year-on-year growth of about 20%, it said.

In 2020, the pandemic-induced global oversupply and oil demand destruction hammered oil prices, and North American producers cut capital budgets and trimmed back drilling and completion programs, focusing on cash flows and returns, Rystad said, adding that many producers were forced to curtail production volumes in addition to taking frac holidays and cutting the number of rigs and frack crews.

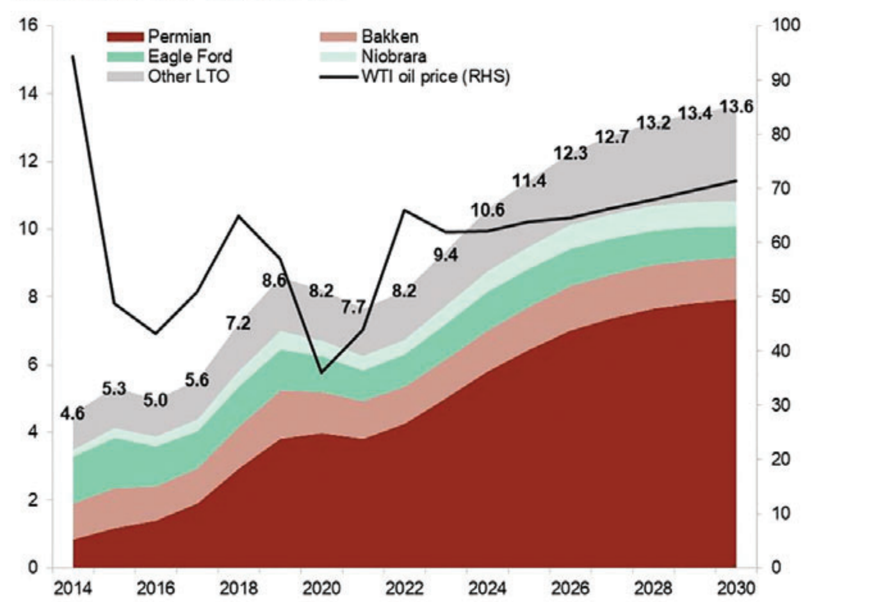
Rystad said production shut-ins and restricted flowbacks on wells peaked in May, when many operators began to return curtailed volumes as oil prices improved.

"We expect that majority of curtailments have been returned online by the end of August 2020," it said, adding that oil production increased over the summer due to shut-in reactivations and higher levels of completion of already drilled wells.

New drilling activity remains low, however, leading Rystad to conclude that oil output will decline again in fourth quarter 2020, falling to 8.2 million bpd this year and to 7.7 million bpd in 2021.

"Producers are poised to keep activity levels low amid uncertain market environment and a focus on capital discipline," Rystad said.

Figure 1: North American light tight oil supply by main shale plays and WTI oil price
Million bpd and USD per bbl



Source: Rystad Energy UCube

In 2021, Rystad estimates that West Texas Intermediate crude prices will recover sharply, nearing $70 per barrel, leading to an upward trajectory in activity and oil production in 2022 that will take North American light tight oil production to 13.6 million bpd by 2030.

"The Permian Basin will be the major contributor to expansive growth going forward with Permian Delaware also remaining the most resilient play during the ongoing downturn," Rystad said.

Saudi/Russia axis

Despite a pair of high-level discussions between Saudi Arabia and Russia, the Organization of Petroleum Exporting Countries and allied nations made no changes in the OPEC+ oil production strategy following its ministerial monitoring committee meeting Oct. 19.

President Vladimir Putin and Saudi Crown Prince Mohammed bin Salman had a telephone conversation Oct. 13 to discuss crude oil markets, followed by a second call Oct.17, the Middle East Monitor reported.

According to statements by the Kremlin, the two leaders exchanged views on the progress of the OPEC+ agreement, and agreed to continue coordination in order to maintain stability in the crude market.

OPEC+ for now is sticking with its plan to ease oil production restrictions in January, from the 7.7 million bpd production cuts in effect now, to 5.8 million bpd.

However, three sources from producing countries said a planned output increase from January could be reversed if necessary, Reuters said in an Oct. 19 report.

OPEC's monitoring committee said in an Oct. 19 release that the economic recovery has slowed due to the resurgence of COVID-19 cases in major economies, particularly in the Americas, Asia and Europe.

The committee told all participating countries to be mindful of "the necessity to be vigilant and proactive given the precarious market conditions and prospects."

Saudi Arabia Energy Minister Prince Abdulaziz bin Salman said OPEC has been flexible during the pandemic, adapting "to changing circumstances when required."

Accommodative statements may be the only tool to assuage oil markets for the next month or so. While OPEC+ ultimately may not ease the production cuts in January, the decision won't actually be made until the full group meeting which will be held Nov. 30 and Dec. 1.

The price of OPEC basket of thirteen crudes stood at $41.04 per barrel Oct. 20, compared with $41.38 the previous day, according to OPEC Secretariat calculations.

Alaska North Slope crude closed down 8 cents at $42 Oct. 20. WTI closed up 63 cents at $41.46 Oct. 20, but it slipped below $40 in trading Oct. 21. Brent closed up 54 cents to 43.16 Oct. 20, but in trading Oct. 21 it fell to $41.73. ●

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AOGCC DENIAL

Commission decision

In its Oct. 15 decision, the commission reviewed evidence presented by ACC and stated the following conclusions in denying the request for reconsideration:

The commission said it "is authorized to require a bond for the performance of the duty to plug wells and the duty to repair wells causing waste. Every operator is required to have a bond in place to ensure compliance with those duties. Any bankruptcy that occurred in 1990 cannot remove subsequent bonding obligations."

Since ACC is the operator of record for the Burglin 33-1, Katalla KS-01 and Mike Pelch 1 wells, it "is required to have a bond in place for all three wells," the commission said.

It said ACC has not provided written documentation of any change of operator for any of the wells, so remains the operator of record "and is responsible for the plugging and abandonment of the wells."

The commission said ACC has not provided any evidence "to support is assertion that it is prohibited from plugging and abandoning any of the wells," and without written proof that landowners have prohibited it from entering the properties to P&A the wells "or that the landowners have agreed to assume responsibility to plug and abandon the wells, ACC remains responsible to do so."

ACC submitted an application to abandon Burglin 33-1 in Jul 2018, the commission said, which was approved in August 2018. "As of the date of this order, Burglin 33-1 has not been plugged and abandoned. In addition to the bond required, the AOGCC reserves the right to pursue enforcement action in connection with the failure to properly plug and abandon Burglin 33-1."

—KRISTEN NELSON

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