Petroleum news

page 6 Gas hydrate: an enticing resource; Japan looks to 2025 commerciality

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This week's Mining News

NORTH OF 60 MINING news

page 8 Dominion intensifies exploration near Ekati, Diavik diamond mines

www.MiningNewsNorth.com — *The weekly mining newspaper for Alaska and Canada's North* — Week of April 23, 2017

NEWS NUGGETS

Compiled by Shane Lasley

TRILOGY METALS INC.

Trilogy Metals is collecting the final data for a prefeasibility study on developing an open-pit mine at the Arctic deposit in Northwest Alaska.

Excellent copper, zinc recoveries in clean concentrates from Arctic

Trilogy Metals Inc. April 19 said recently completed metallurgical testing demonstrates that excellent metals recoveries and clean copper and zinc concentrates can be generated from the copper-lead-zinc-gold-silver ores at Arctic, a volcanogenic massive sulfide deposit at the Upper Kobuk Mineral Projects in Northwest Alaska. During 2016, Trilogy completed four holes targeting mineralized material that is planned to be mined during the first seven years of production at Arctic. A 600-kilogram composite sample of this material was used in bench scale testing to confirm the performance of the previously defined flotation process; as well, a large volume of the sample was processed in a pilot plant to provide sufficient volumes of a copper-lead bulk concentrate to complete detailed copper and lead separation test work. Copper recoveries averaged 91.7 percent and formed a concentrate averaging 28.7 percent copper metal. Zinc recoveries averaged 87.8 percent and formed a concentrate averaging 60 percent zinc metal. The revenue stream in a 2013 preliminary economic assessment for Arctic showed that copper produced 60 percent of the revenue stream, with zinc contributing 21 percent, silver at 9 percent and gold at 6 percent. Lead was the least valuable of the metals. The bulk of the precious metals report to the zinc concentrate and further testing is being carried out to determine optimal recoveries for lead, gold and silver. Neither the zinc nor the copper concentrates contain any significant deleterious penalty metals and are considered excellent quality by world standards. "We are very pleased with the results of this metallurgical test work program at Arctic. Recoveries and concentrate grades for our two principle metals – copper and zinc are excellent. We are currently conducting additional test work to determine the optimal recoveries of our three other metals – lead, gold and silver, and will report on that work in due course," said Trilogy Metals President and CEO Rick Van Nieuwenhuyse. In addition to the metallurgical work, the company reported that the in-pit geotechnical and hydrology studies for Arctic are now completed to a level that they can be incorporated into a prefeasibility study, which is expected to be finalized in the first quarter of 2018. Roughly US$17 million has been budgeted for the 2017 program at Arctic. This work includes US$7.1 million invested into collecting the final information for the Arctic prefeasibility study and US$10 million, funded by South32 Ltd., for exploration at Bornite, a high-grade copper deposit about 16 miles south of Arctic. "The PFS will demonstrate the true value of the high-grade Arctic deposit which we expect will be the first in a series of potential mines in the Ambler mining district," said Van Nieuwenhuyse. "With the recent announcement that the BLM has initiated the permitting process on the AMDIAP (Ambler Mining District Industrial Access Road); our recently announced option agreement with South32 whereby they will fund a $10 million program at our Bornite deposit in 2017; and an upswing in demand for copper and zinc, the company is well positioned to add value for shareholders by advancing development of the Ambler mining district." ●

NANA REGIONAL CORP.

The Red Dog Mine in Northwest Alaska produced 1.29 billion pounds of zinc in 2016, accounting for nearly 5 percent of the global mine output of the galvanizing metal last year. This world class operation is, by far, the largest taxpayer to the Northwest Arctic Borough where it is located.

PUBLIC POLICY

Taxing negotiations

Teck, Northwest Arctic Borough find middle ground on Red Dog Mine taxes

By SHANE LASLEY

Mining News

After roughly two years of taxing negotiations, Teck Alaska and Northwest Arctic Borough have found middle ground on a tax structure that offers the municipality added funds to provide services to a sprawling remote borough without risking the viability of Red Dog Mine during the lows of cyclical metals markets.

Teck is the operator of Red Dog and Northwest Arctic Borough is a regional municipality that blankets 40,750 square miles of Northwest Alaska, a minerals rich expanse about the size of Kentucky.

The agreement on the table, which still needs to go before the borough assembly for a final vote, calls for Red Dog to pay around US$25 million a year into the borough. While this is roughly double what the mine has been paying in recent years, Teck believes the compromised payments in lieu of taxes structure strikes a good balance between the borough's fiscal needs and certainty for world-class zinc mine.

"We are very pleased to have reached this new agreement through discussion and cooperation between Red Dog and the Northwest Arctic Borough," Red Dog General Manager Henri Letient said in the news release. "This agreement will provide more resources for the people and communities of the region, while also supporting Red Dog's ability to stay competitive and continue generating jobs and economic activity."

More than a year later, the two sides have finally found middle ground, settling on a PILT structure that significantly increases funds going into Northwest Arctic Borough coffers while also providing certainty for the future of the Red Dog Mine.

Too far apart

Since Red Dog began production in 1989, the primary source of revenue for the Northwest Arctic Borough has come from payments in lieu of taxes paid by the mine.

These "PILT" payments are the result of agreements negotiated between the Red Dog Mine and Northwest Arctic Borough every five years. The latest negotiated agreement, which averaged roughly US$9.1 million directly to the municipality and another US$2.4 million per year to the school district, expired at the end of 2015.

In the months leading up to the expiration of the 2010 to 2015 PILT agreement, the Northwest Arctic Borough began negotiating for significantly larger payments from Red Dog for the next five years.

The two sides, however, were too far apart to find middle ground before the PILT agreement expired.

In making its case for the higher payments, the

see MINE TAXES page 8

Teck, Northwest Arctic Borough find middle ground on Red Dog Mine taxes. Read more in North of 60 Mining News, page 7.

Conoco confirms LNG plant bids

ConocoPhillips has confirmed that it has received bids for the purchase of the company's liquefied natural gas plant at Nikiski on the Kenai Peninsula.

"We are currently evaluating the bids to determine next steps," company spokeswoman Amy Burnett told Petroleum News in an April 17 email. "We believe the plant is a strategic asset that offers good opportunities for the right buyer."

The company announced in November that it was putting the LNG plant up for sale and had required initial bids for the plant to be submitted by March 17. The company received interest in the plant and, following the end of the bidding period, has now closed the data room for the bidding process, Burnett said.

The plant was originally opened by Phillips Petroleum and Marathon Oil in 1969 to provide a means of monetizing excess

see **PLANT BIDS** *page 14*

Objections raised to production numbers in DOR's spring forecast

There was an unusually political reaction to the Alaska Department of Revenue's April 14 release of the spring update to its Revenue Sources Book.

The release was later than usual, and some legislators questioned whether this was to prevent access to higher production and revenue numbers than projected in the fall forecast.

The other issue was a steep drop shown in the forecast for Alaska North Slope production from fiscal year 2017 to fiscal year 2018.

Revenue Commissioner Randall Hoffbeck addressed those issues April 14 at a Senate Finance Committee hearing. On the issue of when the forecast was released, he said it had been in final draft form about a month ago, but that draft didn't take into account a DOR Advisory Bulletin which clarified existing regu-

see **SPRING FORECAST** *page 14*

ENVIRONMENT & SAFETY

Oil spill is solved

Hilcorp says spill in water next to Anna platform came from flare system

By ALAN BAILEY

Petroleum News

Hilcorp has solved the mystery of an oil spill that happened at the Anna platform in the Cook Inlet on April 1. Apparently the oil had come from the platform's fuel gas flare system, following a jolt to the platform caused by ice on the water of the inlet.

After isolating the fuel gas flare on the platform for maintenance, an alternative fuel gas source for the pilot was drawn from an adjacent well, David Wilkins, Hilcorp Alaska senior vice president, has told Petroleum News. Then, during the repair, small amounts of liquid hydrocarbons were able to drop out and accumulate in the flare system. Later, when the platform was jolted by ice, the fluid was forced out of the flare system line and into the water of the inlet, Wilkins said. Hilcorp estimates that less than three gallons of oil was released, he said.

Hilcorp has taken corrective measures and, in the future, to prevent a re-occurrence, the company will use a gas source upstream of the fuel gas scrubber for this type of operation, Wilkins said.

Hilcorp had originally thought that the leak originated from a subsea pipeline between the Anna and the Bruce platforms. But divers determined that the pipeline was intact, a finding confirmed by the successful pressure testing of the line. And the incident management team assembled to respond to the leak stood down while Hilcorp continued to investigate the cause of the leak.

see **INLET SPILL** *page 15*

ENVIRONMENT & SAFETY

Well under control

Responders stop spray of gas and oil from leaking Prudhoe Bay wellhead

By ALAN BAILEY

Petroleum News

In the early hours of April 17 the team responding to the venting of gas from a well on Drill Site 2 of the Prudhoe Bay oil field succeeded in killing the well and thus achieving control of hydrocarbons escaping from the wellhead. The team killed the well by pumping salt water containing potassium chloride and mixed with methanol into the well, thus offsetting the upward pressure that had been driving gas from the well, according to a situation report issued on April 17 by the Alaska Department of Environmental Conservation.

However, since this dynamic kill of the well means that pressure has to be continuously applied to the wellhead, a mechanical plug will need to be installed before the well can be officially designated as secured, ADEC said. BP is preparing a plan for placing a plug in the well, the agency said.

The response team determined that there were two leaks on the wellhead: an oil leak near the top and a gas leak farther down.

The venting of gas from the wellhead was discovered at 7:30 a.m. on April 14. Initially the gas leak also generated a spray of oil that impacted the

see **BP WELL** *page 15*

EXPLORATION & PRODUCTION

14-well plan for CD-5

Conoco work would continue development activity at new Colville River pad

By ERIC LIDJI

For Petroleum News

ConocoPhillips Alaska Inc. plans to drill as many as 14 wells at the Colville River unit this year and in the first quarter of next year, according to a recent development plan.

The proposed program is mostly associated with the ongoing initial development activities at the new CD-5 pad. But the company is also considering additional development wells at existing pads targeting satellites at the central North Slope unit.

The company announced the 14-well program in its most recent plan of development, submitted to state officials in mid-March and revised in mid-April. The company asked the state to keep the details of the drilling program confidential, and the state obliged, which means the names and locations of many of the proposed wells are not public. The state often allows confidentiality for upcoming development plans on the North Slope.

The proposed 14-well development program does not include an exploration well that the company wants to drill in a proposed expansion area south of the Colville River unit.

The proposed 14-well development program

see **CD-5 WELL PLAN** *page 16*

● EXPLORATION & PRODUCTION

Savant planning Badami exploration

One-well Starfish exploration program would target a newly identified prospect at the unit; Mikkelsen remains stalled

By ERIC LIDJI
For Petroleum News

The Glacier Oil & Gas Corp. subsidiary Savant Alaska LLC is planning to drill an exploration well next winter in a newly identified prospect at the Badami unit.

The company is currently planning to use Rig 36 or a similar rig to drill a well in the Starfish prospect at the eastern North Slope unit, according to a plan of development.

Starfish is one of "several new target 'pods' of interest" that the company identified through a recent geologic and geophysical review of the Badami and Killian sands.

The Starfish prospect is located "to the southwest of the current development area within the Badami Sands" participating area, according to a description included in the 2017 plan of development for the unit, filed with the state Division of Oil and Gas on April 13.

The Badami unit sits along the coast of Mikkelsen Bay between the Liberty unit to the west and the Point Thomson unit to the east. The Badami Sands participating area is in the middle of the unit, with most of its area offshore and a small portion along the coast. The majority of the development drilling to date has been alongside the coast or just offshore.

The company also said it is considering infill drilling at Badami and additional exploration wells at new prospects outside of the Badami Sands participating area.

The Starfish program and the additional development and exploration drilling have yet to be sanctioned and are dependent on "economic conditions," according to the company.

The Starfish program would be the first exploration drilling at Badami since Miller Energy Resources Ltd. emerged from bankruptcy protection as Glacier in early 2016.

Glacier initially focused on development work at its properties, but is permitting the Sabre exploration well at its West McArthur River unit, on the west side of Cook Inlet.

Savant operates the Badami unit. ASRC Exploration holds a minority interest.

Mikkelsen prospect

A second exploration program at Badami remains stalled.

Savant asked the state in late 2012 to expand the unit to include seven exploration leases to the east. In mid-March 2013, the state Division of Oil and Gas only agreed to include two of those leases into the unit. In early April 2013, the company appealed the matter to the Department of Natural Resources, where the matter has

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● FINANCE & ECONOMY

Senate takes up oil tax, credit discussion

Administration, industry testify on HB 111; Hoffbeck says governor supports changes in North Slope credits; industry opposes bill

By KRISTEN NELSON
Petroleum News

The Alaska Senate Resource Committee began hearings on House Bill 111, the oil and gas production tax and credits bill, on April 14, met jointly with Senate Finance for more testimony April 15 and continued to hear the bill the week of April 17.

The House Finance Committee substitute which passed the House April 10 makes a number of changes in the state's oil and gas production tax statutes.

Ken Alper, director of the Department of Revenue's Tax Division, reviewed provisions of HB 111 for Senate Resources at its first hearing on the bill April 14.

The bill keeps the current minimum tax rate, but hardens the floor, preventing most credits from being used to reduce taxes below the minimum tax, with the exception of the small producer credit.

Under HB 111, the state would no longer issue transferable or cashable tax credit certificates for North Slope work. (HB 247, passed last year, focused on ending Cook Inlet credits.)

The 35 percent net operating loss credit for the North Slope is eliminated, Alper said. Instead, the bill allows companies to carry forward 100 percent of their losses to be used against future production tax obligations.

For companies without current production those losses would have to be carried forward until they have production, but with the limitation that after seven years the value of those carried forward losses decreases by 10 percent per year. The bill also contains a "ringfence" provision: expenditures which are carried forward can only be used to offset production value from the lease or property where they were incurred.

HB 111 drops the base tax rate from 35 percent to 25 percent of production tax value, and eliminates the per-barrel credit.

Alper said this would be a tax increase of $100 million to $300 million at oil prices in the $50-$100 per barrel range. The bill also adds a 15 percent surtax on that portion of production tax value greater than $60.

The bill hardens the floor for the minimum tax at 4 percent for legacy production and 3.2 percent for new oil and, a protection for the state at high-tariff fields at low prices, establishes that the gross value at the point of production can't go below zero.

Administration view

HB 111 is not an administration bill. It was introduced by House Resources co-Chairs Geran Tarr and Andy Josephson, Anchorage Democrats.

Department of Revenue Commissioner Randy Hoffbeck told Senate Resources April 14 that the governor feels strongly that oil and gas tax credit reform is a crucial part of a fiscal plan.

HB 247 (introduced by the administration last year) included both credit and tax changes, but passed with a more narrow focus on Cook Inlet credits, Hoffbeck said.

This year the governor has flagged that changes to North Slope credits are necessary, Hoffbeck said, but has left the specifics of how to achieve that to the Legislature. He said the governor stands with the House on moving HB 111 to the Senate for further consideration.

In an overview of the bill Alper said it resolves four "high priority concerns" identified by the governor: transitions the state away from the business of providing cash credits; reduces the state's liability related to potential large future investments; defers the state's direct participation in the cost of a new project until it comes into production; and includes oil industry participation in a fiscal plan for the state.

Industry view

Industry opposes HB 111.

Alaska Oil and Gas Association President and CEO Kara Moriarty told Senate Resources April 17 that HB 111 goes beyond the governor's goals, eliminating not only cashable credits but another portion of the gross value reduction, devaluing net operating losses, both non-cashable and cashable, and eliminating the sliding scale per-barrel credit. That one element, she said, causes a large tax increase in the $45-$80 per barrel range, and basically alters the structure of SB 21.

She argued for a mechanism to maintain as much value as possible to allow for continued investment and said companies need to recover 100 percent of their costs.

Damian Bilbao, BP's Alaska vice president for commercial ventures, said SB 21 made Alaska more competitive for investment and told legislators that North Slope production decline rates will reflect policy.

Alaska policy principles should encourage more oil down the trans-Alaska oil pipeline, extend the life of the North Slope's backbone fields, encourage more independents and not pick winners and losers, he said.

Casey Sullivan, director of government and public affairs for Caelus Energy Alaska, said long-term drivers of policy include natural gas for Cook Inlet and filling TAPS with more oil from legacy fields and oil from big new fields. He said HB 111 is a significant tax increase which negatively impacts project economics and will chill investment, hampering new field development.

Paul Rusch, vice president of finance for ConocoPhillips Alaska, called HB 111 a significant tax increase in an already high-cost environment, representing a 100 percent to 200 percent production tax increase at prices between $60 and $80 per barrel.

He also said the net operating loss provisions in the bill need improvement, telling legislators that ringfencing and reduction of NOLs forces producers to reduce spending in low price environments to avoid NOLs.

Senate Resources action

Senate Resources Chair Cathy Giessel said April 19 that hearings for April 20-21 were cancelled due to members being out of town on state and personal business. The next hearing will be April 24.

As to what Senate Resources might do, Giessel said the bipartisan tax working group she chaired in 2015 began to wrestle with the state's cashable credit system, dividing the topic into three buckets.

Cashable credits held by financial institutions which took them as collateral are now worthless, and that's one bucket

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SAVANT DRILLING

remained for four years.

A few months later, in mid-August 2013, the company also filed a request for a stay of certain requirements under its plan of exploration, which also remains unresolved.

The plan of exploration called for Savant to drill an exploration well through the Canning formation and into the Hue Shale to evaluate the potential of the Killian interval as previously encountered in the East Mikkelsen Bay No. 1 well. Although the company and state officials have met about the matter, according to Glacier it remains unresolved. ●

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● EXPLORATION & PRODUCTION

Turning to 'home cooking'

Canadian-based oil sands operators welcome exodus of foreign players to lower costs, stimulate innovation, raise competitiveness

By GARY PARK
For Petroleum News

The flight by foreign-based oil companies from the Alberta oil sands will result in control of the resource passing to domestic producers who are confident that the consolidation process will drive down operating costs, stimulate innovation and make the industry more competitive.

Brian Ferguson, chief executive officer of Cenovus Energy, told reporters at a Toronto investment symposium that his company's C$17.7 billion March deal for ConocoPhillips assets gives Cenovus "complete control of our future in the oil sands."

He said Cenovus is now concentrating on squeezing greater efficiencies by embracing big data and automation.

At the same event, Steve Laut, president of Canadian Natural Resources, fresh from its US$8.5 billion cash-and-shares transaction with Royal Dutch Shell, believes the industry is now "moving back to a more stable time. Canadian companies are well positioned."

He said the transformation under a handful of companies — consultancy Wood Mackenzie said more than 70 percent of oil sands production will soon be divided among Cenovus, CNR, Imperial Oil and Suncor Energy — will improve project execution, lower costs and advance innovation.

"The advantage is we are committed and we are very focused," he told reporters. "We are committed to R&D and to get those technology breakthroughs. We are going to make it happen."

Chevron could be next out

The next in the exit line could be Chevron, which Reuters, quoting unnamed sources, said is exploring the sale of its 20 percent holding in the Athabasca Oil Sands Project.

Chevron is reportedly holding discussions with investment banks in the hopes of fetching C$2.5 billion from a deal, apparently because it finds the oil sands to be a drag on its profits.

Others who have made either a wholesale pull-out or are divesting large percentages of their holdings include the U.S.-based ConocoPhillips and Marathon Oil, along with Netherland's-based Royal Dutch Shell, France's Total and Norway's Statoil, while state-owned China National Offshore Oil Corp. is said to be quietly shopping its Nexen assets.

Investor concern

Speaking to investors who are worried about the exodus of foreign players on the competitiveness of the oil sands against the Permian basin, Brazil and Saudi Arabia, Laut said Canada can draw solace from Canada's environmental, employment and safety standards over the long haul.

He said the regulatory demands do not prevent companies from achieving higher levels of efficiency and effectiveness.

Laut predicted that oil prices will gradually work their way into a US$50-US$60 range, helping stabilize operations.

Ferguson played down concerns about the debt financing Cenovus is taking on to close its ConocoPhillips deal, pointing to the company's investment-grade rating from Standard & Poor's, DBRS and Fitch, adding that 75 percent of the permanent financing was in place by early April.

To help deleverage the balance sheet, Cenovus plans to divest C$3.6 billion of assets from its existing conventional portfolio and is attracting many calls from prospective buyers, he said, adding that a 10-, 20- and 30-year unsecured-note financing earlier in April was oversubscribed.

Asked about his concerns if there is a further drop in oil prices, Ferguson said Cenovus is keeping C$1 billion in cash and had C$3 billion available in its revolving debt to give the company a "strong contingency" in a low-price environment.

Consolidation aids costs

Alister Cowan, chief financial officer at the oil sands powerhouse Suncor Energy, said the consolidation of projects will help drive down operating costs and make northern Alberta more competitive.

"Being able to increase (Suncor's stake) at a very good price last year was, we thought, a great deal and we've now seen others take that strategy," he said, referring to Cenovus and CNR.

Robert Johnston, chief executive officer of the Eurasia Group, a global political-risk consultancy, told the symposium that he expects to see the global oil market in a deficit by late this decade, with Canadian production looking more attractive as a result.

He said foreign-based companies are eying deepwater plays for long-cycle investments amid concerns about tightening carbon emissions in the oil sands.

Johnston said Cenovus will likely be very focused on how to make the oil sands work as opposed to 200 other plays around the world.

Of those who prefer to hedge their bets, Rob Symonds, chief operating officer for Husky Energy, said his company will diversify across the oil sands, heavy oil in Saskatchewan and natural gas in Asia.

He said Husky plans to retain 70 percent of the cost savings it won during the oil price downturn because of the structural change that has driven many investors away from the industry, compromising the operation of drilling rigs.

"There is a legitimate issue about whether people will come back," Symonds said. ●

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GOVERNMENT

Legislature passes clean energy bill

The Alaska Legislature has passed a bill authorizing the implementation of property assessed clean energy, or PACE, financing by municipalities in the state. PACE financing, which already operates in several states, provides commercial property owners with a means of obtaining long-term financing at attractive rates for installing energy efficiency improvements. A PACE loan requires an audit of the property that is to be upgraded. Payments on a loan are made through existing arrangements for the collection of commercial property taxes. PACE loans can also be transferred along with the title for a property when the property is sold, an arrangement that can make the loans appealing for property owners.

The Alaska Industrial Development and Export Authority's Interior Energy Project has been particularly anxious that the PACE legislation should pass. The IEP is seeking to greatly enlarge natural gas supplies to Fairbanks and sees the future availability of PACE financing as important in encouraging businesses in Fairbanks to convert their buildings to natural gas heating. The conversion of buildings to gas use is particularly important in establishing increased gas demand in Fairbanks, a key parameter in the economics of the IEP.

—ALAN BAILEY

FINANCE & ECONOMY

Permanent fund bill based on POMV

Proposed statute would allow withdrawals from earnings reserve based on market value of fund, not on fund's realized earnings

By **ALAN BAILEY**
Petroleum News

With some broad consensus among lawmakers on the need to use earnings from Alaska's Permanent Fund to help fill the projected shortfall in the state's funding requirements, but with some differing views on the specifics of how those earnings would be apportioned, House and Senate versions of a bill for future use of the earnings agree on one point: Fund withdrawals would be based on a percentage of the market value of the fund, or POMV. Currently, Permanent Fund dividend payouts to state residents are calculated based on fund earnings over the previous five years. The Legislature can then optionally use what is left in the fund's earnings reserve account to either top up the fund's principal, or for special state appropriations.

Endowment approach

The theory behind the POMV approach, a withdrawal approach often used by endowment funds, is that the setting of a regular withdrawal rate based on expectations for long-term returns from fund investments will preserve the fund's long-term value while also accommodating the vagaries of inflation. And, in the case of Alaska's Permanent Fund, the withdrawal formula would somewhat protect state funding from the ups and downs of state oil revenues. However, since, under the state constitution, funds can only be drawn from the earnings reserve component of the Permanent Fund, the POMV approach presumably assumes that the earnings reserve account would hold sufficient funds to cover the withdrawals — the earnings reserve account accumulates realized earnings from the fund, earnings that result from the sale of assets or interest payments, and not from changes in asset values.

Gov. Bill Walker introduced the original version of the Permanent Fund bill earlier in the legislative session as Senate Bill 26, under the moniker the Permanent Fund Protection Act. At the core of the bill is a statute amendment allowing for an annual appropriation from the Permanent Fund of 5.25 percent of the fund's average value over the first five of the preceding six fiscal years. The use of the five-year rolling average value would presumably smooth out fluctuations in the fund's value resulting from changes in the fund's investment performance. Under Walker's version of the bill, Permanent Fund dividends would have come from a percentage of the annual appropriation coupled with a percentage of state oil and gas royalties. Walker estimated that this dividend formula would have resulted in an annual per-person payout of around $1,000 per year.

Senate and House versions

Versions of SB 26 have now passed both the Senate and the House and require reconciliation if the Legislature is to pass a bill for signature by the governor. Both versions of the bill have preserved the POMV, five-year rolling average approach but each has a different dividend formula. Both versions of the bill also include provisions that scale down Permanent Fund withdrawals in the event that state oil and gas revenues recover.

The Senate version starts with a 5.25 percent POMV Permanent Fund appropriation but reduces this to 5.0 percent from July 2020. However, this version fixes the Permanent Fund dividend at $1,000 per resident for the next three years, through to fiscal year 2020. After that, 25 percent of the annual appropriation from the fund would be divided among state residents as dividend payments. The remainder of the appropriation could be used as a source of revenue for state funding. But the Permanent Fund appropriation for state use would be reduced dollar for dollar by the amount that the annual state oil and gas revenues exceed $1.2 billion. Also, the Legislature would be allowed to protect the Permanent Fund from inflation by appropriating back into the fund's principal any amount in the earnings reserve account that exceeds four times the POMV payout. And, under the bill, annual state appropriations from its general fund may not exceed $4.1 billion, with that figure adjusted annually for inflation.

Difference in detail

The House version reduces the 5.25 percent POMV to 5.0 percent in July 2019 rather than July 2020. This version does not have the fixed $1,000 dividend payment for the next three years, but instead requires a minimum dividend of $1,250 in fiscal years 2018 and 2019. The money allocated for dividend payments would consist of 33 percent of the total POMV amount allocated for withdrawal from the earnings reserve. The remainder of the withdrawal allocation could be used for state funding, but would be reduced by 80 cents on the dollar for every dollar that state oil and gas revenues exceed $1.4 billion, adjusted annually for inflation. The bill also allows the Legislature to return 0.25 percent of the withdrawal allocation back into the Permanent Fund principle, while also preserving the clause in the Senate version of the bill allowing topping up of the principle when funds in the earnings reserve account are especially high. The House version would also enable the Legislature to appropriate from the earnings reserve account any POMV amount calculated for fiscal year 2017 above what has already been paid out in Permanent Fund dividends for that fiscal year. And the House version removes the $4.1 billion cap on appropriations from the general fund.

Both the Senate and the House versions of the bill eliminate the payment of oil royalties at a 50 percent rate into the Permanent Fund from some oil leases. All royalty payments into the fund would be at the 25 percent rate required under the state constitution, with the remaining 25 percent from the higher rate royalties then being paid into the state's general fund.

A sting in the tail

And the House version of the bill has a sting in its tail: The bill would only become law if the Legislature enacts a broad-based tax directed at education spending and HB 111, the House bill reforming state oil and gas production taxes. ●

Contact Alan Bailey at abailey@petroleumnews.com

NATURAL GAS

Gas hydrate: an enticing resource

USGS expert overviews research into a potential major future energy source and the challenge of establishing economic production

By ALAN BAILEY
Petroleum News

Gas hydrates, solids in which gas molecules are held inside a lattice of water molecules, are known to exist in vast quantities around the world. And, with the gas in the material usually being methane, the primary component of natural gas, people have long wondered about the possibility of using the hydrates as a source of natural gas, for fuel and other purposes.

On April 18 Tim Collett, an international expert on gas hydrates from the U.S. Geological Survey, talked to the Alaska Geological Society about the current status of gas hydrate research, and about the opportunities and challenges for developing hydrates as an energy resource. Huge quantities of hydrates are known to exist around the base of the permafrost under Alaska's North Slope.

Stability zone

The hydrates are only stable within a certain range of relatively low temperatures and high pressures — move the temperature and pressure outside that range and the hydrates disassociate into water and gas. But, as a solid within its stability range, the hydrate can capture huge volumes of gas. One unit volume of solid hydrate holds about 160 unit volumes of free gas, Collett said.

Methane has been captured in the form of hydrate in many parts of the world, typically in sediments under the oceans, where temperatures are cold, or under the permafrost in Arctic regions. Because most oceans are very cold at depths below around 400 meters, sub-ocean hydrates are even found in tropical regions such as offshore India, Collett commented.

There are known to be vast quantities of hydrates in existence worldwide. In fact, it is estimated that hydrates hold twice as much carbon as all of the world's oil, gas and coal resources, Collett said. However, much of the hydrate resource cannot realistically be developed. For example, much submarine hydrate exists as grains scattered through clay dominated muds.

Interest in hydrate development is now focusing on deposits where the hydrates permeate sand reservoirs, either under the seafloor or under the permafrost, Collett said.

Collett said that testing of gas hydrate production dates back as far as the 1970s, when production from a gas field in western Siberia evaluated the concept of hydrates overlying the gas in the field disassociating and thus bolstering gas production. However, modern hydrate research began with a science-driven ocean drilling program that started in 1995. And, as interest in gas hydrates has grown, the North Slope of Alaska has proved a particularly effective region for research, given the relative ease of access and the proximity of existing infrastructure.

U.S. hydrate research has also focused on the Gulf of Mexico, where extensive gas hydrate resources exist at shallow depths beneath the seafloor.

Elsewhere in the world, Japan has a very active research program, offshore in the Nankai Trough and the Sea of Japan. There have been two very successful gas hydrate drilling projects offshore India, and there are other projects offshore Korea and on the Malaysian ocean shelf. There is also some research into permafrost gas hydrates on the Tibetan Plateau.

The U.S. Geological Survey conducted an assessment of technically recoverable gas hydrates under the North Slope, estimating the possibility of producing perhaps 85 trillion cubic feet of gas from the resource in the region. The Bureau of Ocean Energy Management has assessed how much hydrate may be in place offshore.

Essentially, gas production from a hydrate deposit involves moving the hydrate out of its stability zone, typically by lowering the pressure in the hydrate reservoir, or by raising the temperature.

Hydrate test wells

A key step in research into the potential for gas hydrate production came in 2002 when hydrate cores were recovered from the Mallik well on Canada's Mackenzie River Delta. Testing of that well indicated that production through the application of heat to the reservoir appeared ineffective. However, gas production through pressure reduction did prove successful — in 2007 and 2008 scientists returned to the well and conducted a six-day production test, Collett said.

On the North Slope the USGS has been actively researching techniques for locating gas hydrate deposits in the subsurface and assessing the scale of the resources. However, the agency has also been working with the oil industry and the Department of Energy in conducting research into potential hydrate development. Japanese interests have also been involved in the North Slope research.

A major milestone came in 2007 with the drilling by BP of the Mount Elbert gas hydrate test well in the Milne Point unit into one of two major North Slope gas hydrate accumulations, Collett said. The researchers in the Mount Elbert project gathered gas hydrate cores from the well and also used a technique called modular dynamic testing to evaluate the production characteristics of the hydrates that the well penetrated.

Reservoir permeability

One surprising result from this project was a discovery that the permeability of the hydrate deposit was higher than expected, a finding that is encouraging from the perspective of gas production from the hydrates though pressure reduction, Collett said. Given the solid nature of the hydrates, the researchers had assumed that the hydrates would completely clog the reservoir. However, it turned out that only 80 percent of the pore spaces between the sand grains of the reservoir were actually occupied by hydrate — about half of the remaining 20 percent of the pore space was filled

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North of 60 Mining News

www.MiningNewsNorth.com The weekly mining newspaper for Alaska and Canada's North **Week of April 23, 2017**

page 8 Dominion intensifies exploration near Ekati, Diavik diamond mines

NEWS NUGGETS

Compiled by Shane Lasley

TRILOGY METALS INC.

Trilogy Metals is collecting the final data for a prefeasibility study on developing an open-pit mine at the Arctic deposit in Northwest Alaska.

Excellent copper, zinc recoveries in clean concentrates from Arctic

Trilogy Metals Inc. April 19 said recently completed metallurgical testing demonstrates that excellent metals recoveries and clean copper and zinc concentrates can be generated from the copper-lead-zinc-gold-silver ores at Arctic, a volcanogenic massive sulfide deposit at the Upper Kobuk Mineral Projects in Northwest Alaska. During 2016, Trilogy completed four holes targeting mineralized material that is planned to be mined during the first seven years of production at Arctic. A 600-kilogram composite sample of this material was used in bench scale testing to confirm the performance of the previously defined flotation process; as well, a large volume of the sample was processed in a pilot plant to provide sufficient volumes of a copper-lead bulk concentrate to complete detailed copper and lead separation test work. Copper recoveries averaged 91.7 percent and formed a concentrate averaging 28.7 percent copper metal. Zinc recoveries averaged 87.8 percent and formed a concentrate averaging 60 percent zinc metal. The revenue stream in a 2013 preliminary economic assessment for Arctic showed that copper produced 60 percent of the revenue stream, with zinc contributing 21 percent, silver at 9 percent and gold at 6 percent. Lead was the least valuable of the metals. The bulk of the precious metals report to the zinc concentrate and further testing is being carried out to determine optimal recoveries for lead, gold and silver. Neither the zinc nor the copper concentrates contain any significant deleterious penalty metals and are considered excellent quality by world standards. "We are very pleased with the results of this metallurgical test work program at Arctic. Recoveries and concentrate grades for our two principle metals – copper and zinc are excellent. We are currently conducting additional test work to determine the optimal recoveries of our three other metals – lead, gold and silver, and will report on that work in due course," said Trilogy Metals President and CEO Rick Van Nieuwenhuyse. In addition to the metallurgical work, the company reported that the in-pit geotechnical and hydrology studies for Arctic are now completed to a level that they can be incorporated into a prefeasibility study, which is expected to be finalized in the first quarter of 2018. Roughly US$17 million has been budgeted for the 2017 program at Arctic. This work includes US$7.1 million invested into collecting the final information for the Arctic prefeasibility study and US$10 million, funded by South32 Ltd., for exploration at Bornite, a high-grade copper deposit about 16 miles south of Arctic. "The PFS will demonstrate the true value of the high-grade Arctic deposit which we expect will be the first in a series of potential mines in the Ambler mining district," said Van Nieuwenhuyse. "With the recent announcement that the BLM has initiated the permitting process on the AMDIAP (Ambler Mining District Industrial Access Road); our recently announced option agreement with South32 whereby they will fund a $10 million program at our Bornite deposit in 2017; and an upswing in demand for copper and zinc, the company is well positioned to add value for shareholders by advancing development of the Ambler mining district." ●

NANA REGIONAL CORP.

The Red Dog Mine in Northwest Alaska produced 1.29 billion pounds of zinc in 2016, accounting for nearly 5 percent of the global mine output of the galvanizing metal last year. This world class operation is, by far, the largest taxpayer to the Northwest Arctic Borough where it is located.

● PUBLIC POLICY

Taxing negotiations

Teck, Northwest Arctic Borough find middle ground on Red Dog Mine taxes

By SHANE LASLEY

Mining News

After roughly two years of taxing negotiations, Teck Alaska and Northwest Arctic Borough have found middle ground on a tax structure that offers the municipality added funds to provide services to a sprawling remote borough without risking the viability of Red Dog Mine during the lows of cyclical metals markets.

Teck is the operator of Red Dog and Northwest Arctic Borough is a regional municipality that blankets 40,750 square miles of Northwest Alaska, a minerals rich expanse about the size of Kentucky.

The agreement on the table, which still needs to go before the borough assembly for a final vote, calls for Red Dog to pay around US$25 million a year into the borough. While this is roughly double what the mine has been paying in recent years, Teck believes the compromised payments in lieu of taxes structure strikes a good balance between the borough's fiscal needs and certainty for world-class zinc mine.

"We are very pleased to have reached this new agreement through discussion and cooperation between Red Dog and the Northwest Arctic Borough," Red Dog General Manager Henri Letient said in the news release. "This agreement will provide more resources for the people and communities of the region, while also supporting Red Dog's ability to stay competitive and continue generating jobs and economic activity."

More than a year later, the two sides have finally found middle ground, settling on a PILT structure that significantly increases funds going into Northwest Arctic Borough coffers while also providing certainty for the future of the Red Dog Mine.

Too far apart

Since Red Dog began production in 1989, the primary source of revenue for the Northwest Arctic Borough has come from payments in lieu of taxes paid by the mine.

These "PILT" payments are the result of agreements negotiated between the Red Dog Mine and Northwest Arctic Borough every five years. The latest negotiated agreement, which averaged roughly US$9.1 million directly to the municipality and another US$2.4 million per year to the school district, expired at the end of 2015.

In the months leading up to the expiration of the 2010 to 2015 PILT agreement, the Northwest Arctic Borough began negotiating for significantly larger payments from Red Dog for the next five years.

The two sides, however, were too far apart to find middle ground before the PILT agreement expired.

In making its case for the higher payments, the

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Compiled by Shane Lasley


DOMINION DIAMOND CORP.

Dominion Diamond is carrying out an exploration and development program at its Ekati property in Northwest Territories that includes advancing five diamond deposits to production and drilling six other diamond bearing kimberlite pipes.

Dominion steps up exploration in NWT

Dominion Diamond Corp. April 12 provided an update on its exploration and development pipeline in the Northwest Territories. This includes the advancement of its portfolio of development projects at the Ekati and the Diavik diamond mines and increasing exploration in Lac de Gras, the highly prospective region of Northwest Territories that hosts both operations. "We continue to execute on our long-term strategy and create value for all shareholders. With the support of our strong balance sheet, we are well-positioned to advance a number of key development opportunities and begin reinvestment in near-mine exploration at both Ekati and Diavik," said Dominion Diamond President Jim Gowans. "As an established operator, one of our primary objectives is to leverage our infrastructure advantage in one of the world's most prospective diamond mining districts." This includes a renewed focus on its Ekati property, where no greenfield exploration has taken place since 2006. Dominion said there are 150 known kimberlites on the property, roughly 110 of which have not been extensively tested. The exploration program includes prioritization of the known kimberlites pipes on the Ekati property, and planning for a potential bulk sampling program in fiscal 2019. Diamond drilling is planned on up to six priority targets at Ekati. On the development front, Dominion has several projects in the pipeline at Ekati – Lynx, an open-pit expected to deliver ore to the Ekati process plant in the second quarter of 2018; Sable, where the company is completing an access road and plans to begin pre-stripping in July; Jay, which is in the final stages of permitting; Misery Deep, a resource below the Misery open-pit that is in the pre-feasibility stage of evaluation that could deliver additional high-grade diamond ore to the Ekati mill beyond 2020; and Fox Deep, another underground resource in the pre-feasibility stage that has the potential to signifi-

The exploration program includes prioritization of the known kimberlites pipes on the Ekati property, and planning for a potential bulk sampling program in fiscal 2019. Diamond drilling is planned on up to six identified priority targets at Ekati.

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MINE TAXES

borough pointed out that Red Dog is among the world's largest zinc mines and is well enough established to pay higher taxes to meet the municipality's needs.

"The Red Dog Mine is now one of the largest zinc mines in the world and Teck enjoys the benefits of low, set tax payments to maximize profitability for its shareholders," Northwest Arctic Borough penned in a talking points bulletin.

The borough said it would have collected US$287.5 million in taxes from Red Dog from 2010 through 2015, or US$57.5 million per year, if the mine had been taxed under a severance tax adopted by the borough in 2009.

Teck argues that even under the former PILT agreement, Red Dog pays the highest municipal tax rate of any mine in Alaska. The company points out that if the mine was located in one of the other mining municipalities in the state – such as Fairbanks, Juneau or Delta Junction – it would pay between US$3.7 million and US$4.6 million in local taxes.

With the two sides unable to find workable middle ground before the PILT expired, the borough implemented a reworked version of the 2009 severance tax at the onset of 2016.

While this tax has been around for a few years, Teck was exempt as part of the PILT agreement.

The borough increased the severance tax rate from 3 percent under the plan adopted in 2009 to 4.5 percent in 2015. However, Patrick Savok, director of government affairs, Northwest Arctic Borough, told North of 60 Mining News earlier this year that the new tax is actually lower due to its structure.

"Under the revised structure, the tax allows significant deductions in calculating the tax base," he explained.

Even with the deductions, Teck calculated that Red Dog would be paying US$30 million to US$40 million per year under the severance tax, roughly triple the rate it had been paying.

Red Dog, which is already the biggest taxpayer in the Northwest Arctic Borough, accounting for 70-80 percent of the municipal government's general funds, is the only business that is currently subject to the severance tax. Teck argues that this targeted tax hike is discriminatory.

The company also contends that the steep tax increase is opportunistic, taking advantage of the fact that Red Dog can't be moved to a jurisdiction with a more favorable tax structure, which would be anywhere else in Alaska.

In a move aimed at getting Northwest Arctic Borough officials to the negotiating table, Teck filed a complaint over the tax hike in Alaska Superior court early in 2016.

"It is our hope that, rather than continue the legal process, the NAB will agree to come to the table and work cooperatively to achieve a reasonable new agreement," company officials wrote in a paper laying out their position.

Finding middle ground

More than a year later, the two sides have finally found middle ground, settling on a PILT structure that significantly increases funds going into Northwest Arctic Borough coffers while also providing certainty for the future of the Red Dog Mine.

Importantly, if finalized, this agreement would be effective for ten years, double the time span of previous PILT agreements and the next round of negotiations.

In total, the mine would flow roughly US$20 million to US$26 million into the borough each year under the new agreement.

Roughly US$14 million to US$18 million of these funds would be paid directly to the Northwest Arctic Borough each year, a payment that would be calculated on a percentage of Red Dog's fixed asset value.

The agreement also includes the establishment of a new village improvement fund. Administered by the borough, with input from the 11 villages it encompasses, this fund would be earmarked for community programs, services and infrastructure.

Red Dog has agreed to put an initial US$11 million in this fund and then pay US$4 million to US$8 million a year into it, payments that will be calculated based on the mine's gross profit.

The borough assembly has given this PILT agreement initial approval during an April 11 reading of a borough ordinance on the subject.

"I am happy to share that the assembly took its first step towards approval of the PILT agreement by approving introduction of Ordinance 17-03," said Northwest Arctic Borough Mayor Clement Richards. "This administration has worked hard to negotiate an agreement that meets needs of our borough, which has remained of the utmost importance to us."

The assembly is slated to consider the agreement further on April 25. A passing of the ordinance and final agreement by Teck would put taxing negotiations behind the two parties for at least another decade. ●

Petroleum news

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SEABRIDGE GOLD INC.

Geologists Howard Marcus and Shawn Vandekerkhove examine core from historical drilling at Seabridge Gold's Iskut gold-silver project in Northwestern British Columbia.

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cantly extend the life of the Ekati Mine. At Diavik, a mine owned by a joint venture between Dominion (40 percent) and Rio Tinto (60 percent), drilling of three priority kimberlites is planned in 2017. Additionally, the development of the A-21 kimberlite pipe at Diavik continues to progress on time and on budget with the completion of the dike and the start of de-watering expected in late 2017. First ore from A-21 is expected to be delivered to the Diavik mill in 2018.

Seabridge raises $15.7M, another $22M expected

Seabridge Gold Inc. April 19 announced the closing of a C$15.73 million financing. The company plans to use the proceeds of this public offering to continue exploration and other programs at its KSM and Iskut projects in the Golden Triangle region of Northwestern British Columbia and for general corporate purposes. Four of the zones at the KSM project – Kerr, Sulphurets, Mitchell and Iron Cap – contain 2.2 billion metric tons of proven and probable reserves averaging 0.55 grams per metric ton (38.8 million oz.) gold, 0.21 percent (10.2 billion pounds) copper, 2.6 g/t (183 million oz.) silver, and 42.6 parts per million (207 million lbs.) molybdenum. These reserves support a 53-year mine that would average 540,000 oz. of gold, 156 million lbs. of copper, 2.2 million oz. of silver, and 1.2 million lbs. of molybdenum annually, according to a prefeasibility study published in September. Iskut, about 30 kilometers (19 miles) northwest of KSM, is an earlier staged gold-silver project acquired by Seabridge in 2016. In addition to the C$15.73 million raised through the public offering, the company is raising C$22 million through a private placement that involves the issuance of 1.1 million flow-through shares at C$20 per share. Due to the laws associated with flow-through financing, it is expected that the entirety of the money raised through this private placement will be invested in Seabridge's Canada exploration projects.

Pine Point PEA shows mine may be feasible

Darnley Bay Resources Ltd. April 18 published results of a preliminary economic assessment for Pine Point that indicates developing a mine at this zinc project about 65 kilometers (40 miles) east of Hay River Northwest Territories would be relatively inexpensive and the payback on the initial capital would be realized in less than two years. The PEA examined several development scenarios

Seabridge plans to use the proceeds of this public offering to continue exploration and other programs at its KSM and Iskut projects in the Golden Triangle region of Northwestern British Columbia and for general corporate purposes.

and settled on a mining plan where 10 open-pit deposits are mined in sequence. The deposits included in the mine plan host 25.8 million metric tons of measured and indicated resources averaging 2.94 percent zinc and 1.12 percent lead, plus 3.7 million metric tons of inferred resources averaging 2.9 percent zinc and 0.77 percent lead. Roughly 4,000 to 6,800 metric tons of mineralized material would be mined per day and fed into dense media separation plants for pre-concentration prior to being trucked to a centralized 1,800-metric-ton-per-day mill to produce lead and zinc concentrates with a more traditional mining and flotation circuit. The concentrate will then be trucked to a railway facility at Hay River. This method is similar to that used by Cominco (now Teck Resources) when it operated a mine at Pine Point from 1964 to 1987. Under the scenario outlined in the PEA, developing a new mine at Pine Point is expected to produce 1.35 billion pounds of zinc and 536 million pounds of lead over a 13-year mine life. The capital needed to develop this mine is estimated be C$153.8 million, including a 15 percent contingency, with sustaining capital of C$117.5 million per year over the life of the mine. It is assumed that sustaining capex will be entirely funded out of cash flow. With these parameters, the mine is expected to produce an after-tax net present value of C$210.5 million and internal rate of return of 34.5 percent. This would pay back the initial investment in about 1.8 years. Darnley Bay just bought Pine Point in December for roughly C$3 million in cash and 25 million company shares. This payment was made to KSV Koffman Inc., the court-appointed receiver of Tamerlane and Pine Point Holding Corp., previous owners of the property. Darnley Bay President and Chief Executive Officer Jamie Levy remarked that, "This preliminary economic assessment supports that management's confidence in this project was well-placed when it was purchased this past December," said Levy. "What is also very encouraging is that there are multiple opportunities, including underground mining, to enhance the economics and extend the project life." Notable enhancements include bringing in some higher grade underground resources into

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the mine plan and upgrading historical surface resources to modern NI 43-101 standards with further drilling. Additionally, further metallurgical testing planned for 2017 may increase both recoveries and concentrate grades. Darnley Bay plans to begin this feasibility work in the second half of this year. "The company plans to initiate a feasibility study in the near future while drilling to add additional resources to the mine plan," Levy said. If the feasibility study continues to show developing Pine Point to be economically viable, the company said it would take about 18 months to construct the mine after the permits and financing is secured.

Klondike eyes million-ounce gold discovery

Klondike Gold Corp. April 19 said it plans to invest C$2 million on the 2017 exploration program for its Klondike district property near Dawson City, Yukon. This work will primarily focus on Lone Star, a 4,000-meter-long target that shows the potential for a million-ounce gold discovery. The program will include extensive high resolution 3D imaging of electrical resistivity and induced polarization geophysics to map the geology and subsurface continuity of Lone Star and a large drill program designed to outline the potential of this gold target. Klondike tested a 700-meter stretch of Lone Star with drilling carried out in 2016. Highlights from this drilling include 37 meters of 2.4 grams per metric ton gold in hole LS 16-58; 11.3 meters of 3.5 g/t gold in LS 16-70; and 24.5 meters of 1.5 g/t gold in LS 16-54. The 2017 drilling will start by testing near hole 58. In addition to work at Lone Star, the company plans to complete a larger soil-sampling program spanning the entire Klondike property.

Colomac gold recoveries exceed historical results

Nighthawk Gold Corp. April 19 reported encouraging preliminary results from its metallurgical program on the Colomac Gold project in Northwest Territories. These initial results indicate that recoveries of up to 96.5 percent of the gold may be achieved and the rock is amenable to all standard gold recovery technologies. This is significantly higher than the 88.1 percent recoveries achieved during active mining on the property from 1994 to 1997. "Results from this initial metallurgical testing have significantly exceeded our expectations in comparison to Colomac's known historical recoveries," said Nighthawk President and CEO Michael Byron. "In particular, Colomac material shows excellent grind characteristics, exceptional gold recoveries and responsiveness to all standard gold recovery technologies, comparing favorably to similar projects in North America. It's also important to note that the rock is exceptionally clean as no deleterious materials were detected that could otherwise adversely affect processing, or impact the environment." Nighthawk is planning further testing to optimize and confirm these results. ●

● FINANCE & ECONOMY

IEA thinks oil market may be in balance

Report: Although oil demand growth has slowed a little, OPEC production cuts have proved effective as demand moves ahead of supply

By ALAN BAILEY
Petroleum News

The International Energy Authority in its April Oil Market Report has suggested that supply and demand have come into balance in the global oil market. Moreover, the organization's short-term forecast actually shows demand moving ahead of supply in the second quarter of this year.

Demand and supply

The report says that the IEA's forecast for global oil demand growth has softened slightly relative to the organization's last forecast. That softening results from subdued gains in demand in Russia and India and "weaker momentum" in the countries of the Organization for Economic Cooperation and Development.

But, on the supply side of the equation, oil production dropped by 755,000 barrels per day in March. Following an agreement by countries in the Organization of the Petroleum Exporting Countries and by others to instigate production cuts, OPEC crude oil production dropped by 365,000 bpd to 31.68 million bpd in March. The OPEC drop, led by Saudi Arabia, and by Nigeria and Syria, neither of which was party to the OPEC cut agreement, was actually more than had been planned. Continued implementation of the agreed program of OPEC cuts should drive a further draw on global oil stocks, the IEA report says.

OPEC is now at the halfway point in the six-month time span of its production cut agreement. And, with the implementation of the agreement being effective, prices have stabilized again after falling by about 10 percent in March, the IEA report says. Some unplanned production outages coupled with rising political tension in the Middle East contributed to the price resilience. Compliance by non-OPEC countries in the production cut agreement is difficult to verify but appears to be improving the report says.

Continuation of OPEC cuts?

One major unknown is the question of whether OPEC and the other countries will continue with their lowered production quotas after the current six-month agreement expires. A continuation of the current strategy would likely cause further drawdowns on oil stocks, a phenomenon that would provide support to the global oil price. But an elevated oil price would also provide encouragement for increased production by some producers, in particular producers in the U.S. shale oil industry. And, following unplanned outages in Canada and the North Sea, oil output from these regions will likely start to rise again in May, the IEA report says.

Overall the IEA sees the possibility of a 485,000 bpd rise in oil production for the whole of this year: That compares with a 790,000 bpd decline in 2016. The main impetus for the climb in production this year will come from the United States, where production will likely rise by some 680,000 bpd over the course of the year, the IEA report says.

Indications of balance

And, although the IEA anticipates a slowing down of oil demand growth, the demand growth forecast has only dropped from 1.4 million bpd to 1.3 million bpd. The net result will be an increase in oil production more than offset by increasing oil demand.

Although oil stocks within the OECD appear to have grown a bit this year, stocks in several areas outside the OECD have fallen. A net marginal increase in stocks coupled with an implication from supply and demand data that stocks should have been drawn down by perhaps 200,000 bpd indicates an oil market that is close to balance, the IEA report says.

"As more data become available this will become clearer. We have an interesting second half to come," the report comments with reference to the second half of the OPEC six-month commitment to production cuts. ●

Contact Alan Bailey at abailey@petroleumnews.com

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GAS HYDRATE

with water.

In 2011 ConocoPhillips drilled the Ignik Sikumi gas hydrate test well in the Prudhoe Bay unit. A prime purpose for drilling this well was to test the concept of gas production from hydrates through the substitution of carbon dioxide for methane in the hydrate lattice. Carbon dioxide fits better into the lattice structure than does methane. So, if carbon dioxide is flushed through the hydrate, carbon dioxide should replace some of the methane, thus causing both the production of methane gas and the sequestering of waste carbon dioxide in the solid subsurface gas hydrate, Collett explained.

After conducting a carbon dioxide exchange experiment, the researchers allowed gas to flow from the Ignik Sikumi well, out to 63 days, Collett said. An interesting result from this test was a confirmation of the relationship between hydrate gas production and the temperature of the hydrate reservoir — the disassociation of the hydrate absorbs heat, thus causing the remaining hydrate to cool, as gas production continues. Thus, the continuing production of gas from hydrates will involve the balancing of the relationships between reservoir pressure, reservoir temperature and production rates, Collett explained, commenting that cooling could ultimately result in water freezing into reservoir-clogging ice.

Gulf of Mexico

There has also been significant gas hydrate research in the Gulf of Mexico. An industry led project investigated drilling into hydrate deposits in the gulf and characterized the hydrate resources in sand reservoirs. The Department of Energy has now taken over that project, with the University of Texas conducting a drilling project to collect hydrate cores.

Offshore Japan, the second of two subsea hydrate production tests has just begun. After previous production testing in 2013, the current testing is aimed at mechanical issues relating to well completions, Collett said.

In research offshore both Japan and India a recent development has been the recovery of pressure cores, drilling cores preserved in containers at the pressures experienced in the actual hydrate reservoirs. Research using these cores has revealed new information about the permeability of the reservoirs, suggesting the existence of permeabilities higher than previously thought, Collett said.

Production estimates

Using the range of likely hydrates reservoir permeabilities, scientists have estimated potential gas production rates from hydrate wells ranging from 500,000 cubic feet to 4.5 million cubic feet per day offshore India, Collett said. Modeling of possible production from the Ignik Sikumi well in Alaska suggested a rate peaking at about 4 million cubic feet per day. And there have been estimates of potential offshore production rates as high as 40 million cubic feet per day.

But production tests so far have only demonstrated the production of very small volumes of gas over short time periods, Collett emphasized. The next step towards realizing full-scale hydrate production is a long-term test involving multiple wells. Discussions are currently taking place between the USGS, the National Energy Technology Laboratory and the North Slope operators about the possibility of carrying out a test program of this type, Collett said.

And possible commercial production of hydrates is still a number of years into the future, perhaps in the late 2020s or early 2030s, with Japan hoping to achieve commerciality by 2025.

Production challenges

The challenges with commercial hydrate production will revolve around the need to balance the necessary heat flow into the hydrate reservoir to maintain the reservoir temperature along with gas production from the reservoir and the depressurization needed to cause the hydrate to disassociate. Essentially, given the depressurization, artificial lift of the gas resource will be required from the start of production, and the production of released water along with the gas will become a major economic factor. On the other hand, water flow into the reservoir could help with the temperature maintenance issue. Estimates suggest that gas from hydrates could cost twice as much to produce as gas from a conventional resource, Collett said.

But, given their current relatively high cost of gas, countries such as Japan and India see potential economic benefit in hydrate development. And on the North Slope, gas from hydrates could have value as a fuel or for maintaining reservoir pressures in oil fields. ●

Contact Alan Bailey at abailey@petroleumnews.com

● NATURAL GAS

AGDC submits Section 3 application to FERC

Board approves filing; public awareness campaign to begin; negotiations underway for plant site purchase option from AKLNG LLC

By KRISTEN NELSON
Petroleum News

The Alaska Gasline Development Corp. filed an application with the Federal Energy Regulatory Commission April 17 to obtain a Natural Gas Act Section 3 permit for its Alaska liquefied natural gas product.

AGDC, a public corporation of the state, took over advancing a North Slope natural gas pipeline and LNG export project from a partnership of the state and the North Slope's major producers — BP, ConocoPhillips and ExxonMobil — at the end of the year.

AGDC President Keith Meyer told the Alaska House Resources Committee April 14 that AGDC's board had approved the application filing at an April 13 meeting. The filing triggers a National Environmental Protection Act review process. He said FERC permitting should take about 18 months.

That is to get to a final EIS. AGDC said the draft environmental impact statement under NEPA would likely take about 12 months, with another six months required for the final EIS. AGDC said it also filed major federal permit applications with the Pipeline and Hazardous Materials Safety Administration, the Army Corps of Engineers, the Bureau of Land Management and the National Marine Fisheries Service.

Activities underway

Meyer told legislators the majority of questions received by AGDC on the Alaska LNG project have been addressed with answers submitted as part of the application filing or to be filed during the application review process.

KEITH MEYER

Activities underway include interviewing engineering, procurement, construction firms to assist with regulatory application and provide capital cost estimates input, Meyer said. The final investment decision for the project would take place after receipt of FERC authorization for the project, expected in the first quarter of 2019.

AGDC is finalizing negotiations with AKLNG LLC for a purchase option for the land at the plant site, which needs to be under AGDC control by the end of the FERC process. Meyer said AGDC technically doesn't need title to the land, but is required to either own or control it, and said AGDC is looking at having the option to buy the land.

Financial update

Lieza Wilcox, AGDC vice president, commercial and economics, told legislators there is a market opportunity for Alaska LNG across Asia, and said existing contracts expire in the same timeframe as a projected global shortfall in LNG supply. A contracted supply gap is expected in the Asian market within seven years.

She said the Alaska LNG project is a $40 billion project, and a proposed capital structure of 25 percent equity and 75 percent non-recourse debt is envisioned, with an opportunity to earn 8 percent on the $10 billion of equity investment through the initial period.

Discussing investor economics, she said that for a 20-year firm contract period there would be an acceptable return on investment and delivery of some 25 trillion cubic feet of natural gas.

Debt would be paid off during the contract period, and beyond that an additional 30 tcf of natural gas would be needed to operate for an additional 25 years. The asset value at 2045, she said, could be $50 billion.

The state would have an opportunity to invest and could earn 8 percent through the initial period, going to 13 percent with inclusion of its royalty in kind and tax as gas and payment in lieu of taxes. Meyer said the assumption for PILT, payment in lieu of taxes to municipalities, is $500 million a year.

Wilcox discussed a potential to reduce the capital cost by phasing the project, first building a two-train system, expandable to three trains. That, she said, would reduce the exposure to investors.

Contingency and owners costs (including engineering and project management) are being benchmarked and further reviewed and Wilcox said there is early indication of potential for cost reduction.

AGDC is positioned to bring the pieces of the project together, with the state a potential investor along with Alaskans, strategic and institutional investors, the producers and EPC contractors. AGDC, acting as developer, would pull together risk allocation, a range of investors, a focus on the Asia market and best-in-class project management using EPC firms to manage construction risk. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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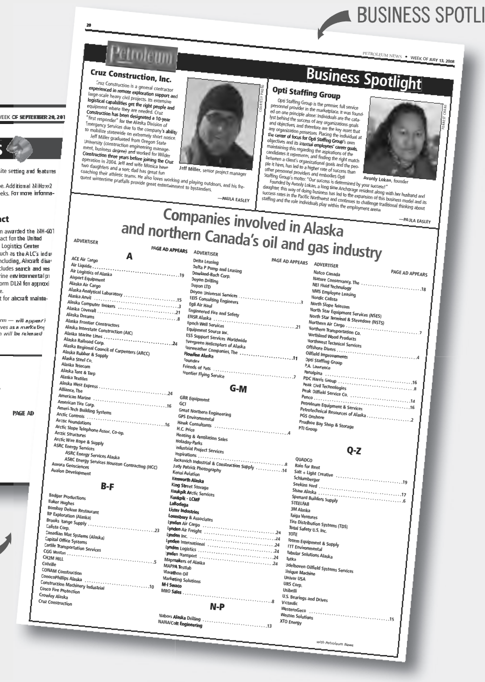

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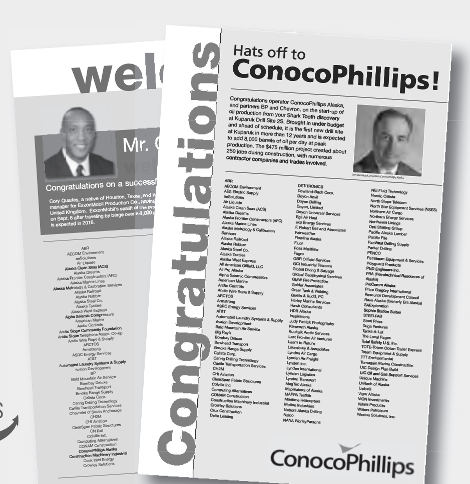

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LAND & LEASING

State lease activity minor in March

The Alaska Department of Natural Resources conducted limited lease activity in March.

•The Glacier subsidiary Savant Alaska LLC relinquished lease ADL 392604. The lease was part of a cluster on the eastern North Slope, along the Canning River, associated with the Yukon Gold prospect. The lease was set to expire at the end of November 2022.

Earlier this year, Savant relinquished ADL 392098, which was also part of the cluster.

•The state terminated two North Slope leases — ADL 392540 and ADL 392541 — operated by Accumulate Energy Inc. for failure to pay rent, but reinstated the leases five days later. The two leases sit just west of the trans-Alaska oil pipeline and just south of the Franklin Bluffs pad where the company has been conducting its Icewine program.

•NordAq Energy Inc. relinquished five Cook Inlet leases — ADL 391597, ADL 392645, ADL 392646, ADL 392647 and ADL 392651. The leases were located off the coast of Nikiski, near the East Foreland Production Facility. One lease was set to expire at the end of February 2018 and the other four at the end of February 2025. NordAq retained one lease in the cluster — ADL 391838 — scheduled to expire at the end of August 2019.

•The state rejected requests from A. Lawrence Berry to transfer 7.875 percent working interests in 37 leases at the Kitchen Lights unit to the Allen Lawrence Berry 2007 Trust.

•The state approved requests from Samson Offshore LLC to transfer small working and royalty interests in 15 Point Thomson unit leases to ExxonMobil Alaska Production Inc.

The interests were all less than 1 percent.

•The state is considering requests from John W. Yule to transfer royalty interests less than 1 percent in two Cook Inlet leases — ADL 374002 and ADL 378114 — to the Yule Family 2016 Trust. The two leases are associated with the Glacier-operated Redoubt unit.

—A copyrighted oil and gas lease map from Mapmakers Alaska was a research tool used in preparing this story.

—ERIC LIDJI

LAND & LEASING

Two spring areawide lease sales June 21

The Alaska Department of Natural Resources, Division of Oil and Gas, has scheduled bid openings for the annual areawide Cook Inlet and Alaska Peninsula lease sales for June 21 at the Atwood Building in Anchorage.

Sealed bids are due June 19 by 4 p.m.

The Alaska Peninsula areawide sale covers some 4 million onshore and 1.75 million offshore acres, with 1,047 tracts ranging from 640 to 5,760 acres on the north side of the Alaska Peninsula from the Nushagak Peninsula south and west to the vicinity of Cold Bay.

There has been almost no recent leasing interest in the Alaska Peninsula in the last decade. The state received no bids in the last two Alaska Peninsula areawide sales, and while two bidders bid in the 2014 sale, taking three tracts, the leases are no longer active. While the state received no bids in the 2016 Cook Inlet areawide oil and gas lease sale that area typically has drawn at least some interest. The Cook Inlet areawide encompasses some 4.2 million gross acres, 815 tracts ranging from 640 to 5,760 acres in the Municipality of Anchorage and the Matanuska-Susitna and Kenai boroughs. Cook Inlet acreage receiving bids in recent years ranged from a low of 5,733 acres in 2009 to a high of 449,164 acres in 2011.

Details on the sales are available on the division's website at http://dog.dnr.alaska.gov/Leasing/SaleDocuments.htm.

—KRISTEN NELSON

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PLANT BIDS

natural gas coming from the Cook Inlet basin as a consequence of oil exploration and development. Over the years the plant produced LNG for delivery by tanker to Japan.

However, in more recent years, as gas supplies from the Cook Inlet tightened and the price of Cook Inlet gas increased, the export of LNG from Nikiski slowed. The number of LNG cargoes dropped to just five in 2014 and six in 2015. Hit by the plunge in global LNG prices, the Nikiski facility did not export any LNG in 2016. A report published in 2006 indicated that, given the plant's age, it will need some modernization.

However, the facility presumably retains value as an operational and permitted LNG plant, at tidewater in a region with plentiful gas supplies, and with local gas producers looking for market outlets.

—ALAN BAILEY

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SPRING FORECAST

lations on application of per-taxable-barrel credits for non-GVR (legacy) oil.

If the spring forecast had been released when the draft was completed, the department would have had to come back later and report an additional $100 million in revenue once companies complied with the advisory bulletin, Hoffbeck said, telling Senate Finance they had finalized the last numbers at 4 o'clock the preceding afternoon.

Both oil price forecasts and oil production forecasts are up by 7 percent for FY 2017 (the fiscal year ending June 30) compared to the fall forecast, Hoffbeck said. Post-FY 2018 the oil price forecast is unchanged from the fall forecast, and long-term prices, in FY 2025 and beyond, are expected to settle in the $70-$75 per barrel range, he said.

The spring forecast for the FY 2017 ANS West Coast per barrel price is $50.05, compared to $46.81 in the fall forecast, while ANS oil production is now forecast at 523,700 bpd for FY 2017, up from 490,300 bpd in the fall forecast, both 7 percent increases.

Alaska North Slope deductible lease expenditures, on the other hand, are down 7 percent from the fall 2016 forecast, an estimated $4,519.2 million in the spring forecast, compared to $4,867.6 million in the fall.

Production forecast another issue

The other wrinkle Hoffbeck addressed was the FY 2018 ANS production forecast — 459,900 bpd in the spring forecast compared to 455,600 bpd in the fall forecast, a 1 percent difference.

With the uptick in the FY 2017 volume, however, that would mean a 12 percent drop in ANS production between FY 2017 and FY 2018.

Hoffbeck said the department is not forecasting a decline. What happened, he said, is that the current year's numbers are updated but the Department of Natural Resources only does a whole new forecast in the fall, so the FY 2018 forecast number is stale.

Chantal Walsh, director of DNR's Division of Oil and Gas, said the fall forecast was the first DNR had done. Ed King, special assistant to the DNR commissioner, said DNR did the forecast in the fall for delivery to the Department of Revenue in the fall. That has not been updated for spring, he said, so the numbers shown for FY 2018 are stale. He said DNR does not anticipate a 12 percent decline over the next year.

Walsh said Alaska has just finished a second year of flat production on the North Slope with virtually no decline from major fields but cautioned that expecting production to hold flat for multiple years with low oil prices would be rather optimistic. We have seen flat production for two years, she said, noting that there had been flat spending.

King said the process has been the same over the last five years, whether the forecast was done by a consultant or in-house, with the spring production numbers just an update. He said the department is collecting the numbers that will go into the next forecast, but said DNR didn't have the resources to do a full field-by-field forecast the way they do it in the fall.

Hoffbeck said FY 2017 unrestricted general fund petroleum revenue was up 20 percent from the fall forecast, $1,158.5 million, compared to the fall forecast of $966.9 million, an increase of $191.6 million.

For FY 2018, the forecast price of ANS on the West Coast remains the same as the fall forecast, at $54 per barrel while unrestricted general fund petroleum revenue is projected to be up by 16 percent from the fall forecast, $1,279 million compared to the forecast $1,099.8 million, an increase of $179.2 million.

—KRISTEN NELSON

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BP WELL

well pad. BP set up a command post on the North Slope for the incident and ramped up an incident management team involving BP, the Alaska Department of Environmental Conservation, the Environmental Protection Agency and the North Slope Borough.

The response team determined that there were two leaks on the wellhead: an oil leak near the top and a gas leak farther down. The sprayed oil had been coming from the top leak, which was stopped by activating the well's surface safety valve, according to an April 15 situation report. BP has said that, following the kill action on April 17, all leakage from the well has now been stopped.

The cause of the leaks has yet to be determined.

Rose three to four feet

According to ADEC, an initial attempt to bring the well under control on April 14 failed because of damage to a well pressure gauge. Apparently, the wellhead had risen three to four feet, causing the pressure gauge to break off, thus preventing the responders from pumping fluid into the well to kill it. The wellhead has since settled by 11 inches and has not moved further, ADEC said. Personnel from well control contractor Boots and Coots safely entered the well house on April 16 and placed a plug in the damaged piping coming from the well head. That then enabled the responders to pump the necessary fluid into the well to kill it.

The initial spray of oil associated with the gas venting landed on the Drill Site 2 gravel pad. According to ADEC, a forward looking infrared overflight on April 14 showed that the crude spray plume did not leave the pad, and that the impact of the oil leak is limited to the pad's reserve pit. However, there have not yet been any reports from cleanup responders on the extent of the oil contamination. ●

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INLET SPILL

Gas leak stopped

Meanwhile divers have successfully stopped the release of gas from the subsea pipeline that supplies fuel gas to Hilcorp's Middle Ground Shoal field on the west side of the Cook Inlet. The divers fitted a clamp over a gash in the line that had been causing the leak, Hilcorp Alaska announced April 14. Hilcorp discovered the leak in early February and in late March shut down the oil field, to enable the gas pressure in the line to be reduced to a minimum level. The company has said that it will not return the gas line to service until the completion of a permanent repair, the conducting of pressure testing of the line and the approval of the restart by government regulators.

Hilcorp had been unable to commence repair operations until winter sea ice in the inlet had receded sufficiently to enable safe diving operations.

Multiple diving operations

The company said that locating the leak and preparing the gas line for repair involved 12 diving operations. The leak point was found to be on the bottom of the pipeline, where the line rested on a boulder embedded in the seafloor. A visual inspection suggested a breach about 2 inches long, but exact measurements determined an actual size of three-sixteenth inches by three-eighth inches, Hilcorp said. After cleaning and preparation of the damaged area, divers installed a steel and rubber clamp over the leak, thus assuring a gas- and liquid-tight seal that will reinforce the pipeline, Hilcorp said. According to the Alaska Department of Environmental Conservation, dive boat operators confirmed that the bubbling of gas from the leak stopped after the clamp had been installed.

The federal Pipeline and Hazardous Materials Safety Administration has expressed concern about the condition of the subsea pipeline that delivers oil from the Middle Ground Shoal field to onshore. The oil line is of similar construction to the gas line and both lines are 8 inches in diameter. PHMSA has said that previous issues with damage to the subsea pipelines in the area appear to have resulted from the vibration of the lines against rocks on the seafloor, as a consequence of water currents in the inlet. The agency wants Hilcorp to inspect the oil line for damage.

Hilcorp said that it has provided details of the repair operation on the gas line to both ADEC and PHMSA. The company said that it was going to conduct further inspections and stabilization of both the gas and the oil pipelines, as weather permits.

"Neither pipeline will be returned to regular service until Hilcorp, along with state and federal regulators, agree it is safe to do so," Hilcorp said.

Environmental sampling

According to ADEC, Hilcorp has been conducting air sampling in the area of the leak to test for the presence of methane, carbon dioxide and volatile organic compounds. The damaged pipeline carries fuel gas, consisting of almost pure methane. However, the line had previously been used to carry oil. Hilcorp has also been conducting water sampling in the area of the leak, to check for concentrations of methane and dissolved oxygen in the water. And on March 24 Hilcorp initiated sampling to monitor methane, carbon dioxide and oxygen levels at the water surface, ADEC said. Hilcorp has been delivering reports from its sampling operations to ADEC.

The company is also investigating a metering discrepancy for gas flowing through the gas pipeline that connects the Steelhead platform to shore. ●

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TAXES AND CREDITS

the Senate seriously wants to solve, Giessel said.

The middle bucket is what the state will do going forward in terms of accruing more debt and how to fix that.

The third bucket is SB 21 and the question of whether it's working. "We believe it is," and fundamentally want to leave it in place, Giessel said, but the 4 percent hard floor is another issue: it was believed to be hard and isn't. "That's something we have to deal with," she said.

But SB 21 is complex and changing one element puts other elements out of alignment, which is a challenge, Giessel said, noting that it was unfortunate the bill came to the Senate so late in the session because the topics are serious and the goal is to make something durable. ●

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EXPLORATION & PRODUCTION

California platform to be decommissioned

A Southern California offshore oil platform will be decommissioned and its operator is seeking bankruptcy protection, nearly two years after the platform was idled when an onshore pipeline ruptured and spilled a massive amount of oil into the ocean, the state and company said April 17.

The State Lands Commission said it received documents from Venoco LLC relinquishing rights to the South Ellwood oil field leases in the Santa Barbara Channel northwest of Los Angeles, including Platform Holly and a pier in the city of Goleta.

Platform Holly has not produced since May 19, 2015, when an onshore, underground line owned by Plains All American Pipeline spilled more than 120,000 gallons of crude into the ocean. The line, which transported oil produced by Holly, remains shut down and there is no estimate for when it might reopen.

Denver-based Venoco, which acquired the leases in 1997 from ExxonMobil, simultaneously announced it has filed for Chapter 11 bankruptcy protection and expects its assets to be sold. Most are in Southern California, except for an onshore field in Texas.

"Today's filing is the result of unfortunate circumstances impacting the company's financial strength, including the ongoing closure of Plains All American Pipeline's Line 901," Mike Wracher, Venoco's chief operating officer, said in a statement.

He added: "We have pursued a number of market-based and regulatory solutions to address these challenges during the last year. Despite these considerable efforts, our financial position now compels us to take this action."

Venoco had been seeking to restructure as recently as last summer to eliminate $1 billion of debt, but said at the time that low price oil prices and the Line 901 shutdown were serious problems.

The State Lands Commission said the relinquishment of claims to the leases effectively ends commercial oil and gas production in state waters at that location in the Santa Barbara Channel and leaves about 85 million barrels of oil in the ground. New offshore oil and gas leases are prohibited by California's Coastal Sanctuary Act.

The decommissioning of Platform Holly is a "landmark in the evolution of California's energy portfolio," Lt. Gov. Gavin Newsom, the commission's chairman, said in a statement.

"As President Trump voices his determination to expand oil drilling and twentieth-century energy policies, California is pioneering the sustainable alternative that protects our coastlines and environment while gaining a strong foothold in the future energy and global economy," it said.

Platform Holly stands a few miles off the south Santa Barbara County's coast, part of a series of oil platforms in waters between the mainland and the Channel Islands.

The commission said it will develop a plan for the costly process of plugging 32 wells in the South Ellwood Field, removing Platform Holly and decommissioning the Goleta Beach Pier, a process expected to take three years.

—ASSOCIATED PRESS

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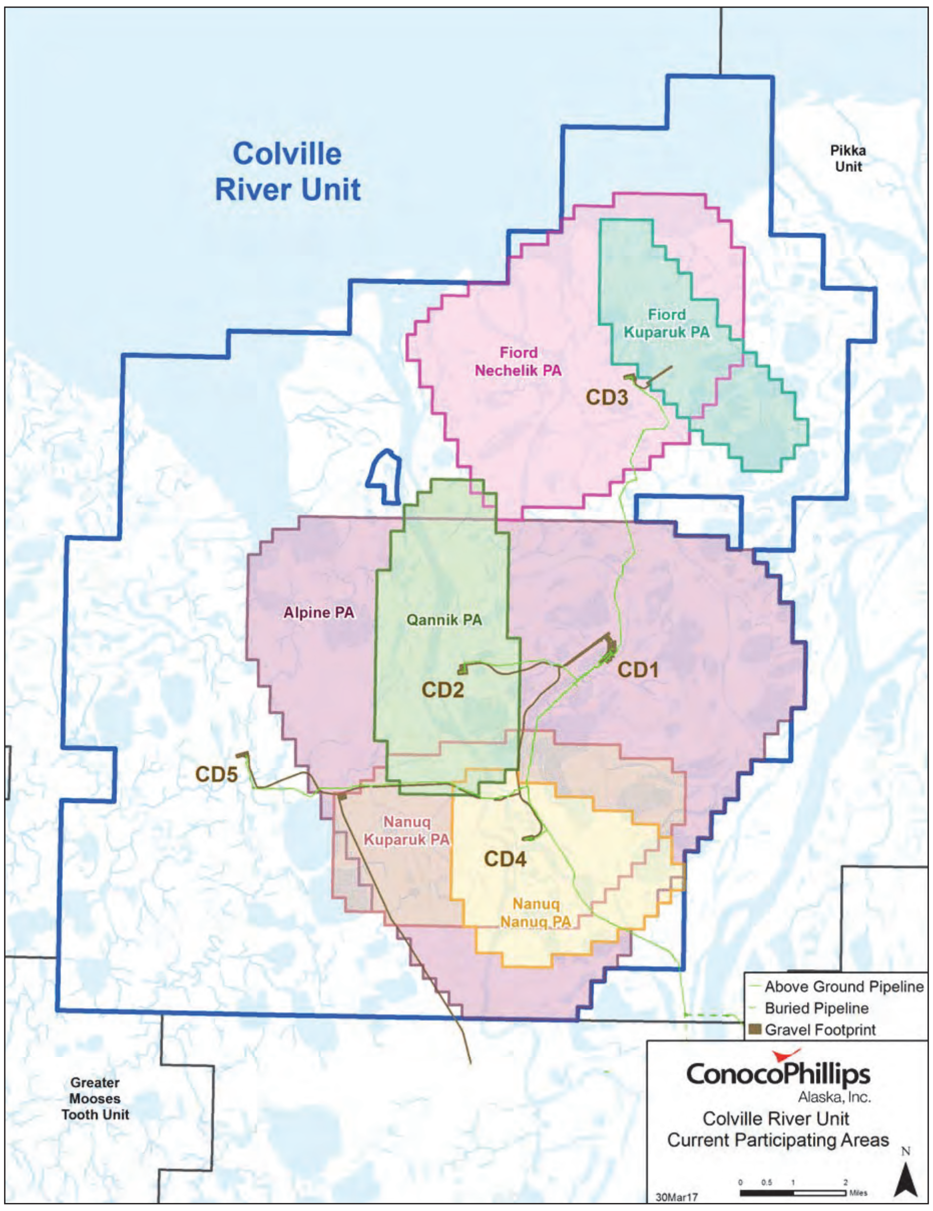
CD-5 WELL PLAN

does not include an exploration well that the company wants to drill in a proposed expansion area south of the Colville River unit.

The future of the exploration program is currently tied up in a regulatory dispute. The state rejected a request from ConocoPhillips to expand the unit, but subsequently agreed to a request from the company to reconsider that decision. ConocoPhillips has offered to drill an exploration well over the coming year or relinquish the expansion acreage.



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Alpine activity

The proposed Putu No. 1 exploration well would target the Nanushuk formation, which is the same formation underlying the recent Armstrong Oil & Gas discoveries at Pikka.

The proposed 14-well development program ConocoPhillips is planning for the Colville River unit this year is largely an extension of its ongoing CD-5 pad development work.

The newest drilling pad at the unit targets the Alpine formation, which is the main oil pool at the unit. ConocoPhillips completed initial development of the Alpine participating area from the CD-1 and CD-2 pads in November 2005 and has since pursued "peripheral opportunities" at corners of the Alpine pool using wells from its satellite drilling pads.

After years of regulatory delays, and months of construction and drilling activities, ConocoPhillips brought the new CD-5 pad into production in late October 2015.

The company drilled nine wells — three producers and six injectors — from the CD-5 pad into the Alpine participating area in 2016, according to its plan of development.

Over the coming year, the company plans to drill both rotary and coiled tubing drilling wells. The rotary program includes seven multilateral wells — three producers and four injectors — into the Alpine participating area, all from the new CD-5 pad. The wells are CD5-20, CD5-17, CD5-19, CD5-9A, CD5-9C, CD5-10AB and CD5-10BC. The company already completed the CD5-18 multilateral well at the unit this January.

The company is also planning four other Alpine participating area wells: three multilateral wells from CD-5 and a re-drill of an existing well at the CD-4 pad. All four wells are currently scheduled for subsequent years, but could be moved to this year.

The coiled tubing drilling program involves adding one or more laterals to the existing CD2-39 and CD2-47 wells. Depending on the results, the company might pursue similar opportunities at the CD2-42, CD2-33B and CD1-03A wells, and other confidential wells.

At the start of 2017, the Alpine pool had 156 wells between the Alpine and Nanuq-Kuparuk participating areas, with 145 wells associated with the Alpine participating area.

The Alpine participating area produced 37,100 barrels of oil per day in 2016, up from 33,300 bpd in 2015. The company attributed the increase to a six-well fracture stimulation program at the Alpine pool. The company is currently planning a five-well fracture stimulation program at the Alpine pool this year, although "the final number could change depending on the opportunities available," according to the company.

The Nanuq-Kuparuk participating area produced 9,600 bpd in 2016, up from 2,300 bpd in 2015. The company said the Nanuq-Kuparuk work "continues to exceed expectations."

ConocoPhillips produced 16.3 million barrels from the two participating areas at the Alpine pool in 2016, up from 13 million barrels produced at the Alpine pool in 2015.

Since bringing the unit into production, ConocoPhillips has drilled three Alpine pool wells on a tract basis: CD1-04, CD1-17 and CD1-47. Although details are confidential, the company provided the state with potential tract wells for 2017 "if geology is present."

Satellites

The recently drilled CD5-18 multilateral well, the seven planned rotary wells, the four un-named wells at CD-5 and CD-4 and the two coiled tubing drilling wells total 14 wells.

But in its plan of development, ConocoPhillips also referred to "other opportunities" at the Alpine participating area and at the other Alpine satellites: Fiord, Nanuq and Qannik.

Those are the confidential listings, at the moment.

ConocoPhillips is not planning any new drilling at the Fiord-Nechelik participating area or at the Fiord-Kuparuk participating area at CD-3 over the coming year, aside from a re-drill of the existing but "collapsed" CD3-111 well. The operation was scheduled for the first quarter of this year. The project includes plans to fracture-stimulate the new well.

As of the start of 2017, the Fiord pool included 28 development wells — 23 at Fiord-Nechelik and five at Fiord-Kuparuk. The participating area produced 8,900 barrels of oil per day in 2016 — 7,800 bpd from Fiord-Nechelik and 1,100 bpd from Fiord-Kuparuk — down from 11,700 bpd in 2015. The decline came entirely from the Fiord-Nechelik.

ConocoPhillips produced 3.2 million barrels of oil from the two participating areas at the Fiord pool in 2016, down from 4.3 million barrels of oil over the course of 2015.

At the Nanuq participating area at the CD-4 pad, ConocoPhillips is considering several potential rotary wells and coiled tubing drilling sidetracks over the coming year.

The list of potential drilling candidates was kept confidential in the plan of development.

At the start of 2017, the Nanuq pool had nine wells. The participating area produced 1,500 barrels per day in 2016, down from 1,600 bpd in 2015. ConocoPhillips produced 500,000 barrels at the participating area in 2016, down from 600,000 barrels in 2015.

ConocoPhillips is also considering several potential rotary wells and coiled tubing drilling sidetracks at the Qannik participating area at CD-2 over the coming year and has also kept the list of potential drilling targets confidential in its plan of development.

At the start of 2017, the Qannik pool had nine wells. The participating area produced 1,500 barrels per day in 2016, down from 1,600 bpd in 2015. ConocoPhillips produced 600,000 barrels at the participating area in 2016, equal to the production rate in 2015. ●

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