Petroleum news

page 5 Federal spend freeze impacts Inlet transmission line, other projects

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'Significant' interest in Alaska booth at NAPE, says Crowther

The Alaska Division of Oil and Gas saw "significant interest in our booth at NAPE (formerly the North American Prospect Expo) Summit" in Houston, Texas earlier this month "where we highlighted the breadth of development and exploration opportunities in Alaska," Alaska Department of Natural Resources Deputy Commissioner John Crowther told Petroleum News on Feb. 18.

"There was a great deal of enthusiasm and awareness of major developments such as Willow and Pikka, questions about additional exploration opportunities, and excitement about what changing federal restrictions and the improving

see INSIDER page 6

Pikka Phase 1 drill, completion time down to 30 days per well

KEVIN GALLAGHER

On Feb. 18 Santos released an update on its Pikka Phase 1 project on Alaska's North Slope.

Santos Managing Director and Chief Executive Officer Kevin Gallagher said, "another strong cash flow year from the long-life gas assets in our base business has enabled the company to deliver returns to shareholders and invest in our Barossa and Pikka development projects that will bring new production online this year and next."

see PIKKA PHASE 1 page 6

CEA, MEA talk to House Energy about Southcentral power supply

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. Part 1 of this three-part series on the meeting covered presentations by Homer Electric Association and Golden Valley Electric Association at the southern and northern ends of the Railbelt electrical system. Part 2 covers presentations by Chugach Electric Association and Matanuska Electric Association in the Anchorage region and the Matanuska Susitna Valley. Part 3 will cover a presentation about a rural Alaska electric cooperative.

1 2 3 SERIES

see POWER SUPPLY page 8

Legislators hear AGDC update; Glenfarne, mil rate, RIV issues

FRANK RICHARDS

The Alaska LNG Project is stirring to life and raising questions from state legislators for the Alaska Gasline Development Corp., the state corporation heading the project.

With the state's historic spending for various plans to move North Slope natural gas south estimated at some $1.1 billion and the budget already stretched, legislators would like to see the project happen but fear the potential of another expensive failure.

Projected shortages of natural gas in Southcentral Alaska

see AGDC UPDATE page 7

EXPLORATION & PRODUCTION

Exploration update

Armstrong and Great Bear drill North Slope 2024-25 exploratory wells

By KAY CASHMAN

Petroleum News

In the 2024-25 Alaska North Slope winter exploration drilling season two wells have been spud — Great Bear Pantheon's Megrez-1 in November and Bill Armstrong's Lagniappe Sockeye-2, which is being drilled as this issue of Petroleum News goes to press.

BILL ARMSTRONG

A third possibility had been Quokka-1 in the Quokka unit, which is held 51% by Santos subsidiary and unit operator Oil Search (Alaska) and 49% by Repsol. The unit is generally south and east of Pikka and west of the Southern Miluveach and Kuparuk River units. But in Oil Search (Alaska)'s application for an Oil Spill Discharge Prevention and Contingency Plan, the company said operations for Quokka-1 are to begin as soon as October of this year, which took the well out of running to be included in this season's exploration wells.

Nonetheless, Petroleum News sources said this past season because of early tundra access the company was able to start pre-packing snow for pipelines early in November as well as build ice roads.

As part of its work commitment with the Alaska Department of Natural Resources' Division of Oil and Gas, Oil Search (Alaska) must drill two wells

see DRILLING SEASON page 4

FINANCE & ECONOMY

Hilcorp buys North Fork

Deal with Gardes Holdings expected to close May 1; change needed for pipeline

By KRISTEN NELSON

Petroleum News

Hilcorp Alaska is in the process of buying the North Fork unit and the associated North Fork Pipeline on the southern Kenai Peninsula from Anchor Point Energy, the pipeline owner, and Vision Resources, the North Fork unit owner, with plans to explore for additional gas in the unit.

In conjunction with the purchase, Anchor Point Energy applied to the Regulatory Commission of Alaska in February for a conditional revocation of Anchor Point's certificate of public convenience and necessity for operation of the North Fork Pipeline as a common carrier pipeline.

When the CPCN was issued, the application said exploration was underway east and north of the North Fork unit which could have resulted in transmission of natural gas from multiple shippers. Exploration east of North Fork was unsuccessful and a separate pipeline was built to transport gas from north of the unit.

North Fork Pipeline has never operated as a common carrier, moving only gas from North Fork.

The CPCN was granted because the Department of Natural Resources authorized the pipeline under an AS 38.35 right-of-way lease, requiring that RCA issue the CPCN.

Anchor Point is applying to DNR for conversion of the right-of-way lease under AS 38.35, requiring regulation of the pipeline as a common carrier, to authorization under an easement under

see NORTH FORK page 7

FINANCE & ECONOMY

Supply risk firms ANS

Drone attack on pipeline in southern Russia crimps shipments to Europe

By STEVE SUTHERLIN

Petroleum News

Alaska North Slope crude crept back above $75 per barrel Feb. 19 — up 36 cents to close at $75.16. West Texas Intermediate was up 40 cents to $72.25 and Brent edged 20 cents higher to close at $76.04.

Supply disruption fears drove prices higher for a second day but were moderated by bearish factors.

U.S. crude inventories rose by 3.34 million barrels for the week ended Feb. 14, market sources said, citing American Petroleum Institute figures Feb. 19, a Reuters report said.

U.S. Energy Information Administration data was scheduled to be released Feb. 20 after Petroleum News press time. Both reports were delayed a day by the U.S. Presidents Day holiday.

Analysts in a Reuters poll forecast that 2.2 million barrels of crude were added to U.S. inventories for the week ended Feb. 14.

Traders were also waiting to see whether OPEC and its allies will delay plans to restore extra production cuts or delay them once again.

"A delay could wipe out the surplus we expect for the market this year, which would leave prices better supported," ING analysts said in a Feb. 19 Barron's report.

Also, preliminary talks between Russia and the

see OIL PRICES page 6

● FINANCE & ECONOMY

EIA revises natural gas price forecast

Increase follows spell of cold weather in Lower 48 at end of January; 2025 forecast now $3.80 per million Btu, up 21% from $3.10

By KRISTEN NELSON
Petroleum News

The U.S. Energy Information Administration has raised its 2025 Henry Hub natural gas spot price forecast average to $3.80 per million British thermal units, up 21% from a January forecast of $3.10 per million Btu. In its February Short-Term Energy Forecast, issued Feb. 11, EIA said cold weather in the Lower 48 at the end of January increased natural gas demand for space heating, contributing to a 12% increase in domestic natural gas consumption compared to the previous 5-year average for the month, with above-average inventory withdrawals.

The January Henry Hub spot price averaged $4.13 per million Btu, with a daily high of $9.86 per million Btu Jan. 17 ahead of the cold snap. This was an increase of more than $1 per million Btu from the December average of $3.01 per million Btu.

EIA said it expects the Henry Hub natural gas spot price to average $3.70 per million Btu in the first quarter of 2025 and to rise through 2026, with an average of almost $3.80 per million Btu this year, up 65 cents from the January forecast, reaching an average of nearly $4.20 per billion Btu in 2026.

Domestic natural gas consumption in residential and commercial sectors averaged 50.6 billion cubic feet per day in January, up 13% from the 5-year average, while consumption in the electric power sector averaged 37.6 bcf per day, up more than 20% compared with the 5-year average.

U.S. crude oil production is forecast to average 13.6 million barrels per day this year, up from 13.2 million bpd in 2024, increasing to 13.7 million bpd in 2026.

In addition to winter weather, timing of new liquefied natural gas production over the forecast period is also a risk, with the imposition of tariffs by China on U.S. LNG expected to have a limited impact on U.S. LNG exports.

"With ample demand for LNG globally, we expect that any LNG not purchased by China would be imported elsewhere," the agency said.

U.S. LNG exports averaged 12 billion cubic feet per day last year and are forecast to average 14 bcf per day this year and 16 bcf per day in 2026.

Oil inventories, production

OPEC+ production cuts are expected to reduce global oil inventories and keep prices near current levels through the first quarter with gradual production increases and relatively weak global demand growth forecast to increase global inventories in the second half of 2025 and in 2026, "placing downward pressure on prices through the remainder of our forecast," EIA said, with Brent expected to average $74 per barrel this year, down from a $79 per barrel average in January, and dropping to $66 per barrel in 2026.

Global production of liquid fuels is forecast to increase by 1.9 million barrels per day this year and by 1.6 million bpd in 2026 on a combination of supply growth from non-OPEC countries and relaxation of OPEC's current production cuts. The agency said it does not anticipate that U.S. sanctions on Russian oil and shipping announced Jan. 10 will significantly affect the oil production forecast.

Global growth in liquid fuels production is expected to be led by countries outside of OPEC+ in 2025, primarily by the United States, Canada, Brazil and Guyana.

U.S. crude oil production is forecast to average 13.6 million barrels per day this year, up from 13.2 million bpd in 2024, increasing to 13.7 million bpd in 2026.

Global oil consumption growth is forecast to be slower than the pre-pandemic trend, with liquid fuels consumption expected to increase by 1.4 million bpd this year and 1 million bpd in 2026, "driven primarily by demand from non-OECD Asia." The largest increase, 0.3 million bpd both this year and next, is expected to come from India, driven by rising transportation fuel demand, with China's consumption expected to grow by 0.2 million bpd this year and next, up from less than 0.1 million bpd in 2024, as that country's economic stimulus efforts increase consumption.

In the U.S., consumption of distillate fuel oil and jet fuel are forecast to grow in 2025 and 2026, while gasoline consumption remains about the same this year as last and drops slightly in 2026, "driven by assumption of increased manufacturing and trucking activity for distillate fuel oil, increased air travel for jet fuel, and a more fuel-efficient vehicle fleet for motor gasoline." ●

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DRILLING SEASON

in the Quokka unit by 2027.

The company likely prefers to drill one well at a time over a two-year period.

First well

On Nov. 10, Pantheon Resources announced that the Megrez-1 well was spud on Alaska's North Slope by Great Bear Pantheon, the target being "three topset horizons which Pantheon estimates to contain an aggregate 2U prospective resource of 609 million barrels of ANS crude (oil, condensate and NGLs) and 3.3 trillion cubic feet of natural gas."

Great Bear Pantheon is exploring the eastern topsets in the Ahpun and Kodiak fields, immediately adjacent to the trans-Alaska oil pipeline and road infrastructure.

Great Bear Pantheon contracted the Nabors 105AC rig to drill the Megrez-1 well.

Construction of the gravel pad next to the Dalton Highway was completed in October, and the pad can be used year-round to support future drilling and development activities, Pantheon said.

On Oct. 14 the Division of Oil and Gas sent Patrick Galvin, Great Bear Pantheon's chief commercial officer, approval to adjust the downhole location of the Megrez-1 well.

The surface location of the Megrez pad remained the same as described in the original approval dated Aug. 29, however the well trajectory passed through ADL 394101 and terminated in ADL 394202.

The non-unitized leases are operated by Great Bear and are directly adjacent to the Talitha Unit

This plan modification also included widening of the driveway from the previously approved width of 24 feet to 34 feet. The increased width was necessary to provide the drill rig and support equipment safe access to the site, Pantheon said.

East: Pikka lookalikes

On Jan. 7 the Alaska Oil and Gas Conservation Commission approved a drilling permit for Lagniappe Alaska's Sockeye-2 exploratory well on the eastern North Slope. Because the well was deemed confidential there was no additional information available from AOGCC.

But as reported in early December by Petroleum News, Bill Armstrong's Lagniappe Alaska returned to the eastern North Slope this winter to drill the Sockeye-2 well on state of Alaska acreage approximately 8 miles southeast of Badami, within the Lagniappe-operated oil and gas lease block.

The Sockeye-2 well surface location is approximately 1,000 feet north of the Sockeye-1 well, drilled in the winter season of 2023-24 as part of the Lagniappe Exploration Program in a search for Pikka lookalikes east of Prudhoe Bay. The wells each targeted large 3D-defined opportunities.

The program called for drilling a total of six wells using three rigs drilling simultaneously over a period of two years with a maximum of three exploration wells per season. But because of record bad weather on the North Slope none of the wells were able to be completed and tested.

The record bad weather included unusually warm temperatures, then really windy weather, followed by more wind, snow and below normal temps.

Sockeye-2, like Sockeye-1, is being drilled using the Doyon 141 rig. ●

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● UTILITIES

The case for Cook Inlet LNG importing

Chugach Electric Association files with the RCA a report on part two of Black and Veatch study into bolstering gas supplies

By ALAN BAILEY
For Petroleum News

Anchorage based Chugach Electric Association has filed with the Regulatory Commission of Alaska a report from Black and Veatch on phase two of the consultancy's investigation into gas supply options for the electric utility in response to dwindling supplies of natural gas from the Cook Inlet basin.

In a letter to the commission accompanying the report Chugach Electric said that Black and Veatch had confirmed the viability of importing liquefied natural gas as a means of ensuring that Chugach Electric can continue to obtain sufficient gas to maintain its required power generation. However, while, as previously reported by Petroleum News, Chugach Electric has now come to an agreement with Harvest Alaska for Harvest to convert Marathon's mothballed LNG export facility at Nikiski into an LNG import facility, the Black and Veatch report assumed that the LNG would be imported using a floating LNG terminal. The report does, however, acknowledge that the conversion of the existing LNG import terminal would constitute a preferred alternative to the use of a floating terminal.

While phase one of the Black and Veatch study evaluated multiple options for addressing the projected shortfall in gas supplies for Chugach Electric, the study ultimately concluded that the importing of LNG was the preferred option. Phase two focused on the permitting and logistical requirements for LNG importing using a floating terminal. Chugach Electric told the commission that it projects a range of LNG import costs between $12 and $16, depending on several factors including terminal infrastructure investments, shipping costs and volumes of gas shipped.

Conversion of existing LNG terminal

The utility told the commission that its own assessment had identified the onshore LNG terminal as the preferred import facility, given its historic record of accommodating vessels of similar size to those envisaged for importing LNG, its direct connectivity to the existing gas transmission pipeline system and its well maintained infrastructure. Hence the agreement with Harvest and Marathon to proceed with the conversion of the terminal to an import facility. However, the converted LNG terminal will require additional pipeline infrastructure for connections to the existing pipeline system, Chugach Electric told the commission.

The utility also told the commission that Black and Veatch had identified some new LNG export facilities under development in western Canada and Baja Mexico, the closest potential locations for exporting LNG to the Cook Inlet.

"Additionally, global LNG supplies and demand are both expected to grow, providing sufficient supply options to serve Chugach's projected gas supply demands over time," the utility wrote.

The utility told the commission that it anticipates making decisions in 2025 in support of the required timeline to begin importing LNG. ●

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● EXPLORATION & PRODUCTION

Baker Hughes US rig count up by 2 at 588

BY KRISTEN NELSON
Petroleum News

The Baker Hughes' U.S. rotary drilling rig count was 588 on Feb. 14, up by two from the previous week, down by 33 from 621 a year ago and up six from two weeks ago. Over the last eight weeks the rig count was unchanged in two weeks, down in three weeks and up in three with a combined loss of 13 and a gain of 12.

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. 14 count includes 481 rigs

see **RIG COUNT** *page 5*

● GOVERNMENT

Government spending freeze impacts Alaska

President Trump's pause on funding from federal government grants impacting Cook Inlet transmission line, other energy projects

By ALAN BAILEY
For Petroleum News

During a presentation to the Alaska House Energy Committee on Feb. 10, Curtis Thayer, executive director of the Alaska Energy Authority, confirmed that the current pause in federal funding associated with federal grants applies to funding assistance for the construction of a subsea electricity transmission line between the Kenai Peninsula and Beluga.

The purpose of the line is to significantly increase the transmission capacity between the Kenai Peninsula and the Anchorage region, while also remediating the problem of the existing transmission line being a single point of failure in the transmission system.

The GRIP program

The federal funding of $206.5 million came through the Department of Energy Grid Resilience and Innovation Partnership, or GRIP, program and requires matching funds. Using initial matching funds of $12.7 million from the state and $50 million in bond funding available from the Railbelt electric utilities, AEA has started work on the project.


CURTIS THAYER

Thayer told the committee that the funding had been appropriated and approved two years ago by Congress and President Biden, and that AEA has a signed grant agreement with the Department of Energy, enabling the project to proceed.

And, although the grant has been paused, DOE has reimbursed AEA for some costs already incurred. Moreover, in the interest of not missing a construction season for the project, AEA is continuing to move forward with the project using the matching funds that are available, Thayer said.

Thayer said that, especially given President Trump's stated awareness of the importance of infrastructure and transmission, he feels confident that the federal grant program will move forward again.

Other projects impacted

Thayer also commented that $20 million in federal funding in support of three projects by Golden Valley Electric Association is also on hold. Thayer later told Petroleum News that a total of $504 million in grant funding that comes through AEA is impacted. And there are also other projects around Alaska that are not funded through AEA that are also impacted — the funding associated with these projects may amount to as much as another $500 million, Thayer said.

Thayer re-iterated his confidence that this is a temporary pause in the funding. This type of pause in federal action is typical of what happens when a new federal administration comes into office, he said. And there is federal money coming in for work that has already been completed, he confirmed.

Although in general the federal funding has been paused, the National Electric Vehicle Infrastructure, or NEVI, funding program for installing high speed electric vehicle charging stations on the road system has been suspended rather than paused. Thayer commented that the implementation of this program has so far has proven disappointing, with only 52 charging stations being approved across the country.●

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RIG COUNT

targeting oil, up by one from the previous week and down 20 from 497 a year ago, with 101 rigs targeting natural gas, up by one from the previous week and down 20 from 121 a year ago, and six miscellaneous rigs, unchanged from the previous week and up by three from a year ago.

Fifty-one of the rigs reported Feb. 14 were drilling directional wells, 524 were drilling horizontal wells and 13 were drilling vertical wells.

Alaska rig count unchanged

Texas (280) was up by two rigs from the previous week while Oklahoma (44) and Utah (13) were each up by a single rig.

Louisiana (30) and North Dakota (32) were each down one rig week over week.

Rig counts in other states were unchanged from the previous week: Alaska (10), California (8), Colorado (9), New Mexico (106), Ohio (9), Pennsylvania (15), West Virginia (10) and Wyoming (20).

Baker Hughes shows Alaska with 10 rotary rigs active Feb. 14, 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 up by one from the previous week at 304 and down by eight from 312 a year ago. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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OIL PRICES

United States to ending the war in Ukraine capped upside on the potential easing of sanctions on Russia's energy sector.

U.S. markets were closed Feb. 17 for Presidents Day — but when U.S. trading resumed Feb. 18, ANS leapt $1.02 to close at $74.80, WTI gained $1.11 Feb. 18 for a close of $71.85 and Brent gained $1.10 to close at $75.84.

Drone attack amps up supply fears

Crude rose after a drone attack by Ukraine on a pipeline carrying crude from Kazakhstan across southern Russia curtailed flows.

On Feb. 17, seven explosive-packed drones hit a pump station on the Caspian Pipeline Consortium, which transports Kazakh oil across south Russia for export via the Black Sea, including to western Europe, according to an Agence France Presse release carried by Barron's.

"The consequences of this hit will be eliminated within one-and-a-half to two months, which could lead to a fall in the volume of oil pumped from Kazakhstan by 30 percent," Transneft, Russia's state-controlled pipeline company said in a Feb. 18 statement.

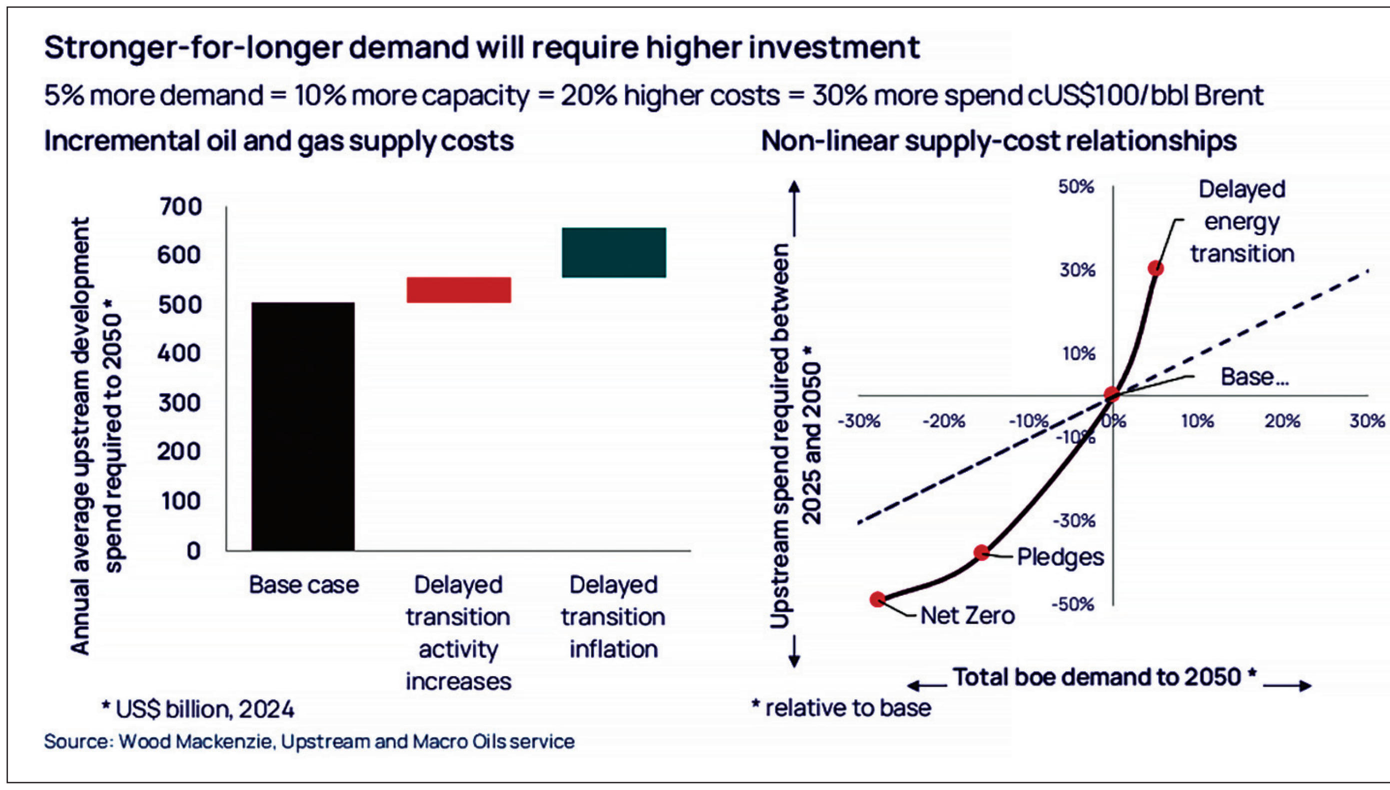
The 930-mile pipeline is owned by a consortium which includes the Russian and Kazakh governments along with Western energy majors Chevron, ExxonMobil and Shell. It moves some 1% of global daily production.

ANS slid 51 cents to a close of $73.78 Valentines Day Feb. 14, as WTI slid 55 cents to close at $70.74 and Brent edged 28 cents lower to close at $74.74.

Feb. 13 was a slight down day; ANS was down 3 cents to close at $74.29, WTI slid 8 cents to close at $71.29 and Brent lost 16 cents to close at $75.02.

From Wednesday to Wednesday, ANS gained 87 cents from its Feb. 12 close of $74.29 to its close of $75.16 Feb. 19.

On Feb. 19, ANS closed at a premium of $2.91 over WTI and at an 88-cent discount to Brent.



A stronger-for-longer demand scenario for oil and gas demand into the next decade will require a boost in investment for oil companies, according to Wood Mackenzie.

Stronger-for-longer demand

A stronger-for-longer demand scenario for oil and gas demand into the next decade will require a boost in investment for oil companies, according to Wood Mackenzie.

It's a great opportunity for organic investment, Simon Flowers, WoodMac chairman and chief analyst wrote in The Edge Feb. 13, adding, "Companies that can find and develop low-cost resource, deliver the incremental barrels the world needs and ride the wave of higher prices in a stronger-for-longer demand scenario will be among the winners over the next decade."

In WoodMac's delayed energy transition scenario, upstream will need to deliver an additional 6 million barrels per day of oil on average — 6% more than its base case — through to 2050, as well as 3% more gas.

The consultancy estimates global investment in upstream will have to increase from its base case by 30% to deliver the incremental supply, from $500 billion a year currently to $660 billion.

Upstream companies will be pushed to add risk to deliver higher supply, tackling new projects and increasing resource capture through M&A and exploration, Flowers said. "Should our scenario turn into reality and oil prices stay firm into the next decade and beyond, the returns will justify higher risk," he said.

Investment would first target lower-cost advantaged resources, then move on to higher-cost plays, with clear implications for oil and gas prices, Flowers said.

The increased development activity required will put extreme pressure on the supply chain, he said, adding, "A service sector that's taken a decade to stabilize finances and rebuild margins will not rush to build new capacity; instead, service costs and margins will go up."

Just one-third of the increase represents higher activity, such as drilling and development, Flowers said. The balance is service sector cost inflation and exploitation of higher-cost resources — even after allowing for operational and efficiency improvements. ●

Contact Steve Sutherlin at ssutherlin@petroleumnews.com

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INSIDER

business environment will mean for Alaska," Crowther said.

"This involved hundreds of conversations with conference goers, and visits from a variety of company representatives looking at opportunities in Alaska. The Division was very encouraged by the conversations," he said.

88 Energy farm-out deal

In mid-February 88 Energy Limited said it has entered into binding terms for a farm-out participation agreement with Burgundy Xploration LLC to fully fund up to US$39 million in a Project Phoenix horizontal test well currently scheduled for the first half of calendar year 2026.

Under the agreement, 88 Energy's wholly owned subsidiary Accumulate Energy Alaska Inc. will be provided with a full carry for costs associated with the horizontal well program, including an extended flow test.

In exchange Burgundy will earn an additional 50% working interest in Project Phoenix on Alaska's North Slope from 88 Energy.

Upon completion of the participation agreement, Burgundy will assume the role of operator, allowing 88 Energy to focus on the advancement and de-risking of Project Leonis, also on the North Slope.

—Oil Patch Insider is compiled by Kay Cashman

Contact Kay Cashman at publisher@petroleumnews.com

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PIKKA PHASE 1

"We continue to see strong progress at our Pikka Phase 1 project in Alaska. The remainder of the pipeline is expected to be installed in this winter season, a year ahead of schedule. Sixteen of 26 wells are now drilled and completed, and we have significantly improved drilling performance with a 25% improvement in drill time over the last few months, down to 30 days per well."

First oil for Pikka Phase 1, Gallagher said, "remains on track for mid-2026 with an early start-up possible but subject to weather and logistics."

Company officials have mentioned possible start-up of Pikka Phase 1 as early as the end of this year.

—KAY CASHMAN

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AGDC UPDATE

triggered AGDC to propose phasing the Alaska LNG Project — starting with the pipeline and beginning with enough natural gas to meet Southcentral needs. Estimated at some $11 billion, the pipeline would be the first part of the $44 billion project.

With that change, AGDC began negotiations with a proposed project developer, Glenfarne Energy Transitions, to act as what AGDC describes as a quarterback for the project, not just for phase one but for the entire project.

Gas for phase one of the project would come from Great Bear Pantheon, which is developing gas which could meet the needs of utilities without conditioning.

Gas for phase one of the project would come from Great Bear Pantheon, which is developing gas which could meet the needs of utilities without conditioning.

At the southern end of the project, in phase one the pipeline wouldn't cross under Cook Inlet, as gas deliveries would be into an Enstar line on the west side of the inlet. The liquefied natural gas facility at Nikiski would also be deferred to phase two of the project.

Issues raised

AGDC President Frank Richards told legislators in committee meetings in early February that investors like the phased approach because the 800-plus mile pipeline is viewed as the riskiest part of the project.

The phased approach was a response to impending natural gas shortages in Southcentral.

The study by Wood Mackenzie last year which evaluated whether North Slope gas from a phase one project would be competitive with the most likely alternative of imported LNG found the pipeline gas, even at an initial rate of 180 million to 200 million cubic feet per day would be competitive.

That comparison, however, included a property tax mil rate of 2 mils. If taxing jurisdictions insisted on the full allowable 20-mil rate, that would raise the cost of the gas to users in Southcentral, an increase which AGDC characterized as Alaskans taxing Alaskans. Legislators said the mil rate was an issue that would need to be resolved.

Another outstanding issue raised by legislators was whether the state would take its royalty share of the gas in-value or in-kind. Richards said gas owners preferred in-value — they sell the state's gas along with their own and pay the state its share — because of the issues that have risen with valuing the state's crude oil when that is taken in-kind.

Glenfarne

Glenfarne was also an issue raised by legislators who wanted to know who the company was, if it was capable of doing the project and how AGDC connected with it.

Richards said AGDC had talked widely with companies who appeared capable of heading up the project and had encountered Glenfarne in this process. It was at last year's CERA Week, however, that a serious connection was made, described by Richards as an introduction from a high level of Exxon to a high level of Glenfarne.

Glenfarne's ability to handle this size of project was questioned, along with its lack of Arctic experience. Richards said Glenfarne would head up the project, bringing in large companies including those with Arctic experience.

He also said the week of Feb. 10 that Glenfarne representatives would be in Juneau that week to meet with legislators.

AIDEA and the backstop

AGDC is in the process of negotiating a deal with Glenfarne whereby that company would takeover the 75% of the project which the state acquired from the producers when they stepped out of the project.

AGDC created 8 Star Alaska as the project company, with three subsidiary 8 Star companies, one each for the conditioning plant, the pipeline and the LNG facility. AGDC is selling 75% equity ownership of 8 Star and retaining a 25% carried interest. The state will have the choice of whether to retain the 25% equity ownership.

In the agreement AGDC is negotiating with Glenfarne, Glenfarne is asking for backstop for the up to $50 million estimated to get to final investment decision on the phase one pipeline — the backstop would cover Glenfarne's cost if it determines not to go ahead with a final investment decision.

The Alaska Industrial Development and Export Agency board voted to provide the backstop and the amount appeared in the budget. Legislators questioned why AIDEA requested an appropriation for the monies when it has its own assets. The appropriation request was ultimately withdrawn.

AIDEA Executive Director Randy Ruaro told legislators the agency determined it could issue a corporate guarantee whereby funds to meet the up to $50 million were held within the agency backed by its own assets thus eliminating the need for the $50 million appropriation.

—KRISTEN NELSON

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NORTH FORK

AS 35.05.850.

The Feb. 5 RCA application requests that the commission revoke the CPCN on condition that DNR authorize the pipeline under AS 35.05.850.

Hilcorp has agreed to purchase both the unit and the pipeline, but "the purchase is conditioned on conversion of the North Fork Pipeline from a pipeline authorized under an AS 38.35 right-of-way lease to authorization under an AS 38.05.850 easement," and DNR has indicated its consideration of a conversion requires the concurrent application to RCA.

The anticipated closing date for the sale is May 1 and a decision from the commission is requested by April 15, an expedited decision which would allow Hilcorp to explore at North Fork by year end.

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North Fork history

Gas has been known at North Fork since the 1960s, but the field lies inland on the southern Kenai Peninsula north of Homer and south of early Kenai Peninsula developments and required pipeline connections for gas delivery.

Chevron, then Standard Oil Company of California, discovered the field in 1965 when drilling for oil at the NFU No. 41-35 well, which tested gas from the Tyonek formation. The unit was formed in May 1965 and was kept alive through a series of negotiated extensions and annual plan of development approvals.

Alaska Oil and Gas Conservation Commission records show production in January and February of 1966 with Gas Pro as the operator, but consistent production did not begin until 2011 after Armstrong Cook Inlet purchased the field in 2007, reentered the NFU No. 41-35, drilled three new wells, acquired 3D seismic over the field and built a 12-mile pipeline to the Enstar line extension to Anchor Point.

In addition to the pipeline from North Fork, production from the field also required extension of Enstar's gas pipeline to Homer from the end of the Kenai Kachemak Pipeline.

North Fork was acquired by Cook Inlet Energy in a deal effective in April 2014 when CIE was a Miller Energy subsidiary. Following bankruptcy in 2016, Miller Energy became a privately held company, Glacier Oil and Gas.

North Fork was acquired by Gardes Holdings in 2020; Vision Operating was the operating company for the unit.

In December, the most recent month for which AOGCC data are available, North Fork averaged 1,692 thousand cubic feet per day, down 17.57% from a December 2023 average of 2,052 mcf per day and down from a December 2018 average of 4,196 mcf per day.

Vision's gas contract with Enstar was amended in June 2023 because Vision was unable to deliver the quantity of gas specified in the 2021 agreement, which called for delivery of 3,000 mcf per day through the first quarter of 2028. The amended agreement dropped the firm gas commitment to 2,000 mcf per day in the second quarter of 2023, with the volume steadily declining to 400 mcf per day in the first quarter of 2028.

In Vision's most recent plan of development, approved in March 2024, the company proposed to enhance production from existing wells, convert a well to water disposal and drill additional wells, but with all operations contingent on favorable market conditions and the ability to raise capital and secure a drilling rig.

AOGCC December production data for North Fork show two wells shut-in and six wells flowing, with all six online for the 31 days of the month. ●

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POWER SUPPLY

Chugach Electric gas supplies

Trish Baker, senior manager government affairs for Chugach Electric, spoke to the committee about her utility, starting with an overview of the utility's gas supply situation. Gas fueled power generation accounts for 78% of the utility's electricity, Baker said. The gas supplies come from two sources: 60% comes from the Beluga River gas field, where Chugach Electric is the majority field owner; the remaining 40% is supplied by Hilcorp Alaska under a firm contract that expires on March 31, 2028.

As part of its policies for maintaining adequate gas supplies the utility is continuing to invest in the Beluga River field, having drilled five new wells last year and planning the drilling of five more wells this year, Baker said

"So we'll try to get us much value out of that asset as we possibly can," she said.

The utility's second strategy for maintaining adequate gas supplies, given the upcoming termination of its firm supply contract with Hilcorp, is to progress plans for the import of liquefied natural gas to the Cook Inlet region, Baker said. As previously reported by Petroleum News, on Feb. 6 Chugach Electric and Hilcorp affiliate Harvest Alaska announced a plan to convert Marathon's mothballed LNG export facility at Nikiski into an LNG import facility.

The utility also plans to expand its renewable energy portfolio, Baker said.

An integrated resource plan

She also told the committee that the utility has a long-term integrated resource plan, considering the future need for replacement of existing assets and the future needs for energy storage. That plan does anticipate needing some amount of natural gas well into the future.

On the other hand, the Chugach Electric board has set an objective of reducing the utility's carbon intensity by at least 35% by 2030 and at least 50% by 2040, without a material impact on electricity rates or supply reliability, Baker commented.

"That remains very, very important to us and very central to our mission," she said, adding that the utility has a community solar project under construction.

In addition, the utility sees its plan for the importing of LNG as a relatively short-term, bridge solution to the gas supply challenge. Future possibilities include obtaining gas from the North Slope or obtaining more gas from the Cook Inlet, Baker said. Chugach Electric anticipates that the cost of imported LNG will impact about 11% of the cost components on the utility's current retail electricity bills, given that a large portion of the charges involves the recovery of fixed costs associated with the electricity system.

Energy storage

At the same time Chugach Electric is advancing its energy storage capabilities, to address the required stability of its electricity supplies. In particular, it has installed a battery facility that the utility jointly owns with Matanuska Electric Association. The concept is to use the battery to store reserve energy as an alternative to what are referred to as "spinning reserves," the availability of active, backup power generation that can be called on to respond to a sudden increase in electricity demand.

While running a backup gas-fueled generation plant in reserve mode does not make efficient use of fuel gas, the new battery storage system provides Chugach Electric with 30 megawatts of instantly available power. This is resulting in 5% savings in gas usage, Baker commented.

Transmission line upgrades

Baker also said that Chugach Electric is currently engaged in a project to upgrade the transmission line between Anchorage and the Kenai Peninsula. That line, among other things, enables the shipment of hydroelectric power north from the Bradley Lake hydropower facility in the southern Kenai Peninsula. The transmission line was built in 1962 and is being upgraded section by section in a project that is running from 2012 to 2032. The objective is to increase the capacity of the line by upgrading the operating voltage from 115 kilovolts to 230 kilovolts, thus also reducing line losses and improving power transferability. The anchoring of the power line structures is also being upgraded.

And Baker commented that Chugach Electric is very supportive of the proposed Dixon Diversion expansion of the Bradley Lake facility, while also supporting the plan to build a new undersea transmission line from the Kenai Peninsula to Beluga, to connect the peninsula region with the Anchorage region.

Matanuska Electric Association

Julie Estey, chief strategy officer for Matanuska Electric Association, talked to the committee about her utility. MEA provides power through 72,000 meters, she said. That compares with a figure in the low 60,000s 11 years ago when she started working for MEA, she added.

The big increase in the number of meters is great from the perspective of spreading the utility's fixed costs over more members. But the utility also has to ensure that it has sufficient power transmission capacity and substations to handle the increasing load. Consequently, the growth does cost money, Estey said.

At the same time, the cooperative has 57,000 members, a relatively low number to spread the costs across.

"That is something that weighs heavily on our board and staff and constantly keeps us in check to make sure that we are making fiscally conservative decisions for our members," Estey said.

In addition, 75% of MEA's members are residential rather than industrial. That impacts the manner in which the utility's costs are spread across the membership. And, as elsewhere in the United States, those costs have been increasing. Currently the cost of bringing power to MEA's customers amounts to 22 cents per kilowatt hour.

However, the biggest drivers behind reducing the cost is access to cheap hydropower or cheap gas, Estey said. And this is a time of great change in the electricity industry.

The fuel supply challenge

One of the biggest challenges facing Alaska is fuel supplies for power generation, especially given the projected decline in firm gas supplies from the Cook Inlet basin. In terms of long-term planning, MEA is looking to diversify its generation portfolio, hoping to decrease its gas usage, while also recognizing that the use of natural gas will remain a cornerstone of power production, Estey said.

At the same time, MEA currently only drives about 10% of the total demand for Cook Inlet gas. Consequently, the utility needs alliances and partnerships with other organizations that use gas, to resolve issues around future gas supplies.

Enstar Natural Gas Co., the Anchorage based gas utility, has done a great job of investigating the various options for addressing upcoming shortages in firm gas supplies from the Cook Inlet basin, Estey said. But, even taking into account a potential clean energy portfolio with 50% clean energy by 2050, the gas demand from the electric utilities is dwarfed by the demand from other uses, in particular the heating of buildings, Estey said.

"So gas is a big issue, and renewables and other clean energy options will absolutely help, but it can't solve that gas problem," she said, adding that the utilities need to solve the problem as a group. LNG imports will be necessary to help fill the gas supply gap. But there is still a predicted gap in adequate supplies before it would be possible to start LNG importing.

New developments

On the other hand, there have been some exciting developments. Enstar has just signed an amended contract with Furie Operating Alaska, reflecting Furie's potential ability to bring more gas to market. And MEA has a proposed solar energy project.

Also MEA's power plant at Eklutna was designed to use diesel fuel as well as natural gas. However, at present diesel costs about three times the cost of natural gas, Estey commented in response to a question from the committee.

Other options being discussed include potential wind projects and a potential West Susitna coal project. There has also been further talk about a North Slope gas pipeline. Estey commented that current federal policies are impacting some possibilities for renewable energy development.

But almost all of the options that MEA is investigating are more expensive than the utility's current cost of power, regardless of whether they involve renewable or non-renewable energy, Estey said.

Estey said that the top priority for MEA's members is electricity supply reliability, closely followed by the cost of the power. At the same time, all of the options for dealing with the gas supply problem involve trade-offs of one form or another. And, while the potential for solutions such as a North Slope gas pipeline or increased Cook Inlet drilling is currently very uncertain, the utilities are at a point where they need to make a decision about LNG importing.

In terms of hydropower, MEA obtains some power from Bradley Lake. The utility also has a share in the Eklutna hydropower system in northeast Anchorage, has some run-of-river hydro projects and some wind and solar power.

Transmission constraints

Constraints in the transmission system that connects the three main regions of the Alaska Railbelt limit the ability to obtain electricity from other regions, thus making it necessary for MEA to keep some spinning reserves in operation.

"Almost every large project that I am looking at for my diversification efforts is currently limited by that transmission," Estey said, commenting that a lack of adequate and redundant transmission is the biggest hurdle to bringing on new power generation and to work with independent power producers and the other utilities.

There is currently the project to build the new subsea transmission line from the Kenai Peninsula, but MEA needs a second transmission line that runs north towards Fairbanks. MEA is also looking to the newly formed Railbelt Reliability Council and the Railbelt Transmision Organization to move towards a more unified approach to the Railbelt electrical system.

"MEA is very committed to a joint energy highway with unified oversight and management and a more systems-wide approach to solving these problems, involving all of the utilities working cohesively," Estey said.

—ALAN BAILEY

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