Petroleum news

page 5 Ed King discusses his view of 'Fair Share Act' initiative impact

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Oil Search Alaska leadership team, new at Revenue, Hilcorp workers

CURRENTLY THE OIL SEARCH ALASKA group numbers 151 — 36 contractors and 115 employees.

In addition to Keiran Wulff moving up from the top executive of Oil Search Alaska to managing director of the parent company, and Bruce Dingeman named as his replacement, there have been other changes in the Alaska leadership team's names and titles, with the net result as follows as of Feb. 5:

Matt Elmer, chief operating officer

Joe Balash, senior vice president government affairs

see INSIDER page 10

Mustang field in final stretch, financial negotiations ongoing

BART ARMFIELD

Mustang, the first oil field on Alaska's North Slope to have been developed and brought online by a small independent oil company, appears to be facing its final challenge — getting its finances in order, something it hoped to have done by the end of January.

Starting production in early November, the field was offline for the entire month of December, per a filing by Mustang operator Brooks Range Petroleum Corp. with the Alaska Oil and Gas Conservation Commission. As of Feb. 5, it was not known whether production had been restored.

see MUSTANG FIELD page 9

Yukon Gold 2021 well possible; Jade gets 100% WI in Sourdough

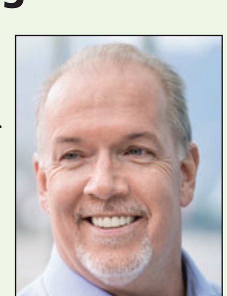
DAVID WALL

88 Energy Ltd. doesn't have much new to say about its eastern North Slope prospect, but it's hard to believe a partnering deal isn't in the works, given the activities of nearby leaseholders — in particular Jade Energy and ExxonMobil, which will likely bring infrastructure within 10 miles of the 1994 untapped Yukon Gold oil discovery.

Australian independent 88 Energy Ltd. says in its Jan. 20 fourth quarter release that while Yukon Gold "discussions continue with nearby resource

see YUKON GOLD page 12

Sudden convert to pipelines: BC's Horgan reinforces change of heart



JOHN HORGAN

From one of Canada's most outspoken opponents of big energy projects, British Columbia Premier John Horgan has turned himself into a champion of big LNG and crude bitumen pipelines that cross his province to tanker ports on the Pacific Coast along with becoming a vigorous defender of high court verdicts that open the way for those transportation systems.

This is the same person who, when leader of the opposition party in the B.C. legislature, took resolute stands against plans by his predecessor Christy Clark for

see HORGAN REVERSAL page 11

FINANCE & ECONOMY

$3.4B for AK in 2020

Conoco 2019 Alaska net $1.44B; half of 2020 exploration dollars to state

By STEVE SUTHERLIN
Petroleum News

MICHAEL HATFIELD

ConocoPhillips remains on track to invest $25 billion of capital over the next 10 years in Alaska, said Michael Hatfield, president of Alaska, Canada and Europe in a fourth quarter conference call Feb. 4.

"These investments will increase the state's production and mitigate the current decline through TAPS," he said.

"In fact, in 2020 alone, our net capital and opex spend in Alaska is expected to be roughly $3.4 billion," he said. "On a gross basis, in 2020, total industry capital and opex spend in Alaska is expected to be about $6 billion."

Alaska will see the lion's share of exploration spending for the company in 2020. Its exploration plan calls for its "largest Alaska exploration and appraisal winter season."

"This year, about half of our exploration capital is going into Alaska, and half is going elsewhere," said Matt Fox, executive VP and COO.

He said an exploration program going on in Malaysia in the shallow water shelf of Sarawak, and a program in Argentina — in the south of the country and in the Vaca Muerta — "are the primary new exploration activity outside

see CONOCO INVESTMENT page 8

FINANCE & ECONOMY

EIA: ANWR after 2030

Agency's outlook has Alaska production up through 2041, initially from NPR-A

By KRISTEN NELSON
Petroleum News

The U.S. Energy Information Administration's "Annual Energy Outlook 2020" sees U.S. production increasing and setting new records through the mid-2020s, with U.S. crude oil and natural gas plant liquids volumes continuing to grow through 2025 in the reference case. U.S. crude production reaches 14 million barrels per day by 2022 and remains near this level through 2045, EIA said in the report released Jan. 29, "as tight oil development moves into less productive areas and well productivity declines."

ANWR after 2030

"Alaska crude oil production generally increases through 2041," EIA said, "driven primarily by the development of fields in the National Petroleum Reserve-Alaska (NPR-A) before 2030, and after 2030, by the development of fields in the 1002 Section of the Arctic National Wildlife Refuge (ANWR). Exploration and development of fields in ANWR is not economical in the Low Oil Price case."

The state is estimated to have no production in 2050 in the low price case, 0.48 million bpd in the base case and 0.78 million bpd in the high oil price.

In the reference or base case, Brent oil reaches

see EIA OUTLOOK page 10

PIPELINES & DOWNSTREAM

Five-day sail to Tokyo

Adak Island proposed for new western Strategic Petroleum Reserve facility

By STEVE SUTHERLIN
Petroleum News

DAVID OTT

Adak Island, a port and former naval base 1,200 miles southwest of Anchorage on the Aleutian Chain, has been proposed as a new federal Strategic Petroleum Reserve facility, an idea that has the support of Gov. Mike Dunleavy and Alaska's congressional delegation.

The base is owned lock, stock and barrel by the Aleut Corp., an Alaska Native regional corporation.

The idea is being promoted by David Ott, president and CEO of Tennessee-based Tuskahoma Enterprises LLC.

Ott, a former U.S. Navy pilot and former infrastructure manager for Shell Alaska, hatched the concept after a strategic study in 2014, which identified Adak as the strongest candidate to base Shell's arctic drilling assets.

After Shell pulled out of Alaska in 2016, Ott continued to consider Adak's port and its unique strategic position in the north Pacific, which he felt could be better utilized to support national security.

"When I left Shell in 2016, I was keen on helping the Aleut Corporation find something for that base. As a naval aviator I knew the history of it even

see ADAK PROPOSAL page 11

● FINANCE & ECONOMY

Helping hand for aboriginals

Cenovus Energy to spend C$50M over 5 years building about 200 homes on First Nations and Metis lands in its operating areas

By GARY PARK

For Petroleum News

Cenovus Energy, one of the big league oil sands producers, is filling a blank left by the Canadian government by pledging C$50 million to build about 200 new homes in six First Nations and Metis communities near the company's major operations in northeastern Alberta.

If the venture, which Cenovus hopes will help build links and "contribute to reconciliation with Indigenous peoples," is successful, the company said it will consider extending the commitment to C$100 million over 10 years.

Chief Executive Officer Alex Pourbaix said he was moved to take action after visiting the communities and encountering parents with large families living in nothing more than a one-room cabin, often without running water or electricity.

"It is an extraordinary problem," he told a news conference. "We can't solve the Indigenous housing crisis by ourselves, but through this initiative, we have the opportunity to significantly improve the lives of many families currently living in overcrowded and unsafe conditions."

A Cenovus official said that while the federal government provides funding for First Nations for housing on indigenous land, existing budget caps prevent the communities from keeping pace with their population growth.

In addition, many First Nations that have joint ventures with oil and gas companies have seen large percentage declines in revenues that make it harder for them to fund their own infrastructure projects.

Vern Janvier, chief of the Chipewyan Prairie Dene First Nation, said oil- and gas-based revenues have dropped in some cases by a third over the past six years since commodity prices tumbled.

He said the fact that a for-profit company is stepping into the breach is significant, especially when the funding is being made available without any strings attached.

Cenovus said it wants to work with the communities to develop a training program so that local residents can get jobs building and maintaining the new homes, while proper housing will allow the company to hire more Indigenous people for its Christina Lake and Foster Creek oil sands projects.

Cenovus recently announced that it has set new environmental, social and governance, ESG, targets that commit the company to spend a minimum of C$1.5 billion with aboriginal businesses on top of the almost C$3 billion it invested over the 11 years since it was founded in a break-up of Encana.

ESG metrics are becoming key milestones to institutional investors and foreign pension funds, many of whom have applied pressure on Canadian oil sands companies to adopt and demonstrate rigorous standards in this sector. ●

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● EXPLORATION & PRODUCTION

December ANS production flat from November

Crude averages 467,224 bpd, NGLs 57,688 bpd; Southern Miluveach, which began production in November, had no production in December

By KRISTEN NELSON
Petroleum News

Alaska North Slope production averaged 524,912 barrels per day in December, basically flat month over month, with volumes down just 0.2%, 826 bpd, from a November average of 525,738 bpd, but down 1.9% from a December 2018 average of 535,256 bpd.

ANS crude was down 0.6% and North Slope natural gas liquids were up by 3.5%. Crude averaged 467,224 bpd in December, down 2,770 bpd from November, while NGLs averaged 57,688 bpd, up 1,944 bpd from November. ANS crude was down 2.6% from a December 2018 average of 479,475 bpd; North Slope NGLs were up 3.4% from a December 2018 average of 55,781 bpd.

Production data reported here is from the Alaska Oil and Gas Conservation Commission, which provides volumes by field and well on a month delay basis.

Of note in the December numbers was the absence of any production from Brooks Range Petroleum Corp.'s Southern Miluveach field, which began production in November at an average of 367 bpd and reported no production in December (see page 1 story in this issue).

The largest month-over-month volume increase was at the ExxonMobil Production operated Point Thomson field, which averaged 5,491 bpd, up 4,228 bpd, 335%, from a November average of 1,263 bpd, but down 48.8% from a December 2018 average of 10,725 bpd. The high-pressure condensate field, on the eastern edge of the North Slope, has had equipment issues and has only rarely reached its rated 10,000 bpd capacity.

Eni's Nikaitchuq averaged 20,564 bpd, up 1,988 bpd, 10.7%, from a November average of 18,575 bpd, and up 123.4% from a December 2018 average of 9,205 bpd when production was ramping back up from a slowdown following subsea pipeline repairs.

The Hilcorp Alaska-operated Milne Point field averaged 30,124 bpd in December, up 1,101 bpd, 3.8%, from a November average of 29,023 bpd, and up 42.9% from a December 2018 average of 21,075 bpd.

Hilcorp's Northstar averaged 10,304 bpd in December, up 7%, 675 bpd, from a November average of 9,629 bpd, but down 7.9% from a December 2018 average of 11,191 bpd. Northstar production includes crude, which averaged 7,211 bpd, up 2.3% from November, and NGLs, which averaged 3,093 bpd, up 19.7% from November.

Other fields down

The largest month-over-month production drop was at ConocoPhillips Alaska's Colville River, which averaged 54,941 bpd in December, down 2,768 bpd, 4.8%, from a November average of 57,709 bpd, and down 3.4% from a December 2018 average of 56,879 bpd. In addition to oil from the main Alpine pool, Colville production includes satellite production from Fiord, Nanuq and Qannik.

The Kuparuk River unit, operated by ConocoPhillips, averaged 102,825 bpd in December, down 2,687 bpd, 2.6%, from a November average of 105,512 bpd and down 7.4% from a December 2018 average of 111,047 bpd. In addition to the main Kuparuk pool, Kuparuk produces from satellites at Meltwater, Tabasco and Tarn, and from West Sak.

ConocoPhillips' Greater Mooses Tooth, in the National Petroleum Reserve-Alaska, averaged 6,297 bpd in December, down 1,763 bpd, 21.9%, from a November average of 8,060 bpd and down 41.9% from a December 2018 average of 11,023 bpd. There are three wells producing at the field, but 94% of its production is from a single well.

Eni's Oooguruk averaged 8,170 bpd in December, down 874 bpd, 9.7%, from a November average of 9,045 bpd and down 17.6% from a December 2018 average of 9,909 bpd.

Production from the BP Exploration (Alaska)-operated Prudhoe Bay field, the North Slope's largest, averaged 277,402 bpd in December, down 270 bpd, 0.1%, from a November average of 277,672 bpd, and down 2.6% from a December 2018 average of 284,918 bpd. Prudhoe crude averaged 223,779 bpd, down 1,724 bpd from November, while NGLs averaged 53,623 bpd, up 1,454 bpd from November. In addition to the primary reservoir, production volumes from Prudhoe include Aurora, Borealis, Lisburne, Midnight Sun, Niakuk, Polaris, Point McIntyre, Put River, Raven and Schrader Bluff.

The Hilcorp-operated Endicott field averaged 7,446 bpd in December, down 59 bpd, 0.8%, from a November average of 7,505 and down 0.2% from a December 2018 average of 7,434 bpd. Crude production from Endicott averaged 6,474 bpd, down 38 bpd from November, while NGL production averaged 972 bpd, down 20 bpd.

The Badami field, operated by Glacier Oil & Gas company Savant, averaged 1,351 bpd in December, down 28 bpd, 2%, from a November average of 1,379 bpd and down 27% from a December 2018 average of 1,850 bpd.

Cook Inlet also flat

Cook Inlet crude oil production was also basically flat month-to-month, averaging 14,145 bpd in December, up 28 bpd, 0.2%, from a November average of 14,117 bpd, but down 12.6% from a December 2018 average of 16,187 bpd.

The only Cook Inlet field with a December production increase was Hilcorp Alaska's Granite Point, which averaged 3,306 bpd, up 594 bpd, 21.9%, from a November average of 2,712 bpd, and also up 22.4% from 2,702 bpd in December 2018.

Hilcorp's Beaver Creek, Cook Inlet's smallest oil field, averaged 198 bpd in December, down 8 bpd, 3.7%, from a November average of 206 bpd and down 72.6% from a December 2018 average of 723 bpd.

BlueCrest's Hansen field, the Cosmopolitan project, averaged 1,181 bpd

see ANS PRODUCTION page 4

Cook Inlet natural gas averages 212,927 mcf

Natural gas is produced from 22 fields in Cook Inlet, the majority of those fields producing small volumes, many just a few mcf per day in association with oil production.

This data is from the Alaska Oil and Gas Conservation Commission, which reports production on a month-delay basis. For natural gas AOGCC reports measurements in thousands of cubic feet, mcf.

The majority of Cook Inlet natural gas, 81% in December, comes from seven fields: Beluga, Kenai, Kitchen Lights, McArthur River, Ninilchik, North Cook Inlet and Swanson River.

Cook Inlet averaged 212,927 thousand cubic feet, mcf, per day in December, down 5.7%, 4,155 mcf, from a November average of 217,128 mcf and down 11.6% from a December 2018 average of 241,260 mcf.

Hilcorp Alaska's Kenai gas field averaged 33,463 mcf per day in December, 15.7% of inlet production, an increase of 540 mcf, 1.6%, from a November average of 32,923 mcf but down 3% from a December 2018 average of 34,501 mcf per day.

Hilcorp's Ninilchik field produced nearly as much, 33,017 mcf per day in December, 15.5% of inlet production, a decline of 1,105 mcf per day, 3.2%, from a November average of 34,122 mcf, and down 12.2% from a December 2018 average of 37,617 mcf.

Hilcorp's Swanson River averaged 30,434 mcf per day in December, 14.3% of inlet production, down 7,032 mcf per day, 18.8%, from a November average of 37,466 bcf and down 3.3% from a December 2018 average of 31,465 mcf.

Hilcorp's McArthur River, the inlet's largest oil producer, averaged 22,188 mcf per day of gas in December, 10.4% of inlet production, down 224 mcf, 1%, from a November average of 22,412 mcf and down 9.7% from a December 2018 average of 24,559 mcf.

The Beluga River field, operated by Hilcorp, averaged 20,416 mcf per day in December, 9.6% of inlet production, down 302 mcf per day, 1.5%, from a November average of 20,718 mcf, and down 28% from a December 2018 average of 28,362 mcf per day.

Hilcorp's North Cook Inlet field averaged 17,421 mcf per day in December, 8.2% of inlet production, an increase of 3,511 mcf, 25.2%, from a November average of 13,910 mcf, and up 20.3% from a December 2018 average of 14,479 mcf per day.

Furie's Kitchen Lights averaged 14,797 mcf per day in December, 7% of inlet production, up 1,602 mcf per day, 12.1%, from a November average of 13,195 mcf, but down 26.8% from a December 2018 average of 20,227 mcf.

Remaining Cook Inlet natural gas producers, ranked by December production, are:

•Beaver Creek (Hilcorp), 7,347 mcf per day in December, down 0.6% from 7,393 mcf in November and down 17.1% from 8,857 mcf in December 2018

•Cannery Loop (Hilcorp), 5,854 mcf per day in December, down 19.8% from 7,279 mcf in November and down 11.7% from 6,629 mcf in December 2018

•Kenai Loop (AIX), 5,323 mcf per day in December, down 1.4% from 5,401 mcf in November and down 0.6% from 5,357 mcf in December 2018

•Hansen (BlueCrest), 5,298 mcf per day in December, down 6.9% from 5,689 mcf in November and down 55.2% from 11,819 mcf in December 2018

•Deep Creek (Hilcorp), 4,220 mcf per day in December, down 5.3% from 4,453 mcf in November and down 8.9% from 4,633 mcf in December 2018

•North Fork (Glacier Oil & Gas subsidiary Cook Inlet Energy), 3,583 mcf per day in December, down 3% from 3,693 mcf in November and down 14.6% from 4,196 mcf in December 2018

see COOK INLET GAS page 4

continued from page 3

COOK INLET GAS

•Granite Point (Hilcorp), 3,267 mcf per day in December, up 20% from 2,722 mcf in November and up 15.8% from 2,821 mcf in December 2018

•Trading Bay (Hilcorp), 3,149 mcf per day in December, up 6.1% from 2,968 mcf in November and down 1.8% from 3,208 mcf in December 2018

•Lewis River (Hilcorp), 1,552 mcf in December, up 35.7% from 1,143 mcf in November and up 351.9% from 343 in December 2018

•Nikolaevsk (Hilcorp), 402 mcf per day in December, down 7.1% from 432 mcf in November and down 6.6% from 430 in December 2018

•Ivan River (Hilcorp), 329 mcf per day in December, down 10.2% from 366 mcf in November and down 21% from 416 mcf in December 2018

•Redoubt Shoal (Glacier's CIE), 292 mcf per day in December, up 4.1% from 280 mcf in November and up 16% from 251 mcf in December 2018

•Nicolai Creek (Amaroq), 285 mcf per day in December, up 53.7% from 185 mcf in November and down 27.5% from 393 mcf in December 2018

•Middle Ground Shoal (Hilcorp), 211 mcf per day in December, down 21% from 267 mcf in November and down 25.3% from 283 mcf in December 2018

•West McArthur River (Glacier's CIE), 79 mcf per day in December, down 27.5% from 109 mcf in November and down 25.1% from 105 mcf in December 2018

Cook Inlet natural gas production peaked in the mid-1990s at more than 850,000 mcf per day.

—KRISTEN NELSON

continued from page 3

ANS PRODUCTION

in December, down 5 bpd, 0.4%, from a November average of 1,186 bpd and down 22.5% from a December 2018 average of 1,523 bpd.

Hilcorp's McArthur River, Cook Inlet's largest field, averaged 4,414 bpd in December, down 139 bpd, 3.1%, from a November average of 4,553 bpd and down 15.4% from a December 2018 average of 5,216 bpd.

Middle Ground Shoal, also a Hilcorp field, averaged 1,263 bpd in December, down 63 bpd, 4.8%, from a November average of 1,326 bpd and down 13.1% from a December 2018 average of 1,453 bpd.

Redoubt Shoal, operated by Cook Inlet Energy, a Glacier Oil & Gas company, averaged 1,320 bpd in December, down 42 bpd, 3.1%, from a November average of 1,362 bpd, but up 0.8% from a December 2018 average of 1,310 bpd.

Hilcorp's Swanson River averaged 737 bpd, down 94 bpd, 11.3%, from a November average of 831 bpd and down 41.4% from a December 2018 average of 1,258 bpd.

Hilcorp's Trading Bay averaged 1,309 bpd in December, down 58 bpd, 4.2%, from a November average of 1,366 bpd and down 3.5% from a December 2018 average of 1,357 bpd.

West McArthur River, managed by Glacier's Cook Inlet Energy, averaged 417 bpd in December, down 158 bpd, 27.5%, from a November average of 576 bpd and down 35.4% from a December 2018 average of 646 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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● UTILITIES

Electric utilities speak to Legislature

Express broad support for HB 151 and SB123, bills designed to enable the regulation of reliability organization for Railbelt grid

By ALAN BAILEY
For Petroleum News

On Jan. 27 representatives from the six Alaska Railbelt electric utilities presented testimony to a joint meeting of the House Special Committee on Energy and the Senate Special Committee on the Railbelt Electric System, expressing support for two bills that have been introduced during the current legislative session. The bills, House Bill 151 and Senate Bill 123, are similar and would give the Regulatory Commission of Alaska regulatory authority over an electric reliability organization for the Railbelt electricity system. The proposed legislation would also give the commission authority to review and pre-approve changes and additions to major generation and transmission facilities in the system.

The concept is to facilitate a more coordinated and efficient approach to the operation of the electrical system, which is owned and operated by six independent utilities and the State of Alaska. A reliability organization would oversee a mandated set of reliability standards for the system and conduct integrated resource planning for the entire system.

Railbelt Reliability Council

In December all six of the Railbelt utilities signed a memorandum of understanding for the formation of the Railbelt Reliability Council, in effect an organization of the type envisaged in the two bills. The utilities are now in the process of forming the RRC, which would be regulated by the RCA. However, the RCA is worried whether it has clear statutory authority to conduct the required regulation — in December the RCA commissioners voted unanimously to support the passage of SB 123. Traditionally the commission regulates individual utilities rather than an organization that itself oversees utilities.

The RRC would maintain and mandate reliability standards; administer rules for open access to the grid; conduct Railbelt-wide system planning; and investigate the economic value of security constrained economic dispatch for all or part of the system. Economic dispatch involves the continuous use of the most cost effective power generation that is securely available.

The RRC will be governed by a board with six members representing the six Railbelt utilities and six members representing other stakeholders in the electrical system. The RRC CEO would have a tie-breaking vote on board decisions. Independent members would consist of two representatives from independent power producers, one member representing consumer interests, a representative from the Alaska Energy Authority and two non-affiliated members. The RCA and the state's Regulatory Affairs and Public Advocacy Section would have non-voting board seats.

The utilities anticipate being able to stand up the RRC, with all of its foundational documentation, by the end of this year.

Testimony from utilities

In testimony during the joint committee meeting, Julie Estey, director of external affairs for Matanuska Electric Association, commented that the development of the RRC constitutes a path parallel to the passage of the appropriate legislation, leading to RCA authority to accept an application for RRC approval.

Brian Hickey, chief operating officer for Chugach Electric Association, commented on the thinking behind some suggested adjustments to SB 123, including a clarification of the scope of RCA pre-approval of development projects.

Anna Henderson, general manager of Municipal Light & Power, commented that the legislation would lead to a robust regulatory process, adding further process and clarification to the regulations.

Tony Izzo, CEO of Matanuska Electric Association, said that the proposed legislation would result in a one-stop shop across the grid for a planning process involving a broad stakeholder group, leading to a reliable service at lowest cost.

John Burns, vice president, Golden Valley Electric Association, said that the

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● FINANCE & ECONOMY

Ed King on Alaska taxes oil companies pay

Economist presents his views on the 'Fair Share Act' and what it would mean for the future of oil and gas investment in the state

By ED KING

Reprinted with permission

Many Alaskans have probably heard something about the oil tax initiative called the "Fair Share Act." You may have been asked to sign a petition while shopping, or you may have read something about it in one of the media outlets. You are likely to see it on the ballot when you vote this November.

But, what is it? Here is a brief description of how we see the issue.

What does the initiative do?

ED KING

The initiative does a lot of different things, but there is one clause that matters more than any of the others. The "Fair Share Act" eliminates the per barrel reduction in tax payments for the three largest oil fields.

Right now, taxes are determined by multiplying the price of oil by the number of barrels produced, subtracting the cost of production, and then taking 35% of that taxable value. From there, you subtract an additional $0 to $8 per barrel (depending on price) to arrive at the tax that is due.

The process is similar to the standard deduction on your federal income taxes. Although there is a nameplate tax rate that you pay, you only really pay that rate on a number less than your total income. So, your effective tax rate is far lower than what the law says. That is the same process in Alaska's oil taxes.

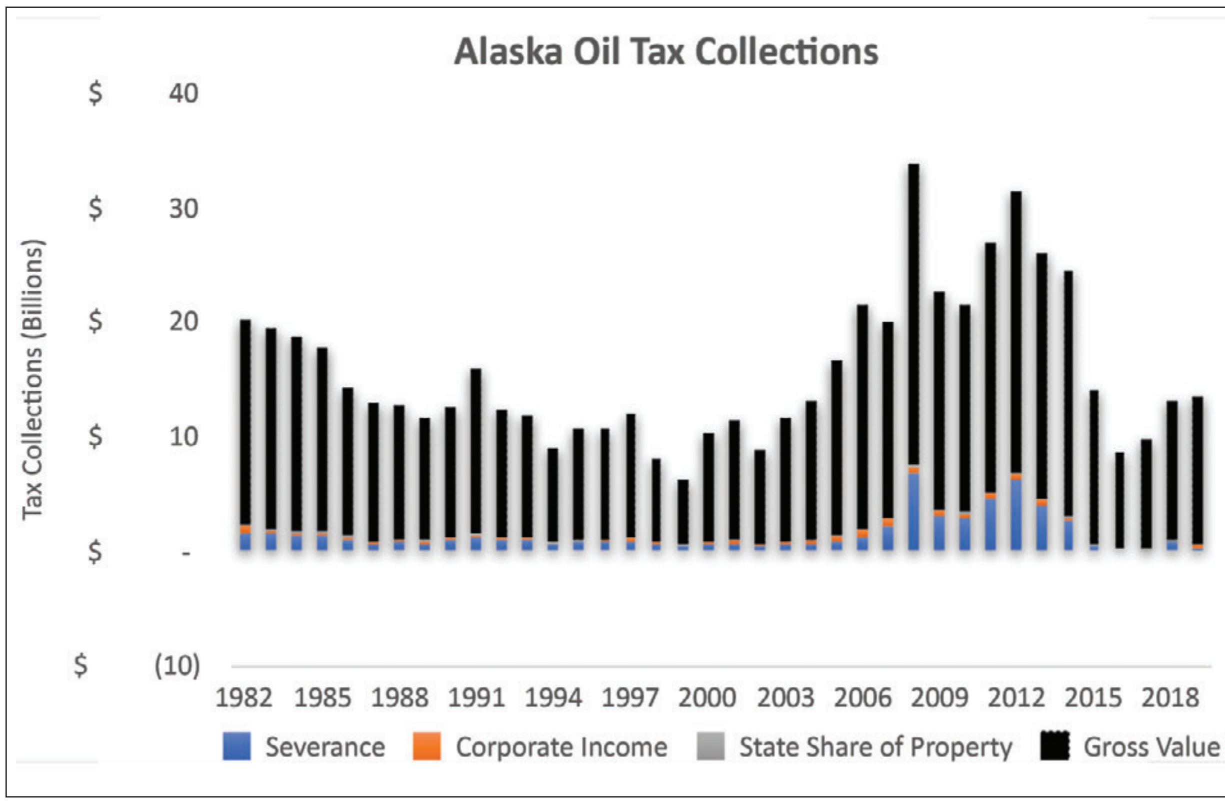
Just like the federal government isn't "giving" you $12,200 as a standard deduction, Alaska is not "giving" money to oil companies. It's just part of the calculation.

In effect, the initiative removes that "standard deduction" at Prudhoe Bay, Kuparuk, and Alpine. Consequently, the effective tax rate for the producers of those fields goes up — by a lot.

The initiative also increases the minimum tax on these fields, turns all fields into separate tax groups, changes the tax law from an annual tax to a monthly tax, and makes all company tax information available to the public.

Who would the initiative impact?

On the surface, the initiative only impacts the Prudhoe Bay, Kuparuk, and Colville River fields (which include the small oil pools surrounding the large oil pool). However, the implications reach beyond these fields.



ED KING

The Pikka field would be impacted as soon as it produces its 400 millionth barrel of oil. That changes the economics of the project. Plus, the investors are likely to anticipate another change in the law as soon as another budget deficit emerges.

The Willow prospect would also be impacted the same way but faces an even larger change to its economics due to the "ring-fencing" provision. By slowing down the recovery of capital, ConocoPhillips would need to reevaluate the project.

Hilcorp would need to consider the consequences of going over 40,000 barrels per day at Milne Point. That might defer investment in those new drill pads and polymer flooding facilities.

ExxonMobil would need to reconsider how much money they are willing to lose at Point Thomson each year, seeing as those losses would no longer be write-offs at Prudhoe Bay.

Oil Search would also see the economics of Horseshoe and other opportunities change, due to the new ring-fencing rule.

In short, it impacts a lot more than first assumed.

What would happen if the initiative passes?

There are two things we know for sure. First, the State of Alaska would see an immediate boost in oil revenues.

Our estimates peg the increase at $1.347 billion next year. That number is a combination of higher severance taxes and lower corporate income taxes. It comes primarily from increased taxes at Prudhoe Bay, Kuparuk and Colville River, but also comes from an increase in ConocoPhillips taxes due to the inability to write off costs associated with Willow.

There is also a knock-on effect in the large oil fields. By reducing the amount of money the working interest owners are willing and able to invest, they have fewer deductions to their taxable income. This results in a higher near-term tax.

That brings us to the second point — The economics of every development decision would be negatively impacted, resulting in less investment.

The most likely outcome would be that projects within Prudhoe Bay, Kuparuk and Colville River would lose out to projects in areas with lower tax rates. And, with less cashflow comes less money to invest in new developments.

Therefore, ConocoPhillips would most likely focus its attention and remaining capital in the NPRA. Without partner alignment in Prudhoe Bay, Hilcorp would not be able to do what they do best. That would probably shift Hilcorp's attention and capital to Liberty, Milne Point, NorthStar, Endicott and Cook Inlet.

We would then see an accelerated decline in the

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OIL TAXES

state's largest oil field, as the higher tax rate forces the working interest owners into "harvest mode" (in which they stop investing in the field and allow it to naturally decline).

ConocoPhillips would similarly lose interest in rate adding activities in Kuparuk and Colville River. In Kuparuk, they may abandon the Nuna, ENEWS and Cairn prospects. In Colville River, they would likely be motivated by the perverse incentive to slow down production until it falls below 40,000 barrels per day (which would take about four years). And, the Narwhal development opportunity would probably be pursued from a drill site outside of the Colville River Unit, rather than by expanding the unit.

How much do oil companies pay in taxes?

There are three separate oil taxes that Alaska charges on oil companies. A property tax, a severance tax, and a corporate income tax. We tax oil production that is owned by the federal government, Alaska Native corporations, and that we have leased to oil companies. Taxes have nothing to do with ownership.

According to Department of Revenue data, here is the history of oil tax payment (after deductible credits) in graphic form.

It adds up to about $85 billion since statehood. There were also $59 billion in royalty payment to the state that are not included here, as well as additional taxes to local and federal governments.

Notice that taxes fell dramatically since 2014, which happens to coincide with a change in the tax law. This coincidence tends to give the impression that the tax change caused the drop in tax revenue. That is a false correlation. SB21 did not cause a drop in taxes.

To understand why, it is helpful to understand how the value of oil production has changed over time. Taxes are a percentage of value. So, if the price of oil falls, or if the amount of oil being produced declines, the potential tax revenue falls — regardless of the tax law.

Regardless, the oil industry has never paid a "negative tax rate." That assertion is a misrepresentation of reality. In fact, the companies paid taxes even when they lost money on the year.

How much do oil companies keep as profits?

The concept of profits can be a little more confusing than people first think. Most people confuse positive cash flows with profits. Or, they confuse accounting net income reported by companies with their profits.

Profits occur when you earn more money than you spend. But, it may take several years of earning positive revenues before you make a profit. When an oil company invests a billion dollars in a project, they don't make a profit until they recover those costs. And, it might take years of receiving positive cashflow just to break even (before paying interest on that money).

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The last time we estimated company cash flows, we pegged the companies at taking in $2.1 billion more than they spend in a year. That number changes every year, depending on what happens with oil prices and production costs. But, that's the ballpark we are playing in. It works out to something like a 13% return on investment, or roughly $100 billion of profits over the life of the basin so far (over the same period, Alaska collected $138 billion).

Is that a Fair Share?

Let's do some simple math. If oil companies invest $10 billion in a new project, they would need to earn positive cash flows of at least $2 billion a year to get their money back in 5 years. After that, they would be making profits. Then they need to make enough profit to make the investment worth their while.

If you only let them keep $1 billion per year, it would take 10 years to recover their investment. That's too long for most investors to wait. There are better ways to invest that money. So, there is some amount of profits that we must allow in order to have anything to tax.

The mere existence of profits (and especially not positive cashflow) does not signal that our taxes are too low. We also need to consider what is fair to the investors for risking their capital. And, we should be careful about renegotiating contract terms through taxation.

What is the total impact?

We see the "Fair Share Act" as a temporary solution, which exacerbates a long-term problem. While passing the initiative would solve the immediate financial problems facing the state, it would create perverse incentives to reduce production, push the major oil fields into harvest mode, and shift capital to federal lands (where the state does not receive the royalties).

The increase in tax collection would then decrease each year - as the accelerated decline in production offsets the gains from a higher tax rate. Within a few years, the higher tax rate is applied to a low enough volume that the state collects less money than it otherwise would have. At that point, the budget deficit resurfaces and the financial problems reemerge. Given the demonstrated willingness to raise taxes as a way to tackle financial problems, investors are likely to view Alaska as a negative investment climate — which locks the basin into a death spiral.

We estimate the total lost production at 800 million barrels — from known resources — over the remaining life of the North Slope. That life is shortened by about five years stemming from the reduced investment in rate replacement. Additionally, the actual number of lost production may be much higher given that we can't know what future exploration efforts would have added to the potential investment pool.

Those lost barrels result in fewer dollars flowing to the future treasury, leading to fewer tools for future Alaskans to deal with the financial problems that were deferred. And, the reduced production from state lands implies that fewer royalty dollars would flow into the Permanent Fund — thus creating even less revenue for future Alaskans.

The mere existence of profits (and especially not positive cashflow) does not signal that our taxes are too low. We also need to consider what is fair to the investors for risking their capital. And, we should be careful about renegotiating contract terms through taxation.

Conclusion

The Fair Share Act is a viable option for addressing the immediate financial problems plaguing the state. Passing the initiative would likely result in more government services, avoided taxes, and larger PFDs for the next few years. If someone has a short time preference, the bill may be beneficial to that individual.

But, for a person that cares about the future of our state, a "No" vote is likely to be more aligned with their views. Forgoing higher tax collections in the near-term allows more development to occur. Those developments will generate taxes, royalties, and jobs for years to come.

It is also worth pointing out that passing the initiative is likely to result in less total oil production. If a person is motivated to "keep it in the ground," passing this law may have a desirable outcome.

Or, if a person is convinced that the end of oil is near, it might make sense to grab as much of the value as possible before everything shuts down. In this frame of mind, no investment is lost because the investment was not going to occur regardless.

In the end, it appears that the Fair Share Act serves as a fork in the road. A "Yes" vote signals that it is time to turn away from oil, and that we should collect as much as we can as we transition away. A "No" vote signals that we want to continue walking the path of increased investment — which leads to a stream of long-term financial and economic benefits. ●

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UTILITY TESTIMONY

envisioned collaboration between the utilities through the RRC would facilitate conversations, shape relationships and build trust, with endless possibilities for achievement. Burns said that the RRC reflects a series of commitments made by the utilities to propose and embrace meaningful, deliberative changes to the Railbelt grid.

And Brad Janorschke, general manager of Homer Electric Association, said that recent developments represented the most alignment he had seen among the utilities and that any remaining differences of opinion could be worked through.

Sen. John Coghill, chair of the Senate special committee, expressed appreciation of the tremendous effort that had gone into what is proposed while also commenting on the importance of recognizing the perspectives of other stakeholders in the electrical system. ●

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● FINANCE & ECONOMY

O&G 2020 construction spend to be $2.9B

Associated General Contractors construction spending forecast says looking ahead, private sector oil industry is 'bright spot'

By KAY CASHMAN
Petroleum News

Public and private sector construction spending in Alaska this year is expected to be $6.7 billion, according to a report by the Associated General Contractors of Alaska, the Construction Industry Progress Fund and the McDowell Group, which was contracted to do the report.

AGC's Construction Spending Forecast estimates $4.4 billion will come from the private sector — $2.9 billion directly from the petroleum industry — and $2.3 billion from government spending. In addition to private construction spending, federal contracts related to construction in Alaska add another $7 million plus for oil and gas pipeline and related structures construction.

Overall 2020 is expected to see an 8% decline in spending compared to 2019, but AGC says that's due mostly in part to the Nov. 30, 2018, earthquake, which caused construction to unexpectedly increase last year and to a decrease in national defense spending this year as F-35 squadron-related work at Eielson Air Force Base is wrapped up.

Looking ahead, the oil industry is a bright spot, the report says, with oil-related construction expected increase over the next several years.

North Slope capital expenditures are anticipated to ramp up over the next few years, the report says, specifically, "ConocoPhillips expects to spend $11 billion through 2029 in the Colville River unit which includes the Alpine field and in the projects in Prudhoe Bay and Kuparuk River units, as well as another $1.4 billion in GMT-2 in the National Petroleum Reserve-Alaska and an additional $4-6 billion on the Willow Project (also in NPR-A). In the first quarter 2020, ConocoPhillips will expand the existing Alpine airstrip apron."

In November 2019, "Oil Search Alaska received approval from Alaska's Division of Oil and Gas for the development phase of its Pikka unit Nanushuk project's plan of operations for up to 151 total production and injections wells. New infrastructure and facilities construction within the Pikka unit will include a processing facility, infield pipelines, import and export pipelines, infield and access roads, storage tanks, cold storage, communications tower, construction camps, a 200-bed operations camp, office, warehouse and maintenance buildings, water and wastewater treatment plants, helicopter landing pad, and a boat ramp, among other developments. Infrastructure and facilities outside the Pikka unit include an operations pad, a tie-in pad, and continuation of roads and pipelines. Oil Search and its partner, Repsol, are still exploring south of Pikka," says the report.

"Eni Oil and Gas will continue work on a long-extended exploration well drilled north from the Beaufort Sea shore to prospects in the federal Outer Continental Shelf."

The report says, "It is unclear what Hilcorp's $5.6 billion purchase of BP's Alaska assets (by Spring 2020) will mean for new investment activity in BP's legacy fields; however, Hilcorp has a reputation for aggressive redevelopment of maturing fields."

2020 Alaska Construction Spending Summary, ($Million)

Category	Total Spending
Private Construction Spending	**$4,370**
Petroleum	2,900
Mining	170
Other Basic Industry	200
Utilities	150
Hospitals/Health Care	300
Other Commercial	300
Residential	350
Public Construction Spending	**$2,280**
National Defense	500
Highways and Roads	600
Airports, Ports, and Harbors	350
Education	200
Other Federal Government	180
Other State and Local Government	350
Earthquake Recovery	100
Total	**$6,650**

Source: McDowell Group.

New this year

In addition to the construction spending forecast, new this year is the Economic Impact Report which AGC says exceeded their expectations in terms of number of construction related jobs in Alaska.

Regarding average annual wages, the report says the oil and gas industry pays the highest yearly wage at $147,660, followed by mining at $112,836. Leisure and hospitality are the lowest paid workers at $24,396 per year, followed by retail at $31,968.

One in 20 jobs in the state is a construction job for a total of more than 23,000 employees, with about 82% of those Alaska residents.

Regarding average annual wages, the report says the oil and gas industry pays the highest yearly wage at $147,660, followed by mining at $112,836.

Leisure and hospitality are the lowest paid workers at $24,396 per year, followed by retail at $31,968.

The average annual Alaska wage is $55,140.

The report says the wage information was pulled from Alaska Department of Labor and Workforce Development 2018 records.

The percentage of positions held by Alaska residents, also taken from the Department of Labor, shows the lowest is the seafood processing industry at 25% and the highest, at 93%, is state government.

Oilfield services percentage of local hires is 64% and oil and gas extraction is 72%. ●

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CONOCO INVESTMENT

Alaska."

In the fourth quarter, ConocoPhillips invested $306 million of capital in the state, leading to a total spend of $1.5 billion of capital last year, company spokeswoman for Alaska Natalie Lowman told Petroleum News Feb. 5.

"So for 2019, ConocoPhillips Alaska has reinvested more than 100% of our adjusted net income of $1.44 billion (year to date) back into Alaska projects," she said. "The estimated capital budget for 2020 is about $1.6 billion."

Fourth quarter estimated obligations to the state of Alaska in the form of taxes and royalties totaled $263 million, she said, adding that those obligations totaled $1.073 billion for the entire year.

Adjusted fourth quarter 2019 earnings for Alaska were $364 million, up from $347 million in 4Q 2018, the company said.

Big operation, lots of drilling on tap

ConocoPhillips activities will see a large amount of activity in legacy fields, and on the frontiers.

"As far as our base operations, we've got a big operation that we continue to execute both at Kuparuk and at Alpine," Hatfield said, adding that the company will execute some smaller turnarounds in 2020 as well. "We've also got the (extended reach drilling) rig that's going to be starting up in the second quarter in Alpine ... we've got a lot of drilling that's going on."

Hatfield said the company is in the middle of its exploration program now.

"We've got four wells that we're going to drill at Willow — four appraisal wells and one flow test that we'll conduct," he said. "We spudded our first well at Willow at the end of January."

Hatfield said ConocoPhillips will spud the first three exploration wells at Harpoon toward the end of February, running two rigs between the Willow and Harpoon programs.

"Now in addition, we have our Narwhal opportunity that we spoke to you about in November where we had drilled the production well, and we had tested that well and flowed it back through our central facilities," he said. "We produced up to 4,500 barrels a day from that production well, and then that well was shut in as we monitored the pressure buildup." Since that time, the company drilled an injection well that reached total depth in early December.

"We flowed that well back to clean it up just recently, and we're quite encouraged with those results; in fact, our peak flow back was around 2,500 barrels a day," Hatfield said. "That well is now being prepared for an injection interference test with the producer that I mentioned we previously drilled, so we're going to do an injection test and interference test to see how those two wells are talking to each other, and that information is going to help us a lot as we optimize future development planning."

Hatfield said ConocoPhillips is quite encouraged with the results it has seen in Narwhal.

'In short, we've got a big program that we're executing across our assets in Alaska, including at the non-op asset in Prudhoe Bay," he said.

Don Wallette, executive VP and CFO, said a previously announced offering of a share in some the company's North Slope fields is on hold for now.

Transformed business model, 'world-class' portfolio improving

CEO Ryan Lance said 2019 capped off a successful three-year period in which ConocoPhillips transformed its business model and significantly improved the underlying performance drivers across its entire business.

In 2019 the company delivered strong earnings, and generated cash from operations of $11.7 billion, delivering free cash flow of over $5 billion, he said.

"Our balance sheet got stronger," he said. "We ended 2019 with over $8 billion of cash and short-term investments and lowered our asset retirement obligation by almost 30%, largely due to dispositions."

"We delivered on our volume projections for the year with roughly 5% underlying growth, including 22% growth from the Big 3 unconventionals," he said. "The rest of our portfolio delivered strong base performance, and we progressed new projects and exploration opportunities across our regions."

Lance said ConocoPhillips' "world-class" portfolio keeps getting better.

"As part of our high-grading efforts, we generated over $3 billion of disposition proceeds, and we have another $2 billion of announced dispositions that we expect to close in early 2020," he said.

But, he said, the company is not just selling.

"We're also on the lookout for opportunities to add low cost of supply resources to the portfolio, like we did last year in the Lower 48, Alaska and internationally," he said.

When reserves closed for the year, he said, ConocoPhillips replaced 117% of its production organically.

The company reported fourth quarter 2019 earnings of $0.7 billion, or 65 cents per share, compared with 2018 earnings of $1.9 billion for the period, or $1.61 per share.

Excluding special items, fourth quarter 2019 adjusted earnings were $0.8 billion, or 76 cents per share, compared with fourth quarter 2018 adjusted earnings of $1.3 billion, or $1.13 per share. Special items for the current quarter included primarily a non-cash impairment related to a planned Lower 48 disposition, partially offset by an unrealized gain on Cenovus Energy equity.

Full-year 2019 earnings were $7.2 billion, or $6.40 per share, compared with full-year 2018 earnings of $6.3 billion, or $5.32 per share. Excluding special items, full-year 2019 adjusted earnings were $4.0 billion, or $3.59 per share, compared with full-year 2018 adjusted earnings of $5.3 billion, or $4.54 per share, the company said.

Taxing matters: Alaska's future in the balance

Hatfield said that if there is a negative change in Alaska's fiscal regime, ConocoPhillips' investment plans will change, but the company is hopeful that a pending ballot initiative that would increase its tax burden will be rejected.

"We've been in Alaska for over 40 years; we know Alaskans understand the industry; it's the lifeblood of the state's economy," he said. "We believe Alaskans will understand that short-term revenue gain is a risky and fleeting proposition if it comes at the cost of billions of dollars of

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EXPLORATION & PRODUCTION

US drilling rig count drops by 4 to 790

Baker Hughes reports the number of rigs drilling for oil and natural gas in the U.S. dropped by four to 790 the week ending Jan. 31, down from 794 the previous week and down by 255 from 1,045 a year ago.

In its weekly rig count the Houston oilfield services company said 675 rigs targeted oil, down one from the previous week and down 172 from a year ago, while 112 targeted natural gas, down three from the previous week and down 86 from a year ago. There were three miscellaneous rigs active, unchanged from the previous week and up by three from a year ago.

The company said 45 of the holes were directional, 711 were horizontal and 34 were vertical.

Colorado was up by one rig from the previous week.

Rig counts were unchanged from the previous week in California, New Mexico, North Dakota, Ohio, Oklahoma, Pennsylvania, Utah, West Virginia and Wyoming.

Alaska was down by one rig.

Louisiana was down by two rigs, as was Texas, the state with the most active rigs at 395. Baker Hughes shows Alaska with nine rigs active for the week ending Jan. 31, up two from a year ago.

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

—KRISTEN NELSON

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MUSTANG FIELD

In a board resolution passed on Jan. 16, the Alaska Industrial Development and Export Authority agreed to change the terms of financing for Mustang to accommodate delayed loan payments by Caracol Petroleum, the field's majority owner. It was not the first extension granted by AIDEA, but it was expected to be the last.

"I want to thank the AIDEA Board and Gov. Dunleavy for assigning a high priority to fixing this problem," Brooks Range CEO Majid Jourabchi said after the resolution passed. "Brooks Range and our contractors on the North Slope are completely aligned in what needs to be done, and the urgency to have it be so."

BRPC President and former CEO Bart Armfield has been with the project from the beginning.

Caracol is owned by Singapore-based Alpha Energy Holdings Ltd.

The latest agreement

BRPC drilled the Mustang discovery well in January 2012 in the Southern Miluveach unit, adjacent to the southwest edge of the Kuparuk River unit.

"The AIDEA mission to advance economic development and create job opportunities can sometimes run into delays, disappointments, and missed production deadlines," said AIDEA Board Chairman Dana Pruhs when announcing the revised financing terms. "Brooks Range startup problems and the oil tax credits veto three years ago, along with other factors, created the largest workout situation at AIDEA as identified by the Dunleavy transition team in early 2019. Producing from these state oil leases in 2020 requires better understanding of North Slope challenges, reserve base lending, and capital requirements."

AIDEA was originally involved in Mustang as an investor. However, in 2019 its investment was restructured into a loan: $64 million for field development plus $6 million in interest, totaling about $70 million. The gross expected value of oil production from Mustang is $1.3 billion.

After one loan extension payments were scheduled to begin Oct. 1, 2019, several months after planned startup. Interest rate on the loan was 8%, to be paid in 29 level quarterly installments,

Under the terms of the Jan. 16 agreement, the interest rate was reduced to 6%, with the first interest payment deferred until three months after closing. The loan principal was effectively reduced to $63.6 million.

Initial payments were interest only, with principal plus interest payments starting in the seventh quarter of the schedule. Principal payments were accelerated, starting in the 14th quarter.

AIDEA also committed to make up to an additional $35 million in loan financing available after July 1 to support Mustang development drilling, contingent on oil production targets being met and the establishment of a debt service reserve fund.

Alpha investment needed

The new loan was also contingent upon Alpha investing $60 million in Mustang in the first quarter of this year and advancing at least $15 million to Caracol in the form of equity or a senior secured loan.

Alpha also had to strengthen management and management oversight of the Mustang project.

AIDEA consented to the sale of certain non-essential oil field equipment and other assets, with the proceeds to be used to pay off creditor debt.

AIDEA said Jan. 16 that other creditors had also agreed to mechanisms for dealing with the Mustang situation, but that not all creditors had yet "come on board." Final agreement was needed by the end of January.

"This is a complex process and the negotiations are ongoing; however, we do not have confirmation yet from Brooks Range that those agreements have been finalized," Karsten Rodvik, AIDEA's external affairs officer, told Petroleum News Feb. 5.

—KAY CASHMAN

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CONOCO INVESTMENT

investment over the coming years."

"We've had ballot measure challenges over the past few years that would have negatively impacted our business and Alaska's economy," he said. "After understanding the issues, Alaska voters have voted 'no' on all of them."

Hatfield said the company is part of an industry group that will provide information to voters about the benefits of the current fiscal regime — the benefits that it has on jobs, investment, oil production and long-term revenue to the state.

"The bottom line is we're working hard to ensure Alaskans understand the significant benefits that investment by this industry brings to the people and the state of Alaska under the current fiscal structure," he said.

Sell down on hold till uncertainty subsides

Don Wallette, executive VP and CFO, said a previously announced offering of a share in some the company's North Slope fields is on hold for now.

"At this point, we only plan to sell down after the uncertainty related to the citizens' initiative has been resolved, and after we fully interpreted the results of our exploration and appraisal program, and when we've progress through Willow through the concept select gate," he said. "After we've satisfied those three criteria, that's when we plan to execute this sell-down, so that pushes the sell-down most likely well into next year."

He said the company would not execute a sell-down in a way that causes it to lose control of the investment pace.

"We're already confident that there's multiple quality parties that are interested in these great assets," he said.

"We would be open to an equal-value strategic transaction or a swap rather than cash, if that makes sense," Wallette said. "We're going to resolve some of these uncertainties, and then we'll approach the market." ●

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Petroleum news

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Mahoney named new Revenue chief

ON FEB. 4, ALASKA GOV. MICHAEL DUNLEAVY said he had appointed Lucinda Mahoney as commissioner of the Alaska Department of Revenue. Mahoney, who has 30 years of broad experience in the areas of consulting, treasury, debt management, investment management, accounting, budgeting and business development, took office that same day.


LUCINDA MAHONEY

"Lucinda's experienced background and outstanding work ethic will make her an excellent Commissioner. Her previous experience with the Municipality of Anchorage, and understanding of debt services, will be valuable to not only the Department of Revenue, but our entire state as we look to create a more prosperous future. I thank Lucinda for her readiness to serve our great state," Dunleavy said.

Mahoney is the owner of Value Solutions LLC, from which she operates as a business consultant and investment manager. Over the years, she has worked with Fortune 10 oil companies, government agencies, Alaska Native corporations and villages, large and small businesses, and not for profit organizations.

She formerly served as the chief financial officer for the Municipality of Anchorage, and as the executive director of the Arctic Slope Regional Corp. shared services center. Prior to that, Mahoney was a director with KPMG LLP, managing its business consulting practice in Alaska.

She received her Bachelor of Business Administration from the University of Texas, her Master of Business Administration from the University of Alaska, certification from the National Association of Certified Valuation Analysts and Investment Portfolio Certificate from the Wharton School of Business.

Mahoney's past boards and appointments include the following: trustee, Police and Fire Retirement Investment Fund, 5 years; trustee, Alaska Municipal League Investment Board, 4 years; trustee, Anchorage Deferred Compensation Investment Board, 5 years; board oversight as CFO, MOA Investment Trust, 5 years; chairwoman, Municipal Health Committee, 5 years; board member/treasurer, Anchorage Community Development, 6 years; and as an advisory board member, Launch Alaska.

"I share the Governor's vision of obtaining long term fiscal sustainability to create opportunities for all Alaskans and move Alaska forward. I look forward to working with Governor Dunleavy and his administration to identify practical and efficient solutions to the issues our state is currently facing," Mahoney was quoted as saying in the Feb. 4 press release.

Mike Barnhill, who was appointed acting commissioner of Revenue in December will now serve as the department's deputy commissioner.

Hilcorp Alaska employees donate $5 million

ON FEB. 4, THE ALASKA COMMUNITY FOUNDATION announced a new partnership with Hilcorp Alaska that will result in more than $5 million in charitable contributions over the next 12 months. Through this partnership, ACF will take over the administration of Hilcorp Alaska's giving program and disperse the employee guided donations statewide, the foundation said in a press release.

"This is innovating news for philanthropy in Alaska, and a partnership we are very excited to begin," said Nina Kemppel, ACF president and CEO. "Hilcorp has a successful history of enhancing its social investment through the Greater Houston Community Foundation, and we're thrilled to have the opportunity to take that proven model and help Hilcorp expand its corporate giving to Alaska beginning with $5,000,000 over the next twelve months."

"The main reason I became interested in serving on the Alaska Community Foundation's Board was its focus on community," said Carol Gore, ACF's board chair. "This investment by Hilcorp Alaska is an example of the community investing in their own community – investing in its people and place."

Under the Hilcorp Giving Program, the company establishes a charitable fund for employees with an initial gift of $2,500 followed by an annual match up to $2,000 every year thereafter. Each employee can then direct the funds to the charities of their choice.

Since the program's inception in 2007, Hilcorp's employees have gifted over $15 million to U.S.-based nonprofit organizations.

"We are proud to have over 90% of our employees from Alaska and we are proud to be in Alaska. There is no better organization than ACF to help our employees invest in Alaska," said Hilcorp Alaska Senior Vice President Dave Wilkins. "Whether it is an after school program for at-risk youth, their church, or a homeless shelter, we empower our employees to become lifelong philanthropists and determine how best they can help their communities."

Hilcorp plans to work with ACF for many years to come as it continues to grow its workforce and operation in Alaska, the foundation said in its Feb. 4 press release.

Established in 1995, ACF is a "statewide platform for philanthropy that connects people who care with causes that matter. Managing more than $124 million in assets and over 550 funds for the benefit of Alaskans, ACF and their affiliates grant $6-$8 million each year to charitable projects and nonprofit organizations across the state," the press statement said.

ACF's mission is to "inspire the spirit of giving and connect people, organizations, and causes to strengthen Alaska's communities now and forever."

For more information, visit www.alaskacf.org.

—COMPILED BY KAY CASHMAN

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EIA OUTLOOK

$105 per barrel in 2019 dollars by 2050, compared to $183 in the high oil case and $46 in the low oil price.

EIA's projections for Alaska production, starting from a base of 0.48 million bpd in 2019, are 0.55 million bpd in 2030 at all prices. But by 2040, in the low price case Alaska production is estimated at 0.30 million bpd, compared to 0.83 million in the base case and 1.17 million in the high oil price. The state is estimated to have no production in 2050 in the low price case, 0.48 million bpd in the base case and 0.78 million bpd in the high oil price.

There is also a high oil and gas supply case, reflecting lower costs and greater U.S. oil and natural gas resource availability, allowing more production at lower prices, and a low oil and gas supply case which "assumes fewer resources and higher costs," EIA said.

Alaska production projections, for 2030, are 0.44 million bpd in the low oil and gas supply case, 0.55 million in the base case and 0.58 million in the high oil and gas supply case. In 2040, projection in the low supply case is 0.46 million, 0.83 million in the base case and 0.99 million in the high supply case. In 2050, in the low supply case the projection is 0.22 million, compared to 0.48 million in the base case and 1.20 million in the high supply case.

US growth through 2025

In the report's base or reference case, EIA said U.S. crude oil and natural gas plant liquids production continues to grow through 2025, with natural gas plant liquids (liquids extracted from natural gas in processing plants), comprising nearly one-third of cumulative U.S. liquids production in the projection period, which covers 2020-50.

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But while U.S. production continues to grow through 2025, EIA said consumption of petroleum and other liquids remains lower than its 2004 peak level through 2050 in most cases (the reference and side cases).

Lower 48 onshore tight oil development continues as the main driver of U.S. crude production, EIA said, accounting for about 70% of cumulative domestic production in the reference case, with the Southwest region leading crude oil production in the U.S. Deepwater discoveries of oil and natural gas in the Gulf of Mexico are the driving factor in offshore Lower 48 production reaching 2.4 million bpd in 2026. "Many of these discoveries occurred during exploration that took place before 2015, when oil prices were higher than $100 per barrel, and they are being developed as oil prices rise," EIA said.

Exports

The U.S. becomes a net energy exporter on an annual basis in 2020, EIA said, and will continue to import and export throughout 2020-50.

In the reference case, EIA said, the U.S. exports more petroleum and other liquids than it imports annually starting in 2020 "as U.S. crude oil production continues to increase and domestic consumption of petroleum products decreases." After 2047, however, the U.S. is projected to return to importing more petroleum and other liquids than it exports based in increasing domestic gasoline consumption and falling domestic crude oil production.

The U.S. became a net natural gas exporter on an annual basis in 2017, EIA said, and in the reference case the U.S. exports liquefied natural gas to more distant destinations and is projected to remain a net natural gas exporter through 2050.

Uncertainties

"Future oil prices are highly uncertain and are subject to international market conditions influenced by factors outside of the National Energy Modeling System (used in the projections)," EIA said. The high oil price and low oil price cases represent "international conditions that could drive prices to extreme, sustained deviations from the Reference case price path," with higher than expected non-U.S. petroleum and liquids demand and lower-than-expected non-U.S. supply in the high oil price case and the opposite in the low oil price case.

Tight oil and shale gas production is uncertain, EIA said, "because large portions of known formations have relatively little or no production history and extraction technologies and practices continue to evolve rapidly." ●

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HORGAN REVERSAL

turning British Columbia into a global LNG power (hopes that have since drastically faded).

When he took office almost three years ago, Horgan also threatened to empty his province's toolbox to fight the Trans Mountain pipeline expansion, waging battle all the way to the Supreme Court of Canada, only to take a resounding setback earlier this year, having paid out millions in legal and consulting fees.

He is now apparently eager to align himself with pipeline backers — including unionized workers, landowners and First Nations — in the remote rural areas of northern and southern British Columbia, where voters have delivered resounding victories to British Columbia's opposition Liberals and Canada's opposition Conservatives.

Gearing up for election

Although he has no plans to call an early election in B.C., Horgan is gearing up for the next provincial vote, backed by his solid financial record that has seen B.C. deliver seven straight years of budget surpluses.

But he may need the electoral support of First Nations and left-leaning voters in rural regions if his support of pipelines erodes his standing with environmentalists and those who want B.C. to abandon natural resource development.

Speaking to a B.C. Natural Resources Forum in Prince George on Jan. 29, Horgan dined heavily on humble pie at a luncheon address.

"Resource development has been part of our spectacular past and I believe is part and parcel of our rosy future," he told delegates.

"What will keep it going is a commitment by everyone in this room to acknowledge there are going to be differences of opinion when it comes to economic activity in British Columbia," Horgan said, urging all British Columbians to establish a "common focus."

He talked about LNG "being on the rise," with the C$40 billion development by LNG Canada creating thousands of jobs, opening up markets for the province's vast gas supplies and offering economic opportunities to Indigenous businesses.

Challenges ahead

However, he conceded there are challenges to deal with, notably resistance to the Coastal GasLink pipeline from a minority of 15 Wet'suwet'en hereditary chiefs, who claim territory along a portion of the pipeline route.

B.C. Liberal leader Andrew Wilkinson told the same forum that Horgan needs to show leadership in the LNG pipeline dispute by telling the activists "that this project is going to get done."

He said the Liberals will work with all residents who demonstrate a willingness to cooperate. "The rest of them are going to be subject to the courts," he said.

Horgan also again conceded to reporters that the Trans Mountain pipeline will go ahead.

"I'm not enamored with the prospect of a seven-fold increase in tanker traffic (carrying crude bitumen from the Port of Vancouver to Asia) through the Strait of Juan de Fuca and the Salish Sea. But the courts have determined that the project is legitimate and should proceed," he said.

Horgan announced in Prince George that he has hired Nathan Cullen, a former federal Member of Parliament, to work as a liaison between First Nations chiefs and his government on Coastal GasLink.

He said that "over time a dialogue will allow us to get to a place where the Wet'suwet'en will see the courts have determined that federal and provincial permits are in order. This is a massive project that has massive benefits to B.C, particularly the Indigenous communities (offering a chance to overcome) systemic poverty."

—GARY PARK

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ADAK PROPOSAL

though I was a carrier guy, not a long runway guy.

"My proposal ... I started with a concept paper last April and I briefed the Department of Energy Office of Fossil Fuels Strategic Petroleum Reserve over the phone, and they were absolutely interested in what I was proposing," Ott said. "They were doing a configuration study of the existing SPR sites as well as defining what the requirements were now and in the future; my timing was really good."

In May, Ott took the idea to the state.

"I engaged the Director of Economic Development Matt Fagnani," Ott said. "Matt and I knew each other from when he was at the Aleut Corporation and I told him what I was thinking."

Fagnani liked the fact that the Department of Energy was interested, Ott said.

Later that month Ott briefed the governor's new industry development team.

In October, Gov. Dunleavy wrote a letter to Secretary of Energy Rick Perry urging the consideration of Adak for the SPR program.

Adak is remote, a lonely dot on the world map, but is actually quite close to energy customers in the Pacific, compared to the current salt dome storage in the Gulf of Mexico region.

Moving some of the Strategic Petroleum Reserve to a western location close to developing strategic partners in the Indo-Pacific makes great sense, Ott said.

"You are able to react to aggression or tsunamis, earthquakes, typhoons — which you see all the time — within days, not weeks," Ott said, adding that vessels with SPR reserve going to Pacific markets must make a 48-day transit from the Gulf of Mexico around South America, because they can't go through the Panama Canal.

Ott is proposing a contractor-owned and operated facility with an initial 21 million-barrel oil capacity, having the ability to scale to 100 million barrels.

"From Alaska, from Adak, it's five days to Tokyo; it's seven days to Seoul; it's about nine days to Indonesia, so you've got the ability to react quickly," he said.

Adak, lonely as it may be, is in a central location.

"Adak is exactly midway between Seattle and Tokyo — 2,500 miles east, or 2,500 miles west," Ott said. "It's about 1,200 miles to Anchorage, 400 miles to Dutch Harbor."

"I didn't even consider Dutch Harbor because I knew having (Shell) infrastructure there with OSI, you were constantly competing for resources," he said. "So I didn't want to negatively influence Dutch Harbor with something like this."

Ott's father, like Ott, a tribal member of the Choctaw Nation of Oklahoma, has a unique perspective on the significance of Adak.

"My dad, as being the Indian chief that I liken him to be, considers Adak the last great American trading post," Ott said. "Manifest Destiny happened because of trading posts moving supplies and goods westward in the great western expansion of the United States."

Public/private venture; no upfront cost to DOE

Ott is proposing a contractor-owned and operated facility with an initial 21 million-barrel oil capacity, having the ability to scale to 100 million barrels.

"What I'm proposing to the federal government and what's got them interested is, they don't own it, they don't buy it, they don't construct it, and there is no upfront cost," Ott said. "All they're doing is paying lease costs for contracted storage as an anchor tenant."

"The government has a requirement, so instead of having 635 million barrels stuck in leaky salt caverns down in the Gulf of Mexico, take 100 million or more, and put it closest to the developing point of need — and that's the why."

The national security scenario is changing, and the SPR program needs to change with it, Ott said.

"The 2017 national security strategy, which is authored by the current administration includes energy dominance, and energy security is an enabling capability, so one of the top five priorities is energy dominance."

"The first time in 75 years, we've become a net exporter so that supply cushion increases, ergo the tank storage wherever has got to increase," he said. "A lot of that tankage is going to be down in the Gulf."

So what changed?

"It was the chaos and the instability quite frankly in the Red Sea and in the Arabian Gulf that I could just see as a train wreck," Ott said. "A couple of natural or manmade disasters in that area of the world and the natural disasters in the Indo-Pacific and you have a real chance to see an impact on the global economy when Tokyo, when Seoul, when China, when Indonesia, Malaysia, and the Philippines start struggling for energy security."

The island with an unmatched array of assets

In the northern waters of Alaska, ports are few, and deepwater ports fewer still.

At Adak, the existing facility has a 36-foot draft at the pier which hasn't been dredged in decades, Ott said. Deeper water is available. The base has two intersecting military grade 7,600-foot runways. Alaska Airlines provides bi-weekly scheduled service.

There are world class logistics capabilities, Ott said, adding, "Plenty of lay down, plenty of dry storage."

Importantly, there is ample level terrain to site the fuel tanks and protective oil containment.

"As far as crude oil storage, I talked to one developer; it would be state of the art and it would be Alaskanized, it would have double dome roofs on the tanks, it would be earthquake strength, it would be triple containment — in other words you would have a tertiary and secondary containment system."

"My depiction of the facility shows 10-acre plots per tank," Ott said. "One million-barrel tank with a 10-acre berm around it as the tertiary consignment, and then you'd have duck pond around the tank and then membrane underneath it."

Ott sees the first quarter of of 2023 as a feasible date for first operations, assuming the federal government moves in a timely fashion to okay the deal.

"It requires a letter of interest from the Department of Energy to begin — and that would be with the planning phase, the design phase," Ott said. ●

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YUKON GOLD

owners" to "optimize the monetization strategy for existing discovered resources" in the vicinity and that permitting for a new well in 2021 is "underway," the company also says drilling is "subject to farm-out."

Those discussions must be serious because 88 Energy did not have a booth at NAPE in early February, while almost all the other companies looking for partners for their Alaska prospects did.

When asked for more details about the discussions with nearby leaseholders, David Wall, managing director of 88 Energy Ltd., told Petroleum News in a Jan. 29 email, "We have not disclosed anything related to the discussions and will not do so at this time," a common response from an oil company while in negotiations.

ERIK OPSTAD

When asked for the kind of permitting that had begun, he said, "Standard work related to permitting. We have not submitted any permits yet," also typical until full project funding has been secured.

Eighty-six million barrels of oil

88 Energy Ltd.'s main Alaska subsidiary is 88 Energy Alaska Inc., which in turn has three subsidiaries — Regenerate Alaska Inc., operator of the Yukon Gold acreage (now referred by the company simply as its Yukon leases); Captivate Energy Alaska Inc. which drilled the Winx 1 North Slope exploration well last winter; and Accumulate Energy Alaska Inc., which is drilling the Charlie 1 exploration well this winter.

Per Alaska's Division of Oil and Gas January 2020 lessee detail report, Regenerate holds eight state leases in the Yukon Gold prospect area, encompassing 15,234.71 contiguous acres.

The company acquired 3D seismic over what it calls its "Cascade prospect" in the Yukon leases in 2018 and, "on final processing and interpretation, high-graded" the Yukon Gold prospect from a "lead to a drillable prospect." The main target of new drilling will be the Tertiary Canning formation.

88 Energy said the Cascade prospect was "intersected peripherally" by Yukon Gold 1, drilled in 1993-94 by BP, and classified as an historic oil discovery.

88 Energy said the mean prospective resource for the prospect is 86 million barrels of oil. A November presentation breaks down the prospective unrisked oil resource as follows: Cascade Canning/Fan net mean of 82.3 million barrels; PETM1 Staines Tongue/Topset 6.2 million barrels; PETM2 Staines Tongue/Topset 1.1 million barrels.

Sourdough, Yukon Gold, ANWR 1002 area

88E's top executive in Alaska for Captivate and Accumulate is Anchorage-based general manager of operations Erik Opstad, a state of Alaska certified professional geologist, who has worked the North Slope for more than 34 years.

Wall directly oversees Regenerate.

Opstad is also 50% owner and manages Jade's operations. 88 Energy does not own any part of Jade, which is operator of the Sourdough prospect, a few miles north and a little east of Yukon Gold.

Both Sourdough and Yukon Gold are on the border of the 1002 area of the Arctic National Wildlife Refuge. The 1002 area is 1.57 million acres in a narrow strip of coastline that was set aside because of its petroleum potential by Congress in 1980 when the 19 million-acre refuge was created.

The Sourdough and Yukon Gold prospects are thought to hold oil pools that cross under ANWR's current border — a border that is disputed by the state of Alaska and currently being litigated in front of the U.S. Bureau of Interior's Interior Board of Land Appeals (see Petroleum News stories "No limit on IBLA's ANWR ruling" in the Feb. 2, 2020, issue and " State/fed ANWR border battle wages on; IBLA decision slides into 2020" in the Jan. 26, 2020, issue).

The Sourdough and Yukon state leases along the border include acreage in what is officially the ANWR 1002 area.

But whether IBLA rules in the state's favor or not, Jade and Regenerate can already tap the oil on their leases under ANWR, thanks to the court-tested "rule of capture" law which allows lessees to drill on a state lease and have the right to what that drilling produces, even though it might be drained from adjacent, undrilled, federal land.

Sourdough drilling next winter

As part of the 2012 settlement between the state of Alaska and the working interest owners of the ExxonMobil operated Point Thomson unit, an East Pad was to be built, an East Pad well drilled and an additional well drilled in the unit.

The state has since agreed that the requirement will be fulfilled through a deal between ExxonMobil and Alaska independent Jade Energy, which is scheduled to drill a new well in the untapped Sourdough oil prospect on a Point Thomson lease in first quarter 2021, utilizing some existing unit infrastructure for its operations.

The well, Jade No. 1, had been planned for first quarter 2020, but because Jade was not able to get into the Point Thomson unit's service pier in summer 2019, the appraisal well had to be deferred until early 2021.

Jade No. 1 will be drilled on state lease ADL 343112 in area F, Tract 32, of the unit, which is the most southeasterly lease in Point Thomson.

The lease holds two mid-1990's Sourdough oil discovery wells that were drilled by BP, which estimated Sourdough held 100 million barrels of recoverable oil.

Point Thomson operator ExxonMobil and the other major working interest owner, BP Exploration Alaska, both assigned their full working interests in ADL 343112's Tract 32 to Jade, retaining a small overriding royalty. The deal gave both North Slope producers some skin in the game, fully aligning them in delivering a successful Sourdough development.

As of Oct. 31, Jade held a 95% working interest in the lease, leaving just ConocoPhillips and its 5% interest in the Point Thomson unit.

On Feb. 4, Opstad said that ConocoPhillips transferred its 5% working interest in ADL 343112 to BP, which was approved by Alaska's Division of Oil and Gas effective Nov. 1.

"That said, BPXA is obligated under an existing farmout agreement to transfer that interest to Jade Energy LLC, a process now underway. Once that transfer becomes effective later this year, Jade will have 100% working interest in Sourdough," Opstad said.

By building a 70,000 barrel per day liquids export pipeline at Point Thomson that connects to the Badami unit and thus moves oil and condensate to Pump Station 1 of the 800-mile trans Alaska oil pipeline, ExxonMobil improved the development economics of other oil prospects to the east. In addition to Sourdough, those prospects include Yukon Gold, Donkel and Cade's Stinson and any future production from the 1002 area.

Based on analysis of Jade No. 1 data, which will be drilled in early 2021, the division's then-acting Director James Beckham said April 4, 2019, that Jade "will move forward accordingly with additional development at Area F and adjoining areas" in the following winter drilling season (2022) and that the overall economic feasibility of a field development program at Area F would be considered following that drilling.

—KAY CASHMAN