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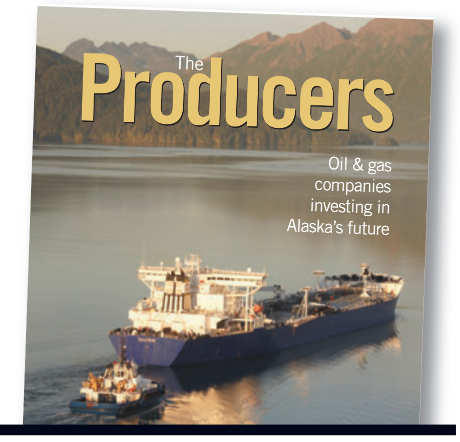

page 4 Furie in bankruptcy; company has gas production from Kitchen Lights

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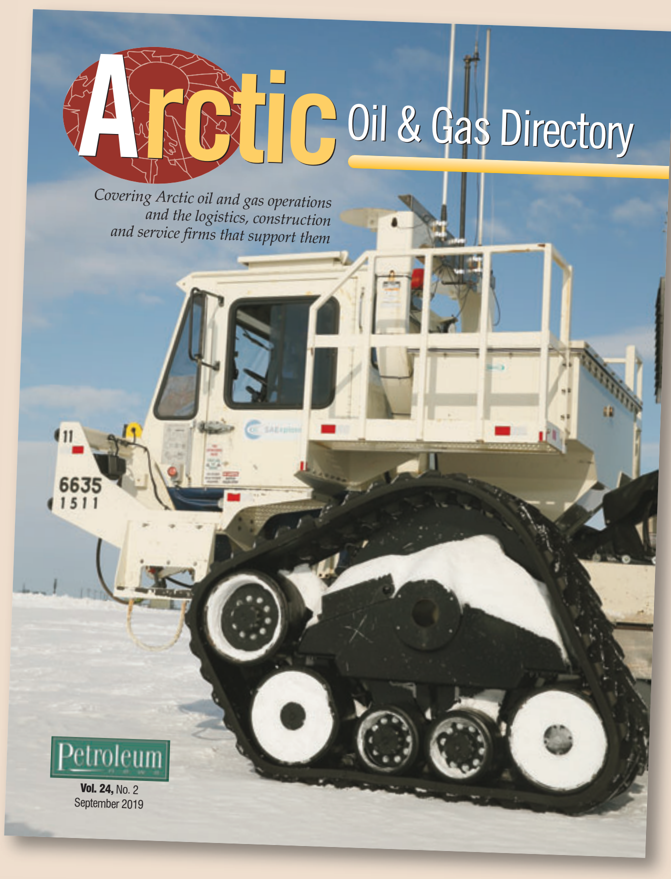
Latest Arctic Directory released



EIA: energy usage up 50% by 2050, crude, liquids production up 30%

Global energy usage will increase by nearly 50% between 2018 and 2050 with crude oil production up nearly 30%, the U.S. Energy Information Administration said in discussing the reference case in its International Energy Outlook 2019, released Sept. 24.

The outlook's focus is on consumption, and it finds that most of the growth in consumption comes from non-Organization for Economic Cooperation and Development nations, particularly in Asia.

The consumption of petroleum and other liquid fuels increases more than 20% in the reference case, EIA said, "driven by non-OECD demand in the transportation and industrial sectors." Total petroleum and liquid fuels consumption reaches more than 240 quadrillion British thermal units in 2050. EIA said OECD demand remains relatively stable while non-

see **EIA OUTLOOK** page 10

Summer fire on Kenai Peninsula expected to add to electric costs

Chugach Electric Association said Sept. 23 that its members can expect rate increases due to this summer's wildfires on the Kenai Peninsula. The cooperative said the Swan Lake Fire damaged the transmission line connecting the Bradley Lake Hydroelectric Project to the Chugach Electric system.

Alaska's Energy Desk at Alaska Public Media reported Sept. 3 that transmission lines from Bradley Lake had been shut off in mid-August due to the fires and Golden Valley Electric Association Chief Executive Cory Borgeson told Alaska's Energy Desk he was concerned the lines may not be fixed until next summer.

Chugach Electric said Sept. 23 that the transmission line has been out of service for several weeks at the request of crews fighting the fire, which has burned more than 167,000 acres.

"Because of the loss of access to Bradley Lake power,

see **FIRE AFTERMATH** page 7

EXPLORATION & PRODUCTION

Oil Search update

Drilling Mitquq and Stirrup, look to bump 2022 Pikka output to 50,000 bpd

By KAY CASHMAN
Petroleum News

While conducting a Sept. 23-25 investor tour of its Anchorage office and the North Slope, Oil Search released a group of slides about its Alaska plans, including an increase in Pikka production and the names of the exploration prospects it will be drilling this coming winter, Mitquq and Stirrup, to test Nanushuk analogues. (See map in pdf and print versions of this article.)

The Pikka East Block Mitquq prospect is approximately 6 miles from the Pikka Nanushuk Development A pad, or ND-A. Oil Search describes Mitquq's oil potential as a "high value tieback" to "future Pikka infrastructure."


KEIRAN WULFF

A heavy-duty ice road is planned to accommodate the Nabors 7-ES rig, starting from the 3S Nuna gravel road and extending six miles to the Mitquq 1 drill site, Oil Search says.

Success at the Stirrup prospect, which is adjacent to the Horseshoe Block and will be drilled with the Doyon Arctic Fox rig, "could de-risk additional fairways to underpin a possible standalone" Horseshoe development, the company

see **OIL SEARCH UPDATE** page 11

PRODUCERS MAGAZINE PREVIEW

Eni restarts drilling

Completes new development wells at Nikaitchuq; exploration moves slowly

By ALAN BAILEY
For Petroleum News

Although Eni US Operating's activities in Alaska tend to represent a small portion of the Milan based company's worldwide activities, the company has been expressing a positive view of its Alaska interests. That view has recently translated into the completion of new wells in the company's Nikaitchuq oil field offshore the North Slope.

In addition, drilling has continued for the NN-01 exploration well that Eni spudded in late 2017 on Nikaitchuq's Spy Island drill site. The well is being directionally drilled under the Beaufort Sea into the Nikaitchuq North prospect in the federal outer continental shelf. The drilling has been proceeding intermittently since the well was spudded.

According to Eni's latest plan of operations the drilling of NN-01 restarted in January but was suspended in April at a measured depth of 30,010 feet because of operational limitations.

In January the company re-enforced its Alaska interests by purchasing Caelus Natural Resources Alaska's 70% interest in the offshore Oooguruk field, to the west of the Nikaitchuq field, thus making Eni the operator and sole owner of Oooguruk.

see **MAGAZINE PREVIEW** page 8

NATURAL GAS

Kitimat LNG firms up

Analysts: Woodside's move to reduce 50% stake seen as sign of capital allocation

By GARY PARK
For Petroleum News

Woodside Energy, the Australian oil and gas power, has hinted it hopes to lower its 50% share of British Columbia's Kitimat LNG project at the same time operator Chevron has applied to almost double its export license to 40 years.

Without specifying exactly what percentage his company would like to unload, Woodside Chief Executive Officer Peter Coleman told Reuters in mid-September that "anywhere between 20% and 40% is the right number" for the "non-operator" of a major project.

On the other hand, as operator "we would like to be between 40% and 60%."

In applying to CER for permission to bolster Kitimat LNG's capacity, Chevron said rich natural gas reserves in the Liard Basin of northwestern British Columbia and the Kaybob-Duvernay play of central Alberta are more than sufficient to support the expansion.

Chevron would not comment on the prospect of adjustments to ownership stakes beyond saying that Chevron and Woodside are engaged with "potential LNG buyers and other parties interested

see **KITIMAT LNG** page 9

● GOVERNMENT

GAO report on BLM bonding urges changes

Government Accountability Office recommends Congress give BLM authority to obtain funds from operators to reclaim orphan wells

By KRISTEN NELSON
Petroleum News

Congress should give the Bureau of Land Management the authority to obtain funds from operators to reclaim orphaned wells, the U.S. Government Accountability Office said in a September report on the risk to taxpayers of insufficient bonds to reclaim wells.

BLM has taken steps over the years to strengthen its management of the potential liability if oil and gas operators don't fully reclaim wells they drill on leased federal lands, GAO said. BLM requires bonds, and has set requirements that bonds be reviewed every 5 years and amounts adjusted, but GAO said it found the average bond value was slightly lower in 2018 compared to 2008 and said "BLM has not obtained bond increases for the majority of instances in which its reviews identify that increases are required. Instead, most bonds are at their regulatory minimum values, which are not sufficient to cover reclamation costs incurred by BLM."

Bond options

Bonds are required to ensure compliance with terms and conditions of the lease, including such things are paying royalties and reclaiming wells, and BLM regulations generally require operators to have one of three types of bond coverage:

• Individual lease bonds — for all an operator's wells on a single lease;

> *If the $10,000 bond were adjusted to 2018 dollars, the minimum would be $66,000; the statewide minimum, set at $25,000, would be about $198,000; and the $150,000 nationwide bond minimum would be about $1,187,000, GAO said.*

• Statewide bonds — for all an operator's leases and operations in a single state; or

• Nationwide bonds — all of an operator's leases and operations nationwide.

Bonds can be either surety bonds or personal bonds.

see GAO REPORT page 3

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Petroleum News | Alaska's source for oil and gas news

continued from page 2

GAO REPORT

The Mineral Leasing Act of 1920, as amended, requires adequate bonds before operators begin drilling. BLM regulations set minimum bond values: $10,000 for individual lease bonds; $25,000 for all of an operator's wells within a state; and $150,000 for all of an operator's wells nationwide. (Bonds for the National Petroleum Reserve-Alaska are different, GAO said, with the minimum bond set in regulation — not less than $100,000 for a single lease and not less than $300,000 for a reserve-wide bond.)

For non-NPR-A bonds, the subject of the GAO report, the regulatory minimums have not been adjusted for inflation since the 1950s and 1960s. If the $10,000 bond were adjusted to 2018 dollars, the minimum would be $66,000; the statewide minimum, set at $25,000, would be about $198,000; and the $150,000 nationwide bond minimum would be about $1,187,000, GAO said.

In addition to orphaned wells identified by BLM over the last decade, GAO said it identified 2,294 wells that may be at increased risk of becoming orphan wells because they have not produced since June 2008 and have not been reclaimed — and the majority have bonds too low to cover typical reclamation costs.

Bond values

"Based on our review of BLM data, the value of bonds held by BLM for oil and gas operations on a per-well basis were slightly lower in 2018 as compared to 2008," GAO said. The total value of bonds in 2018 was higher, about $204 million, compared to about $188 million held in 2008, but there were more wells on federal leases in 2018 — 96,199 — compared to 85,330, an increase of 12.7%.

Calculated on a per-well basis, the value of the bonds was $2,207 in 2008 compared to $2,122 in 2018, a drop of 3.9%.

On average, individual lease bonds covered about 10 wells, statewide bonds covered about 49 wells and nationwide bonds covered 374 wells. As of 2018, individual lease bonds had the highest per well value at $2,691, statewide bonds had an average value per well of $1,592 and nationwide bonds had the lowest per well value at $890.

GAO said the bonds are insufficient to cover reclamation costs, which they identified as low cost and high cost, with an estimated $20,000 to reclaim a low-cost well and $145,000 to reclaim a high cost well. (GAO said the range of BLM's well reclamation cost estimates was $3,096 for the lowest average estimate and $603,000 for the highest estimate.)

When bonds are less than reclamation costs, GAO said, they "may not create an incentive for operators to promptly reclaim wells after operations cease because it costs more to reclaim the wells than the operator could collect from its bond." Less than 1% of bonds BLM currently holds would cover the cost of reclaiming the wells if those were $145,000 or more per well, while 16% of bonds would cover costs between $20,000 and $145,000 per well.

GAO said the problem was that 82% of bonds are at their regulatory minimum.

Wells at risk

GAO distinguished between orphan wells, those actually abandoned, and at risk wells, those out of production which could become orphan wells.

BLM lacks a systematic way to track orphan wells over time, but GAO said in 2010 BLM identified 144 orphaned wells; in 2017 219 orphaned wells were identified; and this April, the list included 296 orphaned wells, of which 89 were not identified in the 2017 list.

In addition to orphaned wells identified by BLM over the last decade, GAO said it identified 2,294 wells that may be at increased risk of becoming orphan wells because they have not produced since June 2008 and have not been reclaimed — and the majority have bonds too low to cover typical reclamation costs.

GAO recommended that Congress consider giving BLM authority to obtain funds from operators to reclaim orphaned wells and recommended that the director of BLM take steps to adjust bond levels to more closely reflect expected reclamation costs. ●

Contact Kristen Nelson at knelson@petroleumnews.com

EXPLORATION & PRODUCTION

US rig count drops again, by 18, to 868

Baker Hughes reports the number of rigs drilling for oil and natural gas in the U.S. continues to drop, down by 18 the week ending Sept. 20 to 868, following a drop of 12 the week ending Sept. 13.

In its weekly rig count, the Houston oilfield services company said the active rig count was down 185 from 1,053 active rigs a year ago.

The company reported that 719 rigs targeted oil (down 14 from the previous week; down 147 from a year ago) and 148 targeted natural gas (down five from the previous week; down 38 from a year ago). There was one miscellaneous rig active (up from zero the previous week; unchanged from a year ago).

The company said 61 of the U.S. holes were directional, 756 were horizontal and 51 were vertical.

Alaska and New Mexico were each up one rig from the previous week.

Colorado, Ohio, Pennsylvania and West Virginia were unchanged from the previous week.

Louisiana and Wyoming were each down one rig; California and North Dakota were each down two rigs.

Texas, with the most active rigs in the country at 423, was down seven rigs from the previous week.

Oklahoma was down 10 rigs.

Baker Hughes shows Alaska with eight rigs active for the week ending Sept. 20, up from five a year ago.

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

—KRISTEN NELSON

COURTESY FURIE OPERATING ALASKA

The Spartan 151 jack-up rig cantilevered over the Julius R platform for development drilling in the Kitchen Lights gas field in Cook Inlet.

● PRODUCERS MAGAZINE PREVIEW

Kitchen Lights on the market

As a result of Furie's bankruptcy, the Cook Inlet natural gas producing unit's assets being sold, includes leases, facilities

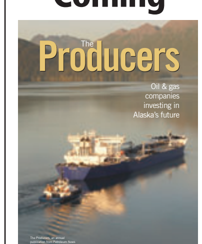
By KAY CASHMAN

Petroleum News

Owned by Texas-based Cornucopia Oil & Gas Co., which in turn is owned by Deutsche Oel and Gas, Furie Operating Alaska LLC is operator of the offshore Cook Inlet Kitchen Lights unit that began producing natural gas in 2015.

In spring 2018, lender Energy Capital Partners started foreclosure proceedings against the owners, scheduling a sale of Furie's assets, but the sale was canceled by ECP when an agreement was reached with the owners.

Coming



Nov. 17, 2019

As a result of that deal, on March 23, 2018, Ankura Consulting Group LLC was retained to assist Furie and its affiliates with interim management and financial advisory services and Scott M. Pinsonnault, a senior managing director at Ankura, was installed as Furie's interim chief operating officer.

Delivering on commitments

Armed with a fresh round of financing from Furie's lenders, Pinsonnault set about augmenting the independent's Anchorage staff, adding a new vice president of operations and a health, safety and environment official, as well as completing the company's planned 2018 drilling program.

With outstanding commitments, both in terms of gas supplies for a big area utility and in terms of the Kitchen Lights unit plan of development with the state of Alaska, Furie's focus was to deliver on those commitments, Pinsonnault told Petroleum News in a July 9, 2018, interview.

"It's been a tremendous effort to get where we are in 90 days, to mobilize, permit, define the operational tempo for the summer," he said.

The 2017 default, issued by the Alaska Department of Natural Resources' Division of Oil and Gas, was because Furie had failed to meet drilling and development commitments.

But, in Furie's new plan approval, issued on Dec. 11, 2018, the division said that Furie had recently complied with its commitments, curing the default.

The terms of Furie's supply agreement with Enstar Natural Gas and its affiliate Alaska Pipeline Co. had also been met by Furie pushing drilling as hard as it could in the last half of 2018 to get a total of four wells online, which was a contractual requirement with Enstar and APC.

SCOTT PINSONNAULT

A later communication from Enstar to Furie said that APC had been very accommodating over the previous three years and could have terminated the contract because of Furie's failure to meet deadlines for the drilling of wells and meeting required gas production capabilities. From the outset, the utility said, Furie had to supplement its Kitchen Lights natural gas production with gas purchased from third parties, or drawn from storage, in order to meet the terms of its APC supply agreement.

Disaster strikes in January

With a vigorous year-end drilling program that both cured the 2017 default with the state and met the gas supply agreement with Enstar, Furie appeared to be headed for a successful 2019.

But then disaster struck. On Jan. 5, 2019, the company ran into problems with hydrate plugs caused by freezing water combining with gas to form solid hydrates at the unit's onshore processing facility and in the 15-mile subsea pipeline from its Julius R offshore production platform, which slowed natural gas delivery to a trickle later that month.

On Jan. 23 Furie sent a letter to Enstar affiliate APC declaring Force Majeure and saying that it could no longer meet its commitments under its gas supply agreement.

At that time Lindsay Hobson, Enstar communications manager, told Petroleum News the utility had not received any gas from Furie since Jan. 25.

Kitchen Lights gas output was a mere 1,886 thousand cubic feet in February.

On March 19, 2019, Pinsonnault said Furie had cleared the obstruction that had been blocking the subsea pipeline.

"We have safely restored utility and communication between our onshore natural gas processing plant and the Julius platform over this past weekend," Pinsonnault said, referring to the field's

see **PRODUCERS PREVIEW** *page 5*

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Kay Cashman	PUBLISHER & FOUNDER
Mary Mack	CEO & GENERAL MANAGER
Kristen Nelson	EDITOR-IN-CHIEF
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Gary Park	CONTRIBUTING WRITER (CANADA)
Steve Sutherlin	CONTRIBUTING WRITER
Judy Patrick Photography	CONTRACT PHOTOGRAPHER
Forrest Crane	CONTRACT PHOTOGRAPHER
Renee Garbutt	CIRCULATION MANAGER

ADDRESS
P.O. Box 231647
Anchorage, AK 99523-1647

NEWS
907.522.9469
publisher@petroleumnews.com

CIRCULATION
907.522.9469
circulation@petroleumnews.com

ADVERTISING
Susan Crane • 907.770.5592
scrane@petroleumnews.com

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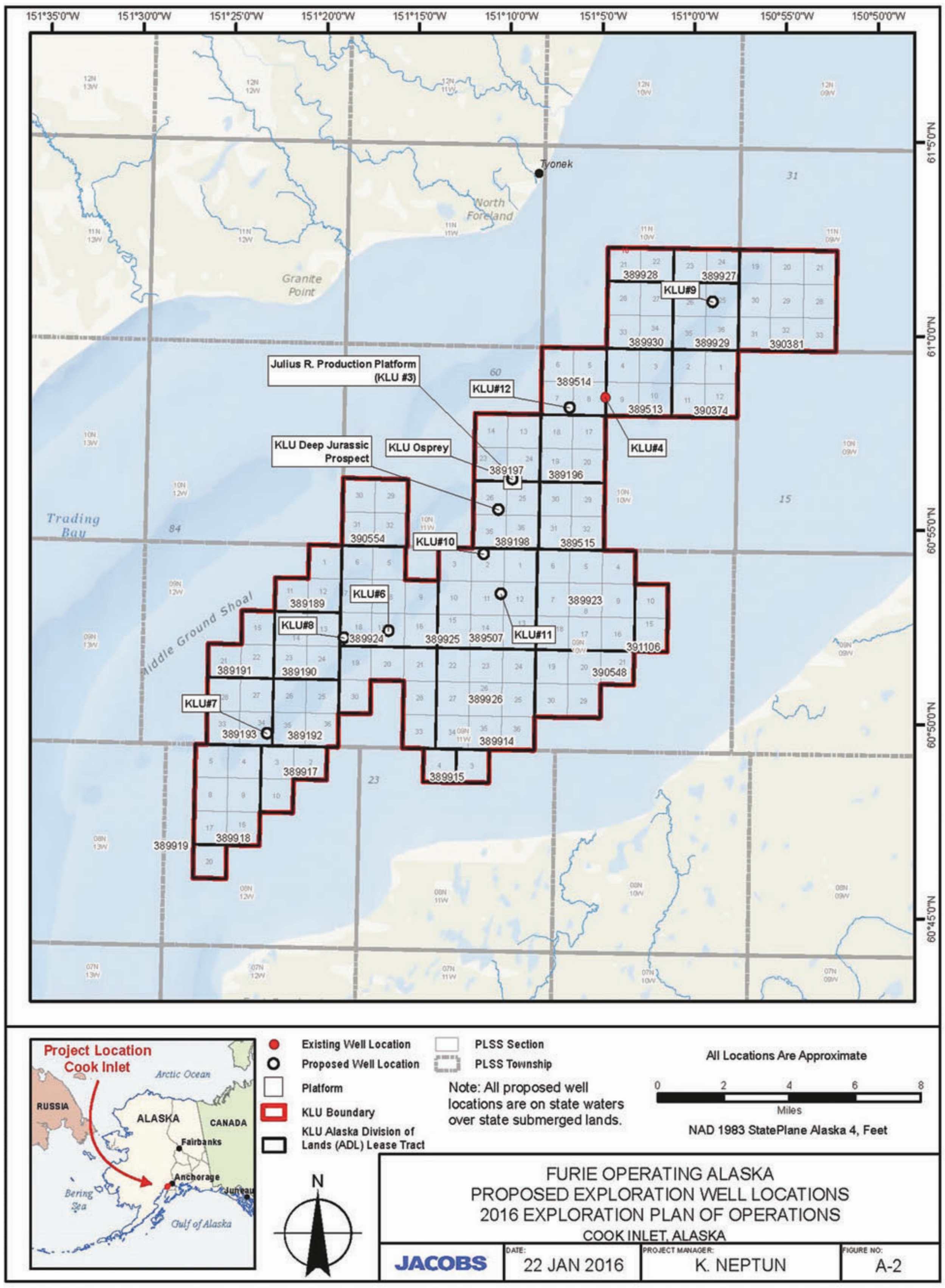


As of April 5, 2019, Furie had submitted no revisions to the well locations in its 2016 map (see map in print and pdf versions of this story) but it did say that it expected the vertical well "bottom hole locations will coincide with the tophole coordinates" provided in the 2016 map.

offshore Julius R production platform. He said Furie would spend the next few weeks making sure that the line was completely clear, functional and safe before restoring gas production.

In April 2019, natural gas output from Furie's platform rose to 347,919 mcf, according to the Alaska Oil and Gas Conservation Commission, and production continued to rise.

Furie files bankruptcy

But financial pressure on the company was rearing its head, and in April 2019 a public notice of a foreclosure sale auction was posted by EPC in the Anchorage Daily News, and in Hart Energy's Industry Voice.

Although that sale was later postponed, on Aug. 9, 2019, Furie filed a voluntary petition for Chapter 11 bankruptcy relief in the U.S. Bankruptcy Court for the District of Delaware, listing about $450 million in debt. The company said it planned to sell its assets, which it listed on its petition with an estimated value of less than $50 million, by early January 2020.

Furie petitioned the court to approve "super priority senior secured post-petition financing in the form of a multiple-draw term loan credit facility in an aggregate principal amount of up to $15 million."

Judge Laurie Selber Silverstein granted Furie and its affiliates access to the first $7 million of the interim debtor-in-possession financing Aug. 12, clearing the way for the company to use $3 million for its interim budget needs, according to a report by Law360 and an Aug. 18 article in Petroleum News. Silverstein warned the company that key provisions of the financing remained subject to challenges, particularly provisions directing $4 million of the loan budget to pay fees incurred by prepetition lenders.

According to the petition, "after any administrative expenses are paid, no funds will be available to unsecured creditors."

Why specifically had Furie filed for bankruptcy protection?

In a first-day declaration filed by Pinsonnault with the court, Furie cited uncertainty with Alaska state tax credit reimbursements that it had historically counted on receiving, years of liquidity issues and breaches of credit facilities, construction delays and cost overruns.

In fact, in a plan of development submitted to state officials in October 2017, Furie said its failure to conduct any new development or exploration drilling at the Kitchen Lights unit in 2017 was due to "the lack of any meaningful appropriation to the oil and gas tax credit fund for the purchase of Alaska oil and gas production tax credit certificates."

"Furie has invested hundreds of millions of dollars in exploring and developing the KLU (Kitchen Lights unit) and has a very substantial amount of tax credit certificates in the queue awaiting purchase by the state," the company said in the plan. "These certificates are a key component to funding further exploration and development activities in the KLU and were relied on by Furie when putting together its work program and budget."

Sale of assets planned

As this issue of The Producers was being prepared for press in late September, a sale of Furie's assets was likely in October. Petroleum News will continue to follow the course of the company's bankruptcy and asset sale.

Furies' assets as reported over the last few years in Petroleum News include the following:

• Kitchen Lights unit consisting of nine state leases. The 83,394-acre unit contains three previously independent prospects that were administratively divided into four exploration blocks: Corsair, North, Central and Southwest.

• Julius R offshore platform with six well slots that was installed in 2015, its monopod structure placed on the seafloor about 10 miles northwest of Boulder Point, near Nikiski off the Kenai Peninsula.

• Onshore natural gas processing facility near East Foreland on the Kenai Peninsula that was completed in 2015 and from which Kitchen Lights natural gas is delivered into the Kenai Peninsula gas transmission pipeline network.

• 15-mile subsea pipeline between the Julius R platform and the onshore processing facility that was installed in 2015 and has a throughput capacity of 100 million cubic feet per day.

• The 10 offshore gas wells drilled to date and their status per AOGCC database as of Sept. 22, 2019: KLU A-4, development, permitted as single completion, spud 8-3-2018, completed 10-11-18, total depth 11,315 feet, into Sterling undefined gas pool, Beluga undefined gas pool, and Tyonek undefined gas pool; KLU A-A2, development, permitted as dual completion, spud 7-9-2016, completed 9-8-2016, total depth 8,160 feet, into Sterling undefined gas pool and Beluga undefined gas pool; KLU A-1, development, permitted as single completion, spud 9-27-2016,re-entered and completed 7-30-2018, total depth 8,243, into Sterling undefined gas, into Beluga undefined gas pool; KLU A-2 (plugged and abandoned), development, permitted as single completion, spud date 6-19-2016, completed 7-8-2016, total depth 7,038 feet, into Sterling undefined gas pool; KLU 5 (plugged and abandoned), exploratory, permitted as single completion, spud 9-4-2014, completed 9-28-2014, total depth 11,827 feet, unknown target; KLU 4 (suspended), exploratory, permitted as single completion, spud 7-18-23, completed date not yet reported to AOGCC but the release date was listed as 10/24/2015, total depth 9,163 feet, unknown target; KLU 3, development, permitted as single completion, spud 4-26-2013, completed 7-10-2013, total depth 10,393 feet, into Sterling undefined gas pool and Beluga undefined gas pool; KLU 2A, (suspended), exploratory, permitted as single completion, spud 10-1-2012, completed 11-5-2012, total depth 10,750 feet, unknown target; KLU 2 (plugged and abandoned), exploratory, spud 9-6-2012, completed 9-30-2012, total depth 9,106 feet, unknown target; KLU 1 (suspended), exploratory, permitted as single completion, spud 9-2-2011, completed 8-18-2012, total depth 15,298 feet (TVD the same), target unknown.

Why specifically had Furie filed for bankruptcy protection? In a first-day declaration filed by Pinsonnault with the court, Furie cited uncertainty with Alaska state tax credit reimbursements that it had historically counted on receiving, years of liquidity issues and breaches of credit facilities, construction delays and cost overruns.

• The Kitchen wells that were in production in August 2019 were KLU A-1 (137,814 thousand cubic feet), KLU A-2A (122,566 mcf), KLU 3 (235,802 mcf). All three were producing from the Beluga gas pool.

• There is the possibility of drilling deep for oil in the Jurassic strata underlying the Tertiary rocks that host producing oil and gas fields in the Cook Inlet basin. ●

Contact Kay Cashman at publisher@petroleumnews.com

● EXPLORATION & PRODUCTION

Pantheon Resources looking for partner

Poised to begin phased oil production from Alkaid-Phecda project on Alaska's North Slope in 2020, well flow test analysis positive

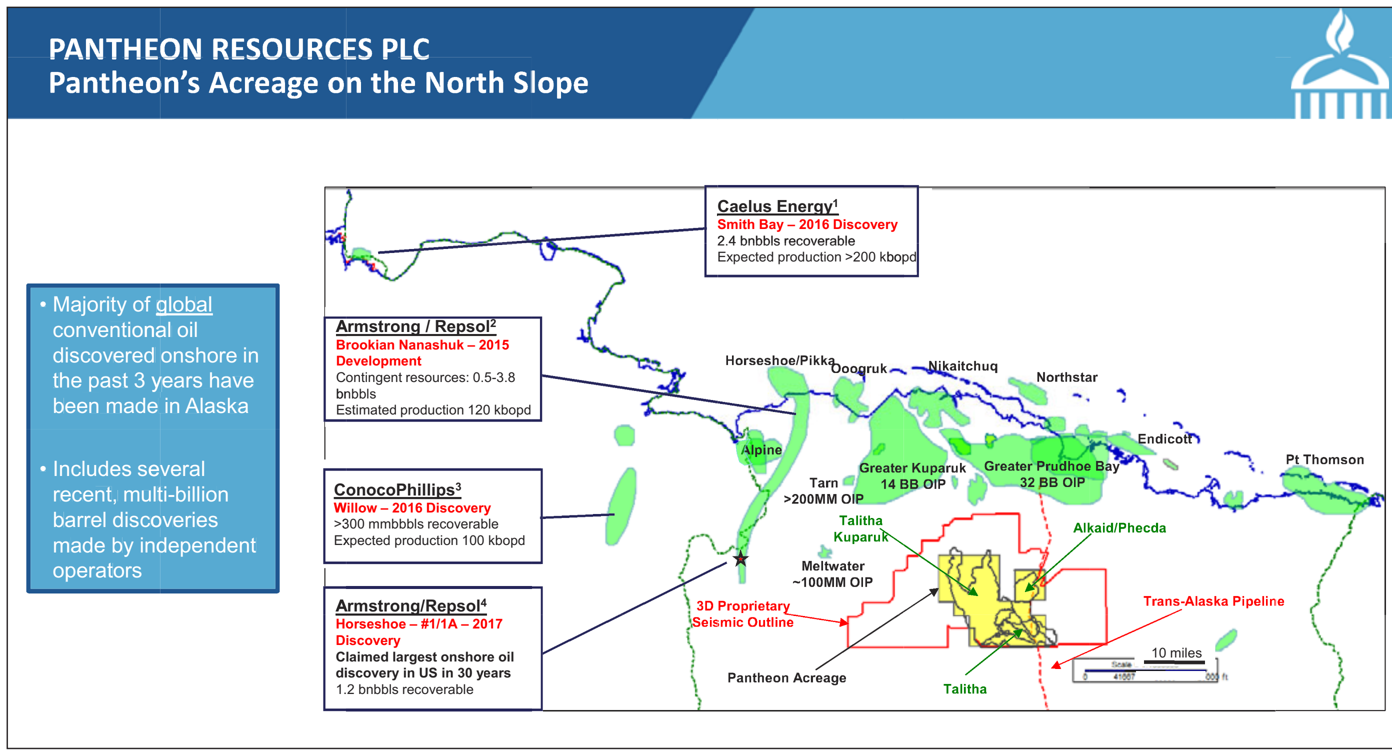
By KAY CASHMAN
Petroleum News

London-based Pantheon Resources Plc, which acquired the North Slope assets of Great Bear Petroleum in January, released an investor update that confirms the independent is preparing to begin phased production from its new Brookian light oil discovery south of Prudhoe Bay in mid-2020, provided it can find a partner to help fund the development.

The AIM-listed oil and gas explorer, which holds between 75% and 90% working interests in some 200,000 acres on the Slope, formed an Alaska affiliate, Pantheon Alaska Petroleum Operating LLC, with an office in Anchorage. That affiliate is headed by Patrick Galvin, chief commercial officer and general counsel, who worked in the same capacity for Great Bear Petroleum, and who is a former commissioner of the Alaska Department of Revenue, former petroleum land manager for the Alaska Department of Natural Resources and was a partner at K&L Gates in Anchorage.


PAT GALVIN

Pantheon says the Alkaid/Phecda phased production project is subject to completion of a successful farmout, noting there are 1.8 billion barrels of discovered oil in place at Alkaid/Phecda and the company's nearby Talitha prospect with recoverable estimates at 180 million to 270 million barrels of oil. Both prospects adjoin the trans-Alaska oil pipeline and the Dalton Highway.



At Alkaid/Phecda, which is a confirmed discovery, Pantheon estimates there is 900 million barrels of oil in place and 90-135 million barrels of P50 technically recoverable 35-plus degree API oil.

Alkaid drilling

Alkaid No. 1 was flow tested in March by Pantheon. The company combined Alkaid with the neighboring Phecda prospect after 3D seismic and re-mapping showed they were part of the same Brookian structural accumulation.

Great Bear drilled the Alkaid well in 2015 as a vertical test well but was unable to conduct flow testing because the drilling program was cut short by flooding on the highway. The well was suspended to avoid equipment being stranded at the location. All zones had been logged and sidewall cores had been taken at the deepest zones, confirming indications of oil in three major zones, from some 4,000 to 8,100 feet.

Great Bear had previously carried out an extensive program of 3D seismic surveying on the acreage and had identified several oil prospects, including Alkaid. The subsequent suspension of payments of state exploration tax credits under the administration of former Gov. Bill Walker — an action that hit small independents such as Great Bear particularly hard — resulted in a pause in the company's exploration program.

Meanwhile the Alkaid well was suspended.

Re-entry, development

The 2019 re-entry of Alkaid No. 1 resulted in a better than expected well test, with a flow of 100 barrels of oil per day from a 6-foot vertical perforated interval through the reservoir, Pantheon says. No oil or water contact was found.

Horizontal wells will be used in field development, enabling much higher flow rates, Pantheon says.

The main zone of interest in the

see PANTHEON FUNDING page 7

continued from page 6

PANTHEON FUNDING

Brookian is estimated to have 240 feet of net pay within 450 feet of reservoir rock.

"Such flow rates are considered to be an excellent result and indicate the potential for materially higher flow rates when wells are drilled in the typical manner for Brookian wells in Alaska — horizontally, stimulated and with larger intervals perforated," Pantheon said in a March 24 statement.

Testing of two secondary targets in Alkaid No. 1 at shallower depths did not prove successful.

In a June 6 press release and webcast, Pantheon said it would use mobile production units to handle output from three or four delineation wells adjacent to the Dalton in the highway's already established transportation corridor, trucking the oil north to Pump Station No. 1 of the trans-Alaska oil pipeline until full-scale development of approximately 50 wells and related infrastructure with a central processing facility could be completed.

Pantheon expects the year-round operation of these three or four wells will each produce about 1,500 barrels of oil per day.

Talitha plans

In its Sept. 24 update, a Pantheon slide gave a brief overview of the Talitha prospect, where the Pipeline State No. 1 well was drilled by ARCO in 1988.

ARCO found interbedded sand/shales. The well was drilled in a lower oil price environment and the trans-Alaska oil pipeline was running at capacity, so ARCO did not further explore the area.

"Modern drilling practices vastly improve project economics," Pantheon says, and would like to drill a new well at Talitha in 2020.

The eastern part of Talitha can be developed from the Dalton, which means a discovery could be "rapidly placed into production."

"Geophysics accuracy at Alkaid increases confidence" in Talitha, Pantheon says. ●

Contact Kay Cashman at publisher@petroleumnews.com

PANTHEON RESOURCES PLC
Alkaid & Phecda Project – Appraisal & Development

ALKAID – CONFIRMED DISCOVERY

- Drilled 2015. Not tested due to weather event
- Tested March 2019
  - 450ft gross pay
  - Perforated 6ft interval
  - Flow tested 100bopd
- No oil/water contact found

SIGNIFICANT CONCLUSIONS

- Alkaid/Phecda – now part of same accumulation
- Proven the accuracy of the high tech geophysics
  - Increased confidence in Talitha appraisal and exploration prospects
- Modelled per well economics
  - Estimated EUR (economic ultimate recovery) of 1.5 – 2.5 mmbo
  - Estimated maximum flow rate exceeding 1,500 bopd
  - Estimated NPV10 per barrel of oil in the ground = US$7 - $12

Alkaid Well - Alaska - View of the Rig at dusk

continued from page 1

FIRE AFTERMATH

more natural gas is being used and will continue to be until the line is repaired and back in service," Chugach Electric said. The cooperative is estimating increases of between 3 and 6% in members' bills because Bradley Lake power usually makes up about 10% of its power supply requirements and natural gas is a more expensive power source.

"We want our members to have notice that they will see rates increase as a result of this fire due to damage to the transmission line that connects Chugach to the Bradley Lake Hydroelectric Project," said Chugach Electric CEO Lee Thibert. "This is a case of natural disaster impacting the power grid, and we will continue to work with fire managers and our neighboring utilities to find out when it's safe to go in and assess the damage and make a plan for repairs," he said.

Chugach Electric said Alaska Wildland Fire Information says the Swan Lake Fire is 68% contained, but there are still hot spots that have prevented ground crews from getting in to do a full damage assessment along the transmission line, although more than 60 poles and associated structures were found to be damaged in a recent aerial survey.

Bradley Lake, the largest of seven hydroelectric facilities in Alaska, produces up to 10% of the Railbelt's energy needs, Chugach Electric said, with damaged power lines connecting the Bradley Lake project with Anchorage, the Matanuska and Susitna valleys and Fairbanks.

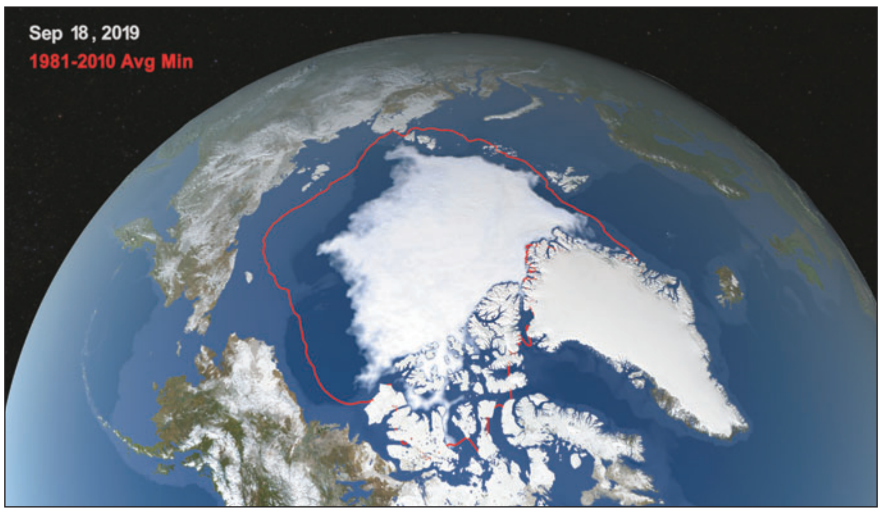
Power from Bradley lake is used by Chugach Electric, the City of Seward, Homer Electric Association, Municipal Light & Power, Matanuska Electric Association and GVEA.

The cooperative said that Homer Electric is still receiving power from Bradley Lake because its service area is south of the damaged line section.

—KRISTEN NELSON

Contact Kristen Nelson at knelson@petroleumnews.com

ENVIRONMENT & SAFETY



NATIONAL SNOW & ICE DATA CENTER

Arctic sea ice likely at minimum extent

Arctic sea ice likely reached its minimum for the year on Sept 18. That minimum, 1.6 million square miles, is the second lowest in the 41-year satellite record, the National Snow and Ice Data Center said in a preliminary estimate released Sept. 23.

NSIDC said that minimum was tied for second lowest in the satellite record with 2007 and 2016, "reinforcing the long-term downward trend in Arctic ice extent."

The seasonal increase in sea ice will now begin, lasting through the fall and winter, the agency said, noting that the Sept. 23 statement is preliminary, with changing winds or late-season melt having the potential to further reduce the Arctic ice extent, something which happened in both 2005 and 2010.

The minimum extent reached Sept. 18 was four days later than a median minimum date of Sept. 14 from 1981 to 2010.

This year's minimum extent was behind only 2012, with all 13 lowest extents in the satellite era occurring in the last 13 years.

The 1.6 million square mile minimum this year was 293,000 square miles above the recent record set in 2012 and 811,000 square miles below the 1981 to 2010 average minimum extent.

This year's maximum extent occurred March 13 and tied for the seventh lowest on record at 5.71 million square miles, a maximum extent tied with 2007, and 332,000 square miles below the 1981 to 2010 average maximum extent of 6.04 million square miles. The lowest maximum extent ever observed was 5.56 million square miles in 2017. Prior to this year, the four lowest maximum extents occurred between 2015 and 2018.

—KRISTEN NELSON

PIPELINES & DOWNSTREAM

Unocal says TAPS sale issues settled

Unocal Pipeline Co. told the Regulatory Commission of Alaska Sept. 3 that issues around sale of its share in the Trans Alaska Pipeline System "have been resolved" and said it is working with other entities on a joint application to the commission on the transfer of its TAPS shares.

Unocal Pipeline requested commission authorization to temporarily suspend service on its share of pipeline capacity in June 2012, "pending the finalization of the sale of its ownership interest." Unocal had the smallest interest of any of the owners, just 1.36%, the company told RCA, and said its share could be sold or transferred to "a third party, another TAPS Owner, or all of the remaining TAPS owners."

Since then, Unocal has told the commission in periodic filings, it and the other carriers (BP Pipelines (Alaska) Inc., Exxon Mobil Pipeline Co. and ConocoPhillips Transportation Alaska Inc.) have been "arbitrating their dispute, as well as litigating portions of the dispute so that the transfer process can move forward."

The TAPS operating agreement was up for a five-year renewal in 2020. "Unocal has decided not to continue TAPS operations for an additional renewal term because its interest in TAPS no longer meets the company's core strategic needs," the company told RCA in 2012.

As recently as September 2018, the company told RCA: "The litigation has been time-consuming and is likely to continue for a significant period of time."

In its Sept. 3 filing with the commission, Unocal asked for an extension through March 1, but said it "expects to submit the joint transfer application soon and well in advance of that date." Unocal was purchased by Chevron in 2005. Chevron holds a 4.95% working owner position in the Kuparuk River unit, 1.16% in the Prudhoe Bay unit and 11.11% in the Duck Island unit.

In a Sept. 19 ruling the commission provided an extension through March 1.

—KRISTEN NELSON

GOVERNMENT

SD regulators want oil, gas drilling bonds

South Dakota regulators will ask the Legislature to require bigger financial guarantees for oil and gas wells in response to a failed 40-well natural gas project in the northwest part of the state.

State minerals and mining administrator Mike Lees says the department will ask for changes to the bonding requirements when legislators meet again this winter.

The Rapid City Journal reports his comments came the week of Sept. 16 during a meeting of the state Board of Minerals and Environment.

Lees says the department will propose that all oil and gas drillers be required to post bonds of either $50,000 per well, or a $100,000 blanket bond for an unlimited number of wells, regardless of depth.

—ASSOCIATED PRESS

BLM HQ in building with O&G companies

The Bureau of Land Management is moving its headquarters to an office building in Colorado that also houses oil and gas organizations, drawing criticism from environmental groups.

The Interior Department announced Sept. 20 it has leased part of a four-story building in Grand Junction.

The building's other tenants include two oil and gas companies as well as a state oil and gas association. The BLM regulates oil and gas leases and development on the land it oversees.

The Denver Post reports representatives of environmental groups are concerned about the close association between oil and gas interests and the agency.

U.S. Interior Secretary David Bernhardt, who was in Grand Junction to address a business group Sept. 21, told The Daily Sentinel that the separate General Services Administration handled the office space leasing.

—ASSOCIATED PRESS

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MAGAZINE PREVIEW

And in August 2018 Eni purchased 350,000 exploration acres from Caelus — this acreage lies on the eastern North Slope between Prudhoe Bay and Point Thomson.

Plan of development

Before the downturn in oil prices in 2014, Eni had been using a number of small drilling projects at Nikaitchuq to try to bolster production from the field. But the oil price fall resulted in those drilling activities being suspended. The activities had included the addition of multilaterals to existing wells; evaluating the potential of a sand reservoir below the producing reservoir; and drilling to the west and east of the existing well pattern.

The field has been developed by drilling from an onshore pad at Oliktok Point and from the offshore Spy Island drill site. At the time of drilling suspension in 2014 an initial Oliktok Point drilling program had been completed but a Spy Island program remained unfinished. New permitting and drilling indicate that the Spy Island program is back underway.

The Nikaitchuq plan of development, approved by the Alaska Department of Natural Resources and the U.S. Bureau of Ocean Energy Management for the period through September, envisaged the possibility of drilling an additional three new wells and eight lateral wells from Spy Island. Two of the wells would be injectors, while the remaining well and the laterals would be producers. In general, the concept is to convert some existing wells to multilaterals, while also drilling some new wells from the surface.

Two laterals completed

Eni did complete two new lateral production wells, the SP33-W03L1 and SP30-W01L1 wells. The company has also permitted a new development well, the SP03-NE2, and a lateral from that well. The SP33-W03L1 well was spudded May 25 and completed on June 20, while the SP30-W01L1 was spudded on June 21 and completed on July 20 according to Alaska Oil and Gas Conservation Commission records.

The SP prefixes indicate that these are production wells drilled from the Nikaitchuq Spy Island drill site.

Eni has also been continuing with maintenance activities on surface facilities, and on preparing tie-ins for future wells to be drilled. And the company has conducted multiple well workovers in the field.

According to the latest Nikaitchuq plan of development, which runs through to September 2020, the company anticipates continuing with facility maintenance and well workover activities through the coming year. Depending on the timing of drilling associated with Nikaitchuq North exploration, the company also anticipates the possibility of drilling three new development wells from Spy Island: one production well and two water injectors.

Nikaitchuq North

The Nikaitchuq North NN-01 well was started as part of an initiative to find new oil resources in federal acreage to the north of the existing field. The ultra-extended reach well is targeting Harrison Bay Block 6423, using the Doyon 15 drilling rig, the same rig that is used for development drilling from Spy Island in the existing Nikaitchuq field. Clearly, the idea is to try to use Nikaitchuq North resources to bolster reserves and production for the overall field. And, with just one rig in operation, there is obviously a linkage between the timeframe for the Nikaitchuq development drilling program and the Nikaitchuq North drilling — the drilling of new development wells could not begin until after the suspension of the NN-01 drilling.

According to Eni Alaska Vice President Whitney Grande the Nikaitchuq production facility has spare capacity, with a capacity of 40,000 barrels per day, expandable to 50,000 bpd. Data published by the AOGCC indicates that Nikaitchuq production in July averaged 20,175 bpd, compared with 18,545 barrels per day in July 2018 (the production

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KITIMAT LNG

in the Kitimat LNG project."

Coleman said that from a capital and risk management point of view Woodside "would rather hold less equity" in British Columbia's most advanced large-scale LNG venture.

Positive response from analysts

The disclosure by Woodside has generated a positive response from analysts, who say the move to find another partner is a sign that the current owners are close to allocating capital to the venture while rationalizing their exposure.

They suggest that state-owned giants from Kuwait and Malaysia would be some of the likeliest buyers.

As part of a fresh round of approvals it is seeking, Chevron disclosed plans to make its Kitimat LNG facility fully powered by hydroelectricity to achieve the lowest greenhouse gas emissions per metric ton of LNG of any large project in the world, while using backup diesel power generators for emergencies.

In a filing with British Columbia's environmental assessment office, the partners estimated the project will produce less than 0.1 metric ton of carbon dioxide equivalent for every metric ton of LNG compared with more than 0.3 metric ton.

They have previously applied to the Canadian Energy Regulator (previously the National Energy Board) to expand project capacity to 18 million metric tons a year from the approval they have already received for 10 million metric tons a year, which has forced a new federal screening of the project.

The disclosure by Woodside has generated a positive response from analysts, who say the move to find another partner is a sign that the current owners are close to allocating capital to the venture while rationalizing their exposure.

In applying to CER for permission to bolster Kitimat LNG's capacity, Chevron said rich natural gas reserves in the Liard Basin of northwestern British Columbia and the Kaybob-Duvernay play of central Alberta are more than sufficient to support the expansion.

"Chevron and Woodside currently together own an approximately 146,000 net hectare position in the core of the B.C. portion of the Liard Basin," the filing said. "In addition to the Liard Basin holdings, Chevron has an approximately 84,000 net-hectare position in the Kaybob-Duvernay resource."

2011 export permit

In 2011, Kitimat LNG was the first LNG venture in British Columbia to receive a federal export permit. (The Shell-operated LNG Canada project announced a year ago that it planned to go ahead with its C$40 billion, 14 million metric tons a year project).

To underpin its application to extend its export license, Chevron said its lease holdings in the Liard Basin are 38 trillion cubic feet, while estimating that its current share of shale gas production in Kaybob-Duvernay is more than 75 million cubic feet per day — production it suggested could partially supply the Kitimat LNG terminal.

If needed, the proponents have said they could secure other supplies from the Western Canada Sedimentary Basin.

Chevron has also submitted a revised plan to B.C. and federal regulators, targeting the start of terminal construction in 2023, following a final investment decision, with production starting in 2029. Front-end engineering is scheduled to take place in 2020-21, at which point negotiations will start for export contracts.

Chevron and Woodside have also proposed construction of a pipeline from the Summit Lake area of the B.C. interior to the terminal facility near Kitimat.

They said that pipeline would be designed to connect with TC Energy's planned 160-mile Merrick pipeline route in northeastern B.C. ●

Contact Gary Park through publisher@petroleumnews.com

Petroleum news — Oil Patch Bits

Colville completes milestone fuel delivery to Prudhoe Bay

Colville, an Alaska-based company providing logistics and fuel transport services for the North Slope oil fields, said Sept. 16 that it received a barge delivery of 3.5 million gallons of ultra low sulphur diesel fuel ahead of another busy season in the oil fields. Crews offloaded the fuel into storage tanks at Colville's Deadhorse tank farm, completing what is believed to be the largest-ever delivery of fuel to Prudhoe Bay by barge.

This barge delivery follows a similar operation in 2018 that successfully delivered 2 million gallons of USLD. Fuel for North Slope oil field operations is typically delivered via the 500 mile Dalton Highway aka "the haul road" from Fairbanks. Colville trucks make 2,000 such trips each year, each hauling nearly 10,000 gallons of diesel. The barge delivery is equivalent to 370 round trips each saving 1,000 miles of overland transit.

The barge fuel delivery was prompted by the increased demand due to exploration and other activity in the North Slope oil fields. "This operation is a reflection of broader communication with our oil field customers, allowing them to proactively develop their exploration and operational plans. We listened to our customers and responded," said Dave Pfeifer, Colville president & CEO.

Pfeifer says that Colville will continue to consider additional barge deliveries of fuel in the future, however, they will not replace the trucking operation.

COURTESY COLVILLE

Companies involved in Alaska's oil and gas industry

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

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EIA OUTLOOK

OECD demand increases by some 45%.

Liquids consumed in large quantities include motor gasoline, diesel and jet fuel particularly in the transportation sector, while liquids such as natural gas plant liquids are consumed in large quantities as industrial feedstock.

EIA described its reference case as providing a baseline for measuring impacts, and said it "reflects current trends and relationships among supply, demand, and prices in the future," and includes some anticipated changes over the 2018-50 period: expected regional and demographic trends; planned changes to infrastructure; and incremental cost and performance improvements. The reference case does not include things like changes to national boundaries and international agreements; major disruptive events; future technological breakthrough; or changes in laws, regulations and stated targets reflected in current policies.

Liquid fuels

In non-OECD regions, petroleum and other liquid fuels consumption nearly doubles, with most of the growth in non-OECD Asia, driven by growing populations and expanding economies. "Non-OECD liquid fuels consumption increases 45% during the projection period, growing from 108 quadrillion Btu in 2018 to 156 quadrillion Btu by 2050," EIA said. Non-OECD Asia will account for some 75% of the global increase in liquid fuels consumption, particularly India which "experiences rapid industrial growth and increased demand for motorized transportation."

OECD liquid fuels consumption, conversely, declines slowly as demand growth is less than efficiency improvements. In OECD Americas and OECD Asia, demand is relatively unchanged, but liquid fuels consumption falls by 15% in OECD Europe, dropping by some 4 quadrillion Btu to 24 quadrillion Btu in 2050.

EIA said transportation remains the largest consumer of liquid fuels in its reference case. There is significant growth in non-OECD countries, consumption is up about 50% from 2018 to 2050, with transportation responsible for more than half of liquid fuels demand in both OECD and non-OECD countries.

Oil production

EIA said in its reference case, world crude oil production is up nearly 30% in 2050, led by production increases in Organization of the Petroleum Exporting Countries.

Most production, however, remains in non-OPEC

In the U.S., crude oil and lease condensate production increases from 11 million bpd in 2018 to some 14 million bpd from 2025 to 2040, "driven by hydraulic fracturing of tight resources in the U.S. Southwest," but then falls to 12.2 million bpd by 2050, EIA said, "as development moves into less productive areas and well productivity declines."

countries.

Worldwide crude oil, lease condensate, natural gas plant liquids and other liquid fuels reach 127 million barrels per day in 2050, about 30% above 2018 levels, with crude and lease condensate production growing by 13 million bpd among OPEC members and by 11 million bpd among non-OPEC producers, increases of about 40% for OPEC members and 25% for non-OPEC members.

But, EIA said, non-OPEC countries produce slightly more than 50% of crude oil output through the 2018-50 period, and amount to 55% of global production in 2050.

OPEC crude oil production increases 37% between 2018 and 2050, from 35 million bpd to 48 million bpd, with most production and growth from the Middle East and OPEC continues to provide more than 40% of world oil supplies.

That OPEC production is concentrated in the Middle East, growing from 27 million bpd in 2018 to 39 million bpd. "Production from large low-cost oil resources in the Middle East remains a critical part of global crude oil supply during the projection period," EIA said.

Non-OPEC

The highest levels of non-OPEC production are from Russia and the United States, although late in the period Canada sees considerable growth.

Non-OPEC crude oil and lease condensate production grows 23% between 2018 and 2050, reaching 59 million bpd in 2050, the agency said. Russia production increases by 22%, the U.S. by 11%, Canada by 126% and Brazil by 59%.

In the U.S., crude oil and lease condensate production increases from 11 million bpd in 2018 to some 14 million bpd from 2025 to 2040, "driven by hydraulic fracturing of tight resources in the U.S. Southwest," but then falls to 12.2 million bpd by 2050, EIA said, "as development moves into less productive areas and well productivity declines." 2050 production will still be 11% above 2018.

Russian production will grow by 2.3 million bpd, mainly from non-tight resources.

In Canada, the 5.4 million bpd increase is from oil sands, particularly toward the end of this period, "as easily accessible global resources are increasingly depleted and global oil prices gradually increase." (In the reference case, the price of North Slope Brent is expected to reach $100 a barrel in 2050, in 2018 dollars.)

The increase in Brazil's production by 1.5 million bpd in 2050 comes from continued development of offshore pre-salt resources.

Refining has the most growth in Asia, "where demand for finished petroleum products is greatest," EIA said. Refinery runs remain largely unchanged in the Americas and in Europe, the Middle East and Asia refinery throughput decreases slightly.

Natural gas

World consumption of natural gas increases more than 40% by 2050, with the demand growth led by non-OECD countries. The increase is 70% in non-OECD countries, EIA said, with the non-OECD share of consumption increasing from about 51% to 61%, while in OECD the increase is 17%.

The consumption growth in non-OECD countries is driven by economic growth and expanded use in the electric power generation and industrial sectors.

Natural gas production is led by the Middle East, the U.S., Russia and non-OECD Asia.

"The United States remains the world's largest natural gas producer throughout the projection period," EIA said, with U.S. gas production up nearly 50% to 43 trillion cubic feet, with production expanding in the Appalachian region and in tight oil formations in and around Texas.

Middle East natural gas production increases to 37 tcf in 2050, up 15 tcf, about a 70% increase, while natural gas production in Russia increases about 40%, reaching 34 tcf in 2050, with most of the increase exported to Asia and Europe.

Canada continues to produce relatively large amounts, reaching 6 tcf in 2050, up nearly 20%.

Pipeline flows continue to account for most of inter-regional gas trade, with non-OECD and Eurasia, primarily Russia, remaining the largest net exporter of natural gas in 2050, followed by the Middle East.

"The Americas grow as a net exporter of natural gas, driven mostly by LNG shipments from the United States to countries outside the region."

—KRISTEN NELSON

Contact Kristen Nelson at knelson@petroleumnews.com

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MAGAZINE PREVIEW

increase is presumably related to the new development drilling).

Drilling delays

Eni had originally planned to complete the NN-01 well in mid-February 2018, and then to conduct flow testing on any oil discovery. However, the drilling did not proceed to plan — the drilling was eventually suspended on Aug. 23, 2018, because of seasonal drilling restrictions. The drilling is presumably challenging, given that, with an expected measured depth of about 35,000 feet, the well would be the longest extended reach well of its type in Alaska.

According to Eni's latest plan of operations the drilling of NN-01 restarted in January but was suspended in April at a measured depth of 30,010 feet because of operational limitations. Petroleum News understands that there was a need for modifications to the drilling rig. The plan of operations says that Eni anticipates continuing the drilling of the well in early February 2020, with the well expected to reach its target measured depth by the third quarter of the year. A reliable Petroleum News source has indicated that testing of the well is anticipated in 2020.

Eni has not publicly identified the drilling target at Nikaitchuq North. The Schrader Bluff formation that hosts the reservoir for the Nikaitchuq field is known to extend a long way north under the Beaufort Sea — it is possible that Eni is seeking a more northerly oil pool in this formation. However, there are other possibilities that, based on circumstantial evidence such as the planned drilling depth, may be more likely. One contender seems to be Jurassic Alpine sands, equivalent to reservoir sands in the Alpine oil field and deeper than the Schrader Bluff. In addition, Kerr-McGee, the previous Nikaitchuq operator, had talked about the possibility of testing the Jurassic Nuiqsut sandstone to the north of the field.

Oooguruk field

As with Nikaitchuq, the Oooguruk field saw significant impacts from the 2014 oil price downturn: In May 2016 Caelus, then the operator, suspended all drilling operations at the field. That drilling suspension continued up to the point at which Caelus sold its interests in Oooguruk to Eni. Eni became the new field operator on Aug. 1 and has thus far not announced any new development plans for the field.

Although not doing any new drilling, Caelus had been conducting some well workovers, including the replacement of some electric submersible pumps. This summer, with the concurrence of Eni, the company carried out some maintenance work in the field's surface facilities. The field has been producing from three pools: the Kuparuk, Nuiqsut and Torok. The Torok formation contains the oil pool for the planned Nuna development that is being purchased by ConocoPhillips, separately from the Oooguruk field. However, the Torok does produce on the Oooguruk offshore production island.

The current plan of operations for the field indicates that two production wells and two injector wells are active in the Kuparuk pool, although Kuparuk production is currently shut in. Caelus has been hoping to obtain regulatory approval for commingling or alternating Kuparuk and Nuiqsut production through one of the Nuiqsut wells. The development area for the Nuiqsut pool has 18 production wells and 10 injection wells, the plan of operations says. Caelus has been in the process of upgrading the system that supplies seawater for injection into the reservoir. The Torok pool has three active wells — two production wells and an injector well. Two wells drilled from the onshore Nuna drill site have been suspended.

In January Eni announced a goal of raising its total Alaska North Slope production to 30,000 barrels per day by drilling more wells at both Oooguruk and Nikaitchuq. In July Oooguruk production averaged 8,720 bpd, compared with 9,696 bpd in July 2018. Taken together, the com-

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OIL SEARCH UPDATE

says, noting Stirrup is a direct analogue to the Horseshoe 1 Nanushuk discovery drilled by Armstrong in 2015.

Drilling Stirrup 1 requires 26 miles of snow trail to mobilize the rig and camp and 16 miles of ice road.

A tour slide says, Oil Search will "continue to build ice road for wheeled traffic during rig mobilization and potentially for surface hole drilling."

The "mobilization and all support on trailers" will be "towed by steigers" at a speed of 5-12 miles per hour, which allows the rig "to spud 10 days earlier."

Oil Search's North Slope exploration group is headed by Josef Chmielowski, vice president of exploration and new ventures, and former geoscientist with Alaska's Division of Oil and Gas, who is known for his knowledge of the Nanushuk and Torok formations in the more westerly region of the Slope

Success at the Stirrup prospect, which is adjacent to the Horseshoe Block … "could de-risk additional fairways to underpin a possible standalone" Horseshoe development, the company says, noting Stirrup is a direct analogue to the Horseshoe 1 Nanushuk discovery drilled by Armstrong in 2015.

EXPLORATION WINTER 2019/20

TWO WELL, HIGH IMPACT PROGRAMME TESTING NANUSHUK ANALOGUES

Oil Search

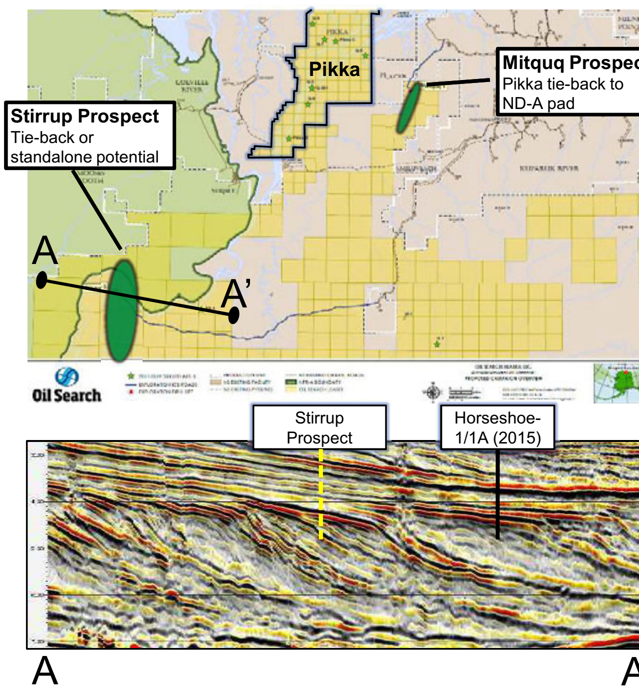
Pikka East Block: Mitquq Prospect

- ◊ Pikka Nanushuk analogue play
- ◊ Located <10km from Pikka ND-A pad
- ◊ High value tie-back volumes to future Pikka infrastructure

Horseshoe Block: Stirrup Prospect

- ◊ Stirrup success could de-risk additional fairways to underpin possible stand-alone Horseshoe CPF
- ◊ Adjacent and direct analogue to Horseshoe 1 discovery drilled by Armstrong in 2015

Option to core and test both Stirrup and Mitquq in the event of success



NORTH SLOPE FULL POTENTIAL

REGIONAL STUDY TO EVALUATE BASIN POTENTIAL DRIVING LONG TERM COMMERCIALISATION AND GROWTH STRATEGY IN ALASKA

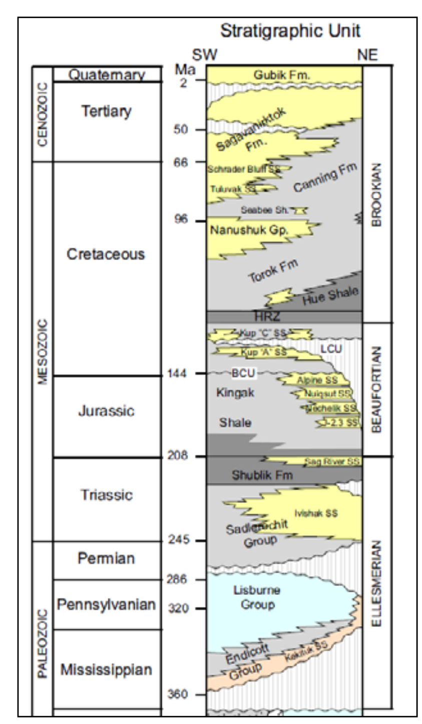
Oil Search

Context

- ◊ 1.5 trillion barrels of oil generated in the Colville trough, only 20 billion barrels oil discovered to date
- ◊ ~10 billion barrels undiscovered potential identified across combined play fairways

Strategic Objective

- ◊ Provide context for future business build and ongoing acreage optimisation – strong commercial focus
- ◊ Provide input to current portfolio risking
- ◊ Frame Oil Search 5+ year work programme targeting identifying gross 1.5 billion barrels with top quartile finding costs
- ◊ Ensure access to emerging plays, identify new plays, ongoing portfolio refresh
- ◊ Ensure high value growth in world class, under-explored, oil-rich basin



Value engineering, improvement

In a slide labeled "Value engineering," Oil Search says it has screened 86 ideas and that five key factors drive "significant value improvement" for Pikka, noting that continuous improvement and value enhancing programs are ongoing.

The five key factors are facility, well spacing, enhanced oil recovery, or EOR, facility/module optimization and EPS throughput. EPS stands for early production system, which is Oil Search's plan to begin production in 2022 using the facilities of a nearby North Slope producer.

Under facility, the slide notes the increase in the nameplate size from 120,000 bpd to a target of 135,000 bpd for Pikka, the effect of which will "accelerate early life production."

Well spacing has been reduced from 1,800 feet to 1,400, the effect of which is to have fewer wells in the Pikka development with "no impact on total resource recovery."

Under EOR, the slide shows an increase of natural gas liquids for injection into the reservoir from 27 million standard cubic feet per day to 80 mmscfd.

A weight and volume reduction are listed under facility/module optimization; the effect of reducing the quantities and size of steel being "reduced capex and opex," referring to capital and operating expenditures.

Under the fifth factor, EPS, the slide shows an acceleration of early production in 2022 from 30,000 bpd to 50,000 bpd.

Rigs and economics

A breakeven Brent oil price in the low $40s for the base Pikka project in advance of the final investment decision, or FID, is provided in a tour slide. The reference says the "initial project carries all infrastructure costs." Tiebacks and extended reach drilling will "reduce long term breakeven estimates," Oil Search says on one slide, noting elsewhere an FID date of July 2020

Oil Search has secured the Doyon and Nabors rigs, as well as contracted for all other services for the coming winter's work.

And the tour slides say the company is in final negotiations for two fit-for-purpose rigs that will be able to drill 80% of the wells Oil Search has planned for the next

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MAGAZINE PREVIEW

bined Oooguruk and Nikaitchuq production falls a bit short of that 30,000 bpd target.

Exploration acreage

Eni has yet to announce any specific plans for exploration in the 350,000 exploration acres that it purchased from Caelus. In 2015 Caelus acquired 175 square miles of new 3D seismic data and reprocessed another 275 square miles of existing 3D seismic, with the objective of imaging prospects in the acreage. Caelus said that, while there are multiple plays in proven stratigraphic horizons within the acreage, surrounding legacy wells confirm relatively shallow Brookian reservoirs and hydrocarbon charge, as well as deeper petroleum system elements. The company also commented that the proximity of infrastructure with available capacity reduces the resource volumes needed for viable development.

In August Eni said that it planned to apply its business model and experience to the exploration acreage, using fast-track exploration and a short time to market for potential new discoveries. ●

Contact Alan Bailey at abailey@petroleumnews.com

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OIL SEARCH UPDATE

few years associated with Pikka development.

Currently the company is "working strategy for third pad rig option" — a "specific extended reach drilling rig," that will be "required for complex Tier 3 & 4 wells."

The ERD rig will not be needed "until 2025+" the company says.

Working with ConocoPhillips

Oil Search's focus is on the development of the Pikka unit and related area exploration and appraisal, with early production of some 30,000 bpd scheduled for 2022 and full production of 120,000 bpd in early 2024, versus its original plan of full production in late 2023. (Note those amounts are 50,000 bpd and 135,000 in the value engineering slide discussed above.)

The early production, Oil Search says, will use existing capacity in the processing facilities of an "adjacent," but unnamed, operator, possibly ConocoPhillips, which would correspond with Oil Search's August declaration that it is working closely on Nanushuk development west of the central North Slope with ConocoPhillips.

In fact, an Oil Search slide from the mid-September CLSA investor forum in Hong Kong, which itself is not public, says the company is "working together with ConocoPhillips to develop Nanushuk (Narwhal) reservoir." It is Oil Search's first public reference to the informal, non-geologic term ConocoPhillips uses for the Nanushuk reservoir — Narwhal or Narwhal trend.

Oil Search's 5-plus year work program target is to identify "gross 1.5 billion barrels with top quartile finding costs," as well as "ensure access to emerging plays" and "identify new plays."

Negotiations with a nearby producer are to be completed by the time a Pikka FEED, or front-end engineering and design, decision, is made in the fourth quarter of this year.

Development work this winter

Currently underway, a tour slide says, is an "independent resource certification" for the core Pikka unit development area, which will initially produce oil from the big Nanushuk formation and later add oil from the Alpine C interval, another one of six stacked plays in the unit, per a 2016 statement by former operator head Bill Armstrong.

In a tour slide Oil Search outlined the Pikka work planned for the coming winter, which includes the following:

• Civil works season 1 of 2.

• Construction of key infrastructure to facilitate both early production and full-field development.

• Season 1 scope (in order of priority).

• Road and bridge to ND-B plus the pad.

• Operations center pad.

• Additional gravel scope as weather permits.

In the winter of 2020-21, the company has the following development work planned: Drilling 50 to 55 producers/injector well pairs; building pipelines and roads; facilities construction and community projects.

In 2022-23, Oil Search aims to look at "120,000 barrel per day plateau and expansion opportunities," with a "targeted contingent resources of 700 million barrels oil" and do a Horseshoe area appraisal tieback or independent CPF (central processing facility), plus community projects.

In regard to the 700 million barrels of oil, that slide includes a notation that reads, "The estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) related to undiscovered accumulations," will require "further exploration appraisal and evaluation."

With only 20 billion barrels of oil discovered to date, Oil Search says in its "North Slope full potential" slide, that 10 billion barrels of "undiscovered potential" has been identified across "combined play fairways."

North Slope potential

The slides from the Alaska investor tour also laid out Oil Search's view of the remaining hydrocarbon potential of the North Slope, describing the Slope as a "world class, under-explored, oil-rich basin."

The company's "context" is the 1.5 trillion barrels of oil generated in the Colville trough, more commonly known as the Colville basin, which spans the entire width of the North Slope.

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Oil Search's 5-plus year work program target is to identify "gross 1.5 billion barrels with top quartile finding costs," as well as "ensure access to emerging plays" and "identify new plays." ●

Contact Kay Cashman at publisher@petroleumnews.com