Petroleum news

page 2 Purchase of Nicolai Creek field approved, new owner takes over

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A slight increase in ANS output

JUDY PATRICK

Alaska North Slope production was up slightly from November, with most of the month-over-month gain at the Alpine and Kuparuk fields. Read more on page 5.

Approved plan, default notice for Furie; required to drill this year

Alaska's Division of Oil and Gas has issued a notice of default to Furie Operating Alaska LLC for the company's failure to meet work commitments in the Kitchen Lights unit in 2017. However, the division has also approved Furie's Kitchen Lights plan of development for the coming year and has said that the company can cure the default by meeting all of the drilling commitments in the new plan.

Two well program

As previously reported in Petroleum News, Furie's new plan of development entails a two-well drilling program in

see **FURIE PROGRAM** page 12

Cross-inlet line permits issued

The Regulatory Commission of Alaska has issued temporary construction permits for new pipelines that Hilcorp Alaska plans to build, to enable the transportation of crude oil by pipeline from the west side of Cook Inlet to Nikiski on the Kenai Peninsula. In a Dec. 29 order the commission allowed Hilcorp subsidiary Cook Inlet Pipeline Co. to start work on a short northward extension of the existing pipeline that carries oil down the west side of the inlet. The idea is to connect the existing oil line to one of the twin Cook Inlet Gas Gathering System pipelines under the inlet. One of the CIGGS lines will then continue to carry gas, while the other line will carry oil.

Hilcorp also plans to maintain existing gas transportation

see **INLET PERMITS** page 12

Drilling permits for Pikka wells

Armstrong Energy LLC has received drilling permits for its Pikka exploration program.

On Dec. 21, the Alaska Oil and Gas Conservation Commission issued permits for the company to drill the Pikka No. 2 exploration well and Pikka No. 2A sidetrack.

The Pikka No. 2 well is designed as a directional well heading westward from ADL 392975. The Pikka No. 2A sidetrack will be a nearly vertical well on ADL 393028.

The well locations are immediately north of the location of the proposed Pikka No. 1 well that the company ultimately cancelled last year at the request of local groups in Nuiqsut.

The purpose of the delineation program is to obtain consid-

see **PIKKA WELLS** page 12

EXPLORATION & PRODUCTION

It's holding steady

The decline in Prudhoe oil production has been halted for a third year

By ALAN BAILEY
Petroleum News

SCOTT DIGERT

JENNIFER STARCK

Despite the challenging oil price environment, production from the Prudhoe Bay unit on Alaska's North Slope has held steady for a third year, rather than continuing the production decline that had previously marked the field's performance, executives from BP Exploration (Alaska), the field operator, have told Petroleum News. The sustained Prudhoe Bay production presumably provided a solid base for increased oil throughput in the trans-Alaska pipeline in 2017.

Prudhoe Bay data for 2017 have yet to be finalized, but preliminary figures show an average production rate of just over 280,000 barrels of oil per day. That compares with 281,800 bopd in 2015 and 280,700 bopd in 2016.

The historical production decline rate would

see **HOLDING STEADY** page 10

NATURAL GAS

Mackenzie project dumped

Canadian Arctic venture dissolved after 17 years of studies and hearings

By GARY PARK
For Petroleum News

Twice in 40 years the dreams of exploiting Canada's northern natural gas resources have been shattered, only this time there seems to be no hope of a bounce back.

The joint-venture partnership underpinning the Mackenzie Gas Project was formally dissolved on Dec. 22, delivering a crushing pre-Christmas blow to those who might have been clinging to hope that the scheme could be saved. For everyone else, the announcement was a foregone conclusion.

It followed the first setback for gas development in the Canadian Arctic after three anchor fields —

By 2016, the estimated capital cost of the MGP had soared to C$16.2 billion from C$5 billion in 2001 and even then observers were suggesting the total would likely exceed C$20 billion.

Taglu, Parsons Lake and Niglintgak — were discovered in the 1971-73 period, resulting in a federal inquiry into the social, environmental and economic impact of a pipeline along the Mackenzie River Valley. That led to a federal moratorium in 1977 that ended commercial activities until 2000.

see **MACKENZIE PROJECT** page 9

FINANCE & ECONOMY

A down and up year

In the first half of 2017 the oil price dropped before climbing steadily

By ALAN BAILEY
Petroleum News

During the first six months of 2017 the price of oil tumbled erratically, in a manner that did not seem promising for an oil industry that had seen a significant price recovery during the previous year. The tumble came despite a late 2016 agreement on oil production quotas by most countries in the Organization of Petroleum Exporting Countries and by Russia.

However, during the second half of the year, the price recovered steadily to above $60 per barrel by year end, and since then has continued to climb. And a graph of the oil price since the beginning of

It is generally agreed that the tumble in oil prices in 2014 resulted from an excess of oil supplies, rather than a shortfall in oil demand.

2016 seems to show that early 2017 price drop as something of a glitch in an overall upward trend.

Commentators have attributed the early 2017 price drop to the fact that Libya and Nigeria were not part of the 2016 OPEC agreement, and to U.S. shale oil development rising in response to the OPEC action. Subsequent time extensions to that

see **OIL PRICES** page 11

● NATURAL GAS

Purchase of Nicolai Creek field complete

Aurora Exploration has taken over as operator of natural gas field on west side of Cook Inlet, plans actions to boost production

By ALAN BAILEY
Petroleum News

Aurora Exploration has now completed its purchase of the Nicolai Creek gas field on the west side of the Cook Inlet from Aurora Gas, Scott Pfoff, president of Aurora Exploration, told Petroleum News in a Jan. 3 email.

"The transaction closed effective January 1, 2018 and Aurora Exploration has taken over operations at Nicolai Creek unit," Pfoff said.

He said that his company's immediate focus would be on the ownership transition and conducting compressor repairs in the field. The company will then use coiled tubing to clear sand from several key wells, to boost production.

"Once these goals have been achieved, we will be in a position to pursue the numerous upside opportunities we see at Nicolai Creek unit such as development drilling, unconventional reserves, gas storage and the potential for oil exploration," Pfoff said.

SCOTT PFOFF

Purchased from Aurora Gas

Aurora Exploration has purchased the field as part of the fallout from the bankruptcy of Aurora Gas. Although similar in name, the two companies are completely separate, each having different ownership and management.

The purchase had been delayed because of issues regarding Alaska Oil and Gas Conservation Commission requirements for surety bonding for the plugging and abandonment of the six Nicolai Creek gas wells. Initial bonding levels mandated by AOGCC ran to several million dollars, levels that Aurora Exploration said would have rendered the field uneconomic. The commission has since reduced the bonding requirement to $200,000, the traditional level for wells in Alaska, thus enabling the field purchase to move ahead.

On Dec. 18 the federal bankruptcy court in Alaska approved the sale of the field. And on Dec. 28 Alaska's Division of Oil and Gas approved the designation of Aurora Exploration as field operator, subject to the company posting an operator bond with the Alaska Department of Natural Resources.

Plan of development

Also on Dec. 28 Chantal Walsh, Division of Oil and Gas director, approved Aurora Exploration's plan of development for the field. As previously reported in Petroleum News, the plan involves the coiled tubing cleanout of existing wells and the drilling of a new well in the field.

see NICOLAI CREEK page 4

contents

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

Alaska - Mackenzie Rig Report

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Kuparuk, De-Mob	ConocoPhillips
Dreco 1000 UE	16 (SCR/TD)	Standby	
Dreco D2000 Uebd	19 (SCR/TD)	Alpine CD5-23	ConocoPhillips
AC Mobile	25	Standby	
OIME 2000	141 (SCR/TD)	Kuparuk, Stack Out	ConocoPhillips
	142 (SCR/TD)	Kuparuk 1H-101	ConocoPhillips
TSM 7000	Arctic Fox #1	Stacked	
Hilcorp Alaska LLC			
	Rig No.1	Milne Point	Hilcorp Alaska LLC
Nabors Alaska Drilling			
AC Coil Hybrid	CDR-2 (CTD)	Deadhorse	BP
AC Coil	CDR-3 (CTD)	Kuparuk	ConocoPhillips
Dreco 1000 UE	2-ES (SCR-TD)	Deadhorse	Available
Mid-Continental U36A	3-S	Deadhorse	Available
Oilwell 700 E	4-ES (SCR)	Deadhorse	Available
Dreco 1000 UE	7-ES (SCR/TD)	Deadhorse	Available
Dreco 1000 UE	9-ES (SCR/TD)	Deadhorse	Available
Oilwell 2000 Hercules	14-E (SCR)	Deadhorse	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Mustang location	Available
Oilwell 2000 Canrig 1050E	27-E (SCR-TD)	Deadhorse	Available
Oilwell 2000	33-E	Deadhorse	Available
Academy AC Electric CANRIG	99AC (AC-TD)	Deadhorse	Available
OIME 2000	245-E (SCR-ACTD)	Kuparuk	Available
Academy AC electric CANRIG	105AC (AC-TD)	Deadhorse	Available
Academy AC electric Heli-Rig	106AC (AC-TD)	Deadhorse	Available
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay	Available
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay	Available
Ideco 900	3 (SCR/TD)	Prudhoe Bay	Available
Rig Master 1500AC	4 (AC/TD)	Oliktok Point, well OP-03	ENI
Parker Drilling Arctic Operating Inc.			
NOV ADS-10SD	272	Prudhoe Bay DS 18	BP
NOV ADS-10SD	273	Prudhoe Bay DSW-59	BP

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
BP			
Top Drive, supersized	Liberty rig	Inactive	BP
Doyon Drilling			
Sky top Brewster NE-12	15 (SCR/TD)	Spy Island NN-01	ENI
Nabors Alaska Drilling			
OIME 1000	19AC (AC-TD)	Cold Stack	

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
BlueCrest Alaska Operating LLC			
Land Rig	BlueCrest Rig #1	Anchor Point, drilling production section of H14	BlueCrest Alaska Operating LLC
Glacier Oil & Gas	Rig 37	West McArthur River Unit Workover	Glacier Oil & Gas
All American Oilfield LLC			
IDECO H-37	AAO 111	In All American Oilfield's yard in Kenai, Alaska	Available
Aurora Well Services			
Franks 300 Srs. Explorer III	AWS 1	Stacked out west side of Cook Inlet	Available
Saxon			
TSM-850	147	Stacked	Hilcorp Alaska LLC
TSM-850	169	Stacked	Hilcorp Alaska LLC

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Hilcorp Alaska LLC			
National 110	C (TD)	Platform C, Stacked	Hilcorp Alaska LLC
	Rig 51	Steelhead Platform, Stacked	Hilcorp Alaska LLC
	Rig 51	Monopod Platform, Drilling	Hilcorp Alaska LLC
Spartan Drilling			
Baker Marine ILC-Skidoff, jack-up		Spartan 151, Stacked Seward	
Furie Operating Alaska			
Randolf Yost jack-up		Nikiski, OSK dock	Furie
Glacier Oil & Gas			
National 1320	35	Osprey Platform, activated	Glacier Oil & Gas
Kuukpik Drilling	5	Granite Point, Well GP24-13RD2	Hilcorp Alaska LLC

Mackenzie Rig Status

Canadian Beaufort Sea

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
SDC Drilling Inc.			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Available

Central Mackenzie Valley

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Akita			
TSM-7000	37	Racked in Norman Wells, NT	Available

The Alaska - Mackenzie Rig Report as of January 4, 2018. Active drilling companies only listed.

TD = rigs equipped with top drive units WO = workover operations
CT = coiled tubing operation SCR = electric rig

This rig report was prepared by Marti Reeve

JUDY PATRICK

Baker Hughes North America rotary rig counts*

	Dec. 29	Dec. 22	Year Ago
United States	929	931	658
Canada	136	210	157
Gulf of Mexico	18	19	22

Highest/Lowest

US/Highest	4530	December 1981
US/Lowest	404	May 2016

*Issued by Baker Hughes since 1944

● EXPLORATION & PRODUCTION

Conoco applies for Meltwater waterflood

Field began with waterflood, then miscible injection, lean gas flood; return to waterflood estimated to allow 1-2% more recovery

By KRISTEN NELSON

Petroleum News

Kuparuk River field operator ConocoPhillips Alaska has applied to the Alaska Oil and Gas Conservation Commission for permission to return the Meltwater satellite to waterflood.

Currently waterflood at Meltwater is allowed only for some specific purposes; ConocoPhillips has applied to return the field to waterflood for enhanced oil production.

Meltwater, a satellite at the southwestern corner of Kuparuk, was originally produced on waterflood. Then the line carrying water to the field became corroded. Returning the field to waterflood is projected to extend field life by five to 10 years and result in recovery of an additional 1-2 percent of original oil in place.

Amendment of AIO

ConocoPhillips is asking for an amendment to the area injection order for Meltwater. Water was injected at the beginning of field production, but stopped in October 2009 because of corrosion in the water supply line. The company said there were no plans to replace the line due to high cost and a determination that miscible injectant was the best mechanism to maximize production at the field.

In 2014, miscible injectant was no longer imported to Kuparuk and only lean gas was sent to Meltwater for lift and enhanced oil production.

ConocoPhillips said the lean gas flood has matured and the gas oil ratio has increased, making the Meltwater wells uncompetitive, with declining production raising freezing concerns for the production line.

The company said it is pursuing water injection below 3,400 psi with the goal of extending field life by reducing the gas oil ratio, providing pressure support and alleviating freezing concerns on the production line.

The water issue

ConocoPhillips said the commission made changes in the area injection order in 2012, listing fluids authorized for injection. Water was not included, the company said, because it did not plan to restore water injection capability.

In a 2015 order, water was authorized for injection, but only for limited purposes.

The change ConocoPhillips is requesting would authorize use of Beaufort Sea and Kuparuk produced water, eliminating the limited purposes listed in 2015.

ConocoPhillips said the lift mechanism at Meltwater would also be changed from lift gas to jet pump.

There is only one functional injection pipeline, so only one fluid can be injected at Meltwater at a time, the company said. The flooding would increase oil recovery compared to not injecting water, the company said. Original oil in place estimates given at a 2012 hearing were 60 million barrels, the company said.

In addition to increasing ultimate recovery by 1-2 percent, waterflood would extend field life. "If water cannot be injected, the field would likely go into depletion or be shut in as it has reached MI maturity and received a lean gas chase," ConocoPhillips said. The injection line servicing Meltwater and other Greater Kuparuk Area drill sites will soon be switched back to MI "to pursue newly drilled targets, but Meltwater is not a target for MI," the company said.

A return to waterflood at Meltwater would allow pursuit of a potential 2 million to 7 million barrels of targets for development drilling, and has the advantage of preventing low flows and freezing concerns in the 24-inch production line.

"With water injection, water can be recycled directly from the injection line to the production line," ConocoPhillips said. "This continuous loop of injection water will keep the production line from freezing even as reservoir production rates decline."

The commission has scheduled a public hearing on the application Feb. 8 at 10 a.m.at its Anchorage offices. ●

Contact Kristen Nelson at knelson@petroleumnews.com

continued from page 2

NICOLAI CREEK

During the first quarter of 2018, Aurora Exploration plans to conduct cleanout operations in the NCU No. 9, the NCU No. 10 and the NCU No. 11 wells. The company has also committed to drill a NCU No. 12 development well by the end of December. The development well will be a 900-foot directional well, drilled towards the west-northwest from a surface location south of the Nos. 3 and 10 wells and targeting the productive Beluga and upper Tyonek sands.

The plan also indicates that Aurora Exploration is interested in the future possibility of converting the NCU Nos. 2 and 9 wells for gas storage operations at some time in the future. The company also plans to negotiate the purchase of some 3-D seismic data from Apache Alaska Corp., to support the evaluation of possible new exploration, development and drilling targets. Apache owns deep rights under the Nicolai Creek unit but has withdrawn from exploration in Alaska, the plan says.

Aurora Exploration has also indicated to the division that Nicolai Creek will likely become uneconomic in 2022, and that the company would likely plan for well abandonment and surface equipment removal during the summer of that year. ●

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● EXPLORATION & PRODUCTION

ANS production up slightly from November

Most of month-over-month gain at Alpine, Kuparuk; in November Cook Inlet averaged 16,198 bpd, up 2% from October volumes

By KRISTEN NELSON
Petroleum News

Alaska North Slope crude oil production averaged 547,687 barrels per day in December, up 0.6 percent from a November average of 544,221, but down 1.6 percent from a December 2016 average of 556,681 bpd. The biggest month-over-month increases were both at ConocoPhillips Alaska-operated fields: Alpine was up 7 percent and Kuparuk was up 2.22 percent.

Volumes associated with the BP Exploration (Alaska)-operated Prudhoe Bay and Lisburne fields were both down month-over-month, Lisburne by 2.21 percent and Prudhoe by 1.15 percent.

Information for December comes from the Alaska Department of Revenue's Tax Division which consolidates North Slope oil production by major facilities rather than reporting individual fields, providing daily production and monthly averages. More detailed data, including Cook Inlet and individual North Slope fields and pools, is reported by the Alaska Oil and Gas Conservation Commission on a month-delay basis.

Alpine, Kuparuk

Alpine production, which includes satellites at Fiord, Nanuq and Qannik, averaged 67,928 bpd in December, up 7 percent, 4,412 bpd, from a November average of 63,516, and up 11.5 percent from a December 2016 average of 60,927 bpd. AOGCC data for November show the majority of Alpine production, 84 percent, coming from the main field, which includes volumes from the CD5 drill site, which the company brought online in the fall of 2015. In 2016 the company announced the expansion of CD5 from 15 to 33 wells, with first production from the new wells expected in the third quarter of 2017.

Volumes shown for the Kuparuk River unit averaged 147,079 bpd in December, up 2.2 percent, 3,195, from a November average of 143,884, and up 4.1 percent from a December 2016 average of 141,287 bpd. Kuparuk volumes include satellite production from Meltwater, Tabasco, Tarn and West Sak, along with the Eni-operated Nikaitchuq field and the Caelus Alaska-operated Oooguruk field.

AOGCC data show Nikaitchuq averaged 19,018 bpd in November, down 3.8 percent, 748 bpd, from an October average of 19,766 bpd, while Oooguruk averaged 13,017 bpd, up 8.2 percent, 988 bpd, from an October average of 12,029 bpd. Both fields are down some 18 percent from November 2016 volumes.

Prudhoe, Lisburne

BP-operated Prudhoe averaged 307,778 bpd in December, down 1.2 percent, 3,578 bpd, from a November average of 311,356, and down 6.7 percent from a December 2016 average of 344,880 bpd.

Prudhoe volumes reported by the Tax Division include satellite production from Aurora, Borealis, Midnight Sun, Orion, Polaris, Sag River, Schrader Bluff and Ugnu, as well as production from the Hilcorp Alaska-operated Milne Point and Northstar fields. Starting in October, the division also rolled in volumes from the

The 9,575 bpd is the highest monthly average since Point Thomson came online in April 2016 and the closest it has come on a monthly average to meeting its facility capacity of 10,000 bpd.

Hilcorp Alaska-operated Endicott field (including satellite production at Eider, Minke and Sag Delta), Badami, operated by Glacier Oil and Gas subsidiary Savant Alaska, and the ExxonMobil Production-operated Point Thomson field.

AOGCC data show Milne Point averaged 17,907 bpd in November, down 4.4 percent, 832 bpd, from an October average of 18,738 bpd, and down 10.2 percent from a November 2016 average of 19,944, while Northstar averaged 8,306 bpd in November, up 2.1 percent, 168 bpd, from an October average of 8,138 bpd, and up 61.6 percent from a November 2016 average of 5,140 bpd.

Badami averaged 778 bpd in November, down 5 percent, 41 bpd, from an October average of 819 bpd. And down 14.3 percent from a November 2016 average of 909 bpd.

Point Thomson averaged 9,575 bpd in November, up 27.8 percent from 7,492 bpd in October, and up 448.9 percent from a November 2016 average of 1,745. The 9,575 bpd is the highest monthly average since Point Thomson came online in April 2016 and the closest it has come on a monthly average to meeting its facility capacity of 10,000 bpd.

BP-operated Lisburne, a part of Greater Prudhoe Bay, averaged 24,902 bpd in December, down 2.2 percent from a November average of 25,465. Lisburne volumes include Niakuk, Point McIntyre and Raven.

Cook Inlet

AOGCC data show Cook Inlet crude oil production averaged 16,198 bpd in November, up 1.9 percent from an October average of 15,889 bpd.

The largest month-over-month per-barrel and percent increase was at Hilcorp Alaska's Granite Point field, which averaged 3,189 bpd in November, up 36.7 percent, 856 bpd, from an October average of 2,333 bpd.

BlueCrest's Hansen field, the Cosmopolitan project, averaged 269 bpd in November, up 16.3 percent, 38 bpd, from an October average of 232 bpd.

There was also an increase at Hilcorp's Middle Ground Shoal field, which averaged 1,568 bpd in November, up 0.9 percent, 14 bpd, from an October average of 1,554 bpd.

All other Cook Inlet fields were down, month-over-month. The Glacier Oil and Gas-operated Redoubt Shoal field averaged 827 bpd in November, down 29.9 percent,

see **ANS PRODUCTION** page 11

● EXPLORATION & PRODUCTION

53rd plan of development for North Fork

No new wells planned; focus on optimizing production from existing wells, including additional compression, separation facilities

By KRISTEN NELSON
Petroleum News

Glacier Oil and Gas, parent company of Cook Inlet Energy LLC, has submitted the 53rd plan of development for the North Fork gas field the company operates on the southern Kenai Peninsula.

If approved by the Alaska Division of Oil and Gas, the POD would cover March 31, 2018, through March 30, 2019.

Glacier's 52nd POD, approved in February 2017, included a number of planned activities at North Fork. In addition to activities planned for the 52nd POD, the company said it intended to complete reprocessing of North Fork seismic data prior to the beginning of the 52nd POD plan year.

Development plans for the 52nd POD year included: conversion of a depleted well for water disposal; workover operations at the NFU No. 14-25 and No. 41-35 wells; seeking opportunities for "small ball" projects such as perforating additional zones and setting plugs to control water intrusion; and additional drilling depending on favorable economic conditions.

Glacier said it completed several "small ball" projects to enhance production, including setting downhole plugs to control water intrusion and locating and perforating zones for increased production in the NFS No. 14-25 and No. 41-35 wells. The company said it also completed an optimization project to improve gas well process flow and replaced well houses on the NFU No. 24-26 and 42-35 wells.

Glacier said that because it was able to control water intrusion it did not convert a well to water disposal, but will continue to monitor water volumes and may convert a well to water disposal in the future.

Current plan

In the 53rd POD Glacier said it plans to enhance production through infrastructure improvements including additional compression and separation facilities; continue monitoring and analyzing production from existing wells, optimizing production, including monitoring water volumes and if necessary converting a depleted well for water disposal; continue a development drilling program based on data review and market conditions "to fully delineate and develop all fault blocks within the current Unit." The company said it will consider additional drilling pad locations as needed for full development and delineation of the reservoir, and will continue to evaluate drilling wells outside the current boundaries of the North Fork participating area.

Plan details

Details for the upcoming year include seeking opportunities for "small ball" projects to make production improvements, including perforating additional zones and setting plugs to control water as necessary. Glacier said additional drilling depends on favorable economic conditions, "including negotiation of long-term gas sales contracts" and said it has several candidates for additional drilling, including NFU No. 42-35A and NFU No. 22-26, with a fallback location to NFU No. 14-26.

As far as surface facilities go, Glacier said in the 52nd POD that longer term it was looking at expanding the existing drilling pad to accommodate new compression and dehydration equipment or possibly building a new drilling pad to better develop the reservoir.

In the 53rd plan under a surface facilities heading Glacier said its "plans do not include any additional permanent facilities at this time."

There are eight wells at North Fork and in a current well status Glacier said three were shut-in, and described their situation as "suspended pending further analysis." Five wells are listed as producing.

In the most recent month included in the POD, November 2017, North Fork produced 168,297 mcf of natural gas; from December 2016 through November the field produced 2,228,707 mcf. ●

Contact Kristen Nelson at knelson@petroleumnews.com

EXPLORATION & PRODUCTION

TAPS volumes up for 2nd consecutive year

The annual volume of crude oil moving through the trans-Alaska oil pipeline has increased for the second consecutive calendar year, Alyeska Pipeline Service Co. said Jan. 2.

The 2016 upturn in volume was the first since 2002, the company said.

The pipeline moved an average of 527,323 barrels per day in 2017, a total of 192,472,797 barrels. That is a 1.5 percent increase from 2016, when volumes averaged 517,868 bpd, a total of 189,539,817 barrels. The 2016 total was a 2.1 percent increase over 2015, when the pipeline carried a total of 185,582,715 barrels, 508,446 bpd. (Fiscal year volumes cited by the Alaska Department of Revenue are an average of 501,000 bpd in FY 2015, 514,700 bpd in FY 2016 and 526,500 bpd in FY 2017.)

The pipeline moved an average of 527,323 barrels per day in 2017, a total of 192,472,797 barrels.

"More oil flowing through TAPS means a safer, more efficient and more sustainable pipeline system," said Alyeska President Tom Barrett. "Increased throughput also signals a stronger economy for Alaska and more opportunities for Alaskans."

Alyeska celebrated its 40th anniversary of operations in 2017 and as of the close of 2017 operations had moved 17,648,210,557 barrels.

The company said the pipeline has faced escalating challenges in recent years — brought on by declining flow, slower moving oil and the potential for cooling temperatures, ice formation in the line and water and wax dropping out and accumulating. Alyeska said its teams have worked to adjust to the lower flows, adding heat, monitoring winter operating temperatures and modifying pigging operations.

"We benefit from an external business and regulatory environment that supports increased, responsible exploration and production on the North Slope and in the Arctic," Barrett said. "North Slope operators are leveraging efficiencies and technology to increase production and discover new oilfields. All of these efforts play into increases in TAPS' flow levels."

—KRISTEN NELSON

● ENVIRONMENT & SAFETY

Porcupine caribou herd at record number

By KRISTEN NELSON

Petroleum News

A photo census done in July of the Porcupine caribou herd shows an estimated 218,000 animals, which the Alaska Department of Fish and Game's Division of Wildlife Conservation called a record high since population monitoring of the herd began in the 1970s.

A 2017 summary, published by the division last summer, describes the Porcupine herd as one of North America's largest migratory caribou herds, and said that in addition to being a large herd, it has "the longest land migration of any animal in the world."

The herd spends time in both Alaska and Canada, and during the winter typically forages from the Brooks Range in Alaska to the Richardson Mountains in Canada, with cows migrating hundreds of miles to the Arctic coastal plain for calving every spring.

Prior to this summer's census showing an estimated 218,000 animals, the herd reached some 197,000 in 2013 when the last photo census was completed; there was a peak of some 178,000 animals in the late 1980s. The first photo census in 1977 identified some 100,000 animals.

The division said caribou populations are known for dramatic population changes and said once a herd becomes too large for its habitat, "the caribou become nutritionally stressed and the herd will decline."

New technology

The division said accuracy of the 2017 photo census was improved with a newly acquired digital photography system. Previously the division used a photo census technique which has been the same since World War II — with black and white photos, which were then printed and lined up to show the entire herd, and each caribou counted.

In the fall of 2016, however, there was an upgrade to a digital system linked to GPS and compatible with what the division called innovative software, allowing photos to be taken in a wide range of light conditions; photos with a larger footprint so fewer photos and less time are needed to photograph the caribou; digital imagery that allows automated alignment of multiple photos, eliminating overlap; and images in color and in high resolution, making it easier to pick out individual caribou so population estimates are more accurate.

Harvesting

The division said harvest of the herd is thought to be between 1 and 2 percent annually. Canada's harvest management plan requires an accurate harvest report from all hunters each year, the division said, and in 2013-14, about 2,920 Porcupine caribou were harvested in Canada, with more than 95 percent of the harvest by Gwich'in or Inuvialuit hunters.

Harvest in Alaska is primarily by local hunters in Arctic Village, Venetie and Kaktovik, the division said, with harvests estimated at 200 to 500 animals a year, but the division said that in Alaska, "harvest reporting is usually low." Reported nonlocal Alaska resident hunters usually harvest fewer than 175 caribou, the division said.

Calving areas

The division said that in the 1980s and 1990s most of the Porcupine herd calved south of Kaktovik in the 1002 area of the Arctic National Wildlife Refuge.

From 2004 through 2011, however, large portions of the herd calved along the Canadian border in Ivvavik National Park in Canada.

From 2012-13, the division said, GPS data showed that most of the radio collared cows calved on the coastal plain or adjacent foothills between the Babbage River in Canada and the Kongakut River in Alaska.

While portions of the herd still calved in Canada in 2014-15, the majority moved back to Alaska and calved on the coastal plain between the Hulahula and Kongakut rivers.

In 2016 most calving occurred on the coastal plain between the Alaska-Canada border and the Sadlerochit River and in 2017 the herd calved on the coastal plain from the Sadlerochit Mountains in Alaska to the Babbage River in Canada. ●

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GOVERNMENT

BSEE proposes OCS regulation changes

The federal Bureau of Safety and Environmental Enforcement is proposing changes to regulations introduced by the Obama administration governing safety requirements for offshore oil production. Known as the Production Safety Systems Rule, the regulations were issued in 2016 in the aftermath of the Deepwater Horizon disaster in the Gulf of Mexico. BSEE says that the proposed changes address provisions that create unnecessary burdens on operators. The regulation revisions will not lower the level of safety and environmental protection associated with offshore production, BSEE says.

The regulations relate to the design and use of systems such as well safety valves, pressure vessels and electrical systems for offshore facilities.

BSEE estimates that the proposed regulation changes would reduce the cost of regulatory compliance by at least $228 million over 10 years for the offshore oil and gas industry.

"I am confident that this revision of the Production Safety Systems Rule moves us forward toward meeting the administration's goal of achieving energy dominance without sacrificing safety," said BSEE Director Scott Angelle. "By reducing the regulatory burden on industry, we are encouraging increased domestic oil and gas production while maintaining a high bar for safety and environmental sustainability."

BSEE estimates that the proposed regulation changes would reduce the cost of regulatory compliance by at least $228 million over 10 years for the offshore oil and gas industry.

"It's time for a paradigm shift in the way we regulate the OCS," Angelle said. "There was an assumption made previously that only more rules would increase safety, but ultimately it is not an either/or proposition. We can actually increase domestic energy production and increase safety and environmental protection."

The public comment period for the proposed regulatory changes ends on Jan. 29.

BSEE has issued three other safety rules in response to Deepwater Horizon: a workplace safety rule, issued in April 2013; an OCS drilling rule, issued in April 2016; and an Arctic OCS drilling rule, issued in July 2016.

—ALAN BAILEY

GOVERNMENT

Alaska Oil and Gas Conservation Commission report: December 2017

• On Dec. 12, the Alaska Oil and Gas Conservation Commission approved (Area Injection Order No. 2C.054) a request from ConocoPhillips Alaska Inc. to continue water injections at the Kuparuk River Unit 2K-06 well. ConocoPhillips reported a potential Inner Annulus x Outer Annulus pressure communication at the well on March 22 while injecting gas. After confirming the gas communication, the company switched to water injections for a 30-day monitoring period. The company did not observe the Inner Annulus x Outer Annulus communication during the monitoring period, but Tubing x Inner Annulus communication was evident. The company shut in the well and began another monitoring period, during which time neither communication was observed. Subsequent diagnostic testing convinced the AOGGC of the integrity of the well.

• On Dec. 17, the AOGCC issued Industry Guidance Bulletin 17-001. The bulletin provided clarification about the testing procedures required for new well casings.

• On Dec. 28, the AOGCC approved (Area Injection Order No. 32.001) a request from Cook Inlet Energy LLC to continue water injection at the Redoubt 3A well. The company reported a potential Tubing x Inner Annulus pressure communication on Dec. 18 while injecting water. Diagnostic testing convinced the AOGGC of the integrity of the well.

• The AOGCC has scheduled a public hearing for Feb. 8 to consider a request from ConocoPhillips revise an existing order to allow for the injection of Beaufort Sea water and produced water from the Kuparuk River unit for enhanced oil recovery purposes.

—ERIC LIDJI

FINANCE & ECONOMY

Alaska to collect taxes after settlement

Alaska expects to collect about $165 million it is owed in back taxes from companies that paid to ship oil down the Trans-Alaska Pipeline after a settlement was reached on rates.

The payments are primarily from oil companies operating on the North Slope are not expected to be made in cash but through tax credits, Alaska's Energy Desk reported.

The settlement reached in December came after years of disputes over the rates set by the pipeline owners.

Dozens of rate cases were filed in 2009-15, causing the state and the independent shippers to file corresponding protests with state and federal regulators, said John Ptacin, a chief assistant attorney general over state regulatory affairs.

Ptacin said regulators determined that the rates were too high, and his office sorted through the open cases to come to an agreement. Under the settlement, a new rate calculation will be put in place and the state can collect its taxes.

The companies are expected to pay their tax bills by buying tax credits that the state owes to other companies.

From the cash-for-credits program the Legislature ended last year, the state owes nearly $1 billion to small oil and gas companies. The law that ended the program included a provision allowing companies to buy the credit and use them for owed taxes.

"Because of that, we believe companies are going to purchase — major producers are going to purchase — about $100 million worth of these tax credits that are in the hands of the smaller companies," said Ken Alper, director of the state Department of Revenue Tax Division.

The settlement still requires approval by the Regulatory Commission of Alaska and the Federal Energy Regulatory Commission.

—ASSOCIATED PRESS

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MACKENZIE PROJECT

Partners comment

Commenting on the break-up of the MGP partnership, Theresa Redburn, senior vice-president, commercial and corporate development at Imperial Oil, the lead partner with a 34.4 percent stake in the consortium, said: "We recognize this is a disappointing day for the people of the North."

"This is a disappointment to Imperial and the other members of the joint-venture as well," she said, referring to the Aboriginal Pipeline Group (33.3 percent), ConocoPhillips (15.7 percent), Shell Canada (11.4 percent) and ExxonMobil Canada (5.2 percent).

Most of the partners had already drastically scaled back or sold off assets in Canada's sickly upstream and shut down operations in Canada's Arctic, with ConocoPhillips making a one-time writedown of C$525 million in its MGP stake. A spokesman for ConocoPhillips Canada said the decision to end the joint venture was a difficult one, given the impact on "many organizations and individuals who have advocated for the development of the natural gas resource in the Mackenzie Delta."

Redburn acknowledged the "considerable investment of time and energy made by the project proponents at the people of the North."

In dangling a slender thread of hope, she said the North "remains an important potential source of future energy, given the right economic and regulatory conditions."

'Just a pipe dream'

With the Northwest Territories government in hibernation for the holiday season there was no immediate reaction from Premier Bob McLeod or any of his cabinet ministers.

But Merven Gruben, the mayor-elect of Tuktoyaktuk, a small community on the shore of the Beaufort Sea, candidly told the Canadian Broadcasting Corp., that "we all knew (the end of the road for the MGP) was coming."

"The pipeline (to initially deliver 830 million to 1.2 billion cubic feet per day from the Mackenzie Delta to connect in northern Alberta with Canada's gas pipeline network) was really just a pipe dream. We gambled on it and a lot of people lost."

He said the Mackenzie Hotel was built in Inuvik in hopes that the MGP would proceed and after initial struggles finally "found its legs, (but) so many other businesses didn't succeed."

Gruben's own construction company was one of the few to benefit by playing a large role in the C$300 million, 86-mile all-season road connecting Inuvik and Tuktoyaktuk that was opened for traffic in November, ending the years of reliance on an ice-road.

He said the remote northern communities might now tap into a gas well drilled off the new highway that could provide them with 100 years of energy supplies, while the prospect of a deepwater port in the Beaufort could be advanced if and when the federal government lifts its latest freeze on offshore oil and gas exploration.

However, Gruben remains especially bitter about the years of studies, community meetings and regulatory hearings related to the MGP that stretched beyond the point where once-economic gas prices evaporated amid a glut of global gas supplies, led by the breakthrough in shale gas development.

Approval time an issue

An Imperial spokesman agreed with that assessment, telling the CBC the co-venturers had not anticipated the length of time it would need for the project to receive approval from Canada's National Energy Board and a final go-ahead from the Canadian government.

He said that when the formal application was filed in October 2004 it was expected the regulatory process would take about two years to complete. Instead, it took seven years.

With the blame-game in full swing, Kevin O'Reilly, a member of the NWT legislature, who was closely connected with the regulatory phase through a social justice organization, accused the proponents of "poor planning," resulting in long delays in responding to information requests from government, aboriginal communities and non-government organizations.

But the end result of that procrastination might have been a blessing, he suggested, given that the surplus of gas supplies across North America might have seen the NWT government faced with demands to bail-out a partially completed project.

Compounding the regulatory delays were the signs of disagreements among the corporate partners, notably when ConocoPhillips said it was suspending investment to enable the MGP to "move forward," pointing to an "inconsistency" in its own and Imperial's definition of "funding."

Soaring costs

By 2016, the estimated capital cost of the MGP had

see **MACKENZIE PROJECT** *page 12*

Petroleum news

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HOLDING STEADY

have resulted in a figure closer to 260,000 bopd in 2017, said Scott Digert, BP Prudhoe Bay subsurface manager. Digert attributed the Prudhoe Bay performance to the efforts of the Prudhoe Bay workforce in improving operational efficiency in the field, rather than to any particular characteristics of the field itself.

"It's a tremendous performance," Digert said. "What we're really happy about is that that has been done, not through the physics of the field, but through human endeavor."

Operational efficiency

A key factor in the field performance is the operational efficiency, the extent to which the production uses the available capacity of the production facilities. Sustained, high operational efficiencies drive steady-state production, with laminar fluid flow enabling more material to move through the systems, explained Jennifer Starck, Prudhoe Bay production manager. The efficiency has climbed steadily from a level around 79 percent in 2014 to around 85.3 percent in 2017, she said.

Achieving such a high level of operational efficiency in a field system as complex as Prudhoe Bay is a major achievement, Digert said. The Prudhoe Bay unit moves 8 billion cubic feet of gas, 150 million barrels of water and 300,000 barrels of oil each day though seven processing facilities and two major gas plants. There are 1,800 well penetrations in multizone reservoirs.

So far about 12 billion barrels of oil have been produced from the field and another 10 billion barrels remain in place.

"To keep all of that running at an 85 percent efficiency is pretty remarkable," Starck said.

Active wells

One key factor that overall efficiency is the number of active wells in the field. The more wells available for use, the greater the possibility of swapping wells out to allow some wells to recover, and the easier it becomes to maintain maximum production from the field. While two years ago there were about 650 active wells, in 2017 that number increased to nearly 750. Having around 630 to 650 wells online at any one time will fill the field facilities, Digert said.

Achieving this high active well count has involved around 500 production related, non-rig well work jobs over the course of 2017, a figure up from around 430 in 2016 and 465 in 2015. Well work typically involves entering and re-perforating an existing well bore. In one particularly effective project, for example, re-perforating a well relatively high in the well bore has resulted in new production of gas rich in natural gas liquids, a gain equivalent to the drilling of a new well at a fraction of the cost.

BP also continues drilling into reservoir areas where untapped pockets of oil remain. The company has been using data from a new 3-D seismic survey in the north Prudhoe Bay area to identify new drilling targets.

New production in the northern area has boosted throughput in the Lisburne Production Center, pushing production in that facility from 23,000-25,000 barrels per day a year and a half ago to 40,000 bpd in 2017, Digert said.

Maintenance efficiency

Although there are days when the high number of active wells enables operational efficiency to approach 100 percent, the need to take equipment out of service for maintenance dilutes the efficiency level over the course of a year. But the efficient planning and execution of maintenance work can minimize maintenance impacts on production without compromising safety.

For example, 2017 saw a major maintenance "turnaround" at Gathering Center 1, one of the hub facilities in the unit. Rigorous planning for this complex project had started two years earlier. The project was completed a week ahead of schedule, with no safety incidents, Starck said.

Work culture

Another factor in improved efficiency has been a change in work culture introduced in 2016, in which people are now identifying work that really needs to be done, rather than automatically continuing traditional jobs, or doing what people want to do without necessarily questioning the benefits. The result in 2016 was a smaller work program that delivered world class results in terms of value to the business, Starck said.

Digert commented that in 2017 the work program expanded but became more efficient, focusing on work simplifications and quickly stopping jobs that were not delivering results. A key is to progress a number of relatively small, efficient jobs, rather than chase elephants, he said. He also commented that science projects have been cut, unless projects deliver value. And projects such as the use of different types of enhanced oil recovery must be justified in terms of cost benefits.

Team structure

Another key change at Prudhoe Bay has been a move from an organization based on functions such as reservoir engineering and production engineering, to a team structure, with one team for each main production facility, Digert said. The field operations manager for a facility is aligned with a reservoir management team in Anchorage. Each team then acts as a business, seeking efficiencies in its sector of the unit and able to make quick decisions over operational improvements. A team takes ownership of the profitability of its sector of the field.

Interconnected facilities

But the teams also operate cooperatively with each other, seeking ways to improve field performance as a whole. This is particularly important, given the manner in which facilities in different parts of the unit are now interconnected, allowing production fluids to be moved from one facility to another, to make optimum use of all of the facilities. For example, in one situation it proved possible to alleviate production constraints in the Lisburne Processing Center by shuttling some production to Gathering Center 1, where there was available capacity. That improved efficiency at Gathering Center 1 while also opening up space in the Lisburne facility, thus enabling some shut-in wells at Lisburne to come back on line.

Extending field life

A question now is how to continue to viably and safely extend the life of the oil field. So far about 12 billion barrels of oil have been produced from the field and another 10 billion barrels remain in place. With the economics of producing additional oil being marginal, the operating efficiency now being achieved is critical to flattening the production decline at a $50 oil price, with well work proving especially profitable, Digert said. The current operations are viable at current oil price levels, he said.

And improved efficiency at Prudhoe Bay has resulted in oil production gains equivalent to bringing a new North Slope oil field on line annually, Digert said. ●

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OIL PRICES

original OPEC production agreement appear to have now lent support to a more robust oil price.

Excess supply

It is generally agreed that the tumble in oil prices in 2014 resulted from an excess of oil supplies, rather than a shortfall in oil demand. And, the fact that the downturn has been supply driven has caused the oil price to remain low for a relatively long time. In particular, an overhang of large inventories of stored crude oil has kept the price depressed. Interestingly, an inspection of the oil price trends and the trends for U.S. oil inventories shows a fall in U.S. inventories preceding the pickup in the oil price in the second half of 2017, with that inventory decline continuing to the present.

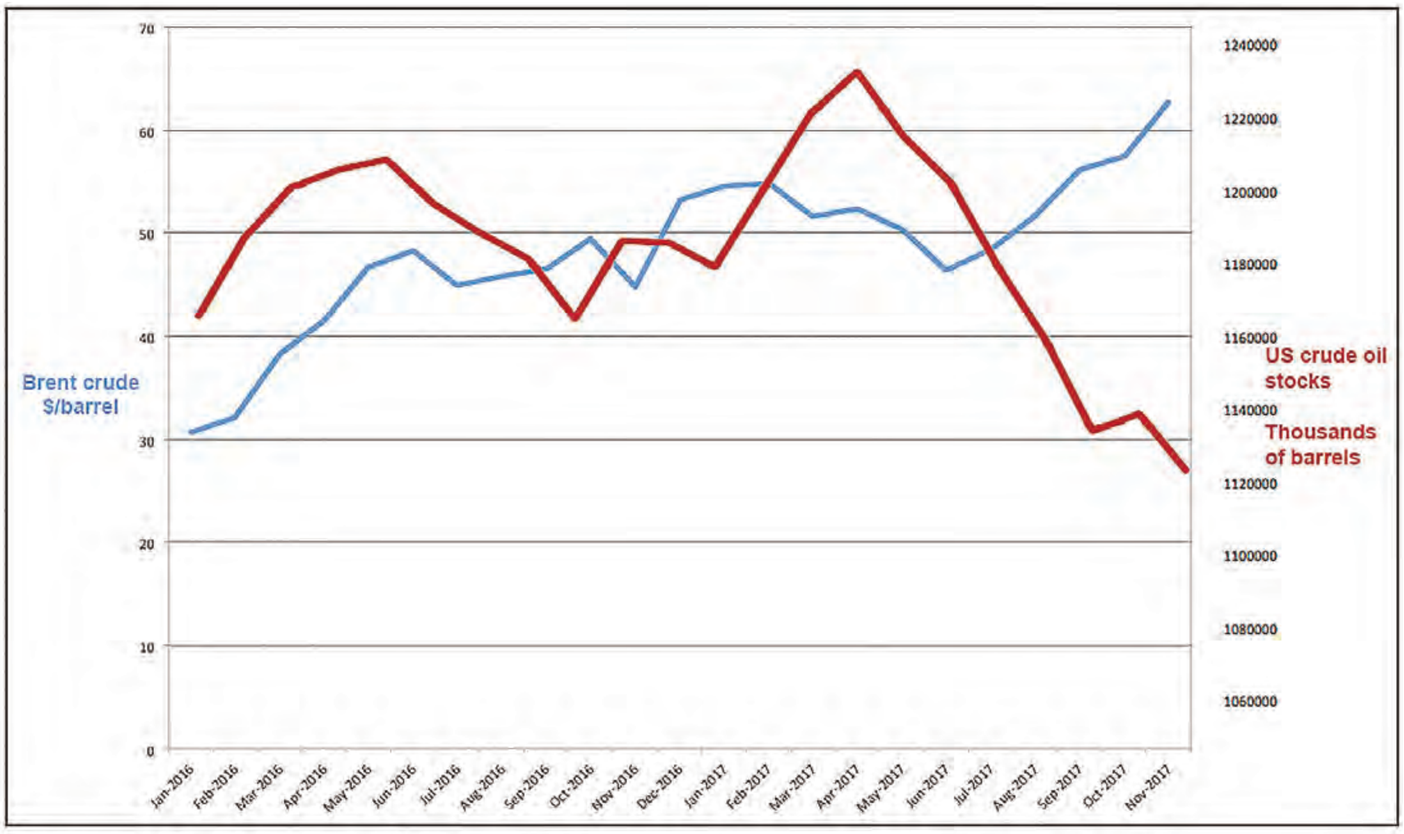
A major unknown when it comes to future pricing is the impact of U.S. shale oil production. This type of production can ramp up and down relatively quickly in response to oil price signals, although there may be constraints in terms of the willingness of investors to put money into development, given recent oil price volatility. Industry commentators have been reporting increasing shale oil investment and development in response to the recent oil price rise.

Commentators have also suggested that Middle East political tensions, particularly between Saudi Arabia and Iran, are currently driving up the oil price because of concerns about potential disruption in oil production.

Industry outlook

BP, in its latest Energy Outlook, published in June, expressed a view that rising oil demand had brought oil supply and demand back into balance, albeit with continuing high oil inventories. The precipitous fall in oil prices in 2014 had primarily resulted from supply growth from U.S. shale oil development, Spencer Dale, BP Group chief economist, suggested.

In April Marianne Kah, ConocoPhillips chief economist, expressed a view that U.S. shale oil had upended the global oil market, causing oil companies to focus on resources with the lowest cost of supply. And ongoing shale oil productivity improvements are continuing to push down the supply cost for tight oil, Kah said. S&P Global Platts, on the other hand, in its oil and gas outlook for 2018, has anticipated strong oil demand growth creating some supply tightness in the near term.



Data source: U.S. Energy Information Administration

The global oil price has been on an upward trend since early 2016, despite a sharp decline in the first half of 2017. Oil inventories in the United States have been dropping in recent months, while the oil price has continued to recover.

Alaska impact

From an Alaska perspective, the price of oil is obviously critical both to the viability of the oil industry in the state and to the state's fiscal situation — state finances are particularly dependent on oil revenues from royalties and production taxes. But, while the continuing oil price rise is welcome from both industry and state perspectives, people are being cautious in their expectations for the future.

The state, it its most recent revenue forecast, has assumed a price level of around $56/$57 over the next couple of years. In November the U.S. Energy Information Administration suggested 2018 pricing at around that same level. Moody's Investor Service has projected oil prices in the range of $40 to $60 in 2018. And major oil companies have indicated that their forward planning assumes continuing relatively low pricing.

Company policies

Kah said that the supply cost target for beating shale oil economics has moved down to a range of $30 to $50, and that ConocoPhillips now has a policy of only investing in lower cost of supply projects. This policy protects the company against future oil price changes, she said. In November company executives told an analyst and investor meeting that the company anticipates being able to achieve all of its financial targets at a $50 oil price, that sustained pricing below $45 would require cost deflation and capital flexibility, and that the company could maintain oil production levels unless there is sustained pricing below $40.

During the World Petroleum Congress in July, BP CEO Bob Dudley said that BP is planning on $50 oil for the next five years. During a later earnings call, Dudley commented that his company's organic cash flows were in balance at a $50 price and that the company's target breakeven price was well into the $30s.

Despite the high cost of oil exploration, development and production in Alaska, the state's oil industry does appear to be weathering the oil price storm, with North Slope production actually increasing somewhat. However, pressure on operating costs has hit the service industry and oil company employment levels in the state. ●

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ANS PRODUCTION

353 bpd, from an October average of 1,180 bpd.

Hilcorp's Beaver Creek field, the inlet's smallest, averaged 123 bpd in November, down 6 percent, 8 bpd, from an October average of 131. Hilcorp's McArthur River field, the inlet's largest, averaged 5,380 bpd, down 3.1 percent, 175 bpd, from an October average of 5,555 bpd.

Glacier's West McArthur River field averaged 1,178 bpd in November, down 2 percent from an October average of 1,202 bpd.

Hilcorp's Swanson River field averaged 1,735 bpd, down 1.2 percent, 22 bpd, from an October average of 1,757, and Hilcorp's Trading Bay averaged 1,929 bpd, down 0.8 percent, 16 bpd, from an October average of 1,945 bpd.

ANS crude oil production peaked in 1988 at 2.1 million bpd; Cook Inlet crude oil production peaked in 1970 at more than 227,000 bpd. ●

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INLET PERMITS

capabilities across the inlet by building a new subsea gas line from the Tyonek offshore gas production platform to Ladd Landing on the west side of the inlet. The new line will in effect extend the existing Tyonek Pipeline that connects the platform to Nikiski. The RCA order approves a temporary permit for onshore work involving the replacement of a section of the existing Tyonek gas line on the Kenai Peninsula.

CIPL wants to carry out the onshore pipeline construction during the winter, when the ground is frozen, to minimize environmental impacts. The company anticipates laying the offshore gas line in the spring, after the sea ice has melted.

Hilcorp is conducting the pipeline project to eliminate the need for the Drift River oil terminal, and the associated oil tanker traffic, as the means of transporting oil to market from fields on the inlet's west side. The use of the Drift River terminal has long been a safety and environmental concern because of the proximity of the terminal to the Redoubt volcano.

CIPL, currently an oil pipeline operator, has applied to RCA for a certificate to transport gas through the Tyonek pipeline. Similarly, Kenai Beluga Pipeline, the operator of the CIGGS system, has applied for a certificate for the carriage of oil.

—ALAN BAILEY

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MACKENZIE PROJECT

soared to C$16.2 billion from C$5 billion in 2001 and even then observers were suggesting the total would likely exceed C$20 billion.

Along with the shrinking demand in Canada for Arctic gas, the gloomy outlook was compounded by the virtual collapse of British Columbia's extravagant belief in its chances of drawing on billions of cubic feet per day to support LNG exports.

However, in keeping with the eternal-hope that prevails in Canada's North, some believe the 6 trillion cubic feet of onshore gas reserves in three anchor fields that backed the MGP might eventually find a market.

Duane Smith, chair of the Inuvialuit Regional Corp., told the CBC that the NEB project certificate that extends the deadline for a construction start to 2022 is a source of optimism that the Canadian government might recognize the value to the national and regional economies of northern gas riches. ●

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PIKKA WELLS

erable subsurface information about the southern half of the proposed Nanushuk development area, which has received less attention to date than the northern half. The results of the program could have "have significant impact on the subsurface basis of design," the company said in earlier filings.

The well locations are immediately north of the location of the proposed Pikka No. 1 well that the company ultimately cancelled last year at the request of local groups in Nuiqsut.

—ERIC LIDJI

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FURIE PROGRAM

2018. The company has committed to complete the KLU No. A-1 development well in the Kitchen Lights gas field and either to drill and test a new development well into the Sterling formation, or to re-enter and deepen the existing KLU No. 4 exploration well, or to drill the KLU No. 6 exploration well to test for oil in the deep Jurassic.

A failure to cure the default by meeting the drilling commitments for 2018 may result in unit contraction or termination, the division told Furie.

Furie had planned to use the Randolf Yost jack-up drilling rig to complete the KLU No. A-1 well and to drill an exploration well into the Jurassic in 2017. In the event, the rig remained moored at in Nikiski for the duration of the drilling season. Furie later blamed the state for the hiatus in the company's drilling program, saying that funding of the drilling depended on state tax credits owed to the company. The company also said that a standoff over the state budget during the summer had led to financial uncertainty, a situation undermining the financing of the company's operations. By the time that the state's budget issues had been resolved, the tugboat required for moving the jack-up rig had already had to leave the state, with no suitable alternative tug available, Furie said.

Gas production

The Kitchen Lights gas field is producing from the Julius R offshore platform from two wells, the KLU No. 3, a converted exploration well, and the KLU No. A-2A well drilled in 2016. Gas from the field is transported by subsea pipeline to an onshore processing facility, from where it is output to the Kenai Peninsula gas transmission pipeline network.

Furie currently has a contract to supply gas to Homer Electric Association Inc. through the end of 2018, with options to extend the contract through the end of 2020. However, that contract only accounts for a portion of the production capability of the Kitchen Lights field.

Enstar contract

In 2016 Furie also signed a gas supply agreement with Enstar Natural Gas Co. for the supply of gas, starting in 2018. That agreement was contingent on Furie completing a third Kitchen Lights development well by the end of 2016, with that drilling deadline later extended to July 31, 2017. The failure to drill in 2017 has resulted in a modified contract between Furie and Enstar, with Furie committing to complete the third well by July 31, 2018. Failure to meet the new drilling commitment will require Furie to provide proof of an alternative source of gas, as a contingency arrangement. And the failure to meet drilling deadlines also triggers a drop in the price to be paid by Enstar for the gas.

The state's new notice of default comments that the latest delay in Kitchen Lights drilling comes after a history of delaying or changing work commitments going back to 2015. A commitment to drill two development wells in 2015 was deferred into 2016. In 2016 Furie drilled the KLU No. A-2 well, then drilling the KLU No. A-1 well to near target depth before running out of time to complete the well. As discussed in the notice, a new plan to complete the A-1 well and drill an additional well in 2017 did not go into effect.

—ALAN BAILEY

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