Petroleum news

Vol. 30, No. 7 • www.PetroleumNews.com *A weekly oil & gas newspaper based in Anchorage, Alaska* Week of February 16, 2025 • $2.50

page 6 20 years ago: Myers sees untapped 20M, billion barrel fields on Slope

ConocoPhillips Alaska '24 report; future exploration west of Willow?

In connection with ConocoPhillips' fourth-quarter 2024 earnings conference call on Feb. 6, ConocoPhillips Alaska reported that it invested $3.2 billion in Alaska in both new and legacy fields in 2024.


EREC ISAACSON

And ConocoPhillips Alaska incurred an estimated $1.5 billion in taxes and royalties in 2024, which included $1.1 billion to the state of Alaska and $400 million to the federal government.

"The company had an exceptional year in 2024," said Erec Isaacson, president of ConocoPhillips Alaska.

"We successfully achieved first oil at Nuna, remaining under budget and ahead of schedule. Additionally, we exercised our preferential rights and acquired additional working interests in the Kuparuk River and Prudhoe Bay units in the fourth quarter. We have also accomplished significant milestones on the Willow project,

see **CONOCO REPORT** *page 10*

Enstar gas delivery case against Hilcorp dismissed by judge

Judge Herman Walker of the Alaska Superior Court has dismissed without prejudice a lawsuit in which Anchorage-based gas utility Enstar Natural Gas Co. claimed that Hilcorp Alaska had broken the terms of their gas supply agreement.

Enstar has claimed that Hilcorp violated the agreement by refusing to supply some gas to Enstar because of the timing with which Enstar was injecting gas into the Cook Inlet Natural Gas Storage Alaska facility on the Kenai Peninsula. As previously reported by Petroleum News the dispute relates to an amendment made last year to Hilcorp's supply contract with Enstar, as part of an arrangement whereby Enstar has been supplying gas to Alaska Electric and Energy Cooperative on the Kenai Peninsula since March, following the termination of AEEC's firm gas supply contract with Hilcorp. AEEC generates power for Homer Electric Association.

Coordination of gas deliveries with CINGSA withdrawals

In the contract amendment Enstar and Hilcorp agreed on a

see **GAS DELIVERY** *page 8*

Hilcorp plans 3 wells to bring Sterling gas field back online

Hilcorp Alaska has plans to bring a nonproducing Kenai Peninsula gas field back into production.

The company has applied to the Alaska Oil and Gas Conservation Commission for spacing exceptions to allow it to drill three wells closer than 1,500 feet to a property line where ownership changes in the Sterling gas field east of Kenai.

Two of the wells would be new; the third is a redrill of a well which was an early producer at the field.

AOGCC records show the Sterling gas field last produced in 2014. It was brought online by Marathon in 1962 and has produced some 14.5 billion cubic feet of natural gas. Hilcorp acquired the field in 2013.

In a July 2017 revised 47th plan of development and operations submitted to the U.S. Bureau of Land Management, Hilcorp said two producing wells went offline in 2014 and "subsequent remediation of the wells with eline and slickline efforts were unsuccessful in returning the field to production

see **STERLING FIELD** *page 11*

FINANCE & ECONOMY

ANS crosses $76 mark

Feb. high short lived on Russia/Ukraine peace bid and US inventory jump

By STEVE SUTHERLIN
Petroleum News

Alaska North Slope crude — after a three-day run — notched its highest high in more than two weeks Feb. 11, up 83 cents to close at $76.11 per barrel. West Texas Intermediate jumped $1.00 to close at $73.32 in the day and Brent jumped $1.13 to close at $77.00.

The Alaska benchmark had closed at $76.20 Jan. 24, after having taken its only foray into the $80s during 2025 on Jan 15, closing at $80.42.

The indexes, however, abruptly snapped a three-day winning streak Feb. 12, seeing ANS plunge $1.79 to close at $74.32, as WTI plummeted $1.95 to close at $71.37 and Brent plunged $1.82 to close at $75.18.

A potential deal for Russia/Ukraine peace, U.S. inventory builds and inflation data combined to ice crude prices Feb. 12.

U.S. President Donald Trump said that Russian President Vladimir Putin and Ukrainian President Volodymyr Zelenskiy in separate phone calls had signaled openness to negotiate a peace treaty, whereupon Trump ordered U.S. officials into talks on ending the Ukraine war.

Trump acknowledged the peace effort on Truth Social, adding, "I believe this effort will lead to a successful conclusion, hopefully soon!"

Trump said he and Putin were planning reciprocal state visits.

A ceasefire, or end of the war, could be bearish

see **OIL PRICES** *page 12*

UTILITIES

Another LNG proposal

Harvest sets agreement with Chugach Electric for Nikiski facility redevelopment

By ALAN BAILEY
For Petroleum News

On Feb. 6 Harvest Alaska and Chugach Electric Association announced an agreement with Marathon Petroleum Corp. for Harvest to acquire Marathon's liquefied natural gas export facility near Nikiski on the Kenai Peninsula, to convert the terminal into an LNG import facility. The concept is to use the importing of LNG to bolster natural gas supplies in Southcentral Alaska, given pending shortages of gas supplies from oil and gas fields in the Cook Inlet basin.

The project is designed to "repurpose existing assets to enable the timely delivery of additional natural gas supplies to the Southcentral market as early as 2026, with full-scale operations beginning as early as 2028," the companies said. Harvest would own, develop and operate the LNG terminal, which is currently owned by a Marathon subsidiary.

Harvest is the pipeline affiliate of Hilcorp Alaska, the main gas producer in the region. Chugach Electric uses gas fueled generation facilities as its prime source of electrical power. All of the gas and electricity utilities in Southcentral Alaska are facing potential gas supply shortages in the coming years. As previously reported by Petroleum News, Enstar Natural Gas Co., the Southcentral gas utility, is pursuing a project with Glenfarne Energy Transition to construct another LNG import facility, also on the west coast of

see **LNG PROPOSAL** *page 12*

EXPLORATION & PRODUCTION

North Slope update

ConocoPhillips, Hilcorp, Santos discuss developments, drilling, production gains

By KRISTEN NELSON
Petroleum News

The Alaska Legislature's House Resources Committee heard Feb. 10 from major North Slope players ConocoPhillips Alaska, Hilcorp and Santos on activities and plans across the North Slope.

The ConocoPhillips Alaska presentation was by Barry Romberg, vice president, commercial and midstream, and Ben Carlson, vice president, finance and IT.

Romberg surveyed ConocoPhillips' interests across the Slope, from its 36.5% non-operated ownership in Greater Prudhoe Bay, to its 99% ownership at Greater Kuparuk, which it operates

The North Slope is in the midst of a renaissance of oil production, Romberg said, attributing that to two major factors: a stable fiscal system in the state since Senate Bill 21 was passed in 2013 and horizontal drilling technology.

and its 100% ownership and operation on the western North Slope — the Colville River, Greater Mooses Tooth and Bear Tooth units.

Along with the development of Willow, in the Bear Tooth unit on the National Petroleum

see **SLOPE UPDATE** *page 11*

● UTILITIES

CINGSA has drilled two additional wells

Completion and perforation of the injection/withdrawal wells planned for this year; subject to availability of coil tubing unit

By KRISTEN NELSON
Petroleum News

Cook Inlet Natural Gas Storage Alaska said in its 2025 plan of development, submitted Jan. 31, that the two new wells at the Cannery Loop unit underground gas storage reservoir and facility were drilled September through December last year, but have not been perforated and completed.

In the POD, submitted to the Alaska Department of Natural Resources' Division of Oil and Gas, Matt Federle, CINGSA director of gas storage plant, said the perforation and completion work hasn't yet been done because there isn't a coil tubing unit available.

CLU Storage 7 was spud Sept. 11 and suspended Nov. 11.

CLU Storage 6 was spud Nov. 20 and suspended Dec. 24. Nordic Calista Rig 37 was demobilized after that well was completed.

Federle said the two wells "will be completed in 2025 when the local coil tube becomes available, or from outside sources in the event that coil tube services are not available locally."

The five original wells at CINGSA, CLU Storage 1 through 5, were drilled in 2011 using Nabors 105.

CINGSA background

CINGSA holds storage lease ADL 391627, which is within the Sterling C gas pool. The wells were drilled from a gravel pad on property owned by the state and leased to CINGSA. The compressor station facilities are on property purchased by CINGSA.

2024 was the 13th calendar year of CINGSA operation, Federle said in the POD.

CINGSA converted the nearly depleted Sterling C1 and C2 sands at the Cannery Loop unit into an underground gas storage reservoir and facility. Hilcorp Alaska retains working interest ownership in the deeper Beluga and Upper Tyonek gas pools, both in production, as well as any zones above the Sterling C.

The Sterling C gas pool produced some 23 billion cubic feet of gas and some 4,000 barrels of produced water prior to shut-in in 2012 and was estimated to have originally held 26.5 bcf of gas; production was from a single well.

The company said storage injections by free flow of gas began April 1, 2012, followed by injection with compression April 28, 2012.

The storage lease originally enabled CINGSA to develop and operate the storage reservoir with a maximum storage volume of 18 bcf, 11 bcf of working gas and 7 bcf of base, an amount updated to 20 bcf in December 2024 to include 13 bcf of working gas and 7 bcf of base gas.

POD activities

Activities under the 2024 POD included normal maintenance and operations; expansion of the compressor building to accommodate two additional compressor skids and associated equipment; drilling of the two new wells and installation of surface piping; beginning installation of additional DEHY purification train on the plant side; expansion of plant pad to accommodate building and traffic on the east side of the compressor building; and expansion of the plant pad by the warehouse to ease access and accommodate traffic to the lay down area.

2024 injection was 5,585,904 thousand cubic feet, mcf, and withdrawal of 5,453,126 mcf.

Proposed 2025 activities include: normal maintenance and operations; completion and testing of the two new wells; and commissioning the purification system and warehouse expansion. ●

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UTILITIES

Alaska's electricity supply arrangements

The huge size of the state and its sparse population give rise to supply arrangements different from elsewhere in the country

By ALAN BAILEY
For Petroleum News

The vast size of Alaska coupled with its sparse population have given rise to electricity systems that differ significantly from those found elsewhere in the United States. And on Feb. 4 representatives from several electricity utilities talked to the Alaska Legislature's House Energy Committee about their utilities, their operations and the challenges that they face.

Essentially, there are three distinct situations for electricity supplies in the state: the Alaska Railbelt, Southeast Alaska and remote towns and villages in rural Alaska. In the Alaska Railbelt there are three tightly integrated regions: the Kenai Peninsula; the Anchorage and Matanuska and Susitna valleys; and the Fairbanks region. These regions are linked together by single, low capacity transmission lines. Power generation is dominated by fossil fuel power stations, but with some significant hydropower and some wind and solar power. Southeast Alaska is dominated by hydropower. Rural Alaska has isolated low capacity generation and distribution systems with the widespread use of small-scale diesel generation and an increasing use of wind and solar farms.

1 2 3 SERIES

Part one of this series of articles will cover two of the Railbelt utilities, part two will cover the two other Railbelt utilities, and part three will cover the Alaska Electric Village Cooperative.

In the early years of Railbelt development several different electricity utilities formed to serve different sectors of the region. Over the years these utilities have become increasingly interconnected to form a more integrated electrical system.

Homer Electric Association

Keriann Baker, chief strategy office for Homer Electric Association, the electricity utility for most of the Kenai Peninsula, emphasized to House Energy that a primary focus of her utility is the maintenance of reliable electricity supplies in the communities that the utility serves. The utility was formed in 1945, with power supplies subsequently starting in 1950 using a small generator.

Over the years the utility expanded its network to encompass much of the peninsula while also expanding and updating its generation systems and other technologies to include, for example, the Nikiski combined cycle gas fueled power plant in 2014, and, more recently, Alaska's first high speed electric vehicle charging station. In 2022 the utility implemented a battery energy storage system for stabilizing power supplies.

In the early years of Railbelt development several different electricity utilities formed to serve different sectors of the region. Over the years these utilities have become increasingly interconnected to form a more integrated electrical system.

Operating as a member based cooperative rather than a for-profit company, the utility now has about 2,500 miles of power lines serving about 25,000 members over an area of about 3,200 square miles, Baker said. The utility obtains power primarily from three gas-fueled power stations and the Bradley Lake hydroelectric power plant in the southern Kenai Peninsula. The utility also has a small backup generator in Seldovia.

Among the services that HEA provides to its customers are an outage map and an energy calculator, to help people assess the potential power cost impact of new appliances. The utility can also provide a line of credit for the installation of technologies such as solar panels or batteries.

Cost inflation

A current challenge results from cost inflation, Baker said. For example, there has been a 400% increase in the cost of computer servers, a 144% increase in the cost of overhead transformers and 100% increase in the cost of copper wire, she said.

And a particular challenge on the Kenai Peninsula has been a huge increase in power outages caused by trees that are outside HEA's rights of way falling onto power lines, Baker said. In addition to power outages, this issue increases the risk of serious forest fires. To address the problem HEA is clearing the rights of way for its power lines and working with property owners to deal with hazardous trees — many of the hazardous trees are outside the power line easements.

The Kenai Peninsula Borough has been helping with funding to support the tree clearance program, Baker said.

Natural gas availability

Another major problem that HEA now needs to address is the availability of the natural gas that fuels the utility's power stations. The supplies of natural gas from the Cook Inlet basin are gradually diminishing. HEA's contract for firm gas supplies from Hilcorp Alaska, the main Cook Inlet gas producer, terminated at the end of March 2024. Since then, the utility has been obtaining its firm gas from Enstar Natural Gas Co. under a new contract with that utility. In addition, HEA has a strategic plan for diversification into different power sources, Baker said. The utility is also looking into upgrading one of its old gas-fueled power generation units and has a power purchase agreement with an independent power producer for 30 megawatts of solar energy.

The objective is to reduce HEA's gas consumption by 21% annually, as well as diversify the utility's energy mix, Baker said.

Golden Valley Electric Association

Ashley Bradish, director of external affairs and public relations for Fairbanks based Golden Valley Electric Association, said that GVEA serves more than 100,000 residents along a corridor extending from Cantwell on the south side of the Alaska Range, north through Fairbanks and Southeast to Delta Junction. The utility connects to four military installations, including Fort Wainwright, Eielson Air Force Base and Fort Greely. A group of large industrial members including two mining operations constitute about 47% of the utility's total load, Bradish said.

And the agency manages just under 3,500 miles of power lines, she said.

Adequate generating capacity

Bradish commented that GVEA has access to adequate generating capacity to meet its load. The utility has nine generating facilities, including four oil-fired plants in Fairbanks, North Pole and Delta Junction, and two coal fired plants in Healy on the north side of the Alaska Range. Aurora Energy in Fairbanks also provides coal-fired power and steam heat for downtown Fairbanks. Until last month GVEA had a contract with Enstar to obtain 20 megawatts of gas fueled power from Chugach Electric Association in Anchorage, delivered through the transmission line from Anchorage to Fairbanks. GVEA obtains, also through the transmission system, 16.9% of the power output from the Bradley Lake hydropower facility on the Kenai Peninsula. In addition, GVEA has the 25-megawatt Eva Creek wind farm and a very small solar farm.

Current challenges

But, although GVEA is in a good position in terms of fuel diversity, the utility's costs do present an issue and a challenge, Bradish said, confirming the inflationary pressures that Brady had alluded to in her

see **ELECTRICITY SUPPLY** *page 4*

● EXPLORATION & PRODUCTION

Hilcorp continues looking at NTBU issues

Will study whether economics work to return Spurr Platform to service; substantial improvements, new equipment would be needed

By KRISTEN NELSON
Petroleum News

Hilcorp Alaska has filed its 2025 plan of development for the North Trading Bay unit with the Alaska Department of Natural Resources' Division of Oil and Gas. There is currently no production from NTBU.

For its 2025 POD, covering May 3, 2025, through June 30, 2026, Hilcorp said it will continue working to restore NTBU production.

"The preliminary platform assessment completed in 2024 identified that the Spurr platform may be economically viable to return to production; however, the platform will require substantial improvements: new quarters, crane, production processing equipment, environmental remediation in existing well modules and more will be needed to support production reactivation," the company said.

The proposal for the 2025 POD is that the company "perform a detailed engineering assessment to fully understand the scope, secure cost estimates and define the timeline needed to restore production," with engineering assessment results "used to further evaluate the economics of production restoration from the Spurr platform."

Hilcorp said it expects to complete the economic analysis during the 2025 POD.

Previous PODs

Hilcorp's 2021 POD was conditioned on drilling a sidetrack, Trading Bay St A-10RD2, from the Monopod Platform in the Trading Bay unit into leases within the NTBU boundary, but the 2022 well encountered mechanical issues; a second attempt at a sidetrack also encountered mechanical challenges.

In 2022 Hilcorp told the state that it would redesign the sidetrack and in 2023 began drilling the A-10RD3. That well, Hilcorp said, reached 11,088 feet measured depth "when the 4-1/2" drill pipe parted in a wash out at a coal at 6,970' MD." The company said drill pipe and bottom hole assembly were left in the hole; the well was suspended with a cement plug.

"The repeated failures indicated further assessment was necessary to ascertain the development potential for the unit. The subsurface complexity of crossing two large faults with greater than 1000 foot throw and drilling at a shallow angle through packages broken by coal seams significantly reduced the probability of successful drilling," the company said.

No drilling was proposed in the 2024 POD.

The company was required to provide a plan of refurbishment and annual inspection reports, which it requested the division to keep confidential, and was required to submit data on reserves and operational plans and designs to re-establish production.

Spark, Spurr integrity

Hilcorp ordered inspections of the structural integrity of both the Spark and Spurr platforms and included a report on those inspections in its POD.

In both cases, Hopper Engineering Associates found the platforms to be overall in good condition. Both are classified as "manned evacuated" in that they technically have living quarters, so personnel could be on board, but the platforms are generally unmanned.

The inspection found "likelihood of collapse" to be low as inspection noted minimal subsea damage, and inspections every 10 years were recommended.

Well plugging & abandonment

Hilcorp said it is committed to maintaining the plugging and abandonment schedule authorized by the Alaska Oil and Gas Conservation Commission, and said according to the schedule Spark and Spurr platform work will occur beyond the 2025 POD period.

The company said priorities of the P&A program are the Baker and C platforms, both in the recently terminated Middle Ground Shoal unit, with that work delaying Spark and Spurr P&A work into 2026 or later. ●

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ELECTRICITY SUPPLY

presentation. Reliance on expensive and volatile priced fuels such as diesel is also problematic. The decline in Cook Inlet gas production is also hitting GVEA, as exemplified by the recent termination in the utility's contract with Enstar. And, currently, the decline in gas fueled power is being counterbalanced by the use of expensive fuel oil. A current temporary loss of power from Bradley Lake, as a consequence of work on the single transmission line from the Kenai Peninsula, is also hitting GVEA, Bradish commented.

And currently GVEA only has limited capacity to integrate variable energy sources, Bradish said.

Bradish commented that GVEA supports the concept of importing liquefied natural gas to the Cook Inlet as a short-term solution to pending gas shortages, with assessments of the feasibility of building a North Slope gas line as a longer-term possibility. GVEA also supports the potential Dixon Diversion expansion to the Bradley Lake hydropower facility.

Aging infrastructure

GVEA also has aging infrastructure that is close to end of life and, thus, will need replacement at significant cost. A recent survey of GVEA members indicated that the reliability of the power supply is the top priority, followed by the cost of the power and then the reduction of carbon emissions, Bradish said.

Bradish also commented on the importance to GVEA of upgrading the transmission system that connects the Kenai Peninsula to the Anchorage area, and the Anchorage area to Healy. The federal government awarded funding support for a new subsea transmission line from the Kenai Peninsula, although that grant requires matching funds. However, an upgrade to the line north to Healy would be of greater benefit to GVEA, Bradish commented. ●

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● EXPLORATION & PRODUCTION

Baker Hughes US rig count up by 4 at 586

January international rig count down four from December, down 60 from January 2024 count of 965; largest drop in offshore rigs

By KRISTEN NELSON
Petroleum News

The Baker Hughes' U.S. rotary drilling rig count was 586 on Feb. 7, up by four from the previous week, down by 37 from 623 a year ago and up 10 from two weeks ago. Over the last eight weeks the rig count was unchanged in three weeks, down in three weeks and up in two with a combined loss of 13 and a gain of 10, and in spite of two consecutive weeks of increases, still overall in line with the downward trend dominant since the beginning of May.

This is the lowest the domestic rotary rig count has been since December 2021.

A drop of 17 to 731 on May 12, 2023, was the steepest weekly drop since June of 2020, during the first year of the COVID-19 pandemic, when the count also dropped by 17 to 284 on June 5, following drops as steep as 73 rigs in one week in April. The count continued down to 251 at the end of July 2020, reaching an all-time low of 244 in mid-August 2020.

For 2024, the count peaked March 1 (and again March 15) at 629, hitting its low point June 28 at 581. In 2023 the count peaked early in the year at 775 on Jan. 13, bottoming out Nov. 10 at 616.

When the count dropped to 244 in mid-August 2020, it was the lowest the domestic rotary rig count had 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 prior to the COVID-19 pandemic, where it remained through mid-March of that year when it began to fall, dropping below what had been the historic low in early May with a count of 374 and continuing to drop through the third week of August 2020 when it gained back 10 rigs.

The Feb. 7 count includes 480 rigs targeting oil, up by one from the previous week and down 19 from 499 a year ago, with 100 rigs targeting natural gas, up by two from the previous week and down 21 from 121 a year ago, and six miscellaneous rigs, up by one from the previous week and up by three from a year ago.

Baker Hughes shows Alaska with 10 rotary rigs active Feb. 7, unchanged from the previous week and unchanged from a year ago.

Fifty of the rigs reported Feb. 7 were drilling directional wells, 523 were drilling horizontal wells and 13 were drilling vertical wells.

Alaska rig count unchanged

Louisiana (31) was up by two rigs from the previous week, while California (8), Texas (278), Utah (12) and Wyoming (20) were each up by a single rig.

Oklahoma (43) was down by two rigs week over week.

Rig counts in other states were unchanged from the previous week: Alaska (10), Colorado (9), New Mexico (106), North Dakota (33), Ohio (9), Pennsylvania (15) and West Virginia (10).

Baker Hughes shows Alaska with 10 rotary rigs active Feb. 7, unchanged from the previous week and unchanged from a year ago.

The rig count in the Permian, the most active basin in the country, was unchanged from the previous week at 303 and down by 10 from 313 a year ago.

International rig count down 4 in January

Baker Hughes' monthly international rig count for January, issued Feb. 7, is down by four from December at 905 and down 60 from a count of 965 in January 2024, with land rigs up by one to 713, month over month, and offshore rigs up five to 197.

Baker Hughes began providing a monthly international rig count in 1975. The international count excludes North America, which is included in the company's worldwide figures.

The Middle East accounted for the most rigs in the international totals for January, 346, followed by Asia Pacific with 206, Latin America with 132, Europe with 120 and Africa with 101.

The U.S. rig count averaged 582 in January, down by seven from December, and down 38 from January 2024, while the Canadian count for January averaged 208, up 47 from December and up by 11 from January 2024.

Worldwide the rig count averaged 1,696 in January, up 36 from 1,660 in December and down 87 from 1,783 in January 2024. ●

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THIS MONTH IN HISTORY

Billions in leftovers on North Slope

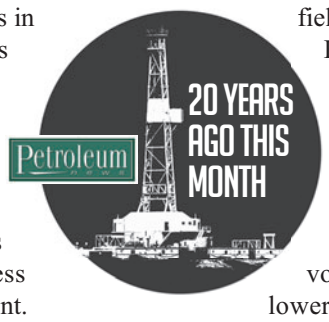
20 years ago this month: DO&G Director Mark Myers talks about untapped 20 million to billion barrel fields north of Brooks Range

Editor's note: This story first appeared in the Feb. 20, 2005, issue of Petroleum News.

By ALAN BAILEY
For Petroleum News

There's a prevailing view that, with production from major oil fields on Alaska's North Slope declining, the North Slope has become a mature oil and gas province. But Mark Myers, director of Alaska's Division of Oil and Gas, takes a different view.

The easier structural plays, particularly onshore and nearshore, have been drilled but many stratigraphic plays have yet to be explored, Myers told Petroleum News in early February 2005. Myers also sees opportunities to develop smaller structural plays close to the existing oil and gas infrastructure.



Myers thinks that success in the Tarn and Alpine fields has moved exploration attention away from the big Prudhoe Bay-style structures towards stratigraphic traps. At the same time the Northstar field has demonstrated great success with an offshore development.

Sustained high oil prices, the use of horizontal drilling and the ability to produce from low permeability reservoirs are making more oil fields economic, Myers said.

Classic North Slope plays

The classic North Slope oil and gas plays occur along a structural high known as the Barrow Arch under the Beaufort Sea coast of the North Slope. These plays originated from the discoveries of oil fields like Prudhoe Bay and Kuparuk River many years ago.

The Prudhoe Bay field consists of a huge combined stratigraphic and structural trap involving Triassic sandstone reservoirs in a Mississippian to lower Cretaceous sequence of sediments known as the Ellesmerian sequence.

Companies are still looking for opportunities in this Ellesmerian play, especially near the existing oil and gas infrastructure, Myers said. "You've got a ton of Ellesmerian structural plays," he said.

The reservoirs for the Kuparuk River field involve sandstones in what's called the Beaufortian or Rift sequence of Jurassic or lower Cretaceous age — the deposition of the sandstones is associated with rifting or pulling apart of the Earth's crust that occurred during the opening of the Canada Basin of the Arctic Ocean.

Although some of the Beaufortian sands can be thin and discontinuous, other areas of more continuous sands give rise to large reservoirs.

"So you get a huge range of potential sizes in the same rift breakup sequence but there are a lot of plays in that 20 million to 70 million or 80 million barrels size," Myers said. "There are still plays in that 300 million, 400 million or 500 million to plus a billion size — they're still out there, but they're almost all stratigraphic."


MARK MYERS

Success with the Alpine field and its Beaufortian Jurassic sandstone reservoir has spurred interest in similar Jurassic plays. There is a series of upper Jurassic sands just below the Alpine sands, Myers said.

"There's at least a billion barrels in place, we think, in that trend," Myers said.

Because of the low permeability of the reservoirs in the Alpine play the gravity of the oil really impacts the ease of oil production. And the oil gravity depends on which of the multiple source rocks in the area generated the oil, Meyers said.

"The source rock's critical and often you get multiple source rocks in a given area," Myers said. "If you look at the Tarn play on the west side of Kuparuk you've got 38 to 37 API gravity in close proximity of 26 to 22 gravity in Kuparuk, because of changes in the sourcing."

However, horizontal drilling techniques can help extract oil from the low permeability reservoirs, Meyers said.

Brookian stratigraphic plays

There is a major Cretaceous and Tertiary sequence of petroleum bearing sedimentary rocks above the Ellesmerian and Beaufortian sequences in northern Alaska. Known as the Brookian sequence, this younger rock sequence extends all the way from the northern edge of the Brooks Range out over the North Slope and across the continental shelves of the Beaufort and Chukchi seas.

Stratigraphic plays involving topset or turbidite strata in submarine fans typify this Brookian sequence. And Myers sees great potential for these plays.

"Some of the … submarine fans are very large," Myers said: "If you had reservoir quality and if you had closure you could approach the billion-barrel mark in some these if you had structural fill."

Then there are other situations where you may find smaller fans with as little as 20 million barrels of oil, Myers said, and where several smaller fans stack together the combined volume of oil could reach around 100 million barrels.

However, production problems in the Badami field have shown that the Brookian plays aren't without risk, Myers said. And compaction of reservoir rocks at depth may prove problematic.

"But there are some good looking fans as well … so it's a question of finding higher quality sands," Myers said. Some of the younger Brookian sandstones contain particularly clean sand because

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HISTORY

they've reworked older sediments, he said.

Because the Brookian sequence tends to overlie Beaufortian or Ellesmerian rocks, there are opportunities to explore for situations where there is more than one play at the same location. A current exploration focus involves looking for classic Ellesmerian plays at locations where there is also Brookian potential, Myers said.

Brookian plays may dominate the coastal plain of the Alaska National Wildlife Refuge, at the eastern end of the North Slope — Myers concurs with a U.S. Geological Survey assessment that the Brookian sequence probably contains the preponderance of oil in that area. However, a couple of intriguing structural trends in the northeast of the ANWR 1002 area include potential Kuparuk-style plays. And Ellesmerian plays occur in thrust sheets along the front of the Brooks Range.

The potential in NPR-A

The National Petroleum Reserve-Alaska, to the west of the North Slope oil fields, offers some interesting exploration possibilities. Along the north of NPR-A there is keen interest in Kuparuk or Alpine style plays in Beaufortian sands.

"In NPR-A the government drilled a lot of the structures, so the plays that are left are Jurassic pure stratigraphic plays," Myers said. "But some Kuparuk plays which are largely stratigraphic in nature could have a structural element to them."

However, as people move farther out from the infrastructure, field size becomes a critical issue.

Some of the individual Jurassic plays beyond the Alpine field are small, Myers said. "You'd have to find a pretty sizable incised valley or forced regression sand out there that would have 200, 300, 400 million barrels," he said.

But Myers sees the potential for a large find in a Brookian stratigraphic play in NPR-A.

"So with the turbidite plays there are some very big submarine fans out there — if one of those works it could be in that hundreds of millions of barrels range," Myers said.

And prolific source rocks have generated huge quantities of oil and gas in the area.

"Most of the sands when you find them are oil charged but it's porosity preservation and permeability that are the issues," Myers said.

The Brooks Range Foothills

Geologists have long considered the Brooks Range foothills, in the southern part of NPR-A and extending east to the Dalton Highway, to be a gas prone province. Myers thinks that reservoir quality will prove critical in locating gas fields in this area.

"When you look at it there's a lot of oil-stained rock in outcrop, so the question is 'can you find enough effective porosity and permeability to make good gas reservoirs?'" Myers said.

Rock units such as the Cretaceous Fortress Mountain formation and the Lisburne dolomites that outcrop in the foothills probably have enough porosity for gas. However, other rock formations that have been buried to relatively shallow depths exhibit better reservoir characteristics.

And in the foothills some rocks, probably from less deeply buried strata, provide evidence of reasonable thermal maturity for oil, Myers said.

Remote areas on the Beaufort Sea and Chukchi Sea outer continental shelves lie a long way from the existing oil and gas infrastructure but probably hold large quantities of oil and gas. For example, there is a very large Eocene and younger basin on the U.S. side of the Mackenzie Basin and some intriguing, large fault blocks in Tertiary strata at the outer edge of the Beaufort Sea continental shelf.

Some spectacular-looking structures lie under the Chukchi Sea.

"If you can find a way to take the economic risk it has huge long-term potential," Myers said.

More drilling

Myers thinks that the oil and gas industry in northern Alaska needs more companies drilling more wells.

"What's fairly slowed down exploration has just been the lack of a critical mass of companies with exploration ideas," Myers said.

However, Myers thinks that companies like Kerr-McGee and Pioneer are moving things in the right direction.

"Once they start developing and turning cash flow we're incrementally going to see a lot more activity, particularly if they make money out of it," Myers said.

And Myers thinks that a gas line from the North Slope will bring a huge boost to the economics of exploration and field development. However, it is essential that there is adequate provision for gas line expansion, so that companies can factor the future export of gas into the commerciality of exploration drilling.

"We think that it's incredibly important that they create a structure that's user friendly for expansion — the reserve base justifies that," Myers said.

Reducing costs

Myers sees cost reduction as a critical factor in encouraging further oil and gas field development in northern Alaska. For example, the use of mobile lightweight drilling rigs combined with a longer drilling season would cut the cost of exploration drilling and enable more wells to be drilled.

"I think we need to get some lightweight rigs up here — we need to get several of them working the North Slope," Myers said.

The state is interested in helping reduce

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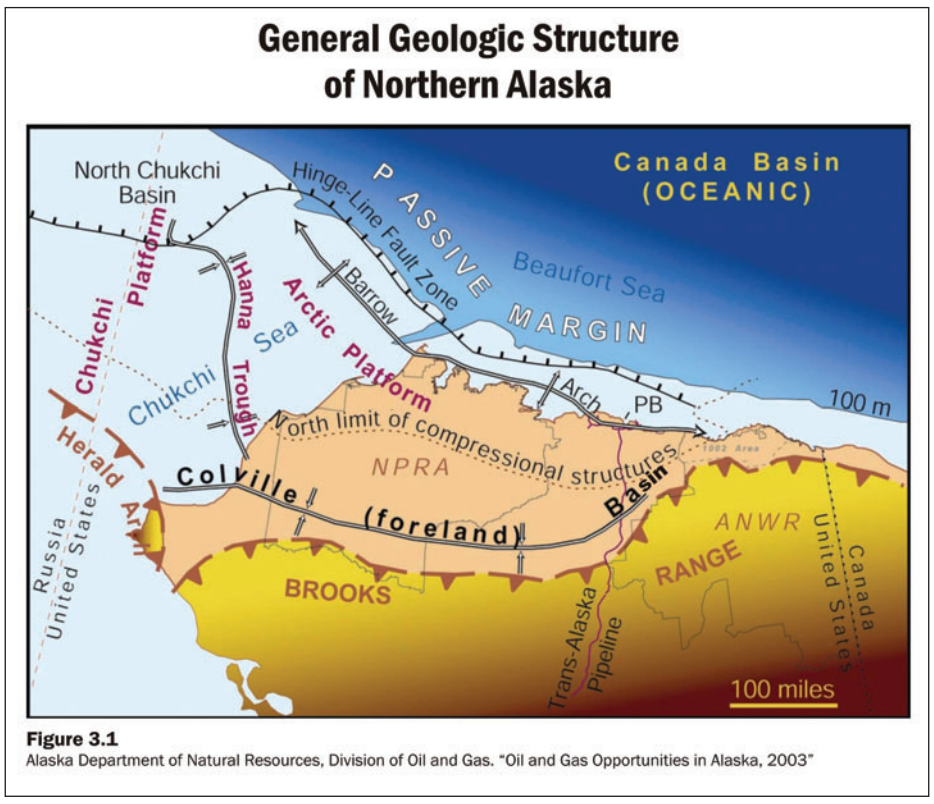

Figure 3.1
Alaska Department of Natural Resources, Division of Oil and Gas. "Oil and Gas Opportunities in Alaska, 2003"

PETROLEUM NEWS FILE

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GAS DELIVERY

protocol for coordinating Enstar's purchase of what is referred to as daily call option gas with gas withdrawals from CINGSA. The coordination requires monthly tranches of mandatory gas withdrawals from CINGSA by Enstar prior to the utility's ability to take monthly tranches of call option gas. Enstar uses gas stored in CINGSA to ensure adequate gas deliverability during high levels of gas demand during cold winter weather.

Essentially the companies disagree on their interpretations of the terms of the contract.

The dispute arose because Hilcorp claimed that Enstar was going to use the requested daily call gas for injection into CINGSA, in contradiction with the terms of the gas supply contract amendment. Enstar claims that it would not have contravened the contract and that it needs adequate amounts of gas stored in CINGSA to ensure that it will be able to withdraw gas from storage at adequate rates at times when gas demand is especially high. Also, Hilcorp alleged that Enstar had already reinjected some daily call gas back into CINGSA.

Essentially the companies disagree on their interpretations of the terms of the contract.

Judge rules dispute resolution protocol must be followed

Judge Walker dismissed Enstar's lawsuit Feb. 6 on the grounds that the utility had failed to follow through on a contractually required procedure for resolving disputes. The contract stipulates that there is a three-stage dispute resolution process: the parties must first negotiate; if negotiation fails they must mediate; and if mediation fails the parties must go to binding arbitration. At the same time, under state law, if arbitration is required contractually to resolve a commercial dispute, the court must compel arbitration, the judge wrote.

In this case the parties have both confirmed that there had been negotiations over the dispute. Then, after the negotiations failed, Enstar asked the court for a mandatory preliminary injunction without going through the mediation and arbitration steps required in the contract, the judge wrote. Enstar told the court that the court could issue an injunction because Hilcorp had sold gas to Marathon Petroleum and Cook Inlet Energy Oil that would otherwise have been sold to Enstar, in sales that contravened the terms of Hilcorp's contract with Enstar.

However, the judge ruled that Enstar had not established that Hilcorp had willfully diverted gas that was intended for its delivery to Enstar.

Urgency of dispute resolution?

The judge also dismissed an argument by Enstar revolving around the urgency of the case, given the potential shortage of gas to meet Alaskans energy needs and the length of time that may be required to conduct arbitration of the dispute. The judge commented that Hilcorp had made a delivery of gas to Enstar a few days prior to oral arguments in the lawsuit and that through mediation and, if necessary, arbitration, the dispute can be resolved in less than 90 days. Thus, the court is going to dismiss the case without prejudice, the judge said.

"The court did not address the contract dispute with Hilcorp but the decision highlights the need for the parties to resolve this matter as quickly as possible," Lindsay Hobson, Enstar director of legal and administration, has told Petroleum News. "We are rapidly proceeding with mediation and will continue to work with Hilcorp to reach a resolution."

In this case the parties have both confirmed that there had been negotiations over the dispute. Then, after the negotiations failed, Enstar asked the court for a mandatory preliminary injunction without going through the mediation and arbitration steps required in the contract, the judge wrote.

"We are pleased Judge Walker heard our concerns and dismissed this frivolous lawsuit as it merely served as a distraction from the fundamental issue — the need for more long-term gas supply in the Southcentral market," Hilcorp spokesperson Matthew Shuckerow told Petroleum News. "Hilcorp remains committed to supporting the utilities, businesses and residents of Southcentral Alaska that rely on Cook Inlet natural gas. We remain diligent in these efforts and anticipate spending hundreds of millions of dollars drilling new wells, recompleting existing wells, and maintaining and enhancing infrastructure in the Cook Inlet this year. That is our priority."

Shuckerow said that when Enstar filed the lawsuit Hilcorp had urged the utility to come back to the table and work with Hilcorp to develop a reasonable resolution that takes into account the needs of all Alaskans that depend on Cook Inlet natural gas.

—ALAN BAILEY

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HISTORY

costs through road construction and by building exploration staging areas.

"One of the things that the state is thinking about is investing in staging areas in the foothills, where you could over-summer equipment," Myers said. "… To do that we can rehabilitate some of the existing airstrips and old pads out there."

These staging areas would reduce the need for lengthy ice roads and thus extend the effective drilling season. New permanent roads proposed by the state could also substantially reduce access costs.

Companies can themselves improve exploration economics by drilling in areas where several petroleum plays occur in close proximity.

"The people who have been most successful at exploration have drilled a number of different play concepts in a single year," Myers said. "If you have a prospect that can stack up multiple objectives that gives you the best opportunity … and then being able to drill multiple wells in a winter season from a single rig becomes a critical element."

However, developing modest sized fields depends on minimizing costs by sharing the use of production and export facilities with other fields.

"A lot of these areas, particularly onshore, where you may not find right off a 500 million barrel field … you might find a cluster of 50 million or 100 million barrel fields," Myers said. "We have to find clever ways to produce these through a single producing facility.

The state recently commissioned a report on the status of oil and gas facility sharing on the North Slope. The state has also been looking at facility sharing practices in the North Sea.

"We would like to see more certainty in the commercial terms around access to the existing infrastructure," Myers said.

The state would be happy to see clarity and certainty emerge from normal commercial negotiations. However, we have alternatives through codes of practice, arbitration or regulation, Myers said.

The state also wants to see lower tariffs on the trans-Alaska pipeline and has protested the recent tariff increase.

Optimistic about the long term

Myers feels optimistic about the long-term future of the oil industry in northern Alaska. We've seen the independent companies buying leases and now we've got to convert that to drilling activities, he said.

"So, I think we'll see just a tremendous amount more oil produced, especially from the stratigraphic plays over time," Myers said. "I think someone will stumble into that 500 million to a billion barrel field size."

And where is that next big find?

"In the long term if I were to bet on a big prospect, the Brookian stratigraphic plays are where I'd put my money," Myers said. ●

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Petroleum news

Oil Patch Bits

ConocoPhillips Alaska welcomes Heather Tash to leadership role

ConocoPhillips Alaska said Feb. 5 that Heather Tash recently joined its leadership team as vice president, asset development. In her new role, Tash will oversee development across the North Slope.

Tash began work in the oil and gas industry in 2007. Her work in the field has included positions with ExxonMobil and Concho Resources.

Prior to her current role, Tash worked for ConocoPhillips in the Permian Basin. While there she held roles in process, facilities, production, and reservoir engineering.

Tash earned a Bachelor of Science in chemical engineering from the Colorado School of Mines in 2007.

"We are delighted to have Heather join our team in Alaska, and looking forward to her leadership," says Erec Isaacson, president, ConocoPhillips Alaska. "Her experience in process and production is an incredible asset for our operations on the North Slope."

HEATHER TASH

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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CONOCO REPORT

including delivery of the Operations Center modules to Alaska, along with infrastructure developments such as gravel roads, pads, bridges and pipelines. This project is progressing well, bolstering Alaska's economy and creating thousands of jobs. We remain on track for first oil in 2029," Isaacson said.

ConocoPhillips Alaska reported net income of $1.3 billion in 2024.

Questions and Answers

In ConocoPhillips Q&A portion of its Feb. 6 earnings conference call, Alaska, and especially Willow, were addressed several times.

The first question that touched on Alaska asked if executives "could dig in a little bit on some of the long-cycle CapEx … and the outlook. Just wondering if you could kind of hit on some of the moving parts around Alaska. … And are we right in assuming that your equity outlays on major projects are peaking in 2025?"

Andy O'Brien, ConocoPhillips senior vice president, strategy, commercial, sustainability and technology, responded to the question.

"As we said, 2025 is expected to be the peak spend as we undertake the biggest winter construction season in Willow," O'Brien said.

"So if you look past 2025, we are going to see the major project spend step down each year. At the same time, we'll start to see the projects coming online delivering on our expected cash flow and free cash flow improvements. And … we'll have Willow in 2029. … But I think the key point I want you to take away is that absolutely, we see this year as the peak spend in these projects," O'Brien said.

Exploration west of Willow

The next question involving Alaska noted that the state has "gotten a lot of attention from the Trump administration so far and even had its own executive order. … Could you remind us how you're thinking about the western North Slope opportunity set and whether or not the policy environment creates more of an opportunity to move forward …over the next few years?"

Kirk Johnson, ConocoPhillips senior vice president, global operations responded.

"Yeah, there's certainly been quite a bit of press out there around NPR-A. … were pleased to see that President Trump and that administration issued an executive order to, in essence, reverse what came about here late last year. … Yes, we're looking forward to partnering with the Department of Interior and especially with the state of Alaska. Fundamentally, we believe that continued exploration west of Willow, it's the right thing to do for energy. It's the right thing to do for the state of Alaska and its stakeholders. And clearly, we're in a really good position. We're putting ourselves in a position to continue exploring west of Willow, as that's enabled for us. So again, some good news out there for us in Alaska.

Unpacking Willow

ConocoPhillips executives were also asked to describe progress at Willow to date.

"There's a few things certainly in there to unpack. I'll start with Willow as you did and certainly happy to report that the progress we made here last year, certainly inclusive of fourth quarter, and even just this last month here in 2025, allows me to say we're really on trend with the progress that we've been making, … that project team there in Alaska just continues to hit all the key milestones that we've laid out certainly since taking FID back in late '23," Johnson said.

"When I think about it, certainly the work that was underway in fourth quarter and even just this last month in January, the initial mobilization of our winter construction season … is our largest for the project, has really gone quite well. So we got a quick and early start. We got some cold weather. Ice road construction activities are … modestly ahead of plan, which is really nice for us. It puts us in a position of taking full advantage of the full winter season knowing that we may certainly have a little bit of weather in front of us … we're in a great position of building on all the activity that we accomplished last year," Johnson said.

"Again, this is a peak year of ice road construction. It's from those ice roads that we're building gravel roads, gravel pads. It allows us to, from those ice roads, build our pipeline networks. And then we've got a few unique activities as well planned this winter season. Think bridge construction as well as some horizontal directional drills for pipeline crossing," Johnson said.

"So again, lots to do. And then you even go into the operation modules that you heard me speak about last year. We floated those — barged those up to Alaska, landed those and onshored those during the ice-free season. … Just this last month those are moving across into the Willow development area," Johnson continued.

"So we're using crawlers to get those into that new pad. So again, some really good progress. We landed our contracts; engineering is on track. That puts us in a great position for full fabrication across the entirety of this year," Johnson said.

"So all that culminates … into this peak year of spend, which is why we're guiding to an expectation of project capital being roughly $500 million more than we spent in 2024," Johnson said.

"We're thinking about all of that spend and manifesting and probably close to one third of our total annual spend expectation here in 2025, showing up in the first three to four months of this year. And then so naturally, then we expect the capital this year to stairstep down in the second, third and fourth quarters. … And … that will continue to stairstep down with very little, if any, spend in 2029, which is when we're expecting first oil. So again, great progress."

Nuna, Coyote etc.

In another question an analyst noted that company executives had highlighted the start of the Nuna project on Alaska's North Slope. "I wonder if you could … put the startup of that project in the context of your overall, call it 180,000 barrels, of oil a day. I know you guys said it was 29 wells, but can you tell us, is that going to be of a magnitude that we're going to be able to observe the effect of that in your 1Q and 2Q volumes in '25?"

Again, Kirk Johnson, ConocoPhillips senior vice president, global operations, responded.

"I appreciate the question on the Alaska base business because certainly, that business continues to chart a course of really sustaining production here with some really modest growth in the next couple of years. And I think it really highlights the amount of investment opportunities that still exist for us in that business with Nuna being a prime example of that," Johnson said.

"Nuna …is a project in which we have built out a new pad, the first one in roughly a decade, and it shows the great work that the teams are doing in exploring and appraising new targets and taking advantage of the infrastructure that we have there. First oil was in December, that came on after drilling and completing and bringing on a couple of wells," Johnson said.

"We do have plans for eight more wells there this year in 2025. And all of that … has actually come on the heels, if you will, of having drilled over 10 wells from existing gravel. So again, it shows the pragmatism that the team has really deployed of ensuring that we understand what these targets are. We de-risk those before we actually put new gravel out there," Johnson said.

"We are, in fact, expecting that production to enable us to more than offset decline as we look at Alaska's production profile for the next year. And then we have a number of other targets that exist out there for us. And you've heard me speak to some of these before in Kuparuk. In addition to Nuna, we have Coyote. Coyote is a really interesting parallel to Willow. And then in WNS and our Alpine asset, we've got Narwhal and Minke," Johnson said.

"And so these Brookian topsets put us in a really nice position of using these wells to advance technology, to advance certainly our capital efficiency, knowing that some of these are great analog or a parallel to Willow, which gives us, again, that much more of an opportunity as we stand up a couple of rigs for Willow in 2027. So really pleased with how that's taking shape for us on our base business in Alaska," Johnson said.

—KAY CASHMAN

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SLOPE UPDATE

Reserve-Alaska, and continued investment in Prudhoe, ConocoPhillips is expanding development at Kuparuk, which came online in 1981, with Nuna and Coyote.

The North Slope is in the midst of a renaissance of oil production, Romberg said, attributing that to two major factors: a stable fiscal system in the state since Senate Bill 21 was passed in 2013 and horizontal drilling technology.

On the subject of the $8 billion Willow project, Romberg noted that this is 100% ConocoPhillips and said you won't find another company around the world — except perhaps national oil companies — willing to invest its own capital at 100%, citing this as evidence of the company's commitment to Alaska.

ConocoPhillips projects

Ben Carlson talked about projects other than Willow and said the company has on average been investing more than $1 billion a year in capital on its legacy assets.

He noted four Alaska projects on production or coming into production soon: Nuna in Kuparuk which had first oil in December and will peak at 20,000 barrels per day; West Sak viscous oil in Kuparuk, being produced in a four-pad development; Coyote in Kuparuk where reservoir evaluation began in 2021 and a drilling program begins this year; and Greater Mooses Tooth in NPR-A which began production in 2021 and averaged 14,000 bpd from GMT-2 last year, with 25 wells completed in the reservoir so far.

In a Willow update, Carlson said there are some 2,400 workers currently working at Willow on the Slope, double the number in 2024, with 2025 construction including: 350 miles of ice road, up from 210 last year; 30 miles of pipeline up from 16 miles in 2024; 1,101,000 cubic yards of gravel, up from 887,000 cubic yards; and installation of two bridges, up from one in 2024.

Also this year the 12 Willow Operations Center modules will be transported to the 30-acre pad, Carlson said.

Kuparuk road access

Asked about the Kuparuk road use issue between ConocoPhillips and Santos, ConocoPhillips' Romberg noted that a judge ruled against the state in December over a permit it issued Santos for road use, and said that parallel to the court case, ConocoPhillips and Santos have been negotiating a commercial road use agreement. Those negotiations have been progressing, he said, with the companies "working really well together and progressing negotiations."

He said access to Pikka, the Santos project, has never been blocked with the companies working under a temporary agreement that has been in place.

Santos' Peter Laliberte was asked about the agreement on road use with ConocoPhillips and said he hoped they were closer to an agreement, but said paying ConocoPhillips will be an unexpected cost that affects the overall economics, along with a cost overrun which the company has had on the project.

The business is risky, he said, and additional costs do affect investment decisions going forward.

Santos

Laliberte, vice president business development for Santos in Alaska, noted that Santos, an Australian company, merged with Oil Search in 2021 which previously held the company's Alaska positions, making Alaska part of the Santos portfolio.

Santos operates and owns 51% of Pikka; the other 49% is owned by Repsol.

Laliberte said he worked for BP for about 17 years and was employee number 47 when he joined what was then Oil Search in 2018 to work on Pikka, in what he and his colleagues felt was a revitalization of the oil industry in Alaska and a resurgence of investment on the North Slope.

Santos currently has some 370 employees in Alaska and expects that number to grow to 400 by the end of the year. Some 80% of its employees have been hired from within Alaska, and some 95% of the workforce lives in Alaska.

Pikka, considered a giant oil field, was discovered by Repsol in 2013, with the discovery confirmed by Armstrong Oil and Gas in 2017.

Phase 1 of Pikka is under development, with phase 2 permitted, and then the company would move on to Quokka and Horseshoe: the three combined are the company's core area, Laliberte said. There is also a large block of non-unitized acreage south of the core area where appraisal will continue.

He said Santos is also looking at similar reservoirs, one to the east, where it has brought in a major investor, APA Corp., and is 50-50 with Armstrong in a large block of acreage in the National Petroleum Reserve-Alaska, which the company refers to as Nanushuk West. There are some 490,000 acres in the core area, 270,000 areas in the eastern Lagniappe block and almost a million acres in NPR-A.

The investment in Pikka Phase 1 by Santos and Repsol is $3.2 billion, with peak production estimated at 80,000 bpd and first oil planned for the first half of 2026, but Laliberte said there is the opportunity to accelerate that, and Santos is trying to complete the pipelines by the end of the winter as the pipelines are "the critical path item in our project," and completion of those would provide the opportunity to start up by the end of the year

There are 2,200 contractors working on the Slope in 24/7 operations; work on Pikka is 74% done.

The target is to finish stalling 120 miles of pipelines this winter, Laliberte said, with 15 of 45 wells drilled.

Hilcorp

Jill Fisk, senior asset team leader for Hilcorp's Milne Point unit, said Hilcorp's target goal is to be the best operator of late-life assets in the industry. As late-life assets are brought into Hilcorp, the company improves operating efficiency, develops the properties, maintains strong cash flow and increases oil and gas recovery. And when the asses reach end of life, Hilcorp is responsible for retiring them, she said.

The company has 1,700 employees in Alaska, which it entered in 2012 with Cook Inlet acquisitions, moving onto the North Slope in 2014 and continuing acquisitions, with the latest, Fisk said, the Eni assets on the North Slope.

Hilcorp has five rigs operating on the North Slope, with a sixth, Doyon 15, recently reactivated at Nikaitchuq where it is doing workovers; that rig will be moved to Deadhorse this winter where it will be staged to move to Point Thomson next winter to start to drill one well in that field. Point Thomson is currently producing some 4,300 bpd of oil from one producer, but after the second well is drilled in 2016, that more than double production, filling the current facility to full capacity again.

Hilcorp holds some 27.1% working interest at Prudhoe and is the field operator, with 830 employees and more than 1,500 contractors working the field, which includes 230 miles of roads, almost 1,000 miles of pipelines, 47 active pads and drill sites and a little over 1,000 producing and injecting wells online on any given day.

Prudhoe facilities

Prudhoe Bay started life as an oil field and is now very much a gas field, Fisk said, with gas the constraint on oil production as 8 billion to 9 billion cubic feet are moved every day.

Hilcorp took over as Prudhoe operator in mid-2020, during the COVID-19 pandemic, and during the company's first 15 months of operating the field there were no rigs running. But Hilcorp was able to arrest decline by looking for ways to control costs across the field by improving operating efficiency, reducing costs and increasing rate. Since then, production has been increasing with well workovers and new wells.

On the west end of Prudhoe Hilcorp is focused on developing Schrader Bluff viscous oil and building a 30-inch production pipeline and 12-inch gas lift line to handle increased production.

The company is also revamping facilities at Gathering Center 2 to handle the heavier Schrader Bluff oil. Compared to Milne Point, Prudhoe Schrader Bluff oil is less viscous than at Milne Point, and Prudhoe also has miscible injectant available.

Milne Point

At Milne Point, where Hilcorp is celebrating 10 years as operator, the company has increased production from 17,000 bpd to some 50,000 bpd with 161 new wells, all horizontal, polymer injection and investment in surface facilities including two new pads. Prior drilling at Milne Point was primarily vertical wells, Fisk said. Hilcorp began with two pilot skids for polymer injection in 2018 and now has 10 polymer skids working and has also increased power generation and added a third train at the central facility.

Fisk said Hilcorp will use knowledge gained at Milne in its recent acquisition of Eni properties at Nikaitchuq and Oooguruk, using horizontal drilling where vertical wells have been drilled and closer placement of wells based its success at Milne. ●

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STERLING FIELD

in 2016."

Hilcorp applied for a suspension of production which was denied. BLM terminated the unit in 2017.

The three wells Hilcorp is currently applying to drill are Sterling Unit 32-16, Sterling Unit 43-10RD and Sterling Unit 43-10.

The commission has tentatively scheduled a public hearing on the spacing exceptions for March 13 at 10 a.m. at its Anchorage offices. The audio call in number is 907-202-7104 conference ID 160 146 389#.

If there are no timely requests for the hearing, the commission said it may issue an order without a hearing. To learn if a hearing will be held call 907-793-1223 after Feb. 25.

—KRISTEN NELSON

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OIL PRICES

for crude if Trump cancels sanctions on Russian energy, Tyler Richey, co-editor at Sevens Report Research, told MarketWatch.

Geopolitical stability may "largely extinguish the still simmering 'fear bid' in the oil market," Richey said.

There's more to the story than meets the eye, said Manish Raj, managing director at Velandera Energy Partners told MarketWatch.

"The immediate effect of a peace deal is that Russian barrels stranded at sea can find a home," Raj said.

US inventories jump

U.S. commercial crude oil inventories for the week ending Feb. 7 — excluding Strategic Petroleum Reserve levels — jumped 4.1 million barrels from the previous week to 427.9 million barrels — 4% below the five-year average for the season, the U.S. Energy Information Administration said in its weekly petroleum report issued Feb. 12.

The inventory build was not a surprise. An analyst survey conducted by S&P Global Commodity Insights called for a build of 4.5 million barrels on average.

Total motor gasoline inventories data were bullish, showing a drawdown of 3.0 million barrels for the period to 248.1 million barrels — 1% shy of the five-year average for the time of year, the EIA said. Distillate fuel inventories increased by 0.1 million barrels.

The S&P survey forecast an inventory increase of 1.3 million barrels for gasoline and a decline of 1.6 million barrels for distillates.

Inflation keeps rate in check

The U.S. Federal Reserve will keep its current benchmark interest rates steady for now.

Fed Chair Jerome Powell said Feb. 11 that the economy is in a good place and that the Fed won't cut interest rates further but is prepared to do so if the labor market weakens unexpectedly or inflation surprises to the downside.

Consumer Price Index data released Feb. 12 showed a sharp rise in consumer prices in January, further bolstering the Fed's reasoning on holding back rate cuts.

"Higher-for-longer" Fed policy could put recessionary pressure on the economy, retarding demand for petroleum products.

The Organization of the Petroleum Exporting Countries said in its Monthly Oil Market Report released Feb. 12 that it expects global crude demand to grow by 1.4 million barrels per day in 2025 and 2026, unchanged from its January forecast. OPEC expects total world demand to average 105.20 million bpd in 2025 and 106.63 million bpd in 2026.

The combination of the Fed's decision to hold interest rates steady and expectations of fewer interest rate cuts in 2025 support the U.S. dollar, OPEC said.

"Indeed, the U.S. dollar index closed 2024 up by 4.5%, y-o-y, and remained at high levels as of the end of January, up by 5.5%, y-o-y," OPEC said. "The relative strength of the U.S. dollar makes commodities priced in the currency more expensive, and therefore a downside risk to demand."

ANS jumped $1.26 Feb. 10 to close at $75.28, while WTI jumped $1.32 to close at $72.32 and Brent jumped $1.21 to close at $75.87.

On Feb. 7, ANS added 48 cents to close at $74.02, WTI added 39 cents to close at $71.00 and Brent added 37 cents to close at $74.66.

ANS and WTI each fell 42 cents Feb. 6 to close at $73.54, and $70.61 respectively. Brent shed 32 cents to close at $74.29.

From Wednesday to Wednesday, ANS added 36 cents from its Feb. 5 close of $73.96 to its close Feb. 12 of $74.32.

On Feb. 12, ANS traded at a $2.95 premium to WTI, and at an 86-cent discount to Brent. ●

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LNG PROPOSAL

the Kenai Peninsula.

The Marathon LNG terminal first went into operation in 1969 as a means of exporting natural gas to Japan during the heyday of Cook Inlet gas production. But with the later decline in production, the terminal stopped operating in 2016 and since then it has remained in long-term warm shutdown mode. Harvest and Chugach Electric say that the facility has a dock historically capable of handling LNG vessels that can carry up to 2.9 billion cubic feet of natural gas in the form of LNG, together with onsite tankage with a 2.3 billion cubic feet storage capacity. The companies say that this infrastructure coupled with existing Federal Energy Regulatory Commission approvals for the terminal will enable the facility to meet near-term energy needs while longer-term alternatives are developed.

Companies express support

"Harvest has a long history of operating critical oil and gas infrastructure across the state and this announcement furthers our commitment to ensuring Alaska has the energy it needs," said Harvest Chief Executive Officer Jason Rebrook. "By repurposing Marathon's existing LNG facility, we aim to provide certainty to the Southcentral gas market while meeting the needs of Railbelt utilities. We are proud to collaborate with Marathon, Chugach Electric and other Southcentral utilities to bring this project online to ensure the reliable delivery of natural gas in a timely and cost-efficient manner."

"Providing our members with safe, reliable and affordable electric service is core to our values and mission. We are pleased to have a potential solution to meet the gas needs of our members and at the right time," said Chugach Electric Chief Executive Officer Arthur Miller. "We've been looking at options to fill the gap left by our expiring Hilcorp contract, which ends on March 31, 2028. This is a great opportunity to work with partners who have extensive experience and knowledge of gas operations in Alaska. We look forward to ongoing discussions and analysis with Harvest Alaska as they progress the front-end engineering and design study over the next several months."

Marathon supports project

Marathon also supports the project — the company's Nikiski oil refinery uses natural gas as a fuel for its operations.

"We believe the Kenai LNG terminal offers the quickest and lowest-cost solution to bring additional natural gas to Southcentral Alaska and beyond," said Bruce Jackman, vice president of Marathon's Kenai oil refinery. "Our Kenai refinery employees work around the clock to provide gasoline, diesel and jet fuel to their fellow Alaskans, and a reliable supply of natural gas is critical to the refinery's operations. We're excited about this partnership with Harvest and Chugach to work toward bringing new natural gas to the region."

Meanwhile, the Regulatory Commission of Alaska has opened a docket to investigate Enstar's proposal to potentially recover some of the initial costs associated with its LNG terminal project through the rates that it charges its customers. ●

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