Petroleum news

page 2 Erin Campell named new DGGS director, state geologist

Vol. 30, No. 34 • www.PetroleumNews.com *A weekly oil & gas newspaper based in Anchorage, Alaska* Week of August 24, 2025 • $2.50

Interior has 6 Cook Inlet sales on new offshore leasing schedule

The U.S. Department of the Interior said Aug. 19 that it will offer at least 30 lease sales in the Gulf of America and six in the lower Cook Inlet from 2025 through 2040. The lower Cook Inlet sales are all slated for March, and will occur in 2026, 2027, 2028, 2030, 2031 and 2032.

DOUG BURGUM

Interior Secretary Doug Burgum called it "a bold, long-term program that strengthens American Energy Dominance, creates good-paying jobs and ensures we continue to responsibly develop our offshore resources."

In its announcement Interior said: "Alaska plays a vital role in America's energy future, and Cook Inlet, along Alaska's southcentral coast near Anchorage, is the center of that opportunity."

The Bureau of Ocean Energy Management lists 11 active leases in Alaska outer continental shelf waters — three off the North Slope, all in production, and eight in the lower Cook Inlet, one of which, from the most recent sale, is shown with a suspension expiration date; the other seven expire Sept. 30, 2027. Hilcorp

see **INLET SALES** *page 10*

AOGCC tells CIE to upgrade/replace Badami equipment or pay

The Alaska Oil and Gas Conservation Commission has fined Cook Inlet Energy, operator of leaseholder Savant Alaska's Badami unit, $357,905 for flaring produced gas at Badami from October 2024 through March of this year. The commission said the amount is based on its regulations which specify a fine of twice the fair market value for the more than 51 million cubic feet of gas flared and only allow preapproval of flaring for testing prior to production.

DAVID PASCAL

CIE reported the flaring to AOGCC and requested authorization for the flaring based on safety considerations.

The flaring occurred due to a non-functioning vapor recovery unit for which CIE had no backup. The commission said CIE also identified significant inefficiency in the plant's eductor system,

see **BADAMI EQUIPMENT** *page 10*

Tiri-1 exploration well in works for winter 25/26, testing 26/27

Captivate Energy Alaska Inc., a wholly owned subsidiary of 88 Energy Ltd., recently filed an application with the Alaska Department of Environmental Conservation for an Oil Discharge Prevention and Contingency Plan.

ASHLEY GILBERT

The onshore project area is within Captivate Energy's state of Alaska oil and gas Leonis lease where the company plans to drill, complete and suspend the Tiri-1 exploration well in the winter of 2025/2026.

The well test, consisting of fracturing with flow back, will be executed in winter 2026/2027.

Tiri-1 will be drilled to about 11,000 feet to sample and test stacked conventional objectives within the Schrader Bluff, Canning, Kuparuk and Ivishak formations.

see **TIRI-1 WELL** *page 10*

FINANCE & ECONOMY

$60s: ANS rangebound

Potentially pivotal possibilities, but no catalyst for big price move

By STEVE SUTHERLIN
Petroleum News

Alaska North Slope crude spent a second consecutive trading week rangebound in the upper $60s despite a series of discussions for peace in the Russia/Ukraine conflict, with potential outcomes that could lead to significant shifts in oil markets.

ANS fell 62 cents Aug. 19 to close at $67.84 per barrel, just 45 cents below its close of $68.28 on Aug. 12. West Texas Intermediate fell $1.07 on the day to close at $62.35 and Brent fell 81 cents to close at $65.79.

Initial progress has been made in the Russia/Ukraine talks; the key variables now are in for a period of uncertainty with cloudy timeframes. A lasting peace agreement will entail balancing a plethora of concerns for the combatants, as well as for the United States and The European Union.

> ***"Not so sure about the peace deal — will have to see if something moves forward over the coming days … It seems oil prices are thrown down one day, followed by a rebound the next," said Giovanni Staunovo, a UBS analyst quoted in an Aug. 20 Reuters report.***

see **OIL PRICES** *page 9*

EXPLORATION & PRODUCTION

13th Cosmo POD filed

BlueCrest, DNR working closely with confidential third-party investor

By KAY CASHMAN
Petroleum News

In 1967, Pennzoil first discovered oil in what is now the Cosmopolitan unit of the Cook Inlet basin. Subsequent operators ARCO, ConocoPhillips and later Pioneer Resources further explored the Cosmopolitan resources.

JOHN M. MARTINECK

Over the decades none of these company operators have been able to solve the development challenges of the Cosmopolitan oil resources.

In 2012, BlueCrest acquired ADLs 384403 and 18790 from Pioneer and subsequently acquired the other two leases from Apache.

In 2013, BlueCrest drilled one of the first offshore Cook Inlet wells that not only confirmed the presence of a large oil deposit but also discovered the huge Tyonek gas field.

BlueCrest has created a new innovative drilling and development approach that allowed for economic development of the Cosmopolitan Unit's, or CU's, oil resources.

Prior to BlueCrest's operatorship, potential development plans included cost-prohibitive and record length horizontal wells drilled from onshore that would have resulted in ineffective oil recoveries using conventional completion

see **COSMO POD** *page 11*

UTILITIES

Railbelt planning a go

RRC initiates moves to develop an integrated resource plan for electric system

By ALAN BAILEY
For Petroleum News

During its Aug. 4 board meeting the governing board of the Railbelt Reliability Council authorized the RRC to move ahead with the development of an integrated resource plan for the Alaska Railbelt electrical system. As a consequence, RRC Chief Executive Officer Ed Jenkin is initiating the process of hiring a contractor to conduct the planning work.

Approved by the Regulatory Commission of Alaska in 2022 as the electric reliability organization for the Alaska Railbelt generation and transmission system, the RRC has a role to maintain and mandate reliability standards for the Railbelt's high voltage electrical system; administer rules for open access to the transmission grid; and conduct Railbelt-wide integrated resource planning. The concept is to minimize the cost of electricity in the Railbelt while also ensuring reliable electricity supplies.

Multiple ownership

The Railbelt electrical system is owned and operated by five independent utilities and the state of Alaska. This fragmentation of ownership leads to some duplication of facilities and other inefficiencies in the manner in which the system operates. There is also an interest in increasing the use of renewable energy sources across the system, in part to help address pending shortages in natural gas supplies for

see **RAILBELT PLANNING** *page 8*

GOVERNMENT

Campell joins DNR as state geologist

Dr. Erin Campbell joined the Alaska Department of Natural Resources Aug. 19 as state geologist and director of the Division of Geological & Geophysical Surveys.

"Dr. Campbell is superbly qualified for this technical role and brings an established record of state-level leadership," said DNR Commissioner John Boyle.

Campbell holds a Bachelor of Science with a major in geology and a minor in mathematics from Occidental College. She obtained her Ph.D. in Geology from the University of Wyoming, specializing in structural geology with a secondary emphasis in geophysics.

ERIN CAMPBELL

She worked as a geologist for Chevron for 4 years in Louisiana and California and then returned to Wyoming where she taught undergraduate and graduate courses at the University of Wyoming for 15 years and directed the Geology Field Camp. She did research in structural geology, geomechanics and CO2 sequestration and established the Cretaceous Tight Oil Consortium in the Powder River basin.

Campbell spent a year as manager of the Energy & Mineral Resources Division at the Wyoming State Geological Survey and was then appointed Wyoming State Geologist and director of the survey in 2017, positions she held until moving to Alaska this summer.

She has worked extensively with the Association of American State Geologists at the national level.

There are 70 employees at DGGS, DNR said. They generate, analyze and interpret data on geologic resources and natural conditions; map and inventory mineral and energy resources on state land; manage programs for hydrology and surficial geology, natural hazards and geophysics; and run the Geologic Materials Center in Anchorage.

DNR said the division was previously led by Dr. Melanie Werdon, who retired earlier in the year.

—PETROLEUM NEWS

● EXPLORATION & PRODUCTION

Baker Hughes US rig count unchanged at 539

By KRISTEN NELSON
Petroleum News

Baker Hughes' U.S. rotary drilling rig count was 539 on Aug. 15, unchanged from the previous week. Over the past 16 weeks, only one week had an increase, with the overall count down 45 over the period. The count was down by 47 from 586 a year ago and down three from two weeks ago. This is the lowest the rig count has been since October 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 Aug. 15 count includes 412 rigs targeting oil, up by one from the previous week and down 71 from 483 a year ago,

see **RIG COUNT** *page 4*

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ON THE COVER

EXPLORATION & PRODUCTION

GOVERNMENT

THIS MONTH IN HISTORY

EXPLORATION & PRODUCTION

Hilcorp expanding Seaview to the north

Addition of Whiskey Gulch will double size of southern Kenai Peninsula unit; Whiskey Gulch has pad, line will connect production

By KRISTEN NELSON
Petroleum News

Hilcorp Alaska has applied for expansion of its Kenai Peninsula Seaview unit to include its Whiskey Gulch prospect to the north, doubling the size of the existing unit. The Alaska Department of Natural Resources' Division of Oil and Gas said in an Aug. 15 public notice that the unit expansion application was filed Feb. 27 and deemed complete Aug. 8. Comments on the proposal are due by 4:30 p.m. Sept. 16.

The proposed expansion would add some 2,929 acres to the existing Seaview unit, approved by the state Oct. 7, 2020, and currently containing some 2,983 acres. The expansion consists of two state leases, ADL 392666 and ADL 393959.

The division said the proposed hydrocarbon accumulations in the expansion area are in the Tyonek and Beluga reservoirs, accessible from the existing Whiskey Gulch and Seaview pads, with additional pad plans being developed.

Earlier exploration

There were three early exploration wells in the area, Hilcorp said in its application: Standard Oil Company of California No. 1 Anchor Point, drilled to a depth of 14,705 feet in the Cretaceous in 1962; Union Oil Company of California's No. 1 Griner, drilled to 6,880 feet in the Middle Tyonek in 2002; and Aurora Gas LLC's No. 1 Endeavor, drilled to a depth of 9,225 feet in the Cretaceous in 2006.

The division said one zone in the Griner flowed noncommercial gas rates; no zones were tested in the Anchor Point No. or the Endeavor No. 1.

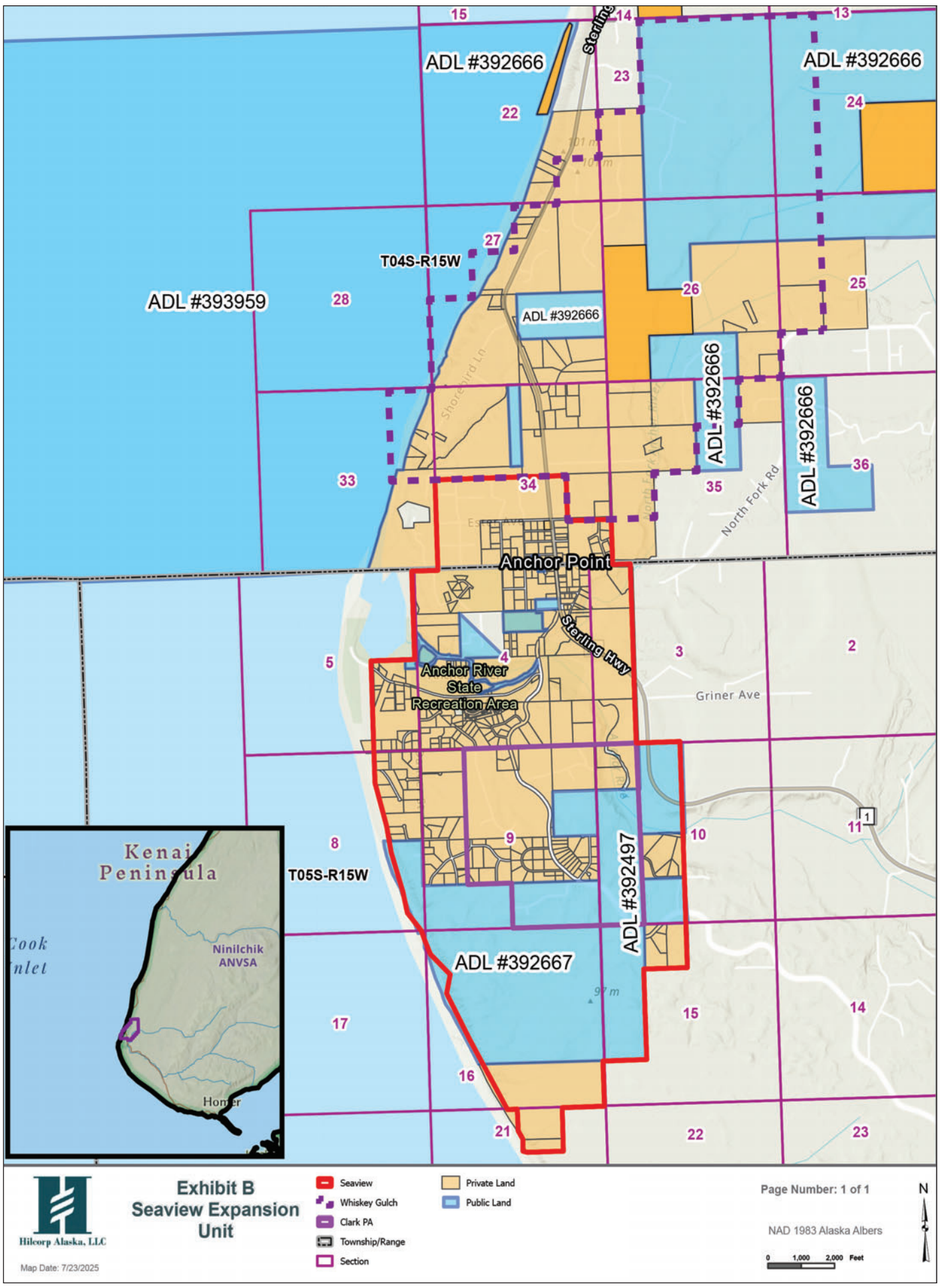
Hilcorp's work in the area

Hilcorp had an aerial survey done over the southern Kenai Peninsula in 2015, the company said in its unit application, "in an attempt to delineate anticlinal closures associated with the Griner #1 wells, and that survey identified the Seaview Prospect lying adjacent and to the west of the Griner #1 well."

In 2016 the company shot 20.54 miles of dynamite 2D "but unfortunately due to shallow gravel, gas, culture, and the transition zone nature of the area" usable seismic could not be processed.

Hilcorp began permitting and drilling shallow stratigraphic test holes in 2017,

see **SEAVIEW EXPANSION** *page 5*



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THIS MONTH IN HISTORY

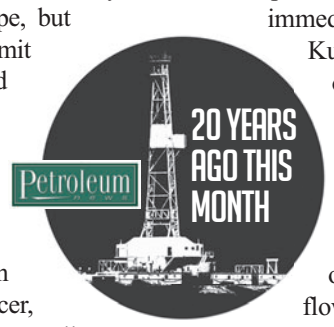
Pioneer submits Oooguruk discovery development apps

20 years ago: Project not yet sanctioned; applications delivered to state agencies in late July; first production could be in 2007

Editor's note: This story first appeared in the Aug. 7, 2005, issue of Petroleum News.

By KRISTEN NELSON
Petroleum News

Pioneer Natural Resources and partner Armstrong haven't sanctioned development of their Oooguruk discovery offshore Alaska's North Slope, but they have submitted permit applications to state and federal agencies.



"I don't think we'd be filing permits if we weren't serious about the project," Scott Sheffield, the company's chairman and chief executive officer, told analysts in a conference call Aug. 2, 2005. Asked if the company might be making acquisitions in the Gulf of Mexico he said, "… longer term our primary focus we think … a lot of the activity will be more focused on West Africa and also the North Slope." And in discussing planning for a 2006 budget, he said the company expects capital spending to be about the same as in 2006, with some decrease in land and seismic, "and then we'll be adding … Oooguruk and our South Coast gas projects to make up the difference."


SCOTT SHEFFIELD

Paperwork filed with agencies in Anchorage in late July 2005 indicates that a unit expansion is in progress, and filings with the state by Anadarko Petroleum for lease ADL 379301, on which the Thetis Island exploration well was drilled by Exxon in the early 1990s, say Anadarko is farming out "its Oooguruk leases (including ADL 379301)" to Pioneer Natural Resources (70%) and Armstrong Alaska (30%) for inclusion in the Oooguruk unit. In addition to the Thetis Island lease, which juts into the Oooguruk unit on the east, Anadarko also holds leases adjacent to Oooguruk on the west.

Offshore drill site

The company's applications indicate that Oooguruk, where Pioneer and Armstrong discovered oil in 2003, will be developed from a 6-acre offshore production drill site, with flow lines bringing production into Kuparuk River unit facilities and a production tie-in pad northwest and immediately adjacent to facilities at Kuparuk River drill site 3H. The offshore drill site will be in 4 to 6 feet of water approximately 2.5 miles north of the mouth of the Colville River Delta, 2.1 miles northwest of Kuparuk and 8.9 miles west of Oliktok Point. The subsea flow line will be buried in a trench and will carry produced fluids 5.7 miles from the offshore drill site to shore, then transition to aboveground flow lines on vertical support members for 2.4 miles and a tie-in at DS-3H.

Pioneer told agencies the targeted oil production zone is the Nuiqsut and Kuparuk reservoirs of the Kingak formation of the Beaufortian sequence. "Reservoirs within the Beaufortian sequences are younger, thinner, and typically laterally discontinuous as compared to the reservoir" at Prudhoe, the company said. Peak oil production is estimated to be some 18,000 to 20,000 barrels of oil per day.

Facilities at the offshore drill site would include development drilling rig and support packages, wellhead modules and truckable production modules.

Space for 48 wells

Pioneer said there will be 48 wells on the drill site with the option to increase to 60; about half the wells will be producers and half injectors, with one Class I/II underground injection control disposal well.

Following the drilling phase a permanent camp facility will be installed on the offshore drill site with a capacity of approximately 15 workers doing facility

see **HISTORY** *page 5*

continued from page 2

RIG COUNT

with 122 rigs targeting natural gas, down one from the previous week and up 24 from 98 a year ago, and five miscellaneous rigs, unchanged from the previous week and unchanged from a year ago.

Fifty-five of the rigs reported Aug. 15 were drilling directional wells, 471 were drilling horizontal wells and 13 were drilling vertical wells.

Alaska rig count unchanged

Louisiana (36) was up two rigs from the previous week.

Texas (242) and Wyoming (13) were each down by one rig.

Rig counts in other states were unchanged from the previous week: Alaska (9), California (7), Colorado (12), New Mexico (95), North Dakota (29), Ohio (11), Oklahoma (43), Pennsylvania (18), Utah (10) and West Virginia (7).

Baker Hughes shows Alaska with nine rotary rigs active Aug. 15, unchanged from the previous week and down by one from a year ago when the state's count was 10.

The rig count in the Permian, the most active basin in the country, was down by one from the previous week at 255 and down by 48 from 303 a year ago. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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HISTORY

maintenance and workover supervision during the production phase of the project.

During construction, a camp onshore will accommodate 200 to 250.

There will be a helipad at the island, and helicopters will be used for personnel and equipment transport during unstable ice periods in the spring and fall. A marine dock will support summer marine resupply operations and marine crew change options. The dock will be 150 feet long to accommodate unloading 200-foot barges.

Electrical power will be purchased from ConocoPhillips Alaska's existing facilities, Pioneer said, or generated at the DS-3H pad, if the existing facilities cannot meet Oooguruk power demands.

Mine site activities late this year

Conceptual engineering and design for Oooguruk development began in the fourth quarter of 2004, and permit review and approval is scheduled for the third and fourth quarters of 2005. Mine site activities will begin in late 2005. Pioneer and Kerr-McGee are coordinating an expansion of Mine Site E as a gravel source as new joint operators. Some 500,000 cubic yards of gravel is the expected requirement for Oooguruk.

Ice road construction would begin in the first quarter of 2006, followed by production drill site construction. Flow line construction would follow in the first quarter of 2007, with rig mobilization and facilities construction in the second quarter of 2007 and development drilling beginning in the second quarter of 2007 and continuing through the second quarter of 2010.

First production is expected in the fourth quarter of 2007.

Winter access to the offshore drill site will be by ice road from DS-3H with conventional vehicles or possibly rolligon. Summer transportation would be by landing craft, hovercraft or shallow-draft crew boats, with marine barging possible for resupply during open-water seasons.

Produced fluids will be transported to DS-3H in a flow line inside a conductor pipe — a pipe-in-pipe design, with a water injection line, arctic heating fuel line and gas injection line bundled to the conductor pipe with spacers and straps. Burial depth will depend on required protection from strudel scour, ice gouging, permafrost thaw settlement, channel seabed erosion and upheaval buckling. Pioneer said its preliminary assessment is that 4 feet to 6 feet burial depth would be adequate for mechanical protection.

The company plans two test trenches during the 2006 winter season.

Some development drilling seasonal

Pioneer said the majority of Nuiqsut formation wells would be drilled year-round as they would have "little, if any, capability to flow without stimulation and/or artificial lift mechanisms." With electrical submersible pumps these wells are expected to have a production rate of 1,000 bpd.

Since Kuparuk formation wells may flow unassisted at rates of 1,500 to 2,500 bpd, "Kuparuk wells would be subject to seasonal drilling restrictions below threshold depths," the company said.

The production life of the drill site is estimated at 20 to 30 years.

Ice roads will be built for winter construction in 2005-06, 2006-07, and for development drilling through 2009-10. A parallel ice road will be built for flow line construction in 2006-07. ●

Contact Kristen Nelson
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SEAVIEW EXPANSION

with 56 drilled to date, helping to lead to the Seaview and Whiskey Gulch shallow gas discoveries.

In 2021 Hilcorp drilled Whiskey Gulch-01 to 10,277 feet measured depth in the West Foreland. Deeper oil targets were wet but the Tyonek looked to be gas charged, the company said, with four zones perforated, although only one zone had producible quantities of gas.

Exploration work

In its exploration plans for the expanded Seaview unit Hilcorp listed its activities prior to the Seaview unit formation, beginning with an aerial gravity and magnetics survey in 2015, followed by 2D seismic in 2016 and seven stratigraphic test holes in 2017.

In 2018 Hilcorp drilled Seaview 8, an exploration well drilled to 10,621 feet MD resulting in a Tyonek gas discovery.

Hilcorp applied to form the Seaview unit and Clark participating area in 2020 and put in pipeline and facilities.

In 2021 the company drilled and tested Whiskey Gulch 1, and began flowing Seaview gas to sales, also drilling and testing Seaview 9.

In 2022 Hilcorp drilled and tested Whiskey Gulch 14.

The company drilled seven stratigraphic test holes in 2024 from Whiskey Gulch south towards the Seaview Pad; drilled and tested Whiskey Gulch 15. Also in 2024 Hilcorp "performed injectivity tests on coal seams in WG-14 and attempted to flow from coal seams in WG-15," along with acquiring multiple 2D seismic lines "to confirm presence of a deeper structure."

The company is evaluating installing facilities to tie Seaview 8 into a low-pressure sales line. "The well is currently too low of pressure to flow into the main distribution line," Hilcorp said.

2025 plans

Hilcorp said that in 2025 it is installing facilities at the Whiskey Gulch pad and tying Whiskey Gulch 1 into a sales pipeline.

It plans to complete additional testing of coalbed methane potential at Whiskey Gulch and/or Seaview.

The company is evaluating installing facilities to tie Seaview 8 into a low-pressure sales line. "The well is currently too low of pressure to flow into the main distribution line," Hilcorp said.

One exploration well may be drilled.

In its July 2 approval of the current plan for Seaview the division said only Seaview 8 has been produced, with production ceasing as of September 2022 with cumulative production of 181.8 million cubic feet of gas. Alaska Oil and Gas Conservation Commission data show the field began producing in June 2021 and produced for just bit more than a year, with the last production recorded in August 2022. ●

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Pikka 1 project modules arrive

SANTOS

Shown here are key processing modules for the Pikka 1 project. On July 30, Santos Ltd. announced the arrival of these modules by barge at Oliktok Point on the Beaufort Sea. This was a complex operation beginning from the Hay River Marine Terminal, Canada, transiting 1,086 miles along the Mackenzie River system to Tuktoyaktuk on the Beaufort Sea and 380 miles via sea barge from Tuktoyaktuk to Oliktok Point.

THIS MONTH IN HISTORY

The race is on; two companies in lead

20 years ago: Two independents — Kerr-McGee and Pioneer — hope to be the first independent to operate a producing field on Slope

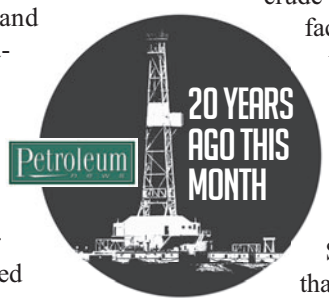
Editor's note: This story first appeared in the Aug. 14, 2005, issue of Petroleum News.

By KAY CASHMAN
Petroleum News

Kerr-McGee filed its permit application for Nikaitchuq in mid July 2005; Pioneer filed for Oooguruk in late July.

The race to be the first independent to operate a producing oil field on Alaska's North Slope is a close one. Ahead of the race are two large independents, Texas-based Pioneer Natural Resources and Oklahoma-based Kerr-McGee.

Both companies are new to Alaska, lured north in the last three years by Colorado-based Armstrong Oil & Gas, an independent which does business in the state through affiliate Armstrong Alaska. Both Pioneer and Kerr-McGee took operatorship and majority interest in prospects identified by Armstrong and, thanks to a permitting process already under way by their smaller partner, immediately drilled exploration wells.



Pioneer came to the state in November 2002, taking the lead in Armstrong's Northwest Kuparuk project in Harrison Bay between the ConocoPhillips' operated Kuparuk River unit and Thetis Island in the shallow waters of the Beaufort Sea. Pioneer later renamed the project Oooguruk, which means bearded seal in the Inupiaq language of the Native people of the North Slope.

Fifteen months later, in January 2004, Kerr-McGee took the lead on Armstrong's Nikaitchuq project, which is just a few miles east of Oooguruk and also north of Kuparuk in the shallow waters of the Beaufort, although plans are to develop this prospect from onshore. Nikaitchuq means "to persevere" and "will target multiple objectives" in Inupiaq.

Pioneer and Armstrong announced the discovery of oil at Oooguruk in 2003 following the drilling of three exploration wells. Oooguruk paperwork filed with state agencies in late July put peak oil production at 18,000 to 20,000 barrels of oil per day.

Kerr-McGee and Armstrong announced a discovery at Nikaitchuq in 2004. Kerr-McGee officials have estimated peak oil production at 60,000 bpd. Neither company has released reserve estimates for the projects.

In its permit applications Pioneer puts first production from Oooguruk in the fourth quarter of 2007. Kerr-McGee puts first production at Nikaitchuq as early as the first half of 2006.

That puts Nikaitchuq in the lead, although one state official said in early August not to rule out Pioneer getting their project up and running first.

"It's too close to call," he said, asking not to be identified because "it's a friendly race — more against the challenges of North Slope development versus each other. Both companies are very serious about making these projects happen."

He also said Kerr-McGee's Nikaitchuq project is bigger than Oooguruk and involves "the construction of standalone processing facilities, which will take more time to construct than Pioneer's drill site at Oooguruk. But Kerr-McGee is also building their project in stages, so it will have production at Oliktok Point up and going sooner, according to their development plan.

"It's my understanding Pioneer is still working on a facility sharing agreement with ConocoPhillips to process Oooguruk crude at Conoco's Kuparuk River facilities," which might also add time to development.

Both companies must have part of their project area rezoned, which requires filing a rezoning application with the North Slope Borough, something that has already been approved for Nikaitchuq, but not for Oooguruk. That process can take months.

"We've not yet filed for rezoning, but we have had some dialogue with the borough. … We plan to have it filed within the month of August," Pioneer's top executive in Alaska, Ken Sheffield, told Petroleum News Aug. 10, 2005.

Permits filed for both projects

Kerr-McGee filed its permit application for Nikaitchuq in mid July 2005; Pioneer filed for Oooguruk in late July.

Neither company has sanctioned their project, but "I don't think we'd be filing permits if we weren't serious about the project," Scott Sheffield, Pioneer's chairman and chief executive officer, told analysts in a conference call Aug. 2, 2005.

Kerr-McGee, which drilled the most exploration wells on the North Slope in the winter of 2005, has also made optimistic statements about Nikaitchuq.

But as one state official put it, both companies could still win the race.

Nikaitchuq could be the first independent that operates a producing oil field onshore Alaska's North Slope. And Pioneer could be the first independent operating an offshore North Slope field in the state.

Mark Myers, director of the state's Division of Oil and Gas, agrees.

"Both projects have been actively worked," he said Aug. 9.

"Both companies have drilled exploration and some delineation wells. The goal for both Pioneer and Kerr-McGee is getting their project sanctioned; mainly by working through the economics of the projects…. They've both worked hard to determine the method of development most appropriate."

Both companies have said they expect to make decisions on sanctioning their projects by the end of the year. ●

Contact Kay Cashman at publisher@petroleumnews.com

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RAILBELT PLANNING

power generation in the Cook Inlet region. In addition, economies of scale in power generation can be improved through regional coordination.

The organization began working on the reliability standards last year and has begun filing standards with the RCA — the RCA recently approved the first tranche of standards. The more recently formed Railbelt Transmission Organization within the Alaska Energy Authority has been developing a new unified tariff for the transmission system. Meanwhile start of work by the RRC on the IRP has been delayed somewhat pending the preparation of a plan for developing the IRP, a prerequisite to being able to hire a contractor with a clear scope of work for determining contractor costs.

The IRP process

During an Aug. 13 RCA public meeting Jenkin overviewed the process that the RRC envisages for developing the IRP. He said that the RRC anticipates hiring a contractor in October, with working group meetings for the project beginning in late October. Definitions and objectives for the IRP would be developed in the first quarter of 2026, with a preferred portfolio for the future electrical system being delivered to the RRC board in late 2026. An action plan for implementing the IRP would then be completed in early 2027.

There are firms in Alaska that may bid for the contractor position, Jenkin commented.

Jenkin emphasized the importance of having clearly understood and agreed objectives for the IRP, as well as making sure that there is a clear set of definitions relating to the planning, before the planning itself begins.

As in the development of reliability standards, the IRP process will involve the use of a technical advisory committee, composed of appropriate technical experts, overseeing working groups that involve the participation of stakeholders in the system. And Jenkin emphasized the importance of stakeholder involvement in all of the RRC's initiatives. Stakeholders include household and commercial electricity consumers; the electricity utilities; independent power producers; and the state of Alaska. At the top of the organization different classes of stakeholders are represented on the RRC board, while there is also the participation of stakeholders and potentially members of the public in working groups that develop RRC products. In addition, the organization communicates to the public through various public meetings.

"We do try to engage publicly as far as what we are doing and why people might be interested in what we are doing, and why they may want to participate in the process," Jenkin told the commission.

Reliability standards

This stakeholder and public engagement process has already been put into action in connection with the progress to date in developing the electrical system reliability standards.

Four of the reliability standards have now progressed through the complete development process, including approval by the RCA, Jenkin said. As previously reported by Petroleum News, those standards address the necessary controls for interconnections on the high voltage electrical system.

Two other standards have now been approved by the RRC board, Jenkin commented. One of these addresses the responsibilities for reliability coordination for the electrical system, while the other addresses the balancing of power generation to ensure stability in the system. Currently the RRC is working on standards for transmission system performance and on guidelines for the penalties that may be applied for infringements of the standards. Once this work has been completed, the organization will move forward with the development of standards for the connection to the Railbelt electrical system for entities that wish to interconnect, Jenkin said.

The transmission system

In response to a question from Commissioner Robert Pickett about the funding needs for upgrading the current low capacity Railbelt transmission system Jenkin commented that, unlike in the Lower 48, where the planning of power generation assets is the focus of an integrated resource plan, the plan for the Railbelt will include both power generation and power transmission. With a transmission constrained system in the Railbelt, it will be necessary to evaluate potential new generation resources in relation to a plan for the transmission system and, thus, consider the transmission aspects of those resources, Jenkin said.

Currently the Alaska Energy Authority is pursuing a project to build a subsea high voltage direct current transmission line under Cook Inlet from the Kenai Peninsula to the Anchorage region. This project has been awarded a federal grant, but the grant requires matching funds. AEA has thus far obtained sufficient matching funds for the relatively low cost initial phases of the project and has expressed confidence in obtaining additional funds as the project progresses. Pickett suggested that construction of this transmission line would be critical to a decision to proceed with a proposed expansion to the Bradley Lake hydropower system in the southern Kenai Peninsula. Bradley Lake currently produces the cheapest electricity in the Railbelt and supplies power to the Railbelt utilities via the transmission system. ●

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OIL PRICES

The forces of bulls and bears seem to be in stasis, with too many factors tugging sentiment in too many directions. No high-confidence trends have emerged.

"Not so sure about the peace deal — will have to see if something moves forward over the coming days … It seems oil prices are thrown down one day, followed by a rebound the next," said Giovanni Staunovo, a UBS analyst quoted in an Aug. 20 Reuters report.

Traders seem to have sucked in their collective breath, waiting to exhale.

The upcoming symposium at Jackson Hole Aug. 22 may be the catalyst the crude oil market is waiting for.

The Jackson Hole event is focused on a singular scheduled event — a speech presented by the U.S. Federal Reserve Chairman Jerome Powell — with the potential to move the needle on liquidity in U.S. financial markets, impacting demand for crude.

Crude futures up on surprise inventory draw

Crude futures regained ground Aug. 20 supported by an unexpectedly large draw on U.S. crude reserves. WTI added 86 cents to close at $63.21 and Brent jumped $1.08 to close at $66.84.

"Gains could be limited as the geopolitical outlook remains uncertain," Felipe Barragán of Pepperstone said in a note, the Wall Street Journal reported Aug. 20. "The potential easing of sanctions on Russian crude continues to hang over market sentiment, while rising OPEC+ output also fuels downside risks."

Total motor gasoline inventories fell by 2.7 million barrels over the week to 223.6 million barrels — 1% below the five-year average for the season, the EIA said. Distillate fuel inventories rose by 2.3 million barrels to 116.0 million barrels — 13% below the five-year average for the time of year.

U.S. commercial crude oil inventories for the week ended Aug. 15 plummeted by 6 million barrels from the previous week to 420.7 million barrels — 6% below the five-year average for the time of year, according to U.S. Energy information Administration data released Aug. 20.

Analysts answering a Wall Street Journal poll had on average estimated a drawdown of 1.5 million barrels. A Reuters poll predicted a fall of 1.8 million barrels.

Total motor gasoline inventories fell by 2.7 million barrels over the week to 223.6 million barrels — 1% below the five-year average for the season, the EIA said. Distillate fuel inventories rose by 2.3 million barrels to 116.0 million barrels — 13% below the five-year average for the time of year.

The Wall Street Journal poll had called for gasoline inventories to fall by 1.3 million barrels, while stocks of distillate fuels were expected to rise by 700,000 barrels.

ANS gained 66 cents Aug. 18 to close at $68.62, while WTI gained 62 cents to close at $63.42 and Brent gained 75 cents to close at $66.60.

Ukraine President Volodymyr Zelenskiy met Aug. 18 at the White House with U.S. President Donald Trump for peace talks in the wake of Aug. 15 talks between Trump and Russian President Vladimir Putin in Alaska.

European leaders were also in Washington Aug. 18.

Price action was negative Aug. 15. ANS fell 79 cents to close at $67.96, WTI dropped $1.16 to close at $62.80 and Brent dropped 99 cents to close at $65.85.

ANS added 88 cents Aug. 14 to close at $68.76, as WTI leapt $1.31 to close at $63.96 and Brent leapt $1.21 to close at $66.84.

On Aug. 13, ANS fell 41 cents to close at $67.87, WTI fell 52 cents to close at $$62.65 and Brent fell 49 cents to close at $65.63.

On Aug. 19 ANS held a $5.49 premium over WTI and a $2.05 premium over Brent.

Oil futures extended gains in Asian trade early Aug. 21 as Petroleum News went to press. WTI and Brent were up 52 cents and 51 cents respectively. ●

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Petroleum news

Oil Patch Bits

GCI continues fiber deployment in remote communities

As reported by GCI News Aug. 8, on the heels of the launch of 2.5 gig residential internet speeds in Bethel, the first community connected through the AIRRAQ Network, project crews remain hard at work in more Yukon-Kuskokwim Delta communities in preparation for the future arrival of fiber. Teams are currently building out local fiber infrastructure in Eek, Platinum, Napaskiak and Oscarville. The AIRRAQ Network is a partnership between Bethel Native Corp. and GCI to bring fiber-optic connectivity to 13 Y-K Delta communities.

In the coming months, project crews will deploy thousands of feet of aerial and underground fiber within each community directly to local homes and businesses.

"Launching fiber-optic service in Bethel was a huge milestone for our project crews, and we're eager to keep the momentum going," said GCI Senior Staff Program Manager Nikki LaTona. "The AIRRAQ Network is an extremely complex project with a lot of moving parts. To make the most of Alaska's crucial and limited summer construction season, our teams have worked tirelessly to ensure all the pieces are in place for construction to go smoothly in each community. That includes everything from permitting and surveys to staging equipment, organizing transportation and lodging for our crews, and more — it's a massive effort."

BNC and GCI launched fiber-optic connectivity in Bethel in May, bringing access to the same speeds, plans and pricing as those in Alaska's urban areas to the regional hub's more than 6,000 residents.

"For the first time, our communities have access to first-class internet service right here at home," BNC President & CEO Ana Hoffman said. "I've often said 'first-class people deserve first-class internet service,' and, with the launch of AIRRAQ, we are making that a reality. AIRRAQ is not just a technology upgrade — it's an economic multiplier and an investment in our people, meaning jobs, training, and capacity-building for our communities, something BNC is deeply committed to."

The 840-mile AIRRAQ Network fiber project is a partnership between BNC and GCI that will deliver affordable 2.5 gig residential internet speeds and unlimited data plans to more than 11,800 people in Western Alaska. The project will connect 13 communities, including: Bethel, Platinum, Eek, Napaskiak, Oscarville, Atmautluak, Kasigluk, Nunapitchuk, Quinhagak, Tuntutuliak, Tununak, Toksook Bay and Emmonak. For more about the AIRRAQ Network fiber project at: https://www.gci.com/bethel-airraq-network.

Companies involved in Alaska's oil and gas industry

All of the companies listed above advertise on a regular basis with Petroleum News

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INLET SALES

Alaska holds all the Alaska OCS leases. Those in Cook Inlet are west and southwest of Anchor Point.

Lower Cook Inlet

There has been oil and gas interest in the lower Cook Inlet for many years, but with very little resulting exploration activity. Geologic features that have high oil and gas potential lie under this part of the inlet but in older rocks than those associated with the producing oil and gas fields of the upper Cook Inlet.

While being subject to the large tidal range observed in the entire Cook Inlet, the waters of the lower inlet are relatively deep, thus presumably necessitating the use of a large jack-up drilling rig. The need to bring a large rig to the region, coupled with the remote location and challenging winter conditions, would presumably render exploration and development relatively expensive. There are also the complexities of permitting of oil and gas exploration and development activities offshore in Cook Inlet.

Hilcorp has shown an interest in exploration drilling in the region for a number of years. In a 2017 lease sale the company acquired 14 leases in the inlet, southwest of Kachemak Bay. The company subsequently conducted offshore 3D seismic surveying during the summer of 2019 — the company appeared interested in an oil prospect penetrated in 1982 by ARCO's Raven No. 1 well. The prospect, about halfway across the inlet, due west of the town of Homer, contains a known oil resource in a Cretaceous reservoir. Apparently the new seismic survey revealed a 65,000-acre, four-way closure with the oil discovery at the top.

In 2021 the company appeared to indicate a plan to conduct some drilling by conducting a geohazard survey in its leases. However, there have been no reports of the company carrying out further activity in the area since then. Apparently the Spartan-151 jack-up rig that the company acquired for drilling in the upper Cook Inlet is too limited for operation in the company's lower Cook Inlet prospect.

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TIRI-1 WELL

Drilling logs and formation samples will be completed this coming winter starting in February, analyzed over the summer season and used to plan the formation testing to be done the following winter.

The Tiri-1 well site is approximately 10 miles southwest of Deadhorse and will be accessible via ice road or snow trail. It is on the North Slope of Alaska approximately 9 miles west of the trans-Alaska oil pipeline.

The well will be drilled from a 600-foot by 600-foot ice pad constructed each winter season that operations occur.

A temporary ice/snow road will connect the Captivate Pad, also known as the CEAINC Pad, to the Spine Road via Hilcorp's X-Pad access road, providing seasonal vehicle access.

All associated facilities to support this project are temporary and will include drilling camp facilities, drilling rig facilities, well test process facilities, and an operations support center.

Captivate has a 60-person fully supplied camp.

The company's Oil Discharge Prevention and Contingency Plan proposes to address a response planning standard of 82,500 barrels of oil based on the default value of 5,500 barrels of oil per day for a blowout lasting 15 days. The primary goal of the plan is to provide for the safety of personnel during drilling and prevent and plan for the response to a hydrocarbon release or other type of fluid spill and minimize potential environmental impacts

The public comment period ends on Sept. 11.

The application was signed by Ashley Gilbert, managing director of 88 Energy and Anchorage-based Captivate Energy.

At the state's December 2024 North Slope areawide lease sale Captivate was high bidder on four tracts adjacent to its existing Leonis lease, some 10,203 acres, for $280,582.

The new acreage is west of the Dalton Highway and south of giant Prudhoe Bay field.

—KAY CASHMAN

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BADAMI EQUIPMENT

resulting in much more gas going to flare when the VRU was down than what was normally captured by the VRU.

Over the winter there was also a two-week turbine outage, requiring use of diesel generators.

The commission said it recognizes that CIE has had repeated issues with the Badami VRU and identified significant inefficiency in the eductor system and said it would give CIE a year from the Aug. 14 date of the order to "complete the upgrade/replacement of both the VRU and eductor system that will prevent future failures, with expenditures within the year being credited against the $357,905 penalty."

CIE cannot credit repair costs for either the VRU or educator against the penalty amount.

CIE and Savant are Glacier Oil and Gas Corp. companies.

Notice of proposed enforcement action

The commission issued a notice of proposed enforcement action to CIE on May 27, noting that CIE had reported the flaring as required.

When Badami's VRU experienced what the commission said was "catastrophic damage of its third state compressor due to a discharge valve failure," CIE requested approval to vent or flare gas for more than one hour. The company estimated that 300,000 cubic feet per day of gas would be flared and emphasized that maintaining facility operations was critical to operation of the Nutaaq pipeline carrying production from both Badami and Point Thomson.

The commission noted, however, that when Badami production was shut-in for two weeks in January and February, operations of the Nutaaq pipeline were not impacted.

CIE notified the commission of the loss of the VRU and requested approval to flare gas on Oct. 9. The commission said it replied the same day by email, explaining that its regulations did not allow pre-approval of flaring or venting outside of well testing prior to production, and asking CIE what steps it was taking to reduce the volume of gas flared. The company said repairing the VRU and getting it back online was the only solution.

Those repairs, the commission said, "took multiple weeks and months, due to increasing complexities of repair needs and parts sourcing."

Wells kept online

CIE chose to keep all production wells online during the flaring event, the commission said, until Badami's one functional power generating turbine had a catastrophic failure. The company again requested permission to flare, this time just from Badami B1-33, and again, the commission said, it responded that it could not pre-approve flaring or venting outside of testing prior to production.

CIE then shut-in all wells and Badami went on emergency diesel generators for power until one of two power generating turbines was brought back online.

The VRU was still not functioning, but all production wells were brought back online, along with associated flaring.

CIE informed the commission on March 9 that the VRU was back online.

The commission reviewed details of the incident and concluded "that no effort was made to minimize the volume of gas flared that the VRU at Badami would normally capture."

Company response

The company requested an informal hearing and submitted a written response on June 17, from CIE Chief Operating Officer David Pascal, after the informal hearing.

Pascal said Badami had to remain operational to ensure transport of oil from both Badami and Point Thomson.

There were extended repair times for the VRU, which "experienced multiple operational failures," he said, citing "vendor delays and post-COVID supply chain issues." Both facility turbines were offline from Jan. 26 to Feb. 18, with one unit undergoing control upgrades and the other "suffering catastrophic failure due to a broken compressor fin."

During that time, and under "extreme Arctic winter conditions," emergency power was from diesel generators, which had to be run continuously, although they were not designed for that and "have since suffered degradation, that will require expensive overhaul," Pascal said.

He said CIE had "complied fully with 20 AAC 25.235," with all gas disposition reported.

Pascal cited 20 AAC 25.235(d)(5) as allowing authorization of flaring beyond one hour "if necessary for facility operations, repairs, or to prevent loss of ultimate recovery."

He listed the events at Badami as:

•Threat to life/property from the emergency loss of both turbines in winter.

•"VRU failure beyond immediate control due to vendor logistics."

•Nutaaq pipeline maintenance critical due to transport of third-party oil.

•"Production of a new well (B1-33A) during initial flowback and ramp-up, where shut-in would cause reservoir damage and loss of recovery."

"These conditions," Pascal said, "clearly fall under authorized exceptions and were unavoidable despite best practices."

Economic issues

Pascal also listed economic and public interest considerations, including royalties received by the state from Badami between October 2024 and March 2025 and the volumes of Point Thomson oil transported by the Nutaaq pipeline.

In its Aug. 14 order the commission said it does not take economic factors into account when enforcing its statutes, beyond "considering whether flaring is necessary to prevent loss of ultimate recovery" pursuant to its regulations.

"When Badami experienced the loss of power turbine generating capacity, and all production wells were shut-in, the emergency diesel generators were enough to supply power to keep the Nutaaq Pipeline operating," the commission said. "Also, this argument proposes a false dilemma, as shutting in some production wells was an option that was not pursued, all across 6 months (minus the 2 weeks during the power turbine outage) the same production wells were kept online."

The cost of gas used by the commission to calculate the civil fine is overstated, Pascal said, citing the amount Savant paid for Endicott gas during the period in question.

In its order, the commission said that in determining fair market value of the natural gas at the point of waste it "has consistently utilized the prevailing value of North Slope gas published by the Alaska Department of Revenue" on its website, described by the department as "the weighted average sales price of gas to publicly regulated utilities in the north slope area."

—KRISTEN NELSON

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COSMO POD

techniques. However, BlueCrest envisioned and implemented a specialized completion technique (vertical open hole fishbone drilling) to the Hemlock and Starichkof oil zones that had never been employed in the industry.

To date, BlueCrest has spent more than $450 million to develop and bring the Cosmopolitan field into sustained production.

On May 23, John M. Martineck, president and chief operating officer of BlueCrest Alaska Operating, was sent a notice of default for the CU from the Alaska Department of Natural Resources.

The default was due to BlueCrest's failure to meet the commitments in the DNR Division of Oil and Gas' Dec. 9, 2024, decision approving with conditions the 11th POD for Jan. 1 through March 31, 2025.

Since that time BlueCrest has requested, and DNR has allowed suspensions of the POD period to provide maximum flexibility to facilitate fulfilling those conditions.

BlueCrest can cure the default through completion of commitments. The primary objective of the state remains that funding is secured to "expeditiously bring development" of the Cosmopolitan Unit forward "to meet the energy needs of Alaskans," with emphasis on natural gas.

Oil and associated gas

The Cosmopolitan Unit's oil zones were developed from an onshore pad located on the southern Kenai Peninsula. Production is primarily oil but there is an associated natural gas component.

Accessed from its onshore pad using directional drilling, the wells extend from the pad under Cook Inlet into state of Alaska submerged lands.

Production is processed onshore, and oil is trucked off location.

Recent filings

Recently BlueCrest submitted its 13th POD to the division for leases ADL 018790, 384403, 391903 and 391904 (the Cosmopolitan unit).

BlueCrest proposed this POD be effective from Aug. 22, 2025, through Aug. 21, 2026.

During the CU 12th POD period, which runs through Aug. 21, BlueCrest's net gas sales to the local utility market have consistently been more than 100 mcf per day, not including the gas used onsite to power their onshore Hansen Production Facility.

Specifically, CU gas averaged 598 mcf per day in June, down 42.47% from a June 2024 average of 1,039 mcf per day. CU crude production in June averaged 518 bpd, down 20.32% from a June 2024 average of 650 bpd.

12th POD review

In its submission of the 13th POD BlueCrest included the following review of the 12th POD, which had been approved with the following conditions:

(1) Provide the division with evidence of fully committed, binding (i.e., contractual) private funding for both the H10 fishbone well and Tyonek gas project no later than 90 days from the date of the notice.

(2) Beginning no later than 30 days from the notice date, update the division bi-monthly on the status of any financing for progressing development of the Tyonek gas project that has been secured, along with updates on the status of operational/project-related progress.

(3) Provide a technical presentation to the division by June 30 to justify the current boundary of the SHPA, or combined Starichkof Sand and Hemlock formation participating area.

BlueCrest said long lead time permitting has been completed, which will facilitate final permitting for the 2025-2026 planned operations.

BlueCrest has met with the division and DNR Commissioner's Office on several recent occasions to discuss the status of BlueCrest's commercial negotiations with a confidential third-party ("Party A").

"BlueCrest and Party A are engaged daily to progress our commercial alignment to cure the default notice, and the State of Alaska has signaled its support for Party A's entrance into the Alaska oil and gas market," BlueCrest said.

As required, BlueCrest provided a technical presentation to the division on June 30. Finally, BlueCrest provided the division with the required bi-monthly updates.

13th Plan of Development

In its 13th POD — Aug. 22, 2025, through Aug. 21, 2026 — BlueCrest said it has actively pursued the capital investment required to restart its onshore oil and gas drilling program and the offshore Tyonek gas drilling program.

BlueCrest said it has faced challenges for years finding suitable investors willing to invest in Cook Inlet.

BlueCrest has already completed a substantial amount of work and required permitting and invested significant capital to prepare for the oil drilling program and the development of the offshore Tyonek Gas Project.

BlueCrest's drilling plans are contingent upon finalizing planned investment for the necessary funds to move forward.

BlueCrest anticipates commencing drilling of the H10 well 10 months after finalizing the commercial structure with Party A; engineering work for the Tyonek gas development would begin within a short period after funding is secured.

Regarding well work/evaluation BlueCrest plans to work over the H14 well and put a velocity string in the well to prevent slugging. This workover will help stabilize the flow from the well.

Using its own equipment BlueCrest will perform hot oil treatments on the Hansen 1AL1, H4, H12 and H16a wells every three to four weeks to maintain production. Hot oil treatments will begin on the H14 well after completing the workover to insert the velocity string.

BlueCrest said long lead time permitting has been completed, which will facilitate final permitting for the 2025-2026 planned operations.

BlueCrest will finalize the remaining permits for the H10 well prior to drilling.

BlueCrest is continuing to work on permits for the offshore gas development to meet the production startup in the second half of 2027, assuming favorable market conditions.

AIDEA application

BlueCrest submitted a loan application to AIDEA, the Alaska Industrial and Development Export Authority, on Feb. 14, to fund drilling up to three Tyonek gas wells from the existing onshore location in 2025.

These onshore extended-reach wells would penetrate the eastern portion of the deepest gas zone (Tyonek A sand) and would be drilled to accelerate new gas production for Railbelt consumers.

Although successful completion of drilling these extreme-extended-reach wells is technically possible, the horizontal reach required in drilling these wells through numerous coal beds adds high mechanical risk. ●

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