Petroleum news

page 3 History: TransCanada, Enbridge, BP, ConocoPhillips argue gas issues

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Bill Armstrong on Alaska oil; 88's Leonis well; Beyer appointed

IN A JAN. 24 INTERVIEW with FOX News reporter Dana Perino, successful Alaska explorer Bill Armstrong talked about how he thinks President Donald J. Trump's energy policies will unlock Alaska's oil and gas resources.

Perino on FOX's America's Newsroom asked Armstrong why this administration change is "possibly different for Alaska."

Armstrong who entered Alaska in 2001, said that before Biden took office "things were going fine. Almost everyone in Alaska wanted to drill. The Eskimos that live up there wanted to drill. It's great for our country and great for the state, for the people who live in Alaska," he said, adding "and we do it in the most environmentally sensitive way in the world. If I showed you the footprint of how we drill up there it's pretty darned tight."

Armstrong pointed out that there are really two major slices of federal land in northern Alaska: "There's a big chunk

see **INSIDER** page 6

RRC coordination of Railbelt electrical system moving ahead

In a Jan. 30 meeting of the House Energy Committee Ed Jenkin, chief executive officer of the Railbelt Reliability Council and Lou Florence, chair of the organization's board, talked about the organization's objectives and its progress towards achieving those objectives. Established to improve the efficiency of the electrical system through unified oversight of the system, the RRC is tasked with developing, maintaining and mandating reliability standards for the Railbelt's high voltage electrical system; administering rules for open access to the transmission grid; and conducting Railbelt-wide integrated resource planning.

The organization was formed as a consequence of a state statute passed in 2020 requiring an electric reliability organization for the Railbelt's electricity generation and transmission system. In 2022 the Regulatory Commission of Alaska approved the RRC as the ERO for the Railbelt. The RRC is governed by a 15-member board of directors, with 13 members appointed to represent specific stakeholder classes including electric utilities, independent power producers and electricity consumers. Two non-voting

see **RRC PROGRESS** page 5

AGDC updates legislators on its Alaska LNG and phase 1 proposal

FRANK RICHARDS

Frank Richards, president of the Alaska Gasline Development Corp., provided an update to the Alaska House Finance Committee Jan. 28 on AGDC's $44 billion Alaska LNG Project and on the corporation's phase 1 plan, which would start by building the pipeline so natural gas could be shipped to Southcentral to meet the area's upcoming shortage.

At House Finance, and earlier at Senate Finance, the cost of AGDC to the state has raised concerns.

House Finance co-chair Andy Josephson noted that AGDC had already come up in budget presentations, and said the corporation is also in the fast track supplemental.

Funding for AGDC, subject to legislative approval, drew comments from Senate Finance co-chairs Lyman Hoffman and Bert Stedman when the administration presented its budget proposal

see **AGDC UPDATE** page 7

FINANCE & ECONOMY

ANS soars beyond $75

ANS foray into upper $70 brief; pulls back Feb. 5 to end week with loss

By STEVE SUTHERLIN
Petroleum News

Alaska North Slope crude made a dramatic move upward to the high side of $75 Feb. 4, up $1.41 to close at $75.32 per barrel. West Texas intermediate fell 46 cents to close at $72.70 and Brent rose 24 cents to close at $76.20.

On Feb. 5, prices reversed and ANS dropped $1.36 to close at $73.96, WTI plunged $1.67 to close at $71.03 and Brent plunged $1.59 to close at $74.61.

The herky-jerky price action is illustrative of a market on its toes, roiled by potential trade wars and poised to respond to a cascade of factors which might propel crude markets into new orbits at any time.

Data from the U.S. Energy Information Administration hit the market Feb. 5 with a bearish indicator — a jumbo surprise surge in commercial crude inventories.

Crude stocks for the week ended Jan. 31 — excluding the Strategic Petroleum Reserve — leapt 8.7 million barrels from the previous week to 423.8 million barrels, 5% below the five-year average for the time of year, the EIA said.

An analyst survey by The Wall Street Journal had predicted crude levels would move up by 1.3 million barrels.

Total motor gasoline inventories increased by 2.2 million barrels for the period to 251.1 million barrels, slightly above the five-year average for the time of year, the EIA said. Distillate fuel inventories

see **OIL PRICES** page 7

UTILITIES

Preliminary cost issue

RCA opens docket over Enstar's request to recover costs through its gas tariff

By ALAN BAILEY
For Petroleum News

In a Feb. 4 order the Regulatory Commission of Alaska denied a request from Anchorage based gas utility Enstar Natural Gas Co. to waive the normal statutory notice period for a tariff change, to enable a funding mechanism for the initial stages of a project for construction of a liquefied natural gas import terminal near Nikiski on the Kenai Peninsula. Instead, the commission has opened a docket to investigate the situation. The commission has scheduled a prehearing conference on Feb. 13 and says that it will issue a final order in the docket by Oct. 25.

The LNG import project is being pursued in response to an imminent shortage of gas supplies from the Cook Inlet basin. As previously reported by Petroleum News, Enstar has signed an exclusivity agreement with New York based Glenfarne Energy Transition to jointly work on the project. In the interest of expediting the planned project Enstar asked the commission to approve the requested waiver by Feb. 21.

Enstar and Glenfarne have agreed to work together over the next few months to develop joint development agreements, with the objective of then working toward a final investment decision that would lead to the construction and implementation of the LNG terminal.

Although the planned project only involves

see **GAS TARIFF** page 8

LAND & LEASING

Grey Owl expanded

DNR approves 32% size increase of Savant's eastern North Slope unit

By KAY CASHMAN
Petroleum News

DEREK NOTTINGHAM

DAVID PASCAL

On Jan. 31, Derek Nottingham, director of the Alaska Department of Natural Resources' Division of Oil and Gas, signed the approval of a proposed expansion of the Grey Owl unit, or GOU, that was submitted on Feb. 21, 2024, by Savant LLC, which owns 100% of the working interest in the GOU. The division deemed the expansion application complete on Oct. 28 and published public notices Nov. 10, with comments due Dec. 9. No comments were received.

The proposed expansion sought to incorporate 17 state leases originally omitted from the Sept. 20, 2023, GOU formation decision and increases the unit by approximately 24,164 acres (32%) to a total size of roughly 74,447 acres, up from 50,283 acres.

The GOU is located on the eastern Alaska North Slope.

The expansion application was signed by Glacier Oil & Gas COO David Pascal.

see **GREY OWL** page 8

GOVERNMENT

CCUS regs update for Senate Resources

DO&G, AOGCC review status of carbon storage program, with divisions' regs filed Jan. 17, AOGCC draft regs due out in February

By KRISTEN NELSON
Petroleum News

The Senate Resources Committee got an update Jan. 29 on the status of the state's carbon capture utilization and storage program, enacted into law by the Legislature in House Bill 50 in 2024.

Haley Paine, deputy director of the Department of Natural Resources' Division of Oil and Gas provided DNR's update. The division's role is to lease state lands for geologic storage of carbon dioxide and issue right-of-way leases for carbon dioxide transportation pipelines, while the Alaska Oil and Gas Conservation Commission regulates geologic storge of carbon dioxide on all lands in Alaska and is also responsible for protecting correlative rights.

DNR program to begin in February

Paine said that since House Bill 50 was passed in 2024, the department has been working to implement it and is now poised to begin the program Feb. 16.

Carbon capture utilization and storage, or CCUS, is the process of capturing carbon dioxide, transporting it and storing it underground, Paine said. Carbon can come from industrial processes or from ambient air, she said, but what's involved is "capturing the carbon dioxide, dehydrating it, compressing it into a liquid-like state and then transporting it to somewhere where you can inject it underground" into formations at least 2,600 deep, with injection managed by AOGCC.

HB50 authorizes DNR as landowner to license the state's pore space for carbon storage just as it licenses state lands for oil and gas development.

Leasing for CCUS will be on a licensing basis, similar to the division's oil and gas exploration licensing program which covers areas not included in areawide sales.

The legislation passed in May and the division looked at what it does for oil, gas, geothermal and gas storage in designing CCUS regulations. They also looked at what other jurisdictions have done for CCUS, both state and federal, putting out a scoping notice in June, Paine said. The bill was signed July 31 and the division published draft regulations Oct. 23.

Revised regulations were transmitted to the lieutenant governor on Jan. 17. The effective date for the regulations is Feb. 16.

Licensing

Leasing for CCUS will be on a licensing basis, similar to the division's oil and gas exploration licensing program which covers areas not included in areawide sales. Once the division receives an application for a carbon storage license, it will provide notice of the application to the public and call for competing proposals.

Under Environmental Protection Agency requirements, the land must be monitored for 50 years once its use for CCUS has ended, so the division's regulations include a plan of abandonment and restoration.

Paine said the division has no applications currently, but two parties are tracking when applications will be available.

AOGCC

Commissioner Greg Wilson of the Alaska Oil and Gas Conservation Commission updated the committee on AOGCC's role in the process, which is to receive needed primacy from the Environmental Protection Agency so it can issue permits for Class VI injection wells for carbon injection. Engagement with EPA and drafting of regulations began in January 2024, with a public scoping hearing in November and final draft regulations due out in February, followed by a month for legal review and two months for public comment with an application for primacy to be submitted to EPA in May and primacy expected in 12 to 24 months thereafter.

AOGCC received state funding for carbon storage and an EPA Class VI grant of $1.93 million awarded in November covering October 2024 through September 2029, at $386,000 per year. Wilson said any state monies not spent would be returned to the general fund.

Wilson said AOGCC's technical team for Class VI primacy includes its underground injection control program manager, who currently manages Class II primacy (enhanced oil recovery and disposal) and a recently hired petroleum/carbon engineer who is currently concentrating on oil and gas issues but would work on carbon storage should a project emerge. ●

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● THIS MONTH IN HISTORY

Property rights: gas line fighting words

20 years ago: TransCanada claims rights on route; Enbridge wants cooperation; BP, Conoco say too early for right of way

Editor's note: This story first appeared in the Feb. 13, 2005, issue of Petroleum News.

By KRISTEN NELSON

Petroleum News

If blunt speaking is any indication the Alaska gas pipeline project is definitely moving forward.

Pipeline and gas owners argued their cases in front of the Alaska Support Industry Alliance "Meet Alaska" conference Jan. 27, 2005, in Anchorage — complete with threats of court action.

It isn't just an issue of who can put together a project today, it's an issue of decisions made in the 1970s when a gas pipeline from the North Slope into the Midwest was first proposed.

TransCanada, one of the two pipeline companies represented at the conference, holds certificates and rights of way dating from the earlier project, and is in the process of acquiring a right of way over state lands in Alaska.

Another Canadian pipeline company, Enbridge, is also working the Alaska gas pipeline project.

BP, ConocoPhillips and ExxonMobil, the major North Slope gas owners, are pursuing a gas pipeline project of their own. The producers, and TransCanada, are negotiating with the state under the Alaska Stranded Gas Development Act for project fiscal terms.

Enbridge: working with producers

Patrick Daniel, president and chief executive officer of Enbridge Inc., told the conference that cooperation will be one of "the key ingredients in order to get the Alaska gas pipeline project underway and to make it a reality." Enbridge has applied under Alaska's stranded gas act but has not signed the required payment agreement to begin negotiations.

"We haven't been as active on our application as some others have because we're working very closely with the producers…," Daniel said. "We think there are enough proposals on the table. We'd rather focus on working with the resource owners today."

Daniel said Enbridge believes that because of the capital investment required and the risk involved it will take "a broad coalition" to do this project, a coalition involving the producers, pipeline companies, Native organizations, the state of Alaska and natural gas customers.


PATRICK DANIEL

The challenges for a project today include more interested stakeholders than in years past for energy projects, Daniel said, requiring cooperation among diverse parties which is "getting harder and harder to achieve."

Cooperation is also going to be key among project participants, he said: "All parties also need to give very due consideration to what is really required, rather than just what is optimum for them. And we've had far too much self-interest so far in this project. I don't think it's going to get off the ground until we can individually get over that and get on with the broader view."

The market will need to be involved, he said, and existing pipeline systems will have to be optimized to take Alaska gas from Alberta to markets farther south. And while natural gas liquids could be processed in Alaska, Daniel said Enbridge thinks "the market will demand that a large amount of those liquids be transported south …" Alberta, he noted, has excess NGL processing capacity.

NPA vs greenfield

The "raging debate" in Canada, Daniel said, is between using the Northern Pipeline Act "vs. a more greenfield approach … subject to the normal National Energy Board and Canadian Environmental Assessment Act oversight." Enbridge believes "that if the Canadian government relies solely on the old Northern Pipeline Act, this is going to create a lot of project uncertainty and delay, if not stall it completely in its tracks if we go that route."

The "traditional and up-to-date NEB-led process" would reduce "the total legislation and litigation and regulatory uncertainty involved in the project," he said.

If the Canadian government decides to allow applications under either the Northern Pipeline Act or the National Energy Board, Daniel said, that would be similar to the decision by the U.S. Congress to allow "either a FERC application or an application under the Alaska Natural Gas Transportation Act…"

Foothills has right to build first line

TransCanada's view is different.

"The Canadian regulatory structure for an Alaska gas pipeline is already in place," said Dennis McConaghy, TransCanada's executive vice president for gas development. Competitive hearings before the National Energy Board in Canada in the 1970s "resulted in a grant to the Foothills company, which is now wholly owned by TransCanada."

That regulatory decision, he said, was "enshrined" in a treaty with the United States and by the Canadian Parliament in the Northern Pipeline Act. "And that act bestowed on Foothills the right to build the first pipeline to carry Alaska gas across Canada."

The Northern Pipeline Act was used for the "pre-build" lines into the United States, and "is a regulatory model unique in Canada in terms of a single-window approach," he said.

The Northern Pipeline Act "has the full authority over the Canadian portion of the Alaska gas project in Canada. … It is the only authority that can do that… So, this is very much from the TransCanada perspective a matter of property rights," he said, property rights which TransCanada will defend.

On US side, either legislation works

TransCanada did not become involved in the enabling legislation passed by the U.S. Congress in October, McConaghy said, even though TransCanada holds the certificate under the Alaska Natural Gas Transportation Act, "and its related property and entitlement," because TransCanada believes the enabling legislation "was a positive contribution to the project and one that we did not wish to thwart, as that was essentially the business of the U.S. Congress to deal with that in U.S. interests.

"But Canada will be different," McConaghy said. "And if there is an assault on the (Canadian Northern Pipeline Act) there will be an obvious reaction and if the objective is to move the project forward as quickly as possible, the NPA is the only way to do that."

Either ANGTA or the enabling legislation will work on the U.S. side, he said, "but in Canada there is only one recipe to do it quickly and without protracted litigation and that is the NPA."

In Alaska, TransCanada already has a federal right of way for the pipeline and reactivated its state right of way application last year, McConaghy said, an application covering some 370 miles of state land. Hearings are complete, and the commissioner of the Alaska Department of Natural Resources is reviewing public comments.

"And we're optimistic that that right of way will be granted this spring," he said.

Canadian decision on target

Canadian Counsel General Jeffrey Parker, based at Canada's consulate in Seattle, said he understands the Canadian Minister of Natural Resources is "on target" to bring a recommendation to the cabinet "for consideration very quickly" on whether Canada would continue to use the Northern Pipeline Act and the Northern Pipeline

see HISTORY page 4

● EXPLORATION & PRODUCTION

Baker Hughes US rig count up by 6 at 582

By KRISTEN NELSON

Petroleum News

The Baker Hughes' U.S. rotary drilling rig count was 582 on Jan. 31, up by six from the previous week, down by 37 from 619 a year ago and up six from two weeks ago. Over the last eight weeks the rig count was unchanged in four weeks, down in three and up in one week with a loss of 13 and a gain of six, 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 Jan. 31 count includes 479 rigs targeting oil, up by seven from the previous week and down 20 from 499 a year ago, with 98 rigs targeting natural gas, down by one from the previous week and down 19 from 117 a year ago, and five miscellaneous rigs, unchanged from the previous week and up by two from a year ago.

Fifty of the rigs reported Jan. 31 were drilling directional wells, 519 were drilling horizontal wells and 13 were drilling vertical wells.

Alaska rig count unchanged

New Mexico (106) was up four rigs from the previous week while North Dakota (33) and Oklahoma (45) were each up by a single rig.

Rig counts in other states were unchanged from the previous week: Alaska (10), California (7), Colorado (9), Louisiana (29), Ohio (9), Texas (277), Utah (11), West Virginia (10) and Wyoming (19).

Baker Hughes shows Alaska with 10 rotary rigs active Jan. 31, 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 five rigs from the previous week at 303 and down by eight from 311 a year ago. ●

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HISTORY

Agency or use "a different kind of regulatory process."

Parker said the government of Canada "takes this very seriously" and recognizes that "it has to provide clarity and it has to do so very quickly in order to ensure that there is no confusion and to ensure that there is as little delay as possible" in moving the gas pipeline project forward.

Parker said he is frequently asked about the role Canada's Native people would play in such a project.

He said it is his point of view that over the last 25 years "there has been an incredible amount of maturity that has occurred in aboriginal governance and aboriginal politics and in the capacity of these organizations to be able to look at, negotiate and deal with and identify what their interests are with respect to resource development as well as economic development throughout the North …"

Canada's Native communities, he said, are not looking for "an all-or-nothing solution," but rather for an opportunity to participate in projects, perhaps in joint ventures and also for participation on regulatory bodies making "choices and decisions in terms of land use planning and routing and those sorts of things."

Canadian aboriginal leadership is "very capable and very sophisticated," Parker said. "I think that they want to participate and I think they know how they can do that, and so therefore I don't believe that there will be a delay factor…"

BP objects to unconditional right of way

BP Exploration (Alaska) President Steve Marshall told the conference that BP believes a grant by the state of Alaska of an unconditional right of way to TransCanada across state lands for a North Slope gas pipeline "could prematurely eliminate competition and prevent the best project from being built."

BP, along with ConocoPhillips and ExxonMobil, is negotiating fiscal terms for an Alaska gas pipeline with the state, and Marshall said the state's proposal to grant an unconditional right of way to TransCanada is "a new wild card" in the negotiations.

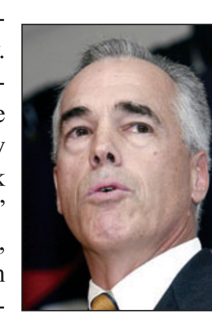
STEVE MARSHALL

"At worst, an unconditional right of way would eliminate the project proposed by the sponsors. At best, it would cause significant delays as inevitable challenges are raised," he said. Marshall said high tariffs benefit pipeline companies, because tariffs are their source of income. "That, coupled with an 'exclusive' right to build, means they have no incentive to build the lowest-cost, most efficient pipeline."

At this stage in the project, he said, "only a conditional, non-exclusive right of way should be considered for any company or group."

Not a property right

Jim Bowles, president of ConocoPhillips Alaska, also had issues with the state granting a right of way. "We see that the project is not at a stage where any company could go in and look at a right of way." The project, he said, is not far enough along in its development for the state to look at "granting an unconditional right of way at this time to any company."



JIM BOWLES

Bowles said ConocoPhillips is also concerned about TransCanada's position on the Northern Pipeline Act, particularly its assertion that it has property rights over the project. "That if we challenge those rights that will be considered an assault on that company … (defended) with protracted litigation."

That is part of the risk the state is taking, he said, if it grants a right of way "to any company" at this stage. "And we'd ask the state to consider very carefully before taking any action along those lines." ●

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● EXPLORATION & PRODUCTION

Colville, Kuparuk pad expansions approved

By KRISTEN NELSON

Petroleum News

The Alaska Department of Natural Resources' Division of Oil and Gas recently approved three pad expansions requested by ConocoPhillips Alaska, two at the Colville River unit and one at the Kuparuk River unit.

The Jan. 30 Kuparuk approval is for a gravel expansion at Drill Site 3T. The expansion is on the north, east and south sides of the pad and totals 2.56 acres, providing space for traffic and equipment movement. The division said erosion control bags filled with 2.1 cubic yards of clean gravel will line the expansion area, protecting against potential erosion, with 33,172 cubic yards of clean gravel needed for both the expansion and erosion control bags. The gravel will come from Mine Site C or other existing permitted sources within the Kuparuk River unit. Drill Site 3T is some 11 miles southwest of Oliktok Point.

Colville River unit

A Jan. 30 Colville River unit approval is for expansion of the northeast side of the Colville Delta No. 1 gravel pad to provide space for up to 55 additional conexes and an aviation warm storage tent. The division said the conexes will store camp catering, housekeeping and operations supplies, "to maintain safe and reliable operation of existing North Slope infrastructure and to support ongoing and planned activities." The expansion will place some 10,740 cubic yards of clean gravel fill on 0.92 acres at the Alpine Operations Center.

CD1 is adjacent to the airstrip apron and existing Shark Tooth camp, with gravel to be sourced from Mine Site C in the Kuparuk River unit or other existing permitted sources. The new aviation warm storage tent, some 60 feet long and 40 feet wide, will support aviation operations, making it possible to decrease the number of flights needed to supply Alpine, as well as increasing aircraft operations, pedestrian and vehicle safety and camp efficiency. The new conexes will be both powered and unpowered, with a new power cable trenched some 91 feet from the existing Shark Tooth camp to the gravel addition to power the new bull rail. The project is scheduled to begin Feb. 15.

A Jan. 31 approval is for expansion of the CD1 pad on the west side by some 0.48 acres requiring some 6,250 cubic yards of clean gravel which will be sourced from Mine Site in the Kuparuk River unit.

The expansion, scheduled to begin Feb. 1, is to increase vehicle and equipment traffic safety and provide additional space for rig movement on the pad. CD1 is some 9 miles northeast of Nuiqsut. ●

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RRC PROGRESS

members represent the Regulatory Commission of Alaska and the Office of the Attorney General's Regulatory Affairs and Public Advocacy Section.

Forming organization and moving forward

Since the RCA approval, the RRC has been forming its organization and starting to move forward with the activities required to achieve its objectives. In particular, the organization has started developing a set of mandatory reliability standards for the Railbelt. Jenkin was appointed CEO in January of this year.

Jenkin told House Energy that the RRC has budgeted for a staff of four this year, a staffing size considerably smaller than originally envisaged but which he believes is sufficient. In addition, the organization has a technical advisory committee composed of technical experts, together with working groups composed of stakeholders in the electrical system, Jenkin said.

"So we have a very strong stakeholder emphasis, where the entities that are affected by the standards, the entities that are affected by the integrated resource plan, have input to the process," Jenkin told the committee.

Mandatory reliability standards

In particular, work has been proceeding in developing mandatory reliability standards for the electrical system, with working group meetings being led by the technical advisory committee, including a technical advisory person with the appropriate expertise.

Four of the standards have now been filed with the RCA for its approval. And three additional standards are about to be presented to the RRC board, with a view to obtaining board approval to seek RCA approval of these standards. The RRC's goal at this point is to have 28 standards completed in 2025, including a large proportion of the operational standards, Jenkin told the committee.

Integrated resource planning

Also the RRC is adding staff to conduct integrated resource planning and is negotiating with an independent technical expert who can support the committee that will be responsible for the plan development. The RRC hopes to complete an integrated resource plan in 2026, Jenkin said.

"We'll apply for a budget revision to increase costs to some degree this year, to facilitate the starting of the integrated resource plan this year," he said.

Florence commented that, with the upcoming work program, the RRC budget will likely peak in 2026 before reverting to a longer-term budget level.

Jenkin said that the RRC recovers its costs from the individual utilities, with the utilities recovering these costs through the rates that they charge their customers. However, the cost to individual customers is low — Jenkin commented that the cost was less than one hundredth of the fuel cost in his recent Matanuska Electric Association bill.

The purpose of the RRC

Jenkin talked about the purpose of the RRC. Essentially, the organization is tasked with developing an overall plan and associated reliability standards for a region where there are five independent electric utilities. A key factor in maintaining reliable electricity supplies is the maintenance of the 60 hertz alternating current frequency across the high-voltage generation and transmission system, he explained. That requires flexibility in the availability of generation capacity or backup battery power in response to fluctuations in electricity demand, or to accommodate some form of power supply outage.

This flexibility involves significant collaboration between the utilities, Jenkin said. In addition, through the direction of the Regulatory Commission of Alaska, two of the utilities, Chugach Electric Association and Matanuska Electric Association are working together to form a single load balancing area. The concept behind the integrated resource planning that the RRC is embarking on is the consolidation of planning across the entire region, trying to make the system more efficient and looking at larger projects that can be used by multiple entities.

"We still feel that we can coordinate those efforts and make a regional plan work for the Railbelt utilities as they continue to move forward," Jenkin said.

Three regions

A key issue is that each load balancing area within the Railbelt has to have the capability to move the system back to that 60 hertz frequency requirement if there is some disturbance in the power generation or demand. But the Railbelt is split into three regions: the southern, central and northern regions. Those regions are connected by power transmission lines with relatively low power carrying capacities.

A consequence of this, together with the independence of the utilities, has been that each utility has built its own generation capacity, to ensure the maintenance of that 60 hertz frequency requirement. But the lack of transmission capacity between the regions is still evidenced, for example, by a notable number of load shedding events in Anchorage in the past summer, Jenkin said.

An upshot has been a strategy in which over the years each utility has built power generation to meet its own needs for adequate power reserves, with a resulting over capacity in power generation for the entire Railbelt system. On the other hand, the utilities are now jointly considering single generation resources, looking forward to an integrated resource plan that can perhaps result in larger facilities used by multiple entities, Jenkin said.

"If we'd regionally plan these types of generation improvements, those results could potentially result in long term lower costs," he said.

Coupled with this there is a need for upgrades to the transmission system to improve the connectivity between the three Railbelt regions.

In connection with the importance of regional planning for the electrical system there is a requirement for unified reliability standards across the system, so that all the utilities are working under the same standards for maintaining that 60 hertz frequency, Jenkin said. And a unified set of standards can help ensure reliable modeling of how the high-voltage electrical system operates and thus prevent system outages, he said.

—ALAN BAILEY

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INSIDER

of federal land to the east which is called ANWR and that is the one that raises all sorts of controversy all of the time," he said noting that environmental groups such as Greenpeace "are always talking about ANWR."

BILL ARMSTRONG

And then, he said, "there is an area to the west of the North Slope called the NPR-A, which stands for the National Petroleum — petroleum — Reserve of Alaska."

When Joe Biden got in "he ostensibly put the NPR-A off limits, changing the rules and changing the regulations. It was an area even though it is very, very prospective was suddenly not available to be drilled," Armstrong said.

"And I'm the largest leaseholder in the NPR-A at slightly less than 1.1 million acres and what Biden did to me and my company was essentially nationalize my position."

At this point Perino broke in to show a chart of Alaska oil production, asking whether there is a "national security argument here" as well: "Increased oil production is not only good for Alaska but good for America?" she asked.

"You're absolutely right," Armstrong said. "What that top curve (in the chart) shows is bringing on the Prudhoe Bay oil field in 1978. It peaked at about 2 million barrels a day." And then it set about on a typical oil field decline curve ever since.

"And now the trans-Alaska pipeline, they call it TAPS, is three-quarters empty," Armstrong said.

"We have all this availability for crude oil to flow into it," he said, noting that a "huge field that me and my partners found about 10 years ago is soon going to start producing into TAPS," referring to Pikka.

"Then there was a big discovery made by ConocoPhillips that's going to start producing at about 200,000 barrels a day, so that curve is going to start going back up again, but what we could do is quite literally fill up TAPS again if we were allowed to drill," Armstrong said.

In updates to Alaska Legislature's House and Senate Finance committees Jan. 22 and Jan. 23, the Alaska Department of Natural Resources' Division of Oil and Gas highlighted recent production and the fiscal year 2025 forecast, as well as the 10-year outlook. Travis Peltier, petroleum reservoir engineer leads the forecast team. He said Santos, owner of Pikka operator Oil Search (Alaska), has said Pikka is expected to be online in the second quarter of 2026, although Peltier said that in investor presentations Santos has said it might be able to accelerate first production to December 2025. Peak rate in phase one is 80,000 barrels per day with an equal amount in phase two, on which a final investment decision is expected in 2027.

"So … what Trump did by removing all the regulations and obstructionist moves by Biden in the NPR-A … takes us one step back to what we do best — produce oil cleanly and effectively for the world and it's also great for national security," Armstrong told Perino. "It's a game changer."

—KAY CASHMAN

88 Energy to drill Leonis

ON JAN. 30, 88 ENERGY said it is planning to drill the Tiri-1 exploration well in its Alaska North Slope Leonis prospect next winter.

Drilling is contingent on the company finding a farm-out partner.

88 Energy has 100% working interest in Leonis, which is close to export pipelines and the Deadhorse services hub.

—KAY CASHMAN

Beyer to oversee Interior offices

ON FEB. 5, THE ENERGY Workforce & Technology Council congratulated former CEO Leslie Beyer on her presidential appointment as Assistant Secretary of Land and Minerals Management at the U.S. Department of Interior.

"The Energy Workforce & Technology Council looks forward to continued collaboration with Assistant Secretary Beyer and the Department of the Interior to ensure a balanced approach to resource development that meets the nation's energy needs while maintaining responsible stewardship of public lands," EWTC said.

LESLIE BEYER

Beyer, who led EWTC from 2014 to 2023, played a pivotal role in advancing the interests of the energy services sector and advocating for oil and gas as a driver of economic growth and energy security. Her leadership, dedication, and deep industry knowledge have made a lasting impact on not only the Council and its member companies, but the energy industry at large, EWTC said in its statement.

Once confirmed by the Senate, Assistant Secretary Beyer will oversee four departmental agencies: the Bureau of Land Management, Bureau of Ocean Energy Management, the Bureau of Safety and Environmental Enforcement and the Office of Surface Mining, Reclamation and Enforcement. Serving under Secretary Doug Burgum, Beyer will also guide the use of about 245 million acres of federal surface lands, 700 million acres of federal mineral interests and the 1.7 billion acre Outer Continental Shelf.

"We could not be more excited and proud of Leslie's appointment as Assistant Secretary of Land and Minerals Management," said EWTC President Molly Determan. "Her unwavering commitment to the energy sector and her innate ability to bring stakeholders together will serve the Department of the Interior well as it navigates challenges related to land and resource management. Leslie has always been a strong advocate for the energy industry, and we have no doubt that she will continue to champion policies that unleash American energy."

EWTC President Tim Tarpley echoed the sentiment, adding, "Leslie's experience and deep understanding of the energy services sector make her an excellent choice for this role. Her leadership at EWTC helped shape meaningful policy discussions, and we are confident that she will bring the same level of dedication and expertise to the Department of the Interior. We look forward to working with her in this new capacity."

Under Beyer's leadership, the council achieved numerous milestones, including strengthening partnerships with policymakers, expanding industry workforce initiatives and advocating for policies that support domestic energy production and innovation, EWTC said.

—KAY CASHMAN

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AGDC UPDATE

to that committee Jan. 27, with Sen. Hoffman noting how much money the state has spent on an Alaska LNG project over the years with no results and Sen. Stedman asking the administration to provide a cost estimate for dismantling AGDC.

Two AGDC items were highlighted in the administration's overview of the operating budget: the first is $50 million in UGF, undesignated general funds, to provide backstop for front end engineering work toward a final investment decision. This amount is for the Alaska Industrial Development and Export Authority, whose board voted at its December meeting to provide up to $50 million in backstop funding for AGDC.

Richards said the backstop is meant to reimburse front end engineering design work if the project doesn't reach final investment decision. The $50 million would be parked in an account and only used in the event FID isn't reached.

The operating budget also includes $2,487,500 to restore AGDC's operating funding in support of continued efforts on Alaska liquefied natural gas development.

It was the operating budget presentation and the $2.5 million that drew comments from Hoffman, who also objected to the backfill amount and said the state has spent close to $900 million on an Alaska LNG project with no insight on whether it will be built. He said the state needs to take a step back and access where it is on the project.

There is also $4.2 million for AGDC in the capital budget, to meet ongoing capital needs. It was this amount which drew the request from Stedman that the administration provide the cost of shutting down AGDA, both operating and capital costs.

House Finance explored the issue of the $50 million budget request for AIDEA, with Josephson asking AIDEA Executive Director Randy Ruaro whether AIDEA could go forward with the backstop without the appropriation.

Ruaro stressed that the amount was up to $50 million and said the amount could be significantly less.

He said the proposed final investment decision in June 2027 would trigger any backstop obligation, and said it probably wasn't necessary to have the amount in the fast track supplemental.

Josephson asked Richards about the timing of that appropriation and Richards said it wouldn't be negatively viewed by the market if the amount was not fast tracked.

Ruaro was asked why, if AIDEA approved the amount, it wasn't funding it out of its reserves.

He said the agency is starting to get stretched, that while it has $400 million in its revolving fund, the board has already approved $200 million in projects and tries to keep $100 million in the revolving fund as reserves for bonding large projects. AIDEA could provide the backstop funds, he said, but likes to be able to keep funding liquidity.

Last session the Legislature requested third-party verification that natural gas from phase 1 of the Alaska LNG Project would be economic compared to imported LNG, and that study, by Wood Mackenzie, was completed in October. It showed that phase 1 of the project, the pipeline from Prudhoe Bay to a junction with Enstar on the west side of Cook Inlet, could deliver gas at or below the cost of imported LNG.

Matt Kissinger, AGDC's venture development manager, reviewed the evolution of the project from its producer-led beginning in 2013, to a 100% state project from 2017-2022, and then to a developer-led project from 2023 forward, with the state going from a 25% equity owner under the producer-led project to 100% equity owner, with a goal of turning over 75% equity to private parties under the current plan, reserving its 25% equity until a final investment decision is made, at which point the state would have the option to continue a 25% ownership role or relinquish its ownership completely.

FID is expected in 2027, which is when the backstop would come into play, in the event FID was not reached.

—KRISTEN NELSON

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OIL PRICES

decreased by 5.5 million barrels to 118.5 million barrels — 12% below the five-year average for the time of year.

Gasoline stocks had been forecast to be up by 100,000 barrels.

Traders had been cheered Feb. 4 by an executive order from U.S. President Donald Trump to put "maximum economic pressure" on Iran, rescuing futures prices from steep losses earlier in the day after additional U.S. tariffs of 10% against China imports went onto force.

Brent had been down more than 2% early Feb. 4 but ended the day in the black.

The National Security Presidential Memorandum was designed to deny Iran "all paths to a nuclear weapon, and countering Iran's malign influence abroad," the White House said in a release.

The NSPM directs the Secretary of the Treasury to sanction or impose enforcement mechanisms on those acting in violation of existing sanctions.

But traders returned to gloom over Chinese demand on Feb. 5.

"The wild price swings earlier this week have exposed the oil market's sensitivity to trade-related headlines," Han Tan, chief market analyst at Exinity told MarketWatch.

Although the 10% U.S. tariff has already "prompted tit-for-tat responses from China, markets are all too aware that trade tensions between the world's two largest economies have room to escalate further," Tan said. "A significant escalation and broadening of a trade war is set to darken the global economic outlook and could lead to oil demand destruction, potentially offsetting further sanctions on Iranian supplies."

ANS fell 96 cents Feb. 3 to close at $73.91, while WTI gained 63 cents to close at $73.16 and Brent fell 80 cents to close at $75.96.

The Organization of the Petroleum Exporting Countries and its allies held the first meeting of the year Feb. 3 resulting in agreement to keep production policy unchanged.

OPEC+ plans to gradually add some 2.2 million barrels per day of supply over 18 months beginning in April, depending on market conditions. It will meet again on Apr. 5.

On Jan. 31, ANS added 29 cents to close at $74.87, WTI shed 20 cents to close at $72.53 and Brent shed 11 cents to close at $76.76.

ANS gained 21 cents Jan. 30 to close at $74.58, as WTI added 11 cents to close at $72.73 and Brent gained 29 cents to close at $76.87.

From Wednesday to Wednesday, ANS lost 41 cents from its close of $74.37 Jan. 29 to $73.96 Feb. 5.

ANS traded at a $2.93 premium over WTI Feb. 5, while trading at a 65-cent discount to Brent.

The energy industry is being pulled into the vortex of America's trade wars, and it could drag on the stocks of oil and gas producers, Avi Salzman said in a Feb. 4 Barron's feature.

U.S. energy is a much bigger industry than it was in President Trump's first term — more intertwined than ever with global trade, Salzman said.

"At the very least, these stocks are vulnerable to constant will-he-or-won't-he headlines about tariffs; at worst, their entire supply chains could be at risk," he said. "It may be one reason why energy stocks have fallen since Trump's election, even as he has promoted fossil fuels, and the overall market has risen."

"If the tariffs disappear quickly, the oil market may emerge unscathed," Salzman said. "But the industry is now too big to ignore, and it's unlikely to avoid the impact if levies linger." ●

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GAS TARIFF

Enstar and Glenfarne, Enstar is actively engaging with the other Railbelt utilities in seeking a solution to the gas supply problem. Enstar, in its RCA filing, says that it will work with other utilities "to conclude back-to-back gas sales agreements and/or terminal capacity sharing agreements."

Potential $58 million in costs

Enstar is seeking RCA approval for the recovery through gas rates charged to its customers for up to $58 million in costs that the utility expects to incur in association with the work leading to a decision on whether to proceed with the engineering and construction of the import terminal.

RCA has previously approved a regulatory asset under which the Alaska Railbelt utilities, including Enstar, have investigated options for addressing future gas supply shortages. Following a decision to move forward with the LNG import option for addressing the shortages, Enstar now wants to include costs associated with the LNG import project in the utility's gas cost adjustment, or GCA, calculations that are used to adjust the fees that Enstar charges its customers.

"Enstar proposes to recover future costs on an 'ongoing' basis through each annual GCA," Enstar told the commission. "This process would ensure that costs of securing the long-term gas supply project are timely reflected in the cost of gas."

Three different cost categories

The utility is seeking approval for the recovery of three different categories of cost: the utility's own costs associated with the project, costs incurred by the project developer and carrying costs associated with the regulatory asset for addressing the pending gas supply shortage.

There are two possible scenarios for dealing with the costs incurred by Glenfarne, the project developer. If the project advances to the construction of the import terminal, the developer costs will be applied to the capital cost of the terminal. The costs would then be recovered through the fees associated with the use of the terminal. If, on the other hand, the construction project does not proceed, Enstar would reimburse Glenfarne for the estimated project costs of up to $48 million and recover this cost through the rates the utility charges to its customers. In the event of this happening, Enstar estimates an impact of $15 per month to its residential customer bills.

In addition, Enstar and Glenfarne will independently fund their costs associated with project related agreements, potentially including a project development agreement, a gas sales agreement and a terminal use agreement.

The upfront costs incurred by Glenfarne are anticipated to include the cost of conducting a front-end engineering and design project, while Enstar's anticipated costs during the course of engineering activities include the finalizing of commercial agreements and oversight of Glenfarne's activities.

Also, the project will need Federal Energy Regulatory Commission approval of required permitting, potentially including an environmental assessment. However, a decision to site the LNG import facility at a location already approved by FERC for an LNG export facility associated with a potential gas pipeline from the North Slope should simplify the permitting process, Enstar told RCA.

The upshot of all of this is the estimated $58 million that Enstar wants to be able to recover through its rates.

In its Feb. 4 order RCA cited a number of issues that need to be resolved regarding what Enstar is asking permission to do. These questions include a potential conflict with FERC jurisdiction over the construction of the LNG facility; why the funding of the regulatory asset for the gas supply investigation should not simply be terminated at this stage; why Enstar's ratepayers should have to assume the costs arising from the risks associated with the project; and why Enstar should be allowed to recover its costs through the GCA rather than through a rate case. ●

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GREY OWL

The expansion area is approximately 20 miles south-southwest of Glacier subsidiary Savant Alaska's Badami unit.

The GOU is roughly 26 miles due east of the Dalton Highway and the Trans Alaska Pipeline and approximately15 miles due west of the Canning River and western border of the Arctic National Wildlife Reserve. The Sadlerochit Mountains in ANWR are approximately 20 miles to the southwest of the GOU and roughly 30 miles to the south are the Brooks Range Foothills.

Exploration efforts within the GOU and immediate surrounding area have been limited, and between 1969 and 1990 included only three wells. Regionally, however, Lagniappe Alaska LLC showed renewed interest in the area by drilling the King Street 1 exploration well in 2024, located 15 miles to the north of the GOU. Bill Armstrong's Lagniappe Alaska is returning to the eastern North Slope this winter to drill the Sockeye-2 well on state acreage approximately 8 miles southeast of Badami, within the Lagniappe-operated oil and gas lease block.

Exploration targets for the proposed GOU unit expansion area are sandstones in the Canning formation interval of the Late Cretaceous and Early Tertiary Brookian sequence.

According to state statute, "a unit must encompass the minimum area required to include all or part of one or more oil or gas reservoirs, or all or part of one or more potential hydrocarbon accumulations."

Savant has submitted confidential geological, geophysical and engineering data, which demonstrate that the area approved for unit expansion includes all or part of an oil, gas reservoir and potential hydrocarbon accumulations.

The division found that the proposed expansion of the GOU promotes conservation of all natural resources, promotes the prevention of economic and physical waste and provides for the protection of all parties of interest, including the state.

The effective date of the GOU expansion is retroactive to Sept. 20, 2023 "based upon the updated interpretation of available seismic data and regional subsurface mapping across the broader region and near-by analogs," the division said.

Two wells

Although Savant committed to just one well in the five-year period, the division in its decision calls for Savant to "drill and test two exploratory wells which, combined with any associated studies, sufficiently demonstrate to the Division that all approved potential hydrocarbon accumulations are viable reservoir targets within the five-year unit term of Sept. 20, 2023, through Sept. 20, 2028."

But the first exploration well called for remains the same in the exploration plan attached to the expansion application — Savant shall evaluate an initial exploratory well (GO-1) through flow testing in the winter season of 2026-2027.

And the division calls for drilling an additional well that sufficiently tests the approved potential hydrocarbon accumulations not tested in the GO-1 well.

OR Savant has the option of drilling a single well that sufficiently tests all approved potential hydrocarbon accumulations.

Seismic in area

The first 2D regional seismic data was acquired in this area of the eastern North Slope during the mid- to late 1960s at the time of the Prudhoe Bay discovery.

In the early 1990s, an additional 2D seismic survey was conducted, which covered the eastern part of the North Slope coastal plain.

The only 3D regional seismic survey overlapping portions of the GOU and its expansion area — the proprietary Shaviovik 3D survey — was conducted in 2001 by WesternGeco and Fairweather Geophysical on behalf of Phillips Alaska (now ConocoPhillips Alaska).

Wells in the GOU

The West Kavik Unit 1 well, located within the GOU, was spud in February 1969 by Texaco Inc.

Although the well originally was designed to target both the Ellesmerian Ivishak and Lisburne formations, it was drilled vertically to 16,613 feet true vertical depth that reached the Lisburne formation carbonates and was ultimately plugged and abandoned in January 1970. The Ivishak sandstones, comprised of a lower quality facies than that produced at Prudhoe Bay, yielded no moveable hydrocarbons. The Lisburne carbonates were tested by DSTs 1-3, each one failing to recover any oil. However, further up section, the Brookian Canning formation, situated stratigraphically above the Lower Cretaceous Unconformity, successfully tested gas with associated oil from stacked turbidite reservoirs. DSTs 4-6 were conducted in the Canning formation, with DST 4 (9,690 feet to 9,790 feet TVD) being the only test to register measurable amounts of oil. Although gas flowed to the surface for more than 30 hours, no oil made it to the surface. However, a 55-foot oil column was reported on top of watery, gas cut mud at 2,261feet depth in the borehole when the testing tool was pulled. Further up hole, DSTs 7-8 failed to recover any hydrocarbons from the Brookian Sagavanirktok formation. No further drilling occurred in the area until the mid-1980s.

1980s and later wells

The Alaska St J 1 well, located approximately 8 miles east of the GOU, was spud in March 1984 by Exxon Corp., vertically drilled to 13,655 feet TVD. It reached the Brookian Canning formation and was plugged and abandoned in June 1984.

The objective of this well may have been to determine the existence of a stratigraphic trap within a thick Canning formation sequence.

Although no testing was conducted, two cores were collected in the lower part of the Canning formation. Core 1 was collected between 12,310 feet and 12,341 feet TVD with 22.5 feet recovered. The dominant lithology was siltstone; no oil or gas shows were identified. Core 2 was collected between 12,668 feet and 12,704 feet TVD with only 9.5 feet recovered, consisting primarily of siltstone and very fine- to fine-grained sandstone with poor porosity and permeability and no oil or gas shows.

No further drilling occurred in the area until the early 1990s.

The Gyr 1 well, located approximately 5.5 miles south of the GOU, was spud in February 1990 by ARCO Alaska Inc. It was directionally drilled to 8,005 feet TVD, reached the uppermost Canning formation shales with some minor sandstone, and plugged and abandoned in April 1990. This well was meant to test a sub-thrust structural trap to evaluate Brookian Sagavanirktok topset sandstones below the main frontal thrust of the Brooks Range Foothills. The only oil show encountered, however, was in the Canning formation at 7,740 feet TVD, and it was not tested. Water wet stacked sandstones within the Sagavanirktok topsets were also encountered and one 31-foot conventional core was collected between 5,463 feet and 5,494 feet TVD within the Sagavanirktok formation. Core analysis yielded a maximum porosity of 14.1%, and associated permeability of 71 measured depth with lithologies consisting of sandstone, silty claystone, pebble conglomerate, and silty sandstone. ●

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