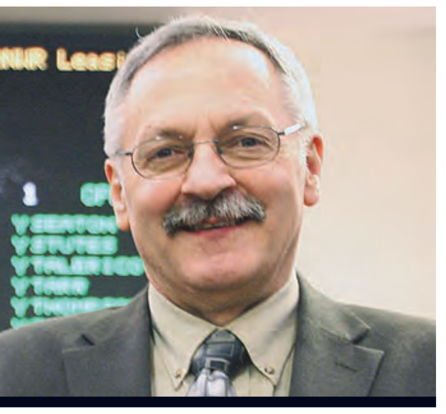
Petroleum news

Celebrating 20 years: 1996-2016



page 5 Q&A: Talerico: Freshman term humbling, required 'heavy lifting'

Vol. 21, No. 27 • www.PetroleumNews.com — A weekly oil & gas newspaper based in Anchorage, Alaska — Week of July 3, 2016 • $2.50

This week's Mining News

NORTH OF 60 MINING news

page 10 Hecla tenders $12M for B.C. silver explorer, Dolly Varden

www.MiningNewsNorth.com — The weekly mining newspaper for Alaska and Canada's North — Week of July 3, 2016

NEWS NUGGETS

Compiled by Shane Lasley

COVENTRY RESOURCES LTD.

Coventry Resources drilled 22 holes at Caribou Dome in 2015, the best of which cut 14.1 meters averaging 9.9 percent copper. This year's planned 8,000-meters program will be nearly double the 4,300 meters drilled last season.

Second rig arrives, more surface copper found at Caribou Dome

Coventry Resources Ltd. June 23 reported the arrival of a second diamond core drilling rig to expedite an 8,000-meter drill program targeting zones of high-grade copper at Caribou Dome, a road-accessible property located about 155 miles north of Anchorage, Alaska. The first rig, which arrived earlier in June, is testing the Lense 3, 9 and 1 targets at Caribou Dome. Coventry reports that the first hole completed in this area hit mineralization where predicted. A second hole is progressing well. The second rig is testing Menel, a high-priority target on strike to the northeast of the 700-meter-long corridor of copper mineralization drilled to date Caribou Dome. Strong induced polarization and copper-in-soil anomalies have been identified at Menel. Additionally, significant copper mineralization was mapped directly above and immediately along strike from the IP anomaly, while preparing to drill the Menel target. Upon completion of initial drilling at Menel, the rig will test Guardian, another untested IP anomaly that was delineated during 2015. Very encouragingly, outcropping gossans were identified during follow-up mapping; with rock chip sam-

see NEWS NUGGETS page 12

CONTANGO ORE

By the spring of 2013, when this photo was taken, Contango Ore had narrowed its exploration primarily to the Peak Zone. According to a resource calculated later that year, this deposit hosts the equivalent of 1.2 million ounces of gold when you include the value of the copper and silver also found there.

EXPLORATION

Making the connection

$11 million program targets area between high-grade gold zones at Tetlin

By SHANE LASLEY

Mining News

From a Texas oilman discovering rich mineral prospects at Tetlin while investigating the natural gas potential of these Native owned lands to a royalty company setting aside its business model to get in on the ground floor of what is shaping up to be a multimillion-ounce deposit of high-grade gold lying alongside the Alaska Highway, Contango Ore Inc. is adding some intriguing new entries to the annals of Alaska geology.

The latest chapter of the Tetlin story includes a US$11 million exploration program – likely the largest such program in Alaska this year – that aims to prove that the Peak deposit and North Peak zone are actually one large continuous deposit of high-grade gold-copper-silver mineralization.

This robust exploration campaign is being funded by Royal Gold Inc., which is well on its way to earning up to a 40 percent interest in Tetlin by investing up to US$30 million in this expansive and still underexplored project by October 2018.

Finding Peak

Contango Ore President and CEO Brad Juneau was not looking for gold when he ventured into Alaska in 2008. Instead, his privately held company, Juneau Exploration L.P., was investigating the natural gas potential of a large land package owned by the Tetlin Village Council, an Alaska Native group.

Juneau's exploration of Tetlin did not turn up much in the way of natural gas potential, but the

see TETLIN page 10

Royal Gold's $11 million program targets area between high-grade gold zones at Tetlin. Read more in Mining News, page 9.

Aurora Gas files for bankruptcy

Aurora Gas LLC entered bankruptcy protection earlier this year after three creditors petitioned a bankruptcy court, claiming nearly $400,000 in combined unpaid debt.

In a statement filed with the United States Bankruptcy Court for the District of Alaska, Aurora Gas President J. Edward Jones reported a loss of $923,238 for 2015. Jones blamed the loss on a combination of declining natural gas production and a workover project that cost more than $1 million but failed to

see AURORA GAS page 18

88 Energy plans Icewine follow-up

88 Energy Ltd. is planning a second well at its Icewine prospect.

Through its subsidiary Accumulate Energy Alaska Inc., the Australian independent is permitting and fundraising for the proposed Icewine No. 2-H well at the onshore prospect covering nearly 272,000 acres in the central North Slope, south of the Prudhoe Bay unit.

Along with minority partner Burgundy Xploration, 88

see ICEWINE FOLLOW-UP page 16

EIA anticipates oil price rise

The Energy Information Administration's newly published Energy Outlook 2016 report foresees in its reference case an oil price of $52 per barrel in 2017, rising to about $100 in 2030. But, when introducing the new report on June 28, EIA Administrator Adam Sieminski cautioned about the huge uncertainties in oil price forecasting — Sieminski suggested that people use the various energy scenarios that EIA has analyzed and the corresponding energy price models as a basis for evaluating what is hap-

see PRICE RISE page 20

NATURAL GAS

The momentum issue

AGDC head says it can step into lead in AKLNG with alternative structure

By KRISTEN NELSON

Petroleum News

KEITH MEYER

Keith Meyer, the new president of the Alaska Gasline Development Corp., told a joint House-Senate Resources committees meeting June 29 that with infrastructure-type financing AGDC could step into the lead on the Alaska LNG Project, maintaining momentum in an unfavorable market.

Under the plan which the Legislature approved with Senate Bill 138 in 2014, the state took an equity share in the project along with the producers, with shares based on natural gas ownership.

Meyer said the technical team has done an excellent job on cost reduction, but it is now time to look at other aspects of cost, financing and the cost of capital to get the project done, including taxes.

The project cost is a bit high now to clear the market and as a result the project is slowing down, Meyer said.

1 2 SERIES

Asked by Rep. Mike Hawker, R-Anchorage, if he was prejudiced against producer participation and ownership, Meyer said he was not. Equity-based financing, with each party owning a share of the capacity, works well in certain regimes and works well for project participants because it

see AGDC ROLE page 19

FINANCE & ECONOMY

Walker vetoes credits

$430 million in oil, tax gas credits dropped from budget but obligation remains

By TIM BRADNER

For Petroleum News

KEN ALPER

Gov. Bill Walker signed a new law June 29 sharply cutting oil and gas exploration tax credits and also vetoed $430 million in funding for the credits.

Walker acted to stem red ink as Alaska faces multibillion-dollar budget deficits due to low oil prices.

Alaska industry officials reacted in dismay.

"These credits were earned in good faith by companies investing in Alaska oil and gas development projects under the state's own policy. The veto is shortsighted because the state is obligated to make good on its commitments," said Kara Moriarty, president of the Alaska Oil and Gas Association.

Alaska's tax credit program is intended to spur new oil and gas development, and a unique feature is that the state purchases the credits for cash, mainly from small companies.

Some firms are caught in the middle of developments. The actions may have effects on at least three new projects, Caelus Energy's planned Nuna and Brooks Range Petroleum's Mustang projects on the North Slope, and BlueCrest Energy's Cosmopolitan project in Cook Inlet.

These could add 25,000 barrels a day or more to

see CREDITS DROPPED page 18

PIPELINES & DOWNSTREAM

Trudeau talks 'tradeoffs'

Prime minister cautions that not all can be satisfied if oil export line approved

By GARY PARK

For Petroleum News

Canadian Prime Minister Justin Trudeau has given a broad hint that his government is prepared to approve at least one new export pipeline out of the oil sands.

In ruling out any prospect of reaching "100 percent unanimity" among governments, industry, local communities, First Nations and environmentalists on any project, he said final decisions are all about "tradeoffs" that are "an art as much as a science."

"We have complex situations with multiple answers, with people who do better out of some scenarios than others," he told PostMedia News.

"What we need to do as a government is fold in a broad range of perspectives, understand the concerns, work to allay the fears as much as we possibly can on a broad range of levels" and work towards consensus, Trudeau said.

"You don't ever hope for total 100 percent unanimity but you do hope you're going to get a sense that this is the right way to move forward."

If his message was intended to point towards a green light for at least one of the three projects now before the federal government or federal regulators the best chances lie with Kinder Morgan's C$6.8 billion expansion of its Trans Mountain network from Edmonton to Vancouver — a proposal that is expected to receive a final verdict in December.

Trudeau's comments coincided with results of a new poll by the Angus Reid Institute of 1,505 Canadians between May 30 and June 6 that showed

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ON THE COVER

ENVIRONMENT & SAFETY

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Alaska - Mackenzie Rig Report

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

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Milne Point C-15A	Hilcorp
Dreco 1000 UE	16 (SCR/TD)	Standby	BP
Dreco D2000 Uebd	19 (SCR/TD)	Alpine CD5-12	ConocoPhillips
AC Mobile	25	Standby	
OIME 2000	141 (SCR/TD)	Kuparuk 2S-12	ConocoPhillips
	142 (SCR/TD)	Kuparuk 1L-20	ConocoPhillips
Hillcorp Alaska LLC			
	Rig No.1	Milne Point	Hilcorp Alaska LLC
Kuukpik Drilling	5	Offshore Modification	Hilcorp
Nabors Alaska Drilling			
AC Coil Hybrid	CDR-2	Kuparuk 2F-18	ConocoPhillips
Dreco 1000 UE	2-ES (SCR-TD)	Deadhorse	Available
Mid-Continental U36A	3-S	Deadhorse	Available
Oilwell 700 E	4-ES (SCR)	Deadhorse	Available
Dreco 1000 UE	7-ES (SCR/TD)	Deadhorse	Available
Dreco 1000 UE	9-ES (SCR/TD)	Deadhorse	Available
Oilwell 2000 Hercules	14-E (SCR)	Deadhorse	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Mustang location	Available
Oilwell 2000 Canrig 1050E	27-E (SCR-TD)	Deadhorse	Available
Oilwell 2000	33-E	Deadhorse	Available
Academy AC Electric CANRIG	99AC (AC-TD)	Deadhorse	Available
OIME 2000	245-E (SCR-ACTD)	Oliktok Point	ENI
Academy AC electric CANRIG	105AC (AC-TD)	Deadhorse	Available
Academy AC electric Heli-Rig	106AC (AC-TD)	Deadhorse	Available
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay, Standby	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay Drill Site K, Well 07	BP
Ideco 900	3 (SCR/TD)		Available
Parker Drilling Arctic Operating Inc.			
NOV ADS-10SD	272	Prudhoe Bay DS 18	BP
NOV ADS-10SD	273	Prudhoe Bay DSW-59	BP

North Slope - Offshore

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

Interior Alaska

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
TSM 7000	Arctic Fox #1	Nenana Toghotthele #1	Horizon Oil

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Miller Energy Resources			
Mesa 1000	Rig 37	Mobilized to North Fork to begin drilling this winter	Miller Energy Resources
All American Oilfield LLC			
IDECO H-37	AAO 111	In All American Oilfield's yard in Kenai, Alaska	Available
Aurora Well Services			
Franks 300 Srs. Explorer III	AWS 1	Stacked out west side of Cook Inlet	Available
Saxon			
TSM-850	147	Stacked	Hilcorp Alaska LLC
TSM-850	169	Stacked	Hilcorp Alaska LLC

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Hilcorp Alaska LLC			
National 110	C (TD)	Platform C, Stacked	Hilcorp Alaska LLC
	Rig 51	Steelhead Platform, Stacked	Hilcorp Alaska LLC
	Rig 51	Monopod Platform, Drilling	Hilcorp Alaska LLC
Spartan Drilling			
Baker Marine ILC-Skidoff, jack-up		Spartan 151 Upper Cook Inlet KLU#1	Furie
Cook Inlet Energy			
National 1320	35	Osprey Platform, Suspended	Cook Inlet Energy

Mackenzie Rig Status

Canadian Beaufort Sea

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

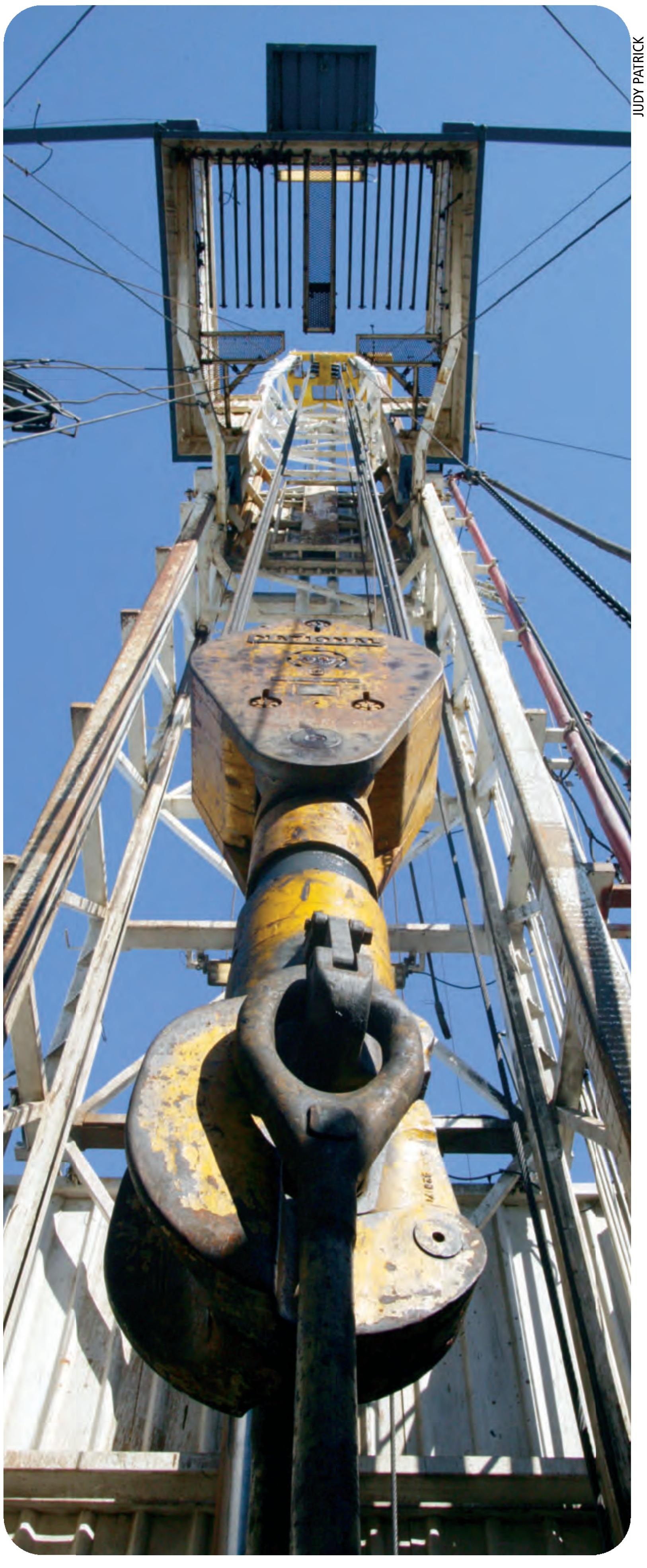
Central Mackenzie Valley

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

The Alaska - Mackenzie Rig Report as of June 29, 2016.
Active drilling companies only listed.

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

This rig report was prepared by Marti Reeve



JUDY PATRICK

Baker Hughes North America rotary rig counts*

	June 24	June 17	Year Ago
United States	421	424	859
Canada	76	69	135
Gulf of Mexico	20	21	28

Highest/Lowest

US/Highest	4530	December 1981
US/Lowest	488	April 1999
Canada/Highest	558	January 2000
Canada/Lowest	29	April 1992

*Issued by Baker Hughes since 1944

● PIPELINES & DOWNSTREAM

CIE protests Cook Inlet Pipe Line tariff

Rate determined by settlement agreement between pipeline, state; Cook Inlet Energy not a party, says it is not bound by the terms

By KRISTEN NELSON
Petroleum News

Cook Inlet Energy is protesting the new tariff for the Cook Inlet Pipe Line the company uses to ship its crude oil on the west side of Cook Inlet to market.

A protest filed with the Regulatory Commission of Alaska in December by Brena, Bell & Clarkson on behalf of CIE said a settlement reached between CIPL and the state in 2001, last amended in 2009, granted a waiver from certain filing requirements "based upon the then-short life expectancy of the CIPL facilities," and said that as a result, the pipeline has not "filed testimony or submitted certain information typically required in support of a proposed rate change."

The protest also said that since CIE is not a party to the settlement it is not bound by its terms, or by the rates resulting from the settlement.

"The RCA has long held that nonparties to a settlement are not bound by the terms of the settlement and are free to require a just-and-reasonable rate be established," the protest said.

2010 settlement

In an order establishing a docket, and inviting participation by the state attorney general, RCA noted that a 2010 settlement between CIPL and CIE resolved relevant issues in a 2010 docket, but did not change any of the Cook Inlet settlement methodology provisions established in the 2001 settlement and subsequent amendments.

The commission said the 2010 settlement left the settlement methodology uninterrupted "with the 2010 Settlement Agreement terms being implemented separately from the tariff." That 2010 settlement agreement expired at the end of 2014, RCA said.

While CIE protested 2015 rates (rates are files annually), RCA said it "ruled that CIE's comments were in violation of the 2010 Settlement Agreement."

CIPL filed 2016 rates in December and CIE protested.

"Because of the protest and because the rate contained in (the new tariff filing) has not been shown to be just and reasonable and may be unjust and unreasonable," the proposed rate is suspended and CIPL is allowed to collect it on a temporary basis, the commission said.

The proposed 2016 rate is $4.47 per barrel, an increase from $3.75 per barrel.

The Regulatory Affairs and Public Advocacy Section of the attorney general's office filed to participate in the docket in early January.

Settlement methodology

Cook Inlet Pipe Line, responding through its attorneys Guess & Rudd, said the tariff was filed in accordance with the Cook Inlet Settlement Methodology as required by the pipeline's settlement agreement with the state.

Since CIE is protesting the settlement agreement, CIPL expects the state to participate in the docket "in support of the continuing validity and enforceability of the Settlement Agreement and the CISM."

The response says CIPL denies the CIE allegation "that changed circumstances warrant the termination of the use of the CISM for ratemaking purposes," as well as denying allegations that the settlement methodology "does not result in just and reasonable rates" including allegations that dismantlement, removal and restoration and the pipeline's capital expenditures "are not properly included in CIPL's rates."

In a January update to the commission Ed Sniffen Jr. of the Department of Law's Regulatory Affairs and Public Advocacy section, said the parties were engaged in discussions which might resolve the issues presented in filings, and requested a procedural stay for 60 days.

Disagreement on procedure

But a subsequent status report, filed by CIE's attorneys June 14, requested that scheduling of a prehearing conference, and said that settlement discussions between CIE and CIPL since early in the year "have not been successful," and said it was requesting a prehearing conference because of "the breakdown in settlement attempts."

A June 15 filing by CIPL's attorneys requested "institution of alternative dispute resolution ... including appointment of a mediator" and said CIPL and the state "worked long and hard to develop a durable settlement agreement that would be suitable for the remaining life of the pipeline and would result in rates that were fair both to the pipeline and its shippers."

In a June 27 response to the motion for alternative dispute resolution procedures, CIE reiterated that it was not a party to the settlement agreement between CIPL and the state and said informal settlement discussions between January and May were unsuccessful.

A settlement process may be useful in the future, CIE said in its response, but that would be only after CIPL makes a filing with the commission and CIE has an opportunity to conduct discovery.

"In the experience of CIE and its counsel, the most productive settlement discussion, whether through mediation or otherwise, occurs after the parties have a full understanding of the matters at issue," which cannot happen, CIE said, until CIPL "lays out its rate case in the form of a 275(a) filing, and CIE has had an opportunity to review that filing and to conduct discovery thereon." ●

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LAND & LEASING

No substantial new info for fall sales

The Alaska Department of Natural Resources' Division of Oil and Gas has issued a decision of no substantial new information for the state's fall areawide oil and gas lease sales — Beaufort Sea, North Slope and North Slope Foothills.

The division said June 24 that it only received one timely comment, that on the North Slope Foothills best interest finding, that referenced and included documents. There were no comments received on the Beaufort Sea and North Slope best interest findings.

The North Slope Foothills comment was from the National Park Service and addressed issues ranging from concerns about wildlife populations in the area to the impact of oil and gas development on the Gates of the Arctic National Park and Preserve. The decision found that much of the information provided by NPS did not constitute substantial new information or would not substantially change information discussed in the best interest finding. Other comments from the agency were outside the scope of the best interest finding on lease sale issues or did not relate to authorities of the division.

The division said the information received would be reviewed and updated when the division begins work on the next best interest findings for the areawide lease sales.

—PETROLEUM NEWS

● GOVERNMENT

Talerico: Freshman term humbling

Healy Republican says first two years in office required some 'heavy lifting,' including conference committee emergence of HB 247

By STEVE QUINN
For Petroleum News

House Resources Co-Chair David Talerico is closing out his freshman term on an intense note, serving as chair for the conference committee that hashed out differences on HB 247, Gov. Walker's oil tax credit bill.

Talerico's work may not be done yet, depending on what Walker brings forth in the coming special session. There was also the June 29 AKLNG quarterly update.


REP. DAVE TALERICO

The Healy Republican spoke to Petroleum News about his tenure shortly after the House and Senate gaveled out, before Gov. Walker called the Legislature back into session and outside Petroleum News deadline to get thoughts on the AKLNG quarterly update.

Petroleum News: First, let's start by looking at your two years as co-chair. Freshman lawmaker comes in and is voted to be co-chair of resources. What your thoughts on those two years?

Talerico: You know what there's been some heavy lifting these two years. What always comes to mind is HB 247 and oil tax credits, which was not only a heavy lift — a lot of consideration went into it — a lot of study. What an educational process this has been. I thought I knew a little something about oil taxes and credits before I got here and I did study up a little bit.

I certainly know a lot more know about what we have in place. I know more about the history and where we are headed in the future.

I consider myself to be really fortunate to be put in that position to be able to deal with it. It's probably a very historical session, and getting more historical as we go. Historical or hysterical however you want to look at it. I felt honestly privileged to be able to participate in this part of it. Right now I would say the general consensus, at least from my perspective, is I'm not sure everyone understands the magnitude of the change that we made.

I get a lot of emails from people saying that tax credit bill is flawed and we really didn't really eliminate anything. Quite honestly the transitional period over the next two years and what was done in Cook Inlet is incredibly substantial: Getting rid of well lease expenditures, qualified capital expenditures. Just really carving all of that down to where we don't have that big liability in 2018 and beyond is pretty substantial.

The hardest part is when I explain it to people. They talk about we are giving away $775 million in credits. Actually those are credits that have been certified and acquired. So that's something we've got on our books. Whether we pay for it right now or later, those are credits people had already earned at this point. What we have done is we are taking a transitional step over two years and eliminating a bulk of that credit program.

That's a big, big step, I think. There has been a lot of discussion on the North Slope and the net operating loss. And of course the net operating losses are really tied to the producers. It's not unusual to have a net operating loss system where taxes are tied to people who produce. I think that's something that will come up in the future. Where we go on it, I don't know.

One of the changes we did make on the North Slope that we did put in place on SB 21 was the gross value reduction. It didn't have an end date — when does a new well turn into a legacy well? When does that new oil end? That actually does have a timeline on it now, something else we did in HB 247.

It seems like everybody didn't get what they wanted but that's the legislative processes, where we got. You want the whole pizza and we got half or three-quarters. I know people seem to be pretty distraught that they don't think we went far enough. It actually did make what I think is a significant change that we are advancing forward on. We took a giant bite out of Cook Inlet.

Petroleum News: Were you surprised that you were made chair of the conference committee, realizing that it was a House bill so it was going to come from your chamber?

Talerico: I was a little surprised, yeah I was. But I took it seriously. I'm not a person who has tremendous amount of legislative experience at the state level. I'm glad I had the previous municipal experience that I had. Probably a difference with me is I'm not real shy in front of a crowd. I don't have much problem in having my voice heard, but I was sitting there with seasoned veterans. I was the only freshman legislator on the committee. We had good people from the House, Rep. (Geran) Tarr and Rep. (Kurt) Olson. The Senate had Sen. (Peter) Micciche, Sen. (Cathy) Giessel and Sen. (John) Coghill. When people came in the room, I try to read people's faces. I didn't feel awkward, but I didn't know if anyone else wondered, why is Talerico chairing this meeting? He's got the least amount of experience of anyone up there at least at the state level. The other five were great people to work with. The one thing I wanted to make sure of from the chair's position is that everyone had the opportunity to be heard and that it was thorough and I think we did do that.

Petroleum News: Do you foresee these issues coming up again in the next two-year session?

Talerico: I would assume it's going to be brought up. A lot of it, of course, is going to depend on our fiscal situation. So much hinges — everything really for 30 years — on the price of a barrel of oil. Some of the promising news I've seen was to at least stop the decline of the flow of oil that came down the pipeline last year. We had a day where we were really close to 600,000 barrels (574,000 on Jan. 11). Future legislators have to look for a way to further diversify our revenue stream. Is it more resource development outside of oil and gas? That probably helps. Do we keep our fingers crossed with tourism, although tourism is looking pretty strong? What does our future hold? What are we going to do to generate more revenue? The more diverse stream we have of being able to generate revenue, obviously that provides stability to your economics. There is a lot people need to start considering now. For quite a few years, oil will be the driver. I have a pretty upbeat positive look on where we are headed because of the production numbers that I've seen and what's going on in the North Slope, plus a few things that happened in Cook Inlet. One of those things was the royalty oil contract in Cook Inlet with Tesoro (HB 373). I think that's a positive thing for the state, but as we look forward with our fiscal situation and how we fix this budget, there seems to be a lot of focus on these large $100 million grabs and fixes.

I hope we can continue to look at those smaller things as well. We still are going to have to look at the efficiencies of our government and try to make the necessary cuts. There will be more prioritization of departments and programs and how we can do that to make it run better. Efficiencies generally mean money savings. You know a lot of people come up to me said we need to do something rapidly. We've got to fix it.

Petroleum News: When you were running for office in the summer of 2014, oil was still at $100 a barrel, then hit $80 by the time you got elected. So you weren't even discussing this with your constituents. So what does it tell you that when you're running for office, it stands at one number then by the time you get sworn in it was about half of that?

Talerico: It's a very volatile market. It's something we all need to consider. It hasn't just been oil as well.

see TALERICO Q&A page 17

● NATURAL GAS

CEA proposes price for Beluga field gas

Asks RCA to approve internal billing of $5.57 per mcf for gas used for power generation from its share of Cook Inlet gas field

By ALAN BAILEY
Petroleum News

In a June 21 tariff advice to the Regulatory Commission of Alaska, Chugach Electric Association has asked for approval for a price of $5.57 per thousand cubic feet for gas that the utility obtains from its share of the Beluga gas field on the west side of Cook Inlet. Although gas production costs may vary considerably from one field to another, depending on factors such as the size, age and complexity of the field, the filing sheds some light on the cost of gas production from a major Cook Inlet gas field and, hence, the price threshold for producer profitability in the Cook Inlet gas market.

Earlier this year utilities Chugach Electric and Municipal Light & Power purchased ConocoPhillips' interests in the Beluga River field, a transaction that resulted in Chugach Electric owning 10 percent of the field. ML&P, which already owned a portion of the field, now owns a 56.67 percent interest. Hilcorp Alaska, the other field owner, with 33.33 percent, is field operator.

The electric utilities' interest in part owning the field is their ability to obtain gas supplies at below market cost — the utilities need to be able to recover their shares of the field operating costs but do not need to make a profit on the gas production.

The gas transfer price

The $5.57 gas price that Chugach Electric has proposed is the utility's internal Beluga field gas price, referred to as a gas transfer price, or GTP. The GTP and associated Beluga gas supply volumes are added to the utility's portfolio of gas prices and supply volumes that ultimately determine the cost of the gas fuel that the utility uses. That fuel cost forms a major factor in the price that the utility charges its customers for electricity.

Currently Chugach Electric is applying an interim GTP of $5.88 to its gas from the Beluga field. According to RCA tariff filings the utility is also obtaining gas at $1.88 per mcf through a ConocoPhillips contract which expires in December, and at $7.42 through a supply agreement with Hilcorp Alaska. The ConocoPhillips contract is indexed to gas prices in the Lower 48, while the Hilcorp pricing is based on a consent decree agreed between Hilcorp and the state of Alaska.

Essentially, Chugach Electric has determined the new GTP, which will apply from Oct. 1, 2016, by estimating future operating costs and dividing these by projected gas usage. A new GTP will be calculated on an annual basis, starting in 2017.

The proposed GTP is based on estimated costs and gas production levels from April 22 to Dec. 31, 2016, Chugach Electric told the RCA.

Because the GTP is based on estimated future costs and gas volumes, the tariff arrangements include a mechanism for reconciling actual costs and gas usage with the estimates used for the GTP calculation. Essentially, a balancing account will capture the discrepancies between actual data and estimated data over the course of a calendar year, with these discrepancies being factored into the GTP calculations for the next pricing cycle — cumulatively over time the internal price of the gas will accurately reflect the actual cost of gas production.

Several cost elements

The proposed GTP is based on estimated costs and gas production levels from April 22 to Dec. 31, 2016, Chugach Electric told the RCA. The cost elements consist of Chugach Electric's share of operating and maintenance expenses; administrative and general expenses; the field depreciation, depletion and amortization expense; an asset retirement obligation; the cost of interest on loans; and a margin on the cost of the loan interest. The loans were required to fund the purchase of Chugach Electric's portion of the gas field — the margin presumably protects the viability of the financing.

The asset requirement obligation is equivalent to what is often referred to as dismantlement, removal and restoration, an amount of money set aside to pay for the eventual dismantlement and abandonment of the field.

In taking over some of ConocoPhillips' interests in the Beluga River field, Chugach Electric picked up portions of two existing contracts, with already approved gas pricing, under which ConocoPhillips supplied gas to local gas and power utilities. One of those contracts was with Enstar Natural Gas Co. and one was with Chugach Electric itself. Since these contracts will remain in effect for a while, Chugach Electric proposes using its revenues from the contracts to offset some of its Beluga field costs.

The price calculation

According to the June 21 tariff advice, Chugach Electric's estimated Beluga field operating costs for the period of the GTP calculation amount to $5.8 million. Subtracting the revenues from the existing Chugach Electric and Enstar supply contracts, and also subtracting a royalty adjustment, leaves a net revenue requirement for the field of $1.5 million. Chugach Electric expects to obtain from the Beluga field a total volume of gas of 280,035 mcf, excluding the gas supplied under the contracts transferred from ConocoPhillips. Dividing the net revenue requirement by the gas volume used and adding 8 cents per mcf for field depreciation results in the GTP of $5.57 that Chugach Electric has proposed to the RCA. ●

Contact Alan Bailey at abailey@petroleumnews.com

LAND & LEASING

State extending comment deadlines

The state Division of Oil and Gas is extending the comment period on two matters — a request from ConocoPhillips Alaska Inc. to expand the Colville River unit and a request from Hilcorp Alaska LLC to expand and rename the South Middle Ground Shoal unit.

The state will now accept comments on both proposals through July 25.

ConocoPhillips wants to include three leases onto the southwestern border of the North Slope unit. The additional 5,085 acres would create a shared boundary between the Colville River unit and the ConocoPhillips-operated Greater Mooses Tooth unit, making it easier and simpler for the company to gradually extend oil development to the west.

The request from Hilcorp would expand the South Middle Ground Shoal unit to include a neighboring operation acquired from XTO Energy Inc. The request is part of a largest attempt by the company to consolidate operations throughout the Cook Inlet region.

—ERIC LIDJI

● EXPLORATION & PRODUCTION

BlueCrest holds Cosmopolitan open house

Newest Cook Inlet crude oil producer has well in production, plans to start drilling 2 more this fall; large rig on way to Alaska

JUDY PATRICK

From left, acting Department of Natural Resources commissioner Marty Rutherford, Sen. Dan Sullivan's chief of staff Joe Balash, Sen. Peter Micciche, BlueCrest board chairman Robert Israel, Sen. Lisa Murkowski, BlueCrest CEO Benjamin Johnson, BlueCrest COO John Martineck, BlueCrest CFO Kenneth Sanders, former state chief geologist and former deputy DNR commissioner Bob Swenson (the geologist who named Cosmopolitan) and BlueCrest vice president of Alaska operations Steve Massey pose for a photo at the ceremonial opening of the Cosmopolitan oil gas production facilities near Anchor Point.

By TIM BRADNER
For Petroleum News

There was a little rain and it was a bit breezy, but otherwise a fine day for BlueCrest Energy's June 25 ceremonial opening of its Cosmopolitan oil gas production facilities near Anchor Point, on the Kenai Peninsula.

Thirty-five to 40 Alaskans had been invited to see BlueCrest's production facilities in operation — the company is producing now from one well — including U.S. Sen. Lisa Murkowski, Joe Balash, chief of staff to U.S. Sen. Dan Sullivan and a former state natural resources commissioner, and state Sen. Peter Micciche, of Kenai.

John Hanson, an Alaskan who homesteaded the land where BlueCrest's production facility is located, also attended. Hanson is now in his 90s.

The first exploration well drilled at Cosmopolitan, by ARCO Alaska, was named Hanson No. 1 in honor of the family.

Slots for up to 20 wells

BlueCrest President Benjy Johnson said the production facility has slots for up to 20 wells and is capable of processing up to 10,000 barrels per day, a target he believes can be achieved at Cosmopolitan.

"We are quite confident we can achieve 10,000 barrels per day," Johnson said. That is based on the company's results of exploration drilling in 2013 that confirmed the presence of the production zones. Production tests were done and fluid samples taken.

BlueCrest's one producing well now produces about 250 barrels per day and this is being trucked to the Tesoro Alaska refinery near Kenai. The one producing well is a well originally drilled for exploration by Pioneer Natural Resources, a previous owner, and was not drilled to one of the more productive parts of the Cosmopolitan prospect, Johnson said.

As for the production facility, Johnson said "It's large. There is a lot of tankage and piping, and more than 84,000 welds." It is built on a 38-acre land parcel so that facilities can be expanded in the future if drilling results merit.

Johnson believes BlueCrest can eventually overtake Hilcorp Energy as Cook Inlet's top oil producer.

Additional wells this fall

The company plans to begin the drilling of two additional production wells by early fall — mid-August is the target — when the assembly of a large drill rig is completed at the site.

Delivery of the rig from a fabrication facility in Liberty, Texas, was delayed due to heavy rains and flooding in the region, but the rig components are now en route to Alaska, Johnson said. "This will involve about 125 truckloads of equipment, and about 100 trucks are already on the road," he said.

Many of the trucks are headed to Tacoma, Washington, from where the equipment will be barged to Seward or Anchorage and then trucked to the Kenai Peninsula, but some trucks will come all the way by land, Johnson said.

The first production well drilled this fall will be a 20,000-foot horizontal well — almost four miles — that will be completed near the end of the year. The second well, to be drilled in the spring and completed by mid-2017, will be a "dual lateral," one well with a second drilled off to a separate place in the reservoir.

This will give BlueCrest production from three wells, Johnson said.

The company will eventually install a waterflood, a project to inject water, to maintain reservoir pressure, but this won't likely be done for two years, Johnson said.

Tax credits a concern

BlueCrest is also watching developments in the state's oil and gas incentive tax credit program. As enacted this spring by the Legislature, House Bill 247, which changes the program, "is very painful," Johnson said, because it cuts in half the state incentive credits for 2017 and eliminates them in 2018.

"The main benefit of the tax credits to

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NORTH OF 60 MINING news

page 10 Hecla tenders $12M for B.C. silver explorer, Dolly Varden

www.MiningNewsNorth.com *The weekly mining newspaper for Alaska and Canada's North* Week of July 3, 2016

NEWS NUGGETS

Compiled by Shane Lasley

COVENTRY RESOURCES LTD.

Coventry Resources drilled 22 holes at Caribou Dome in 2015, the best of which cut 14.1 meters averaging 9.9 percent copper. This year's planned 8,000-meters program will be nearly double the 4,300 meters drilled last season.

Second rig arrives, more surface copper found at Caribou Dome

Coventry Resources Ltd. June 23 reported the arrival of a second diamond core drilling rig to expedite an 8,000-meter drill program targeting zones of high-grade copper at Caribou Dome, a road-accessible property located about 155 miles north of Anchorage, Alaska. The first rig, which arrived earlier in June, is testing the Lense 3, 9 and 1 targets at Caribou Dome. Coventry reports that the first hole completed in this area hit mineralization where predicted. A second hole is progressing well. The second rig is testing Menel, a high-priority target on strike to the northeast of the 700-meter-long corridor of copper mineralization drilled to date Caribou Dome. Strong induced polarization and copper-in-soil anomalies have been identified at Menel. Additionally, significant copper mineralization was mapped directly above and immediately along strike from the IP anomaly, while preparing to drill the Menel target. Upon completion of initial drilling at Menel, the rig will test Guardian, another untested IP anomaly that was delineated during 2015. Very encouragingly, outcropping gossans were identified during follow-up mapping; with rock chip sam-

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SHANE LASLEY

By the spring of 2013, when this photo was taken, Contango Ore had narrowed its exploration primarily to the Peak Zone. According to a resource calculated later that year, this deposit hosts the equivalent of 1.2 million ounces of gold when you include the value of the copper and silver also found there.

EXPLORATION

Making the connection

$11 million program targets area between high-grade gold zones at Tetlin

By SHANE LASLEY

Mining News

From a Texas oilman discovering rich mineral prospects at Tetlin while investigating the natural gas potential of these Native owned lands to a royalty company setting aside its business model to get in on the ground floor of what is shaping up to be a multimillion-ounce deposit of high-grade gold lying alongside the Alaska Highway, Contango Ore Inc. is adding some intriguing new entries to the annals of Alaska geology.

The latest chapter of the Tetlin story includes a US$11 million exploration program – likely the largest such program in Alaska this year – that aims to prove that the Peak deposit and North Peak zone are actually one large continuous deposit of high-grade gold-copper-silver mineralization.

This robust exploration campaign is being funded by Royal Gold Inc., which is well on its way to earning up to a 40 percent interest in Tetlin by investing up to US$30 million in this expansive and still underexplored project by October 2018.

Finding Peak

Contango Ore President and CEO Brad Juneau was not looking for gold when he ventured into Alaska in 2008. Instead, his privately held company, Juneau Exploration L.P., was investigating the natural gas potential of a large land package owned by the Tetlin Village Council, an Alaska Native group.

Juneau's exploration of Tetlin did not turn up much in the way of natural gas potential, but the

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NORTHERN NEIGHBORS

Compiled by Shane Lasley

DOLLY VARDEN SILVER CORP.

An indicated resource of 31.8 million ounces of silver contained within 3.07 million metric tons of material averaging 321.6 grams per metric ton (10.34 oz.) silver was calculated in 2015 for four deposits located near historic mines at Dolly Varden Silver Corp.'s namesake property in northwestern British Columbia.

Hecla makes bid to take over BC silver explorer

Hecla Mining Company June 27 reported a takeover bid for all of the outstanding shares of Dolly Varden Silver Corp. that it does not already own. At C69 cents per share, Hecla's offer reflects roughly a 97 percent premium based on the volume-weighted average price of the Dolly Varden shares on the TSX Venture Exchange for the 20 trading days ending on June 24. Assuming exercise of the 1.25 million warrants it currently holds, Hecla owns and controls 3,870,291 Dolly Varden shares, or roughly 19.8 percent of the shares calculated on a partially diluted basis. "To protect ourselves and other shareholders, we are offering to buy Dolly Varden shares for cash at C69 cents. If we acquire all shares we expect to spend about $12 million." Earlier in June, Dolly Varden said it had entered definitive agreements with three lenders – Sprott Resource Lending Partnership, a second Sprott affiliate, and The K2 Principal Fund L.P. – for a C$2.5 million loan. If finalized, roughly C$2.1 million of the proceeds would be used to repay its existing senior secured loan from Hecla Canada Ltd. and Robert Gipson. "The new loans permit Dolly Varden to discharge the Hecla/Gipson loan and to complete an equity financing to repay the new loans prior to their maturity date without obtaining the consent of the new lenders," said Rosie Moore, interim president and CEO, Dolly Varden Silver. In connection with the new loan, Dolly Varden agreed to issue 2.5 million warrants to the trio of investors that would entitle the warrant-holder to purchase one Dolly Varden share for a period of two years for a price equal to the greater of C30 cents, or the minimum price permitted by the TSX Venture Exchange on the date of issue. "While we believe that Dolly Varden can one day be a significant silver producer, we are very concerned with the current board's value destruction for shareholders," said Hecla President and CEO Phillips Baker, Jr. "These directors are not acting in shareholders' best interests with a new loan arrangement that causes substantial dilution at a low share price. Their plan starts with issuing warrants with an 'option value' of C27.5 cents each and an exercise price of C30 cents, which is well below the current share price and our offer price. The warrants

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Petroleum news

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TETLIN

Texas oilman was convinced this roughly 675,000-acre land package was prospective for more solid minerals, such as gold and copper.

To confirm his hunch, Juneau set out to find a geologist familiar with Alaska and willing to take a look at this geologically unknown property. While dubious that an important mineral deposit was hiding in plain sight, Fairbanks-based geologist Curt Freeman agreed to take a look at the property.

It did not take long for Freeman and his team at Avalon Development to get excited about the discovery potential of this enigmatic property. Over the next couple of years, Avalon and Contango Ore identified numerous precious and base metal targets across what is now a roughly 774,000-acre land package made up of the original lands that Juneau leased from Tetlin Village and adjoining State of Alaska lands that the Texas-based company staked to cover similar prospective lands to the west.

While the property turned out to be rife with prospects worthy of serious geological investigation, by 2012 the search was narrowed to a zone in the heart of the Tetlin lease named Peak, after co-founder and original CEO of Contango Ore, Kenneth Peak.

By the end of the 2013 exploration season, 6 million metric tons of indicated resource averaging 3.46 grams-per-metric-ton gold, 11 g/t silver and 0.25 percent copper had been identified at Peak. Additionally, the resource calculation published early in 2014 included 3.9 million metric tons of inferred resource averaging 2.07 g/t gold, 14.28 g/t silver and 0.23 percent copper. In total, this equates to 1.2 million oz. of gold when you calculate in the value of the copper and silver.

As it turns out, Peak is a unique type of skarn deposit that was formed when metal-laden magmatic fluids came in contact with carbonate-enriched sandstones, causing the metals to quickly drop out and result in high-grade concentrations of gold and copper suspended in acidic fluids.

Attracted by the growth potential of the high-grade gold-copper-silver deposit resulting from this process, along with prospects for discovering other similar deposits across the district-scale land package, Royal Gold agreed to become an active partner in Tetlin exploration early in 2015.

Peak Gold, the resulting limited liability joint venture forged between Contango Ore and Royal Gold, completed US$6.8 million of exploration in 2015, a program that expanded the breadth and depth of the Peak deposit as well as discovering Peak North, a seemingly parallel zone of mineralization with similar grades and thicknesses about 250 meters to the north.

"We really like the Royal Gold people, and we really like the joint venture and how it is functioning," Juneau told Mining News in May. "They have done everything they said they would do, and are very straightforward and open."

The Contango Ore CEO said Royal Gold's contribution to Tetlin goes beyond the nearly US$20 million the Denver-based royalty company will have invested in the project by the end of 2016.

"The folks at Royal Gold have definitely made a material impact, both with their capital and their work," he said.

Making the connection

Peak Gold got an early start on 2016 exploration by kicking off the first-ever winter drill program at Tetlin in February, a program focused on drilling at and around the Peak and North Peak zones.

Using a single rig, the road-supported winter program completed 4,040 meters of diamond core drilling in 19 holes.

"We continue to be impressed with the efficiency of the drilling operations, as we are seeing significant improvements in the cost per foot drilled, which stands currently at approximately $115 per foot," Juneau continued. "In addition, the number of holes that encounter skarn material, a prerequisite for finding gold in this area, has improved such that most holes find this type of mineralization."

The partners had budgeted US$4.4 million for the first phase of 2016 exploration, but between the efficiency of the program and an early spring, only US$1.9 million was spent before breakup.

Winter drilling at North Peak, a deposit not included in the resource but extensively drilled in 2015, continued to return good results:

•TET16192 cut six mineralized intercepts at North Peak, including 13.27 meters averaging 49.19 g/t gold, 4.5 g/t silver and 0.035 percent copper from a depth of 78.5 meters;

•TET16204 cut three mineralized intercepts at North Peak, including a silver-rich 1.82-meter zone averaging 16.34 g/t gold, 328.4 g/t silver and 0.157 percent copper from a depth of 60.95 meters; and

•TET16206 cut 43.43 meters at the North Zone averaging 3.6 g/t gold, 2.08 g/t silver and 0.108 percent copper from a depth of 78.5 meters.

•The most intriguing and potentially the most important intercept came in hole TET16210. Drilled about 200 meters southeast of North Peak and 200 meters northeast of Peak, TET16210 cut two mineralized intercepts, including 43.96 meters averaging 3.28 g/t gold, 30.6 g/t silver and 0.402 percent copper.

Drilled in a zone dubbed Connector, this final hole of the winter program tested an idea that Peak and North Peak may be two parts of a continuous band of skarn mineralization.

Given the grades and thickness of the mineralization are similar to the other Peak zones, the geological model seems to hold up.

"The winter drilling program was successful in expanding the known limits of both the Peak and North Peak zones, and perhaps most importantly found new, significant mineralization in its first drill hole in the Connector Zone that may lead to a better understanding of the relationship between Peak and North Peak and possible further expansion of the mineral system," explained Juneau.

New entries

As soon as the snow melted and the ground dried, the Peak Gold partners set out to further test their idea that the Peak, Connector and North Peak zones link up to form a roughly 2,000-meter arc of contiguous high-grade skarn mineralization. This would be roughly three times the footprint of the Peak deposit outlined in a resource estimate calculated in 2013.

On June 27, Contango Ore released results from 11 more holes drilled at North Peak and West Peak, a zone immediately west of the Peak deposit.

Highlights from North Peak include:

•TET16211 cut four mineralized intercepts, including 10.31 meters averaging 3.5 g/t gold from a depth of 16.11 meters;

•TET16220 cut three mineralized intercepts, including 26.03 meters averaging 4.67 g/t gold from a depth of 30.2 meters; and

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TETLIN

•TET16221 cut four mineralized intercepts, including 17.92 meters averaging 8.23 g/t gold from a depth of 21.61 meters.

All three highlighted intercepts were to the southeast of North Peak, in the direction of the Connector zone.

Highlights from West Peak include:

•TET16218 cut five mineralized intercepts, including 15.01 meters averaging 7.1 g/t gold from a depth of 191.47 meters; and

•TET16219 cut two mineralized intercepts, including 9.9 meters of 1.37 g/t gold from a depth of 37.65 meters.

These holes represent the most northwesterly drilled at Peak-West Peak and other holes are planned further northwest during the second phase 2016 program at Tetlin.

"With the new drill-hole data, we are continuing to find significant thickness and impressive grades of gold," Juneau commented. "Our immediate goal is to extend the known limits of the deposits we have found, and to provide enough information to provide reliable data on the continuity of the gold distribution in each area."

The results from this year's drilling and the more than 14,000 meters of drilling completed in 2015 is anticipated to be included in an updated resource estimate to be calculated after the phase 2 drilling is complete. Considering that drilling has expanded Peak at depth and the lateral extension of the skarn mineralization beyond the deposit, a significant increase in resource should be expected.

Prospecting, meanwhile, continues to identify and prioritize drill targets beyond Peak.

"We are continuing our surface recon program and may carry out additional soil geochemical sampling work to develop new drilling targets this summer" Juneau said. "Our cumulative drilling from 2011 through the present has tested less than one percent of the acreage that we currently have under lease."

Given the large number of prospects across the huge Tetlin property with geochemical and geophysical signatures similar to Peak that have yet to be drilled, it is likely that at least one of these future drill targets will be the topic of Contango Ore's next entry in the annuls of Alaska geology.

Or as Juneau put it when Mining News asked about the future of Contango Ore, "I see no reason to do anything different."

Considering that the Contango Ore share price has rocketed from a low of US$2.43 in February to US$13.49 on June 29, the market seems to agree that staying the course is good policy. ●

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NORTHERN NEIGHBORS

are issued in exchange for a loan with maturity only three months longer than the existing loan and (that add) little to the treasury." Hecla has notified the TSX Venture Exchange of its concerns and requested that the exchange not approve the issuance of warrants to Dolly Varden's proposed new lenders. Moore contends that "the warrants issued with the new loans are no more dilutive than the same number of warrants with a lower exercise price issued to Hecla and Gipson under the Hecla-Gipson loan." The Hecla-Gipson loan is set to expire in September. Hecla, however, said it has been willing to extend the loan and offer Dolly Varden a loan with a longer maturity date, lower interest rate and double the new funding. Restrictions on equity financings, however, seem to have been a sticking point in the negotiations. "We've had a number of discussions this year with Hecla regarding options for Dolly Varden to repay the Hecla-Gipson loan. Dolly Varden, Hecla and Gipson were not able to come to terms on converting debt to equity, a loan extension or an equity financing," Moore explained. Dolly Varden said it will seriously consider Hecla's takeover proposal and notify shareholders of its recommendations. Hecla has already entered into support agreements with shareholders who collectively hold 2.5 million Dolly Varden shares and 1.25 million Dolly Varden warrants. Hecla and the supporting shareholders hold 5.12 million shares and 2.5 million warrants, or about 34.4 percent of Dolly Varden's shares on a fully diluted basis. Each warrant entitles the holder to acquire one additional share at a price of C30 cents per share.

BHP funds C$4 million exploration program at Storm copper project

Aston Bay Holdings Ltd. June 28 said a C$4 million exploration program at its Storm copper project is set to begin in early July. The program includes roughly 2,000 meters of drilling; re-logging of existing core mapping; soil sampling; and prospecting. "As the operator of the project, Aston Bay is excited to test high-priority targets while advancing additional targets for future drill programs," said Thomas Ullrich, executive vice president, exploration, Aston Bay. Under the terms of an option agreement finalized in May, BHP Billiton Ltd. can earn a 75 percent interest in Storm by spending a minimum of C$40 million on exploration of the property over a period up to nine years. This year's program is to be included in the earn-in.

DOMINION DIAMONDS CORP.

Since going into production in 1998, the Ekati diamond mine in Northwest Territories has become world-renowned for its premium diamonds. A recent fire in the processing facility is expected to curtail the production of these gem-quality diamonds in 2016.

Fire forces shutdown of Ekati's production for next three months

Dominion Diamond Corp. June 27 said the processing plant at its Ekati diamond mine in Northwest Territories is out of operation due to a June 23 fire. The blaze was quickly extinguished and all personnel were safely evacuated from the plant without injury. The damages were limited to a small area of the process plant, with no damage to the main structural components. Repairs will require the replacement of one of the main degritting screens and associated components, as well as some electrical wiring and related infrastructure. The repairs to the plant are expected to take about three months, after which the plant is expected to resume operations at full capacity. Dominion has initiated a plan to reduce operating and capital costs during this time, which includes an adjustment of mining operations to pause mining at lower priority and lower value ore bodies, a deferral of non-essential sustaining capital, and a temporary layoff of affected staff across the company. The company will continue to mine higher value material during the process plant shutdown. Ore mined during the process plant downtime will be stockpiled, with the intention to prioritize the processing of the highest value material when the plant restarts. Dominion said it will provide further updates as information becomes available. In addition to owning controlling interest and operating Ekati, Dominion owns a 40 percent stake in the Diavik diamond mine, also in Northwest Territories.

Seabridge to remediate old workings at Iskut while seeking new finds

Seabridge Gold Inc. June 28 reported that it has begun robust environment remediation of historical mining activity at its newly acquired Iskut property in northwestern British Columbia, including the historical Johnny Mountain Mine. The Tahltan Central Government, the administrative governing body of the Tahltan First Nations, has expressed its support of this environmental work. "We have a strong interest in the remediation of the Johnny Mountain mine site on our traditional territory," explained TCG President Chad Day. "We expect to work closely with Seabridge to ensure that Tahltan citizens benefit from this work and that we are kept fully informed of the progress that is being made in the planned clean-up programs. During the eight- year Environmental Assessment Process for KSM, Seabridge demonstrated (its) willingness and openness in addressing environmental issues, and we look forward to continuing our excellent working relationship with (the company)." Seabridge's planned environmental and engineering work for this summer will begin the evaluation and development of remediation programs to mitigate the impacts of past mining activity at an estimated cost for this year of C$750,000. This program will include a comprehensive evaluation of best practices for future remediation on the property, drawing from the Seabridge environmental team's experiences at KSM and other North America sites and input from the Tahltan First Nation and British Columbia regulators. Work will begin with a general site cleanup in the vicinity of the Bronson Slope Airstrip. The environmental work will be completed in conjunction with Seabridge's planned 2016 exploration program for the property. Seabridge Chairman and CEO Rudi Fronk said, "We take pride in being a responsible mineral exploration and development company. Integrating a substantial environmental work plan into this year's exploration program sets us on a path to improving site conditions. Going forward, exploration will go hand in hand with remediation."

Commander cuts deal to acquire Flume, other Bearing gold properties

Commander Resources Ltd. June 23

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NEWS NUGGETS

ples assaying up to 16.5 percent copper. In the past week, while constructing drill pads to evaluate the Lense 9 IP Target, geologists identified outcropping copper mineralization, including bornite, immediately to the southwest of the Guardian IP anomaly. In addition to drilling, a geophysical survey crew has been collecting new IP data at Caribou Dome Project since mid-June. This work began by targeting a deeper response at the Menel and Guardian targets. The geophysical surveying will be extended to the northeast of this area, where no IP data has been acquired previously, but where extensive copper-in-soil anomalies were identified in 2015. This IP survey is expected to take around a month to complete, and the company is prepared to reprioritize drill targets based on the results. Coventry expects to report initial assay results from the current drilling before the end of July.

MSHA to stiffen enforcement of 'Rules to Live By' standards

The U.S. Department of Labor's Mine Safety and Health Administration June 27 unveiled plans to begin enhanced enforcement of "Rules to Live By," an initiative focused on preventing mine fatalities. Joseph Main, assistant secretary of labor for mine safety and health, said "mine operators need to conduct better site inspections and take appropriate action to improve compliance with" MSHA's Rules to Live By and other safety standards. An agency analysis of hundreds of U.S. mining fatalities in a 10-year period shows that fatalities associated with Rules to Live By standards have decreased an average of 23 percent, and significant and substantial citations and orders issued for violations of these standards have declined an average of 37 percent. Beginning July 1, MSHA will employ its web-based Rules to Live By calculators more extensively to determine the number of citations and orders issued during the most recent completed inspection periods for which data are available. Inspectors will provide mine operators with a copy of the results, encouraging them to use the tools to monitor their own compliance and take action to eliminate violations. The results will be added to criteria for consideration of impact inspections, particularly targeting mines with elevated non-compliance of these standards. ●


JOSEPH MAIN

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NORTHERN NEIGHBORS

said it has finalized an agreement to acquire four mineral exploration properties from Bearing Resources Ltd., including the Flume gold property in Yukon Territory, two in British Columbia and one in Mexico. Three royalties, including a production-defined royalty on a portion of the Boundary Zone deposit at Imperial Metals' Mt. Polley Mine in British Columbia, is also part of the agreement. Situated about 60 kilometers (35 miles) southwest of Dawson City, the Flume property was recently explored by Ryan Gold Corp. The best intercept of nine holes drilled by Ryan gold was two meters averaging 5.76 grams per metric ton gold. Commander reports that a 10-kilometer- (six miles) long gold-in-soil anomaly targeted by this drilling has only been partially drill-tested in one area. The acquisition also will include the October Dome gold-copper property in central B.C. and the Pedro gold property in Durango, Mexico. Under terms of the acquisition pact, Commander will issue 12 million shares and pay to Bearing C$15,000 for all the assets.

Mount Polley tailings dam repaired, back in use

Imperial Metals Corp. June 23 reported that the British Columbia Ministry of Energy and Mines and the Ministry of Environment have authorized the Mount Polley Mine to return to normal operations making use of its repaired and buttressed tailings storage facility. Imperial said the management and staff at Mount Polley worked in close cooperation with regulatory agencies, First Nations and members of the local communities, to repair and reinforce the tailings facility in accordance with best applicable practices identified by a panel of independent engineers. Thorough investigations by an independent engineering review panel, the B.C. Ministry of Energy and Mines, and a team from Golder Associates Ltd. – the engineer of record retained by Mount Polley – all concurred on the failure mechanism that led to the breach of the tailings dam in 2014. The updated design of the embankment in the area where the failure occurred reflects the results of these investigations. Furthermore, all the existing TSF embankments were investigated, and foundation conditions throughout were comprehensively characterized. These investigations led to modification of the embankments to assure that the stability of the structure meets or exceeds all applicable legislative requirements and guidelines. "A return to normal operations is important to the region as Mount Polley is a significant contributor to the economy, directly providing about 350 jobs, as well as supporting the local communities of Likely, Williams Lake and the surrounding region, said Imperial Metals President Brian Kynoch. "Mount Polley is committed to working with First Nations and local communities to complete rehabilitation of the areas impacted by the breach, and we thank all those involved in the rehabilitation for the excellent work that has been completed to date." Since the breach of the Perimeter Embankment, Mount Polley has completed significant rehabilitation of the areas that were affected by the breach, and will continue necessary rehabilitation and monitoring of those areas. Imperial said research and monitoring indicates the environment impacted by the tailings breach is recovering rapidly and no long-lasting effect is anticipated. ●

The updated design of the embankment in the area where the failure occurred reflects the results of the investigations.

EXPLORATION & PRODUCTION

Doyon optimistic about Nenana exploration

Says previous exploration, drilling results increased the probability of finding oil or gas with Toghotthele well being drilled

By ALAN BAILEY
Petroleum News

Doyon Ltd. thinks that there is a one-in-two chance of finding a viable gas resource and a one-in-four chance of finding commercial oil in the prospect being tested by the Native regional corporation's Toghotthele No. 1 well in the Nenana basin in Alaska's interior, James Mery, Doyon's vice president for lands and natural resources, told a press briefing on June 22. At the time of the briefing, the well had reached a depth of 6,394 feet. The drilling crew was casing the well in preparation to continue drilling down to target horizons, to a total depth of 10,000 feet.

Characterizing Doyon's multi-year exploration program in the Nenana basin as an exercise in de-risking the potential hydrocarbon resource, Mery said that a combination of seismic surveying and the drilling of previous wells had established the prerequisites for a significant find. The corporation has conducted 2-D seismic surveys across wide areas of the basin and a detailed 3-D survey in the central part of the basin, where the corporation has been drilling. Previous drilling consisted of the Nunivak No. 1 well, drilled in 2009, and the Nunivak No. 2, drilled in 2013.

All three wells, including Toghotthele No. 1, are located to the west of the town of Nenana, on a structural high into which hydrocarbons may have migrated from deeper parts of the basin. The target horizons are in an uplifted, faulted block.


ALAN BAILEY

Doyon's Arctic Fox drilling rig on location on a gravel drilling pad, drilling the Toghotthele No. 1 well in the Nenana basin, west of the Nenana River.

Encouraging findings

The verification of the presence of good quality reservoir rocks at depth; a subsurface hydrocarbon trapping structure; and coals and shales with hydrocarbon source potential have all helped to lower the exploration risk, Mery said. And, in particular, the Nunivak No. 2 well encountered wet gas, gas which includes natural gas liquids such as propane. The presence of wet gas indicates that the hydrocarbons were formed from the heating of organic material, rather from microbial action — this thermal mechanism could have generated oil as well as gas.

The structure being tested by the drilling could hold recoverable volumes of about 70 million barrels of oil or 200 billion cubic feet of gas, Mery said.

Mery said that the No. 2 well encountered about 400 feet of gas-bearing rock, which appeared to be a depleted gas reservoir. But the reservoir contained too much water to be commercially viable.

"The trap that we tried to penetrate had apparently leaked," Mery said. "We saw gas from top to bottom."

There was an effective seal rock capping the reservoir — the trap consisted of a three-way closure bounded by a fault which appears to have acted as a conduit for the gas leakage, Mery said. The Toghotthele well is testing a potential trap with a fault that is likely to present a better seal, he said.

Close to the highway

The drilling is taking place quite close to the Parks Highway, with the gravel drilling pad accessible using gravel roads that Doyon has constructed on the west side of the Nenana River. With the state highway system being on the east side of the river, vehicles have to cross the river by barge.

However, the location would be convenient for development, should a viable resource be found. Oil could be transported to the trans-Alaska pipeline at pump station 7, just north of the basin, or at North Pole, where there are already connections for oil to flow in and out of the pipeline, Mery commented.

From a gas perspective, the route of a proposed major gas sales line from the North Slope passes near where the Nenana basin drilling is taking place, leading to the possibility of delivering gas into that line. There should be available capacity in the line for a modest-sized Nenana gas project. Gas delivery by pipeline to Fairbanks is also a possibility. And, with the drilling site being close to the truck and river system, there is the potential to ship propane from Nenana to

see NENANA EXPLORATION page 15

A question of timing for the IEP

With Doyon's exploration efforts in the Nenana basin and the Alaska Industrial Development and Export Authority's Interior Energy Project both having the potential to provide a new natural gas supply for the city of Fairbanks, questions have been raised by the state Senate over the timing of the AIDEA project. On May 14, in a letter from the Senate Finance Committee, committee co-chair Anna MacKinnon questioned the advisability of putting state funding into AIDEA's IEP while simultaneously supporting Doyon's project through state tax credits.

The IEP team is in the process of negotiating arrangements for a Cook Inlet gas supply and the construction of a Cook Inlet liquefied natural gas plant for the delivery of an expanded LNG supply to Fairbanks. The team had hoped to present a recommendation to the AIDEA board in March on whether to approve construction of the LNG plant, but discussions over the proposal are still in progress. MacKinnon suggested deferring the AIDEA decision "for a minimum of six to 12 months," to allow Doyon time to use the results of the drilling it is conducting this summer to determine the gas production potential of the Nenana basin.

see IEP TIMING page 15

● PIPELINES & DOWNSTREAM

TransCanada files $15B XL claim against US

By GARY PARK

For Petroleum News

TransCanada has shed its cool and calm exterior by claiming US$15 billion in damages from the Obama administration's rejection of the Keystone XL pipeline.

In applying for arbitration under the North American Free Trade Agreement, TransCanada has argued its proposal for the pipeline was delayed more than seven years through a succession of "arbitrary and contrived" analyses and justifications.

It said the final decision by the White House was "symbolic and based merely on the desire to make the U.S. appear strong on climate change, even though the State Department had itself concluded (in five environmental impact assessments between 2008 and 2015) that denial would have no significant impact on the environment."

In a 42-page filing, the company said the U.S. government "ultimately denied Keystone's application, not because of any concerns over the merits of the pipeline, but because President Obama wanted to prove his administration's environmental credentials to a vocal activist constituency that asserted the pipeline would lead to increased production and consumption of crude oil and, therefore, significantly increased greenhouse gas emissions."

A three member panel will determine, in what TransCanada expects will be a lengthy process, whether the company was treated unfairly when Obama rejected Keystone XL last Nov. 6.

TransCanada said six months ago it would seek US$15 billion in compensation over the US$8 billion project because it has been left with billions of dollars of worthless assets and because of lost economic returns.

TransCanada said a negotiated settlement is still possible, although its efforts in recent months to reach an amicable agreement have failed.

Sierra Club Executive Director Michael Brune said TransCanada's efforts to make U.S. taxpayers hand over US$15 billion "because the company's dirty Keystone XL pipeline was rejected shows exactly why NAFTA was wrong and why the even more dangerous and far-reaching Trans-Pacific Partnership must be stopped."

"The TPP would empower thousands of new firms operating in the U.S., including major polluters, to follow in TransCanada's footsteps and undermine our critical climate safeguards in private trade tribunals."

But Obama told a news conference in Germany three months ago he is confident that, regardless of opposition from many Democratic lawmakers, that he can gain ratification of TPP once the heat from the U.S. primary election season cools off.

The Obama administration has insisted there will be adequate protections in the TPP to prevent the arbitration process from being exploited.

Since NAFTA was implemented in 1994 corporate claims against the U.S. have been rare and the U.S. has established a strong record of fending off those disputes. ●

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● GOVERNMENT

DEC to require registering small tanks

Regulations expected this fall for fuel tanks from 1,000-420,000 gallons; because of spills from operator error, next step training

By TIM BRADNER

For Petroleum News

Alaska's Department of Environmental Conservation will be rolling out new regulations this fall requiring registration of fuel tanks from the 1,000-gallon to 420,000-gallon size.

In concept form the plan will be made public in July, said Kristin Ryan, director of DEC's Division of Spill Prevention.

"Seventy percent of our environmental contamination is from fuel storage tanks," mostly in the small to medium-sizes, Ryan said.

Larger bulk storage facilities are regulated by the DEC and must file spill contingency plans with the agency. But the locations of most small fuel storage facilities and even how many there are is unknown, Ryan said.

"We need to know where they are, and how many there are, and points of contact for the responsible persons. There are certainly hundreds of tanks and there may be several thousand. We need to know how big the universe is," she said.

Many small communities in rural Alaska have several medium-sized fuel tanks, usually with different owners and operators. "It's common that a school would have its own tanks, the village wastewater system its tank, and typically there is a separate storage facility to supply heating oil and gasoline to consumers," Ryan said.

Operator error at smaller tanks

The bulk of the small spills from these tanks are due to operator errors, and sometimes maintenance problems, so the second phase of DEC's fuel facilities initiative, once the location and number of tanks is known, is training for operators, Ryan said.

Becky Spiegel, program manager in the spill response division, said, "We're doing this in phases. Right now the priority is to find out how many and where these tanks are. We'll be beginning a discussion of this with stakeholders in July and hope to have a set of draft regulations by the end of the year."

Once these rules are in place, DEC would build on them with requirements for operator training. Eventually, some kind of spill prevention and response capability would be built in, "but this would be a very basic kit," Spiegel said.

A full-blown regulatory regime like that applying to large bulk fuel tanks isn't in the cards for small tank fuel

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OPEN HOUSE

us is that they would allow us to continue developing Cosmopolitan at a lower oil price, at about $10 a barrel lower price, in fact," he said.

If HB 247 is enacted as now written — and there could yet be changes — BlueCrest would hope for some oil price recovery in 2017 and 2018 to continue the drilling beyond two new wells now planned, he said.

In presentations to legislative committees this spring Johnson showed lawmakers how a limited investment by the state through tax credits would be more than quickly repaid by state royalties and taxes once production started.

"This should be looked at as a good investment by the state in an oil project with confirmed reserves," Johnson told legislators. The expected return on investment will be quite good, he said.

Fracturing not new

On another matter, Johnson said he is puzzled by a letter written by an environmental group, the Center for Biological Diversity, to a federal agency complaining about BlueCrest's plan to use hydraulic fracturing to stimulate Cosmopolitan's wells.

Fracturing has long been done both in Cook Inlet and the North Slope, and in fact at least one of the early test production wells was fractured by a previous owner, Johnson said.

The quantities of fluid and solids injected in that were much larger than what BlueCrest plans in any one fracture, he said.

BlueCrest's plan involves a series of incremental small fractures rather than one big fracture, he said. The technique is now being used with success by other companies on the North Slope.

It's also unclear how the fracturing of a well almost a mile and a half underground and that is drilled from shore could have any adverse effects on marine life in Cook Inlet, the subject of the group's concern, Johnson said. ●

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● GOVERNMENT

Attorney general, DNR commissioner resign

THE ASSOCIATED PRESS

There were major changes to Gov. Bill Walker's cabinet on June 23, with announcements that the attorney general and the acting Natural Resources commissioner were leaving their posts.

Walker also appointed a new natural resources commissioner. No replacement was named for attorney general.

All the changes were announced in statements from the governor's office.

Attorney General Craig Richards, 41, cited personal reasons for his resignation.

"I feel I need to re-focus on my family, which is impractical given the travel and workload requirements of the job," he said in the statement.

"With great reluctance, I have accepted Craig's resignation," Walker said in the statement.

"When I appointed Craig in December 2014 as Attorney General, I knew Alaskans would benefit from his deep respect for the law and his vast knowledge of finance. As the state's top attorney, work has pulled him away from his 3-year-old son, and I am grateful for the sacrifices he and his family have made in service to Alaska," Walker said.

Richards was not asked to resign, Walker spokeswoman Katie Marquette said in an email to The Associated Press.

Walker has appointed deputy Attorney General Jim Cantor to lead the Department of Law until Walker appoints a new attorney general.

Marquette said the governor will fill the position as soon as possible.

Mack named for DNR

Later June 23, Walker picked Andy Mack, an attorney with oil and gas experience, as his new commissioner of the Department of Natural Resources. Mack replaces Mark Myers, who retired in February.

ANDY MACK

Mack is a managing director of Pt Capital, a private equity fund.

He was born and raised in Soldotna and is an adviser to Alaska Native corporations involved with North Slope oil and gas activity.

Mack worked as a civil and criminal defense attorney for five years and as a legislative assistant for more than 10 years.

MARTY RUTHERFORD

Marty Rutherford has been working as acting commissioner. The governor's office announced she is retiring June 30 after 27 years with the state, but also on June 23 named her a trustee on the Permanent Fund Corp. board.

Richards is Walker's former law partner and was the governor's first choice for attorney general.

Richards' legal experience includes areas of oil and gas and taxation. He was involved in long-running litigation by municipalities over the assessment of the trans-Alaska oil pipeline system.

"Given Craig's knowledge of gas line issues, I'm certain the state will continue to benefit from his oil and gas expertise as we push toward completion of a project," Walker said June 23 in the statement.

The governor's spokeswoman declined to clarify that statement or elaborate whether Richards might have a future role in the administration.

"We do not have any further comment beyond what is in the press release," Marquette said. ●

Lindemuth named attorney general

Alaska Gov. Bill Walker has named Jahna Lindemuth to replace Craig Richards as attorney general.

JAHNA LINDEMUTH

In a June 28 statement the governor's office said Lindemuth was born and raised in Anchorage and brings extensive experience in complex commercial litigation, appeals to the Alaska Supreme Court and 9th Circuit Court of Appeals.

Lindemuth is a partner at Dorsey & Whitney LLP and is head of the firm's Anchorage office.

Walker said Lindemuth was one of four finalists he interviewed recently for a vacancy on the Supreme Court and said he was "struck by her outstanding resume and legal experience."

Lindemuth has represented such clients as Cook Inlet Region Inc., Arctic Slope Regional Corp. and ConocoPhillips Alaska in state and federal court, arbitrations and before administrative agencies.

She earned a law degree from the University of California at Berkeley Boalt Hall School of Law in 1997.

Lindemuth lives in Anchorage with her two sons. She will begin her new position in early August.

—PETROLEUM NEWS

ALAN BAILEY

Positioning well casing for insertion into the well bore of Doyon's Toghotthele No. 1 well in the Nenana basin.

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NENANA EXPLORATION

communities in the Interior, Mery said.

The convenient project location in the Nenana basin would render a relatively modest oil find economic. Even at an oil price in the range $50 to $60, a find in the range of 30 million to 35 million barrels could be viably developed, Mery said.

Another well planned

In the interest of moving forward quickly with the appraisal of any find from the Toghotthele No. 1 well, Doyon has already started the permitting for a Toghotthele No. 2, potentially to be drilled as a delineation well from the Toghotthele gravel pad later this summer. By drilling into the target structure in a different direction from the No. 1 well, the No. 2 well could establish greater confidence in any find, enabling a development decision without having to wait until next summer's drilling season, Mery said. But Doyon would probably only drill the No. 2 well this year in the event of a gas discovery, rather than an oil discovery, he said.

To allow adequate time for well testing and the drilling of a second well this year, Doyon started drilling the Toghotthele No. 1 well on June 1, an earlier date than the spud dates of previous wells.

"We wanted to get an early start because we're really constricted on the tail end of the project," Mery said. It is necessary to demobilize equipment back across the Nenana River before the sizable drop in river level that typically takes place in mid to late September, he explained.

A large acreage

In addition to 400,000 acres in state oil and gas leases, Doyon owns about 40,000 acres of the subsurface and operates a Mental Health Trust lease in the Nenana basin. The Toghotthele No. 1 is being drilled in state land.

"We've got a lot of work to do because it's a lot of acreage and it's still well underexplored," Mery said, commenting that Doyon pays more that $1 million to the state each year for the right to explore. Mery has previously commented that Doyon is making use of state tax credits in support of its exploration efforts.

Doyon owns about 1.5 million acres of subsurface in the Yukon flats basin, a basin north of Fairbanks that has similar geology to the Nenana basin. The corporation is currently focusing its efforts on the Nenana basin because, being closer to infrastructure than the remote Yukon Flats, it is cheaper to operate in and could be more quickly developed, Mery said. Also, there was initially more information available about the Nenana basin, he said. ●

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IEP TIMING

Governor's response

In a May 17 letter responding the MacKinnon, Gov. Bill Walker said that AIDEA anticipates concluding its IEP negotiations in August or December and that the requested delay in a development decision might then defer that decision by about 60 days, a not unreasonable request. However, Walker said that before discussing the matter with the AIDEA board he would require an analysis of the legality of the delay and any potential for resulting litigation.

In a June 29 email AIDEA spokesman Karsten Rodvik told Petroleum News that progress continues in confidential discussions between the parties involved in the IEP.

In 2015, under the IEP, the two Fairbanks gas utilities, Fairbanks Natural Gas and the Interior Gas Utility, began building out the gas distribution infrastructure in Fairbanks, in anticipation of an expanded gas supply for the city. Rodvik confirmed that no further expansion of the distribution system has so far taken place this year. The two Fairbanks utilities continue to look at ways in which future expansion and LNG storage can facilitate consolidating the two utilities into a single unified system, he said. AIDEA, which owns Fairbanks Natural Gas, wants to consolidate the utilities before spinning them off to a local control entity.

—ALAN BAILEY

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ICEWINE FOLLOW-UP

Energy expects to spud the follow-up well from the Franklin Bluffs drilling pad sometime in the first quarter of 2017.

Between now and then, the partners need to complete a preliminary analysis of a 2-D seismic survey conducted earlier this year and finalize financing for the project.

The companies drilled the Icewine No. 1 well in late 2015 to assess the resource potential of the HRZ shale — one of the three stacked source rocks in the central North Slope.

According to the company, the results indicated the potential for commercial development, pending similar results from the follow-up well. "Analysis of core, logs and geochemistry indicates compelling prospectivity based on thermal maturity, matrix permeability, and resource concentration," 88 Energy told investors in June 2016.

The goal of Icewine No. 2H is to prove the production potential of the HRZ shale. As currently envisioned the well would proceed directionally for 14,877 feet to a total vertical depth of 11,100 feet and include a 3,000-foot lateral through the target formation.

With the recent seismic acquisition — funded with a credit facility from Bank of America secured against state of Alaska tax credits — 88 Energy hopes to not only de-risk the horizontal section of the well but also identify conventional development opportunities.

Economics

If recent experience holds true, those opportunities will be important.

To date, the few independent companies that have tried to develop North Slope source rocks have struggled to initiate production in a region where economies of scale are both crucial and hard to create. Unlike a traditional reservoir, where a relatively small number of wells can use underground pressures to drive hydrocarbons to the surface, source rock development requires a vast grid of wells to drain small sections of a formation.

In recent years, Great Bear Petroleum Operating LLC and Royale Energy Inc. both determined that any unconventional program would require a corresponding conventional program to fund operations in the short term until infrastructure could be developed.

Earlier this year, DeGolyer & MacNaughton estimated that the HRZ shale at Icewine contains 985.3 million barrels of liquids in a mean case. The estimate included both oil and wet natural gas and condensate. Internally, the companies believe the prospect contains more than 2.6 billion barrels of liquids in a mean case. The difference, according to 88 Energy, comes from a disagreement over how much of the acreage is productive.

Currently, 88 Energy expects to drill as many as 1,200 wells to develop the entire Icewine prospect — between 10 billion and 21 billion barrels of oil in place, depending on the differing estimates. The development would include 30 wells each from 40 pads, with eight processing facilities. By comparison, more than 3,400 wells have been drilled to pursue the approximately 25 billion barrels of oil in place at the Prudhoe Bay unit.

According to 88 Energy assumptions, each Alaska well would cost between $9 million and $17 million, compared to an average cost of $7.8 million for a Lower 48 well, according to U.S. Energy Information Administration estimates. And other operating costs in Alaska also appear to be higher than Lower 48 equivalents with the possible exception of royalties, which can vary depending on private landowners. All told, 88 Energy is presenting a range of exploration and development costs between $27 and $68 per barrel, depending on the total size of the resource and the severity of its expenses.

One undeniable advantage of the project is its location, which would require a 15-mile transmission line and a short road to the trans-Alaska oil pipeline and Dalton Highway.

—ERIC LIDJI

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TALERICO Q&A

Some of the other things that we produce are riding a rollercoaster, too. Gold rides somewhat of a rollercoaster — silver and zinc, too. Every one of those commodities has fluctuation. That is something we'll look at in the future. How do we flat line a little bit with our budget. We can't follow every peak and valley, saying wow we are in an incredibly wealthy state then we are burning through our savings. We are in a global market so we don't have as much control over this as we would like.

It's important for us to maintain good business relationships and keep oil flowing for sure. At the same time, we hear from a lot of constituents and the best part of hearing from constituents is we do get a lot of good ideas from people and it does give them a place to voice their frustrations. I think in the future I hope we continue to look at how do we diversity this economy.

It's more than operating state government. The more opportunities that we have that means our job market is more rich for those who are out here looking to work and raise their families and things like that. A strong job market keeps home values where they need to be, keeps money in the state flowing. People can borrow money and do reasonable things. When it falters — boy I think I saw oil fall to $27 a barrel once this year. I think I'm probably like every legislator in that I go to www.oilprice.com every morning to see where that price is.

One of the things I think we've done that I don't think we should overlook and I think is really promising. Stopping the decline and even having an increase — that means 12.5 percent of the oil that went down that pipeline belongs to the state of Alaska. A little bit of climb in oil prices and a climb in production is good news for us when it comes to actual dollars. When we start talking about credits, we always seem to forget about royalty oil.

Petroleum News: Some people don't think that's a valid argument in the context of oil taxes. Others believe it's germane in the argument of government take. Where do you see it?

Talerico: If we get 500,000 barrels of oil a day and we get 12.5 percent that means we get 50,000 to 55,000 barrels of oil. If the price of oil is nearly $50 a barrel, I think that's significant for the state. That's much better than when we were doing 400,000 barrels and getting 12.5 percent of that and oil was selling at $30 a barrel. That's simple math — dollars and cents. I think that tweaks the spring forecast from the Department of Revenue. Even their production numbers weren't as high as the most recent production numbers we've seen. We'll get the fall forecast to get the adjustment. I wish I could say things are going to stay the way they are and we are going to keep that volume and keep watching prices climb. I can't say that. If they do, that's a positive for us. Best statement is that's money in the bank. That's reasonably simple math.

Petroleum News: OK, let's say in January, you're back here for another term and oil is approaching $100, what do you do as a legislator, whether you're back as co-chair of Resources or in another position, what do you do to remind people of what it was like when you started in office?

Talerico: That's something I think is going to take a particular amount of discipline from the Legislature. If that climbs back up there, there is the savings we depleted that we should restore. This might be a really valuable lesson for us. We still need to look for those efficiencies in government. We still need to right size our government for the number of people who live in Alaska. There might be something to that in some areas. I don't think we step back and relax and say, "Wow, we are OK." I think we need to keep everything under a microscope, hopefully the lesson we learned from this dip will help us re-establish ourselves, rework ourselves to where we are: a little leaner and a little meaner.

I'm still thankful to legislators who came here before me and put money away. But our budgets had grown substantially. I'm looking at stuff that was done in 2007. We had fees for people who had certificates and licenses to do business in the state of Alaska. Back then I think we decided to subsidize that. It used to cost $200; we cut it to $50. We had money. What do you tell constituents at the time? The state is bringing in all sorts of money, but you're still charging me all of these fees. There was a lot of pressure to bring that down. We might have learned that lesson. Before we make that move, we might want to look further out into the future.

You know one of the things that I dealt with over the last couple of years, which wasn't very popular when I first put it out there, and that's HB 137, the hunting and fishing fees. Quite honestly we hadn't done anything with resident fees for nearly a quarter of a century. We hadn't done non-resident fees for over 17 years. In the meantime we are watching the federal government collect excise taxes from firearms and ammunition.

Regardless of whether you think it's the current administration that created the rush on guns and ammo a few times, but this Pitman Robertson account is growing like mad. All of our matching funds are based on license fees and tag fees and we haven't raised them in a quarter of a century. We are missing out on a three-to-one matching fund on Pitman Robertson funds; Dingall Johnson funds I don't think pay out three-to-one. That's for the fishing fees. But what it does is eliminates a fair portion of our undesignated general funds paying for our fish and game services, and frees it up to be used somewhere else.

So those are the kinds of things I'm talking about when I say looking elsewhere (away from the oil industry). It's not a $100 million hit, but it's millions of dollars that can be transferred back over to the general fund.

As we make these adjustments, I'm hoping we start to see some things level out a little bit. Somebody told me you're taking money from other states where they buy guns and ammo. We buy a lot of guns and ammo up there. You know I think a fair portion of those funds we are going to get back are funds we contributed to. I'm hoping as we go, we can find more of those things.

I realize oil is going to be in the driver's seat as far as revenues go. We've put all of our eggs in one basket for a while. It's not out of the question that we need to diversify and we need more industries. I think what some of the younger people are looking at, they are thinking Alaska has produced a lot of raw products. But what do we do to build an entire industry?

Petroleum News: Nobody knows what next year's legislative makeup will look

see **TALERICO Q&A** *page 18*

PIPELINES & DOWNSTREAM

Alyeska 36-hour shutdown June 25-26

Alyeska Pipeline Service Co. completed a 36-hour major maintenance shutdown of the trans-Alaska oil pipeline June 25-26.

North Slope field operators typically schedule maintenance work around the annual pipeline shutdown and to take advantage of milder summer weather.

Both BP and ConocoPhillips had scheduled maintenance activity at fields which they operate.

ConocoPhillips Alaska spokeswoman Natalie Lowman said scheduled maintenance at the Kuparuk River Unit's Central Processing Facility 1 was scheduled to start in late June and last approximately three weeks.

A scheduled maintenance shutdown at Alpine, Lowman said, is planned for late July and will also last about three weeks.

As reported in the June 19 issue of Petroleum News, BP's summer maintenance, a scheduled turnaround at the Prudhoe Bay seawater treatment plant, was underway prior to the Alyeska shutdown.

Alyeska had work scheduled at Pump Station 1 and at the Valdez Marine Terminal, as well as an annual inspection and maintenance of the Pump Station 9 power substation.

—PETROLEUM NEWS

GOVERNMENT

BSEE increases maximum civil penalty

The federal Bureau of Safety and Environmental Enforcement has announced an increase in the maximum civil penalty for violations of the Outer Continental Shelf Lands Act. In an interim final rule that will become effective on July 18, the maximum penalty will increase from $40,000 to $42,017 per day for each violation, BSEE says.

"BSEE uses civil penalties as an enforcement tool to deter unsafe practices that are not in compliance with regulations," said BSEE Director Brian Salerno. "We review penalty rates annually to make sure they keep pace with inflation. This ensures they remain a mechanism that emphasizes to industry the importance of safe and environmentally responsible operations."

BSEE says that it imposes civil penalties when an operator on the outer continental shelf "fails to correct a violation that has been recorded or commits a violation that constitutes a threat of serious, irreparable or immediate harm or damage to life, property, any mineral deposit, or the marine, coastal or human environment."

Under a federal statute the agency must periodically adjust the maximum permissible penalty in line with the consumer price index. BSEE's last inflation adjustment took place in 2011. The agency determining that no adjustment was warranted in 2014 and 2015.

—ALAN BAILEY

State will charge for use of the GMC

As one of a couple of bills signed by Gov. Bill Walker on June 23 to increase state revenues, Senate Bill 170, authorizing Alaska's Division of Geological and Geophysical Services to set and collect fees for the use of the Geologic Materials Center in Anchorage, has become law.

"With a $4 billion budget deficit, we must leave no stone unturned as we look for new ways to fund state government," Walker said at the time of the bill signing. "I thank Senator Giessel for bringing this legislation forward, and for finding new ways to reduce the draw on unrestricted general funds."

The Alaska Department of Natural Resources operates the center in cooperation with the U.S. Bureau of Land Management, the U.S. Geological Survey and the U.S. Bureau of Ocean Energy Management. The center contains a major archive and library of Alaska rock samples and holds an almost complete collection of core and drill-cutting samples from oil and gas wells drilled in Alaska and on the Alaska outer continental shelf. The collection at the center also includes numerous microscope slides from well samples and many thousands of rock samples from the mining industry.

Under the new legislation the division can collect fees for the rental of space for confidential sample storage; the rental of sample viewing facilities; the retrieval, processing or sampling of geological material; the use of equipment in the center; and for analyses, maps, reports, data or other products authorized by the division. There is a provision to allow the waiving of some fees for the use of the center by students for educational purposes.

—ALAN BAILEY

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AURORA GAS

yield an expected uptick in production.

The local independent filed for bankruptcy protection under chapter 11 after Aurora Well Service LLC, Shirleyville Enterprises LLC and Tank-A-Lot Inc. filed an involuntary petition with the court in early May. According to the court, as of June 1, Aurora owes its 20 largest creditors nearly $1.5 million. In addition to the three petitioners, Aurora owes more than $100,000 to four other Alaska-based companies: Tyonek Contractors LLC, Tyonek Native Corp., Alaska Eco Resources LLC and AIMM Technologies Inc.

Aurora is one of the oldest independent oil and gas companies operating in Alaska.

The utility Aurora Power Resources Inc. created Aurora Gas in 1999 as an exploration and production arm, at a time when major consolidations throughout the oil industry were creating opportunities for smaller companies to pursue overlooked fields in Alaska. In August 2015, Rieck Oil Inc. acquired Aurora Gas from a consortium of previous owners.

Aurora currently operates five producing natural gas fields on the west side of Cook Inlet — Nicolai Creek, Lone Creek, Moquawkie, Albert Kaloa and Three Mile Creek.

Earlier this year, in a presentation to Alaska lawmakers, Aurora proposed a major development program for the remainder of 2016 and 2017, including two extension wells at west Moquawkie, an extension well and a step-out well at Nicolai Creek. The presentation also included potential projects contingent on the results of a package of 3-D seismic over the region that the company was looking to acquire from Apache Corp.

—ERIC LIDJI

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TANK REGISTRATION

facilities. "We're not interested in having a program that doesn't work for people," she said. "A system similar to what is done for large bulk facilities is too complex for small operations," Spiegel said.

Plans required for larger tanks

Large fuel tanks, or combinations of tanks in one facility that store more than 420,000 gallons must have an approved spill contingency plan from DEC that includes not only a spill containment and cleanup capability but preventative and maintenance measures, including corrosion control and periodic inspections, Spiegel said.

There are 141 contingency plans currently approved for bulk fuel and crude oil facilities in the state, but this isn't an accurate count of large fuel facilities because they include bulk fuel vessels and pipelines. One contingency plan can also cover several tank facilities, however.

Contingency plans must be renewed every five years, and in any one year several are in the renewal process, Spiegel said. ●

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CREDITS DROPPED

Alaska production by 2018 if developed as now planned.

"While we are certainly disappointed that Governor Walker chose to ignore the state's previous commitments to small oil companies investing in Alaska, we are hopeful that some sort of accommodation can be worked out," said Benjy Johnson, president of BlueCrest Energy.

"The governor reiterated that the tax credits are a continuing obligation of the state and that his veto did not make those payments obligations go away," he said.

Payments delayed

Although current year funding is cut the payments are only delayed, state revenue officials reaffirmed. Ken Alper, the state tax director, said the structure of the program, although now scaled down, remains intact.

Companies earning tax credits, mostly small independents, will eventually be paid when an appropriation is approved. They are meanwhile free to sell them to third-party buyers, such as major Alaska producers, who are able to use them as credits against their own state production tax liability. The credits would likely be purchased at a discount, however.

In the new tax law tax approved June 29 the incentive credits for Cook Inlet development are being largely phased out over two years.

Those include tax credits for 20 percent of capital investments; 40 percent of well lease expenditures and 25 percent of net operating losses in Cook Inlet.

On the North Slope, a 35 percent credit for net operating losses will continue, a point of contentious by critics of the program in the Legislature. Other North Slope tax credits have ended, however, including the 20 percent capital investment tax credit that was repealed in 2013 by the Legislature.

While the state is essentially writing IOUs to explorers and new developers, the backlog of payments due on credits is building.

Applications total $693 million

Alper said to date the state Department of Revenue has received tax credit applications totaling $693 million, mostly for work done in 2015.

Ken Alper, the state tax director, said the structure of the program, although now scaled down, remains intact.

This includes $200 million in prior tax credits carried forward from last year left after the governor vetoed $200 million of the appropriations, which had totaled $700 million.

To date the state has made full payment on $485 million of the tax credits approved for last year, Alper said, which is close to the $500 million allowed by the governor after his veto.

As IOUs by the state, the tax credits become a financial liability although they are only a "moral obligation" subject to payment on appropriation by the Legislature. While not legally obligated to pay, the Legislature has a good track record of honoring moral obligations.

Credibility an issue

However, the erratic nature of the state's actions on the tax credit program is undermining the state's credibility.

Benjy Johnson, at BlueCrest, said "What (the governor's action) did is create a tremendous distrust of the state's integrity going into the future. Unless something is worked out to help the small oil companies work through the payment delay, this is going to have a long term negative impact to the state and will surely come into play as the state tries to obtain financing for new capital programs."

The governor's veto actions mainly affect the tax credit payments made to small explorers and developers. Large North Slope producers BP, ConocoPhillips and ExxonMobil, and Hilcorp Energy in Cook Inlet, are not eligible for cash refunds for the credits. Those companies are still eligible for credits on net operating losses, but the credits must be applied to their future production tax liability, not taken in cash payments. ●

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TALERICO Q&A

like and even from there the caucus make up. With that in mind, would you like another term as co-chair of Resources?

Talerico: Now that I've had one behind me, I think I wouldn't mind doing that. That would certainly be up to people who cast a vote. I've gained all this perspective on oil and gas, plus all of our other resources. I think I would be interested in that if I'm successful.

One of the things I think is very interesting is I'm looking at some of the retirements coming up. You've got Sen. (Johnny) Ellis with his institutional knowledge; we can't replace that with a new person. Then there's Sen. (Charlie) Huggins and Sen. (Lesil) McGuire.

On the House side, the very unfortunate passing of Rep. Gruenberg, who although we were on different sides on the aisle, when I was a staffer I got to work with him a little bit. We were on the same floor. I've got a picture I keep on my phone of Rep. Gruenberg and I talking about HB 137. He's a great wordsmith so we won't have that in our halls.

Rep. (Kurt) Olson is leaving. Rep. (Mike) Hawker is leaving: So we are losing the Labor and Commerce chair (Olson) and the LB&A chair (Hawker); both on Resources, by the way. Nobody crunches numbers as fast or better than Rep. Hawker.

Those who return and are serving now will have to step up their game. I think a lot about that. The hardest part for me to return, all of those people, regardless of their affiliation, we'll miss those folks. We really will.

One of the things that's promising is there are a lot of good people in this building who work pretty hard and I think we'll be able to fill some of those shoes, but it's going to require an extra effort. There will be a different makeup of the Resources Committee no matter what. So if it happens, it will be a little odd for a guy in his second term; I'm going to look around the room and see I'm one of the senior people in this room. It's going to be felt all over. ●

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AGDC ROLE

gives them more significant control over the project.

He said he didn't necessarily support equity-based financing for major infrastructure in Alaska because if the pipeline is built it will lower the barrier to develop North Slope resources, providing a significant transportation corridor and if there was open access to that pipeline providing capacity for newcomers.

Meyer said it's a cost of capital issue — when times are tight an equity based model has a somewhat higher hurdle because producers have a higher cost of capital than infrastructure investors.

In response to a question from Rep. Dan Saddler, R-Eagle River, on why Meyer was recommending a shift in the project structure, Meyer said his basic charge was to see how AGDC can get the project moving, pick up the pace and see if the project can hit the next market window in the mid-2020s.

That's what the discussion is about, he said: is there a different structure that may lend itself to infrastructure financing, federal tax exempt financing.

Meyer said while he has suggested the state could increase its ownership share, there isn't a link between share and funds that need to be invested. That's only for an equity project.

On an infrastructure project, he said, the majority of project investment can come from large infrastructure funds that take a lower rate of return.

The producers are welcome to be owners, Meyer said, but if the project is done right it won't meet hurdle rates for the producers, while for infrastructure funds the returns will be very attractive.

Meyer said that on the current path the project it is not going forward; the issue, he said, is should the project be slowed down or should we try something different.

The producers are willing to work collaboratively, he said, and discussions are underway on what can be done differently.

Meyer said he was not suggesting that work has been wrong or that the path is wrong, but the market has changed rather significantly. And in a downturn you can delay or look for something different. There is enough support among the state's partners to look for something different, he said.

Sen. Mike Dunleavy, R-Wasilla, asked how Meyer came to the conclusion that the project was not moving forward.

Meyer said there was some disagreement on the pace of FEED, and probing deeper he found the parties were not aligned on going to FEED.

Hawker asked for any concept documents on the proposed changes that AGDC has presented to the producers and Meyer said those could be forwarded. He said the AGDC team wants to provide what they're going for, but not the blow-by-blow negotiating documents, which become confidential once producer comments are incorporated.

Under the commercial framework concept Meyer presented to the committees AGDC would form a special purpose entity which would be the project company, which would have principles designed to keep the project on track with competitive rates. The project company would engage competent technical and commercial advisors.

He said the roles of the producer parties might change because while AGDC's aim is to keep project participants together, some may choose not to invest in the next stage.

He also said the framework would allow parties to participate and exit with minimal impact on the project pace.

And under the concept project ownership may not equate to gas ownership.

The project company would be a midstream business and there would be the potential for alternative financing with federal tax reduction options, lower-cost third-party equity investors and non-recourse debt to minimize financial exposure.

Hawker questioned decoupling the state from the risks of ownership.

The state has two choices, Hawker said: a cautious and deliberative approach or a more aggressive approach where AGDC takes the lead, owns the entity and a third-party would fund it.

Hawker asked how the state's risk in the project would be managed and said the state has positioned itself to minimize risk and maximize benefits. With ownership comes risk.

Meyer said the proposed changes would decrease risk because under an open equity structure there is significant cost overrun risk.

Hawker said risk hedging means the owner transfers, offloads the risk. But, he said, for less risk you pay a price and receive less somewhere along the way.

Meyer agreed that you have to pay to give up risk, and said the contractor would charge you for taking some of the construction risk.

Hawker questioned whether if the state owned the project and laid off risk through an artificial entity and secured financing on a non-recourse basis, if it could really walk away if the project failed and the investors lost. He asked if the state could abrogate that much risk and whether there would be the risk that investors would "pierce the veil" and go after the permanent fund.

Meyer said risks would have to be identified, quantified and acceptable to the state before it took them on.

Under either structure, Meyer said, the risk has to be acceptable to the state or the project wouldn't go forward. ●

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EXPORT LINE

41 percent of respondents agreed the National Energy Board made the right decision in May when it recommended approval of the Trans Mountain expansion subject to 157 conditions. (Only 24 percent disagreed with the NEB, while 35 percent were undecided. In British Columbia, which faces the most heated opposition to the project, 41 percent supported the NEB and 34 percent were opposed.)

"What I've heard from business communities is that they've recognized that ignoring community voices, trying to run roughshod across environmental concerns, has resulted in not getting pipelines and projects built that people wanted," he said.

Trudeau said the failure by the government of Prime Minister Stephen Harper to obtain "social license" created a barrier to pipeline plans and has forced the energy industry to acknowledge that it now needs "broad support."

Whatever progress Kinder Morgan might have made towards swaying the Trudeau government, opposition to the project has intensified, with the City of Vancouver now joining a First Nation and two environmental groups in launching a court challenge to quash the NEB's endorsement of the plan to triple capacity on Trans Mountain to 890,000 barrels per day.

Mayor Gregor Robertson said the regulatory review by the NEB was "flawed and biased" because it ignored scientific evidence on the consequences of a major oil spill and the impact of associated greenhouse gas emissions.

"An expanded Kinder Morgan pipeline is not in Vancouver or Canada's economic of environmental interest," he said in a statement.

The city is also asking the Federal Court of Appeal to prevent the federal government from making a decision until after the NEB conducts a "lawful" review of Kinder Morgan's application.

Although it comes too late to affect the Trans Mountain case, the Trudeau government has announced it will overhaul the NEB's mandate as part of an effort to rewrite and strengthen environmental laws.

Natural Resources Minister Jim Carr said the strategy to "modernize" the federal regulator's role will give Canadians "trust in the regulatory process" and "restore credibility" to the system.

As part of the changes, Environment Minister Catherine McKenna said a panel will be established to review current environmental-assessment laws.

Fisheries Minister Dominic LeBlanc, who said his department will ensure the protection of fish habitat, said Canadians "want us to ensure that economically beneficial and environmentally responsible projects are advanced and projects with minimal benefits and high risks are not."

Candice Bergen, a Member of Parliament for the opposition Conservative Party, said Trudeau is creating "massive uncertainty when it comes to building pipelines."

Also in the uncertain category is when and how the Trudeau administration will meet a promise made in last year's federal election campaign to "formalize" a ban on oil tanker traffic off the northern British Columbia coast.

"We're working every day to get both the environmental and the economy protected right across the country," Trudeau told PostMedia.

Beyond that he would not say whether a ban will be imposed by early 2017 — the deadline promised by Transport Minister Marc Gurnee.

But Trudeau, who has repeatedly voiced opposition to Enbridge's Northern Gateway project to ship 525,000 bpd of oil sands bitumen from Kitimat, said again that "crude oil supertankers have no place" in that region.

Gavin Smith, a staff lawyer with West Coast Environmental Law, said that a ban imposed through legislation or regulation would give the government time to determine what offshore geographic area it wanted to cover and deal with possible diplomatic issues with the United States.

Enbridge, which was required under the terms of the NEB's 2014 approval of Northern Gateway to start construction by the end of 2016, recent asked the NEB for a three-year extension of that permit to the end of 2019.

The company said the extra time would allow it to increase community and aboriginal support.

Smith said it "could be more palatable" for the federal government to refuse Enbridge's request for an extended lease "on the grounds that it was granted a federal approval but failed to meet its conditions."

That would in turn set the stage for the "natural death" of Northern Gateway and allow the government to act quickly on a tanker ban, he said. ●

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The price of delays

Canada's oil producers' lobby group has made clear the cost of stalling on new pipelines by trimming 1.4 million barrels per day from its targeted output by 2030.

Although volumes are expected to grow over the next 14 years, the rate will be slower than expected in the conventional and East Coast sectors, the Canadian Association of Petroleum Producers said in its annual forecast.

All told, the industry is counting on 4.9 million bpd in 2030, up 1.1 million bpd from the forecast for 2016, but far short of the 6.4 million bpd in the outlook CAPP issued in 2014.

The report said oil sands producers intend to add 850,000 bpd between 2015 and 2021, largely from projects begun before oil prices started their slide in 2014.

Another 700,000 bpd is expected between 2021 and 2030, despite cancellations or postponements of major projects over the past two years, CAPP said.

Aside from the economic factors which have cut into anticipated growth, CAPP said the numbers are affected by a desperate shortage of new pipeline capacity.

"The need to build new infrastructure within Canada is clearly urgent," said CAPP President Tim McMillan.

"New pipelines will deliver more Canadian energy (to markets), build our country's prosperity and help Canada meet the world's growing energy needs."

McMillan said the Canadian industry is "sitting on a knife's edge," noting that its pipeline system is limited to only 4 million bpd, with current output at 3.98 million bpd.

What is keeping Canada's upstream sector moving ahead is the rise in global demand, with all forecasts showing that the demand for crude oil will "increase fairly substantially between now and 2030," McMillan said, adding that Canada can be "that supplier of choice."

Despite repeatedly slashing their capital budgets, Suncor Energy and Husky Energy are among the oil sands producers poised to generate significant cash flow as commodity prices edge back into the US$50-US$60 a barrel range this year, said analysts at Citigroup Capital Markets.

However, they said growth prospects remain challenged, even after accounting for deflation and lower natural gas input costs, adding that companies will need to significantly lower costs under a scenario in which U.S. shale output caps future oil prices at or under US$75.

"The large upfront costs of the oil sands also pose a challenge in a volatile oil price environment by exposing capital for a longer period," the Citibank analysts said.

CAPP said it expects its member companies will spent C$17 billion on the oil sands this year.

—GARY PARK

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PRICE RISE

pening rather than as a means of definitive price prediction.

"Even in the very near term there's a wide spread in how we look at oil prices," Sieminski said. "You should be very, very careful assuming that those point forecasts are going to give you the right answer."

Against a backdrop of an assumed U.S. economic growth rate of 2 percent per year, EIA has assessed a range of potential future scenarios, from scenarios involving low world oil prices to high oil prices, and including various possibilities for future energy regulation in the United States. The low oil price case predicts a price of about $50 in 2030, while the high price case raises the price level to nearly $200. And an analysis of oil option market prices indicates oil prices ranging anywhere from $25 to $80 over the next year or so, Sieminski said.

Oil production

The EIA sees the rising oil price driving a corresponding increase in U.S. oil production, although the rate of increase is sensitive to further advances in production technologies. But the agency's oil production forecast shows Alaska production steadily declining to near zero by 2035.

In response to a question about the Alaska forecast, Sieminski said that production from the oil fields on the North Slope is declining and that the EIA data reflect existing regulations that do not allow oil development in areas such as the Arctic National Wildlife Refuge.

"Unless more oil is found in Alaska or along the (trans-Alaska) pipeline right of way, it's very possible that the Alaska pipeline itself, which delivers oil from the northern part of the state to Valdez, would end up shutting down," Sieminski said.

In terms of U.S. liquid fuel demand, the share of energy consumption by light-duty vehicles in the United States continues to grow. But proposed new vehicle fuel economy standards, if implemented, would reduce the relative share of energy consumption by these vehicles while also leveling off the use of diesel fuel by medium- and heavy-duty vehicles. The subsequent drop in diesel oil demand could cumulatively amount to a much as 2.5 billion barrels from 2021 to 2040, the EIA report suggests.

Natural gas

When it comes to natural gas, EIA, in a low price scenario, sees the possibility of Henry Hub market prices in the United States remaining below $4 per million Btu for several decades, while, at the high end, prices could rise to about $9 by 2040. The reference case suggests a price climbing to about $4.50 by the mid-2020s and then leveling off. A robust natural gas resource base coupled with production competition will tend to keep prices down, Sieminski said.

But, with a continuing upsurge in shale gas production in the United States, EIA anticipates continuing strong growth in U.S. gas production despite the soft price outlook, with the country becoming a net exporter of gas sometime around the middle of 2017, as domestic production overtakes domestic consumption. In the near term the agency anticipates the exporting of liquefied natural gas from the United States and the export of pipeline gas to Mexico, with gas imports from Canada dropping a bit, Sieminski said.

Electricity generation

The EIA expects electricity generation and industrial gas usage to drive growth in natural gas demand in the United States. Residential gas demand will likely flatten.

The agency anticipates U.S. electricity use continuing to grow. However, the rate of growth will continue a multi-decadal downward trend, thanks to moves towards less energy intensive industries in the U.S. economy, higher electricity prices and improved energy efficiency.

Questions over whether the Obama administration's Clean Power Plan will be implemented, the manner in which it is implemented and implementation of the plan beyond 2030 figure large in some of the energy cases that the EIA has considered and, in particular, the impact of those cases on future power generation. EIA's reference case for the Energy Outlook does assume that the Clean Power Plan will be implemented, Sieminski said.

The carbon dioxide emissions targets under the Clean Power Plan will tend to act as an accelerator for energy trends which are already underway. Implementation of the plan will challenge all U.S. regions that produce coal although, given the decline that has already taken place in the coal industry in the Appalachian region, coal production in the west will now be particularly impacted, Sieminski said.

Growth in renewables

Under the Clean Power Plan the agency sees natural gas and renewable energies, in particular wind and solar power, overtaking coal as the primary energy sources for power generation by 2030. If the Clean Power Plan does not go into effect, coal demand will likely remain level, with only natural gas overtaking coal in the power generation mix. Implementation of the Clean Power Plan would raise electricity prices by some 4 to 7 percent in 2030, EIA has estimated.

However, the declining capital cost of wind and solar is driving the uptake of these technologies.

"So even without the Clean Power Plan we are expecting quite a bit of increase in wind and solar generation," Sieminski said.

In general, the growth in the use of technologies such a solar power will increase the tendency for buildings to generate their own power, thus dampening the demand for centralized electricity power generation. Implementation and extension of the Clean Power Plan will tend to accentuate this trend, the EIA thinks.

Falling energy intensity

The EIA expects continuing reductions in energy intensity, the amount of energy consumed per unit of economic activity, with the reduction largely offsetting growth in the U.S. gross domestic product. As a consequence, overall U.S. growth in energy consumption will be slow, the agency thinks. At the same time, a shift towards fuels that contain low carbon content or no carbon will cause the U.S. carbon dioxide intensity, the volume of carbon dioxide emitted per unit of economic activity, to continue to fall. The falling cost of solar power and the increasing use of natural gas will particularly push a drop in carbon dioxide emissions, the EIA thinks.

The EIA also anticipates that the energy consumption per person will fall slowly in the United States, as a consequence of improved appliance and vehicle efficiencies, and because of a tendency of the retiring "baby boomer" sector of society to move from cooler to warmer regions of the country.

Industrial energy consumption will tend to grow, but with the petroleum feedstock's share of the energy mix rising while coal's share drops, the EIA predicts.

"We are expecting to see more natural gas consumption, especially for feedstocks," Sieminski said. "Lower natural gas prices mean a lot more natural gas being used in the petrochemicals and fertilizers industries, as well as just general industrial output."

—ALAN BAILEY

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