Petroleum news

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EXPLORATION & PRODUCTION

Dispelling myths

Corri Feige pokes holes in misperceptions about Alaska oil & gas at NAPE

By KAY CASHMAN
Petroleum News

Department of Natural Resources Commissioner Corri Feige spent part of her time at the recent NAPE Summit in Houston tackling two major myths about doing business in Alaska's oil and gas basins: one was about the number of rigs working on the North Slope and the other the regulatory environment.

CORRI FEIGE

"The first of the myths I poked at was that just because the North Slope basin doesn't have a hundred rigs working doesn't mean we're not enjoying an exploration renaissance and that it isn't a hot spot for oil and gas exploration and development," Feige reported in a Feb. 10 interview with Petroleum News.

"I told them while a high rig count is a direct indication of how well a Lower 48 shale play is doing, on Alaska's North Slope reaching more resource with fewer wells is the name of the game."

Back in 1970, Feige explained, it took a 65-acre gravel pad on the North slope to produce roughly 3 square miles of reservoir. "Fast forward to today, and through the advances in extended reach drilling and advanced completion technologies, one 12-acre pad can produce approximately

see FEIGE AT NAPE page 7

EXPLORATION & PRODUCTION

State OKs Placer POD

First production still 2022; road and pad permits filed, 'back on track'

By STEVE SUTHERLIN
Petroleum News

The dispute over the Placer unit, between the Alaska Department of Natural Resources' Division of Oil and Gas and ASRC Exploration, has been resolved, DNR Commissioner Corri Feige told Petroleum News Feb. 10.

The Placer unit had been terminated by the division in July. Placer was discovered in 2004 by former operator ConocoPhillips and it was unitized in 2011 by AEX.

Feige said AEX came forward with a new plan of development and the division approved it, adding, "there is a performance attached to it and they updated their timelines."

> *Feige said AEX came forward with a new plan of development and the division approved it, adding, "there is a performance attached to it and they updated their timelines."*

"If memory serves, first production by late 2022, taking it though Brooks Range (Mustang) facilities," Feige said. "So yes, they are back on track and moving forward."

AEX is working very closely with the U.S. Army Corps of Engineers to get an environmental assessment done, and the company is working on

see PLACER POD page 8

EXPLORATION & PRODUCTION

Shift to conventional

At NAPE Conoco seeks partner for North Slope; Hilcorp for Lower Cook Inlet

By KAY CASHMAN
Petroleum News

More than 11,000 oil and gas professionals and 700 exhibitors packed the George R. Brown Convention Center at the NAPE Summit in Houston in early February, including at least seven Alaska exhibitors, six of whom were touting their oil and gas prospects in the state.

The Alaska Department of Natural Resources' Division of Oil and Gas had a booth with an all-star cast — DNR Commissioner Corri Feige, DNR Deputy Commissioner Sara Longan, Division Director Tom Stokes, Division Deputy Director Jason Black, resource evaluation chief Kevin Frank, and other support personnel such as a commercial analysis expert and geoscientists.

"We've seen a shale mania craze at the last several NAPEs, but now we are seeing a shift. Companies are looking for ways to balance their portfolios … to get conventionals back in the mix… and Alaska has an abundance of those — shallow, and onshore," Feige said. (See related interview with her in this issue.)

ConocoPhillips, Hilcorp look for partners

The companies pushing for partners in their prospects at NAPE included Alaskan Crude, ConocoPhillips, Hilcorp Energy, Malamute Energy and XCD Energy.

see NAPE SUMMIT page 9

Fine tuning Prudhoe: Seawater injection switch to add barrels

Ending seawater injection at two Prudhoe Bay drill sites and increasing seawater injection in the gas cap at the field will increase ultimate recovery from those drill sites, as well as increasing overall recovery by increasing field-wide pressure, field operator BP Exploration (Alaska) told the Alaska Oil and Gas Conservation Commission.

The company is applying to the commission to change depletion operations in a portion of the Prudhoe Bay miscible gas project to permanently cease seawater injection at drill sites 1 and 12 and transfer the seawater to another portion of the Prudhoe Oil Pool.

Frank Paskvan, a reservoir engineer and fieldwide team leader

see SEAWATER INJECTION page 10

Celebrations fizzle out as Trans Mountain faces 70% cost overrun

Government leaders and the Alberta-based oil industry had little time to pop the champagne corks after what many viewed as the removal of the final legal barrier to the Trans Mountain pipeline expansion, TMX.

They were quick to start the celebrations on Feb. 3 when Canada's Federal Court of Appeal issued a unanimous verdict emphatically rejecting four challenges from First Nations in British Columbia.

In a 95-page judgment, the court told First Nations that case law is clear that "although Indigenous peoples can assert their uncompromising opposition to a project, they cannot tactically use the consultation process as a means to try and veto it.

"Canada must act in good faith (in consulting with First

see TRANSMOUNTAIN page 10

Furie sale hearing moves again Omnibus adjourned until Feb. 19

The sale hearing on the assets of Furie Operating Alaska LLC, in its Chapter 11 bankruptcy case, has been adjourned to Feb. 19, 2020, at 2 p.m. before U.S. Bankruptcy Judge Laurie Selber Silverstein in the United States Bankruptcy Court for the District of Delaware.

HEX LLC, 100% owned by member manager John L. Hendrix of Anchorage, was the successful bidder for the Furie assets, primarily the Cook Inlet Kitchen Lights offshore unit, and related infrastructure such as the Julius R offshore platform, onshore processing facility and related pipelines.

The sale hearing was part of an omnibus hearing previously set for Feb. 11. The sale hearing was originally scheduled for

see FURIE SALE page 6

Ray of hope in Canada: first oil sands capex gain since 2014

Reeling from a double whammy of stumbling oil prices, stemming mostly from the expected impact of the spreading coronavirus infections, and a drastic slide in Western Canadian heavy crude values, it's hard to imagine much good news.

But there has been some, with predictions of the first increase in oil sands investment since 2014.

The Canadian Association of Petroleum Producers has forecast capital spending in the sector will rise by 8.4% this year to C$11.6 billion, crediting a corporate tax reduction in Alberta where the government has also eased oil production limits, and Saskatchewan's decision to boost oil output by 25% to 600,000 barrels per day over the next 10 years.

see CAPEX GAIN page 9

● EXPLORATION & PRODUCTION

Expansion, contraction for Qannik oil pool

By KRISTEN NELSON
Petroleum News

ConocoPhillips Alaska has requested a vertical expansion and an aerial contraction of the Qannik Oil Pool in the Colville River unit.

In a Feb. 6 application to the Alaska Oil and Gas Conservation Commission the company requested modification of the Qannik Oil Pool conservation order, expanding the QOP vertically by raising the top of the pool from 6,086 feet measured depth to 6,030 feet MD, and the contraction of one full and one partial section of land out of the pool "to align with lease ownership."

"This accumulation stratigraphically defines the oil-bearing sandstone body named Qannik," ConocoPhillips said. Pool rules were established and the accumulation defined by AOGCC in 2008.

Since formation, nine development wells have been completed in the QOP and some 7.7 million barrels of oil have been produced from QOP.

ConocoPhillips said the lands proposed for exclusion from QOP were subject to mandatory contraction from the Colville River unit effective Feb. 15, 2014, and the leases for the contracted lands expired at that time.

ConocoPhillips is the working interest owner in the unit and said the contraction was a housekeeping measure which align the QOP with its lease position. The company said it was its understanding that AOGCC "prefers the administrative clarity of having pools match lease positions when feasible, and we support that objective with respect to the QOP."

The area proposed for contraction is at the southeastern corner of the oil pool as defined in AOGCC Conservation Order 605.

New drilling opportunities

ConocoPhillips said its request to amend the QOP vertically would expand the QOP "from the top of the K-2 to the top of the K-3 Basal Siltstone as defined in the CS2-11 type log."

Sands above the K-2 in the current QOP area show minimal thickness and interbedded shales, but "new information shows that in areas reachable from the CD4 drillsite, the interval above the K-2 thickens and develops into reservoir quality sands and contain significant levels of hydrocarbons."

Extending the QOP vertically to the top of the K-3 Basal Siltstone "will allow for testing the producibility of the recently drilled and hydraulically fractured CD4-499 producer. Depending on results, it would allow for future development of the QOP from CD4 pad."

ConocoPhillips said for planning purposes its base case, "subject to contingencies, provides for drilling 3-5 wells into the vertically expanded QOP from 2020 to 2023."

It drilled the CD4-499 production well as a productivity test of the Qannik reservoir in the CD4 area and said the well "inverted at the toe to test the extent and quality

see **QANNIK POOL** page 3

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● UTILITIES

More support for electric system bills

Stakeholders in the Railbelt electrical system provide testimony to joint Senate and House committees over SB 123 and HB 151

By ALAN BAILEY
For Petroleum News

On Jan. 29 several stakeholders in the Alaska Railbelt electrical system testified to a joint meeting of the Senate Railbelt Electric System Committee and the House Special Committee on Energy regarding two bills being considered during the current Alaska legislative session. The bills, Senate Bill 123 and House Bill 151, would give the Regulatory Commission of Alaska regulatory authority over an electric reliability organization for the Railbelt, and would also give the commission authority to review and pre-approve changes and additions to major generation and transmission facilities.

In a previous joint meeting of the committees the Railbelt electric utilities presented their testimony on the two bills. The Jan. 29 meeting gathered testimony from other system stakeholders: the Renewable Energy Alaska Project, the Alaska Energy Authority, the Alaska Independent Power Producers Association and the Alaska Public Interest Research Group. Overall, the organizations expressed support for the legislation.

Purpose of legislation

The Railbelt electricity system, extending from the southern Kenai Peninsula north through Southcentral Alaska to the Fairbanks region, is owned and operated by six independent electric utilities and the State of Alaska. The purpose of implementing an electric reliability organization, or ERO, regulated by the RCA and with RCA oversight of major changes to the electrical system, is to achieve a more coordinated and efficient approach to the operation of the system.

In December all the utilities signed a memorandum of understanding for the formation of the Railbelt Reliability Council, or RRC, an organization that would constitute an ERO for the Railbelt. Formation of the RRC is moving ahead. However, the intent is to establish RCA regulation of the organization before the organization goes into operation: hence a primary purpose of enacting legislation as expressed in SB 123 and HB 151. The RCA is concerned that current statutes do not give it clear regulatory authority over an organization such as the RRC.

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 RCA is concerned that current statutes do not give it clear regulatory authority over an organization such as the RRC.

REAP's perspective

Chris Rose, executive director of Renewable Energy Alaska Project, expressed his organization's support for the legislation as proposed, including RCA oversight of the RRC or, should the RRC not be implemented, the authority of the RCA to mandate the formation of a similar organization.

Rose commented on the evolving nature of the electricity industry, including the growth in the use of renewable energy sources and the dramatic fall in the cost of energy sources such as wind and solar power. Concerns about climate change and the carbon impact of electricity supplies are also impacting business decisions about where electricity consuming businesses will locate their operations, he said. REAP thinks that reform of the Railbelt electrical system would create a more level playing field for renewable energy producers, stabilize electricity prices, decrease greenhouse gas emissions, attract new investment and help diversify the economy, Rose said.

However, Rose did express some concern about the governance structure of the RRC — questions over governance revolve around the need to balance the interests of the utilities with the interests of a broader spectrum of stakeholders in the electrical system. The governance board of the organization would have 12 members, plus the organization's CEO, who would have a tie-breaking vote on board decisions. Six board members would represent the six Railbelt utilities and six members would represent other stakeholders. But one of those other stakeholders would be the Alaska Energy Authority, a state entity that owns generation and transmission assets and, thus, acts in effect as a seventh utility, Rose suggested. That would give utility interests a majority on the board, he said.

REAP would also like to see a requirement that any minority views expressed during RRC integrated resource planning for the electrical system must be reported to the RCA, Rose said. However, he also commented that meetings with the utilities over the last year and a half have been very productive, and he criticized a recent effort to completely rewrite SB 123.

AEA support

Curtis Thayer, executive director of Alaska Energy Authority, commented on AEA's perspective, especially given the agency's ownership of the Bradley Lake hydropower facility in the southern Kenai Peninsula and of the transmission intertie between Southcentral Alaska and the more northerly sector of the transmission grid. He said the proposed legislation would not impact the state's rights and responsibilities for budgeting improvements to the state-owned facilities, and that the utilities manage the facilities through the Bradley Project Management Committee and the Intertie Management Committee.

Thayer said that that the manner in which SB 123 expresses legislative intent, ensuring appropriate RCA oversight, rather than being over prescriptive, is appropriate. SB 123 is the right vehicle at the right time to address long-sought institutional reform, he said.

Independent power producers

Duff Mitchell, executive director of Alaska Independent Power Producers Association, said that his organization has been working with the utilities and the RCA to promote the use of more competitive power generation in the state. Whereas in the United States as a whole 42% of power comes from independent producers, in Alaska only 4% of power is independently generated, he commented.

Mitchell said that, while SB 123 and HB 151 are not perfect, his organization does support them. Key issues for his organization are the need for an open access tariff for use of the transmission grid, the need for an independent board of directors for the ERO and the need for RCA authority over the ERO. He emphasized the growing importance of dealing with cybersecurity, as part of security oversight of the electrical system, and the importance of regional integrated resource planning, with RCA pre-approval needed for major projects.

He also said his organization would like to see stronger language in the legislation for ensuring open access to the electrical grid.

However, Mitchell said that his organization sees the proposed legislation and the formation of an ERO for the Railbelt as foundational to achieving lower electricity costs in the region.

Public interest group

Veri Di Suvero, executive director of Alaska Public Interest Research Group, commented that electricity costs in the Railbelt are among the highest in the nation and that the two bills form a critical step towards improved efficiency in the electrical system. She said that her organization is nonpartisan and nonprofit, representing the interests of the public and consumers, including advocating for ratepayers. She emphasized the importance of regional planning in achieving efficiencies.

AKPIRG would like to see a mandate for public participation as well as public comment in planning processes and ensure that the RCA has full regulatory oversight of the RRC. However, the priority at this point needs to be passage of the legislation, without that passage being slowed by major changes, Di Suvero suggested. The bills, as written, substantially serve the interests of consumers and the public, she said. ●

Contact Alan Bailey at abailey@petroleumnews.com

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QANNIK POOL

of the overlying K-3 Basal Siltstone away from existing well control."

AOGCC has tentatively scheduled a hearing on the request for March 17 at 10 a.m. at its Anchorage offices but said in its Feb. 10 notice that if a timely request for a hearing is not filed, it may consider issuance of an order without a hearing.

The commission will accept written comments through March 14 at 4:30 p.m., unless a hearing is held, in which case written comments will be accepted through the end of the hearing. ●

Contact Kristen Nelson at knelson@petroleumnews.com

● FINANCE & ECONOMY

EIA drops 2020 Brent forecast to $61

Prices expected to be below $60 in first half of year; US crude oil production growth to slow, averaging 13.2 million bpd this year

By KRISTEN NELSON
Petroleum News

In its Feb. 11 Short-Term Energy Outlook the U.S. Energy Information Administration said it expects global petroleum and liquid fuels demand to average 100.3 million barrels per day in the first quarter of the year, 900,000 bpd less than its January forecast. The agency said the change reflects both the coronavirus and warmer than normal January temperatures in the northern hemisphere.


LINDA CAPUANO

Brent crude oil spot prices averaged $64 per barrel in January, EIA said, down $4 per barrel from December, with Brent prices falling steadily in January and into the first week of February, closing on Feb. 4 below $54 per barrel, the lowest price since December 2018.

"EIA expects that travel restrictions in response to the coronavirus, along with the related economic showdown in China, will reduce petroleum demand and keep crude oil prices below $60 per barrel through the first half of this year despite current disruptions to crude oil supply," said EIA Administrator Dr. Linda Capuano.

"EIA reduced its forecast for global oil consumption growth through 2020 to 1.0 million barrels per day in the February Short-Term Energy Outlook," she said. "Changes in the forecast mostly result from the coronavirus and its effects on oil consumption in China."

Expectations from OPEC

EIA said it expects the Organization of the Petroleum Exporting Countries will reduce crude oil production by 500,000 bpd from March through May because of lower expected global demand. The agency said this reduction is in addition to cuts announced in December. EIA is now forecasting OPEC crude production to average 28.9 million bpd in 2020, down 300,000 bpd from the January forecast. The lower forecast reflects Libya's crude oil production outages in the first quarter.

EIA said that it assumes OPEC "will limit production through all of 2020 and 2021 to target relatively balanced global oil markets."

Brent crude

EIA said several events in January contributed to uncertainty in crude oil markets and the world economy.

"Early in the month, geopolitical developments drove oil prices," the agency said, and Brent closed at $70 on Jan. 6, the highest level since May, "following U.S. military operations in Iraq."

The agency said it now expects Brent to be $7 per barrel lower than previously forecast during the first six months of the year, with prices $1 per barrel lower than previously forecast in the second half of the year, averaging $58 per barrel in the first half of the year and $64 per barrel in the second half, rising to average $68 per barrel in 2021.

Crude prices fell as tensions in the Middle East deescalated and concerns over oil supply disruptions faded and those price declines accelerated with economic concerns over the coronavirus outbreak, with oil prices declining for five days starting Jan. 21. Demand was further reduced by warmer-than-normal northern hemisphere temperatures in January, which reduced heating oil consumption.

EIA said that while the magnitude and duration of effects of the coronavirus are uncertain, it is reducing estimates of Chinese and global oil consumption for 2020 as a result. Travel restrictions in China are disrupting petroleum demand there and in other countries. EIA said it is assuming effects of the travel restrictions will be most severe in China from February through April and is reducing its expectation of liquids fuels consumption in China by 400,000 bpd, an average of 14.8 million bpd, during that period.

US crude, natural gas

"The current outlook for U.S. crude oil production reflects slowing growth, with production expected to average 13.2 million barrels per day in 2020, up 8% from 2019, and 13.6 million barrels per day in 2021, a 3% increase from 2020," Capuano said.

EIA said the 2020 forecast is an increase of 1 million bpd from 2019, with most of that increase and the increase forecast for 2021 coming from the Permian region of Texas and New Mexico.

EIA said it expects a decline in U.S. natural gas production.

"Because of low natural gas prices, EIA expects natural gas production to decline somewhat on a monthly basis through 2020, with dry gas production falling from 95 billion cubic feet per day in January to between 92 billion cubic feet per day and 93 (billion) cubic feet per day in December," Capuano said.

EIA said the Henry Hub natural gas spot price averaged $2.02 per million British thermal units in January as warm weather contributed to below-average inventory withdrawals, putting downward pressure on natural gas prices. The price stood at $1.86 on Feb. 6, and EIA said it expects prices to remain below $2 in February and March.

U.S. dry natural gas production set a record in 2019, averaging 92.1 billion cubic feet per day, EIA said, and while it forecast production averaging 94.2 bcf per day in 2020, EIA said it expects monthly production to generally fall this year, from an estimated 95.4 bcf per day in January to 92.5 bcf in December.

"The falling production mostly occurs in the Appalachian and Permian regions," EIA said, with low natural gas prices in Appalachia discouraging natural gas directed drilling and low prices in the Permian expected to reduce associated gas output from oil-directed wells.

In 2021, EIA said, it expects dry natural gas production to stabilize near December 2020 levels at an annual average of 92.6 bcf per day, "a 2% decline from 2020, which would be the first decline in annual average natural gas production since 2016." ●

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● NATURAL GAS

DOE proposes non-FTA gas export extensions

Authorizations have been issued for 20 years; but based on 2018 study, agency says 30 years, through end of 2050, more appropriate

By KRISTEN NELSON
Petroleum News

The U.S. Department of Energy's Office of Fossil Energy is proposing to extend the standard 20-year term for authorizations to export natural gas, including liquefied natural gas, from the Lower 48 states to countries with which the United States does not have a free trade agreement for natural gas and with which trade is not prohibited by U.S. law or policy.

Holders of existing non-FTA authorizations could apply to extend the term of those authorizations through Dec. 31, 2050, the Office of Fossil Energy said in a Feb. 11 Federal Register notice. All future authorizations would have a standard term through 2050, unless a shorter term is requested.

DOE is inviting comments on the proposal, with comments due by 4:30 p.m. Eastern time March 12.

DOE said while this policy proposal is for non-FTA authorizations, it expects that if the policy is adopted that FTA authorization holders would likely request a comparable extension.

DOE said its first conditional long-term export authorization for domestically produced LNG from the Lower 48 was issued to Sabine Pass Liquefaction in 2011. Sabine Pass requested an export term of 20 years, and DOE said it determined that a 20-year term was in the public interest and has continued to issue long-term non-FTA authorizations for 20-year terms, even when longer terms were requested, with the exception of a conditional authorization to export LNG to non-FTA countries from Alaska. DOE said the Alaska LNG Project requested a 30-year export term, citing unique aspects of the Alaska-based project. DOE said it has not yet issued a final order in that proceeding.

New economic study

DOE said it commissioned a new economic study in 2017 from NERA Economic Consulting, which had done a 2012 economic study for the department. The new study, referred to as the 2018 LNG Export Study, like prior studies analyzed outcomes of different LNG export levels on U.S. natural gas markets and the U.S. economy.

DOE said that for the first time the 2018 study "assessed the likelihood of different levels of 'unconstrained' LNG exports, defined as market-determined levels of exports," examining 2020 through 2050 and beyond. DOE said the study was based, in part, on projections in the U.S. Energy Information Administration's Annual Energy Outlook 2017 through 2050.

DOE said it received and responded to comments on the 2018 study, and based on the record, determined that the study provides support for non-FTA applications for export volumes between 0.1 billion and 52.8 billion cubic feet per day of natural gas.

Authorizations to date

DOE said it has issued 38 final long-term authorizations to export domestically produced LNG or compressed natural gas to non-FTA countries, with a cumulative volume of 38.06 bcf per day of natural gas, 13.9 trillion cubic feet per year.

There are 18 long-term non-FTA applications pending, with a cumulative volume of 24.5 bcf per day or 8.94 tcf per year.

DOE said it has also authorized exports of 56.24 bcf per day of natural gas to FTA countries, but said the FTA and non-FTA volumes are not additive, because each order grants authority to export volumes to FTA or non-FTA countries to provide flexibility to the authorization holder to determine export destinations.

DOE cited EIA's estimate that U.S. domestic dry natural gas production for 2019 averaged 92.03 bcf per day and said U.S. LNG export capacity operating or under construction totals 15.54 bcf per day, which covers eight large scale export projects in the Lower 48.

30-year requests

DOE said authorization holders have recently indicated that a 30-year export term would better match the operational life of their LNG export facilities, allowing "more security in financing their facility and maximizing their ability to contract for exports."

DOE said LNG export terminals are typically designed for a 30 to 50-year service life.

It said the 20-year export terms in existing authorizations were based on earlier studies, but "that limitation is no longer required based on the findings of the 2018 LNG Export Study that included analysis of an expanded time period."

The extension through 2050 would not, DOE said, alter currently approved maximum daily rates of export, which are based on each facility's capacity or set by the agency approving the siting and construction — either the Federal Energy Regulatory Commission or the U.S. Maritime Administration. ●

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FINANCE & ECONOMY

RCA OKs sales agreement confidentiality

Requires supplemental filings by Feb. 18 on financial statement confidentiality from Harvest Alaska and BP Pipelines (Alaska)

By KRISTEN NELSON
Petroleum News

The Regulatory Commission of Alaska said in a Feb. 11 order that it grants the petition for confidential treatment of the purchase and sale agreement in the sale by BP of its Alaska assets to Hilcorp.

RCA is hearing issues related to the sale of BP's interest in the Milne Point Pipeline, BP's interest in the PTE Pipeline, BP's certificate of public convenience and necessity in the trans-Alaska oil pipeline and its interest in the Valdez Marine Terminal to Hilcorp Alaska's pipeline subsidiary Harvest Alaska.

The commission said the applicants cited the negotiated nature of the purchase and sale agreement to justify confidential treatment and said the applicants also noted that the purchase and sale agreement covered more than the pipeline transactions, also including terms and conditions of the entire transaction under which BP is exiting Alaska.

"We agree with the applicants that disclosure of the terms of one transaction may weaken the disclosing party's bargaining position with regard to other unrelated transactions, providing insight into the disclosing party's negotiating strategy and economic valuations of interests in oil and gas properties," RCA said. It also noted that no entity has requested access to the purchase and sale agreement.

More questions on financials

The parties also requested confidential treatment for financial statements.

RCA said it did not believe the parties had made as strong a case in requesting confidential treatment for financial statements.

While the commission has granted confidentiality to financial statements in other cases, in those cases the confidential treatment was not opposed by entities seeking public disclosure, which is the case here, RCA said. Requests that the financial statements be made public have been made on the grounds of assessing the ability of applicants to operate the trans-Alaska oil pipeline and the Valdez Marine Terminal, RCA said. And previous cases are for specific Alaska pipelines not the transfer of TAPS and the Valdez terminal, "an acquisition of assets on a much larger scale and that carries with it both greater performance expectations and increased potential financial risk should a catastrophic event occur," RCA said.

RCA said it has also previously "required a more detailed showing of potential competitive harm to justify confidential treatment."

It said the applicants have not provided "information in any level of detail and do not provide any demonstration of specific harm."

RCA is requiring applicants to supplement petitions for confidential treatment of financial statements "with a more detailed discussion of the filed information and an explanation of the specific harm that would result from disclosure of components of the financial statements."

RCA said it was also concerned about its legal ability to require disclosure of financial statements, and said it interprets state statute "to preclude us from disclosing to the general public documents related to the finances of a pipeline carrier subject to federal jurisdiction when the document is not required to be filed with a federal agency." These pipelines are subject to federal jurisdiction, "so we would be limited in our ability to disclose this information should federal agencies not require the filing."

RCA said the applicants should include in their supplemental filings "an explanation as to whether any of the submitted financial statements are required to be filed with a federal agency, and how and whether they relate to the finances or operations of the pipelines at issue."

The commission is extending the time to rule on the petitions to March 12 and requiring filings by the applicants, Harvest Alaska and BP Pipelines (Alaska), of a detailed discussion of the filed information, explanation of specific harm from disclosure and an explanation of whether any of the financial statements are required to be filed with a federal agency by Feb. 18. ●

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FURIE SALE

Nov. 20, under a bidding procedures order signed Sept. 26 by Selber Silverstein. The hearing was moved to Jan. 13, then to Jan. 27, prior to being set for the February date.

Most of the matters to heard in the omnibus hearing have been adjourned to Feb. 19 as well.

CISPRI motion moves forward

One matter went forward at the Feb. 11 hearing: A motion by Cook Inlet Spill Prevention and Response Inc. over an arbitration provision in the Uniform Time Charter Party for Off-Shore Supply and Support Services between CISPRI and the debtor.

The matter involved an allocation of fault arbitration begun prepetition in July 2019 against Furie, due to the injury of a CISPRI employee on Furie's gas production platform.

Selber Silverstein issued CISPRI's requested Order Granting Relief from the Automatic Stay to Continue the Pending Arbitration, with conditions.

"For today's purposes, what I'm going to do is grant relief from the stay so that the arbitrator can decide the issues that are fully briefed in front of him or her, and I'm going to hold this motion open with respect to the remainder of the relief for a period of 75 days, and then we'll revisit it," Selber Silverstein said in issuing the order.

—STEVE SUTHERLIN

STATE OF ALASKA

Major Recent Brookian Discoveries

	Smith Bay	Willow + West Willow	Pikka-Horseshoe/Narwhal
Operator(s)	Caelus	ConocoPhillips	Oil Search/ConocoPhillips
Reservoir Formation	Torok Fm	Nanushuk Fm	Nanushuk Fm
Penetrations to date	2	7	12
Location	State Waters Offshore of NPRA	Federal Onshore Northeast NPRA	Onshore Colville Delta
Road/Pipeline Tie-in	~ 125 miles	~ 28 miles	~ 20 miles
Trap type	Turbidite Stratigraphic	Topset Stratigraphic	Topset Stratigraphic
Net Pay	183-223 ft	42-72 ft	< 225 ft
Oil Gravity	40-45 degree API (calc)	41-44 degree API	30 degree API
Test Rate	No Flow Tests	< 3,200 bopd vertical	~ 2,100 bopd vertical; 4,600 bopd horizontal
Contingent Recoverable Resource	1.8-2.4 BBO (est)	400-750 MMBO	1.15-1.4 BBO*
Expected Production (Operator Releases)	< 200,000 bopd	100,000 bopd	< 250,000 bopd

* Oil Search estimates assume 2019 delineation drilling successful; moves some 3C resource to 2C (P50) resource category. 2

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FEIGE AT NAPE

125 square miles of reservoir. … On Alaska's North Slope it's the accuracy of those drill targets that matters. It's the play type that matters. … In the last 5 years we have seen three Brookian oil discoveries all in excess of 1 billion barrels of resource," she pointed out in a Prospector's Presentation and at the state's booth.

Feige told attendees that the North Slope Brookian Nanushuk and Torok discoveries of recent years represent an unmatched shallow, onshore, conventional opportunity: "These are not discrete stratigraphic trap accumulations. These are laterally extensive stratigraphic trends that run for miles. In the case of the Nanushuk-Horseshoe trend, it exceeds 40 miles in length."

Project timelines stay on track

"The second big myth is everybody will tell you, is that Alaska's regulatory environment is too complex and unpredictable," Feige said. "In fact, Alaska's regulatory environment is robust, science-based and transparent."

"The Department of Natural Resources houses the Office of Project Management and Permitting," she told NAPE attendees "which exists to help coordinate federal and state permits and assist project developers in navigating the permitting process," in particular federal permits that do not have timelines associated with them.

"We can help make sure project timelines don't drag. Somebody must stay at the table to keep their finger on the pulse to make sure things keep moving. And so being able to provide the services that OPMP provides can take a lot of that regulatory risk out of the picture," Feige said.

"OPMP also ensures that the State of Alaska has a seat at the table in discussions regarding developments within Alaska and any federal action that may impact them. No one takes better care of Alaska than Alaskans and we have been leading the world in environmentally sensitive arctic oil and gas development for more than 40 years. That kind of experience doesn't add regulatory risk it reduces regulatory risk," Feige said.

As a result of streamlined permitting and "with 3D seismic and all the well data that's available through DNR you can really get your feet on the ground and get moving a lot quicker than you used to in Alaska and that is part of our renaissance," she said.

A little known asset

One thing that the State of Alaska, specifically DNR's Geologic Materials Center, part of the Division of Geological and Geophysical Surveys, can offer companies is easy access to publicly available well core samples, drill cuttings, log data, well history files, geologic data and modern 3D and 2D seismic data they can purchase.

Many of the firms Feige talked to had no idea the information was available.

"As a part of being 'open for business' in the modern oil and gas industry, driven by big data and machine learning, the State of Alaska offers an extensive collection of publicly available information. … The Geologic Materials Center functions as a clearing-house for all of this data, housing data and samples from more than 3,000 wells, over 3,000 square miles of modern 3D seismic data and nearly 1,300 line miles of 2D data," she said.

The agency has "the technical personnel with expertise to help companies find what they're looking for; the GMC is truly a unique facility designed to help jumpstart exploration programs."

Conventionals back in the mix

As mentioned in the "Shift to conventional" story in this issue about NAPE and the oil companies that were marketing Alaska prospects or looking for partners there, Feige said she took away from NAPE this year "a different tone than in the past where the shale craze has been the story."

Technologically the shale industry has "hit that next barrier … their wells are in decline so there's some challenges for them right now."

"Companies are looking for ways to balance their portfolios … to get conventionals back in the mix … and Alaska's North Slope has an abundance of those — shallow and onshore," Feige said she repeatedly told attendees.

"That shift in thinking we saw coming. We first saw it last year at CERA Week, evidence companies were interested in balancing their portfolios away from shale, and adding conventional oil," she said.

Another "kernel" Feige took away from NAPE has also been developing for some time and that is Lower 48 refineries "needing a good source of heavy and viscous crude. We have over a 100 million barrels of it."

Interacted with small to large companies

When asked who she talked to at NAPE, Feige named a large number of company officials, from small independents such as Jim White of Alaskan Crude, to Bill Armstrong and his team, representing mid-sized independents, to the people manning ConocoPhillips' booth.

"Bill Armstrong was there with Nate Lowe, Ed Teng and members of his team. They're very bullish … about exploration both in NPR-A, as well as the Lagniappe piece over on the east side of the North Slope. They've been more excited about the G&G work they've been doing over the last year or so than I've ever seen them, so from an exploration standpoint that's going to be

see **FEIGE AT NAPE** *page 11*

EXPLORATION & PRODUCTION

US drilling rig count holds steady at 790

Baker Hughes reports the number of rigs drilling for oil and natural gas in the U.S. the week ending Feb. 7 is unchanged from the previous week at 790. The count is down by 259 from 1,049 a year ago.

In its weekly rig count the Houston oilfield services company said 676 rigs targeted oil, up one from the previous week and down 178 from a year ago, while 111 targeted natural gas, down one from the previous week and down 84 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 46 of the holes were directional, 711 were horizontal and 33 were vertical.

The company said 46 of the holes were directional, 711 were horizontal and 33 were vertical.

The New Mexico rig count was up by three from the previous week.

Alaska and Utah were each up by one rig.

Rig counts were unchanged from the previous week in California, Colorado, Louisiana, North Dakota, Ohio, Pennsylvania and Wyoming.

Texas, which at 394 has the largest number of active rigs in the country, was down by one rig from the previous week, as was West Virginia.

Oklahoma was down by three rigs.

Baker Hughes shows Alaska with 10 rigs active for the week ending Feb. 7, down one from a year ago.

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

January's international rig count

On Feb. 7 Baker Hughes released the international rig count for January. The company said the average international count (excluding North America) was 1,078, down 26 from 1,104 in December and up 54 from 1,024 in January 2019. Active land rigs totaled 833 in January; offshore rigs totaled 245.

The average U.S. rig count for January was 791, Baker Hughes said, down 13 from 804 in December and down 274 from 1,065 in January 2019. The average Canadian rig count for January was 204, up 69 from 135 in December and up 28 from 176 in January 2019.

The average worldwide count — international and North American combined — was 2,073 in January, up 30 from 2,043 in December and down 192 from 2,265 in January 2019.

—KRISTEN NELSON

EXPLORATION & PRODUCTION

New work at Milne Point I Pad approved

On Feb. 10 Alaska's Division of Oil and Gas approved Hilcorp's Alaska's plan of operations amendment request to install infrastructure and utilities to bring additional power to I Pad in the Milne Point unit.

The work is being done in anticipation of developing additional production and wells.

The project includes building an ice pad and trenching in tundra through it.

The project includes building an ice pad and trenching in tundra through it. The trench will be 8 inches wide and 4 feet deep and will extend from the tundra onto I Pad.

Also, a new cable will be installed in the trench connecting existing power pole MP-135C to the new electronic submersible pump, or ESP, electrical module on I Pad. The existing buried power line for the pad will be located using a "hot water wash and supersucker," the division said.

The trench will be backfilled with excavated material and monitored for rehabilitation.

The infrastructure includes one ESP electrical module, one transformer platform, one switch compartment module and one test separator module.

—KAY CASHMAN

FACILITIES

US DOT announces $20 million Port of Alaska grant

The U.S. Department of Transportation announced a $20 million grant to the Port of Alaska Feb. 11, as part of its Port Infrastructure Development Program.

The grant comes on the heels of a $25 million grant to the port from the federal "Better Utilizing Investments to Leverage Development Transportation Discretionary Grants program," to build the third and final phase of an upgrade to its petroleum products and cement handling facilities.

A spike in tariffs for petroleum and cement at the Port of Alaska began Jan. 1, as established by an Anchorage ordinance unanimously passed Dec. 17. The rates are designed to partially fund construction of the new $200 million petroleum and cement terminal. Terminal users have expressed concerns about the design and the process, as well as the significant tariff increases to users — which will impact customers of the affected products that land at the port.

While helpful to defray construction costs, which are yet to be fully determined, it is uncertain whether the $20 million will provide tariff relief.

"When they came up with the number for the tariff increase, that assumed that we would get some grants and some favorable loan packages that would reduce the amount of the total project cost," Jim Jager, director of external affairs for the port told Petroleum News in November. "At some level, it was already cooked into the plan that the Port Commission has for how we're going to pay for the new docks."

The second phase of the terminal involving the trestle and deck, is to be built in 2020.

In 2021, the goal will be "to put in the mooring dolphins, and all of the fendering, and then all of the infrastructure on top of the deck that makes it useful — things like the pipes, the cement and fuel offloading systems, and equipment," Jager said. "That work is what the tariff increase would pay for."

—STEVE SUTHERLIN

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PLACER POD

ground studies this winter she said.

In mid-December AEX applied for a permit with the Corps of Engineers for work in waters of the United States, specifically involving the Miluveach River, with the possible result of connecting Placer to the nearby Mustang field.

In its 30-day public notice, AEX described a project near the village of Nuiqsut, proposing a gravel road to a drilling pad.

AEX President Teresa Imm told Petroleum News in a May 28 interview that the company is open to selling all or part of the field.

The road would originate from the existing gravel road between the Mustang pad and the Mustang gravel pit. Located 45 miles west of Deadhorse, Mustang is road accessible via the Spine Road.

The company plans to "develop oil within the Kuparuk C reservoir, contained within the Placer unit," the public notice said.

AEX would discharge approximately 68,000 cubic yards of gravel for a five-foot high seven-acre gravel pad. The top width is variable between 250 and 400 feet, the bottom width is 270 to 420 feet, and overall length is 1,000 feet.

The total footprint of the single-pad Placer project would be 45.5 acres.

Approximately 325,000 cubic yards of gravel will go into the 24-foot wide seven-mile access road.

The road will have a 37-acre footprint.

The crux of the problem

According to AEX's filings with the division: The Placer unit cannot support its own standalone processing facility and is 100% owned by AEX, whereas most North Slope oil fields are explored and developed with partners that help shoulder the costs and risks.

For the division, the issue was the length of time it was taking AEX to get its state leases into production.

The parties have been in negotiations for some time.

The Placer unit had been terminated by the division in July, but in a subsequent emailed statement Feige said "ASRC Exploration LLC and the Department of Natural Resources continue to work closely together to move the Placer unit forward into development and, ultimately, production. We are hopeful to resolve soon."

Placer put up for sale in 2019

AEX President Teresa Imm told Petroleum News in a May 28 interview that the company is open to selling all or part of the field.

It's possible a transaction has taken place, which could account for revived activity on the project, but the company has not announced whether it has made a deal or not.

The 8,768-acre unit could have 110 million barrels of original oil in place, with between 35 million and 45 million barrels of oil recoverable across all horizons, according to an offering by Detring Energy Advisors of Houston, Texas.

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

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

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

Placer is a neighbor of ConocoPhillips' Kuparuk River oil field on the east, and it borders the Oil Search-operated Pikka unit on the west. Pikka is scheduled to come online in 2022 with 30,000 barrels of oil processed in a neighboring company's facility and then in 2024 with its own 120,000 barrel a day facility.

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

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

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CAPEX GAIN

That is expected to generate a rise in overall upstream investment to C$37 billion, which, regardless of the modest oil sands turnaround, is still far from the C$81 billion posted in 2014 (when oil sands outlay was C$33.9 billion).

However, Tim McMillan, chief executive officer of CAPP, praised some "hard work" by the Alberta government of Premier Jason Kenney to "put Canada back in a position where it can start to attract appropriate levels of capital again."

Energy Minister Sonya Savage said the lowering of corporate taxes to 10% this year from 12% and a scheduled further reduction to 8% in 2022, sends out a message that "Alberta is open for business and results (like the gain in capital spending) proves our plan is working."

CAPP said there is cautious optimism that badly needed pipeline expansions — Enbridge's Line 3 and Keystone XL — will improve access from Alberta to U.S. refineries, ending years of delay.

Cenovus Chief Executive Officer Alex Pourbaix said his company expects to make a final investment decision later this year on two "significant" expansion phases at its oil sands operations.

The Petroleum Services Association of Canada, PSAC, has joined the upbeat mood, raising its 2020 target for well completions across Canada to 4,800 wells, up 7% from 2019, although overall drilling activity this year is forecast to dip by 2%. It estimates 2,460 wells will be drilled in Alberta, an improvement of 14% from its original target.

"On a positive note, three major oil sands companies are planning higher activity this year with some production quotas relaxed," said PSAC President Gary Mar, although he noted that many upstream companies have made a strong start to 2020 because of work deferred from the fourth quarter of 2019, adding that will not translate into increased activity for the rest of 2020.

Commenting on the widening gap between West Texas Intermediate and Western Canadian Select heavy oil prices, Peter Tertzakian, executive director at the ARC Energy Research Institute, said that a combination of US$50 for WTI and US$20 for WCS represents a "danger zone for companies."

RS Energy Group Vice President Al Salazar told the Calgary Herald the spread of coronavirus could lower oil consumption in China by 300,000 bpd in the first quarter, adding it is less clear what the impact could be on global consumption.

He said the snowball effect of drastic cuts in air travel and the "fear factor" could accelerate the trend.

Surge Energy Chief Executive Officer Paul Colborne said his company has already deferred drilling five wells and about C$6 million of capital spending until later this year.

"We're already adapting to WTI prices dropping because if you don't adapt you will run up your debt," he said. "We can wait and see if crude bounces back."

—GARY PARK

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NAPE SUMMIT

Long-time Alaska lease speculators Dan Donkel and Sam Cade also had a booth touting their eastern North Slope prospects that adjoin the ANWR 1002 area.

While ConocoPhillips was reportedly looking for a North Slope exploration and development farm-in partner to take a 15% interest in some of its prospects, companies such as Malamute with the untapped Umiat oil field south of ConocoPhillips giant Willow discovery, were open to farm-ins or outright purchases.

Hilcorp was reportedly looking for partners for Lower Cook Inlet exploration. On hand at its booth were four geoscientists and landmen knowledgeable about those opportunities: Kevin Tabler, Jim Shine, Dave Boothman and Steve Dietz.

Alaskan Crude: fee simple mineral interests

Jim White, who owns both Alaskan Crude and Wolfpack Land Co., had information at his booth about several thousand acres of onshore land for lease near Kenai, Alaska, in the Cook Inlet basin.

Wolfpack is offering the fee simple mineral interest land at $3,000 per acre, with a 25% overriding royalty.

"These fee mineral rights have significant known hydrocarbons on or very near them," the company said in an advertisement, adding seismic data is available and that the prospect is road accessible, winter and summer, with easy access to oilfield suppliers.

In an interview about NAPE, White was quick to point out how unusual it was for an individual to own fee simple mineral interest land in Alaska.

"Ninety-eight percent of Texas is owned by Texans. Alaska is just the opposite," he said, except for land owned by Native regional and village corporations.

"In Texas, you make a deal with individual farmers, not the state or federal government. All those farmers get a 25% royalty on the oil and gas produced from their land. … Sixty years after statehood not a single Alaskan or an Alaskan-owned company has an oil and gas field in the state."

While White was pleased with the traffic his booth and prospects attracted, this year's NAPE confirmed his observation that the oil and gas prospect market "has changed a lot over the last five years. Today people are increasingly strapped for cash."

Armstrong on oil rally

Bill Armstrong attended NAPE and made the rounds of the booths marketing Alaska prospects. Credited with starting the revival of North Slope exploration by finding oil reservoirs such as the Nanushuk that had been missed or ignored by previous explorers, he said "NAPE … is a great place to get together annually with everyone in the business. This year was 'busy' but the energy level at the conference was at an all-time low. Low oil prices, even lower gas prices, has everyone hunkered down. I think we may be in for a bit of a slow slog. … Oil prices have

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TRANSMOUNTAIN

Nations), but at the same time accommodation cannot be dictated by Indigenous groups."

The three-person court, which halted work on TMX in 2018, citing at the time insufficient consultation between the Canadian government (which owns TMX) and Indigenous communities, said in its fresh judgment that the government's latest attempt at reconciliation was "anything but a rubber-stamping exercise."

Kenney lauds finding

The court's finding was lauded by Alberta Premier Jason Kenney, whose government desperately needs the chance to ship 890,000 barrels per day of oil sands bitumen on TMX to Asia, as "historic and critical," reinforcing a recent string of court and regulatory decisions that have supported major pipeline projects.

"It's a great day for Canada because it demonstrates that the vast majority of Indigenous groups (the court estimated that 120 of 129 First Nations have endorsed TMX) will not have their voices ignored. It demonstrates that we do have a rule of law ... that big projects can be completed."

Kenney said TMX will "result in billions of dollars of economic prosperity for Canada."

British Columbia Premier John Horgan, once the most outspoken opponent of TMX, said "the courts have determined that the project is legitimate and should proceed."

Canada's Natural Resources Minister Seamus O'Reagan said the court decision was a result of the "most comprehensive consultation (between government and First Nations) ever undertaken for a major project in our history."

Tim McMillan, president of the Canadian Association of Petroleum Producers, said the sudden series of court breakthroughs for pipeline projects are "really adding momentum collectively."

Chris Bloomer, chief executive officer of the Canadian Energy Pipeline Association, said Canada's pipelines saga has a pattern of "going three steps forward, two steps back, two steps forward, one step back. (The TMX ruling) is many steps forward."

As the legal barriers have been lowered, after seven years of being dragged through litigation, construction has resumed on the pipeline, with more than 2,200 workers now involved in the project, raising some hopes that TMX can start delivering bitumen to the Port of Vancouver by late 2022, two years behind the original schedule.

Decision to be appealed

But, with the champagne going flat from the initial celebration, the proponents had to take a dose of reality.

The four First Nations have indicated they will apply for a hearing before the Supreme Court of Canada, while the Canada Energy Regulator (formerly the National Energy Board) is laying the groundwork for what could be a massive round of permit hearings to determine the unresolved 32% of the final pipeline route, which will include concerns of one First Nation about the possible impact on its aquifer.

Will George, a spokesman for the Tsleil-Waututh Nation, left no doubt his community and supporters across Canada will carry their fight to the limit.

"For the longest time, I've been under strict orders from my elders to (conduct this protest) in a peaceful way," he said. "Personally, I'm fed up. If it has to get ugly, it will get ugly."

Opposing projects

The Squamish Nation, just outside Metropolitan Vancouver, has put out a call for British Columbia residents willing to face arrest by staging protests against oil tankers in the Port of Vancouver that are expected to total about 54 a month if TMX is completed.

But critics note that the same nation has signed an agreement with partners in the Woodfibre LNG project north of Vancouver that is valued at C$1.1 million in cash and land, plus about 2,000 part-time and full-time jobs.

It took no time for opponents of TMX to send out a clear signal of their intentions, as supporters disrupted operations at Vancouver's main seaport and brought all passenger and freight rail traffic to a halt in Canada's major population triangle of Toronto, Montreal and Ottawa.

Meanwhile, at least 11 protesters were arrested by the Royal Canadian Mounted Police for ignoring an injunction against setting up blockades along the Coastal GasLink pipeline route, designed to ship natural gas to the LNG Canada liquefaction plant and tanker terminal at Kitimat, on the northern British Columbia coast.

"Our work is not done," said Chief Leah George-Wilson of the Tseil-Waututh Nation, declaring that the TMX ruling "isn't going to define us or stop us."

New cost estimate

Compounding that threat was a startling announcement by Trans Mountain Corp., the federal agency that has control of TMX, that the expansion will cost C$12.6 billion (on top of the C$4.5 billion the government spent acquiring the existing Trans Mountain system), up 70% in the past two years.

However, Finance Minister Bill Morneau was adamant that TMX "continues to be a strong project" and is within the range of a "commercially viable" venture, noting that TMX has already contracted 80% of its capacity.

Ian Anderson, chief executive officer of Trans Mountain, said the corporation has a contingency of C$500 million to cover additional costs and delays, including protests and civil disobedience.

He blamed the surge in cost estimates on delays (with every addition of one year to the timetable adding C$1 billion to the total), plus higher prices for materials and changes to the project.

—GARY PARK

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SEAWATER INJECTION

for Prudhoe Bay depletion planning, and reservoir engineer Gerrit Verbeek testified to the commission Jan. 21 on the application for what the company calls the Sea Water Optimization Plan, SWOP.

BP applied to make the change in December (see story in Dec. 29 issue of Petroleum News) and Paskvan said the testimony was to provide additional context for the application package.

SWOP benefits

BP itemized benefits of SWOP: expanding more efficient gas-based recovery mechanisms into Prudhoe waterflood areas in the drill sites 1 and 12 region; reducing waterflood impacts on the gravity drainage waterflood interaction boundary region; increasing fieldwide pressure by 50 psi over the life of the field; reducing injection management support work; will cause shut-in of Put River southern lobe, which is supported by a drill site 1 water injector; benefit is 20 million barrel oil recovery increase, result of 21 million gain from SWOP less 1 million from Put River southern lobe.

Gravity drainage

Gravity drainage, Paskvan told the commission, is at the heart of Prudhoe, with waterflood and miscible gas projects at the periphery, the boundary between them the gravity drainage waterflood interaction area, GDWFI, and the gas cap at the crest of the structure.

The SWOP area, primarily drill sites 1 and 12, is in southeastern portion of the field.

Seawater is injected at drill sites 1 and 12 and some at drill site 4, Paskvan said. All other injection is produced water because starting with seawater, produced water comes back, so other than those specific drill sites all the others in the Prudhoe Oil Pool are injecting produced water or miscible gas.

He said seawater diverted from drill sites 1 and 12 would go to the East Dock gas cap water injection project, also known as the pressure support initiative, which has been maintaining reservoir pressure at the field since 2002.

Gas-based recovery mechanisms are more efficient than waterflood, Paskvan said, and SWOP would reduce impacts of waterflood on the gravity drainage area because Prudhoe is a highly permeable reservoir and some of the injected water moves into the gravity drainage area.

Recovery mechanisms

Verbeek said original oil in place at Prudhoe was some 25 billion barrels, with 24 trillion cubic feet of free gas and an additional volume of some 16 tcf of gas in solution.

The current depletion plan attempts to keep the boundaries of the GDWFI stable, Verbeek said, which has resulted in a total field recovery of 50%, with 43% recovery from waterflood with miscible gas injection and 53% from gravity drainage supplemented with lean gas vaporization enhanced oil recovery.

Those differences in recovery are not driven by differences in investment or development history, he said, but occurred because gas is more efficient than water as a displacement mechanism for oil.

The core of the SWOP proposal, Verbeek said, is to remove the push from waterflood that is resisting gas moving down from the north, permitting gravity drainage to expand into the GDWFI area to allow gas-based recovery, the more efficient mechanism, to move into that area of the field.

Gas projects

Prudhoe production began with gravity drain gas cycling, Verbeek said. Then the central gas facility was built in 1986, enabling miscible injectant enhanced oil recovery in the waterflood area and

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FEIGE AT NAPE

exciting to watch," she said.

The commissioner also spent time at Hilcorp's booth, discussing both Cook Inlet and the North Slope.

"We talked about as cold as this winter has been they have been producing all out so they're very excited about new Cook Inlet gas prospects," as well as "the new prospects they have down in the southern waters in Lower Cook Inlet," Feige said, noting Hilcorp officials are "feeling very bullish about both oil and gas down there. They were actively talking to people visiting their booth about it," confirming what other visitors to the Hilcorp booth said about the company seeking a partner(s) for the area.

The commissioner also spent time "chatting with the guys from the Australian contingent. … They seem to find themselves in a somewhat similar position to Alaska, and they like working up here. We've seen an influx of Australian companies (Oil Search, XCD Energy, etc.). They're comfortable working in the regulatory environment here. They appreciate that we've got seasonal limitations — in many parts of Australia you have to avoid the heat. … They, too, have a fairly small population," Feige said, noting the Australians she spoke with were enthusiastic about Alaska "and what Alaska can mean for their operating companies."

She also made the rounds visiting with companies at their booths and asking them, "have you considered Alaska. I know you're rounding out your portfolio and you're beginning to think more about conventionals; I'd love to talk to you about Alaska." Feige said many company officials were receptive to learning more about the state's oil business.

Feige said her team was also very active at the conference. They included DNR Deputy Commissioner Sara Longan, Division Director Tom Stokes, Division Deputy Director Jason Black, resource evaluation chief Kevin Frank, and other support personnel such as geoscientists and a commercial analyst/engineer.

"We had a really good team and got lots of questions," she said.

'Where companies are made'

"It's always good to go to NAPE and get a sense of the tone of the domestic industry. What I've always come away with is a better way to pitch Alaska," the commissioner said.

"Alaska offers some really unique aspects … that no shale basin will ever give you and that no Lower 48 play is going to give you either. We have a great story to tell here; we just can't be bashful about it."

The State of Alaska as landowner-lessor "offers competitive lease terms, standard royalty rates, and large land tracts available for exploration and development," Feige said. "This is not just where wells are drilled, this is where companies are made." ●

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SEAWATER INJECTION

enabling natural gas liquids production and lean gas vaporization.

The 1990s saw a series of gas handling expansions and an MI expansion, and more recently rich gas liquids have been targeted — focused on finding areas where gas has not been cycled that still have original condensate and gas liquids, he said.

Pattern waterflood was begun in 1981 and gas cap water injection — the seawater supplemental volume injection — in 2003.

Field wide pressure is now held constant at about 3,300 pounds per square inch from an initial pressure of 4,420 psi, Verbeek said.

Data from bottomhole pressures throughout the field fall primarily within a band of plus or minus 75 psi, he said, showing how connected Prudhoe is, and with high permeability and a lack of significant internal flow barriers, that allows pressure support for the field from somewhat remote areas.

Verbeek said it's another piece of evidence providing confidence that if pattern waterflood ceases at drill sites 1 and 12, and that seawater is injected miles away in the gas cap, there is enough connectivity at Prudhoe to provide pressure support between the areas, allowing the advantage of improved gas recovery mechanisms without pressure decline in the region.

The original estimate for ultimate recovery was 9.6 billion barrels and ongoing projects, with SWOP proposed as the next, have increased estimated ultimate recovery to more than 14 billion barrels, with some 12.5 billion recovered, 50% of the 25 billion barrels of original oil in place.

Verbeek said ultimate recovery estimates are based on a cessation of production date of roughly 2060, and Paskvan noted that the estimates are based on business environment factors such as the future oil price and cost of operations and said the 14 billion is an estimate of ultimate recovery.

Mature processes

Verbeek said both waterflood and gravity drainage are reaching maturity. Switching a waterflood area to gravity drainage provides opportunity for more production because residual oil saturation can be driven lower, he said.

He told the commission that gravity drainage results in residual oil saturation of roughly 20%, whereas waterflood has a residual oil saturation of roughly 28%. Each of the mechanisms has an associated enhanced oil recovery mechanism, with gravity drainage supplemented by oil vaporization by lean gas cycling.

The recovery mechanism at Prudhoe is somewhat unique because it was enabled by the installation of the central gas facility and by the fact that gas wasn't exported, which

The recovery mechanism at Prudhoe is somewhat unique because it was enabled by the installation of the central gas facility and by the fact that gas wasn't exported, which isn't typical at many oil fields, Verbeek said.

isn't typical at many oil fields, Verbeek said. Waterflood is supplemented with miscible gas injection, also enabled by the CGF, but miscible gas injection is limited by supply volume and the scale of Prudhoe.

After almost 30 years of operating a miscible water-alternating-gas project, we've reached the saturations we have today, he said.

Gas processes

Prudhoe is increasingly dependent on gas processes, Verbeek said, and BP is increasingly seeking to exploit gas processes to drive ultimate recovery.

Prudhoe processes and reinjects some 6 billion cubic feet per day of dry, lean gas after it has been stripped of condensates, NGLs and miscible injectant. At surface conditions that gas is the equivalent of roughly 50 million barrels per day.

The CGF enables production of dry gas and when that is reinjected, some of the lighter hydrocarbon ends such as propane and butane are drawn into the gas, Verbeek said — and while the gas becomes heavier, it remains mobile compared to residual oil. That lean gas travels through the reservoir and comes back up the wellbore and is cycled through the CGF where the lighter hydrocarbon ends are stripped out.

Lean gas as an EOR mechanism recovers condensate and NGLs, he said.

The typical API gravities for Prudhoe were 26 degree API black oil from 1977 until the mid-1980s. After the CGF was constructed Prudhoe was producing miscible injectant EOR oil, where MI injectants draw lighter hydrocarbon ends into the oil, so shipped API gravity started creeping up and in the late 1990s was about 36 degrees API, he said.

For reference, Verbeek said, the lubricant WD-40, has an API gravity of roughly 40 to 42.

Prudhoe is thought of as a black oil field, as a conventional light oil field, he said, but what's being shipped down the trans-Alaska oil pipeline today is approaching WD-40.

After the rich oil projects started in 2012, Verbeek said, Prudhoe is roughly 39 degrees API.

Paskvan noted that on the slides BP presented, for the total life of field recovery, 78% is black oil and 22% comes from the gas phase, whereas for the remaining recovery, 35% is black oil and 65% is from the gas phase. He said because the black oil component is currently only about a third of current output, they've started using the term sales liquids rather than oil sales.

The total life of field recovery, with 78% black oil, is split out between waterflood and gravity drainage and GDWFI, Verbeek said. The 22% is from vaporization EOR, NGL production and MI production. He said MI comes up the wellbore in the form of oil but since that's only due to the CGF and gas processes, it's considered a gas-based recovery.

For remaining recovery, two-thirds is from the gas phase — lean gas vaporization, NGL production, targeting rich gas, and expanding that gas phase recovery is what SWOP is about, Verbeek said.

Recovery rates

Addressing the issue of Prudhoe's level of recovery, Paskvan said global recovery factors for fields have historically been around 15% but that includes a large number of small oil fields with just natural depletion, no reinjection.

With modern oil field techniques, 30 to 40% recovery is typical, he said, and Prudhoe is projected to get about 60% recovery.

Discussing SWOP benefits, Verbeek said some 9.4 million barrels are projected to come from the immediate SWOP area, with an additional 11.3 million barrels field-wide because of a 50 psi reservoir pressure increase, for a total of some 21 million barrels. The goal with SWOP, he said, is to shift the GDWFI boundary south, reducing the waterflood area and allowing the gas recovery mechanism from the gravity drainage region to move into the areas of drill sites 1 and 12.

Since the same volume of water is being injected, but now into the gas cap, less water is produced up the wellbore because it's being reinjected farther from producers, with a roughly 50 psi reservoir pressure increase because volume is maintained inside the reservoir. Injected at drill sites 1 and 12, water is only some 1,500 feet from a producer, quickly cycles through and has to be treated at the surface, whereas water injected into the gas cap stays in the reservoir, he said.

Verbeek said SWOP reflects a shift from waterflood to gravity drainage and also reflects that treating Prudhoe as a gas field yields higher net recovery.

He said oil rate is expected to increase by 1,000 to 2,000 bpd through the life of the project and water rate is expected to decrease by some 20,000 bpd until 2045 — when the additional water injected into the gas cap begins to make its way back through the field.

The Put River southern lobe would be shut-in with SWOP, Verbeek said, for a total loss of some 1 million barrels, but a separate project to restore pressure support for that area is being evaluated, so that volume is deferred, not lost.

With the gain of some 21 million barrels, overall, and the deferral of some 1 million barrels at the Put River southern lobe, the net gain from SWOP would be 20 million barrels.

The drill site targets

Verbeek said drill sites 1 and 12 were targeted because they are on the seawater injection system and it was technically and financially simple to cease water injection there and direct that volume of water to the gas cap injection.

He said SWOP reduces waterflood impacts on gravity drainage and waterflood interaction boundary and allows that boundary to shift south allowing gas-based recovery mechanisms at drill sites 1 and 12.

Field-wide pressure is increased by 50 psi over the life of the field, benefiting the entire field.

As to why BP is proposing this project now, Paskvan said waterflood was essential to maintain reservoir pressure and when waterflood was begun they didn't have the geological information necessary to move forward with the gas cap water injection project. Since that project came online in 2003 there is much greater confidence that the gas cap water injection project is viable, he said.

There has also been data collected and evaluated on vaporization that wasn't available earlier.

Paskvan said at Prudhoe they've been learning more about the depletion mechanisms and technology and improving understanding of the reservoir over time, allowing major project investments to be made.

The Prudhoe waterflood is very mature, he said, with 90% plus water cuts on the margin. With deeper understanding and the gas cap water injection project in place, SWOP is a natural next step for the field.

And just because waterflood will stop at drill sites 1 and 12, there are still tons of mobile water in the reservoir, Paskvan said, it's just that the water will be driven by an encroaching gas boundary.

Addressing the impact that diverting more water to the gas cap might have on recoverable gas reserves, Verbeek said gas sales were considered and SWOP would not impact gas recovery in a major gas sale.

Paskvan said analysis indicates that seawater injection into the gas cap displaces gas from the area, mobilizing it and making it available for gas sales. The concept development for a major gas sale would have seawater injection cease concurrently with the start of a major gas sale, he said. The field would start depressuring, dropping the psi toward 1,500 psi and doubling the gas volume as it is produced.

In general, he said, gas cap water injection increases the amount of gas available for a gas sales project.

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NAPE SUMMIT

been down since 2014. I think they may be down for another 18-24 months. But who knows?”

Regarding the Lower 48 oil industry having “gone all in for unconventional/shale oil,” Armstrong said “that game is financially challenged even with good oil prices. So, this could be a scary time for lots of payers. But here is a fact: The world is consuming way more oil than the industry is finding, an untenable situation. Things are setting up for a significant and long-term rally in oil. Gas? Hmmm, not so much” as there’s “way too much supply worldwide.”

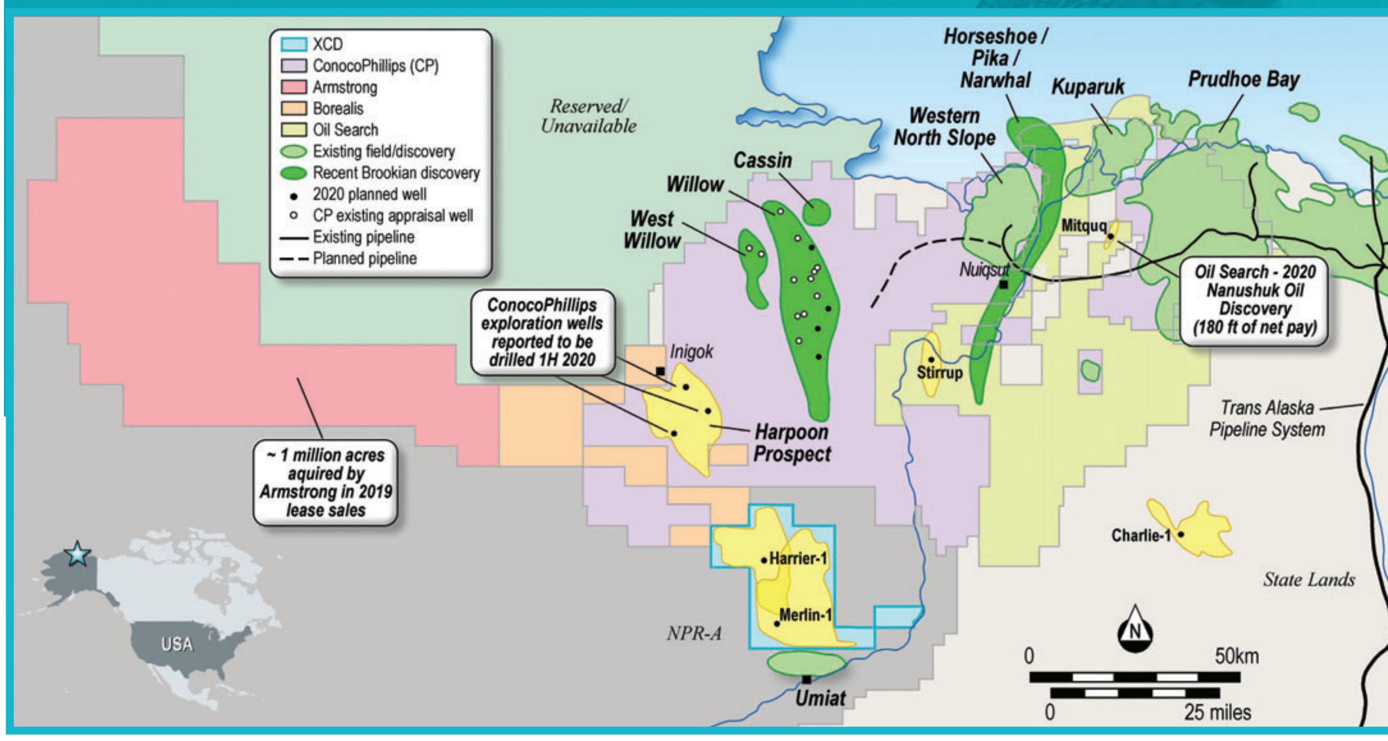
Donkel, Cade next to ANWR

Donkel and Cade hold two primary groups of leases, one north of ExxonMobil’s Point Thomson producing unit and another east of Point Thomson, commonly known as the Stinson prospect, which is north and offshore the ANWR 1002 area and surrounds the Stinson No. 1 oil discovery well drilled by ARCO in 1989.

The well is on a lease held by Andrew Bachner and Keith Forsgren.

“I think Dan is looking to sell the Point Thomson and Stinson leases for $20-$25 million with a work commitment of 3D seismic around Stinson and north of Flaxman Island and north of Challenge Island and over Tracts 79 and 80, and to drill two wells — one near Stinson and one on Tract 79 or Tract 80. … As always, the deal is negotiable to some degree,” Bill Van Dyke told Petroleum News Feb. 11. A petroleum engineer, and a former director of Alaska’s Division of Oil and Ga, Van Dyke represented Donkel and Cade at NAPE.

Nanushuk Play Activity on the Alaskan North Slope



XCD ENERGY

Donkel said he is also asking for an overrising royalty of one-quarter of 1% and that Cade wants three-quarters of 1%.

Former BP Prudhoe Bay geophysicist Monte Mabry, another one of several experts staffing the Donkel booth, said in an email that the “proposed E. Pt. Thompson 3D seismic survey would be acquired using an ultra-high density data system optimized to define stratigraphic traps. The survey area would extend over leases offshore the Point Thompson field and also encompass additional near shore leases which directly adjoin the high potential ANWR 1002 area. The survey area, as planned, is approximately 350 sq. miles.”

Very pleased with the turnout at NAPE this year, Donkel said the same leases he is offering “sold for $150 million back in the 90s.”

Bachner and Forsgren are asking $1.75 million for the Stinson well lease, “retaining a 3.33 ORRI, but we are always open to consider any reasonable offer,” Bachner said.

Malamute, lots of ‘good conversations’

Malamute President Leonard Sojka said the folks at the Minnesota independent’s booth “had a lot of good conversations with potentially interested parties” at the conference.

“The traffic through Malamute’s NAPE booth was very steady on Thursday, as is typical. We also thought that the traffic was more diverse, in the sense of interest from investors not already in Alaska,” he noted.

The company was touting its Umiat unit on the southeastern edge of the National Petroleum Reserve-Alaska, which not only contains a very shallow Nanushuk oil field, but possibly a deeper oil target in the northernmost of its two leases.

Malamute’s focus since acquiring Umiat in 2016 has been to de-risk technical challenges in producing the shallow field, which Ryder Scott estimated contains 2P reserves of nearly 99 million barrels of oil equivalent.

Malamute conducted a multidisciplinary reservoir workshop and extensive tests on Umiat oil and those tests, Sojka said, “confirmed that both the gasoline and the diesel fractions are low in total sulfur and have less than detectable readings for dibenzyl disulfide. That makes the Umiat oil a good candidate for producing ultra-low sulfur fuels for sale” to the North Slope market.

The company has conducted a total of three technical studies with the University of Alaska Anchorage, the first two of which are complete, with the preliminary results of the third revealed at NAPE.

A former owner of the northernmost lease said seismic suggests the oil in the permafrost at Umiat seeped from the deeper reservoir to the north.

XCD’S 1.6 billion barrels

XCD Energy launched its farm-out campaign for North Slope Project Peregrine at NAPE, keeping its pitch “as broad as possible to attract as many players — large and small — as possible,” said XCD managing director Dougal Ferguson, meaning the company will be offering both a full option to access all three onshore prospects with a mean unrisked recoverable prospective resource of 1.6 billion barrels of oil, as well as a low-cost alternative that would drill only the shallow Nanushuk play in the Merlin and Harrier prospects, which contain approximately two-thirds of Peregrine’s total oil.

“NAPE went a lot better than I expected — with numerous ‘large’ companies visiting our booth to see what we had on offer. I think some of the big guys might have felt they have missed the boat a little, particularly on the Nanushuk play,” Ferguson said Feb. 10.

“I didn’t hear anything that was negative about Alaska from anyone, in fact, quite the opposite. I think everyone has gotten over the tax credit issue and are looking toward the developments in the area.” ●

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