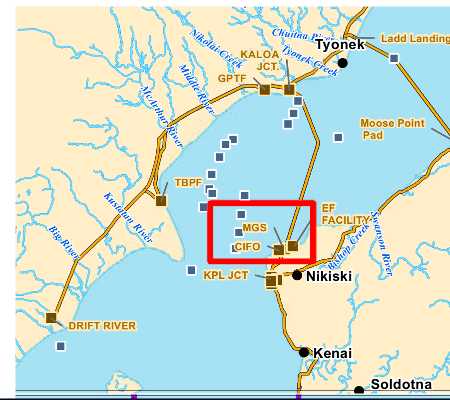
Petroleum news

Vol. 26, No. 52 • www.PetroleumNews.com

A weekly oil & gas newspaper based in Anchorage, Alaska

Week of December 26, 2021 • $2.50



page 7 Corps permitting replacement of gas line from platform A at MGS to shore

Revenue Resources Book sees ANS output growth over next 10 years


LUCINDA MAHONEY

The Department of Revenue released the Fall 2001 Revenue Sources Book Dec. 15, forecasting — as the department did in preliminary numbers released in late October — increases in both oil price and North Slope production volumes from last spring's forecast.

"Compared to the Spring 2021 forecast, the Alaska North Slope oil price forecast has increased by $14.72 per barrel for fiscal year (FY) 2022 and $9.00 per barrel for FY 2023," Revenue Commissioner Lucinda Mahoney said in the RSB.

see **REVENUE FORECAST** *page 9*

Theta West ops plan approved with alternative B drill site for well

The Alaska Division of Oil and Gas has approved a plan of operations for Great Bear Pantheon's Theta West drilling program with alternative B for the drill site.

In a Dec. 15 decision, the division said GBP will use Nordic-Calista Rig No. 3 to drill the Theta West No. 1 exploration well, a vertical hole planned to a depth of 9,300 feet "to test and evaluate multiple targets in the Brookian formation with an emphasis on the Basin Floor Fan." Theta West is some 15 miles west of Dalton Highway milepost 386.7 near the confluence of the Toolik and Kuparuk rivers, the division said.

A 10.5-mile ice road will be constructed to the Theta West site,

see **THETA WEST** *page 14*

DO&G approves Kitchen Lights 2022 POD with modifications

Alaska Department of Natural Resources' Division of Oil and Gas Director Tom Stokes has approved — with modifications — the 2022 Kitchen Lights plan of development submitted ty Furie Operating Alaska.

The Kitchen Lights unit was formed in 2007 as the Kitchen unit, with Escopeta Oil Co. the operator. The unit was renamed Kitchen Lights in 2009 when it was expanded to include acreage from the former Corsair unit, a proposed Northern Lights unit and other leases, the division said. Escopeta changed its name to Furie in 2012, and on July 1, 2020, HEX LLC acquired the assets and equity interests of Furie out of Chapter 11 bankruptcy proceedings.

HEX has continued to operate Kitchen Lights as Furie.

see **KITCHEN LIGHTS** *page 15*

Enbridge line in knots; company loses bid for tariff change at CER

Canada's top energy regulator has tossed a curve ball at Enbridge's proposal to keep its huge Mainline oil pipeline network operating at capacity, forcing the company to start exploring options for a network that carries more than 3 million barrels per day of crude from Alberta to the U.S. Midwest and Gulf Coast as well as Ontario and Quebec and also includes the controversial Line 3 and Line 5.

The dispute over the future of a 70-year system has amounted to an epic showdown between North America's largest crude carrier and Alberta crude producers, who are divided amongst themselves over the issue that affects about 70% of Canada's ability to ship crude from Western Canada to continental markets.

The Calgary-based company had launched a proposal two

see **ENBRIDGE BID** *page 14*

FINANCE & ECONOMY

Oil demand robust

Post omicron rally resumes; Analysts: US rigs, global exploration needed

By STEVE SUTHERLIN
Petroleum News

Alaska North Slope crude shook off a two-day COVID-19 omicron variant price panic, adding $1.52 Dec. 22 to close at $77.06 per barrel. West Texas Intermediate gained $1.64 to close at $72.76, while Brent gained $1.31 to close at $75.29.

The post omicron rally was back on track, with ANS closing just a penny shy of its post omicron record of $77.07 set on Dec. 8.

On Dec. 20, WTI fell below the $70 mark, losing $2.54 to close at $68.32, while ANS lost $1.41 to close at $73.42 and Brent fell $2.00 to close at $71.52.

Rystad Energy warned that global oil and gas discoveries in 2021 are on track for the lowest full-year level in 75 years unless significant finds are added in December.

But the indexes roared back the next day on reports that omicron appeared milder and less deadly than the delta variant, along with bullish inventory drawdowns reported by the American Petroleum Institute. ANS jumped $2.13 Dec. 21 to close at $75.55, WTI leapt $2.54 to close at $68.32

see **OIL PRICES** *page 13*

EXPLORATION & PRODUCTION

Unravelling Slope history

Research indicates three major source rocks may have expelled 250 billion barrels

By ALAN BAILEY
For Petroleum News

The fact that Alaska's North Slope is a major oil province is well known. But how did oil end up in the various oil fields in the region? And how does that relate to the region's geologic history?

In a talk to the Alaska Geological Society on Dec. 16, geological consultant Dallam Masterson described the results of some research into the North Slope oil systems. The information that Masterson presented came from a paper coauthored with colleague Albert Holba, published by the American Association of Petroleum Geologists in June.

The analysis mainly related to the established, producing fields, rather than recent discoveries.

Three rock sequences

In general terms, there are three major rock sequences involved in the North Slope petroleum system: the Ellesmerian, the oldest and deepest of the sequences, contains the Ivishak sandstone, the primary reservoir for the giant Prudhoe Bay field. At the time of deposition of the Ivishak, the North Slope was connected to what is now the north coast of Arctic Canada, with the Ivishak being deposited southward in a marine basin, to the south of what is now the Beaufort Sea coast.

In late Jurassic and early Cretaceous, Arctic Alaska drifted away from Arctic Canada, with what is now the Beaufort Sea opening up. The associated

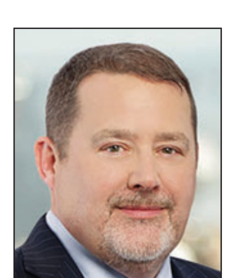
see **OIL SYSTEMS** *page 11*

EXPLORATION & PRODUCTION

Cenovus on 'next boom'

Oil sands producer launches three carbon-capture projects to lower GHG by 35%

By GARY PARK
For Petroleum News


ALEX POURBAIX

Cenovus Energy, one of Alberta's oil sands powerhouses, is in hot pursuit of climate reduction targets, rolling out plans for three new carbon-capture projects over the next five years that it estimates will lower its greenhouse gas emissions by 35%.

Chief Executive Officer Alex Pourbaix said that shrinking emissions by that amount for each barrel of crude it produces "could very easily be the next boom in the Alberta oil sector," creating employment and drawing investment in technology and research dollars.

"We no longer see the need for major growth phases in our oil sands business," he said.

"Our plan is to sustain the increased upstream production we've established this year while also reducing greenhouse gas emissions."

In his four years as the corporate leader, Pourbaix has targeted expansion phases at its operations that would typically add incremental phases of 50,000 barrels per day to its current output of about 800,000 barrels of oil equivalent per day. That would require multi-billion-dollar-plus phases over a period of up to six years.

"Our plan is set to sustain the increased upstream production we've established this year,

see **CARBON CAPTURE** *page 12*

● EXPLORATION & PRODUCTION

Hilcorp working to P&A Birch Hill well

Gas well drilled by Standard Oil Company of California in 1965, only produced gas in June of that year; issue road access for work

By KRISTEN NELSON

Petroleum News

When Hilcorp Alaska took over from earlier major operators in Cook Inlet beginning in 2012 it acquired mature oil and gas properties and has focused on maximizing remaining production from those properties.

It also, however, acquired Birch Hill, a non-producing gas discovery with a single well northeast of Swanson River in the Kenai National Wildlife Refuge.

Alaska Oil and Gas Conservation Commission records show the well, Birch Hill Unit 22-25, the discovery well, drilled by Standard Oil Company of California in 1965, only produced for 12 days during a single month — June of 1965 — with a total volume of 65,331 thousand cubic feet.

Hilcorp's focus at Birch Hill in recent years has been on finding a partner to explore the area, or alternatively, planning to plug and abandon the well.

Because of its location in the Kenai National Wildlife Refuge, Birch Hill is managed by the federal Bureau of Land Management.

In recent plans of development filed with BLM, Hilcorp has focused on potential road access to Birch Hill, meeting with BLM and Cook Inlet Region Inc., which holds a 20% working interest, on potential northern road access.

The Corps said "recent reviews have determined that the estimated recoverable gas from the well does not justify the cost to produce it. As such, BLM has required P&A of the well by May 1, 2022."

Hilcorp told BLM it has made efforts to find partners to develop Birch Hill, but no real interest developed and as a result, Hilcorp said, it "is moving forward with the planned P&A work for Birch Hill."

In its 2021 plan, Hilcorp said the road design would be finalized in the summer, with grubbing/clearing for the gravel road path to occur, followed by construction of a gravel road in the fall and P&A of the Birch Hill Unit 22-25 well in the fall/winter.

If the surface owner requires road removal, that would occur in the spring/summer of 2022, Hilcorp said.

Corps of Engineers

On Dec. 16 the U.S. Army Corps of Engineers Alaska District published notice of an application from Hilcorp related to road construction to the Birch Hill Unit 22-25 well.

The Corps said the southern 1.6-mile road segment is on land conveyed to Tyonek Native Corp. within the Kenai National Wildlife Refuge.

The Corps said material will be discharged into wetlands "to provide a stable base for constructing the road that would accommodate the P&A rig and associated equipment. Secondarily, the road would be utilized to provide access to their lands for subsistence and recreational activities for shareholders of TNC."

The entire road length would be 2.4 miles, the Corps said.

The Corps said Union Oil Company of California received a permit in 2010 to discharge gravel fill into 2.65 acres of wetlands for construction of an access road between the Swanson River oil and gas field, North Swanson River satellite and the Birch Hill unit.

That permit was transferred to Hilcorp Alaska in November 2011.

A permit modification authorized in 2015 granted a five-year extension.

"To date, the authorized southern route was cleared, however, the access road was never constructed, and the permit has now expired. The current proposal listed under 'Proposed Work' would access the Birch Hill Unit from the north," the Corps said.

The Corps said the well has never been produced, so

see BIRCH HILL WELL page 4

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ON THE COVER

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EXPLORATION & PRODUCTION

Baker Hughes US rig count up by 3 to 579

Baker Hughes' U.S. rotary rig count for the week ending Dec. 17 continued its upward climb, adding three rigs from the previous week for a total of 579, up 233 from a count of 346 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.

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.

Baker Hughes shows Alaska with five rigs active Dec. 17, unchanged from the previous week and up by two from a year ago, when the state's rig count stood at three.

The Dec. 17 count includes 475 rigs targeting oil, up by four from the previous week and up 212 from 263 a year ago, with 104 rigs targeting gas, down one from the previous week and up 23 from 81 a year ago, and no miscellaneous rigs, unchanged from one the previous week and down by two from a year ago.

Thirty-two of the rigs reported Dec. 17 were drilling directional wells, 521 were drilling horizontal wells and 26 were drilling vertical wells.

Alaska rig count unchanged

Texas (276) was up by three rigs from the previous week.

Oklahoma (48) was up by two rigs while Louisiana (49) and Pennsylvania (19) were each up by a single rig.

California (8) and New Mexico (89) were each down by one rig week-over-week, while West Viriginia (10) was down by two rigs.

Rig counts in all other states were unchanged week over week: Alaska (5), Colorado (12), North Dakota (27), Ohio (11), Utah (10) and Wyoming (15).

Baker Hughes shows Alaska with five rigs active Dec. 17, unchanged from the previous week and up by two from a year ago, when the state's rig count stood at three.

The rig count in the Permian, the most active basin in the country, was up by two from the previous week at 288 and up by 114 from 174 a year ago.

—KRISTEN NELSON

continued from page 2

BIRCH HILL WELL

the volume reported by AOGCC must have been a test. The Corps said "recent reviews have determined that the estimated recoverable gas from the well does not justify the cost to produce it. As such, BLM has required P&A of the well by May 1, 2022."

Mitigation measures

The Corps said the road has been planned to avoid wetlands as much as possible, and with a minimum road width to provide access to the well to permanently P&A it.

The planned road is connected to the existing Kenai Spur High extension, maximizing use of current developed rights of way.

"The road is sited on natural uplands and existing disturbed uplands, and completely avoids permanently inundated wetlands and WOUS," the Corps said.

It is tied to the existing BHU pad which, the Corps said, "should have adequate spacing for P&A activities."

"The road avoids placement of gravel in locations designated as Critical Habitat under the Endangered Species Act," the Corps said, and there will be no concrete or asphalt surfacing. There will be pullouts in upland areas, allowing for safe passage of construction equipment.

The Corps said Hilcorp will install 15 18-inch diameter by 30- to 35-foot-long culverts in wetlands to maintain natural drainage.

The public comment period expires Jan. 14. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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Kay Cashman	PUBLISHER & FOUNDER
Mary Mack	CEO & GENERAL MANAGER
Kristen Nelson	EDITOR-IN-CHIEF
Susan Crane	ADVERTISING DIRECTOR
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Steve Sutherlin	CONTRIBUTING WRITER
Judy Patrick Photography	CONTRACT PHOTOGRAPHER
Forrest Crane	CONTRACT PHOTOGRAPHER
Renee Garbutt	CIRCULATION MANAGER

ADDRESS
P.O. Box 231647
Anchorage, AK 99523-1647

NEWS
907.522.9469
publisher@petroleumnews.com

CIRCULATION
907.522.9469
circulation@petroleumnews.com

ADVERTISING
Susan Crane • 907.770.5592
scrane@petroleumnews.com

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. 26, No. 52 • Week of December 26, 2021

Published weekly. Address: 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.

GOVERNMENT

AOGCC holds required hearing on waste

Alaska Supreme Court ordered hearing on complaint by Hollis French; results of commission's work on 2017 fuel leak presented

By KRISTEN NELSON
Petroleum News

In a September opinion the Alaska Supreme Court remanded a waste complaint by Hollis French to the Alaska Oil and Gas Conservation Commission for further proceedings.

French petitioned the commission in 2019 for a hearing on the issue of waste related to a fuel gas leak in Cook Inlet in 2017. The commission denied the petition; French appealed to Alaska Superior Court, which found for the commission.

But the Alaska Supreme Court, to which French appealed the Superior Court decision, ruled the request for a hearing was improperly denied and remanded the matter to the commission for further proceedings.

The commission said it investigated the leak and made a waste determination, the Supreme Court said, but even if the commission could deny a hearing because it had investigated waste, "the factual assertion that it has done so must be supported by substantial evidence. The Commission's statements about having investigated whether the leak was waste are wholly unsupported. The Commission's dismissal order contains several factual statements about the alleged investigation and waste determination, but there is no supporting evidence in the administrative record."

The Supreme Court said AOGCC improperly denied French's request for a hearing.

"The Commission has jurisdiction over waste determination, and substantial evidence does not support its assertion that it investigated and concluded this leak was not waste," the Supreme Court said, reversing the Superior Court decision and remanding the matter to the commission "for further proceedings consistent with this opinion."

Prohibition of waste

French said in his Dec. 15 presentation at the hearing that state statute prohibits waste of oil and gas. Gas bubbling up in the inlet (as the fuel gas did in 2017) is gas escaping into the air that will never be used, he said.

French said he was a commissioner when the leak occurred and said he suggested the commission do something about it as it seemed clear to him that it was waste. But he was told the commission didn't have jurisdiction because the gas was not coming from the platform but was going back to the platform.

That gas had already been metered, and French said the other two commissioners were adamant that AOGCC's jurisdiction ended at that point — upstream of the meter AOGCC had jurisdiction, downstream of the meter it did not.

But French said jurisdiction is like a light switch — either you have it or you don't.

He said the 1955 Alaska law of conservation prohibits waste of oil and gas in Alaska, originally stating that waste of oil and gas was prohibited in the territory of Alaska, later amended to say waste of oil and gas was prohibited in the state.

The commission's reading of the law is contrary to the law and also harmful to the public and the public interest, he said.

Cost of enforcement is not an issue because AOGCC is paid for by the regulated oil and gas industry, he said, and there is "prosecutorial discretion," so you may not choose to act on the smallest of leaks, but you want the power in serious cases.

The metering issue

Jim Regg, AOGCC inspection program supervisor, testified in the Dec. 15 hearing on the commission's work on the Middle Ground Shoal pipeline leak and the result of the investigation done of the leak at the time it occurred.

He said the investigation included reviewing AOGCC field files, inspection files and Cook Inlet oil and gas pipeline infrastructure and gathering and reviewing information about the source of natural gas in the MGS A pipeline.

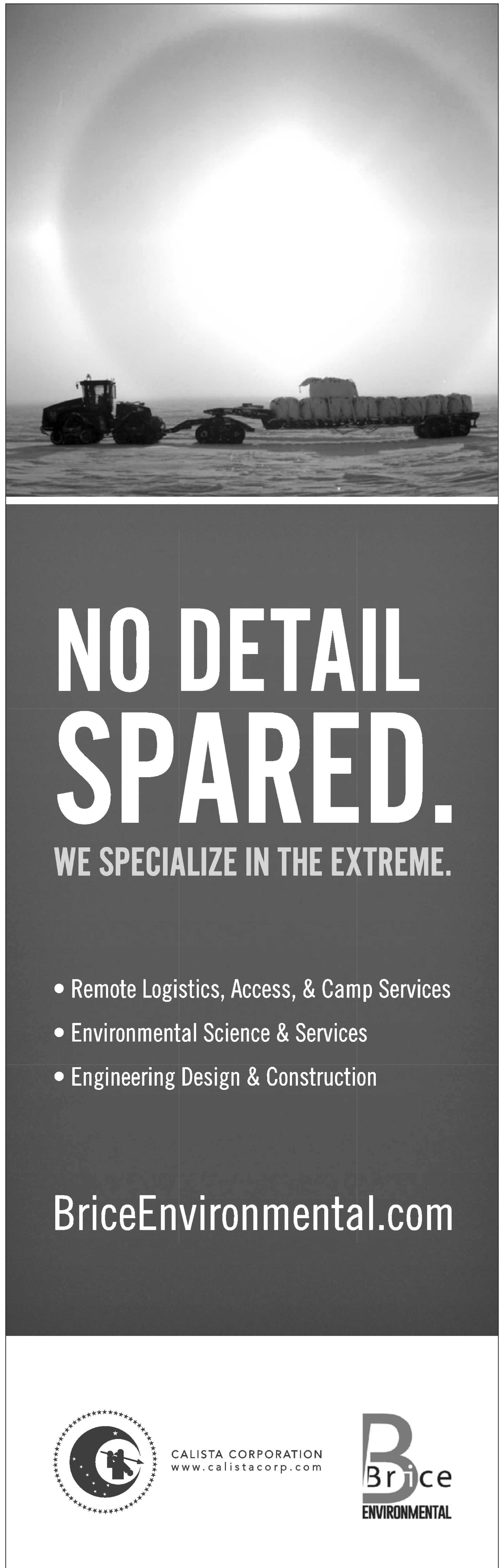
Similar produced natural gas pipeline leaks and how those were handled were reviewed, along with information from the federal Pipeline Hazardous Materials Safety Administration, the Alaska Department of Environmental Conservation and Hilcorp related to the leaking pipeline.

Regg said the 8-inch pipeline was converted in 2005 from a liquids line to a fuel gas line, moving gas from onshore to Middle Ground Shoal, where it was used on the platform as fuel for heat, light and power and artificial lift.

MGS does not produce enough gas to support the platform, which in February 2017 required more than 40 million cubic feet per day, while producing slightly more than 15 million cfpd, so MGS must buy gas from outside the field to operate.

Regg said the law requires that natural gas be measured before removal from the lease, unit or property where it is produced, and this, he said, is the point at which AOGCC has always deemed the resource, gas or oil, to have been produced.

see AOGCC HEARING page 6



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AOGCC HEARING

AOGCC, he said, has always interpreted the prohibition against waste to be related to maximizing production, and because the gas leaking from the MGS line had been purchased by Hilcorp, AOGCC deemed it recovered or produced and not susceptible to being deemed waste.

Public comments

The commission also heard from two members of the public, Lois Epstein and Harold Heinze, both of whom urged the commission's consideration of public interest in its decisions.

Epstein, an engineer, said that while the view of the commission's authority proposed by French does expand the commission's jurisdiction, there is prosecutorial discretion. And because this was a long-lasting leak, it made the state of Alaska look bad nationally, she said, which makes it something the commission might want to take on if such a situation occurred in the future.

Harold Heinze, who has been involved in the industry in Alaska since the 1960s, said he'd been before the commission almost 10 years ago arguing that propane should be produced from Prudhoe Bay, and that the lack of propane production constituted waste.

He said he thinks the issue before the commission is about the breadth of its duties and responsibilities.

Heinze said that he's been dealing with AOGCC for some 50 years and said he thinks the agency has done a wonderful job on the technical side but urged more consideration of the commission's public interest responsibility. He said the commission may be the only agency that can look at the public interest in the broadest sense and try to protect it. ●

Contact Kristen Nelson at knelson@petroleumnews.com

● GOVERNMENT

Higher US standards for more pipelines

By JOHN FLESHER

Associated Press Environmental Writer

A new federal regulation requires higher safety standards for pipelines carrying oil and other hazardous liquids through the Great Lakes region, marine coastal waters and beaches, officials said Dec. 16.

The rule issued by the U.S. Pipeline and Hazardous Materials Safety Administration designates those locations as "high consequence" zones where pipeline operators must step up inspections, repairs and other measures to avoid spills.

The agency estimated that 2,905 additional miles of hazardous liquid pipelines will be covered under the new rule, primarily in states along the Gulf of Mexico.

"The Great Lakes and our coastal waters are natural treasures that deserve our most stringent protections," said Tristan Brown, the agency's deputy administrator. "This rule strengthens and expands pipeline safety efforts."

Congress ordered the pipeline safety agency last year to include the Great Lakes, coastal beaches and coastal waters among "unusually sensitive areas" meriting extra attention.

"We know a pipeline spill in the Great Lakes would be catastrophic," said Sen. Gary Peters, a Michigan Democrat who sponsored the provision.

The natural gas and oil industry "is committed to the safe and environmentally responsible operation of U.S. energy infrastructure, and pipelines remain one of the safest ways to deliver affordable, reliable energy," said Robin Rorick, a vice president of the American Petroleum Institute, a trade association.

Large oil releases would severely damage shoreline and underwater environments, fisheries, human health and coastal community economies, the regulation says.

The 53-page document acknowledges there's no way to know how many disasters the new requirements will prevent. But it offers several previous examples of damaging spills in the designated areas.

Among them: last month's release from an oil pipeline in Southern California and a 2010 spill of about 840,000 gallons of crude near Marshall, Michigan, which contaminated nearly 40 miles of the Kalamazoo River.

It also notes a 2018 anchor strike that dented Enbridge Energy's Line 5 in Michigan's Straits of Mackinac connecting Lake Huron and Lake Michigan, although it didn't cause an oil leak.

The new rule requires operators to include any pipeline that could affect the designated environments in their safety management programs.

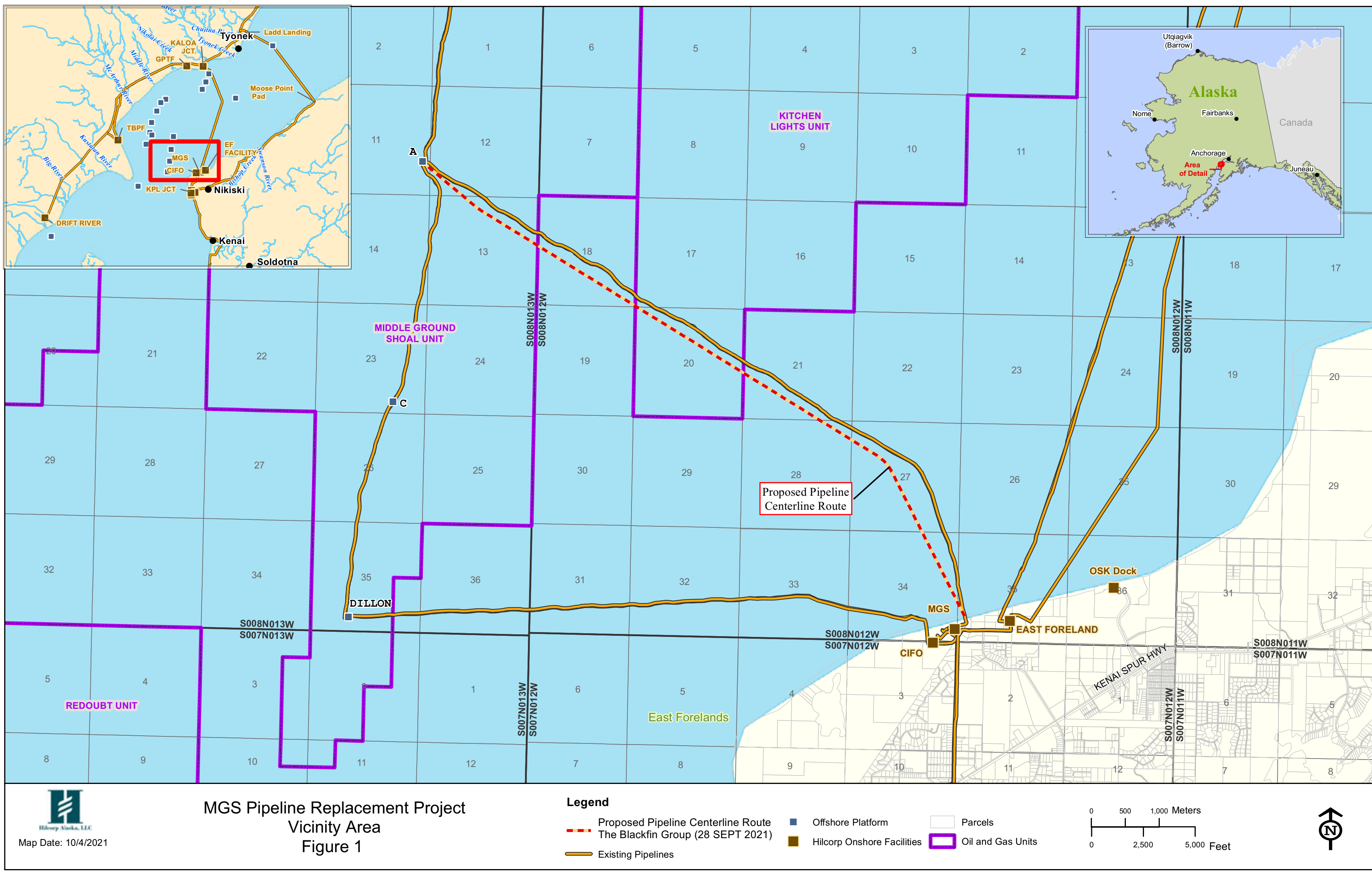
Those procedures include in-line inspections, pressure tests and other methods to measure pipeline integrity, as well as analyses of significant threats such as corrosion.

Environmentalists praised the measure but said they would continue pushing to shut down Enbridge's Line 5, which moves oil between Superior, Wisconsin, and Sarnia, Ontario.

"The aging pipelines in our basin are a risk to our water and way of life," said Beth Wallace, Great Lakes campaign manager for the National Wildlife Federation.

Enbridge said its integrity management program for Line 5 already meets the new requirements.

"Our goal is to protect the waters of the Great Lakes while safely and reliably delivering affordable energy to Michigan and the region daily," spokesman Ryan Duffy said. ●



● PIPELINES & DOWNSTREAM

Corps permitting MGS gas line replacement

Hilcorp proposes to lay 6.49 miles of dual 8-inch diameter pipelines from platform A to Middle Ground Shoal onshore facilities

By KRISTEN NELSON
Petroleum News

The Middle Ground Shoal fuel gas pipeline in Cook Inlet began leaking in April of 2021 and platforms A and C have been shut-in since. The federal Pipeline and Hazardous Materials Safety Administration required Hilcorp to replace the line. PHMSA said this was the fifth leak in the MGS-A line since June 2014. Previous leaks were repaired with bolt-on split-sleeve clamps.

The line provides fuel gas to the platform from facilities onshore.

The Division of Oil and Gas approved a suspension of operation and production at MGS in June.

In an update on Hilcorp's Cook Inlet activities in September, Dan Polito, Hilcorp's project manager for the MGS pipeline replacement, said the company looked at alternatives ranging from lighthousing the platforms to repairing or replacing the gas line.

The decision was to replace the existing 8-inch lines.

Polito said a lay barge will be used because of the 7-mile length of the MGS pipelines. He said the company was working on planning, engineering and permitting the work and planned to mobilize as soon as the ice moves out of the inlet, probably in late May. The pipe lay will take three to four weeks, followed by about two months of pipeline stabilization, tie-ins and commissioning.

Polito said Hilcorp hopes to have the platforms back online in about a year.

Corps permitting

The U.S. Army Corps of Engineers Alaska District posted a public notice Dec. 16 for the work, noting that Hilcorp's stated purpose is to satisfy PHMSA requirements and allow MGS to continue producing, "as well as decreasing the future likelihood of fatigue or abrasion leaks on these pipelines."

Inter-tidal work involves burial of the lines in a three-foot deep trench.

For the marine work, the Corps said a 200-foot section of the existing line would be removed from each end — MGS platform A and the MGS onshore facility — and the remainder of the line would be abandoned in

see **MGS GAS LINE** page 8

E&P

USGS: Less recoverable oil in western ND

A federal report shows that untapped recoverable oil in western North Dakota has dropped significantly in the last eight years due to the number of new wells.

The U.S Geological Survey estimates that the Bakken and Three Forks rock formations contain another 4.3 billion barrels of crude, a 40% drop from the agency's last estimate in 2013.

About 11,000 wells have been drilled into the formations in the last eight years, collectively producing billions of barrels of oil predicted in the earlier estimate.

"We weren't all that surprised that the number went down," state Mineral Resources Director Lynn Helms said Dec. 17. "I think we were surprised how much the number went down."

The wells drilled into the rock formations have produced 4 billion barrels of oil to date. Helms said he anticipates the future output of those wells will consist of another 4 billion barrels, The Bismarck Tribune reported.

Helms said about 80% of what's considered the best mineral acreage in the Bakken oil patch has already been drilled and companies are looking to innovate in parts of the region farther from the center.

The USGS also revised down its expectations for natural gas production. The 2013 estimate anticipated 6.7 trillion cubic feet per day of additional recoverable gas. The latest estimate puts the figure at 4.9 trillion cubic feet per day.

—ASSOCIATED PRESS

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MGS GAS LINE

place. "As part of the abandonment process, each abandoned pipeline has been cleaned using the static sheen test procedure (EPA Method 1617) and no additional cleaning would be required per PHMSA regulations," the Corps said.

New dual 8-inch diameter lines will be laid from MGS platform A "to the tie-in location on the beach below the MGS onshore facility, for a total distance of 6.49 miles."

The Corps said the pipelines, laid on the inlet floor, "would be pinned to the seafloor with Seacrete bags (sandbags)," which would be placed at 76 locations along the route.

Site selection included making the most use practicable of areas previously disturbed, with the pipeline to be placed within the existing pipeline right of way "to the extent practicable," with a route analysis done to identify the best method, resulting in the route being straightened, removing a bend in the original route. The Corps said benefits from the route analysis included: a shorter pipeline; avoidance of subsea obstacles such as a large pinnacle along the historic route; access to shore at a non-perpendicular angle to increase bottom stability; and replacement line to be tied in directly or with "very minimal spool piece length."

Closing date for comments is Jan. 14, 2022. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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REVENUE FORECAST

ANS averaged $54.14 per barrel in FY21.

The fall forecast is based on an annual average ANS oil price of $75.72 per barrel for FY22 and $71 per barrel for FY23, but those numbers are lower than the preliminary numbers released in October, which were an estimated FY22 West Coast Alaska North Slope crude price of $81.31 per barrel, and $76 per barrel for FY23.

Alaska's fiscal year runs from July 1 through June 30.

The RSB said forecasts assume ANS prices will be in the mid- to high-$60s over the 10-year forecast period, averaging $68 by 2031.

Mahoney said the department has made a change in how it forecasts long-term oil prices. Recent forecasts were "derived based on two years of futures market projects for Brent crude followed by an assumption that prices would increase with inflation thereafter. Beginning with the Fall 2021 forecast, the oil price forecast utilizes futures market projections for as many years as are available (in this case, through FY 2029), followed by an assumption that prices will increase with inflation thereafter. The change was made in an effort to provide a more accurate projection of oil prices and thus state revenue over the medium and long term," Mahoney said.

The ANS production forecast for FY22 is 486,700 barrels per day, down slightly from the preliminary fall forecast which was 488,400 bpd. The FY23 forecast remains the same at 500,200 bpd.

The FY22 ANS production forecast is up 27,100 bpd from the spring forecast and the FY23 forecast is up 23,600 bpd, Mahoney said.

Petroleum revenue up in FY22

The state's total unrestricted petroleum revenue was $1,217.6 million in FY21 and is forecast to be $2,274.6 million in FY22 and $2,082.3 million in FY23.

The largest proportion of the unrestricted total is from oil and gas royalties, $702.9 million in FY21 and forecast at $1,036.2 million in FY22 and $990.1 million in FY23.

Production tax is the next largest source of petroleum revenue, $389 million of unrestricted revenue in FY21 and forecast to be $979.6 million in FY22 and $741.2 million in FY23.

> *Overall, ANS production, which averaged 486.1 thousand bpd in FY21, is forecast to grow steadily through the forecast period to 586.2 thousand bpd in FY31.*

The RSB said unrestricted petroleum revenue is expected to provide between 25% and 40% of unrestricted revenue over the next 10 years, lower than the historic share, "due in part to including a portion of the value of the Permanent Fund as unrestricted revenue beginning in FY 2019." With the Permanent Fund share excluded, petroleum would be expected to provide between 74% and 85% of unrestricted revenue over the period.

There is also restricted petroleum revenue. That totaled $300.6 million in FY21 and is forecast at $379.1 million in FY22 and $393.6 million in FY23, bringing total petroleum revenue (restricted and unrestricted) to $1,594 million in FY21 and forecast at $2,732.1 million in FY22 and $2,591.5 million in FY23.

On the impact of COVID-19, the RSB noted temporary disruptions in oil production and prices April through June of 2020 and said: "Oil prices and production have since stabilized; the forecast is based on oil prices as indicated by futures markets and does not assume any further production curtailments."

Expenditures

The RSB said the Department of Revenue compiles expenditure forecasts from company submitted estimates and other documentation.

Total North Slope lease expenditures (of which deductible North Slope lease expenditures were 89% in FY21), were $3,946.9 million in FY21 and are forecast to be $4,282.2 million in FY22 and $4,896.4 million in FY23). That includes operating and capital expenditures.

Information about lease expenditures comes from "annual tax returns and monthly information filings from oil and gas companies operating in the state," the RSB said, with the department also receiving semiannual projections of lease expenditures, by unit, for up to five years in the future.

Capital expenditures generally represent company investment in new developments, but also include major field maintenance. Ongoing costs of operating fields are shown as operating expenditures, the RSB said.

Spending estimates "are subject to many uncertainties, including oil prices, and the ability of projects to obtain final company approval, and financing," the RSB said. "Many new developments included in the production forecast are included on a 'risked' basis, meaning they are only partially counted in the forecast based on a probability of occurring within the 10-year horizon."

Production forecasting

The production forecast is developed internally, with the Alaska Department of Natural Resources producing the forecast with assistance from the Department of Revenue. There are three categories:

•Currently producing includes oil wells in production prior to the start of the forecast.

•Under development includes wells and pools planned, funded and with partner alignment, with production typically expected in the first 12 months of the forecast period.

•Under evaluation includes new wells and pools expected to begin production in years two through 10 of the forecast period that "may not yet have final funding decisions or partner alignment."

Looking at the production forecast, the category expected to grow the most over the 10-year forecast period (starting from zero in FY22 and reaching 140.3 thousand bpd in FY31, is labeled "other" and includes Alkaid, Guitar, Narwhal, Pikka, Placer and Smith Bay.

National Petroleum Reserve-Alaska (GMT1, GMT2, Willow and Umiat) averaged 2.9 thousand bpd in FY21 and is forecast to grow from 3.6 thousand bpd in FY22 to 41.5 thousand bpd in FY31.

Overall, ANS production, which averaged 486.1 thousand bpd in FY21, is forecast to grow steadily through the forecast period to 586.2 thousand bpd in FY31.

Cook Inlet production, which averaged 10.6 thousand bpd in FY21, is forecast to average 8.6 thousand bpd in FY22, reach a forecast-period peak of 10.3 thousand bpd in FY27 and decline to 7.8 thousand bpd in FY31.

—KRISTEN NELSON

Contact Kristen Nelson at knelson@petroleumnews.com

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OIL SYSTEMS

rifting of the continental crust resulted in the second major North Slope rock sequence, the Beaufortian sequence. The reservoirs for the Kuparuk River and Alpine fields are situated in this sequence.

Then, between the Cretaceous and the early Cenozoic, a massive amount of sedimentary material flowed into a trough between the emerging Brooks Range and what is now the Beaufort Sea coast, and ultimately across a geologic high along the coast. This sediment flow formed the Brookian sequence, the youngest and shallowest of the rock sequences. Recent major oil discoveries in the Nanushuk formation are in the Brookian.

There are three major oil source rocks: the Shublik, the Kingak and the HRZ. The Shublik lies in the Ellesmerian, immediately above the Ivishak. The Kingak is also in the Ellesmerian, above the Shublik. The HRZ, Cretaceous in age, lies at the boundary between the Beaufortian and the Brookian.

Oil signatures

The research that Masterson presented involved determining signatures for identifying the oil from each of the oil sources and using these signatures to figure out where the oil in each North Slope oil field had originated. The results can be used to assess a model for how the North Slope geology has evolved over time — the model predicts how much oil from each oil source would have ended up in each field reservoir.

A key signature for characterizing an oil source relates to the fact that there are two hydrogen isotopes with different atomic weights within hydrocarbons, Masterson said. The formation of hydrocarbons involves the fractionation of the isotopes into differing proportions. And the use of gas chromatography to separate components of the oil into components of different weights results in each oil from each oil source having a distinctive pattern of components across the component weight range.

Gas chromatography of oil from a specific field reservoir can then match the component pattern for that oil with the component patterns of potential source oils.

The component pattern for the Tarn field in the Kuparuk River unit, for example, clearly indicates that the oil in this field came from the HRZ, Masterson said. The Kuparuk River field itself shows an origin in the Shublik. The oil in the Alpine field, on the other hand, exhibits a pattern distinctive of a Kingak source. The Fiord field, northeast of Alpine, also appears to have a Kingak source.

The Prudhoe Bay field is more complicated. The component pattern for much of the field is fairly close to the Shublik, but slightly towards the HRZ, suggesting a dominant Shublik component but with some HRZ oil. However, oil at the western end of the field exhibits some sourcing from the Kingak.

Bulk oil properties

The bulk properties of the oils such as the sulfur content and API gravity also tell a story. Shublik oils, for example, have a high sulfur content, Masterson said. High gravity oils at Alpine and Tarn, on the other hand, have low sulfur content and low concentrations of asphaltenes, chemicals formed when sulfur combines with organic matter, he said. And this line of research suggests that the Prudhoe oils consist of about 60% Shublik and 40% HRZ and Kingak.

Biomarkers can provide more detailed information. These are trace oil components identified using a mass spectrometer. They indicate the presence of tiny organisms within the organic material that formed the oil. The organisms provide evidence for the age of the organic material and the environment in which the organic material formed.

Assessments of oil biomarker contents have confirmed the findings of the other techniques for the sources of oils in various field reservoirs.

The origin of the thick, viscous oil found in the relatively shallow West Sak reservoir in the central North Slope is particularly intriguing. In this oil, located in a relatively cool, shallow reservoir, microbes have been active, preferentially consuming the lighter, easier to biodegrade hydrocarbon molecules. The biomarker signature for West Sak is almost identical to that of the Prudhoe Bay oil, despite the fact that gas chromatography demonstrates that the West Sak oil is missing the light components that would have been biodegraded away. This supports a theory that the bulk of the West Sak oil had been spilled upwards from the Prudhoe Bay reservoir below.

However, the deeper oils in West Sak are associated with secondary condensates that have an isotope content closely matching that of oil in the underlying Kuparuk River field. This is interpreted as a secondary charge from the Kuparuk field after the West Sak oil had already been biodegraded, Masterson said.

The Trinity Basin Model

To try to make sense of all of this, it is valuable to use a model of how the North Slope geology evolved, to test whether the model predicts the manner in which different field reservoirs have been filled with oil from different sources — Masterson reviewed how a commercial model, the Trinity Basin Model, might explain the North Slope oil sourcing for the major oil fields with Ellesmerian and Beaufortian reservoirs.

According to the model, Kuparuk C sandstones that later formed part of the Kuparuk River reservoir, were deposited during the Cretaceous on the downthrown sides of steep faults formed during the crustal rifting associated with the Beaufortian sequence. At this time the underlying Ivishak sandstone was tilted, to form an emerging "Prudhoe high" towards the east.

By the late Cretaceous, about 66 million years ago, the HRZ, had spread across the basin plain ahead of the incoming sediments of the Brookian sequence, and had submerged the Prudhoe Bay high. Then, as the Brookian sequence flooded across and into the basin forming under what is now the North Slope, the HRZ would have been buried to a sufficient depth to form a hydrocarbon seal above what had by then become the Prudhoe Bay oil trap. At the same time, the oil source rocks would have been pushed down deep enough to be in the temperature window where oil would have formed.

A large Prudhoe Bay trap

At that time, the Prudhoe Bay oil trap would have been substantially larger than at present, while the Kuparuk River trap would not yet have formed. About 70 billion barrels of oil may have flowed upslope through the Ivishak into the Prudhoe Bay trap, while 15 billion barrels may also have flowed into the trap from the HRZ. A closure in the HRZ would also have trapped around 17 billion barrels of oil expelled from the HRZ source.

By the middle Eocene, about 45 million years ago, the rocks had reached their maximum burial depths. A large amount of oil would have been expelled into a huge structure in the northern part of the current Prudhoe Bay field — 32 billion barrels from the Shublik, but with some from the Kingak, and 26 billion barrels from the HRZ.

At this time the Kuparuk River trap was also starting to form. And the model indicates that, possibly supported by the stressing of steep faulting from the rifting era, 6 billion barrels of oil would have been expelled from the Shublik, vertically upwards into the Kuparuk River trap. The Tarn reservoir, on the other hand, would have connected directly with the HRZ — hence its charge with HRZ oil. And the Alpine field would have been located in an area where the Shublik would have been generating gas, while the Kingak, in the oil window, would have fed oil into the Alpine trap.

Tilting to the southeast

Moving forward to the present day, thrust faulting and crustal erosion in the area of the Arctic National Wildlife Refuge caused the rocks under the North Slope to tilt a little towards the southeast. That tilting reduced the size of the Prudhoe Bay trap, with oil spilling to the west and upward into the West Sak, with the oil probably moving through pathways generated by rift faults. Gas would also have moved through younger faults upwards from the Kuparuk River field into West Sak.

It turns out that this model for the evolution of the North Slope accounts for the nature of the oils in the established North Slope fields, thus supporting the credibility of the model. For the Prudhoe Bay field, the oil composition predicted by the model is within 5% of the actual composition, as measured, Masterson said.

And the model indicates that, in total, 250 billion barrels of oil would have been expelled from the oil sources in the model area, with 168 billion barrels of that oil coming within the fetch area of the Prudhoe Bay field, he said. ●

Contact Alan Bailey at abailey@petroleumnews.com

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CARBON CAPTURE

while also reducing GHG emissions," said Pourbaix.

Now, the company is positioned to move steam and oil from existing facilities to new oil sands expansions up to 12 miles away, eliminating the need to construct additional central processing facilities.

"It will save us billions of dollars over the decades to come," Pourbaix told reporters.

Sustaining production levels

While taking bold steps to join its peers in embracing carbon capture, utilization and storage, CCUS, to reduce emissions and demonstrate that it is serious about tackling climate change, Cenovus believes it can sustain 2021 production levels over the next five years and increase the amount of crude it processes by about 14%.

> *"Our plan is to sustain the increased upstream production we've established this year while also reducing greenhouse gas emissions." —Cenovus CEO Alex Pourbaix*

The company's Chief Sustainability Officer Rhona DelFrari told the company's annual investor day that one of the three new planned CCUS projects will be tied to Cenovus's heavy oil upgrader at Lloydminster (which straddles the Alberta-Saskatchewan border).

She said it could capture up to 430,000 metric tons of carbon dioxide annually, while the other two in Manitoba and northern Alberta will capture 100,000 mt and 60,000 mt respectively.

Over the longer term to 2035, Cenovus hopes to expand its CCUS operations to larger facilities, such as its Foster Creek and Christina Lake oil sands operations and its Lima, Ohio, refinery.

Cenovus is part of the production group accounting for 90% of oil sands production that has pledged to achieve net-zero emissions by 2050, while replacing steam with insolvents in the extraction of bitumen from the oil sands.

Tax credits crucial

But the extent of CCUS deployment in the oil and natural gas sector hangs on what the Canadian government will offer by way of tax credits.

The federal administration of Prime Minister Justin Trudeau has said that CCUS projects tied to enhanced oil recovery, EOR, will not be included in the tax credit program that is scheduled for introduction over the next year.

Pourbaix told reporters he is urging the government to "keep an open mind" about including EOR in the tax credit.

The Alberta government is campaigning for more than C$30 billion in federal incentives over the next decade for CCUS initiatives, including EOR projects.

Alberta Premier Jason Kenney said tax measures must be competitive with the credits introduced by the United States in 2018 of US$50 per metric ton for carbon dioxide stored underground and US$30 per mt for EOR developments — programs that Enbridge Chief Executive Officer Al Monaco said have put the United States in the global forefront, although he said Canada is close behind.

He said CCUS can be used in other major industrial sectors, including power generation and manufacturing, to meet emissions-reduction goals, and should soon be involved in a "very steep ramp-up" in the technology.

Joining the corporate stampede to carbon capture, pipeline giant Enbridge announced that as part of its C$1.1 billion capital spending program for 2022, C$300 million is earmarked for an Ontario pipeline close to a petrochemical region in Sarnia, positioning the company to build a hydrogen and CCUS center.

That followed Enbridge's plan to partner with Edmonton-based Capital Power Corp. on a CCUS project for its Alberta power generating station to capture up to 3 million mt a year of carbon dioxide.

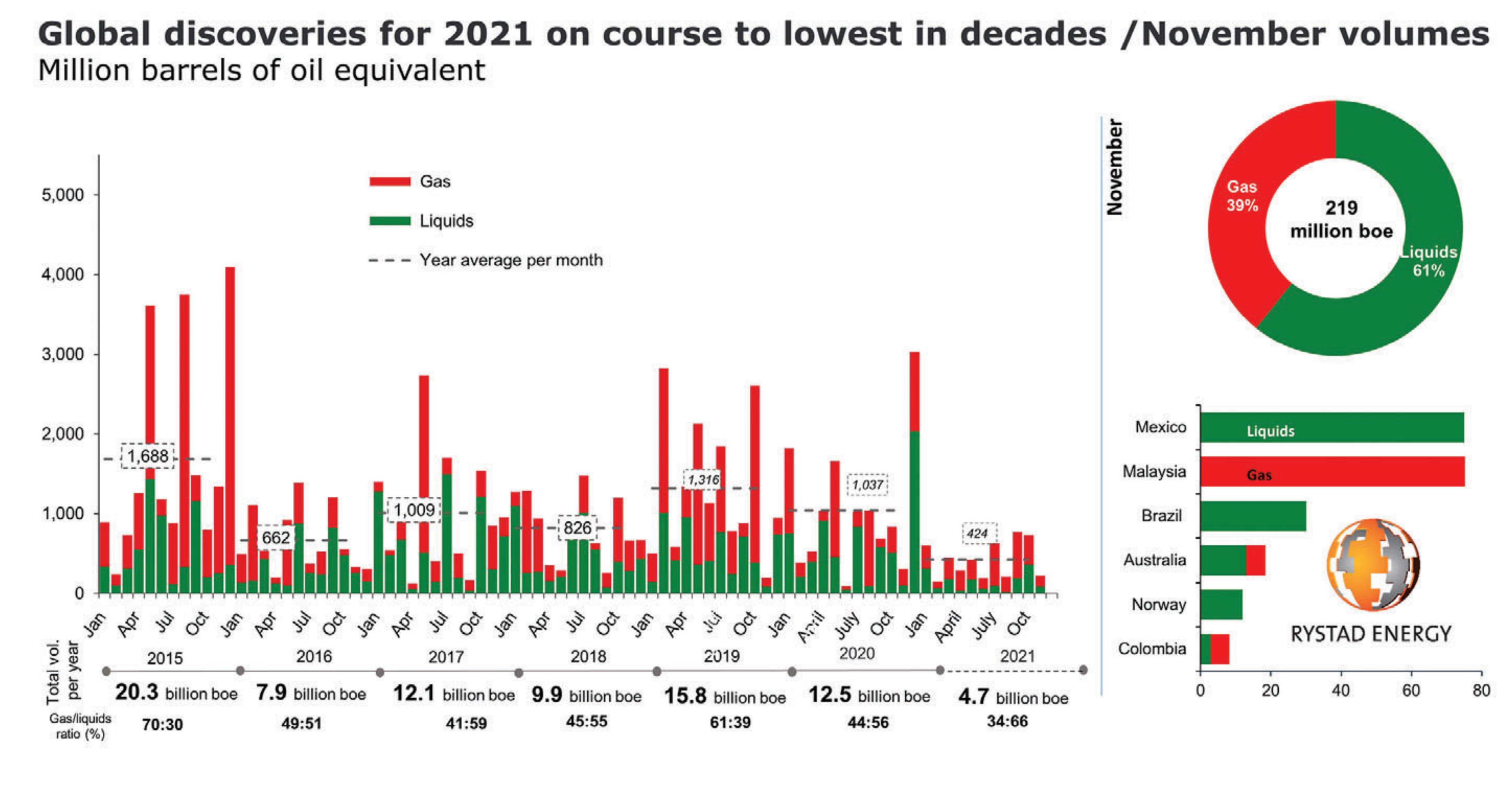
Monaco said the CCUS technology "is going to be a necessity" when it comes to meeting emissions-reduction goals, adding he expects to soon see a "very steep ramp-up" in CCUS.

He said Canada must close the gap on the United States CCUS tax credit to have any hope of attracting private capital "to get moving on CCUS."

Phil Skolnick, an analyst with Eight Capital, said tackling the emissions challenge is a "two-track system because there is a mandate in place by investors to focus" on Cenovus's plans.

"If the federal investment tax for carbon sequestration is significantly less generous than the 45Q (the U.S. tax credit strategy) we will see a flow of capital from Canada to the United States," warned Kenney. ●

Contact Gary Park through publisher@petroleumnews.com



Source: Rystad Energy ECube, UCube, research and analysis

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OIL PRICES

and Brent popped $2.46 to close at $73.98.

Dec. 22 price action was buoyed by a U.S. Energy Information Administration report issued the same day, showing that U.S. commercial crude oil inventories for the week ending Dec. 17 — excluding those in the Strategic Petroleum Reserve — decreased by 4.7 million barrels from the previous week.

At 423.6 million barrels, U.S. crude oil inventories stood 8% below the five-year average for the time of year, the EIA said.

Prices fall at the pump

The U.S. average regular gasoline retail price decreased 2 cents to $3.30 per gallon Dec. 20, $1.07 higher than a year ago, according to the EIA. U.S. gasoline prices hit a high of $3.42 per gallon in mid-November — a level not seen since September 2014 — before dropping due to omicron variant concerns.

But the relief at the pump may be short-lived, Ryan Sitton, energy data analyst and former Texas Railroad Commissioner said in remarks to the Energy Data Minute podcast.

"While the price easing is welcome news for consumers preparing for holiday road trips, there is reason to be cautious — the biggest cause of this drop is economic concerns caused by yet another round of covid fears," Sitton said. "While some countries are taking steps in response to the omicron variant, there appears to be little impact on energy consumption, so while there is speculation of potential demand reduction this may all be leading to higher prices on the horizon after these latest fears subside."

U.S. oil prices will likely continue higher in 2022, according to a Dec. 20 report on weekly rig count implications by Vincent Lovaglio and Silvio Micheloto, Mizuho Americas research analysts.

"Rig activity across the five largest U.S. oil plays would need to increase by 50 plus weekly through year-end to reach a sustainable plateau to hold current oil volumes in 2022," Lovaglio and Micheloto said. "Based on weekly rig additions, we do not forecast drilling activity reaching a sustainable pace with completion cadence until 2Q 22."

The analysts said the situation is positive for the commodity and for large-cap E&P companies.

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THETA WEST

starting from the Talitha A pad.

Two sites were proposed for the well, Alt A and Alt B. The division said GBP requested "direction on whether Alt A was within one-half mile of the Toolik River, and as a contingency, proposed Alt B for the Theta West Drill site."

The division said it determined that Alt A was within a half mile of the Toolik River and GBP was directed to use Alt B.

Overall winter plan

GBP will be reentering and testing untested zones of the Talitha A well it drilled last winter, as well as drilling the Theta West 1. The Theta West ice pad will be some 10 miles west of the Talitha pad.

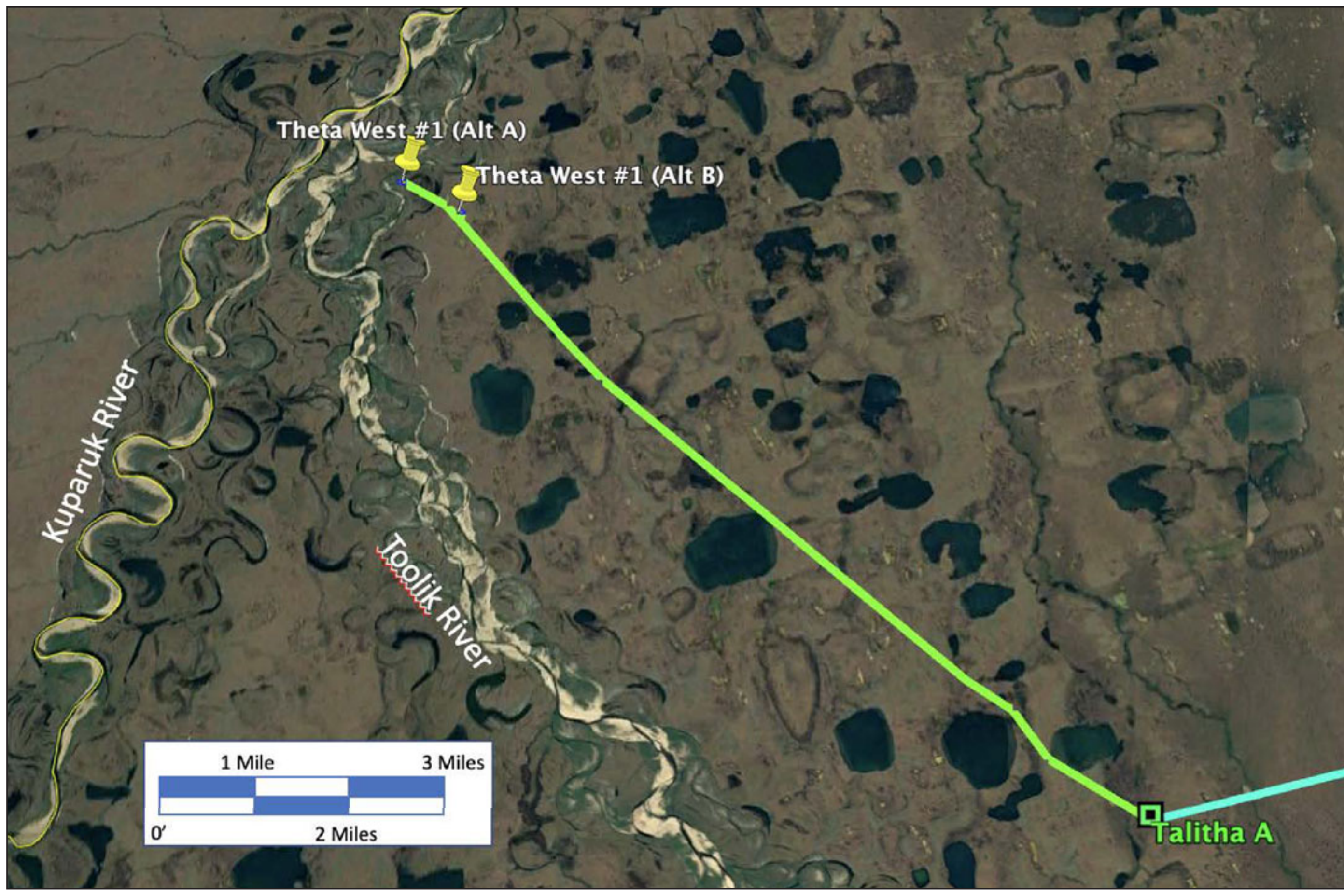
In announcing financing for this winter's work on Dec. 8, Pantheon Resources CEO Jay Cheatham said the company plans to assess as many as "eight targets across three wells," including four at Talitha A (drilled in 2021), which will be reentered, "and two targets each at Theta West and at our Alkaid 2H development well adjacent to the Dalton Highway and TAPS."

Bob Rosenthal, Pantheon's technical director, told Petroleum News in early November that Great Bear Pantheon, a Pantheon subsidiary, considers Theta West 1 to be an appraisal well of last winter's discovery at Talitha.

Work schedule

Prepacking and then constructing the ice road and drill pad were proposed to start Dec. 15 and be completed by Jan. 16.

The rig would be moved to Talitha A starting Jan. 4, with the rig moved to Theta West beginning in mid-January and a coil unit moved in at Talitha A.



GREAT BEAR PANTHEON

Theta West 1 is scheduled to be spud Jan. 18, with drilling, casing, testing and suspension of the well complete by April 15, followed by rig down and move out by the end of April.

Winter cleanup is scheduled for the end of April, with summer cleanup in late June and early July.

The Theta West well will likely be fracture stimulated, with decisions on stimulation and testing "based on seasonal timing and logging results," the division said.

The ice pad, some 520 by 240 feet, will house the drill rig and temporary support facilities, including a full crew camp with a 50- to 100-bed capacity, storage areas and maintenance buildings.

An 8-mile ice road will connect the Talitha A pad to the Dalton Highway and an additional 10.5 miles of ice road be built from the Talitha pad to the ice pad at Theta West.

The division said GBP "plans to install thermistor strings along the ice road routes that will be used to monitor ground temperatures to assist in agency decision-making regarding tundra opening."

Based on results of the Theta West exploration, the division said it anticipates that GBP may submit plans for additional exploration wells.

The plan was amended to incorporate mitigation measures from the North Slope Areawide Oil and Gas Lease Sale Final Finding.

—KRISTEN NELSON

Contact Kristen Nelson at knelson@petroleumnews.com

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ENBRIDGE BID

years ago that would have forced oil producers to sign long-term agreements extending over 20 years for 90% of Mainline's capacity, leaving only 10% available for spot shipments. Currently the entire network is open access.

CER ruling

Having heard conflicting arguments by Canada's energy giants, the Commission of the Canada Energy Regulator, CER, decided that if long-term contracting dominated Mainline's business, access to the network would change "suddenly and dramatically."

The CER said Mainline contracting "would likely reduce the access to pipeline capacity realistically available to certain shippers. The package of tolls, terms and conditions in the services offered would result in a distribution of benefits and negative impacts that is uneven and disproportionate."

Enbridge had argued that the current system allows producers to decide the volumes they want to ship each month, without firm commitments, putting the pipeline operators at a disadvantage with its rivals.

The conflict among producers over operational changes to Mainline prompted Canadian Natural Resources to raise concerns that Enbridge could abuse its market control, while BP, Cenovus Energy and ExxonMobil's Imperial Oil endorsed those who pay to reserve space on the network.

CNR accusation

CNR accused Enbridge of abusing its considerable market power to make the change, an allegation Enbridge described as "absurd."

CNR argued that approving Enbridge's switch would be contrary to its legal obligations as a common carrier and "contrary to the Canadian public interest."

The CER's ruling said Enbridge's proposed tolling method would offer a bigger discount to those customers with longer-term contracts and greater volumes and would "excessively favor shippers that signed long-term contracts."

The regulator said a change would "cause a foundational shift in Canada's oil pipeline system (by) single-handedly moving the transportation of oil by pipeline in Canada from predominantly uncommitted service to mostly committed capacity."

The Trans Mountain expansion project to the Pacific Coast and TC Energy's existing Keystone pipeline that provides links to the U.S. Gulf Coast both offer the most capacity to shippers with contracts, while requiring them to pay a regular fee regardless of whether they use the capacity or not.

Enbridge, after taking three days to mull the ruling, said it will consider several options for Mainline, including a modified version of its existing toll agreement.

The company said it will reach out to Mainline customers and non-shippers for input on alternatives for the pipeline's commercial framework, as well as seeking industry input on whether there is any appetite for future expansion of the network.

Enbridge said it has heard "significant concerns from industry over continuing Mainline apportionment, due to growing Western Canadian production and lack of sufficient egress."

However, it acknowledged there seems to be no consensus on the shape of a new commercial structure.

The current tolling agreement expired in June. Interim tolls will remain in place until the CER approves a new agreement. Enbridge said it expects to start consultations with the industry but doesn't expect a new CER verdict until 2023.

—GARY PARK

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OIL PRICES

"We maintain our positive view on the E&Ps," they said.

Dismal discovery year

Rystad Energy warned that global oil and gas discoveries in 2021 are on track for the lowest full-year level in 75 years unless significant finds are added in December.

"As of the end of November, total global discovered volumes this year are calculated at 4.7 billion barrels of oil equivalent and, with no major finds announced so far this month, the industry is on course for its worst discoveries toll since 1946," Rystad said in a Dec. 20 release. "This would also represent a considerable drop from the 12.5 billion boe unearthed in 2020."

Rystad said liquids continue to dominate the hydrocarbon mix, for 66% of total finds.

Seven new discoveries announced in November added 219 million boe of new volumes, bringing the monthly average of discovered volumes this year to 424 million boe, the consultancy said, adding that the reduction in cumulative volume highlights the absence of large individual finds, as in previous years.

"Although some of the highly ranked prospects are scheduled to be drilled before the end of the year, even a substantial discovery may not be able to contribute towards 2021 discovered volumes as these wells may not be completed in this calendar year," said Palzor Shenga, Rystad vice president of upstream research. "Therefore, the cumulative discovered volume for 2021 is on course to be its lowest in decades."

Estimated at 75 million boe of recoverable resources, the largest discovery in November was Russian group Lukoil's Yoti West, offshore Mexico, Rystad said.

Lukoil's cumulative discovered volumes at the find are insufficient for commercial development, which would require further discoveries of a comparable scale. Rystad said. The discoveries do give hope that Mexico can halt or slow down its production decline.

Offshore Malaysia, Nangka-1 was the second successive exploration well drilled within Block SK 417, Rystad said. The wildcat, drilled by Thai state operator PTTEP to a depth of 3,758 meters, discovered sweet gas in the Middle to Late Miocene Cycle VI clastic reservoirs.

Norway added small-to-medium finds, providing an opportunity to materialize the discoveries with available infrastructure, Rystad said. ●

Contact Steve Sutherlin at ssutherlin@petroleumnews.com

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KITCHEN LIGHTS

There are 30 state leases, 83,394 acres, in the unit, with 2020 calendar year gas production of 5.09 billion cubic feet, up from 4.35 bcf in calendar year 2019, the division said.

By contrast, between 2018 and 2019 production dropped from 6.21 bcf to 4.35 bcf.

Alaska Oil and Gas Conservation Commission production data show production of 4.06 bcf for January through October 2021, down from 4.24 bcf for the same period in 2020.

Previous POD

The division said that because HEX took over at Kitchen Lights July 1, 2020, the 2021 POD was conditionally approved for July 1, 2020, through Jan. 3, 2022.

Furie's commitments for the 2021 POD included:

•Continue development of Kitchen Lights' proven gas reserves.

•Continue and increase natural gas production from the Julius R Platform.

•Continue exploration in the unit, "including the new analysis of seismic data and offset wells to identify specific targets for exploration outside of the Corsair Block."

•Update the unit's joint operating agreement "to reflect the realities of operating in Cook Inlet."

In a November 2020 decision, the division required modifications to the 2021 POD to include two additional requirements:

•Furie will complete existing participating area applications or submit a new application by Dec. 21, 2020.

•Furie will provide a technical presentation to the division by July 1, 2021, "detailing with specificity the progress made on the subsurface description of the KLU, along with any other activities undertaken by Furie related to the further development of the KLU and exploration activities."

The division said Furie continued production and development of existing gas reserves during the 2021 POD.

While the company said it had completed a detailed assessment of the unit area, the division said the company has not elaborated on the detailed assessments or the results.

And the company has not reached an agreement with other working interest owners on an amended joint operating agreement and has not accomplished either of the modifications to the POD required by the division.

Proposed 2022 POD

In Furie's proposed 2022 POD, submitted in October by John Hendrix, Furie Operating Alaska CEO, Furie said the four wells on the Julius R platform all had "one or more downhole intervention(s) completed, or intervention work is in progress to continue development and increase production from the KLU."

The interventions included bailing fill from tubing, adding perforations, shifting sliding sleeves, removing a plug and wireline toolstrings and wireline and retrieving a wireline toolstring fish.

Furie said it installed a produced water handling system and obtained permits "to allow production of gas zones with higher water content. This may result in increased ultimate gas recovery."

"A detailed assessment of the KLU area and adjacent acreage was completed and led to Furie being the high bidder on the adjoining leases" at the state's June 2021 Cook Inlet areawide lease sale, the company said.

While no agreement has been reached, an amendment to the joint operating agreement was submitted to the working interest owners.

On the modifications by the division to the seventh POD, Furie was required to complete its existing PA application or submit a new PA application by Dec. 31, 2020, but said it "continues to evaluate available data to submit a draft PA application for review."

After Furie was high bidder on adjacent leases, division personnel "suggested that Furie consider unit expansion prior to finalizing the draft PA application," the company said.

On the requirement for a technical presentation by July 1, 2021, the company said its personnel spent much of the first half of 2021 analyzing data in preparation for the June lease sale.

"Due to confidentiality concerns prior to the lease sale, Furie preferred not to provide specificity regarding progress on the subsurface description," and offered to provide a technical presentation at an August meeting with the division, although that presentation has not yet been scheduled.

The 2022 POD

The division said for the 2022 POD Furie has proposed to continue development of proven gas reserves; continue optimization efforts for production and safety enhancements, along with minimizing the environmental footprint of the unit; continue progress on the PA; and evaluate drilling of additional wells.

The division said Furie has not completed either of its modifications from the 2021 POD.

On the requirement to complete a PA application or submit a new one, Furie has said it continues to evaluate data, the division said, but "has not provided any additional justification to suggest its inability to accomplish this modification, and does not provide an estimated timeline for when it anticipates submitting complete PA applications to the Division."

Furie proposes to continue work on the PA, but the division said, "it believes it is in the best interest of all parties for Furie to complete its PA application in the 2022 POD period, not simply progress its efforts."

On the technical presentation, the division said Furie's justification for not meeting the July 1, 2021, deadline is that its personnel were preparing for the lease sale and it had confidentiality concerns.

The division said it has addressed Furie's confidentiality concerns and will not address them further.

"It is imperative nevertheless that the Division explain its role in governing oil and gas development on State of Alaska lands.

"The Division has a responsibility to evaluate the geological and engineering characteristics of a potential hydrocarbon accumulation or reservoir when considering each requested authorization or approval under" its regulations. The technical data is not a division preference, but "a regulatory requirement to submit technical data in support of any proposed unit actions."

The division is adding requirements to the 2022 POD, and said it requires Furie to accept the modifications in writing by Jan. 3, 2022.

The modifications include:

•Submittal of a complete PA application by Aug. 31, 2022.

The division is requiring milestones for this requirement:

•The company will provide results of its detailed assessment from the 2021 POD no later than Feb. 28, 2022; and

•Provide a confidential pre-application technical presentation by July 31, 2022, "detailing with specificity the progress made on the subsurface description of the KLU along with any other activities undertaken by Furie related to further development of the KLU and exploration activities."

—KRISTEN NELSON

Contact Kristen Nelson at knelson@petroleumnews.com