Petroleum news

page 4 HISTORY: Pioneer OKs Oooguruk, first independent-run Slope field

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Strong Energy applies to form Gubik unit on Alaska North Slope

On Feb. 1 the Alaska Department of Natural Resources' Division of Oil and Gas posted a public notice saying Strong Energy Resources of Houston, Texas filed an initial application on July 25 to form the Gubik unit on Alaska's North Slope. Strong is 100% working interest owner and operator of the proposed unit.

The application was signed by Strong Energy Resources President and CEO James S. Watt.

The proposed Gubik unit will encompass 1,928.14 acres of state land between the National Petroleum Reserve-Alaska and Arctic Slope Regional Corp. lands, within the riverbed of the Colville River.

GG&E characteristics

The Gubik unit leases, acquired in 2015 and 2024, have direct offset wells that tested hydrocarbons in the Brookian sequence. Within these leases, Strong said it has identified contiguous geologic pay horizons in the Tuluvak and Nanushuk formations.

The on-structure offset wells substantially decreased technical risks for these pay horizons, which is supported by a

see GUBIK UNIT page 6

BLM seeks input, nominations for ANWR coastal plain O&G lease sale

On Feb. 2 the Department of Interior's Bureau of Land Management took a key step toward holding a lease sale in the coastal plain of the Arctic National Wildlife Refuge by seeking comments and nominations of lands to be considered for leasing.

KEVIN PENDERGAST

"Since passage of the Tax Cuts and Jobs Act of 2017, the BLM has had a clear congressional mandate to administer a competitive oil and gas program for the coastal plain," BLM Alaska State Director Kevin Pendergast said in a Feb. 2 press release. "With the new decision in place, bolstered by Congress's recent and emphatic direction in the One Big Beautiful Bill Act, this lease sale process provides a clear path forward to finally unlock the coastal plains resource potential."

The 1,563,500-acre coastal plain of ANWR is a frontier basin

see ANWR LEASE SALE page 8

BOEM issues final notice for Cook Inlet March 4 lease sale

The U.S. Bureau of Ocean Energy Management said a Cook Inlet outer continental shelf oil and gas lease sale, Big Beautiful Cook Inlet (BBC1), will be held March 4. The final notice of sale, released Jan. 30, includes information on lease terms: a 10-year primary term, a minimum bonus bid of $25 per hectare and a 12.5% royalty rate.

The sale was authorized under the One Big Beautiful Bill Act and is the first of a series, one each year from 2026-28 and from 2030-32,

The lease area covers 1.05 million acres in federal waters of Cook Inlet north of Augustine Island.

"Regular and predictable federal leasing is the minimum standard for maintaining domestic energy production," said BOEM Acting Director Matt Giacona. "Energy security is national security, and this sale reflects a clear, congressionally mandated path forward for Cook Inlet leasing. By offering predictable terms and a transparent process, we are supporting Alaska's role in meeting

see INLET LEASE SALE page 8

FINANCE & ECONOMY

ANS roller coaster

US-Iran tensions heat crude prices — proposed negotiations cool them

By STEVE SUTHERLIN

Petroleum News

Crude prices have been on a wild ride as the market attempts to gauge the geopolitical risk of a U.S.-Iran faceoff that has sent oil higher, juxtapositioned against hopes for a peaceful resolution from proposed talks between the parties.

North Slope crude rose 67 cents Feb. 3 to close at $66.77 per barrel after six Iranian gunboats made an unsuccessful attempt to halt and board a U.S.-flagged oil tanker in the Strait of Hormuz. WTI jumped $1.07 on the day to close at $63.21 and Brent jumped $1.08 to close at $67.38.

The tanker sped up and was escorted from the area by a U.S. Navy vessel.

In a separate incident the same day, an Iranian drone was shot down after it "aggressively" approached a U.S. aircraft carrier.

North Slope crude rose 67 cents Feb. 3 to close at $66.77 per barrel after six Iranian gunboats made an unsuccessful attempt to halt and board a U.S.-flagged oil tanker in the Strait of Hormuz.

Just the day before prices fell precipitously on remarks by U.S. President Donald J. Trump that Iran is negotiating seriously to end the conflict. A rising U.S. dollar added further downside for prices by making dollar-denominated crude oil more expensive for buyers that must convert other currencies for oil purchases.

ANS plummeted $3.64 Feb. 2 to close at

see OIL PRICES page 6

UTILITIES

Four years in making

Bob Gardes was the driver behind the Cook Inlet LNG bridging project

By KAY CASHMAN

Petroleum News

The Cook Inlet LNG project featured in the Feb. 1 issue of Petroleum News was roughly four years in the making. It began with the efforts of Bob Gardes who predicted that Cook Inlet producers were never going to drill their way out of an upcoming shortage of natural gas to meet the needs of the large Southcentral Alaska market.

BOB GARDES

Cook Inlet LNG LLC, a subsidiary of Gardes Holdings, is advancing an offshore liquefied natural gas import project utilizing a Floating Storage and Regasification Unit, or FSRU, and existing platform and pipeline infrastructure to cover unmet gas demand and storage needs for the region in the coming years. It is being developed as a bridge project to provide energy security for the most populous region of Alaska while longer-term solutions are advanced and realized.

"FSRU's have proven effective as a simple, safe solution to fill energy gaps across the world. We are proud that this project will do the same for Alaskans," Gardes said.

"Bob began pulling together individuals with the key skillsets he wanted to see in the project," one of

see BRIDGING PROJECT page 8

EXPLORATION & PRODUCTION

Positive oil news

Conoco, Hilcorp, Santos brief House Resources on exploration & production

By KRISTEN NELSON

Petroleum News

Drilling, development and more production were the highlights as Alaska's major oil and gas producers and the new entrant which will soon join them with production on the North Slope provided the Alaska Legislature's House Resources Committee with upbeat updates at a Jan. 28 hearing.

ConocoPhillips Alaska and Hilcorp are the state's major oil and gas producers, operating between them the majority of producing fields and production across the North Slope. Santos will be on its way to being the third-largest producer on the Slope when it brings the Pikka unit online in March.

ConocoPhillips and Santos work the North Slope; Hilcorp works both the Slope and Cook Inlet.

Santos

The Santos presentation, "Powering Alaska's next 50 years: delivering Pikka & beyond," set the tone for remarks by Joe Balash, Santos senior vice president for external affairs and Pete Laliberte, Santos vice president of business development.

Santos is developing the Pikka field, discovered

see COMPANY REPORTS page 7

● GOVERNMENT

Preliminary injunction on NPR-A denied

Suit by Sovereign Inupiat et al against Department of the Interior over approval of ConocoPhillips' 2026 winter exploration program

By KRISTEN NELSON
Petroleum News

Judge Sharon Gleason of the U.S. District Court for the District of Alaska has denied a motion for a preliminary injunction by plaintiffs suing U.S. Department of the Interior Secretary Doug Burgum over the Bureau of Land Management's approval of a request by ConocoPhillips for approval of winter exploration work in the National Petroleum Reserve-Alaska.

The 2026 winter exploration program covers four exploration wells and a seismic program within NPR-A including work within the Teshekpuk Lake Special Area.

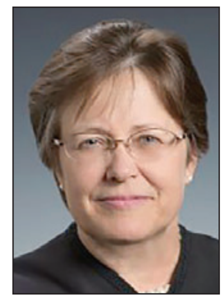
Plaintiffs — Sovereign Inupiat for a Living Arctic, Center for Biological Diversity and the Wilderness Society — filed a lawsuit Dec. 11, 2025, and a motion for a preliminary injunction the same day, alleging that measures BLM approved to mitigate impacts on vegetation are ineffective, violating the National Petroleum Reserves Production Act's requirement of adequate mitigation and maximum protection.

Final EA

At issue is the 2026 winter exploration program, for which BLM issued a final environmental assessment, EA, Nov. 26 along with a record of decision approving the winter program.

The EA includes mitigation measures — required operating procedures or ROPs — previously adopted in the 2022 Integrated Activity Plan, IAP, governing NPR-A operations.

One ROP in the 2022 IAP, C-2, included a requirement that frost and snow cover be at sufficient depths to protect the tundra before ground operations can take place.


SHARON GLEASON

The Dec. 11 lawsuit and motion for preliminary injunction challenge the November record of decision, alleging its measures to mitigate impacts on tundra are ineffective, thereby violating a directive in the NPRPA requiring adequate mitigation and maximum protection.

2025 IAP

BLM issued a 2025 Integrated Activity Plan Dec. 11, including a revised ROP C-2(a), requiring that soils be frozen to 23 degrees F or lower at a depth of 12 inches and that there are 6 inches of snow cover, before off-road travel is allowed.

Provisions of ROP C-2(c), (e) and (f) require that off-road travel generally be conducted with low-ground pressure vehicles unless otherwise approved by the BLM authorizing officer, prohibiting bulldozing of tundra mat and vegetation and requiring that ice roads be located to avoid the most sensitive tundra types. ROP C-2 (d) requires vehicles to be selected and operated in a manner eliminating direct impacts on tundra, with heavy equipment not allowed on the tundra until requirements of ROP C-2(a) are met — frozen soil and snow cover depth.

On Dec. 11 BLM issued a revised EA to conform with the 2025 IAP and reissued its record of decision authorizing the 2026 winter program. A new FONNSI, finding of no new significant impact, was also issued.

Plaintiffs filed an amended complaint on Dec. 29, reflecting the December 2025 IAP, EA and record of decision, with the amended complaint recognizing that some of the implementing regulations regarding NPR-A on which plaintiffs rely were rescinded between the November and December approvals of the 2026 winter program.

Denial

In denying the plaintiffs' request for an injunction, Gleason said plaintiffs failed to show "that they have a fair chance of success on the merits regarding their claim that BLM's chosen mitigation measures for the 2026 Winter Exploration Program, and particularly ROP C-2, are arbitrary and in violation of the NPRPA."

The act contains provisions to protect surface resources while petroleum resources are developed in the NPR-A, Gleason said, noting that while the act provides for competitive leasing it also specifies "conditions, restrictions, and prohibitions as the Secretary deems necessary or appropriate to mitigate reasonably foreseeable and significantly adverse effects on the surface resources of the" NPR-A.

Unless those measures are arbitrary, courts have less power to specify measures and must give deference to the agency's mitigation measures, she said.

Plaintiffs argue that a 6-inch snow depth was arbitrary because evidence available to the agency showed ROP C-2 would not be effective, but, Gleason said, "The

see **NPR-A INJUNCTION** *page 3*

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● GOVERNMENT

AOGCC rules against CIE on Badami flaring

Cook Inlet Energy has been disputing findings on flaring of produced gas in 2024-25; original order in October, final in January

By KRISTEN NELSON
Petroleum News

Cook Inlet Energy, operator of leaseholder Savant Alaska's North Slope Badami unit, has been disputing Alaska Oil and Gas Conservation Commission findings that its release of natural gas from October 2024 through March 2025 constituted waste.

In a Jan. 23 final order the commission found CIE had wasted natural gas and imposed a civil fine.

CIE was unable to recover produced gas because the vapor recovery unit at Badami was non-functioning from October 2024 to March 2025.

After the commission issued a notice of proposed enforcement action on May 27, 2025, it issued an order Aug. 14 imposing a civil fine of $357,905 for the flaring but, as reported in Petroleum News, allowed the company to write-off upgrading or replacement of the non-functioning vapor recovery unit if those expenses were documented within a one-year period following issuance of its final order.

CIE appealed the order. After a public hearing in October and receipt of additional information from CIE, AOGCC issued its final order Jan. 23. CIE has 20 days to file for reconsideration and if that is denied, the final order may be appealed in Alaska Superior Court.

Reduced fine

In addition to discussing information received from CIE, AOGCC's final order imposed a civil penalty of $313,166, again providing CIE the opportunity to reduce the penalty by replacing or upgrading the vapor recovery unit and eductor system over a one-year period following the issuance of the order and requiring submission of supporting documentation for parts and labor for the work.

The fine was reduced from the original order because of a difference in volumes of gas flared. AOGCC said CIE had not accurately reported volumes as it had included purchased gas.

AOGCC said CIE included gas purchased from Endicott, resulting in "an inflated initial waste determination volume."

Issues cited by CIE

AOGCC said CIE characterized the flaring event as "emergency- and safety-driven and hence not subject to waste cauterization" under AOGCC regulations, citing vapor recovery unit failure, power turbine failure, arctic conditions, Nutaaq Pipeline flow assurance, personnel safety and facility integrity.

The commission said it agreed "that the primary cause of the flaring was the failure of the VRU unit, for which CIE had no backup unit to provide redundancy."

As for the arctic conditions, those "are prevalent across the Alaska North Slope and are thus a reality faced by all North Slope operators for much of each year. Good oilfield practices are expected to be followed throughout the year by all operators, regardless of weather challenges," AOGCC said.

There was also a 23-day power turbine failure at Badami during which all wells were shut-in and there was no flaring. "As such, any emergency situation caused by the power turbine outage does not justify Badami's flaring associated with the extended VRU failure" and the order addresses only flared volumes "related solely to the VRU failure," the commission said.

During the 23-day power turbine outage, diesel generators at the field powered the Point Thomson (Nutaaq) pipeline systems at Badami. Point Thomson operator Hilcorp Alaska told the commission in an email that Point Thomson production via the Nutaaq pipeline does not rely on Badami oil production, but only on power for pipeline systems.

The commission said it agreed on the importance of personnel safety and facility integrity but said "those considerations cannot be used as blanket justifications for a facility to operate at full production and remain in continuous flaring status for nearly half a year."

The commission said "flaring did not occur during the power turbine outage and therefore had no direct relation to personnel safety concerns or the prevention of life-threatening conditions. Rather, the evidence demonstrates that preserving existing oil production was a primary driver for the flaring, as CIE elected to maintain full production throughout the flaring period."

AOGCC said "CIE provided no evidence demonstrating that it took actions in accordance with good oil field engineering practices and conservation purposes to minimize the volume of gas released, burned, or permitted to escape into the air."

Other operators

CIE told the commission it was being treated differently than other Slope operators, citing the commission's approval of flaring by Great Bear Pantheon at its Alkaid 2 well.

The commission said applicable statutes and regulations only allow pre-authorization of flaring or venting of gas "for the purpose of testing a well before regular production."

CIE described Badami B1-33A as an exploration well, but the commission said B1-33A had been in regular production through the Badami production facility for some 134 days prior to the power turbine outage, precluding pre-authorization of flaring or venting from the well.

The commission said it approved flaring at the Alkaid 2 well because that was required to allow Great Bear Pantheon to determine whether it had made an economic discovery and to design production facilities for that discovery. Alkaid 2 relied on temporary production facilities which lacked gas injection capability with produced liquids trucked to another field for final processing.

"CIE also appears to confuse the usage of the word 'economics'," AOGCC said. "In the case of Great Bear Pantheon, the flaring was needed to help determine project economics. In the case of CIE, the flaring was used to contribute to its bottom-line economics." ●

Contact Kristen Nelson at knelson@petroleumnews.com

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NPR-A INJUNCTION

NPRPA does not require BLM to prevent all impacts to surface resources in the TLSA (Teshekpuk Lake Special Area) or elsewhere in the NPR-A," but can satisfy the act's maximum-protective direction with mitigation measures deemed necessary or appropriate by the Secretary of the Interior.

"Here, BLM conducted a reasonably thorough analysis of the impacts of the Winter Program on tundra in the project area on various types of vegetation," Gleason said, and concluded minor impacts to vegetation would be expected and would be minimized through mitigation measures.

"ROP C-2, the measure on which Plaintiffs hang their claim for a preliminary injunction, not only prohibits off-road travel when the soil is insufficiently frozen and snow depth is on average less than 6 inches, but also requires that off-road travel generally use low-ground-pressure vehicles, prohibits bulldozing tundra mat and vegetation to construct trails or seismic lines, and requires that vehicles be selected and operated so as to eliminate direct impact on the tundra."

Considering directives of the act and the record in the case, and deference owned BLM in selecting necessary or appropriate mitigation measures, "the Court finds that Plaintiffs have not shown that they have a fair chance of success on the merits regarding their claim that BLM's chosen mitigation measures for the 2026 Winter Exploration Program, and particularly ROP C-2, are arbitrary and in violation of the NPRPA," Gleason said. ●

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● EXPLORATION & PRODUCTION

Baker Hughes US rig count up 2 at 546

By KRISTEN NELSON
Petroleum News

Baker Hughes' U.S. rotary drilling rig count was 546 on Jan. 30, up by two from the previous week and down 36 from 582 a year ago. The domestic rig count has ranged from the 530s through the 550s since the beginning of June.

For 2025, the count peaked Feb. 28 (and again March 21) at 593, hitting its low point Aug. 29 at 526. 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.

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.

When the count dropped to 244 in mid-August 2020, it was the lowest the domestic rotary rig count had been since the Houston based oilfield services company began issuing weekly U.S. numbers in 1944.

Prior to 2020, the low was 404 rigs in May 2016. The count peaked at 4,530 in 1981.

The count was in the low 790s at the beginning of 2020 prior to the COVID-19 pandemic, where it remained through mid-March of that year when it began to fall, dropping below what had been the historic low in early May with a count of 374 and continuing to drop through the third week of August 2020 when it gained back 10 rigs.

The Jan. 30 count includes 411 rigs targeting oil, unchanged from the previous week and down 68 from 479 a year ago, with 125 rigs targeting natural gas, up by three from the previous week and up 27 from 98 a year ago, and 10 miscellaneous rigs, down by one from the previous week and up by five from a year ago.

Fifty-three of the rigs reported Jan. 30 were drilling directional wells, 478 were drilling horizontal wells and 15 were drilling vertical wells.

Alaska rig count unchanged

Oklahoma (46) was up by three rigs from the previous week. Louisiana (38), North Dakota (27) and Pennsylvania (19) were each up by a single rig.

Texas (226) was down by three rigs week over week while Ohio (13) was down by a single rig.

Rig counts in other states were unchanged from the previous week: Alaska (9), California (8), Colorado (14), New Mexico (102), West Virginia (7) and Wyoming (16).

Baker Hughes shows Alaska with nine rotary rigs active Jan. 30, 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 two from the previous week at 242 and down by 61 from 303 a year ago. ●

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● THIS MONTH IN HISTORY

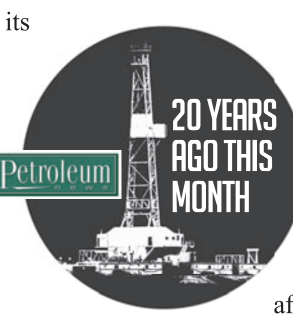
Pioneer OKs project

20 years ago this month: Work begins at offshore Oooguruk field, first independent-operated North Slope field, discovered in 2003

Editor's note: This story first appeared in the Feb. 12, 2006, issue of Petroleum News.

By KAY CASHMAN
Petroleum News

Pioneer Natural Resources said Feb. 6, 2006, that it has approved and is beginning development of its Oooguruk field offshore Alaska's North Slope.



In the shallow waters of the Beaufort Sea, Oooguruk was discovered in 2003 and is approximately 8 miles northwest of the ConocoPhillips-operated Kuparuk River unit.

Oooguruk will be the first independent-operated oil field on the North Slope, which has long been dominated by majors BP and ConocoPhillips. Together with ExxonMobil the three mega-majors own most of the infrastructure on the Slope, including the 800-mile trans-Alaska oil pipeline which transports crude from northern Alaska to the port of Valdez for shipment to Lower 48 markets.

Pioneer's board had been waiting for both a U.S. Corps of Engineers' permit and final issuance of a royalty modification on area leases from the State of Alaska to approve the project. Both the royalty modification and the Corps permit were received Feb. 1, 2006, making it possible for the Dallas-based independent to immediately begin operations to install an offshore gravel drilling and production site.

Pioneer said in a Feb. 6 press release that it plans to complete gravel hauling activities in the 2006 winter construction season.

Pioneer has a 70% working interest in the field. Houston-based Eni Petroleum Exploration, an affiliate of Italy's Eni SpA, has a 30% working interest. Pioneer said Eni is expected to make its participation election for the project during the first quarter of 2006.

Pursuant to a January 2004 farmout agreement, ConocoPhillips retains the right to elect to participate in the project, Pioneer said. (ConocoPhillips, Pioneer and ConocoPhillips are partners elsewhere on the North Slope, including in the National Petroleum Reserve-Alaska.)

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● EXPLORATION & PRODUCTION

Hilcorp plans 2 new wells at Paxton Pad

Ninilchik began production in September 2003 and to date has produced 300 billion cubic feet of gas from 10 pads on south Kenai

By KRISTEN NELSON

Petroleum News

Hilcorp Alaska is planning two grassroots wells and associated infrastructure at the existing Ninilchik unit Paxton Pad.

Paxton is one of the most southerly of the 10 pads at Ninilchik, which follows the coast of the Kenai Peninsula from south of Kasilof to north of Ninilchik.

The Alaska Department of Natural Resources' Division of Oil and Gas said in a Jan. 27 unit plan of operations amendment decision that work at the Paxton Pad would include drilling the Paxton 14 and Paxton 15 wells and installing associated infrastructure required to tie the wells into existing Paxton Pad production facilities. Infrastructure will include: gas flowlines, electrical instrumentation, line heaters, separators, compressors, and well cellars and conductors.

The division said the pad is within the boundaries of the Ninilchik unit some 4 miles northeast of Ninilchik on privately owned surface and subsurface lands.

In December, the most recent month for which Alaska Oil and Gas Conservation Commission production data is available, the Paxton Pad produced 308,007 thousand cubic feet, mcf, of gas, 36% of the field's 852,151 mcf. Twelve wells were in production at the pad in December, with one well shown as shut-in.

Earliest production drilling at the pad was in 2004.

Development by Marathon, Unocal

Ninilchik was developed in the early 2000s by a partnership of Marathon Oil Co., the unit operator, which held 60% interest, and Unocal Alaska with 40%.

The companies announced discovery of a new natural gas reservoir in January 2002 with the drilling of the Grassim Oskolkoff No. 1 35 miles south of Kenai, the first exploration well drilled under a joint operating agreement between the companies in the 25,000-acre Ninilchik exploration unit. Marathon estimated 60 billion cubic feet of gross proven recoverable gas reserves and Unocal acquired additional separate prospects and estimated a net unrisked resource potential at Ninilchik and its additional prospects between 100 billion and 600 billion cubic feet.

AOGCC production data show cumulative production of 300 billion cubic feet through the end of calendar year 2025.

Pipeline needed

The division said in 2003 that 14 exploration wells were drilled on the Ninilchik anticline in the late 1950s, with recent work in the area spearheaded by Marathon which began drilling in the area in 1996 at Corea Creek No. 1.

But a pipeline connection was required.

The companies told the Regulatory Commission of Alaska Jan. 16, 2002, that they planned to order pipe for the Kenai-Kachemak Pipeline in June, geared to meet a Jan. 1, 2004, date for gas to be delivered to Enstar. Subsidiaries of Marathon and Unocal own the pipeline, which started its open season — asking for expressions of interest in contracting for pipeline space — in late 2001.

Construction of the 32-mile, 12-inch diameter Kenai Kachemak Pipeline began in January 2003.

Marathon and Unocal announced official startup of the Ninilchik unit on Sept. 10, 2003, with gas moving through the recently completed pipeline. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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HISTORY

A subsea flowline and facilities will be installed during 2007 to carry produced liquids to existing onshore processing facilities at the Kuparuk River unit. Some 40 horizontal wells will be drilled to develop 50 million to 90 million barrels of estimated gross oil resources, the company said in its press release. According to past reports Oooguruk is expected to hold some 70 million barrels of recoverable oil and produce 15,000 to 20,000 barrels per day.

KEN SHEFFIELD

In its Feb. 6 release Pioneer said drilling could begin as early as fall 2007. In January Pioneer Natural Resources Chairman and CEO Scott Sheffield said first oil could be produced as soon as 2008.

Total gross capital investment for the project, including drilling and facility costs, is estimated at $450 million to $525 million.

Production is expected to peak in 2010. "Using current oil prices, the field is expected to produce for at least 25 years before reaching its economic limit," Pioneer said.

"The Oooguruk field development is the first of what I believe will be many successful projects for Pioneer in Alaska and adds a new long-lived asset to our strong U.S. base," Scott Sheffield said in the Feb. 6 release.

Ken Sheffield, president of Pioneer's Alaska subsidiary, said the company appreciated "the cooperative spirit demonstrated by the State of Alaska, the North Slope Borough and the federal regulatory agencies in working with Pioneer" on its plan and allowing it to maintain its project schedule.

The Corps permit includes a list of approved maintenance work on the island, as well as six general conditions and 18 special conditions, including directives regarding abandonment of the site once production has ceased, the terms and conditions listed in U.S. Fish and Wildlife's January biological opinion, Mine Site E rehabilitation and navigation-related requirements. ●

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GUBIK UNIT

series of successful tests within the ASRC acreage, most recently starting with the Gubik No. 3 well in 2007. These wells have delineated a gas column within the proposed Gubik unit area, collectively containing in excess of 1 trillion cubic feet of sweet gas. There is also evidence of light oil in the system.

Strong has conducted reviews of the successful wells and studied the petroleum systems capable of high pressure at unusually shallow depths.

This work is proposed to continue with well and seismic on offset lands, identifying the basis for a potential commercial gas development.

Although no exploration wells have been drilled on the applicant's leases, several wells drilled in close proximity to the proposed Gubik unit have formed Strong's geological interpretations.

The Gubik wells, 1, 2, 3 and 4, and Chandler No. I provide geologic control regarding the reservoir, source and seal characteristics of the rocks they penetrated and are crucial for understanding the reservoir characteristics, source rock potential, and sealing capabilities of the region.

These and other wells have been studied and tied to the local seismic dataset, including Anadarko's 3D, Renaissance Alaska's 2D and 3D seismic surveys. Multiple vintages of 2D seismic data were acquired after the start of the NPR-A drilling program, with the most significant data being GSI USGS NPRA data set, Strong said.

Timing is right

Strong believes that the federal government's current emphasis on Alaska resource development has improved the investment climate, and the company is committed to advancing Foothills gas to market.

Public reserve estimates place the Gubik field reserves at approximately 1 TCF of sweet gas in-place, with no CO_2 or H_2S processing required, with substantial gas reserves in the immediate Foothills area referenced during the previous consideration of the Anadarko's bullet line feasibility.

Strong plans to collect and assess the drilling and seismic data in the Gubik Foothills area to determine the reserve distribution and then let a contract to a third party(ies) study to determine the commercial feasibility of a gas development.

Based on this valuation, it is expected that collectively the Gubik Foothills Area contains sufficient potential reserves to justify the estimated development and infrastructure costs for the stranded gas accumulations. This will lead to additional seismic and drilling in the area in the five-year timeframe attached to Strong's proposed plan of exploration.

Strong's field program will be supported by an approximately 80-mile tundra snowpack trail extending from the Dalton Highway to the Gubik unit.

Local ice roads and pads may be constructed to support drilling operations. Access to the area during the summer is by the nearby Seabee airstrip and pad.

Proposed unit POE

Strong believes there is a timely opportunity to further assess both the Gubik field and the near Foothills region and has engaged with ASRC and the Alaska Gasline Development Corp. to gauge general interest.

This suggests a timeframe of approximately five years for a potential lease extension, Strong said.

As part of a work program Strong plans to: integrate Anadarko and Renaissance 3D programs, as well as the 2D data in 2026-27; initiate a third-party reserve and commercial feasibility study in 2027; seek a major investor to acquire additional acreage surrounding the Gubik feature and to partner in the work program; assess potential pipeline routes; begin collecting environmental data to support the proposed winter drilling program in 2030-31; drill one to two additional wells; finalize area development plan and proceed with approvals and environment permits.

Background

Strong began to acquire leases in the Gubik field in 2020 and has a combined current leasehold of 1,928 acres.

The Gubik anticline was first drilled after World War II in 1951 by the U.S. Navy (currently referenced as Gubik 2). The well blew out while pulling pipe to change the bit, proving the structure to be hydrocarbon productive.

Gubik Unit No. 1 was drilled in 1963; one zone tested at a max rate of 890 thousand cubic feet per day, and another at 500 mcf per day.

Gubik No. 2 was drilled in 1951; the well blew out while pulling pipe.

ASRC selected the Gubik acreage near and east of the Colville River as part of the Alaska Native Claims Settlement Act given the area's oil and gas potential. These lands did not include the river bottom acreage that the state retained.

In 1998 ASRC entered into an agreement with Anadarko Petroleum Corp. covering 3.2 million acres. Anadarko drilled two additional wells, No. 3 and 4, on the structure in 2008-09.

Gubik No. 3, 2008, tested 14.4 million cubic feet per day in the Tuluvak and 0.9 mmcf per day in the Nanushuk.

Gubik No. 4, 2008, had gas shows on the mud log but no test was conducted.

Chandler No 1, also drilled by Anadarko, was directly south of the Gubik field and established the presence of a deeper gas reserve.

East Umiat also had gas potential. Based on 3D and well results Anadarko proposed a bullet line from the area to provide gas to Southcentral Alaska.

Gubik leases

Strong, as a partner in Renaissance Alaska, first acquired Gubik leases in 2007-08. In addition to geologic studies, Renaissance shot high-resolution seismic across the structure.

Renaissance sold the Umiat field to Linc Energy in 2010. Linc later relinquished the leases.

Woodstone acquired ADL 392717 and 392718 in 2015, and Strong acquired the Woodstone leases in June 2020. An in-depth evaluation of the Gubik feature using 2D seismic and well data from DNR's database has been recently concluded.

The areal extent of the Gubik field is not fully defined, and approval of the Gubik unit will allow the unit operator to build and utilize one set of infrastructure and facilities to develop all of the Gubik field leases, maximizing the efficient recovery of oil and gas from the leases and minimizing the adverse impacts on the surface and other resources, including hydrocarbons, gravel, sand, water, wetlands, and valuable fish and wildlife habitat'

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OIL PRICES

$66.10, as WTI plunged $2.32 to close at $62.89 and Brent plummeted $4.39 to close at $66.30.

The Organization of the Petroleum Exporting Countries and its allies agreed Feb. 1 to keep oil production levels unchanged for March.

On Feb. 4 crude futures turned sharply higher on reports that U.S.-Iran talks scheduled for Feb. 6 might not happen over venue and subject matter disagreements.

WTI jumped $1.93 Feb. 4 to close at $65.14 and Brent gained $2.08 to close at $69.46.

Iran wants only to discuss its nuclear program, while the U.S. seeks a wider range of subjects including Iran's nuclear program, its ballistic missiles and its sponsorship of militia groups in the region, The Wall Street Journal reported Feb. 4.

"We'll see if we can get back to the right place," U.S. Secretary of State Marco Rubio said. "If the Iranians want to meet, we're ready."

As Petroleum News went to press Feb. 5, WTI and Brent prices were lower in Asian trade after reports that the U.S.-Iran talks were back on track for Feb. 6.

Surprise drawdown of US inventories

The Feb. 4 crude price jump was supported by a surprise drawdown of U.S. reserves.

U.S. commercial crude oil inventories for the week ended Jan.30 — excluding Strategic Petroleum Reserve supplies — decreased by 3.5 million barrels from the previous week to 420.3 million barrels — 4% below the five-year average for the time of year, according to U.S. Energy Information Administration data released Feb. 4.

Commercial crude stocks were expected to be unchanged according to the average estimate of nine analysts and traders in a Wall Street Journal poll.

Total motor gasoline inventories increased by 0.7 million barrels on the week to 257.9 million barrels — 4% above the five-year average for the season, the EIA said. Distillate fuel inventories decreased by 5.6 million barrels to 127.4 million barrels — 2% below the five-year average for the time of year.

Gasoline inventories were estimated in the Journal poll to have risen by 1.3 million barrels, while distillate fuel inventories were estimated to fall by 2.4 million barrels.

ANS fell 13 cents Jan. 30 to close at $69.74, while WTI fell 21 cents to close at $65.21 and Brent edged 2 cents lower to close at $70.69.

On Jan. 29, ANS jumped $1.94 to close at $69.87, WTI leapt $2.21 to close at $65.42 and Brent leapt $2.31 to close at $70.71.

ANS jumped $1.49 Jan. 28 to close at $68.55, as WTI rose 82 cents to close at $63.21 and Brent rose 83 cents to close at $68.40.

ANS rose 29 cents over the week from its close of $67.06 Jan. 27 to a close of $66.77 Feb. 3. ●

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COMPANY REPORTS

in 2013. Oil Search became the 51% working interest owner in 2017 in partnership with Repsol. Oil Search was acquired by Santos in 2021.

Phase 1 of Pikka development is 98% complete, Laliberte said, with first oil expected in the first quarter of this year, ramping up to 80,000 barrels of oil per day by the third quarter of the year. It's a $3 billion investment, including 120 miles of pipeline, a seawater treatment plant at Oliktok Point, 25 wells drilled to date — with a total of 45 wells planned — and production facility modules in place and undergoing commissioning.

The first phase will develop roughly 400 million barrels of oil, Laliberte said.

Laliberte also discussed marketing the oil.

Santos doesn't own transportation infrastructure other than its own pipeline, so it has flexibility in selling its oil — on the U.S. West Coast or possibly in Asian markets — allowing it to look for the best price, benefitting both Santos and the state.

Balash, who was previously in Alaska's Department of Natural Resources, said because Santos doesn't own major transportation infrastructure, it will be easier for the state to value oil for royalty calculation.

Santos believes Quokka and Horseshoe are of comparable size to Pikka, with a Quokka discovery made in 2020, and an appraisal well spud there Jan. 3 which the company hopes will provide enough information to proceed with the next stages of development there, Balash said. Another well at Horseshoe is planned in the winter of 2026-27, allowing for the continued growth of production from the area.

And there is growth planned at Pikka: One drill site is in operation and two others are permitted, but require additional investment, and the production facility will ultimately need to be expanded to handle up to 120,000 bpd.

ConocoPhillips

ConocoPhillips Alaska's presentation, by Barry Romberg, vice president for commercial and midstream, and Colin Wolfe, vice president for finance, looked at five areas of the company's activity: core business stability, major projects and programs, generational investments, exploration and critical infrastructure.

Wolfe discussed the complexities of operating on the North Slope: Arctic conditions, the distance to market and logistics, subsurface uncertainty, oil price and state fiscals. The two largest variables impacting economics are fluctuations in price and subsurface risk, he said.

Core business stability requires investments to address the natural decline of fields and stabilize production, as well as ensuring that major equipment stays in good condition, including reservoir development, operating excellence and workovers to ensure wells continue to flow, stemming base decline.

Major projects are "rate-adding projects," Wolfe said, with four currently underway: Nuna, Coyote and Narwhal on the western North Slope and West Sak at Kuparuk. These projects can cost almost a billion dollars and require at least a few years to come to full production, he said, noting that since the passage of Senate Bill 21 ConocoPhillips has "consistently spent about a billion dollars per year in this category."

Willow is an example of a generational investment, Romberg said, with first oil expected in 2029, and has taken close to 25 years from initial exploration to where it is today. Kuparuk in the 1980s and Alpine in the early 2000s are other examples of generational investments, he said.

Willow is also a greenfield project — there was no infrastructure in place, no road access, Romberg said. Work on fabrication and delivery of the Willow operations center took place in 2024-25, and Central Facility fabrication, delivery and commissioning began in 2024 and will continue through 2028, followed by pre-drilling from 2027-28 and complete tie-ins in 2028.

2025 work at Willow included construction at the Bear Tooth 1 drillsite so pre-drilling of wells can begin in 2027, Romberg said. During the 2025 winter construction season 12 modules were delivered to the Willow Operations Center and the Willow Construction Camp opened, enabling year-round construction. Willow Central Facility pad work to prepare for delivery of modules which are about 50% complete on the U.S. Gulf Coast and will travel up on the 2027 sealift.

The expected winter construction headcount at Willow is around 3,000, with 300 permanent jobs expected following startup.

Romberg said ConocoPhillips has four exploration wells and seismic planned for this winter. He said those wells aren't expected to add barrels anytime soon: That exploration in the National Petroleum Reserve-Alaska will be "our children's future."

The fifth area is infrastructure. Romberg said ConocoPhillips is the only Alaska oil company operating in every piece of the value chain — from exploration to transporting cargoes to the West Coast and Asia. The company is one of the owners of the trans-Alaska oil pipeline system, owns tankers and operates a fleet of airplanes.

Hilcorp

Luke Saugier, Hilcorp Alaska senior vice president, told the committee that Hilcorp operates on both the North Slope and in Cook Inlet, with two rigs active in Cook Inlet and six on the North Slope. (See story on Hilcorp's Cook Inlet operations in Feb. 15 issue of Petroleum News.)

On the North Slope Hilcorp operates from the Point Thomson unit on the east to Nikaitchuq and Ooguruk in the west, including Endicott, Prudhoe Bay, Northstar and Milne Point.

In 2025, it had rigs at Nikaitchuq, Milne Point, Prudhoe Bay — where it operates on behalf of itself, ConocoPhillips and ExxonMobil — and at Point Thomson, where it operates on behalf of itself and ExxonMobil.

Hilcorp will drill a development well at Point Thomson, the first since 2016, in a project that started in 2024, and required moving Doyon 15 from Nikaitchuq to Point Thomson during the 2025 barging season, multiple ice roads and major construction projects.

The new well is forecast to produce 6,000 barrels of oil per day, with first oil anticipated in the second half of 2026.

The 2025-26 ice road season, from November through January, saw 107 miles of ice roads built at a cost of more than $50 million, with the longest the 48-mile Point Thomson ice road.

There was a turnaround at Gathering Center 2 at Prudhoe which involved 500 people over 34 days and included: upgrading the gas dehydration system, valve and piping repairs/replacement, PWI pump control upgrades, installation of tie-in for future interstate vessel and replacement of flare tips. The project improved the gas quality going to the gas plants and increased the gas rate from 1.05 billion cubic feet to 1.3 bcf.

At Prudhoe, work has begun on Project Taiga, two new drilling pads: Omega and I, to develop additional Schrader Bluff resource in western Prudhoe Bay. Initial development was from L Pad in 2024, with some 10,000 bpd of new production online.

Additional appraisal and a plan were developed in 2025, leveraging Hilcorp polymer flood experience.

Gravel will be laid for O Pad in 2026, with front-end engineering and design progressing.

Investment is estimated at $1 billion-plus for each pad, resulting in 30,000 additional bpd from each.

At Nikaitchuq Hilcorp plans a 13-well program, installation of polymer injection and a production header expansion with 2026 production adding 9,000 bpd and first oil in the first quarter. ●

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INLET LEASE SALE

America's energy needs, strengthening national readiness and creating opportunities for investment and jobs."

Bid evaluation

The lease sale will be held March 4 with bids opened online at 10 a.m. BOEM must receive bids by 10 a.m. March 3.

BOEM said it would evaluate high bids using its bid adequacy procedures. The Department of Justice and Federal Trade Commission will review results for antitrust considerations before the bids are accepted and leases issued.

The complete lease sale package including instructions for accessing the livestream of the bid reading is available at www.boem.gov/ak-bbc1.

BOEM received no bids in a 2022 federal Cook Inlet sale and a single bid, from Hilcorp, in the 2023 Cook Inlet sale.

The most successful recent federal Cook Inlet sale was in 2017, when Hilcorp took 14 tracts.

There are currently eight active federal OCS leases in Cook Inlet, all held by Hilcorp.

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ANWR LEASE SALE

with strong potential for oil and gas development, BLM said, noting the area may contain between 4.25 billion and 11.8 billion barrels of technically recoverable oil, according to the U.S. Geological Survey.

A call for nominations and comments notice will be published in Feb. 3's Federal Register to solicit feedback on what tracts should be made available in a lease sale this winter, which will be the first lease sale in the 1.56-million-acre coastal plain following passage of the One Big Beautiful Bill Act in July.

This announcement comes after Interior issued a new record of decision in October reopening the coastal plain to oil and gas development, reversing the previous administration's plan that offered only the statutory minimum amount of acreage, and placed other restrictions that made development all but impossible, BLM said, noting the Feb. 2 action, "advances the President's direction to unleash Alaska's extraordinary resource potential, consistent with Executive Order 14153 and Secretary's Order 3422."

Under the One Big Beautiful Bill Act, the BLM must hold no fewer than four lease sales in the coastal plain by 2035, with each sale offering at least 400,000 acres for lease. When developing sales, BLM can consider tracts currently available for leasing under the 2025 Coastal Plain Oil and Gas Leasing Program Record of Decision.

Interested parties may nominate or comment on tracts until March 5, 2026.

Additional information, including a map showing available areas and legal descriptions of the tracts are available on the BLM Alaska Oil and Gas Lease Sales website.

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BRIDGING PROJECT

those individuals, Corri Feige, former commissioner of the Alaska Department of Natural Resources, told Petroleum News in a recent interview with key members of the team.

It's important to note that there will only be vaporous gas moving off the FSRU. Not LNG. All LNG will be regasified on the FSRU.

Gardes Holdings Inc., an independent oil and gas company that has operated in the Cook Inlet basin for several years will be working in partnership with Glacier Oil & Gas Corp., a long-time Cook Inlet producer.

"With proven, existing infrastructure, facilities, and pipelines in the southernmost area of the Cook Inlet, we are excited to embark on the next phase of delivering energy solutions for Alaskans, by Alaskans," Stephen Ratcliff, CEO of Glacier Oil & Gas Corp. said when the project was first announced. "Our ability to utilize our infrastructure allows a timely solution for meeting a gas supply demand in real time, while upholding our standard for health and safety of our employees and the environment we operate in."

"It's no secret that Southcentral Alaska faces a critical energy gap in just a few short years that many players in our industry are working hard to overcome. With our FSRU project, Cook Inlet LNG aims to meet an immediate gas supply need, not impede longer-term gas supply projects currently being discussed in the public sphere," said Cook Inlet LNG Project Lead Rob Bryngelson when the project was first announced. He has brought more than a dozen FSRU projects to market worldwide.

In PN's most recent interview with key players in the project Bryngelson said Cook Inlet LNG has "completed an extensive amount of work related to the design of the project. Most recently, we wrapped up our metocean analysis looking at the wind, waves, currents, and extreme conditions to ensure that the project can operate as anticipated in the local environment, even under extreme conditions. In parallel, we are advancing the design of the mooring system and gas interconnection from the FSRU to the platform, while confirming gas flow dynamics into the regional gas system."

The project will maximize the use of existing oil and gas infrastructure in the Cook Inlet basin with the initial project

"In parallel, we are advancing the design of the mooring system and gas interconnection from the FSRU to the platform, while confirming gas flow dynamics into the regional gas system."
—Rob Bryngelson

structured to supply 22 billion cubic feet of natural gas per year to the region.

The FSRU will be moored alongside the existing Osprey platform on the west side of Cook Inlet. Gas will be fed into the pipeline system through the platform's existing infrastructure.

Perfect timing

The developers said the timing is ideal for converting the Osprey platform because oil production from it is waning, which means it is nearing the end of its economic life; it will be shut-in in about two years.

Cook Inlet LNG's project will be coming online in mid-2029.

Osprey best choice

There are other platforms in Cook Inlet that have already been shut-in but the benefit to using the Osprey is that it is currently being fully maintained. Once a platform is shut-in putting it back online involves additional cost and risk, Gardes said.

Keeping costs as low as possible is a goal of the FSRU project developers.

The mooring anchors that will be placed on the floor of Cook Inlet for the mooring of the FSRU are the only new infrastructure that will be required for Cook Inlet LNG's project.

Mines, other customers

The developers of the FSRU project said it can be expanded, depending on demand, although there are no plans to do that at this time.

But they want to be sure there is sufficient energy to meet the possibility of new mining projects and other developments during the gap before longer-terms LNG projects come online.

"It's a very exciting project, based on proven technology," Bryngelson said. "We're offering a bridging solution, an insurance policy for natural gas supply but it can also be a permanent solution." ●

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