Petroleum news

page 4 EIA says US crude continues at record rate; Brent at $64 in June

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Airborne surveys over ANWR 1002 unlikely but USGS still releasing new geologic data prior to lease sale

With SAExploration's 3D seismic survey delayed until next winter, there will be less data about the geologic potential of the ANWR 1002 area available to bidders in the federal lease sale later this year.

"The latest news indicates that an airborne gravity gradiometry survey, which has been discussed by at least two vendors, seems unlikely this summer. So, only those companies that co-own the vintage 2D data will have any subsurface data," USGS senior research geologist Dave Houseknecht told

see **ANWR SURVEYS** *page 11*

ANWR border dispute talks fail; IBLA ruling expected by year-end

The high-level talks to resolve the ANWR border dispute between the U.S. Department of the Interior and the Alaska governor's office either failed or never materialized because both a state and a federal official told Petroleum News they are waiting for a ruling on the matter from Interior's Board of Land Appeals; a decision that is expected before the end of the year.

When Interior refused to transfer the 19,322 acres between the Canning and Staines rivers that run perpendicular to one another along the western side of the Arctic National Wildlife Refuge, the state filed an appeal with IBLA, an administrative law court within Interior. A decision would either change the current border of ANWR and put the acreage in state's hands

see **BORDER DISPUTE** *page 11*

Clarification regarding Eni's Nikaitchuq, Oooguruk processing

The June 30 issue of Petroleum News carried a story titled, "Eni takes over at Oooguruk on Aug. 1; to finish drilling, test Nikaitchuq North well in 2020," reporting on news that Eni had taken over 100% ownership and operatorship of the North Slope Oooguruk unit, which is adjacent to Eni's Nikaitchuq unit.

The following paragraph needs clarification:

Already 100% owner and operator of the adjacent Nikaitchuq oil field, one of the reasons Eni gave for taking over at Oooguruk was because it wanted new oil to take advantage of significant spare capacity in its standalone Nikaitchuq production facility, which can handle 40,000 barrels per day and can be expanded to 50,000 bpd, per Eni Alaska Vice President Whitney Grande.

In fact, Grande did not say that one of the reasons Eni took

see **ENI CLARIFICATION** *page 7*

Kalubik Creek exploration site cleanup includes piling removal

Final cleanup is scheduled this summer for an exploration well drilled some 50 years ago with the debris removal plan, prepared by Weston Solutions Inc. for Chevron Environmental Management Co., targeting surface debris, including 55-gallon drums and wooden pilings from a drilling platform.

Unocal drilled the exploration well, Kalubik Creek No. 1, in the winter of 1970. The site is in the Kuparuk River unit between the Palm prospect and Drill Site 3H. Chevron Environmental Management Co. is involved because Unocal, Union Oil Company of California, was acquired by Chevron in 2005.

see **KALUBIK CREEK** *page 7*

LAND & LEASING

Placer terminated

Unitized in 2011, ASRC Exploration commits to production in 2022

By KAY CASHMAN
Petroleum News

The increasingly bitter dispute between Alaska's Division of Oil and Gas and ASRC Exploration appears to focus on two related issues.

For AEX, a subsidiary of Arctic Slope Regional Corp., the issue seems to be the challenge of developing the small oil field (small by North Slope elephant standards) at a pace its corporate leadership is obviously not comfortable with. One of the reasons for that discomfort is clear from AEX's filings with the division: The Placer unit cannot support its own standalone processing facility and is 100% owned by

CORRI FEIGE

AEX, whereas most North Slope oil fields are explored and developed with partners that help shoulder the costs and risks.

For the division, part of the Alaska Department of Natural Resources, the issue is the length of time it is taking AEX to get its state leases into production. Discovered in 2004 by former operator ConocoPhillips and unitized in 2011 by new operator AEX, the latest proposed plan of development for the Placer unit puts it in production in 2022, at the earliest, whereas other unit operators make the effort to bring their fields online within a shorter timeframe. In fact, most operators complain about the length of time

see **PLACER TERMINATED** *page 6*

LAND & LEASING

Deep Creek contracted

Hilcorp wants more time; state refuses to further extend beyond producing area

By KRISTEN NELSON
Petroleum News

The Alaska Department of Natural Resources' Division of Oil and Gas has denied a request from Hilcorp Alaska for another extension of contraction of non-participating area portions out of the Cook Inlet Deep Creek unit. Units contract to the area contained in producing participating areas 10 years after production begins, subject to DNR commissioner discretion.

Deep Creek is jointly managed by DNR and Cook Inlet Region Inc., both of whom own leases included in the unit.

The Deep Creek unit was formed in 2001; sustained natural gas production from the Happy Valley participating area began in November 2004, which put the 10-year mandatory contraction date in November 2014.

In late December 2011, as the sale of Union Oil Company of California's Cook Inlet properties to Hilcorp Alaska was closing, the division and CIRI agreed to delay any "discretionary contraction" of the unit "for a reasonable period of time after close of the pending asset sale between Union and Hilcorp Energy Alaska LLC."

Hilcorp's request

Since the 2011 agreement, Hilcorp has requested and the division has granted, delay of contrac-

see **DEEP CREEK** *page 10*

NATURAL GAS

Gas on collision course

One-time 'clean energy' linked by researchers to coal based on release of methane

By GARY PARK
For Petroleum News

For years natural gas has sheltered itself in a self-proclaimed world of clean energy ... well, at the very least, cleaner than its first cousin, crude oil.

Now that boast, which has just started to generate handsome returns from such products as liquefied natural gas and compressed natural gas and renewed Canadian optimism in the resource, is coming under assault.

A fresh analysis from Global Energy Monitor, GEM, a global network of researchers tracking fossil fuel projects, has produced a blunt warning that natural gas, rather than being a partial answer to climate problems, is instead the "new coal."

> *Methane, the main component of natural gas, is reckoned to be 30 times more harmful than carbon dioxide emissions through a super-heating effect that could be twice as damaging as the current installed base of coal in the United States, GEM told CNN Business.*

The explosion of spending on new LNG facilities — most of them in the U.S. and some in Canada — will be accompanied by new calculations for methane leakage from the LNG supply

see **COLLISION COURSE** *page 8*

● EXPLORATION & PRODUCTION

Jade on target with Sourdough permitting

C-plan review underway; Jade #1 to be drilled this coming winter from ice pad in Area F of Point Thomson unit, eye on development

By KAY CASHMAN
Petroleum News

Permitting for Jade Energy LLC's new Sourdough well on the eastern North Slope is on track member-manager Erik Opstad told Petroleum News July 10.

Opstad oversees Jade's operations in Alaska and is a 50% owner. The company plans to drill an oil well in the first quarter of 2020 in the Sourdough prospect on ADL 343112 in area F of the Point Thomson unit, or PTU.

The state lease, the most southeasterly in PTU and adjacent to the western border of the ANWR 1002 area, holds two mid-1990's Sourdough oil discovery wells that were drilled by BP. In a 1997 press release BP estimated Sourdough holds 100 million barrels of recoverable oil.

Jade is part owner of the lease, per a farm-out agreement with PTU operator ExxonMobil and the other working interest owners. In November, as part of the farm-out, ExxonMobil assigned a 63% working interest in ADL 343112's Tract 32 to Jade, retaining a 2% overriding royalty.

ERIK OPSTAD

Jade's multiyear oil discharge prevention and contingency plan is currently up for review with the Alaska Department of Environmental Conservation. It proposes to address prevention and response measures for a response-planning standard volume of 5,500 barrels per day for 15 days, a total 82,500 barrels.

Brookian main target

The primary target, the application said, is the "Point Thomson Brookian resource, which is 25 API gravity oil, contained within the overpressured reservoir sands found throughout the PTU and nearby Badami oil field, which is 22 air miles west of PTU."

Along with recent 3D seismic work, "this well will allow Jade to evaluate and then select an option for development of the Brookian reservoir."

According to the application, Jade's initial plans call for drilling and testing the Jade No. 1 exploration/appraisal well this coming winter on an ice pad about 3.7 air miles southeast of the PTU airstrip that will be accessed by an ice road from the PTU mine site.

Once a vertical pilot hole is drilled to true vertical depth the well will be plugged back and drilled at a high angle into the Brookian reservoir, Jade said, noting it

see JADE PERMITTING page 4

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● EXPLORATION & PRODUCTION

Cryo: cutting edge cuttings analysis

The measurement of volatiles from drill cuttings — the under-utilized byproduct of drilling; cuttings free, but not worthless

By STEVE SUTHERLIN
Petroleum News

A cutting-edge technology to analyze volatiles from drill cuttings via a cryo trap mass spectrometer can provide significant cost savings compared to conventional methods of petroleum system analysis, according to Mike Smith, President of Advanced Hydrocarbon Stratigraphy Inc.

"It's a pretty inexpensive operation because you're just using the natural byproducts from the well," Smith said in a presentation to a May 31 technical breakout session at the state Geologic Materials Center in Anchorage. The session focused on the potential for new investigative technologies and machine learning systems to better assist geoscientists and resource companies to meet the challenges of interpreting Alaska geology.

The proprietary volatiles analysis service invented by AHS is distributed by Baker Hughes.

"This machine is aimed at present day volatiles that are in rocks, not the ancient volatiles," Smith said.

The process yields two types of deliverables, operational recommendations and acreage and basin assessment, he said.

"VAS delivers the occurrence and composition of oil and gas in the cuttings, as well as mechanical strength, permeability, oil saturated water, proximity to pay and location of potential pay zones and faults," Smith said. "This approach allows for rapid cost-effective data integration across well generations for understanding bypassed pay, optimizing landing zones, and petroleum system assessments."

The analysis has two main focuses, Smith said.

The first is pay identification and evaluation, he said, adding, "Where is it, what is it, and how much is there?"

The second is reservoir properties, he said. "How is it going to produce, and will it produce?"

Gently, please

Smith said the rocks from the well site require very gentle handling, particularly in light of modern polycrystalline diamond compact drill bit technology.

"We had a big change in the '90s when we introduced PDC bits on a wide scale: the cuttings became very small and difficult to analyze for volatilizes," he said. "We're very gentle when we catch the cuttings; we don't want to get them on the shaker table; we take a kitchen strainer where the flow line pours into the possum belly."

There are two kinds of cutting analysis, one where samples are sealed at the well, and one where samples are washed and dried before shipping to the lab. Smith said, adding, "They tell somewhat different information."

"The seal-at-the-well ones (with) water based mud, we rinse them off and they're sealed in a little brass tube, and we put them in as they're coming to the surface.

"If it's oil based mud — you know those little tea balls when you make tea, you have the leaves of tea and you kind of bob it up and down — we fill those with cuttings, take a hose to it and wash the oil based mud off of it," he said. "We never use solvents; we don't use detergents; we don't use diesel; we just use water from the hose to get rid of the oil."

Cryo time

The captured cuttings are fed into a cryo trap mass spectrometer invented and built at AHS, Smith said.

The measurement of volatiles from drill cuttings relies on an extraction and analysis technology that utilizes all of the volatilizes in the cuttings sample, he said.

"Volatilizes from samples are frozen onto liquid nitrogen traps and analyzed by allowing the frozen volatiles to sublimate and enter the mass spectrum spectrometer, according to their sublimation points under high vacuum," he said. "With the cryo trap mass spectrometer, if it freezes it's gonna get analyzed — so you see everything; you see the hydrocarbons; you see the organic acids; the inorganic acids."

Helium and methane are analyzed prior to beginning to warm the cryo trap as they aren't frozen.

"Some things don't freeze: the helium and the methane are two biggies; we catch them in a little valve and then we burst them into a pipe by themselves.

"It's kind of like the butcher and the pig, 'everything but the squeal;' we even want to catch the squeal."

Volatiles are extracted from each individual sample at two distinct pressures. This provides a measure of compound separation and quantification like that obtained in gas chromatography-mass spectrometry systems — however unlike GCMS this unique CTMS system is non-selective. All volatile compounds that can be extracted and frozen are analyzed.

"It's non-selective." Smith said. "Do I want to do core compounds, do I want to do noncore compounds … acids, non-acids?"

Multiple millibars

"Our samples go into a little brass tube, a quarter inch in diameter, we come in with a piston and we squeeze them — we always squeeze with the same amount of pressure, we always put in the same amount of rock," Smith said. "The soft rocks are very thin and the hard rocks are very thick, so we just measure that with a micrometer and plot it, and then we have

see **CUTTINGS ANALYSIS** page 5

EXPLORATION & PRODUCTION

US drilling rig count down 4 at 963

On July 3, prior to the Fourth of July holiday, the number of rigs drilling for oil and natural gas in the U.S. was down four from the previous week at 963.

A year ago, the count was 1,052 active rigs.

Houston oilfield services company Baker Hughes reported that 788 rigs targeted oil (down five from the previous week) and 174 targeted natural gas (up one). One miscellaneous rig was active.

The company said 66 of the U.S. holes were directional, 839 were horizontal and 58 were vertical.

New Mexico was up three rigs from the previous week, Alaska was up by two and West Virginia was up one.

In California, Colorado, North Dakota, Ohio, Pennsylvania, Utah and West Virginia the rig counts were unchanged from the previous week.

Texas, with the most active rigs in the country, 463, was down one rig from the previous week.

Louisiana was down four rigs from the previous week; Oklahoma was down five.

Baker Hughes shows Alaska with nine rigs active, up two from a year ago.

The U.S. rig count peaked at 4,530 in 1981. It bottomed out in May 2016 at 404.

The June international rig count, which Baker Hughes also reported on July 3, stood at 1,138, up 12 rigs from 1,126 counted in May and up 179 from 959 in June 2018. The company said the international offshore rig count was 246, up six from May and up 51 from 195 active in June 2018.

The U.S. rig count averaged 969 in June, down 17 from May and down 87 from the 1,056 last June.

Worldwide, the June average was 2,221, up 39 from May and up 69 from the 2,152 counted in June 2018.

—KRISTEN NELSON

● FINANCE & ECONOMY

US crude production continues record rate

EIA says Brent averaged $64 in June, down $7 from May, down $10 from June 2018; Henry Hub forecast to average $2.50 per million Btu

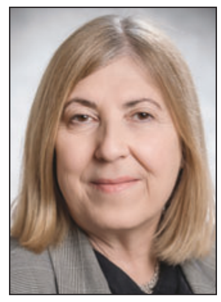
By KRISTEN NELSON

Petroleum News

Brent crude oil spot prices averaged $64 per barrel in June, down $7 from May and down $10 from June 2018, the U.S. Energy Information Administration said in its July Short-Term Energy Outlook, released July 10. The agency said it expects Brent to average $67 per barrel in the second half of 2019 and to remain at that level in 2020. Brent averaged $71 in April and May.

"The recent price declines largely reflect increasing uncertainty about global oil demand growth as a result of increasingly weak global economic signals," EIA said. Upward pressure on prices has been limited by weakening oil demand and strong supply growth in the U.S., the agency said, factors which have outweighed decreasing supply in Venezuela and Iran, extension of the OPEC-plus production limitation agreement through the first quarter of next year and Saudi Arabia's continued over-compliance with the existing agreements.

EIA said it expects markets to be relatively balanced in the second half of the year and is forecasting Brent crude to remain near current levels, averaging $67 from July through December.



LINDA CAPUANO

Factors which could cause crude prices to vary significantly from annual average forecasts include global economic developments, geopolitical events, adherence to the OPEC-plus targets, events in Venezuela and Libya and any disruptions in transportation, EIA said.

The agency noted that "the U.S. tight oil sector continues to be dynamic, and quickly evolving trends in this sector could affect both current crude oil prices and expectations for future prices."

West Texas Intermediate are forecast to average $62 per barrel in the second half of the year and $63 in 2020.

Natural gas

The forecast for natural gas prices is down from EIA's June short-term outlook.

"EIA expects that natural gas prices at Henry Hub will average $2.35 per million British thermal units through September, down quite a bit from our previous forecast," EIA Administrator Dr. Linda Capuano said in a statement accompanying the outlook. "EIA lowered the forecast after mild June temperatures reduced gas power burn, contributing to several weeks of plus-100 billion cubic feet storage injections. EIA is also seeing continuing efficiencies in drilling technology that reduce the cost of natural gas production and contribute to a lower price environment," she said.

US crude oil

"EIA continues to expect record U.S. crude oil production in 2019 and again in 2020, due in large part to significant development in the Permian basin in Texas and New Mexico. The July forecast expects U.S. production to exceed an average of 13 million barrels per day in 2020," Capuano said.

U.S. crude oil production reached a record-high 11 million bpd in 2018 and is expected to average 12.4 million bpd this year and 13.3 million bpd in 2020, the agency said.

"If the domestic and global forecasts are realized, the United States would maintain its status as the world's leading crude oil producer in both years," EIA said.

The U.S. is increasing oil production from tight oil formations in the Permian region of Texas and New Mexico, which accounts for almost 1 million bpd of the increased production expected in 2019 and 700,000 bpd of the 2020 increase. The agency said it expects the remaining growth to come from the Bakken, Niobrara, Anadarko and Eagle Ford regions, with the federal Gulf of Mexico accounting for 200,000 bpd of growth in 2019 and 100,000 bpd in 2020.

Production from the Permian is expected to average 5.4 million bpd by the end of 2020. "Favorable geology combined with technological and operational improvements have been responsible for making the Permian one of the most prolific regions of U.S. crude oil production," expected to average 4.4 million bpd this year and 5.1 million bpd in 2020, EIA said.

2018 pipeline constraints in the Permian have been partially alleviated by the Sunrise and Seminole pipelines, constructed in the first half of the year. EIA said a downside risk in the Permian is increased production of associated natural gas. "If natural gas pipeline constraints are not eased and tighter limits are put in place on flaring natural gas, drilling in areas with high concentrations of natural gas in the Permian region might be reduced," the agency said.

The Eagle Ford is forecast to rise by 57,000 bpd from 2018 levels to 1.4 million bpd and then grow by another 34,000 bpd in 2020. EIA said the Eagle Ford is significantly smaller than the Permian, with fewer opportunities to drill.

In the Bakken, production for 2018 is estimated to have been 1.3 million bpd and is forecast to grow by 130,000 bpd this year and by 50,000 bpd in 2020. New pipeline projects out of North Dakota will further reduce pipeline constraints, but the area has a downside risk in that drilling is more susceptible to cold weather and lower crude oil prices.

In the federal Gulf of Mexico, expected to average 1.9 million bpd this year and 2 million bpd in 2020, 14 new projects came online in 2018, nine more projects are expected to come online this year and three more in 2020. ●

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JADE PERMITTING

"firmly believes … the deployment of horizontal production wells is a critical element in commercializing the PTU Brookian opportunity in Area F, as well as its adjoining areas."

Upon completion of "drilling and extended production testing, analysis of that data will be integrated into the Jade 3D Brookian seismic model."

With those results in hand, the company will put together a second plan of development and submit it to the Alaska Department of Natural Resources.

Jade's first plan of development for Area F was approved April 4 by acting Division of Oil and Gas Director James Beckham.

In his approval, Beckham said that based on analysis of the appraisal well data, Jade "will move forward accordingly with additional development at Area F and adjoining areas in the 2020-2021 winter drilling season. Current plans include drilling an additional lateral into the Brookian reservoir and production testing. The need for additional delineation wells and the overall economic feasibility of a field development program at Area F will be considered following the 2020-2021 season." ●

Contact Kay Cashman at publisher@petroleumnews.com

● PIPELINES & DOWNSTREAM

Refiners' ad criticizes ethanol mandates

By TODD RICHMOND

Associated Press

An association representing oil refineries launched a television ad in four swing states July 8 criticizing President Donald Trump's moves to expand the use of ethanol in gasoline.

The American Fuel and Petrochemical Manufacturers' 30-second spot will run statewide through July in Michigan, Pennsylvania, Ohio and Wisconsin. The group didn't immediately say how much it was spending on the buy.

The ad claims that Trump promised a "win-win energy policy for all Americans. But for small refineries, unchecked ethanol mandates are job killers, hurting the backbone of our manufacturing economy."

It goes on to say: "President Trump, only you can fix this."

The ad underscores how Trump's administration has found itself caught between the oil industry and corn growers, two key flanks of Trump's base.

For more than a decade federal law has mandated that oil refineries mix ethanol into their fuel. The Trump administration's former Environmental Protection Agency chief, Scott Pruitt, had angered lawmakers, growers and ethanol processors by granting exemptions sparing refineries from that mandate. The dispute sparked a billboard campaign and a tractor rally by angry Midwestern farmers last year.

This past May the administration tried to calm the dispute by lifting a summertime ban on gasoline mixed with 15% ethanol. The ban had been imposed out of smog concerns but the administration's move cleared the way for year-round sales and expanded the ethanol market. Only a fraction of U.S. gas stations currently sell the 15% blend, known as E15.

Officials in the EPA Region 5 office, which is responsible for Wisconsin, Michigan and Ohio, didn't immediately respond to an email seeking comment on the ad. No one immediately responded to an email sent to the general inbox for the EPA Region 3 office, which oversees Pennsylvania.

Corn growers pushed back against the ad. Tad Nicholson, executive director of the Ohio Corn and Wheat Growers Association, said in a statement that the ethanol industry supports tens of thousands of jobs and gives consumers a choice at the pump. Jim Zook, executive director of the Michigan Corn Growers Association, said the industry has contributed to millions of dollars of economic activity.

"This ad is nothing more than another attempt by the petroleum industry to maintain their near-monopoly on the fuel supply at the expense of American consumers," Zook said.

No one immediately responded to emails sent to corn grower associations in Pennsylvania and Wisconsin. ●

NATURAL GAS

Big lift to Canadian Atlantic LNG venture

After years of making measured progress towards a final investment decision on the first LNG project for Canada's Atlantic Coast, Pieridae Energy has taken a giant leap forward.

It is paying C$175 million in cash and issuing C$15 million worth of shares to Royal Dutch Shell as it closes in on securing the remaining feedstock natural gas it needs for the first train of the Goldboro project.

Pieridae said the acquisition of Alberta gas production is a key step towards approving the C$10 billion plant to be located northeast of Halifax, Nova Scotia, with its sights set on starting commercial operations in 2023 to ship 10 million metric tons a year to the northeastern United States and Europe.

Company Chief Executive Officer Alfred Sorensen said that, with all of the regulatory approvals in place, Shell's ownership stake in Goldboro will be beneficial.

"Obviously they are a big player in the LNG story and we'll take advantage of their expertise anyway we can while they are a shareholder and hopefully they will remain one for a while," he told the Globe and Mail.

Shell also active on Pacific Coast

Shell is also leading the charge to build the first large-scale LNG operation on the Pacific Coast, with its 40% stake in the C$40 billion LNG Canada project along with a consortium of Asian partners.

With the acquisition, Pieridae will get production of 29,000 barrels of oil equivalent in natural gas, natural gas liquids and condensate, along with three gas plants in southern Alberta.

The company plans to use TC Energy and Enbridge-owned pipelines to ship Alberta gas to the Nova Scotia facility and has signed a long-term sales agreement with Uniper, a German utility.

The Shell assets will ensure Pieridae has enough gas to meet the sales contract.

The German government has said Uniper is eligible in principle for up to US$4.5 billion in loan guarantees, including US$1.5 billion for upstream natural gas development.

Shell Canada President Michael Crothers said his company is pleased to take the Shell assets "to the next stage of their development."

If the Goldboro project gets a corporate go ahead it will plug the gap created when the Sable Offshore Energy Project (in which Shell was a 31.3% partner) ceased operations last December after 19 years of shipping gas to Nova Scotia, New Brunswick and the northeast U.S.

—GARY PARK

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CUTTINGS ANALYSIS

permeability from cuttings.

"So how do you get permeability from cuttings? This machine was designed to do that," he said. "We analyze each sample under two different pressures, the washed and dried samples we analyze at 20 millibars, we do a chemical analysis of that.

"Same exact piece of rock, same sample, we pull out another extract at 2 millibars — so first a 50th of an atmosphere then a 500th of an atmosphere; we analyze that and then we compare those and that's what lets us do permeability."

High is low

At the beginning developers at the company thought the higher pressure — 20 millibars — would yield more oil and gas from high permeability rocks.

"It turns out to be just the opposite," Smith said. "The real high permeability rocks don't give anything at 20 millibars and they give a lot at 2 millibars.

"Between the drilling and coming up two miles in the mud, and washing, and drying, and everything else, your good reservoir rock — you lose your oil and gas from those."

"Old timers like me will talk about seeing a core: 'if it doesn't bleed oil till it gets to the surface, it's probably too tight to produce.'

"It's the same thing with cuttings, if you have sub-millimeter cuttings and they're still loaded with oil and gas, they're probably not going to produce much of anything," Smith said.

"Then we have stuff that tells us about the nature of the oil," he said, adding, "The benzene/xylene ratio is very important for mapping oil migration pathways."

AHS delivers two kind of logs, a property log and an oil and gas component log.

"We use about 400 microliters of rock, so that's a little bit less than a tenth of a teaspoon," Smith said. "We like to get a teaspoon if we can; we can go down to 200 microliters if we have to." ●

Contact Steve Sutherlin at stevepna@hotmail.com

AEX puts Placer on market

ASRC Exploration President Teresa Imm told Petroleum News May 28 that the company put its North Slope Placer oil field on the market.

"We have a 100% working interest," Imm said. "We feel it's time to market the asset."

She would not say whether the company would consider all offers, including a partner in the project. Imm has since told Alaska's Division of Oil and Gas that AEX is open to partnership offers.

TERESA IMM

AEX, a subsidiary of Arctic Slope Regional Corp., the Native regional corporation for northern Alaska, retained Detring Energy Advisors of Houston, Texas, to sell the North Slope unit and related assets.

AEX is currently analyzing its production options, including the management of development costs.

According to Detring, the Placer unit offsets multiple prolific oil fields and includes a development-ready project with the Kuparuk C reservoir and the potential for additional stacked pays in the Alpine and Nanushuk intervals.

The 8,768-acre unit could have 110 million barrels of original oil in place, with between 35 million and 45 million barrels of oil recoverable across all horizons, Detring said, noting Placer is in a good neighborhood, with the ConocoPhillips' Kuparuk River oil field on the east and bordering the promising Oil Search-operated Pikka unit on the west, which is scheduled to come online in 2022 with 30,000 barrels of its own oil processed in a neighboring company's facility and then in 2024 with its own 120,000 barrel a day facility.

"Well and analog data indicate the field is an ideal development candidate due to favorable average porosity (23.4 percent), high permeability (430 mD), and light oil viscosity (26.2API @ 1.51-1.85cP)," Detring said, adding, the "reservoir model indicates Kuparuk C development generates $107 million PV-10 value (BTAX) and greater than 8,000 barrels per day of oil peak rate utilizing two producers and two injectors."

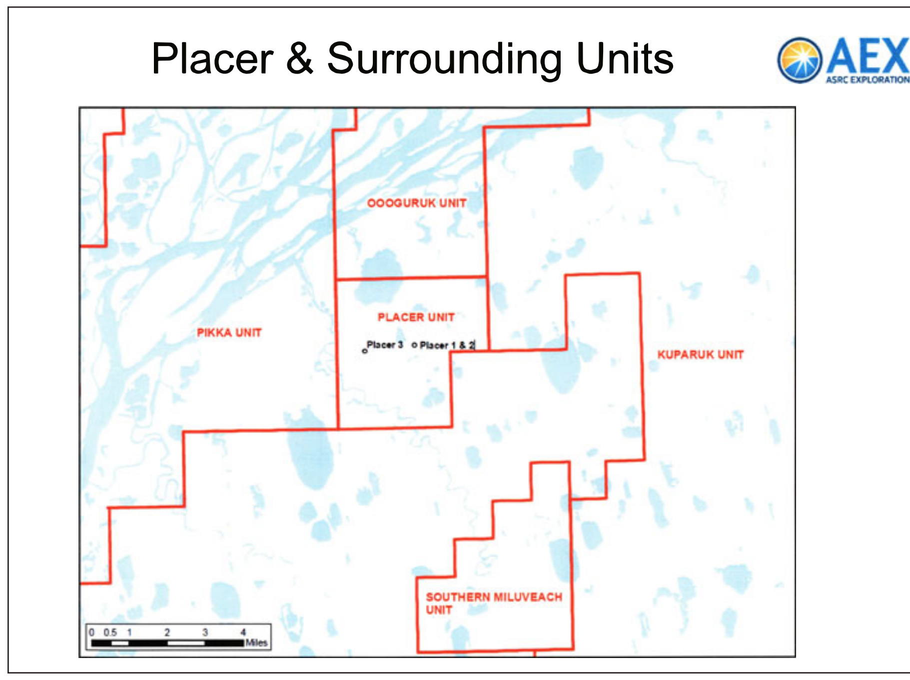
Two of three wells suitable

Detring said that of three wells drilled to date in the Placer unit, two are usable for future development.

According to Petroleum News records, AEX drilled the Placer No. 3 well in 2016, which the state certified as being capable of producing in paying quantities in December of the same year. Placer No. 1 and Placer No. 2 were drilled in 2004 by former field operator ConocoPhillips, with Placer No. 1 dubbed the discovery well. Placer No. 2 was never tested and dubbed a dry hole.

The offering also includes three seismic datasets merged and re-processed to

see ON THE MARKET page 8



continued from page 1

PLACER TERMINATED

permitting takes in Alaska to bring a discovery to production.

A law degree would have been an asset during Petroleum News' review of the filings by AEX and subsequent decisions by the division, because the agency's July 2 decision to terminate the Placer unit and reject the company's latest proposed plan of development appears to partly ignore DNR Commissioner Corri Feige's April 18 ruling on a Sept. 28 appeal from AEX.

One of the primary complaints in AEX's appeal to the commissioner, which followed the division's approval of the company's 2018 plan of development, or POD, was the division's continued insistence that a POD, by statute or regulation, required "on-the-ground" activity, or field work to advance a unit to production when office-based analysis and planning was all that was sometimes needed.

AEX asked Feige to direct the division to stop demanding on-the-ground activities for approval of unit plans — a requirement that threatened the Placer unit's existence and thus the retention of its leases by AEX.

Field work not required

Agreeing with AEX on that, but not all, points raised by the company, the commissioner told the division in her ruling that Alaska law does not require field work, or on-the-ground activity, to be contained within a POD to preserve a unit.

"Although field work is a valid consideration among other variables, field work by itself is not one of the specific criteria listed and required … under 11 AAC 83.303. In Alaska's regulations related to unitization, there is no definition of 'operations,'" she wrote in her decision.

The division's interpretation of its regulations requiring on-the-ground activity as the definition of operations for a POD approval is "reversed, with limitations," Feige ruled seven months after the appeal was filed. (The delay was likely due to the fact the Sept. 28 appeal was filed with former DNR Commissioner Andy Mack, but when a new governor, Mike Dunleavy, was sworn in Dec. 3 and Feige was named commissioner, the appeal was shuffled to her.)

> *"To be clear, the division is within its authority to apply the criteria in 11 AAC 83.303 et. seq. and determine that on-the-ground field work is necessary to progress a unit with a certified well toward production and thus condition approval of a proposed plan of development accordingly."*
> *—Corri Feige, commissioner, Department of Natural Resources*

The limitations Feige noted in her decision included the division's right to require field work to help advance a unit to production.

"To be clear," she wrote, "the division is within its authority to apply the criteria in 11 AAC 83.303 et. seq. and determine that on-the-ground field work is necessary to progress a unit with a certified well toward production and thus condition approval of a proposed plan of development accordingly."

Missed deadline leads to termination

AEX told the commissioner in the appeal that it "reluctantly" included in the 2018 and third POD the re-entry of Placer No. 3 in order to satisfy the division's insistence that on-the-ground activity was nec-

see PLACER TERMINATED page 8

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KALUBIK CREEK

While there was an ice pad and access via an ice road, there was no gravel pad, instead, the plan prepared for CEMC by Weston Solutions says, "the drilling rig was set on a wooden deck supported by pilings."

Kalubik Creek No. 1 was spud Dec. 16, 1969, completed and suspended March 27, 1970, and plugged and abandoned May 4, 1973.

Alaska Oil and Gas Conservation Commission records show the well, a vertical hole, reached a total measured and vertical depth of 10,107 feet.

Work done to date

The plan says the reserve pit at the well was capped and closed in the winter of 2002-03, work approved by the Alaska Department of Environmental Conservation in late 2004.

The U.S. Army Corps of Engineers required that the overburden cap on the reserve pit be vegetated and monitored for 10 years or until performance standards were met.

Performance monitoring continued through 2015, the plan says, with debris observed in the vicinity of the reserve pit in a 2015 inspection by the Alaska Department of Natural Resources, CEMC and Weston Solutions.

DEC and DNR requested field investigations of the debris, which were conducted in 2017 and 2018, and the report says that based on investigation and remediation activities to date, "final removal of various historical debris present at the site, including debris discovered in 2015," is the only remaining activity anticipated at the site.

"The debris types associated with the affected areas generally included abandoned 55-gallon drums along with various cans, canisters, wooden pilings, metal parts, plastics, plywood, and pallets."

The report says small oily sheens were also reported on surface water, and surface water was sampled in 2017, with laboratory analysis results "within the range typically found in North Slope ponds," and as a result no further remedial action is required "beyond the drum and debris remedial."

Following a site investigation in 2018, which included geophysical surveys, results indicated that the reserve pit appeared stable, with encapsulated waste frozen in place.

2019 work plan

There are seasonal restrictions for debris removal activities at Kalubik Creek and based on investigations debris removal activities are planned for July or August when tundra and surface water bodies are typically thawed. Access will be by helicopter and track mounted Tucker vehicles.

Debris site 1 is a shallow pond some 350 feet northwest of the well marker, with known debris including some 55 empty drums within the pond, and various cans, canisters, metal parts, plastics, wood pallets and plywood. Previous investigation has shown that none of the drums contain original contents, all are in poor condition, rusted and contain holes.

Debris site 2 is a thermokarsted pond some 400 feet south of the well marker. Known debris includes four rusted, perforated drums and heavy gauge wire.

The cement mound is some 10 feet west of the well marker, with known debris including gravel, cement cobbles, pieces of dimensional lumber, nails and ash.

Some 200 wooden pilings were used to support the drill rig platform. They were cut to approximately tundra grade in 1998, but many have been pushed to some 18 inches above tundra grade by seasonal ice formation.

Removal

Waste and debris removal will be based on visual observations with all large items to be removed, the report says, although it is anticipated that the entirety of the small items in the ponds may not be realistically recoverable.

The tundra pond, debris site 1, will be dewatered as the 55 drums and other debris are submerged and dewatering will prevent the need for a diving operation. The estimated volume of the pond is 380,000 gallons and it is estimated at 250,000 gallons will be removed so drums and other debris can be safely removed. The tundra pond is expected to recharge following dewatering and drum removal.

Drums and other debris will be removed manually to the extent possible, with a tripod and pulley system used to assist.

Debris will be sorted by type and placed in supersacks for transport.

The drums are believed to be empty of original content; any drums found to contain what appears to be original content "will be placed into an over-pack drum for transport," with samples of the drum contents collected for waste characterization prior to disposal.

A Bell 412 helicopter will sling load the supersacks from Kalubik Creek to a staging area; in the event of weather conditions unsuitable for helicopter use, the supersacks will be transport on tundra travel vehicles.

In the staging area debris will be placed in roll-off containers and transported to Deadhorse or the Oxbow Landfill. The report says it is estimated that two roll-off dumpsters will likely contain the site waste.

Drums will be transported to Deadhorse "for appropriate cleaning and crushing" prior to disposal.

—KRISTEN NELSON

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ENI CLARIFICATION

over at Oooguruk was because it wanted new oil to take advantage of significant spare capacity in its standalone Nikaitchuq production facility — this was an assumption made by Petroleum News. Rather, all Grande said (in a November 2017 presentation) was that the Nikaitchuq production facility can handle 40,000 barrels per day and be expanded to 50,000 bpd. He said this in relation to the Nikaitchuq North exploration well, should it prove successful.

A decade ago, when Pioneer Natural Resources operated the Oooguruk unit, it did consider using the facilities at Nikaitchuq which company officials said would require an eight-mile line to deliver Oooguruk oil to Nikaitchuq. But nothing ever came of it and Oooguruk oil is still processed at the ConocoPhillips-operated Kuparuk River unit.

It remains to be seen whether Eni will build the pipeline and cancel its agreement with ConocoPhillips to process Oooguruk oil in its own processing facility at Nikaitchuq.

—KAY CASHMAN

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COLLISION COURSE

chain, warns the report titled The New Gas Boom.

It said the combination of plunging renewable energy costs and rising climate change concerns will make many LNG projects "unprofitable in the long term," putting much of US$1.3 trillion of investment in the sector at risk.

Issue 'fugitive gas'

The so-called "fugitive gas" could see the world spurn gas in the same way it has mounted a threatening campaign against crude oil, the report suggested.

James Browning, one of the authors, said new research has proved there is considerably more fugitive gas than studies found five years ago, and the gas is "also a bigger contributor to climate change than was understood."

Methane, the main component of natural gas, is reckoned to be 30 times more harmful than carbon dioxide emissions through a super-heating effect that could be twice as damaging as the current installed base of coal in the United States, GEM told CNN Business.

The report said the falling cost of LNG technology has resulted in at least 202 world-wide LNG projects in the development stage, including 116 export terminals and 86 import terminals, with that development concentrated in North America.

Warning to investors

That has prompted the authors to issue a warning to those who are investing in LNG, undercutting an estimate by the Canadian Association of Petroleum Producers that Canada could meet domestic consumer demand for the next 300 years.

While most of the LNG industry confidently rides the wave of vast supplies and rising demand it is being faced with a tidal wave of international agreements to lower natural gas consumption, which could deter lenders and investors if the "new coal" label takes hold.

Browning said that countries suffering the impact of climate change will soon be looking for less costly alternatives to gas, especially as it becomes clearer that escaping methane from drilling and shipping can make gas as damaging as coal.

Already, India, which is suffering from rising temperatures, is discovering that solar energy is cheaper than fossil fuel alternatives.

Search for fixes

The gloomy GEM assessment only compounds the frantic search by the Alberta government of Premier Jason Kenney for ways to reverse the fortunes of a resource that is vital to its economic well-being at a time when scores of smaller producers are facing threats of bankruptcy at a time of rock-bottom commodity prices.

The government and producers are searching for fixes, including possible production cuts.

"There's certainly a concerted effort to fix what is going to be a pretty significant crisis this fall," said Tristan Goodman, president of the Explorers and Producers Association of Canada.

"I get the impression that the government is really interested in working with everybody to get some stability in the market," he said.

The immediate response from the Kenney administration is to offer tax relief this year for shallow gas producers by lowering municipal taxes on shallow wells and pipelines by 35% — a one-time deal that will be covered by the government.

It will benefit about 30 companies operating upwards of 66,000 wells in southeastern Alberta.

A government official confirmed that in future years the tax rate will be lowered.

But many of the challenges are viewed as intractable, such as volatile prices, infrastructure constraints, shrinking markets in the United States resulting from shale gas, investor apathy and growing liability from abandoned wells.

Goodman said the government action "corrects, fairly rapidly ... the unreasonable tax rates that could lead to further bankruptcies." ●

Contact Gary Park through publisher@petroleumnews.com

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ON THE MARKET

create a geologic model, Detring said, adding that the reservoir simulation model ties directly to AEX geologic, geophysical, and petrophysical frameworks.

The Placer project is a contiguous, operated unit ideally situated for production, Detring said, adding that there are six suitable drilling rigs on the North Slope.

The Kuparuk C sand is a proven and delineated reservoir with more than 3.5 billion barrels of oil produced to date on the North Slope, Detring said.

The giant Nanushuk topset discovery in the Pikka unit is the newest North Slope discovery with more than 1.5 billion barrels of oil potential, Detring said.

The Nanushuk is well defined by seismic, with oil shows in nearby wells. Alpine C is the eastward extension of the Alpine C discovery in the Pikka unit, Detring said, adding that the main reservoir in the ConocoPhillips operated Colville River unit has produced more than 440 million barrels of oil to date.

The virtual data room for the Placer project offering opened June 5. Detring said at the time that bids would be due on July 17.

—KAY CASHMAN

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PLACER TERMINATED

essary to preserve the unit.

The company did not re-enter the well as promised in the winter of 2019-20.

The July 2 letter from the division's acting director advising AEX of the termination of the Placer unit was based on AEX's failure to re-enter the Placer No. 3 well and conduct bottom-hole pressure testing. It also alerted the company to another July 2 letter denying its latest and fourth POD.

The termination letter said, "In approving the 2017 POD, the division raised concerns that AEX did not include any unit operations in its POD. The division pointed out that AEX's plans for office-based work of analysis and planning activities were not unit operations," noting the last "operations" were done in 2016 when the company first drilled and tested Placer No. 3.

The situation is further complicated by a Feb. 28 letter from AEX to the division with the first amendment to the third POD that said, "AEX is currently waiting on the division to approve the amended plan of operations submitted on January 8, 2019. Based on the 30-day approval period we anticipated the POO approval by February 7, 2019 in order to commence our operations in a timely manner. To date, AEX has received all other permits necessary to conduct the testing operations with the exception of the ADEC MG-2 permit, which can be authorized in 1-day, and the USFWS Polar Bear LOA, which may not be required. AEX has been communicating with the division throughout the permitting process and were told that the amended POO was complete and awaiting final approval. It now appears that the division has been with-holding its approval of our amended POO until AEX provides an amendment to the 3rd POD, instead of approving the amended POO and requesting the amendment to the 3rd POD simultaneously to the POO approval. Without an approved POO, AEX cannot go ahead with its Placer #3 testing operation this winter."

A POO is a plan of operations, yet another issue raised in the flurry of filings and decisions.

AEX has 20 days to file an appeal with the commissioner. ●

Contact Kay Cashman at publisher@petroleumnews.com

Wolfpack Land Company is Offering 4,761 Acres of Prime Mineral Interest Ownership in the Kenai, Alaska Area for Oil and Gas Leasing

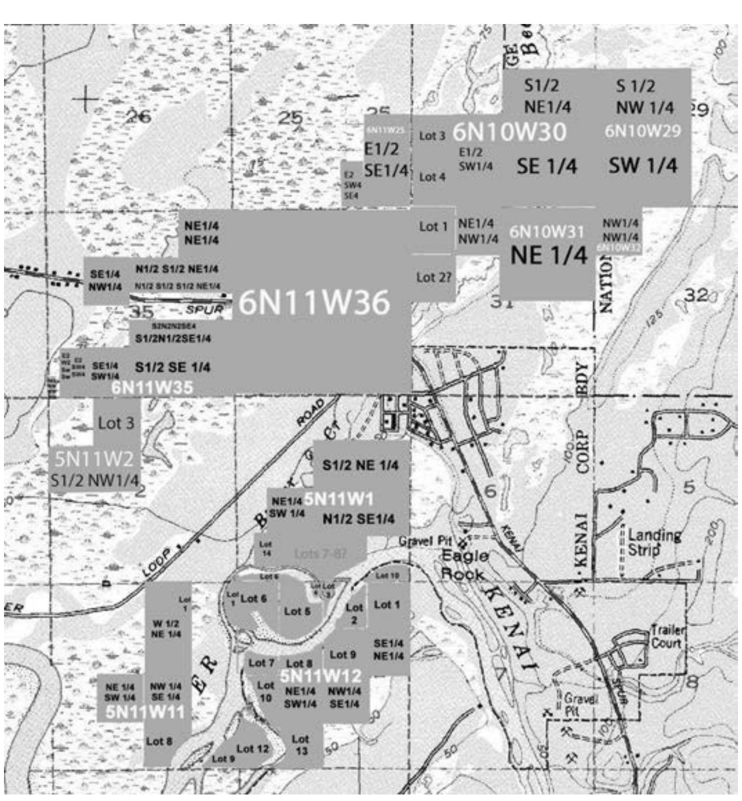
Beaver Loop Road Area

Township 5 North, Range 11 West (Surveyed)
Section 1, Lots 6-8, 10, 14, S1/2NE1/4, N1/2SE1/4, NE1/4SW1/4;
Section 2, Lots 3 and 6, Sl/2NW1/4.
Section 11, Lots 1, 8, 9, W1/2NE1/4, NW1/4SE1/4, NE1/4SW1/4;
Section 12, Lots 1-13, NE1/4SW1/4, SE1/4NE1/4, NW1/4SE1/4.
Containing 1,063.51 acres, more or less.

Township 6 North, Range 10 West (Surveyed)
Section 29, SW1/4, S1/2NW1/4
Section 30,Lots 3 & 4, E1/2SW1/4, SE1/4, S1/2NE1/4
Section 31,Lots 1 & 2, NE1/4NW1/4NE1/4
Section 32,NW1/4NW1/4
Containing 947.98 acres, more or less.

Township 6 North, Range 11 West (Surveyed)
Section 25, El/2SE1/4,El/2SW1/4SE1/4
Section 35, NE1/4NE1/4, N1/2S1/2NE1/4, N1/2S1/2S1/2NE1/4, SE1/4NW1/4, E1/2SW1/4SW1/4, E1/2W1/2SW1/4SW1/4, W1/2SW1/4SW1/4SW1/4, SE1/4SW1/4, S1/2SE1/4, S1/2N1/2N1/2SE1/4, S1/2N112SE1/4.
Section 36,All
Containing 1,105 acres, more or less.

Aggregating 3,116.49 acres, more or less.

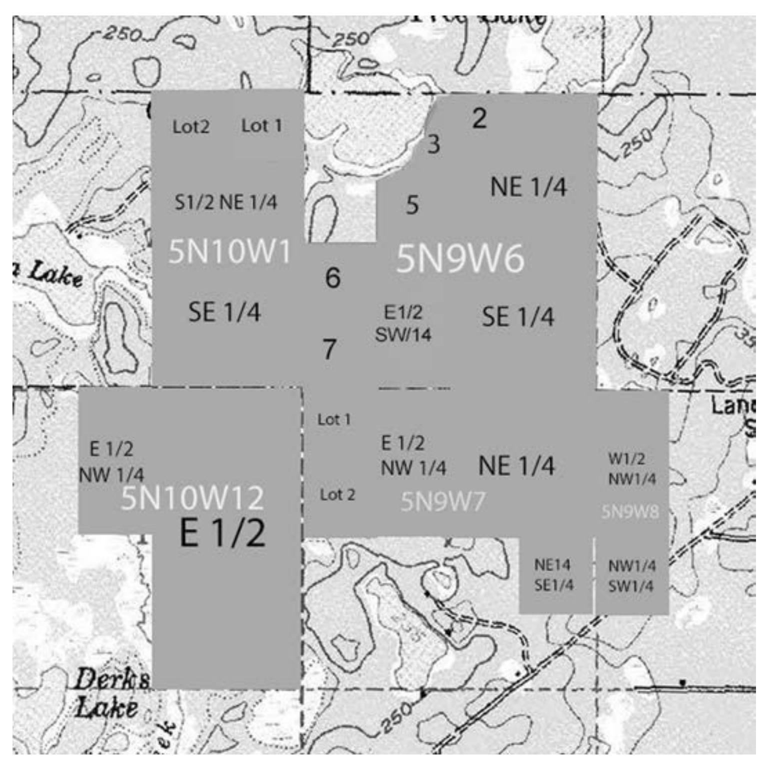


Robinson Loop Road Area

Township 5 North, Range 9 West (Surveyed)
Section 6, Lots 2, 3, 5-7, SW1/4NE1/4, El/2SWl/4, SEl/4;
Section 7, Lots l, 2, El/2NWl/4, NEl/4, NEl/4SEl/4;
Section 8,Wl/2NW1/4, NWl/4SWl/4.
Containing 926.23 acres, more or less.

Township 5 North, Range 10 West (surveyed)
Section l, Lots l, 2, Sl/2NEl/4, SEl/4;
Section 12, El/2, El/2NWl/4.
Containing 718.96 acres, more or less.

Aggregating l,645.19 acres, more or less.



These fee mineral rights have significant known hydrocarbons on or very near them. This prospect is not in a remote area. Everything is road accessible, winter and summer, with easy access to oilfield suppliers. Seismic data available.

Terms: $3,000/acre, 25% royalty.

For more details contact Wolfpack Land Company, Houston, Texas, at jim5thgn@outlook.com, jim@applecapital.net, or (907) 394-9148.

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DEEP CREEK

tion of the unit.

On July 2, however, division acting Director Jim Beckham denied a request from Hilcorp to delay contraction of the unit.

In a May 1 request, Hilcorp Alaska said it was requesting another extension, this until May 31, 2021, "in order to support the continued exploration efforts for the DCU."

Hilcorp said in 2017 it completed two of six planned stratigraphic test wells "in the vicinity of the DCU." It said those two tests, with other data the company had already obtained, "significantly progressed our exploration and development efforts."

But unexpected high-water flow rates from the Sterling formation encountered in drilling the stratigraphic test wells, and unusually muddy conditions, prevented the company from drilling two of the four stratigraphic test wells planned in 2017, Hilcorp said.

The company planned to continue the stratigraphic test well program in 2018, but due to "unanticipated high costs of drilling the stratigraphic test wells in the DCU area," the company decided not the drill the remaining four stratigraphic tests in the DCU area.

The company said results of its 2016-18 exploration drilling programs in the area tempered its 2019-20 plans for Deep Creek.

"The high costs associated with drilling the stratigraphic test wells in this area made it very difficult to justify the economics of the test well project," Hilcorp said, but noted it had already "made a substantial investment in exploring the DCU" including completion of a 3D seismic program/data processing in 2013; completion of remote sensing data/data processing in 2015; completion of 2D seismic program/data processing in 2016; and completion of two of the six planned stratigraphic test wells in 2017.

Hilcorp's plans

The company said results of its 2016-18 exploration drilling programs in the area tempered its 2019-20 plans for Deep Creek.

Hilcorp said it drilled and evaluated the Greystone No. 1 0.6 miles south of DCU in 2016-17 and drilled and evaluated the Seaview No. 8 well 12 miles southwest of DCU in 2018.

"Both these new field wildcats changed our ideas about successful trap types and reservoirs," the company said, and based on that, the company plans to continue exploring Deep Creek by re-processing and analyzing seismic "using potential field's data" and by drilling one or two shallow 2,500-foot exploratory wells targeting the Lower Sterling and Upper Beluga formations.

"The planned shallow exploratory well will be done using new technology, and the details of the proposed drill wells are confidential," the company said, but indicated it would provide details at the request of DNR and/or CIRI.

"The proposed exploration plans will not be completed until at least the end of 2020, requiring Hilcorp to request this delayed contraction until May 31, 2021," the company said.

State's rejecting

In rejecting the request to delay mandatory contraction, the division cited both Hilcorp's 2019 plan of development for Deep Creek and the request to delay contraction, and said it was denying Hilcorp's request and contracting Deep Creek to the existing participating area effective June 1. All production from the unit is allocated to the Happy Valley participating area, the division said.

While Hilcorp described long-range plans, it made "no firm commitments to further explore or develop the DCU," the division said, and noted that in the 2019 POD for Deep Creek Hilcorp stated that it had not completed planned work from the 2018 POD and had no short-term plans to continue exploration or development at Deep Creek.

"The public has an interest in diligent exploration and development of the State's resources," and the division said Hilcorp's plans "do not further exploration or development in the DCU outside of the Happy Valley Participating Area."

Hilcorp has 20 calendar days from the July 2 date of the decision to appeal to the DNR commissioner. ●

Contact Kristen Nelson at knelson@petroleumnews.com

Petroleum news — Oil Patch Bits

The Alliance seeks nominations for board members

The Alliance Board Nominations & Elections Committee said July 1 that it is seeking members to serve on the Alliance Board of Directors. There are seven, three-year terms available in the FY 2020 election. Election results will be announced at the annual meeting on Oct. 17. Newly elected members will begin serving their term Oct. 18.

Board members of the Alliance are leaders in the oil, gas, and mineral resource industries. The number one priority for the Alliance is to advocate on behalf of their members to the oil, gas, and mining producing and exploring companies. Board members facilitate this priority by focusing on improving the business climate for the support industry by communicating with legislators and the administration in Juneau, educating the general public about the support industry and issues that affect it, serving on committees and participating in and supporting Alliance events throughout the year. These events are prime networking opportunities for all members of the Alliance.

Board members review industry issues, voice Alliance positions and develop strategies to improve and empower its organization. An individual may serve a maximum of two consecutive 3-year terms on the board.

If you are interested in running for a seat on the Alliance Board of Directors, please forward the following materials to the Alliance office: Written statement of candidacy — Nominees must confirm their intent to run for a seat on the board. This may be provided in a letter format. Biography — A brief summary of employment, involvement in industry and/or business-related organizations and other pertinent information. Photograph — Electronic headshot preferred.

Nominations must reach the Alliance office by Sept. 3. Your company must be a member in good standing in order for you to qualify as a candidate for the Alliance Board. Email nominations to: rlogan@alaskaalliance.com or mail: 3301 C Street, Suite 205, Anchorage, AK 99503.

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ANWR SURVEYS

Petroleum News July 10.

The agency has completed a grounds-up reprocessing of 1,451-line miles of vintage 2D seismic data collected from the ANWR 1002 area in 1984 and 1985. The purpose was to tease out more detail than was apparent in the initial data.

The 2D survey was funded by a consortium of companies led by Exxon. The 11 that are left are Anadarko, BP, Chevron, ConocoPhillips, ExxonMobil, Hess, Marathon, Murphy, Oxy, Shell and Total.

Houseknecht was hoping the reprocessed data would be available to them, but the U.S. Department of Interior's Office of the Solicitor "has determined that the USGS is not permitted to make the reprocessed 2D data available to any companies, including those that own the rights to the original raw seismic data," he said.

But there is other information that USGS is releasing to the public.

"Our seismic interpretations … are focused on reducing critical geological uncertainties. We are not permitted to show or publish images of the reprocessed ANWR data, so our public presentations use analogs from offshore (ANWR 1002) and state lands west of the Canning River. In both areas, we are permitted to show images of seismic data that we have licensed from certain seismic companies," Houseknecht said.

COURTESY PHOTO

Dave Houseknecht on the last day in the USGS field trip last summer — rainy and buggy and working in muddy source rocks.

Field work results

Led by Houseknecht, the USGS has conducted field work in and near the ANWR 1002 area during the past two summers, with a particular focus on oil-prone source rocks, geochemistry of oils from oil-saturated outcrops and nearby wells (including the Stinson and Kuvlum discovery wells), distribution and quality of potential reservoir rocks, and structural evolution of the area.

When asked to comment on the most important information released in recent presentations, Houseknecht said, "The presence of Triassic (Shublik Formation) and Jurassic (Kingak Shale) source rocks is a significant uncertainty in the 1002 Area. Those units are truncated by the Lower Cretaceous Unconformity across a large part of the northeastern North Slope as indicated by well penetrations and seismic data east of Prudhoe Bay and by outcrop data in the Sadlerochit Mountains. The Triassic and Jurassic source rocks may be present in northeastern 1002 Area if they are preserved in graben basins. Regardless, the presence of a thick (up to 200 meters) and rich (up to 26 weight percent total organic carbon) Brookian source-rock interval is known in the 1002 Area from outcrop studies."

"And, in the eastern 1002 Area those Brookian source rocks were imbricated by Cenozoic thrust faults. In that area, the source rocks have immature thermal maturity values in outcrop and are modeled to be in the oil window in the subsurface. Thus, the Brookian represents a viable, oil-prone source rock that could charge both stratigraphic and structural in the 1002 Area," Houseknecht said.

A summary of this information was presented at the AAPG Convention in May and will be posted on the AAPG Search and Discovery website later this summer.

—KAY CASHMAN

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BORDER DISPUTE

or force the state to take the matter into the federal court system.

A senior Interior official told Petroleum News Jan. 7 "we are engaged at the highest level with the governor and his staff on the Canning/Staines river boundary issue," suggesting an agreement could be reached much sooner than a decision from IBLA.

Interior press secretary Molly Block said July 8 that the matter was "still under litigation (with IBLA) and we expect it to be resolved before the end of the year."

Dan Saddler. communications director for the Alaska Department of Natural Resources, concurred with Block: "There is no progress to report … we are still waiting on IBLA," he said.

If the state is awarded the land, existing state leaseholders with undeveloped oil discoveries such as Jade Energy's Sourdough prospect and 88 Energy's Yukon Gold, thought to hold oil pools that cross under ANWR's current border, would gain valuable real estate — real estate they won in state lease sales and were awarded with a caveat acknowledging the boundary dispute with the feds.

Initially, Interior's Bureau of Land Management had tentatively approved the lands between the Canning and the Staines rivers that had been selected by the state and then rescinded that approval under the conveyance process back in the '60s.

The state once again started working on the ANWR boundary issue in 2012 during the administration of then-Gov. Sean Parnell, claiming the western boundary of ANWR had "been improperly mapped" for many years by the U.S. Fish and Wildlife Service, which manages the refuge.

The Parnell administration's renewed effort included historical and legal research as well as a field inspection by DNR and the Alaska Department of Law.

—KAY CASHMAN

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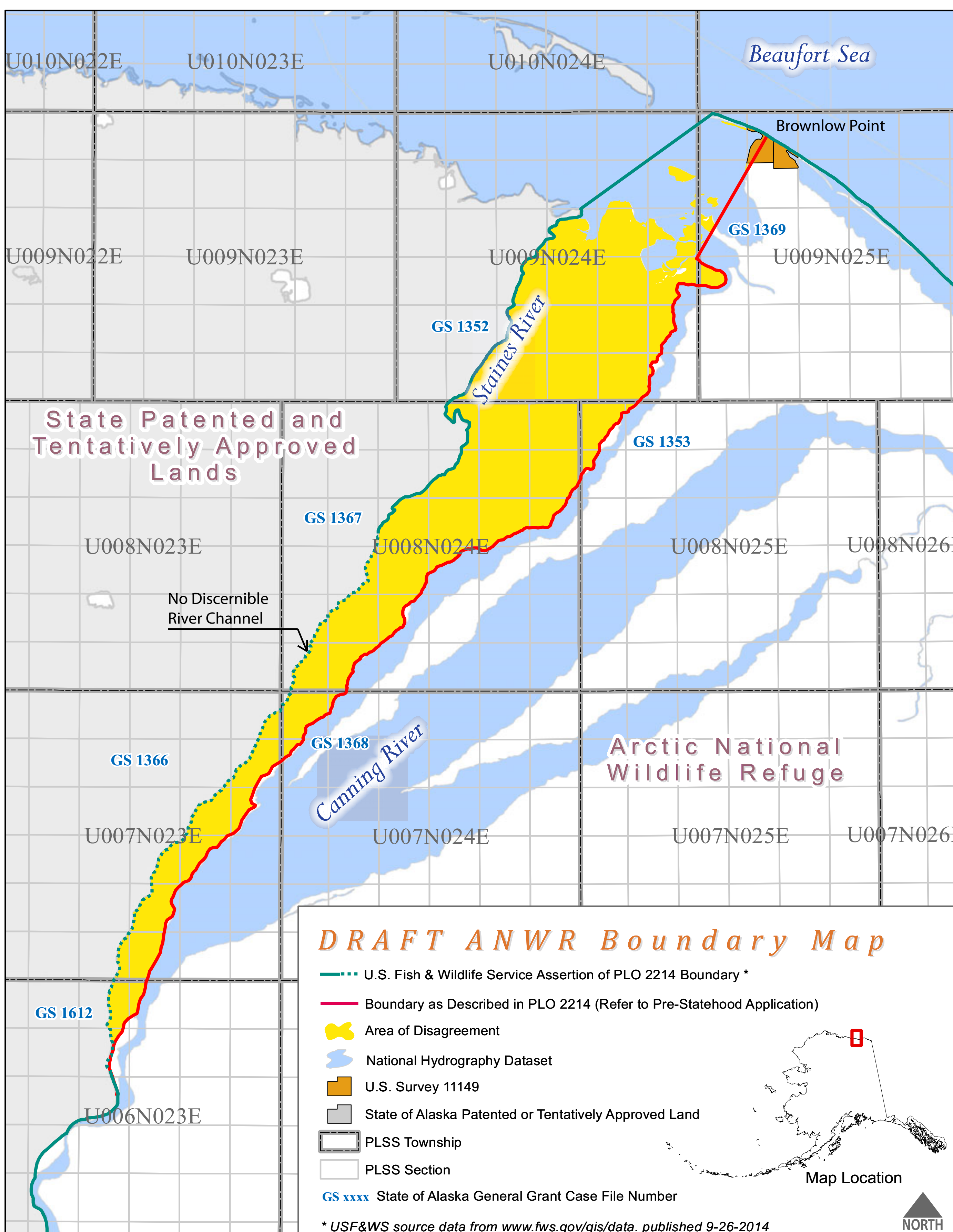


Welcome to a
new era in cybersecurity
for business
The new
AT&T Cybersecurity
The scale and power of AT&T Business now includes Alien Labs, one of the world's largest open-access threat intelligence communities (OTX) with over 100,000 security experts. We help protect your business around the clock and from edge to edge.
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