Petroleum news

page 2 EIA says Brent will average $59 in 4th quarter, reach $57 by Q2

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Hilcorp gets OK for gas chiller project to boost Northstar output

On Sept. 30 the Alaska Department of Natural Resources' Division of Oil and Gas approved Hilcorp Alaska's feed gas chiller project for Northstar Island, which will allow the company to increase natural gas liquid recovery during the summer months by holding the NGL separator at its optimum process temperature year round. This will boost the field's annual sales oil production.

Hilcorp had applied for an amendment to its Northstar unit plan of operations on Aug. 29.

How much NGL output will increase was not provided in the company's filing or the division's decision, but NGL production this past summer averaged about 1,350 barrels per day, while the other nine cooler months averaged some 3,010

see **NORTHSTAR PROJECT** *page 7*

UAF researchers say ANWR snow conditions would pose challenges

A research team from the University of Alaska Fairbanks Geophysical Institute has published a report on the results of research into snow conditions on the coastal plain of the Arctic National Wildlife Refuge. The team's findings point to significant differences between the snow conditions in ANWR and conditions farther west on the coastal plain. These differences will likely require changes in the way oil and gas explorers conduct off-road winter transportation, when conducting activities in ANWR, the researchers suggest.

In particular, strong winds in the ANWR region tend to blow snow into drifts on the lee sides of river and stream-cut banks, leaving relatively thin snow cover on plateaus and

see **ANWR SNOW** *page 5*

DOR looks to simplify regs, reducing taxpayer, state burden

The Alaska Department of Revenue has proposed changes to existing regulations governing the administration of the oil and gas production tax and oil surcharge regarding depreciation, and the weighted average cost of capital for transportation of oil by a vessel and for liquefied natural gas transportation facilities.

In an Oct. 4 public notice the department said existing regulations regarding the return on investment or cost of capital for transportation costs are extremely complex, and the calculation model requires in excess of 2,000 inputs.

The proposed changes "restructure the cost of capital calculation by eliminating calculations over multiple time periods in calculating the cost of capital allowance," the department said.

see **O&G REGS** *page 4*

IGU enters final construction phase

DAN BRITTON

The Interior Gas Utility said Oct. 8 that the balance of plant work is "currently being completed on the large storage tank" in North Pole as it enters its final phase of construction.

The tank will be complete and will begin receiving liquid natural gas deliveries by the end of November, the utility said.

The completion of the tank "ensures meeting the requirements to qualify" for the state of Alaska's storage tax credit for Fairbanks, IGU said.

"Balance of plant work is one of the final steps toward completing the construction of our 5.25 million-gallon LNG storage

see **IGU PLANT** *page 5*

NATURAL GAS

Valdez attorneys respond

City tells FERC Anchorage doesn't need gas, route to Valdez would meet objectives

By KRISTEN NELSON
Petroleum News

The Federal Energy Regulatory Commission has received numerous comments on the draft environmental impact statement for the Alaska LNG project, including requests for a supplemental DEIS from the Matanuska-Susitna Borough (see story in Oct. 6 issue of Petroleum News) and the City of Valdez, both related to the choice of a pipeline route from the North Slope to Cook Inlet with a liquefaction facility at Nikiski, the proposal evaluated in the DEIS.

Ahtna and Cook Inlet Region Inc. expressed concern about subsistence impacts, and the state cited issues on which it disagreed with FERC, noting that FERC had refused to accept the state as a cooperating agency in development of the DEIS.

Valdez

Valdez, the city at the terminus of the trans-Alaska oil pipeline, has long yearned to also be the terminus of a companion natural gas pipeline, with a liquefied natural gas facility producing LNG for export.

The most recent iteration of a plan to commercialize Alaska North Slope natural gas, the Alaska LNG Project, proposes a pipeline terminating at Nikiski on Cook Inlet, with options for natural gas to Alaska communities along the pipeline route.

Valdez is not in the picture.

The city's attorneys, Brena, Bell & Walker,

see **DEIS COMMENTS** *page 10*

EXPLORATION & PRODUCTION

Securing Nicolai Creek

Amaroq says three factors critical to onshore Cook Inlet unit's long-term survival

By KAY CASHMAN
Petroleum News

SCOTT PFOFF

If approved by the state, the 46th annual plan of development for the Nicolai Creek unit that Amaroq Resources LLC filed with the Alaska Department of Natural Resources' Division of Oil and Gas on Oct. 1 will be in effect from Jan. 1 through Dec. 31, 2020. In the proposed plan of development, or POD, the company says long range production of the onshore natural gas field on the west side of Cook Inlet is "highly dependent" on the following factors:

1. The ability to economically dispose of produced water. Absent a water disposal solution, the field becomes uneconomic in "short order," operator Amaroq said in the POD. The company is in the process of conducting an injectivity test on NCU No. 1B well in preparation for the filing of a disposal injection order application with the Alaska Oil and Gas Conservation Commission, the purpose of which will be to convert the depleted gas well to a produced water disposal well.

2. The outcome of Amaroq's motion for reconsideration in the AOGCC matter of increased bonding requirements. Amaroq says if it has to post a $2.4 million bond with AOGCC pursuant to

see **NICOLAI CREEK** *page 8*

GOVERNMENT

Canada faces showdown

Alberta and Saskatchewan up against a wall with election, climate-change targets

By GARY PARK
For Petroleum News

JUSTIN TRUDEAU

So deep and entrenched is the anger in Alberta and Saskatchewan with Prime Minister Justin Trudeau's energy policies that Canada's two largest oil and gas producing provinces could turn themselves into a political wasteland if the governing Liberal Party is reelected on Oct. 21.

Entering the election campaign, Alberta was represented by 29 Conservatives, three Liberals, one New Democrat and one Independent, while Saskatchewan had 10 Conservatives, three New Democrats and one Liberal.

While it may be inconceivable that the Liberals will emerge from the vote emptyhanded, the oddsmakers suggest that is a real possibility.

Whatever, it is unlikely that the Conservatives will lose their current dominance and, if Trudeau wins the vote across the rest of Canada, Alberta and Saskatchewan are poised to tackle head on the Trudeau government's resolve to meet Canada's climate change targets through a carbon tax, while shrugging off initiatives by both provinces to lower greenhouse gas emissions by imposing a carbon cap on the oil sands in Alberta and using technological advances to sequester carbon in Saskatchewan.

see **OCT. 21 ELECTION** *page 6*

● FINANCE & ECONOMY

EIA: Brent to average $59 in 4th quarter

Agency sees downward price pressure as inventories rise in first half of 2020, with Brent falling to $57 per barrel by 2nd quarter

By KRISTEN NELSON

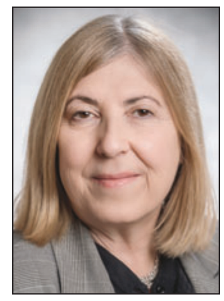
Petroleum News

The Brent crude oil spot price averaged $63 per barrel in September, up $4 from August, the U.S. Energy Information Administration said Oct. 8 in its October Short-Term Energy Outlook. This September's average was down $16 from September 2018.

EIA said Brent prices began September at $61 per barrel and rose to $68 after the attacks in Saudi Arabia disrupted that country's crude oil production.

The agency said spot prices have fallen since, reaching $58 per barrel Oct. 4, as Saudi Arabia restored production "and concerns about oil demand based on the condition of the global economy rose."

"EIA expects global energy prices to decrease through 2020," EIA Administrator Dr. Linda Capuano said in a statement, "as indicators suggest that GDP growth will slow worldwide. The October Short-Term Energy Outlook revised the forecast for average 2020 Brent crude oil spot prices down $2 to $60 per barrel, despite last month's higher prices following the attacks on Saudi oil installations. The events in Saudi Arabia and other supply risks are balancing downward price pressures resulting from decreasing demand," Capuano said.



LINDA CAPUANO

She said Saudi Arabia was able to increase its production relatively quickly after the attacks in mid-September and their production is estimated to have averaged 8.5 million barrels per day in September, but the decline was still enough to push production from the Organization of the Petroleum Exporting Countries to its lowest level since November 2003.

Drop in 2nd quarter

EIA said it is forecasting Brent spot prices to average $59 per barrel in the fourth quarter of this year, then fall to $57 per barrel by the second quarter of 2020, $5 per barrel lower than forecast in September, with downward oil price pressure expected "to emerge in the coming months as global oil inventories rise during the first half of 2020."

The agency expects balances to tighten later in 2020 with Brent rising to an average of $62 per barrel in the second half of the year.

"EIA's October forecast recognizes a higher level of oil supply disruption risk than previously assumed," the agency said, "more-than-offset by increasing uncertainty about economic and oil demand growth in the coming quarters, resulting in a lowered oil price forecast."

OPEC production is estimated to have averaged 28.2 million bpd in September, down 1.6 million bpd from August, and down 4 million bpd from September 2018, with the year-over-year decrease primarily the result of

see EIA OUTLOOK page 4

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GOVERNMENT

GAO testifies on BLM energy oversight

Comments on recommendations relating to lease revenues, well bonding, royalty compliance and minimizing methane emissions

By ALAN BAILEY

For Petroleum News

In recent testimony to the U.S. House Committee on Natural Resources, the Government Accountability Office overviewed some concerns about issues relating to Bureau of Land Management oversight of energy leasing on federal land. In Alaska, BLM manages oil and gas exploration and development in the National Petroleum Reserve-Alaska and will manage any future oil and gas activity in the Arctic National Wildlife Refuge.

The testimony focused on four issues relating to oil, gas and coal development: land lease terms and conditions; bonding for energy related activities; royalty compliance; and methane emissions.

Land lease revenues

In terms of land leasing, the GAO questioned the fact that federal lease terms have not changed for several decades, a factor that raises potential issues regarding whether the federal government now receives a fair return on energy related activities on its lands. For example, lease rental rates and the royalty rates on oil and gas production have not been adjusted over the years.

In 2016, in response to a GAO recommendation, BLM adopted regulations providing for royalty rate flexibility. But royalty rates remain at a minimum of 12.5% of production value. Oil and gas land tracts are generally leased for 10 years, with a rental rate of $1.50 per acre for the first five years, rising to $2 per year thereafter. Some states have royalty rates higher than the federal rates, a situation that raises questions over whether the federal government is making an appropriate return from energy production on its land — BLM does conduct periodic assessments of its oil and gas fiscal system and plans to conduct its next assessment in late 2019, the GAO said.

Bonding and well remediation

The GAO recently issued a report recommending that Congress should provide funding for the reclamation of orphaned oil and gas wells, while also suggesting that required bonding levels for drilling oil and gas wells are too low. In its testimony to Congress the agency re-iterated these concerns, commenting that well reclamation costs can range from $20,000 to $145,000. While BLM generally sets bonding at the minimum required levels, those minimum levels have fallen far behind inflation over the years and appear to be below realistic reclamation costs, the GAO told the House committee.

The GAO also said that BLM has commented that the agency does not have the authority to seek or claim funds from operators for the reclamation of orphaned wells. Congress should consider giving BLM this type of authority, the GAO suggested.

Royalty compliance

With reference to BLM's ability to meet its royalty compliance goals, ensuring that all oil and gas royalties are fully collected and accounted for, the GAO questioned whether the agency sufficiently accounts for and verifies its revenues. The GAO has recommended, and BLM has concurred with, the establishment of goals for the accuracy of royalty payments.

Methane emissions

In 2010 and 2016 the GAO issued recommendations for steps that the Department of the Interior, including BLM, should take to better account for and manage methane emissions from oil and gas development. Methane is a par-

see GAO TESTIMONY *page 5*

EXPLORATION & PRODUCTION

XCD completes Peregrine ground survey, ERCE to do independent resource report

XCD Energy said Oct. 9 that it has finished its summer archaeological ground survey for its Peregrine project, which is on 149,590 acres in the National Petroleum Reserve-Alaska.

XCD describes itself an oil exploration company focused on early stage exploration assets.

DOUGAL FERGUSON

The ground survey is an "important ingredient" in the independent prospective resource report which the Alaska-focused Australia based oil junior commissioned with ERC Equipoise Pte Ltd, or ERCE. The report is expected to be finalized in late October.

"Valuable data was collected from the survey and is now being collated and documented to ensure any areas of cultural, historic or archaeological significance are identified," XCD said.

The ground survey, the company said, had to be done in the summer and was required before XCD could permit "future on-ground operations," including seismic and drilling.

"Completion of the field work during the 2019 summer was critical to allow the company to commence operations in the 2019/20 winter season should the opportunity arise. The engagement of ERCE to undertake the independent prospective resource report is another step towards achieving the objectives we set ourselves this calendar year and will set the company up well to commence a farm-out campaign later this year," XCD's Managing Director Dougal Ferguson said.

With the survey done, XCD said its attention will shift back to its integrated Nanushuk technical regional overview project, which is nearing completion.

—KAY CASHMAN

US rig count continues down, dropping 5

Baker Hughes reports the number of rigs drilling for oil and natural gas in the U.S. continues to drop, down by five the week ending Oct. 4 to 855, following a drop of eight the week ending Sept. 27.

In its weekly rig count, the Houston oilfield services company said the active rig count was down 197 from 1,052 active rigs a year ago.

The company reported that 710 rigs targeted oil (down three from the previous week; down 151 from a year ago) and 144 targeted natural gas (down two from the previous week; down 45 from a year ago). There was one miscellaneous rig active (unchanged from the previous week; down one from a year ago).

The company said 54 of the U.S. holes were directional, 749 were horizontal and 52 were vertical.

New Mexico was up four rigs from the previous week.

Alaska, North Dakota and Utah were each up by one rig.

The rig counts in Ohio and Pennsylvania were unchanged from the previous week.

California, Colorado, Louisiana and Wyoming were each down one rig from the previous week.

West Virginia was down by two rigs and Oklahoma was down by three.

Texas, the state with the most active rigs, 414, was down by four from the previous week.

Baker Hughes shows Alaska with nine rigs active for the week ending Oct. 4, up from five a year ago.

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

—KRISTEN NELSON

continued from page 1

O&G REGS

"As a result, the scope of the input data is reduced and the calculation is simplified. This should also work to reduce the administrative burden on both taxpayers and the state."

"Additionally," the department said, "the weighted average cost of capital rate previously obtained from third-party sources has been replaced with a U.S. Treasury yield rate coupled with a set risk premium."

All the proposed changes under the notice affect 15 AAC 55 of the Alaska Administrative Code, dealing with the oil and gas production tax.

Written comments regarding the proposed changes must be received by the department Nov. 7, no later than 4 p.m.

In an Oct. 4 public notice the department said existing regulations regarding the return on investment or cost of capital for transportation costs are extremely complex, and the calculation model requires in excess of 2,000 inputs.

15 AAC 55.193 to be amended

Under 15 AAC 55.193, the calculation of costs of transportation for oil and gas produced after June 30, 2007, is proposed to be amended to change the reference from 15 AAC 55.195 to 15 AAC 55.196 in regards to the cost of transportation of oil by a vessel, or for LNG transportation facilities, that are owned or effectively owned by a taxpayer.

Under the proposed amended terms, if transportation of oil is by a vessel that is owned or effectively owned, in whole or in part, by the producer of that oil, the transportation cost for the oil would be the sum of voyage and port costs incurred with respect to that transportation; the positioning cost, amortized over 36 months, for that vessel; and the depreciation of the vessel and a cost of capital allowance calculated under 15 AAC 55.196(d).

15 AAC 55.195 to be repealed

The department proposes to repeal 15 AAC 55.195, return on investment or cost of capital allowance to be used in calculation of costs of transportation for oil or gas, other than certain LNG or vessel transportation costs for oil or gas produced on or after Jan. 1, 2003.

15 AAC 55.196 to be amended

15 AAC 55.196. Cost of capital allowance to be used in calculation of costs of vessel transportation for oil or gas produced on or after Jan. 1, 2003, other than certain costs pertaining to vessels placed in service before Jan. 1, 1995, and in calculation of transportation costs for gas by an LNG transportation facility placed in service after Dec. 31, 2010, is proposed to be amended to replace and simplify the current model which is used to calculate a Cost of Capital Allowance that incorporates both the depreciation cost and the after-tax return on capital for vessels transporting oil, or for LNG transportation facilities, that are owned or effectively owned by a taxpayer.

Under the proposed amended terms of 15 AAC 55.196(a), a producer may elect to expense the first $2 million in costs incurred with respect to improvements during a calendar year.

Under the proposed amended terms of 15 AAC 55.196(d), a cost of capital allowance under this section must be calculated using the methodology set out in the department's publication Computation of a Cost-of-Capital Allowance under 15 AAC 55.196, Incorporating Depreciation and Return on Invested Capital for Marine Vessels and Improvements, Edition 4.0.

15 AAC 55.192, 15 AAC 55.800 to be amended

15 AAC 55.192. Monthly share of annual transportation costs; and 15 AAC 55.800. Retroactive application of regulations, are proposed to be amended to make conforming changes to references to other regulations affected by this notice.

Comments on the proposed regulation changes, including the costs to private persons of complying with the proposed changes, may be submitted to: John Larsen, audit master, Alaska Department of Revenue, 550 W. 7th Ave., Ste. 500, Anchorage, AK 99501, by email to john.larsen@alaska.gov, or by fax to 907-269-6644.

—STEVE SUTHERLIN

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EIA OUTLOOK

falling production in Iran and Venezuela and the recent disruption in Saudi Arabia.

OPEC production is forecast to average 29.8 million bpd this year, down 2.1 million bpd from 2018, and 29.6 million bpd in 2020.

US production down in July

EIA said U.S. crude oil production averaged 11.8 million bpd in July, the latest month for which data are available, down 300,000 bpd from June as a result of Gulf of Mexico disruption caused by Hurricane Barry.

"U.S. crude oil production remained relatively flat during the first seven months of 2019 because of disruptions to Gulf of Mexico platforms and slowing growth in tight oil production," the agency said, with tight oil production growing more slowly because of relatively flat oil prices and slowing growth in Lower 48 well productivity. EIA said it expects growth to pick up as Gulf of Mexico production returns and pipelines come online linking the Permian basin with Gulf Coast refining and export centers.

The agency is forecasting U.S. production growth to level off in 2020 "because of falling crude oil prices in the first half of the year and continuing declines in well-level productivity."

EIA is forecasting U.S. crude oil production to average 12.3 million bpd this year, up 1.3 million bpd from 2018, and rising by 900,000 bpd in 2020 to an annual average of 13.2 million bpd.

Natural gas

EIA said the Henry Hub natural gas spot price averaged $2.56 per million British thermal units in September, up 34 cents from August, the first monthly price increase since March. The agency is forecasting Henry Hub to average $2.43 per million Btu in the fourth quarter, down more than $1 from the fourth quarter of 2018, and then rising to an average of $2.52 per million Btu next year.

"Although the United States remains on track to set new records for dry natural gas production in 2019 and 2020, EIA believes that low natural gas prices will cause production to start to level off going into 2020," Capuano said. "The October STEO expects production to increase in 2019 by about 10%, exceeding 91 billion cubic feet per day, year-over-year, while 2020 will experience a smaller increase to more than 93 billion cubic feet per day, if the forecast holds," she said.

EIA said prices have fallen this year because strong supply growth enabled natural gas inventories to build more than average during the April through October injection season. ●

Contact Kristen Nelson at knelson@petroleumnews.com

ENVIRONMENT & SAFETY

Methane sensors deployed in Permian basin

Methane sensors will be put on planes, trucks and atop towers in the West Texas and southeastern New Mexico desert in a new effort to gauge the extent of greenhouse gas emissions from surging oil and natural gas production, advocates with the Environmental Defense Fund announced Oct. 2.

The yearlong project in the Permian basin petroleum production region involves researchers from Pennsylvania State University and the University of Wyoming, and low-flying planes from a Colorado-based atmospheric research company.

The new methods will be used because traditional estimates of methane emissions have not kept up with the rapid expansion petroleum exploration in the area spanning roughly 85,000 square miles, said Environmental Defense Fund Regulatory Affairs Director Jon Goldstein.

The Permian basin is by many measures the country's most active basin for oil and gas development, he said.

Data from the study organized by the Defense Fund will be made public while research is still in progress. Results will include a map of emissions across the region. Organizers expect scientific work to be submitted for peer review.

The goal is to produce useful measurements for the oil and gas industry as it strives to reduce waste as well as for regulators and observers who are concerned about climate pollutants, Goldstein said.

Methane, the main component of natural gas, frequently leaks or is intentionally released during drilling operations. It traps far more heat in the atmosphere than carbon dioxide, doing 25 times the damage over the long term despite surviving for less time, according to the EPA.

—ASSOCIATED PRESS

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ANWR SNOW

other flatter areas. Thus, the overall snow cover tends to be thinner than in state lands to the west and in the National Petroleum Reserve-Alaska.

Field research

In research conducted since 2014, the UAF team assessed winter snow conditions on the ANWR coastal plain using ground measurements of snow depths and densities combined with aerial photogrammetric mapping. In 2018 and 2019 the team mapped about 200 square kilometers of the 1002 area in April, at around the time of peak snow depth. The mapping confirmed the wind-blown nature of the snow cover and showed remarkably consistent snow patterns, despite significant differences in the amount of snowfall in each of the years. However, with relatively less snow in 2019 compared with 2018, the average snow depth in wind-scoured areas was less in 2019 than in 2018, while the snow drifts were similar in horizontal extent.

Snow roads needed

It is likely that winter transportation across wind-scoured areas will require the building of snow roads to protect the underlying tundra, the researchers suggest. And, since there are fewer lakes in ANWR than farther west, there will be issues regarding the use of water in snow road construction, potentially driving a need for new construction techniques. On the other hand, it may prove possible to use snow from the deep drifts when building snow roads, the researchers say.

New technologies, in particular high precision mapping from aircraft, have the potential to help in the planning for off-road transportation on the coastal plain, the UAF report says. But, the mapping of snow thicknesses as a precursor to planning off-road access requires mapping of the land surface before the winter snow arrives — subsequent mapping after the snow has fallen would then provide data concerning snow cover thicknesses. However, the researchers cautioned that the snow cover tends to build up over time during the winter, perhaps leading to maximum snow cover in February or March.

The report suggests that these considerations would likely apply to any on-land exploration activities planned for the winter season of 2019-20.

—ALAN BAILEY

Contact Alan Bailey at abailey@petroleumnews.com

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IGU PLANT

facility designed to provide security of winter supply and increase access to natural gas for thousands in our community," Dan Britton, IGU's general manager, was quoted as saying in the press release. "This is a massive step forward for affordable clean-burning energy, and we are excited to help ensure affordable energy choices for our community."

IGU's North Pole LNG storage facility ground improvement contract has been awarded and will begin "this week."

The ground improvement is "a major step towards constructing the North Pole LNG storage facility and adding residential and commercial customers in the North Pole area," IGU said.

"Progress has not always been as smooth or as fast as we would have liked," IGU board chair Steve Haagenson said. "However, progress has been steady and always targeted to IGU's stated mission."

"As we celebrate public Natural Gas Week nationwide (Oct. 6-12) we recognize these two IGU milestones that bring natural gas closer for thousands more residents in our community. There are approximately 1,000 public natural gas systems throughout the United States, serving more than 5 million customers, and IGU is proud to be the Fairbanks North Star Borough's natural gas provider," the utility said, noting that is "focused on lowering energy costs and improving the quality of life for all those who live here and visit here."

—KAY CASHMAN

Contact Kay Cashman at publisher@petroleumnews.com

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GAO TESTIMONY

ticularly virulent greenhouse gas. The GAO also commented that data reporting gas flaring and venting on federal leases probably underestimate the scale of the emissions.

In 2016 the GAO recommended the BLM should issue new guidance on estimating gas emissions from operations on federal leases.

In July 2016 the Department of the Interior took steps to implement the GAO's recommendations for the improved control of methane emissions. However, in June 2017 Interior postponed the compliance date for several sections of new emissions regulations. And in September 2018 the agency issued new regulations that were not compliant with the GAO's findings and recommendations, the GAO told the House committee. Some states have emissions regulations more stringent than those of the federal government, the GAO commented. ●

Contact Gary Park through publisher@petroleumnews.com

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OCT. 21 ELECTION

Bill C-69 issue

Unless a second-term Trudeau government removes the club it holds over the heads of Alberta and Saskatchewan, they will press ahead with their arguments filed with the Supreme Court of Canada that a carbon tax is unconstitutional and their court challenge in Alberta to block Bill C-69 that rewrites environmental assessments for major resource projects.

Saskatchewan Justice Minister Don Morgan says scuttling Bill C-69 is an "absolutely imperative" to prevent the federal government from trampling on provincial rights to regulate development of oil and gas resources that are owned by the provinces. Alberta Premier Jason Kenney has derided Bill C-69 as the "no more pipelines law."

But Trudeau has insisted a new regime is needed to protect the environment and the rights of indigenous communities.

Kenney's opponents describe the Bill C-69 legal fight as mere "political theatre," to which the Alberta premier replies "it's about the rule of law; it's about an economic union (in Canada); it's about respect for the fundamental law of the land and the Constitution of Canada."

Saskatchewan has applied for intervener status at the first round of the legal fight before the Alberta Court of Appeal, with Morgan echoing Kenney's case that it's "absolutely imperative for us that we stick up for the rights of (our provinces) and their ability to regulate business and regulate industry" within their jurisdiction.

"We've got a strong and vibrant oil and energy sector (in Saskatchewan, which is Canada's second largest hydrocarbon producer, after Alberta) and we have to do everything we can to make sure that sector continues to be vibrant, strong and continues to grow," he said.

Kenney's stand is endorsed by an unlikely source — Alberta New Democratic Party leader Rachel Notley, whose government was toppled in last April's provincial election.

She criticized Bill C-69 and acknowledged the need for a legal challenge.

Federal authority

However, Martin Olszynski, a law professor at the University of Calgary, said previous court rulings have made it clear that the Canadian government has the authority to assess the environmental impact of resource projects, even though resource development comes under provincial control.

"The constitutional principles that apply are settled and they're very clear," he told the Globe and Mail, adding that when Bill C-69 and the old law for regulatory reviews are put side by side, "in terms of basic architecture, these laws are almost identical."

While that test case looms and will extend far beyond the Oct. 21 federal vote, the Kenney government is pressing on with its investigation of foreign funding of environmental groups opposed to oil sands development and pipeline construction and its creation of a so-called "war room" to counter what it views as misinformation on the oil and gas industry.

Kenney rejected criticism on social media that his request for the public to send information on foreign-funded campaigns into the inquiry amounts to a snitch line.

Former Alberta Environment Minister Shannon Phillips said the exercise was a "silly little witch hunt," to which Kenney said that "if the political left in Alberta is opposed to investigating foreign money behind campaigning to landlock Alberta oil, that shows how out of touch they are."

He said his government is merely "asking for public input into a formal public inquiry to a very serious issue that's materially affecting our prosperity."

Kenney said previous federal and provincial governments and oil industry leaders have pledged to fight anti-industry campaigns, but lost ground because they "responded defensively and reactively" while the Energy East pipeline to Atlantic Canada and the Northern Gateway pipeline to export 525,000 barrels per day of Alberta bitumen to Asia were cancelled and Keystone XL and Trans Mountain were delayed.

Amnesty International spat

Another sideline spat has found Kenney at odds with Amnesty International, which claims 7 million supporters in 150 countries.

It sent a personal letter to Kenney blasting the government funded probe as an attack on "human rights defenders — particularly indigenous people, woman and environmental human rights defenders, exposing them to intimidation and threats, including threats of violence."

For Kenney that represented proof his opponents see no value in Alberta government plans to establish an economic development agency to underpin efforts by First Nations to invest in oil and gas support services and possibly acquire ownership stake in pipelines.

Greens the wild card?

The wild card in the federal vote could be seeing the Green Party rise from its current position of having two lawmakers among the 338 in the House of Commons to the role of powerbroker.

If neither the Liberals nor the Conservatives can obtain an outright majority on Oct. 21 they would likely need to form a coalition with the Greens, who have made strong gains in the latest polls, or the New Democratic Party.

Under the control of Elizabeth May, the Greens have the most fickle of the party leaders. Four months ago she issued a Mission Possible document calling for a ban on all imports of oil into Eastern Canada, dominated by almost 600,000 bpd for refineries in New Brunswick, Ontario and Quebec.

She said at the time that "as long as we are using fossil fuels we should be using our fossil fuels." That would include production from the oil sands, which she views as the curse of Canada's efforts to lower greenhouse gas emissions.

But that objective was short-lived when the Greens issued their energy plan in mid-September, targeting a lowering of GHG emissions by 60% from 2005 levels by 2030; banning hydraulic fracturing in the natural gas industry; cancelling the Trans Mountain pipeline expansion; and eliminating fossil fuel subsidies.

May said that under her party there would be no new pipelines, or coal, oil or gas development. For Alberta alone that would eliminate 270,000 direct oil and gas jobs.

Her plan said that "inevitably, jobs in fossil fuel sectors will disappear, (but) the Green Party is committed to a 'just transition' of workers in these sectors into new ones. This will include measures such as income protection, job guarantees, retraining and resettlement."

But May admitted the proposal has yet to undergo an independent cost review, although she expressed confidence "in our ability to pay for what we are promising."

If the Greens do end up holding the balance of power their impact on national policy will quickly override all other considerations, likely forcing Alberta and Saskatchewan closer to the brink of a serious debate over separation from Canada. ●

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NORTHSTAR PROJECT

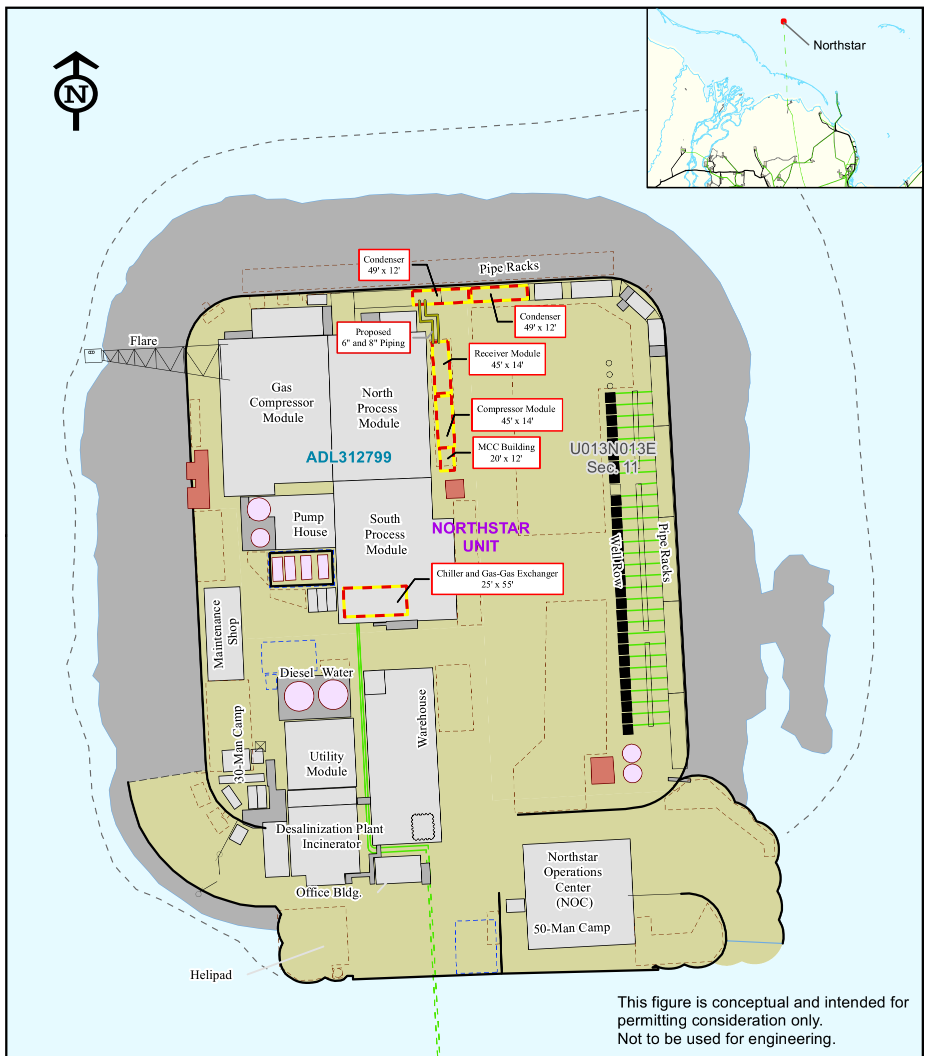
bpd, the difference being 1,660 bpd less for June, July and August.

Recently Alaska economist Ed King reported encouraging fiscal year 2019 output numbers from Hilcorp's Northstar field, his data taken from the Alaska Oil and Gas Conservation Commission.

After starting regular production in 2001, the Northstar field is already nearing the end of its economic life, currently producing about 10,000 bpd of a combination of crude oil and NGLs for Hilcorp, he said.

However, Hilcorp, which purchased Northstar from its previous operator BP in 2014, has "a talent for getting oil out of fields that others are ready to give up on," King said. "In fact, the Northstar unit saw an increase of 317,587 barrels of oil" (including NGLs) in FY 2019, a 9% increase over FY 18.

Among other things, Hilcorp's tool chest to increase output from mature fields in Alaska and elsewhere includes more drilling, reworking wells, reinjecting natural gas and injecting polymer and water into reservoirs, employing and sometimes developing technology such as the chiller project, upgrading infrastructure to ensure that pipelines and wells can continue to perform effectively, plus the company has a robust integrity and management program for all its facilities and pipelines.



Hilcorp Alaska, LLC
3800 Centerpoint Dr. Suite 1400
Anchorage, AK 99503
Map Date: 8/28/2019

Northstar Unit
Northstar Production Island
Feed Gas Chiller Project
Facility Map

1 inch = 100 feet
0 50 100 Feet
FIGURE: 2

Scope and timing

In its description of the scope of the project, the division said Hilcorp had requested and been approved to install a chiller and a gas-to-gas heat exchanger on Northstar Island within the Northstar Island unit.

"Accompanying this new equipment will be a new motor control center, a propane compressor, condenser and receiver," the agency said in its decision. "The chiller and gas-to-gas exchanger will be installed on top of the existing south process module."

Per Hilcorp's schedule, work on the chiller project was to begin immediately with gravel excavation to place concrete footings for a new steel support frame above the footings and modules, with a completion target of May 20 when things such as making electrical connections and installing additional infrastructure and tie-ins, as needed, will be done.

Northstar Island, the division said. is approximately 18 miles east of Milne Point. The gas chiller project will involve state lease ADL 312799.

Project activities

Planned project activities in Hilcorp's words include the following:

• Excavation of gravel to allow footing installation from the existing artificial island.

• Installation of pre-cast concrete footings within the existing artificial island.

• Mounting a 110 foot by 14 foot steel support frame above the concrete footings.

• Securing a 45 foot by 14 foot by 14.5 foot in height compressor module.

• Securing a 45 foot by 14 foot by 14.5 foot in height receiver module.

• Securing a 20 foot by 12 foot by 14.5 foot in height motor control center, or MCC, building.

• Mounting a 100 foot by 12 foot steel support frame above the existing North pipe rack.

• Securing two 49 foot by 12 foot by 14.5 foot in height condensers.

• Removing two existing crude oil coolers from the roof of the South process module.

• Installing a vessel support frame on the roof of the South process module.

• Securing a 32 foot by 6 foot by 12.5 foot in height chiller vessel on the roof of the South process module.

• Securing two 43 foot by 5 foot by 7 foot in height gas-gas exchanger vessels on the roof of the South process module (the gas-gas exchanger vessels are in the same footprint as the chiller vessel).

• Installing approximately 400 feet of 24 inch process piping between the chiller, gas-gas exchanger, existing feed gas coolers and the existing NGL separator.

• Installing approximately 1,500 feet of propane piping, ranging in size from 3 inch to 14 inch, between the chiller, compressor module, condensers and receiver module.

• Installing electrical connections between the existing Northstar power system and the MCC building.

• Installing electrical connections between the existing MCC building and the two condensers.

• Installing additional infrastructure and tie-ins as required.

The division provided a review and comment opportunity for these activities, which ended Sept. 24. No comments were received.

—KAY CASHMAN

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NICOLAI CREEK

the agency's newly established requirements, the Nicolai Creek field "immediately becomes uneconomic and is likely destined for cessation of operations." A hearing on the motion has not yet been set.

3. The ability of Amaroq to attract the additional capital necessary to effectively further develop the unit, which has "tremendous upside potential" for natural gas and conventional oil, unconventional gas and storage development, per the company. If Amaroq is successful in attracting the investment dollars to pursue "any or all of these upsides," the Nicolai Creek field would likely remain in operation for years to come.

Unit production

Amaroq said the Nicolai Creek unit produced 145,486 mcf from Sept. 1, 2018, through Aug. 31.

Thanks to well work and surface facility improvements, gas production from the field has recently doubled, Scott Pfoff, president of Amaroq, told Petroleum News on Aug. 30.


COURTESY LYLE SAVAGE

The compressor facility in Amaroq Resources' Nicolai Creek gas field.

"We've gone from about 250,000 cubic feet (per day) to 500,000 cubic feet (per day)," Pfoff said.

One issue involved fine sand passing through screens designed for sand capture, a problem that necessitated improvements to the sand handling capabilities of the surface facilities, he said.

Since its acquisition of the Nicolai Creek field in January 2018, Amaroq has pursued a program of field maintenance and well workovers, rather than drilling new development wells. That strategy continues, with the company focusing on achieving good performance from the field's existing wells, Pfoff said.

In its Oct. 1 filing with the state the company said it has no development or drilling plans for the unit during the 46th POD timeframe.

Under well data in the POD, Amaroq indicated it has six producer wells — NCU 1B, 2, 3, 9, 10 and 11 — although not all the wells are currently in production.

Wells that were abandoned by previous operators include NCU 4, 5, 6, 13 and 14.

Status of producers

Amaroq said the NCU No. 1B producer, which it would like to convert to a water disposal well, was directionally drilled by a previous operator as a sidetrack to NCU No. 1 well in 2002 into state of Alaska lease ADL 17585. It won't be much of a loss as a producer because the well only produced 5,414 mcf between Sept. 1, 2018, through Aug. 31 of this year.

Per the POD, slickline was run in NCU No. 2 well in August 2018 to ascertain well bore conditions and evaluate potential for future production and/or gas storage. Mechanical issues in the well were identified but no further work was performed and the well remained shut in and will likely require rig intervention to correct the issues, Amaroq said in the POD.

Per the company NCU No. 3 well was shut in due to formation sand and silt plugging. It will require 1.25-inch coiled tubing for the cleanout, which was not readily available in the Cook Inlet area, so there was no output from the well between Sept. 1, 2018, through Aug. 31.

The NCU No. 9 well produced 93,333 mcf from Sept. 1, 2018, through Aug. 31. Amaroq said the well has been on production with no intervention since a coiled tubing cleanout was successfully performed in the third quarter of 2018.

As for producer NCU No. 10, it produced 1,556 mcf between Sept. 1, 2018, through Aug. 31.

A coiled tubing cleanout and chemical sand control of the Carya 2-4.2 completion was attempted during third quarter 2018. However, as a result of parted tubing, the procedure was "unable to be completed." Attempts to put the well back on production subsequent to the coiled tubing work proved unsuccessful due to excessive water and sand production, Amaroq said.

NCU No. 10 was shut in until a series of downhole sand screens were installed with slickline in the first quarter of this year but attempts to produce the well

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NICOLAI CREEK

"were again unsuccessful due to excessive water and sand production. The well was shut in again until the third quarter at which time enhanced surface equipment modifications were made and the well was put back into production," Amaroq said in the POD.

Production was stabilized but due to the lack of water disposal options, the well was currently shut in pending conversion of NCU No 1 B to disposal, per the POD.

The company also said it would continue evaluating the economics associated with a gravel pack and/or rig workover during 2020 for NCU No.10, "which would facilitate production at much higher rates."

The sixth producer, NCU No. 11, yielded 45,183 mcf between Sept. 1, 2018, through Aug. 31.

A coiled tubing cleanout of the well was successfully performed in third quarter 2018, which resulted in increased output for a time, but "as a result of a steep decline in production, slick line work was performed to remove sand from the tubing" in the third quarter of this year and the well was recently put back into production and "is in the process of stabilizing to rates observed pre-wireline," Amaroq told the state in the POD.

More on upsides

Although, at this time Amaroq has no plans for exploration outside the Nicolai Creek field, there is potential to extend the existing field, Pfoff said in the Aug. 30 interview.

As partly referenced in the third factor critical to long-term production of Nicolai Creek, the company is also interested in developing oil and gas pools at deeper levels below the field. Currently, rights to those deeper prospects belong to Apache Alaska Corp., which acquired 3D seismic over the acreage in early 2012.

Pfoff acknowledged the potential to drill an additional production well, the Nicolai Creek No. 12 well, targeting deeper sands in the Beluga and Upper Tyonek formations to the north of the current production area. The previous operator, Aurora Gas, had conducted an evaluation of the potential of this well.

However, Amaroq does not want to tackle it until the company has dealt with achieving good performance from the field's existing wells, Pfoff said.

Market healthy

Pfoff sees the Cook Inlet gas market as relatively healthy.

"Right now, the way I see it, I can increase production quite a bit at Nicolai Creek and not have any trouble selling the gas at a good price," he said.

Using the current wells and well completions the field probably has a remaining four to five-year life, Pfoff said. But, with much upside possible, if successfully developed, field life could be considerably extended, he said.

Pfoff expressed satisfaction with the progress that his company has made in saving the Nicolai Creek field from closure. ●

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Petroleum news

Oil Patch Bits

Lynden Air Cargo completes Hercules fleet modification

Lynden Air Cargo said Oct. 4 that it has completed another Hercules modification this summer, installing a "Short-POD APU" to enhance the reliability and performance of its aircraft. According to Lynden Air Cargo President Rick Zerkel, the size of the project required Federal Aviation Administration approval.

COURTESY LYNDEN

"It took about a year and thousands of hours to take the military data and convert it to an FAA-approved package, conform the kits, convert an existing auxiliary power unit, modify the airframe, install and test, then compile and finalize over 1,000 pages of reports and manuals," Rick explained. The project required support from multiple groups inside and outside Lynden Air Cargo, such as the staff from the FAA aircraft certification office, engineering representatives, personnel from Lockheed and Kellstrom Defense, KF Aerospace and Lynden Air Cargo's quality control team, engineering, publications, maintenance and special projects.

The upgrade kit provides aircraft operators with increased reliability, quicker engine starts, and reduced maintenance and operating costs by replacing the out-of-production gas turbine compressor/air turbine motor with a modified APU that will help standardize the fleet with the other APU-equipped aircraft.

Denali Universal Services receives safety award

Denali Universal Services said Oct. 1 that it is honored to announce that its security division at the Chevron Phillips Chemical sites in Texas has been awarded the Contractor Safety Excellence Award, a safety award for outstanding safety accomplishments.

The award is presented annually to contractor companies that achieve superior safety performance while working for Chevron Phillips Chemical during the award year. There are several eligibility requirements to include cumulative hours worked and meeting Chevron Phillips Chemical total recordable incidence rate safety target.

"On behalf of our leadership team, I congratulate the security division at the Chevron Phillips Chemical sites for their commitment to high standards of safety every day," said Corey Parrent, director of health safety and environment for Denali Universal Services. "We're proud to receive this award because it shows our commitment to safety performance and honored to have been selected as a recipient two years in a row."

Editor's note: Some of these news items will appear in the next Arctic Oil & Gas Directory, a full color magazine that serves as a marketing tool for Petroleum News' contracted advertisers. The next edition will be released in March.

Companies involved in Alaska's oil and gas industry

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

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DEIS COMMENTS

argue in an Oct. 3 filing with FERC that the DEIS for the project to Nikiski does not comply with the National Environmental Policy Act because it does not accurately present the Valdez alternative and relies on "unsupported assertions" from the Alaska Gasline Development Corp., the project proponent, about impacts associated with the Valdez option.

The filing requests environmental impact data and comments, and says AGDC "has failed to provide the environmental impact data necessary to conduct an objective comparative analysis of the proposed pipeline route to and terminal site at Nikiski … and the alternative pipeline route to and terminal site located at Valdez … required in the Draft Environmental Impact Statement."

The filing goes on to say that "the data that AGDC has provided is presented in a manner that obfuscates the true nature of the impacts associated with each alternative."

The Palmer Spur issue

The filing says AGDC has aggregated data for a Valdez option with a 148-mile spur pipeline from Glennallen to Palmer, which would provide natural gas for Anchorage if the line went to Valdez, and notes that AGDC and FERC "have dedicated less than three pages in the DEIS to analyzing the Valdez Delivery Option despite the fact that both FERC and the U.S. Army Corps of Engineers have previously determined it to be the preferred alternative."

FERC denied the state's request to be a cooperating agency on the EIS and the absence of input from state agencies "is apparent," Martineau said, listing deficiencies in a number of areas, with "three topics that require substantial improvement and would benefit from engagement with State regulatory agencies prior to finalizing the EIS."

Valdez told FERC it supports the "stated purpose" of the Alaska LNG Project to commercialize ANS natural gas, bring cost-competitive LNG to foreign markets and provide interconnections to allow for in-state gas deliveries.

But, the filing says, failure to address issues it has identified "will inevitably lead to costly delay and litigation from environmental advocacy groups and others."

The filing on behalf of Valdez requests that FERC issue a supplemental DEIS to address the issues it has identified.

Those issues include what the filing calls a lack of sufficient data to compare the Valdez and Nikiski alternatives.

AGDC, the filing says, has aggregated data on impacts of the Valdez alternative with impacts of the Palmer Spur, asserting "the Palmer Spur is a reasonably foreseeable indirect impact and, therefore, must be included in FERC's analysis of the Alaska LNG Project."

In 2014, in the prefiling process, AGDC "never suggested analysis of the Palmer Spur was necessary," the Valdez filing says, and provided no data on the Palmer Spur until 2017, when it aggregated Palmer Spur impacts with Valdez impacts.

"Unlike the Fairbanks Lateral associated with the Nikiski Alternative, the Palmer Spur is not required to satisfy the Alaska LNG Project's purpose and is not a reasonably foreseeable aspect of the Valdez Delivery Option," the filing argues. "No where in the statement of purpose for the Alaska LNG Project does delivery of natural gas to the greater Anchorage area appear," since Anchorage is not an area with little or no access to natural gas.

The filing further argues that there is no evidence the Palmer Spur would ever be economically or commercially viable, based on existing natural gas in the Anchorage area and potential delivery of natural gas to Anchorage from Valdez by rail, truck or tanker, "all of which may be more economically viable than constructing a 148-mile spur pipeline through mountainous terrain."

The filing says FERC's reliance on the Palmer Spur as a "primary disadvantage" of the Valdez option "unlawfully relies upon analysis of a project impact that is not reasonably foreseeable and therefore fails to comply with NEPA."

The filing also disputes AGDC's estimate of the amount of overburden and rock which would have to be removed at Anderson Bay to build a liquefaction facility there, saying AGDC has provided no data or engineering analysis to support its estimates, which contradict earlier FERC adopted estimates for excavation and fill requirements at Anderson Bay.

On the positive side, Valdez would not require a Cook Inlet pipeline crossing, the filing notes.

"These flaws in the DEIS render it subject to judicial challenge for failing to provide the objective comparative analysis mandated by NEPA and failing to render a decision on a scientific and analytical basis," the filing says.

Use of the existing right of way to Valdez is also not compared with the Nikiski route, and the filing argues that comparison would reveal "substantial environmental advantages" of the Valdez option compared to Nikiski.

"Absent a finding that the use of the existing TAPS utility corridor is impracticable, FERC cannot legally issue permits for the Alaska LNG Project utilizing the Nikiski Alternative," the filing says, in summarizing the right of way issue.

Native corporations

Ahtna Inc., the Native regional corporation with lands from the Nenana River to the Chugach Range, told FERC it "supports safe and responsible development" and is commenting to identify issues where FERC's "analysis and process should be improved to better address the impacts of this proposed development on the Ahtna people."

Comments from Cook Inlet Region Inc., the Native regional corporation in Southcentral Alaska, struck a similar note, with CIRI telling FERC that it "expresses general support for environmentally responsible resource development throughout the State of Alaska and for the AKLNG project."

Ahtna told FERC it is the sixth largest private landowner in Alaska and "the largest private property owner impacted by the Alaska LNG pipeline"; CIRI said it is the largest private landowner in Southcentral Alaska. Ahtna has more than 1.7 million acres; CIRI has more than 1.3 million acres of subsurface and large surface estates shared with its seven village corporations.

The pipeline, as proposed, would cross 35 miles of Ahtna land, the corporation said.

Ahtna said it has rights under terms of the Alaska Native Claims Settlement Act and the Alaska National Interest Lands Conservation Act and urged FERC to expressly recognize that the Alaska LNG project is subject to specific and unique statutory requirements "and to fulfill the consultation requirements" under statute.

To date, Ahtna said, neither FERC nor AGDC have communicated with Ahtna or made any commitments to Ahtna regarding access to the 35 miles of right of way over Ahtna land.

Ahtna also said the DEIS does not adequate analyze how the proposed pipeline "would affect customary and traditional use of wild game by the Ahtna people or how the pipeline's impacts would aggregate ongoing cumulative impacts to Ahtna subsistence use and way of life." Ahtna said it was particularly concerned that a pipeline "built through the Cantwell community area and extended to Anchorage would further negatively impact Ahtna ways of life, both during the construction and operation of the pipeline." The Native Village of Cantwell is 210 miles north of Anchorage and 27 miles from the Denali National Park entrance.

CIRI expressed subsistence related concerns, but also expressed business concerns, saying it would like assurance that there would be available capacity in the pipeline within the Cook Inlet region that gas from Southcentral would benefit from proximity to the line, and also requested that AGDC "make gas off-take accessible to CIRI at commercially reasonable rates to ensure future economic development opportunities near the AKLNG."

CIRI said it appreciated the extensive discussion in the DEIS about subsistence

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DEIS COMMENTS

"and the acknowledgement that the magnitude of the impacts are largely unknown," and requested "the opportunity for representatives from impacted village corporations and tribes to participate in future discussions."

Trespass is an issue raised by CIRI, which said the DEIS reports that 481 new roads will be required. CIRI said landowners should not be required to notify AGDC that the road is to be removed after construction — "AGDC should flag the issue of permanency for the individual landowners at the time of seeking permission to build the road."

Since some of the new roads will provide access to otherwise inaccessible locations, "it is incumbent that AGDC also help mitigate the economic and resource damage through trespass that the project will invite."

State comments

Comments from the state of Alaska, authored by Faith Martineau, executive director of the Office of Project Management and Permitting in the Department of Natural Resources, represent a review team with participants from DNR and the departments of Environmental Conservation; Fish and Game; Commerce, Community and Economic Development; Health and Social Services; Transportation & Public Facilities; and Public Safety.

Martineau said the oil and gas industry in the state has a history of successful construction in permafrost and the state would require AGDC to implement best management practices for construction in permafrost as a condition of state authorizations.

Martineau said AGDC, the project proponent, was not on the review team.

She said the state found the draft EIS "to be satisfactorily written and supports the applicant's Proposed Action."

FERC denied the state's request to be a cooperating agency on the EIS and the absence of input from state agencies "is apparent," Martineau said, listing deficiencies in a number of areas, with "three topics that require substantial improvement and would benefit from engagement with State regulatory agencies prior to finalizing the EIS."

These topics are buried pipeline construction in permafrost; impacts to the Central Arctic Caribou Herd; and primary regulatory authority for air quality.

Martineau said the oil and gas industry in the state has a history of successful construction in permafrost and the state would require AGDC to implement best management practices for construction in permafrost as a condition of state authorizations. She said the state "found multiple instances in the Draft EIS where details concerning permafrost construction techniques and monitoring efforts were not well explained," and "recommends further detail and clarification on these topics."

On the Central Arctic Caribou Herd, the Department of Fish and Game "found multiple instances in the Draft EIS where information concerning the Central Arctic Caribou Herd was inconsistent with ADF&G data." There has been substantial research on caribou over the last 40 years and the department "is providing FERC with references to several pertinent research papers" for consideration.

"ADF&G disagrees with FERC's assessment that the Alaska LNG Project would result in significant adverse impacts to the Central Arctic Caribou Herd and requests that FERC update their caribou information: including the adoption of mitigation of mitigation measures that are considered effective in contemporary oil and gas development."

Martineau said the state is also asking FERC to remove a "Sensitive Class II" designation from the air quality portion of the DEIS. ●

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