Petroleum news

page 4 EIA forecasts record US crude oil output at 13.2 million bpd in 2024

Vol. 29, No. 11 • www.PetroleumNews.com A weekly oil & gas newspaper based in Anchorage, Alaska Week of March 17, 2024 • $2.50

Hickory-1 well operations have begun on Alaska's North Slope

ASHLEY GILBERT

On March 11, Australia-based 88 Energy Ltd. released an ASX announcement, saying Hickory-1 well operations have commenced, with well bore preparations complete and perforation of the Upper SFS zone to begin ahead of perforating, fracking and flow testing the Upper SFS zone. Hickory-1 was drilled but not tested last winter.

Two flow tests are scheduled, one each in the Upper SFS and SMD-B reservoirs, with each frac and flowback operation expected to take approximately 10 days.

88 Energy said it has strengthened its technical advisory team to include additional engineering expertise, as well as experienced members of the Pantheon Resources Great Bear team being available to share their relevant recent and extensive

see **HICKORY-1 WELL** *page 10*

Hilcorp applies to expand Milne Point unit; new drilling planned

As Hilcorp Alaska continues to expand production from its North Slope Milne Point unit it is now looking at acreage it holds adjoining the unit and has applied to the Alaska Department of Natural Resources' Division of Oil and Gas to expand the Milne Point unit by some 13,275 acres.

A map accompanying Hilcorp's Dec. 29 application shows the majority of the expansion area to the north of the existing unit, with one smaller proposed expansion area near the unit's southeast edge.

Hilcorp said in its application that accumulations in the proposed expansion area include the Kuparuk and Schrader Bluff reservoirs, accessible from the Moose, Raven (or R) and F pads. The F Pad is the most northerly of the three, with the R Pad under construction to the southwest of F Pad and the Moose Pad, developed in 2018, southwest of the R and F pads near the western boundary of the unit.

The expansion area includes parts of six leases: ADL 355017, ADL 355018, ADL 355021, ADL 355016, ADL 28232 and ADL 394167.

Hilcorp said three of those, ADL 355017, ADL 355018 and

see **MILNE EXPANSION** *page 10*

Bill for Railbelt transmission changes could improve usage

GWEN HOLDMANN

On March 4 the Alaska Senate Resources Committee heard testimony on Senate Bill 217, a bill introduced by Gov. Mike Dunleavy to change the way in which the electricity transmission system in the Alaska Railbelt is managed and funded. An identical bill, House Bill 307, has been introduced to the House of Representatives. As previously reported by Petroleum News, the bills would change the way in which transmission costs are recovered by the utilities that operate sections of the transmission system and would require the utilities to form an integrated transmission system association to assist in administering the arrangements for transmission system cost recovery.

Currently the use of the system is hindered by the wheeling or "pancaking" of the fees that each utility charges for the use of its individual sections of the system. This can render the

see **RAILBELT BILL** *page 10*

FINANCE & ECONOMY

Demand supports ANS

US oil inventories fall as Ukraine strikes major Russian oil facilities

By STEVE SUTHERLIN
Petroleum News

Oil futures leapt some 3% March 13 as the U.S. Energy Information Administration reported a drawdown of U.S. crude reserves and gasoline reserves.

West Texas Intermediate crude lofted $2.16, or 2.8% March 13 to close at $79.72 per barrel and Brent leapt $2.11 or 2.6% to close at $84.03.

The daily Alaska North Slope crude closing price estimate from the Alaska Department of Revenue for March 13 was not released by press time for Petroleum News. ANS and Brent have been closely correlated of late, in fact Brent on March 12 held a slim 19-cent premium over ANS.

The United States produced more crude oil than any nation at any time, for the past six years in a row, the EIA said in a March 11 report.

Assuming a corresponding 2.6% increase for ANS March 13, ANS likely jumped some $2.12 to close in the vicinity of $83.85.

The Alaska Department of Revenue in its Spring Revenue Forecast released March 13 said the ANS price for FY 2024 is projected at $84.08, and $78.00 for FY 2025.

Although an ANS crude price was then yet

see **OIL PRICES** *page 9*

UTILITIES

A bill for clean energy

Railbelt electric utilities support intent of targets for future energy sources

By ALAN BAILEY
For Petroleum News

During its March 7 meeting the Alaska House Resources Committee gathered comments from Alaska Railbelt electric utilities on House Bill 368, a bill designed to enact a clean energy standard for the generation of electricity in the Alaska Railbelt.

Officials from utilities Homer Electric Association, Matanuska Electric Association and Golden Valley Electric Association expressed positive views of the bill, which would set a target of 35% clean power generation by Dec. 31, 2036, and 60% of clean power generation by Dec 31, 2051. These target dates would be delayed if the Railbelt electricity transmission system is not upgraded to meet the minimum capabilities required to support the shipment of the clean energy.

The renewable energy portfolio standard

During the 2023 legislative session two bills were introduced, Senate Bill 101 and House Bill 121, proposing a renewable energy portfolio standard, or RPS, for Alaska. The RPS would require all electric utilities in the state to supply at least 25% of their electricity from renewable sources by Dec. 31, 2027, 55% by Dec. 31, 2035, and 80% by Dec. 31, 2040. Financial penalties would be assessed for utilities that do not meet the RPS targets. These bills were strongly supported by advocates for the use of renewable energy, while electric utilities raised questions over

see **ENERGY STANDARD** *page 8*

NATURAL GAS

Inlet's energy dilemma

House Resources Committee reviews tough alternatives as gas shortage looms

By KRISTEN NELSON
Petroleum News

Cook Inlet natural gas provides the fuel for most Southcentral heat and power, but it's in short supply, with the supply getting shorter.

Is there more gas in the Cook Inlet basin?

Absolutely, members of the Alaska House Resources Committee were told in a March 4 presentation by Trevor Jepsen and Ed King, staff to committee Chair Tom McKay.

But additional Cook Inlet gas will cost more to produce, as it requires development costs in some cases, exploration costs in others and for a third tranche of gas, research and development costs.

The U.S. Geological Survey has estimated there are some 19 trillion cubic feet of natural gas in Cook Inlet, King said, but not all those gas molecules are equal — not as accessible and not as developable.

He said the Alaska Department of Natural Resources estimates that 820 billion cubic feet of gas are proved and developed, requiring just operating costs to get to market, at some $8 to $10 per thousand cubic feet.

That is the gas that Hilcorp Alaska, Furie and a few smaller producers are currently providing.

Then there is discovered but undeveloped gas, which has development costs, and is likely to cost $11 to $16 per mcf, King said.

The next tranche is undiscovered, economically viable, estimated at $17 to $25 per mcf because of

see **INLET ENERGY** *page 8*

● EXPLORATION & PRODUCTION

North Fork unit POD approved with mods

By KAY CASHMAN
Petroleum News

On March 5, the Alaska Department of Natural Resources' Division of Oil and Gas approved with modifications the North Fork unit 2024 plan of development.

The POD was filed by unit operator Vision Operating LLC, a fully owned subsidiary of Gardes Holdings Inc. The North Fork unit, or NFU, is on the southern Kenai Peninsula. The approval letter was sent to Gardes and Vision executive Mark Landt by division Director Derek Nottingham.

In its 2024 POD Vision proposed to enhance production from existing wells, convert a well to water disposal and drill additional wells; however, all operations are contingent on favorable market conditions and the ability to raise capital and secure a drilling rig.

The division approved Vision's POD with these conditions: "Vision will begin drilling a well in the NFU by the end of the calendar year 2025 and maintain operations to bring that well into production. Based on these conditions, the NFU 59th POD is approved through the end of 2025. Updates to this POD are due July 1, 2024, Jan. 1, 2025, and July 1, 2025. Failure to begin drilling and maintain operations to bring the well into production by end of calendar year 2025, may result in default of the NFU."


MARK LANDT

Natural gas production from the NFU has averaged 2,432 thousand cubic feet of gas, or mcf, per day from Dec. 1, 2022, through Nov. 30, 2023, representing a 23% year over year decrease.

Contraction is required after a unit has been in production for 10 years, at which point it is contracted to areas that are producing. The division has the right to delay contraction.

Unit history

NFU was formed as a federal unit on May 27, 1965. The U.S. Department of Interior's Bureau of Land Management, or BLM, and the state of Alaska co-managed the NFU, which was comprised of two state and two federal oil and gas leases totaling 58,113.40 acres, originally. In 2006 BLM waived its administration rights and transferred its NFU leases to the state.

Currently, the NFU is comprised of five state oil and gas leases totaling 2,601.84 acres, and one participating area, or PA, the NFU Gas Pool #1 PA, or GPA.

Effective May 1, 2021, Vision took over as operator. The company has not drilled a well in the unit since then.

During the 2023 POD period, Vision planned to maintain production and evaluate opportunities to increase production, including well workovers, additional perforations, or drilling new wells. Any new wells would be dependent on favorable economic conditions. Additionally, Vision planned to apply to expand the GPA.

Actual operations consisted of a well workover, which attempted to add perforations and increase production. However, the workover was unsuccessful. Further, no new wells were drilled due to a lack of available capital. Vision requested and was granted a delay in unit contraction until Oct. 6, 2024, and did not apply for a GPA expansion. ●

Contact Kay Cashman at publisher@petroleumnews.com

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EXPLORATION & PRODUCTION

Division approves Hilcorp's Kenai seismic

The Alaska Department of Natural Resources' Division of Oil and Gas has approved an application from Hilcorp Alaska for its Southern Kenai Transition Zone seismic program.

This is the second seismic program Hilcorp has planned on the Kenai Peninsula. In February the division approved the company's Sterling Highway 2D seismic program between Clam Gulch and Anchor River (see story in Feb. 25 issue of Petroleum News).

The March 8 approval of the Jan. 5 Southern Kenai Transition Zone application includes discussion of comments the division received on the proposal from other state agencies, a local resident and a conservation organization, with responses from Hilcorp and the division.

The division said the program will use a vibroseis truck, seismic source receiver nodes, Vibrogel Minihole charges, utility terrain vehicle, a mobile drilling unit, a marine vibroseis unit and boats, with up to nine seismic recording lines onshore, offshore and in tidal zones.

The mobile drilling unit will drill three 5-foot-deep holes every 55 feet onshore for placement of the charges, with the charges backfilled to prevent blowouts and so no open holes will be left, the division said. No charges will be placed on the west side of the Sterling Highway.

Onshore receiver nodes will be placed by a utility terrain vehicle every 27.5 feet.

The offshore survey will use a boat equipped with a marine vibroseis unit as the seismic source with offshore and tidal zone receiver nodes placed every 55 feet.

In its public notice on the seismic the division said the area covered is between Ninilchik and Anchor Point. Hilcorp said in its application that the shoot includes up to nine different lines for a total of 60.2 miles (see story in Feb. 4 issue of PN).

Hilcorp has an active development drilling program at its Ninilchik unit and an exploration program underway farther south with wells planned at both Whiskey Gulch and Cottonfield.

—KRISTEN NELSON

● GOVERNMENT

AOGCC fines Hilcorp for DIU violations

$55K fine stems from requirements imposed in 2022 for installation of new Coriolis custody transfer meters at Duck Island unit

By KRISTEN NELSON

Petroleum News

The Alaska Oil and Gas Conservation Commission has fined Hilcorp Alaska, the Duck Island unit operator, $55,000 for failure to provide the commission with advance notice of monthly meter proves and for failure to submit monthly meter prove results within seven days. Both were conditions of a 2022 approval of new meters.

In a Feb. 6 notice of proposed enforcement action, the commission said Hilcorp failed to provide at least 24-hour notice of opportunity to witness monthly meter proves in December 2023 and January 2024, and failed to submit meter performance reports for November 2023 through January 2024.

Hilcorp requested permission to replace two of four Duck Island unit oil custody transfer meters in 2022. The two were out-of-service turbine meters and were to be replaced with Coriolis meters, a change which required a variance, AOGCC said at the time.

It required a one-month demonstration comparing results from the Coriolis and turbine meters, with Hilcorp required to demonstrate that the new meters met a performance level acceptable to the commission. Once AOGCC accepted the meters, it required monthly proves, with 24-hour notice to allow it the opportunity to witness the meter proves, and required Hilcorp to provide it with results of the monthly meter proves within seven days.

AOGCC said in its Feb. 6 notice that it conditionally approved use of the Coriolis transfer meters in June 2022, and a successful demonstration period began in September 2023 and was completed in October.

AOGCC said in its Feb. 6 notice that it conditionally approved use of the Coriolis transfer meters in June 2022, and a successful demonstration period began in September 2023 and was completed in October.

Since then, however, Hilcorp has "repeatedly violated" two of the approval conditions, the commission said: failing to provide the 24-hour notice of the monthly meter prove in December and January; and failing to provide monthly performance reports for November through January.

In a Feb. 8 response to the notice of proposed action, Hilcorp said it would not appeal and submitted payment of the $55,000 fine.

The company described the measures it put in place to ensure the problem does not recur:

"Added all Conditions Of Approval (COA's) for oil custody transfer meters to Compliance Task Manager system to trigger notifications to submit 24 hour notice and subsequent reports bi-weekly."

It also said reviews will be held on all management of change in the future to ensure all parties are aware of the conditions of approval and said a paper copy of the conditions of approval will be attached to new equipment before startup.

In its March 5 order on the matter,

see HILCORP FINES page 5

● FINANCE & ECONOMY

EIA forecasts growing US crude production

Henry Hub to average $2.25 per million Btu in 2024, down 10% from 2023, 65% from 2022, slightly decreasing domestic gas production

By KRISTEN NELSON
Petroleum News

U.S. crude oil production set a record in 2023 and is forecast to continue growing this year and next, the U.S. Energy Information Administration said in its March EIA Short-Term Energy Outlook, released March 12.

EIA said both 2024 and 2025 are expected to exceed the U.S. production record set in 2023, with production averaging 13.2 million barrels per day this year, up from the record-setting 12.9 million bpd in 2023 and increasing to 13.7 million bpd in 2025.

The agency said the growth in U.S. production should help offset continued voluntary production cuts announced by the Organization of Petroleum Exporting Countries and associated producers, OPEC+, but EIA still expects a tight balance between supply and demand, resulting in higher Brent spot oil prices this year than were expected at the beginning of the year.

JOE DECAROLIS

"Some significant sources of uncertainty remain in our crude oil forecasts, including how the Red Sea conflict could affect production and how strictly OPEC+ members will adhere to their voluntary production cuts," said EIA Administrator Joe DeCarolis.

Globally, EIA said it expects liquid fuels production to increase 0.4 million bpd this year, down from a 0.6 million bpd growth projected last month, and down from a 1.8 million bpd global increase in 2023.

The OPEC+ cuts limit overall 2024 growth, the agency said, but non-OPEC production is forecast to rise by 1.5 million bpd, "driven primarily by four countries in the Americas — the United States, Guyana, Brazil and Canada."

Global liquid fuels production is projected to be up 2 million bpd in 2025 on a 0.9 million bpd increase in OPEC+ production as targets expire at the end of 2024, and an additional 1.1 million bpd of production outside of OPEC+.

U.S. vehicle miles traveled are expected to hit an all-time high this year and next based on population employment and economic growth trends, EIA said, but motor gasoline consumption will remain relatively flat through 2025 because of increased fleetwide vehicle fuel efficiency.

Brent prices

The Brent crude oil spot price averaged $82 per barrel last year, EIA said, and is projected to average $87 per barrel this year and $85 per barrel in 2025, a forecast up from February, when the agency forecast Brent to average $82 per barrel this year and $79 in 2025.

This month's forecast has Brent averaging $88 per barrel in the second quarter, up $4 per barrel from the February forecast, and $87 per barrel for 2024. up 5.6% from the previous forecast of $82 and up 6.7% from the February forecast for 2025 ($79) to $85.

The increase in forecast prices is based on extended crude oil production cuts by OPEC+, resulting in lower production growth contributing to "significant global oil inventory declines" for the second quarter.

EIA said its global oil balances forecast and the impact on prices "remain significantly uncertain."

U.S. vehicle miles traveled are expected to hit an all-time high this year and next based on population employment and economic growth trends, EIA said, but motor gasoline consumption will remain relatively flat through 2025 because of increased fleetwide vehicle fuel efficiency.

Henry Hub

EIA expects the Henry Hub spot price to average about $2.25 per million British thermal units this year, down 10% from last year and down 65% from 2022, with low natural gas prices slightly decreasing domestic gas production.

"Some producers have announced curtailments in production or reductions in upstream spending on natural gas-directed activities this year," DeCarolis said. "But with so much domestic natural gas production tied to growing crude oil production, we expect natural gas production to decrease far more slowly than prices have."

The agency is forecasting that Henry Hub will stay under $2 per million Btu in the second quarter because natural gas inventories are projected to remain relatively high compared to the five-year average as natural gas consumption is lower in the shoulder season.

It was a mild winter in the Lower 48, EIA said, with 8% fewer heating degree days than the 10-year average.

Natural gas production

EIA estimates that that U.S. dry natural gas production was almost 104 billion cubic feet per day in February, following a decline to 102 bcf per day in January due to weather-related outages, and expects production to remain near the February level in March and then decline slightly through the rest of the year, "as some producers have announced production curtailments because of low prices."

Average production is forecast to fall to 103 bcf per day by December and then average 104 bcf per day in 2025. \

The agency said it does not expect production to return to the December 2023 record of 106 bcf per day in this forecast period.

While low prices and a relatively stable rig count keep production at a slight decline through the rest of this year, EIA said, it expects it to begin to increase in 2025, as prices are forecast to rise to some $3 per million Btu, and there is an increased demand for liquefied natural gas.

EIA said most U.S. natural gas production is from three regions: the Permian, the Haynesville and Appalachia, with most production growth this year from the Permian, where most natural gas is associated gas from crude oil production. Haynesville production is mostly flat in 2024 because of low prices and a relatively low rig count, the agency said, but increases in 2025 because of Haynesville's relatively proximity to new LNG export facilities. Appalachian basin production is expected to remain relatively flat because of natural gas pipeline capacity constraints. ●

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

OWNER: Petroleum Newspapers of Alaska LLC (PNA)
Petroleum News (ISSN 1544-3612) • Vol. 29, No. 11 • Week of March 17, 2024

Published weekly. Address: P.O. Box 231647 Anchorage, AK 99523-1647
Subscription prices in U.S. — $118.00 1 year, $216.00 2 years
Canada — $206.00 1 year, $375.00 2 years
Overseas (sent air mail) — $240.00 1 year, $436.00 2 years

"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News, P.O. Box 231647 Anchorage, AK 99523-1647.

● EXPLORATION & PRODUCTION

Baker Hughes US rig down by 7 to 622

By KRISTEN NELSON
Petroleum News

Baker Hughes shows Alaska with 13 rotary rigs active March 8, unchanged from the previous week and up by three from a year ago when the count was 10.

The Baker Hughes' U.S. rotary drilling rig count was 622 for the week ending March 8, down by seven rigs from 629 the previous week, and down by 124 from 746 a year ago. The rig count increased in five of the last eight weeks and decreased in three, with a gain of 14 against a loss of 11 over the period, bucking a downward trend dominant since the beginning of May.

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 2023, the count hit its low point Nov. 10 at 616, down from a high of 775 on Jan. 13, 2023. In 2022, the count bottomed out at 588 Jan. 1, reaching a high for the year of 784 on Nov. 23.

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 March 8 count includes 504 rigs targeting oil, down by two from the previous week and down 86 from 590 a year ago, with 115 rigs targeting natural gas, down by four from the previous week and down 38 from 153 a year ago, and three miscellaneous rigs, down by one from the previous week and unchanged from a year ago.

Fifty-two of the rigs reported March 8 were drilling directional wells, 557 were drilling horizontal wells and 13 were drilling vertical wells.

Alaska rig count unchanged

New Mexico (106) was up by three rigs from the previous week.

Texas (291) was down by eight rigs and Louisiana (43) was down by two.

Rig counts in other states were unchanged from the previous week: Alaska (13), California (6), Colorado (16), Kansas (1), North Dakota (32), Ohio (12), Pennsylvania (24), Utah (12), West Virginia (8) and Wyoming (11).

Baker Hughes shows Alaska with 13 rotary rigs active March 8, unchanged from the previous week and up by three from a year ago when the count was 10. Twelve of the Alaska rigs were onshore, up by two from the previous week, with one rig working offshore, unchanged from the previous week.

The rig count in the Permian, the most active basin in the country, was down by two from the previous week at 313 and down by 30 from 343 a year ago. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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HILCORP FINES

AOGCC noted its inspectors did witness three meter proves at Endicott during a trial demonstration period, with the successful demonstration completed in October and associated reports were provided which documented performance of the meters.

AOGCC said Hilcorp provided notice of an opportunity to witness meter proving on Nov. 25, which the commission waived, but said no notice was received of meter proves in December and January.

In its order the commission said there were no mitigating circumstances in Hilcorp's favor, and imposed the proposed $55,000 fine, based on $10,00 for failure to notice the opportunity to witness meter proves — two months at $5,000 each; and $45,000 for failure to submit meter performance reports — three months at $15,000 per month. ●

Contact Kristen Nelson at knelson@petroleumnews.com

THIS MONTH IN HISTORY

Cook Inlet natural gas supply goes short

20 years ago this month: Major industrial gas user Agrium working with exploration companies, might even partner to find more gas

Editor's note: This story first appeared in the March 14, 2004, issue of Petroleum News.

By KRISTEN NELSON
Petroleum News

The fertilizer plant on the Kenai Peninsula south of Anchorage, Alaska, was built to take advantage of a stranded gas situation, as was the liquefied natural gas plant next door: big gas discoveries had been made on the Kenai and in Cook Inlet by companies exploring for oil.

That plant started up in 1969, Bill Boycott, general manager of Kenai Nitrogen Operations for Agrium, told the Resource Development Council in Anchorage March 4, 2004.

Today Agrium, which acquired the Nikiski facility when it purchased Unocal's fertilizer operations in 2000, is struggling in Cook Inlet with both shortages of natural gas to run the plant and with rising gas prices.

"2001 was the last year that the plant operated at full capacity, and that was roughly 53 billion cubic feet" of natural gas for the year.

Last year the plant only got 40 bcf of natural gas," Boycott said.

"In 2004 we're projecting roughly 36 billion cubic feet of gas deliveries to the facility," he said.

Cost of plant written down last year

Agrium, a global producer and marketer of fertilizer based in Calgary, Alberta, wrote down the carrying cost of the Alaska nitrogen facility at the end of last year by $140 million.

Mike Wilson, Agrium's president and chief executive officer, said in a Dec. 2, 2003, statement that the write-down occurred because Unocal failed to meet the plant's natural gas requirements. An arbitration hearing is scheduled to begin in May.

When the sale to Agrium was completed in September 2000, Unocal said its Alaska oil and gas business unit would continue to supply natural gas to Agrium "from certain Cook Inlet fields and other sources pursuant to a 1998 agreement …"

Agrium said in December: "The indicated gas supply from Unocal to the Kenai, Alaska, facility will be insufficient to operate the facility past the end of 2005."

Unocal has made or participated in new gas discoveries on the Kenai and is selling that gas to the local gas distribution company, Enstar Natural Gas, under a contract which bases the price of the gas on a 36-month NYMEX average. Enstar negotiated that contract with Unocal because it was running short of natural gas for its customers (see story in March 7, 2004, issue of Petroleum News.)

Gas supply picture has changed in Cook Inlet

Boycott said he was sure most people were aware that "the gas supply situation has changed in the Cook Inlet." It is still a stranded gas play, he said, but Cook Inlet no longer has long-term stranded gas; now it only has short-term, i.e., Cook Inlet is still not connected to a larger natural gas market, and its supply of gas has dwindled.

"The reality of that is that our future is threatened by that. We've seen the gas availability to our plant decline and we've seen upward pressure on pricing in the Cook Inlet."


BILL BOYCOTT

Agrium's Alaska ammonia and urea competes with producers around the Pacific Rim.

"Gas is far and away the largest component of our cost of production and so as you start looking around the world, and looking at who your competition is and what sets the … value of your product, you're going up against folks that are pulling gas from other stranded gas fields in the world," Boycott said.

Cook Inlet natural gas prices are in the $1.50 to $3 range, he said, but in Indonesia and Malaysia gas is $1-$2 and in Trinidad $1.

"We have to have a large supply of gas at a competitive rate to stay economically viable," Boycott said. Based on forecasts of natural gas availability in Cook Inlet, he said, the economic viability of the Nikiski plant "is threatened beyond the end of 2005, if the picture doesn't change."

Employees have taken over on maintenance

Agrium isn't sitting idly by waiting for Cook Inlet gas to dwindle away, Boycott said.

Over the winter, when the plant could only be operated at 50% of capacity, Agrium reassigned people to maintenance. Within the last two weeks, some of the gas has come back, and "we're now running about 80% of capacity," Boycott said.

The company is trying to find new gas, but if it doesn't succeed, and Agrium closes down, "the Cook Inlet would go from a short position to a long position of gas, and the incentive for exploration would be reduced."

Agrium also brings value to the gas industry because it has a large, stable gas demand, not dependent on weather.

And while there is promising exploration going on in Cook Inlet, and discoveries have been made, "we are still short in the market … We need to see continued exploration and we need to see success."

Price is also a concern, Boycott said: "We're actually seeing pressure towards Lower 48 type pricing, and quite frankly, if we were to see Lower 48 pricing the way it exists today, our business cannot economically exist."

Agrium is "aggressively seeking a solution" on the supply side, Boycott said.

"We are trying to encourage exploration. … I believe we're probably working with everybody who is or has the potential to produce natural gas in the Cook Inlet."

Agrium is also concerned that independents have access to pipelines to move their gas, he said, and access at reasonable rates. "And so we're interested in ensuring that we have reasonable pipeline tariffs, that we have reasonable access to pipelines."

see HISTORY page 7

JUDY PATRICK

The Alpine field on Alaska's North Slope, from March 7, 2004, issue.

● THIS MONTH IN HISTORY

Phase 2 of Alpine capacity expansion approved

20 years ago this month: Output at ConocoPhillips Alaska-operated western North Slope field to go from 100,000 to 140,000 bpd

Editor's note: This story first appeared in the March 7, 2004, issue of Petroleum News.

By KRISTEN NELSON

Petroleum News

ConocoPhillips and Anadarko Petroleum Corp. said March 3, 2004, that they will increase oil production capacity at the Alpine field on Alaska's North Slope to 140,000 barrels of oil per day (gross). The field, which started production in November 2000, currently produces some 100,000 bpd.

The companies said phase 2 of the Alpine capacity expansion project, or ACX2, will be completed by mid-2005.

This expansion will increase both the oil handling and seawater injection capacities at Alpine.

The project is expected to cost $58 million (gross) and follows the previously announced ACX1 project, which will start up later this year. The companies said more than 300 Alaskans are employed across the state on the construction and fabrication phase of the two projects. ACX1, approved in May 2003, increases production capacity from 100,000 bpd to 105,000 bpd.

"Many of the modules are already under construction and the first truckable modules will be arriving on the slope this winter," ConocoPhillips Alaska spokeswoman Dawn Patience told Petroleum News March 3. Both projects increase production from the Alpine field, and do not address potential additional production from Alpine satellites, she said.

There are eight truckable modules in the two projects, Patience said, with the majority going to the Slope this winter.

The two expansion projects will increase oil production and maintain reservoir pressure. Eighty-one wells, 39 production wells and 42 injection wells, have been drilled to date, the companies said, with 94 wells in total planned for the two Alpine drill sites. Alpine has been developed exclusively with horizontal well technology and employs enhanced oil recovery.

"The field's unique design and use of EOR will help extract more oil from the reservoir," the companies said in a statement.

The 40,000-acre Alpine field was developed on just 97 acres, the companies said, two-tenths of 1% of the surface area. The field is a "near-zero discharge facility," with waste generated at the field "reused, recycled or properly disposed."

There is no permanent road to Alpine.

Instead, ice roads are constructed each winter for the transportation of equipment and drilling supplies. Small aircraft also provide service to the field.

ACX1 and ACX2 contractors include NANA/Colt Engineering LLC, VECO Alaska Inc., ASRC Energy Services, Nanuq Inc., Steelfab, Flowline, The Weld Shop and Parsons Energy and Chemical.

ConocoPhillips Alaska operates the Alpine field, owned 78% by ConocoPhillips and 22% by Anadarko Petroleum. Alpine was declared commercial in 1996 and is the largest onshore oil field discovered in the United States in more than a decade, the companies said. It is the western-most producing oil field on Alaska's North Slope, some 34 miles west of the Kuparuk River field in the Colville River area near the border of the National Petroleum Reserve-Alaska. ●

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HISTORY

Agrium might even look at partnering in exploration

Chris Tworek, Agrium's Calgary-based vice president of supply and management, told Petroleum News that Agrium is looking at several ways to work with companies who want to explore for new supply.

The easiest thing is a commercial contract, Tworek said, but Agrium will take "any version of a take or pay contract," anything that will provide supply security.

"We'll even prepay for the gas to allow the producer to use the prepay to do his development."

Agrium is also working with producers to see if there is "a way of actually participating in the venture, and that's where we do some sort of farm-in type situation," Tworek said, "some sort of situation where we'll put in some of the capital to de-risk his exploration effort" in exchange for a contract assigning the gas to Agrium. "And so it's a bit of a pre-buy."

A third option, Tworek said, would be for Agrium to get "directly involved in exploration and production." It's not the company's area of expertise, he said, "so we're stepping outside of our core competency," but "in Alberta we do have a small oil and gas company." If Agrium exercised that option, it would probably be looking at a partnership, "preferably with a little more experienced operator," and "what we bring to the party is some capital and what we also bring is a take-away gas contract."

Chris Tworek, Agrium's Calgary-based vice president of supply and management, told Petroleum News that Agrium is looking at several ways to work with companies who want to explore for new supply.

Tworek agreed that Agrium has talked to everyone working in Cook Inlet.

"There is no one in Cook Inlet that we have not talked to," he said. "… We've talked to people who have reserves, who've got a developed track record of exploration and production, and we've talked to people who've got more ideas than money, so we've covered the gamut. ●

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ENERGY STANDARD

the potential impacts on electricity costs and reliability. The Regulatory Commission of Alaska formed a docket to gather information relevant to the proposed RPS and in December passed a motion opposing the proposal.

Neither of the RPS bills has yet been reviewed during the current legislative session.

A different approach

The proposals in HB368 differ significantly from the proposed RPS. Firstly, the clean energy standard would include nuclear power and generation using low sulfur coal, as well as renewable energy sources such as wind, solar, tidal and geothermal energy. If power generation produces carbon dioxide, the carbon dioxide emissions would need to be offset by an amount of carbon dioxide absorbed or removed from the atmosphere. Secondly, the implementation targets for the proposed clean energy standard are less aggressive than those in the RPS. Thirdly, it would be possible for the Regulatory Commission of Alaska to waive the clean energy standards under specific extenuating circumstances, including the absence of an electricity transmission system that is capable of supporting the clean energy goals. And fourthly, under the clean energy standard utilities could gain tax credits by achieving the required goals, rather than being financially penalized for not meeting the goals. One concern about the penalties associated with the RPS relates to the question of how the utilities would recover the associated costs.

During the March 7 House Resources meeting Brandon Spanos, acting director for the Department of Revenue Tax Division told the committee that at this stage the department did not yet have an estimate of the impact on state revenues of the tax credits proposed in the bill.

Perspectives of electricity utilities

Daniel Heckman, regulatory manager for Fairbanks based Golden Valley Electric Association, told the committee that, while GVEA has yet to adopt a formal position on HB 368, he does think that the bill has addressed many of the concerns associated with the RPS bills. For example, the target dates in HB 368 are much more achievable than those in the proposed RPS. GVEA is also pleased that the proposed legislation recognizes the need to build out an adequate transmission system, Heckman said.

Keriann Baker, chief strategic officer for Homer Electric Association, characterized HB 368 as “a step in the right direction.” She particularly commended the removal of the penalties associated with the RPS, saying that HEA would have to pass on the penalty costs to its members, some of whom would be struggling to afford them.

HEA is especially concerned about its high level of dependence on Cook Inlet gas, most of which comes from a single supplier. The utility has been seeking ways of diversifying its energy sources, while also recognizing that generation technologies are changing rapidly. And HEA has adopted a policy requiring the utility to become more fuel and energy diverse, Baker said.

Baker also commented on the limitations of only having a single transmission line that connects the Kenai Peninsula electrical system with the rest of the Railbelt. But, with a relatively small population, there is a significant issue with how to recover the cost of any major transmission system upgrade, she suggested. On the other hand, it should be possible to transmit electrons across the entire Railbelt, to be able to achieve economies of scale and to be able to buy power at the lowest cost.

Julie Estey, chief strategy officer for Matanuska Electric Association, said that MEA already has its own goal of achieving 50% clean energy by 2050. The utility supports the manner in which HB 368 specifies attainable goals that align quite closely with MEA’s own goals, she said.

“MEA is supportive of a clean energy standard with incentives that can be a catalyst for change and not set up to fail,” Estey said.

MEA views these goals as realistic but also an aspirational stretch because of a number of factors, including the limitations of the existing electric system, the realities of rate making, the current regulatory and permitting environment, and the harsh environment in Alaska, she commented.

Estey expressed MEA’s support for a number of provisions within the bill, including a recognition that energy efficiency and the renewable energy production by consumers can offset some use of natural gas fueled power generation. And the proposed tax credits are a creative means of incentivizing change, she said.

In terms of the inclusion of coal within the clean energy specification, Estey commented that coal fueled generation could have a lower environmental impact and lower cost than the import of liquefied natural gas.

Both Estey and Baker commented that the cost of renewable power is now becoming competitive with natural gas fueled power generation. At the same time, power supply reliability is essential to everyone. The clean energy standard could be a catalyst for an energy transition, Estey said.

Given the critical importance of the transmission system to the future of reliable, affordable and diverse energy supplies in the Railbelt, Estey strongly urged the Legislature to provide the necessary matching funds for a recently awarded $206-million Department of Energy grant for building a second transmission line from the Kenai Peninsula to the Anchorage region. The state has recently applied for a further federal grant for upgrading the transmission line from Southcentral up to Fairbanks, she said. Estey characterized the federal funding as a once in a generation opportunity. ●

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INLET ENERGY

exploration costs.

Beyond that is a tranche of undiscovered but technically recoverable gas, which has research and development costs and is pegged at more than $25 per mcf, which means, King said, it is only recoverable at a price higher than the market would bear.

Survey results

What is the view of residents who rely on Cook Inlet gas and pay for it in their utility bills?

Jepsen reviewed results of a survey of Southcentral residents done for Enstar by Dittman Research this past summer.

It showed that while 54% of respondents were aware of an upcoming natural gas shortage, only 1% were aware that importing natural gas was being considered. Jepsen said that may have been because the survey was taken before there was general awareness of options the utilities were considering.

On the issue of who is responsible for ensuring uninterrupted gas supply, he said 41% of residents believe the responsibility lies with government, while 25% said the utilities were responsible and 16% put the primary responsibility on oil and gas companies.

There was strong support for incentives to spur exploration and production in Cook Inlet, 59%, and significant opposition, 72%, to importing natural gas, although 60% would support imports if they were the cheapest option.

There was 87% support for a pipeline to deliver North Slope gas for in-state use, but an even split (49% each), supporting and opposing reducing the permanent fund dividend to help fund such a project.

Alternatives

Jepsen said the state would need to decide if it is willing to accept higher cost energy with lower risk or lower-cost energy with higher risk.

Supply could be increased through a reduction in taxes and royalties, by providing subsidies, shifting risks, offering “patient capital” — public or angel investor capital paid back over a longer period of time— or by decreasing demand by substituting electricity generation, using alternative heating fuel, increasing efficiency or restricting growth.

Then there is LNG.

The Kenai LNG facility could be converted into a gasification facility to receive small LNG shipments, Jepsen said, with some 1.5 bcf of storage available in above ground tanks. More storage could be added and, he said, underground storage is available, with Senate Bill 220 providing the Regulatory Commission of Alaska authority to regulate natural gas storage facilities.

LNG imports could start as a short-term solution, but if importing LNG is the state’s long-term response to the Cook Inlet gas shortage it could also work in the long term.

But McKay warned that getting on the LNG path drives local gas producers to the side and, he said, could snuff out Cook Inlet gas.

He described decisions facing the state as deciding what path you’re on — and if you’re willing to stay on it — because the result could be driving Cook Inlet investors out.

Jepsen said the goal of House Bill 387, jack-up rig credit, is to get a second jack-up rig in Cook Inlet, one with the capability to drill into deeper south Cook Inlet areas than the existing Spartan 151, which is booked for the foreseeable future.

HB 388, reserve-based lending, would allocate state dollars to a dedicated fund to invest in Cook Inlet, which could be in the form of a loan or a loan guarantee.

On royalty and tax decreases, Jepsen said the market has spoken — under current tax and royalty structure Cook Inlet is not ideal for investment.

He said while current bills are a step in the right direction, the state could do more to improve project economics and attract investment, especially with a goal of increasing gas production, which has a lower return than oil.

HB 223 would provide 0% royalty on new gas, 50% reduction in royalty on new oil.

In discussing aggressive royalty and tax reductions, Jepsen said while the North Slope represents billions in revenues to the state, Cook Inlet represents only tens of millions, and if imported LNG were used — and the cost was high— the impact on the ratepayer would be high.

And on the alternative of North Slope gas, HB 222 would allow investment of funds from the Alaska Permanent Fund to achieve 25% ownership of a gas pipeline from the North Slope. ●

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OIL PRICES

unknown, March 13, 1968, will live in history; it was the day the Atlantic Richfield Co. and Humble Oil and Refining Co. made headlines with the discovery of oil at Prudhoe Bay on the North Slope.

March 12, 2024, marks the 56th anniversary of the discovery. The first measured oil flow — 1,152 barrels per day — from the Prudhoe Bay State #1 well came March 12, 1968.

Prudhoe Bay came on stream June 20, 1977.

U.S. commercial crude oil inventories for the week ended March 8 — excluding Strategic Petroleum Reserve supplies — fell by 1.5 million barrels from the week prior, to 447.0 million barrels — 3% below the five-year average for the time of year, the EIA reported March 13.

Total motor gasoline inventories decreased by 5.7 million barrels for the period to 234.1 million barrels — 3% below the five-year average for the time of year, the EIA said.

Ukraine's reported successful attacks on Russian energy infrastructure and continued uncertainty around the Israel-Hamas war also contributed to the jump in prices, which were already moving higher prior to the EAI report, analysts said.

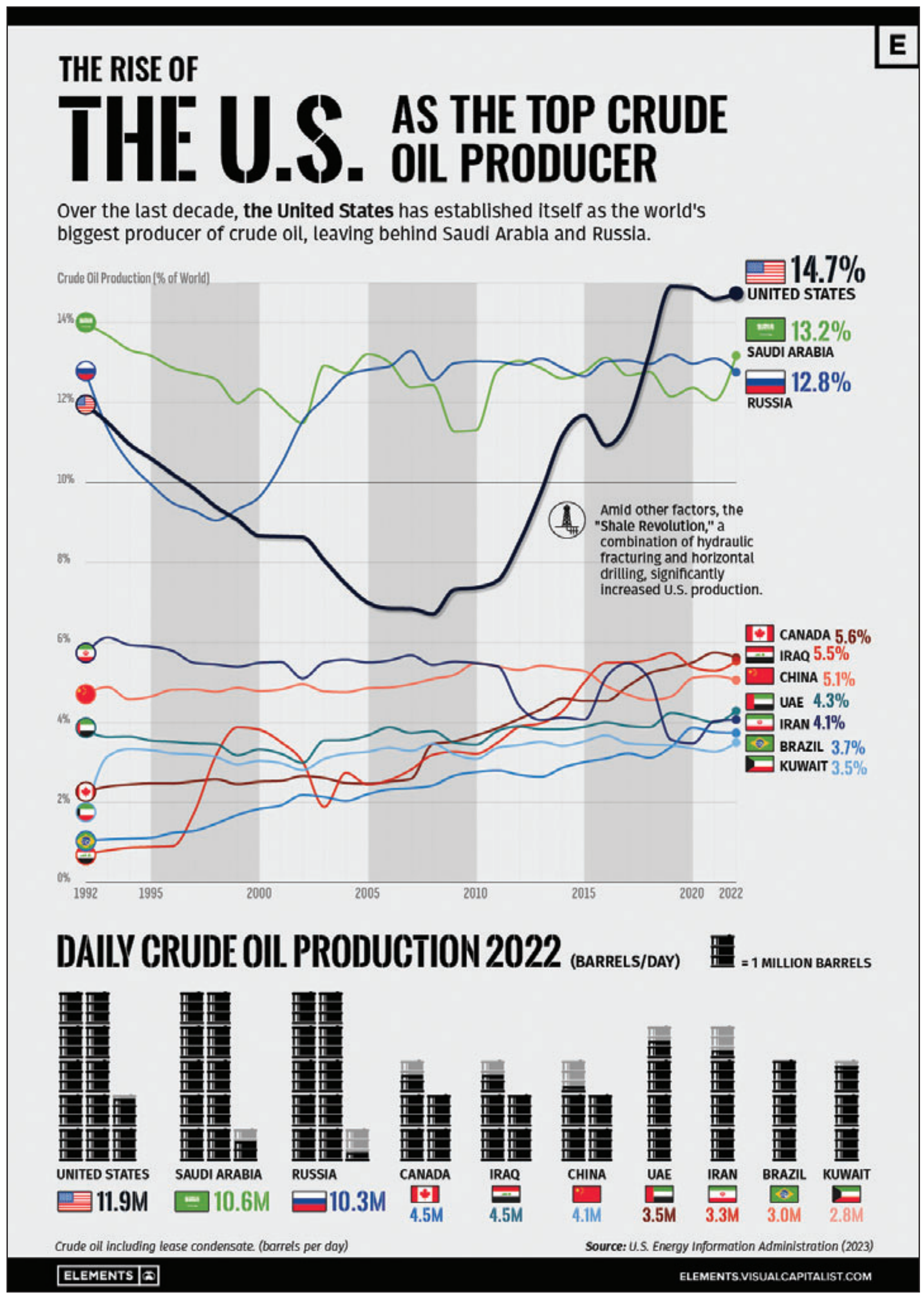
Ukrainian drones struck a Rosneft refinery in the Ryazan region some 130 miles from Moscow on March 13, followed by strikes on the Novoshakhtinsk refinery in the Rostov region.

On March12, Ukraine hit a Lukoil refinery in Nizhny Novgorod, 265 miles from Moscow.

The damage may cause Russia to import fuel for domestic use.

A full repair of the facilities normally would take a couple of months, but sanctions have tightened Moscow's access to Western parts, the Wall Street Journal reported.

Russia has sourced some Western parts from third countries, but the process is complicated and slow, especially for specialized parts, WSJ said, adding that



Russian and Chinese equivalents are sometimes incompatible.

Russia has already cut exports of fuel, and while the United States doesn't allow imports of Russian petroleum products, the Russian deficits could indirectly cause higher U.S. fuel prices. ANS edged 2 cents lower March 12 to close at $81.73, as WTI fell 37 cents to close at $77.56 and Brent fell 29 cents to close at $81.92.

Oil traders were wary of hot U.S. inflation data and the specter of delays in Federal Reserve rate cuts that had been expected in June.

On March 11 ANS gained 17 cents to close at $81.75, WTI fell 8 cents to close at $77.93 and Brent added 13 cents to close at $82.21.

ANS dropped 89 cents March 8 to close at $81.58, while WTI dropped 92 cents to close at $78.01 and Brent dropped 88 cents to close at $82.08.

ANS added 13 cents March 7 to close at $82.47, as WTI turned in a 20-cent loss to close at $78.93 and Brent was unchanged at $82.96.

The Organization of the Petroleum Exporting Counties raised its world economic growth forecast for 2024 to 2.8%, while its economic growth forecast was unchanged at 2.9% for 2025. Its U.S. economic growth forecast for 2024 was revised up to 1.9%, as the "healthy momentum from 2H23 is expected to continue," it said in the March Monthly Oil Market Report issued March 12.

OPEC maintained its forecast that world oil demand will increase by 2.25 million barrels per day in 2024 and by 1.85 million bpd in 2025.

Non-OPEC liquids production in 2024 is expected to grow by 1.1 million bpd, slightly revised down from the previous month's assessment.

"In 2024, the main drivers for liquids supply growth are expected to be the U.S., Canada, Brazil and Norway, while the largest declines are anticipated in Russia and Mexico," OPEC said.

The United States produced more crude oil than any nation at any time, for the past six years in a row, the EIA said in a March 11 report.

U.S. crude production averaged 12.9 million bpd in 2023, breaking the U.S. and global record of 12.3 million bpd, set in 2019, the EIA said. Average monthly U.S. oil production established a record in December 2023 at more than 13.3 million bpd.

The production record is unlikely to be broken in the near term because no other country has reached production capacity of 13.0 million bpd, EIA said. Saudi Aramco scrapped plans to increase production capacity to 13.0 million bpd by 2027.

Together, the United States, Russia, and Saudi Arabia accounted for 40% (32.8 million bpd) of global oil production in 2023. The three countries have produced more oil than any others since 1971.

The next three largest producing countries — Canada, Iraq, and China — combined produced 13.1 million bpd in 2023. ●

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HICKORY-1 WELL

knowledge of multiple flow tests on adjacent acreage.

Results from the Upper SFS reservoir will be available on completion of flow back activities, 88 Energy said.

The Hickory-1 well is located within 88 Energy's Project Phoenix acreage, directly adjacent to the Trans-Alaska Pipeline System and the Dalton Highway.

The Upper SFS will be the first zone tested followed by the SMD-B zone. Each zone will be independently isolated, stimulated and flowed to surface using nitrogen lift to assist in the efficient clean-up of the well.

Although as mentioned the entire program for each zone is expected to take approximately 10 days, 88 Energy may choose to adjust the schedule during the flow back program to ensure optimal data collection.

Extensive suite

An extensive suite of data will be captured, including but not limited to downhole and surface fluid samples, downhole pressure and temperature data, surface pressure and temperature data. Flow rates of oil, gas and water will also be recorded.

The entire testing program is scheduled for completion during March 2024.

The March 10 announcement was authorized by the company's board, including Ashley Gilbert, Managing Director.

See map on page 11

Approval on Nov. 30

As reported in the Dec. 10 issue of Petroleum News, on Nov. 30, an operating subsidiary of 88 Energy received approval for the Toolik River unit, Hickory 1, frac and flow testing unit plan of operations amendment from the Alaska Department of Natural Resources' Division of Oil and Gas.

The Toolik River unit or TRU, is approximately 30 miles south of Deadhorse in oil and gas lease 392314.

88 Energy planned to build a 500-foot by 500-foot ice pad connected to the Dalton Highway by a 400-foot by 35-foot ice road, with a total footprint of approximately six acres.

All buildings used for the project were to be temporary.

Ultra-low sulfur diesel fuel will be trucked to the project site by commercial carriers and stored in four 9,980-gallon tanks on pad as needed to support operations.

Spill response equipment will be staged on location and managed by an onsite spill technician contracted through Alaska Chadux Corp.

Stick picking and site inspection will occur during the following summer.

Tundra travel and ice construction will be permitted separately through LAS 34367.

Plan activities include the following:

•Construct ice pad and driveway
•Re-enter Hickory 1 well
•Frac and flow tests
•Stick picking
•Closeout site inspections

The Nov. 30 approval letter was addressed to Gilbert.

Pantheon: Talitha, Alkaid

In an Oct. 12, 2023, ASX release, 88 Energy said it remains very encouraged by the progress of its neighbor to the north of Project Phoenix, Pantheon Resources (operated by Great Bear), which recently announced a "material, independently certified contingent resource for the Lower Basin Floor Fan, or BFF, reservoir," noting that the BFF reservoir was the deepest of the multiple hydrocarbon-bearing pay zones intersected as part of the Hickory-1 exploration well.

Four of the wells drilled in 2022 were drilled by Great Bear Pantheon. The company completed the Alkaid 2 well in its Alkaid discovery, together with a near vertical pilot hole for that well. The company also drilled a pilot hole in its Talitha prospect and drilled its Theta West 1 exploration well. All of these wells were drilled near the Dalton Highway, south of Prudhoe Bay.

—KAY CASHMAN

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MILNE EXPANSION

ADL 355021, are net profit share leases.

Hilcorp earlier applied to the Alaska Oil and Gas Conservation Commission for a smaller expansion to the northwest of the existing Schrader Bluff oil pool as described in AOGCC Conservation Order 477. (See story in Jan. 23 issue of Petroleum News.)

The AOGCC request lists four affected leases, two of which coincide with the six leases in the unit application expansion.

In addition to being a larger expansion, the unit expansion request includes both Kuparuk and Schrader Bluff reservoirs.

Proposed drilling

Hilcorp told the division it proposes to drill 10 wells in the expansion area this year and next, three Kuparuk formation wells — one from K Pad and two from F Pad — and seven Schrader Bluff wells, all from R Pad. The company told the division an additional 18 wells targeting Schrader Bluff across two leases, ADL 355018 and ADL 355021, are planned by the end of 2008.

Both of those leases are listed in the Schrader Bluff expansion request to AOGCC.

F Pad and R Pad are in the northern expansion area, with R Pad currently under construction.

K Pad is in the southern expansion area. The most recent work at that pad was approval earlier this year of a Hilcorp proposal to install a 6-inch FlexSteel line inside an existing abandoned 14-inch line from SK Junction to K Pad. The new line will bring high-pressure water to K Pad for injection and production support. That project was approved in January and is expected to be completed by April.

AOGCC production data for January shows K Pad production all coming from the Kuparuk River oil pool.

Previous drilling

Hilcorp listed four wells previously drilled in the northern area of the proposed expansion and said there has been no drilling in the proposed expansion area in the southeast.

Exploration activity in the northern expansion area occurred between 1992 and 2004.

NW Milne 1 was drilled in 1992. Hilcorp said the well "logged oil to the base of the Kuparuk sands."

In 1996, N Milne 1 and N Milne 2 were drilled, with N Milne 1 logging oil to the base of the Kuparuk sands while N Milne 2 found those sands to be wet.

Nikaitchuq 2, drilled in 2004, did not encounter Kuparuk sands, Hilcorp said.

The first three wells found the Schrader Bluff interval to be wet.

The fourth well, Nikaitchuq 2, logged an oil water contact at 4,171 feet true vertical depth, "marking the northern extent of the oil in the Schrader Bluff Oil reservoir in the main fault block of the expansion area," Hilcorp said.

Nikaitchuq 2 was not tested, while the other three primarily targeted the deeper Kuparuk, "with the intent to try to determine the extent of the oil accumulation."

—KRISTEN NELSON

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RAILBELT BILL

transmission of power across multiple sectors of the system uneconomic, because of the manner in which the fees charged by individual utilities stack up. Instead, under the terms of the new bills, a new transmission cost recovery mechanism would involve a tax that each independent power producer and electric cooperative would pay, based on the amount of electricity that each of these entities generates. Independent power producers would also become exempt from paying local taxes, in a similar manner to nonprofit electric cooperatives.

Moving cheap power

Gwen Holdman, University of Alaska Fairbanks Associate Vice Chancellor for Research, Innovation & Industry Partnerships, told the committee that the transmission issues revolve around moving cheap power to consumers, wherever they are located, from whatever sources are available. And she characterized the current Railbelt transmission system as being "kind of in the dark ages." The expectation is that future power supplies will involve much more movement of power between different regions of the Railbelt — power generation systems benefit from economies of scale, a factor that drives the need to be able to viably ship power to wherever it is needed.

For example, were a major geothermal energy project to be constructed at Mount Augustine in Cook Inlet, Golden Valley Electric Association in Fairbanks would likely want to be able to make use of some of that power, Holdman suggested.

MEA and the neighboring Chugach Electric Association are operating an economic dispatch arrangement in which they minimize electricity costs through shared use of their most efficient power generation.

Transmission system upgrades needed

Tony Izzo, chief executive officer of Matanuska Electric Association, told the committee that a top priority recommendation from the Railbelt subcommittee of the governor's Energy Security Task Force had been the need to upgrade and unify the Railbelt transmission system. The wheeling and pancaking of transmission fees, together with significant limitations in the capacities of transmission interties between different regions of the Railbelt, constrain the possibilities for utilities to use the lowest cost power generation in the system.


TONY IZZO

On the other hand, the utilities are cooperatives that have systems that are built under the constraints of what their members can afford, without shareholders to provide investment dollars, Izzo said.

Economic dispatch

MEA and the neighboring Chugach Electric Association are operating an economic dispatch arrangement in which they minimize electricity costs through shared use of their most efficient power generation. As part of this arrangement, the utilities do not charge each other wheeling fees for use of their transmission systems, Izzo said.

If the current constraints in the use of the major transmission interties could be eliminated, the whole Railbelt could benefit from a similar arrangement, he commented. Izzo also commented that federal grants for upgrading the transmission system, together with required state matching funds, could make possible the construction of a system that could lower electricity costs by enabling the development of large-scale renewables while also improving supply reliability.

A critical point

John Burns, chief executive officer of Fairbanks based Golden Valley Electric Association, told the committee that the Railbelt electrical system has reached a critical point, with a need for transformative change. The requirement to make it possible to viably move low cost electrons from relatively large scale generation sources to wherever they are needed, without constraint, will require appropriate legislation, he said.


JOHN BURNS

"We should be agnostic as to where generation sources are located," Burns said.

—ALAN BAILEY

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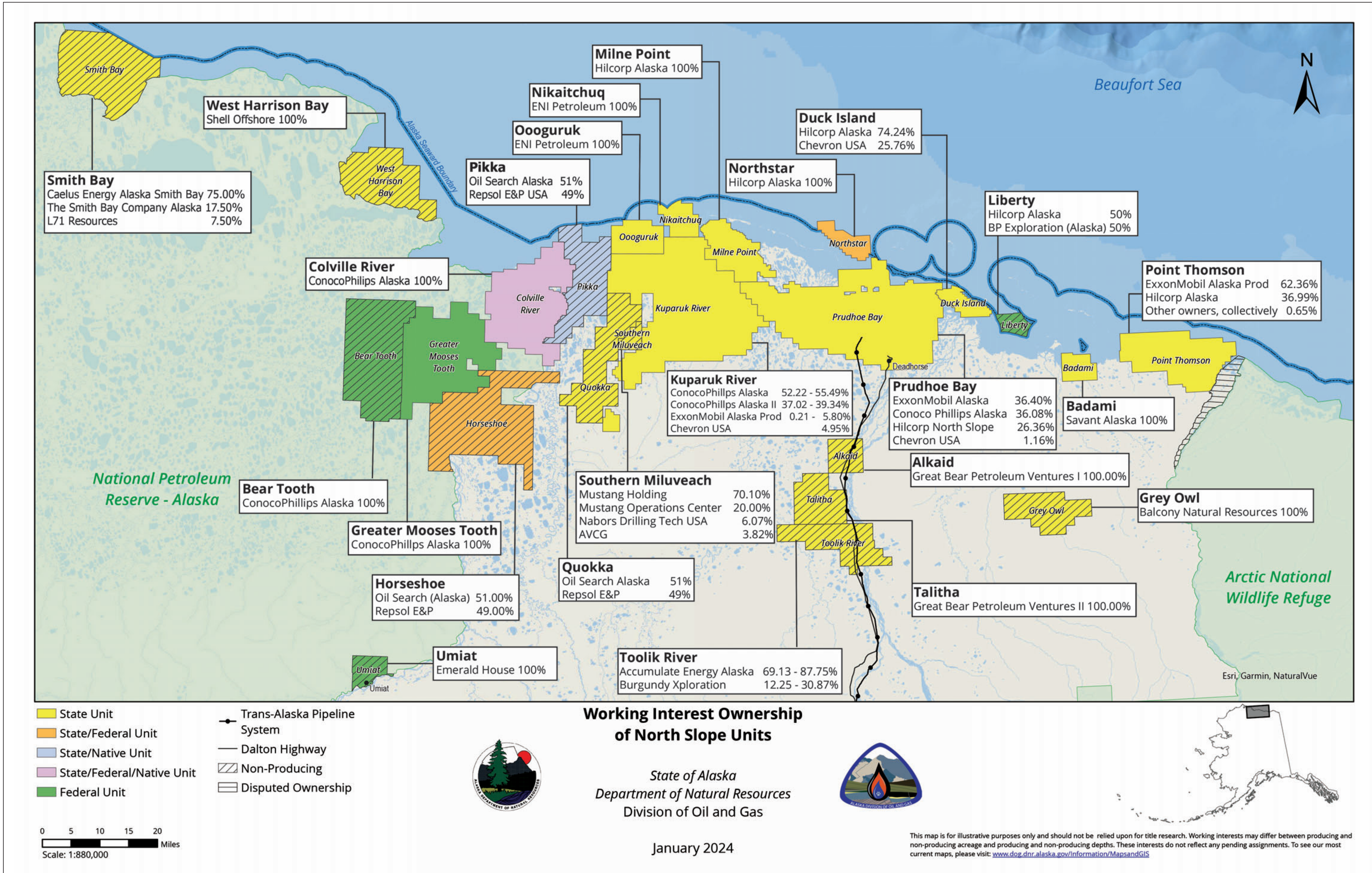
Smith Bay
Smith Bay
Caelus Energy Alaska Smith Bay 75.00%
The Smith Bay Company Alaska 17.50%
L71 Resources 7.50%
West Harrison Bay
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West Harrison Bay
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Nikaitchuq
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Milne Point
Hilcorp Alaska 100%
Oooguruk
ENI Petroleum 100%
Pikka
Oil Search Alaska 51%
Repsol E&P USA 49%
Duck Island
Hilcorp Alaska 74.24%
Chevron USA 25.76%
Northstar
Hilcorp Alaska 100%
Beaufort Sea
N
Liberty
Hilcorp Alaska 50%
BP Exploration (Alaska) 50%
Point Thomson
ExxonMobil Alaska Prod 62.36%
Hilcorp Alaska 36.99%
Other owners, collectively 0.65%
Colville River
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Pikka
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Nikaitchuq
Milne Point
Northstar
Kuparuk River
Prudhoe Bay
Duck Island
Liberty
Southern Miluveach
Bear Tooth
Greater Mooses Tooth
Quokka
Horseshoe
Deadhorse
Badami
Point Thomson
Kuparuk River
ConocoPhillips Alaska 52.22 - 55.49%
ConocoPhillips Alaska II 37.02 - 39.34%
ExxonMobil Alaska Prod 0.21 - 5.80%
Chevron USA 4.95%
Prudhoe Bay
ExxonMobil Alaska 36.40%
Conoco Phillips Alaska 36.08%
Hilcorp North Slope 26.36%
Chevron USA 1.16%
Badami
Savant Alaska 100%
Alkaid
Alkaid
Great Bear Petroleum Ventures I 100.00%
National Petroleum Reserve - Alaska
Bear Tooth
ConocoPhillips Alaska 100%
Southern Miluveach
Mustang Holding 70.10%
Mustang Operations Center 20.00%
Nabors Drilling Tech USA 6.07%
AVCG 3.82%
Talitha
Grey Owl
Grey Owl
Balcony Natural Resources 100%
Greater Mooses Tooth
ConocoPhillps Alaska 100%
Toolik River
Horseshoe
Oil Search (Alaska) 51.00%
Repsol E&P 49.00%
Quokka
Oil Search Alaska 51%
Repsol E&P 49%
Talitha
Great Bear Petroleum Ventures II 100.00%
Arctic National Wildlife Refuge
Umiat
Umiat
Umiat
Emerald House 100%
Toolik River
Accumulate Energy Alaska 69.13 - 87.75%
Burgundy Xploration 12.25 - 30.87%
Esri, Garmin, NaturalVue
State Unit
State/Federal Unit
State/Native Unit
State/Federal/Native Unit
Federal Unit
Trans-Alaska Pipeline System
Dalton Highway
Non-Producing
Disputed Ownership
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Scale: 1:880,000
Working Interest Ownership of North Slope Units
State of Alaska
Department of Natural Resources
Division of Oil and Gas
January 2024
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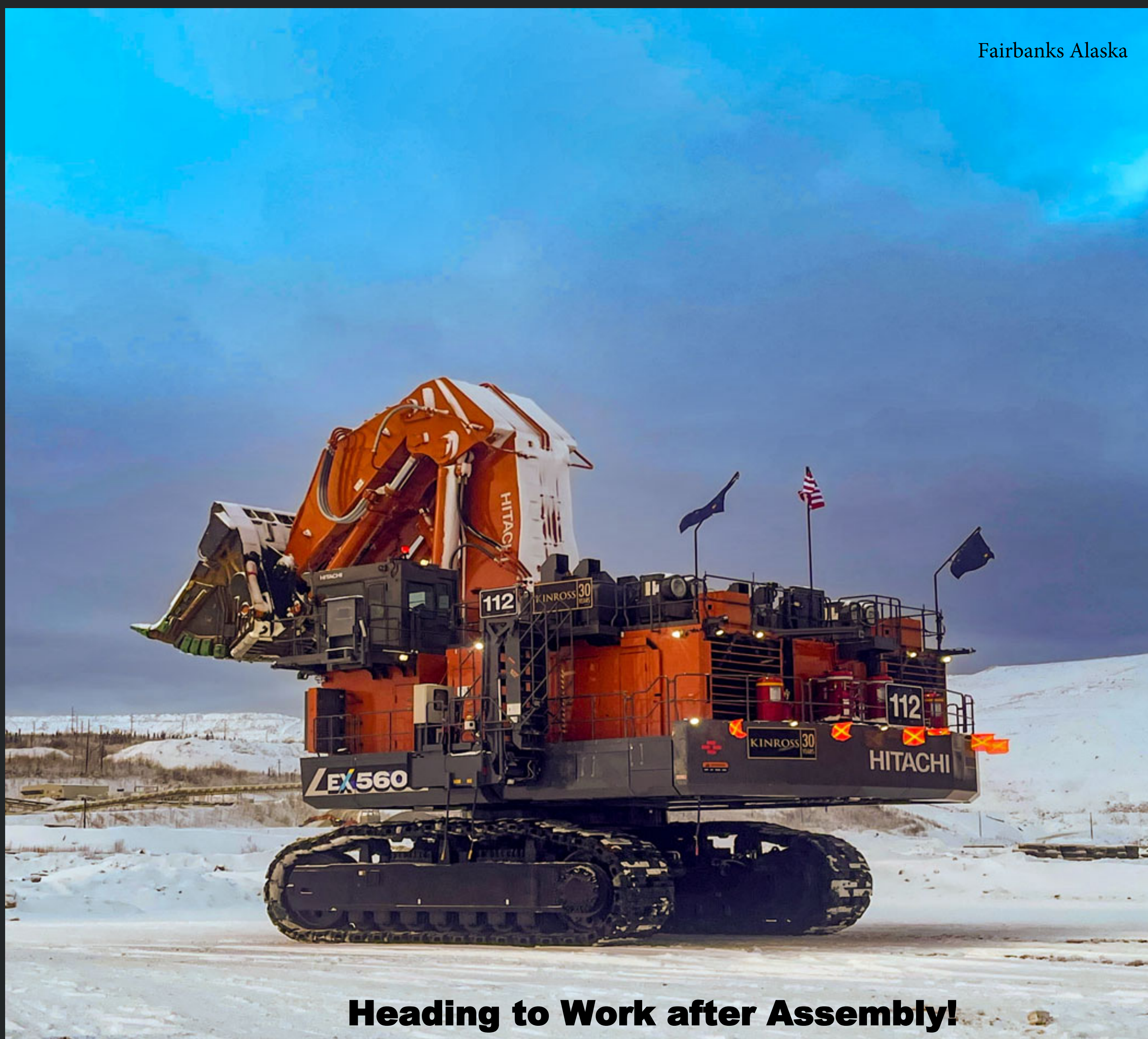

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