Petroleum news

Celebrating 20 years: 1996-2016

page 11 Company focuses on forming battery-grade graphite from deposit

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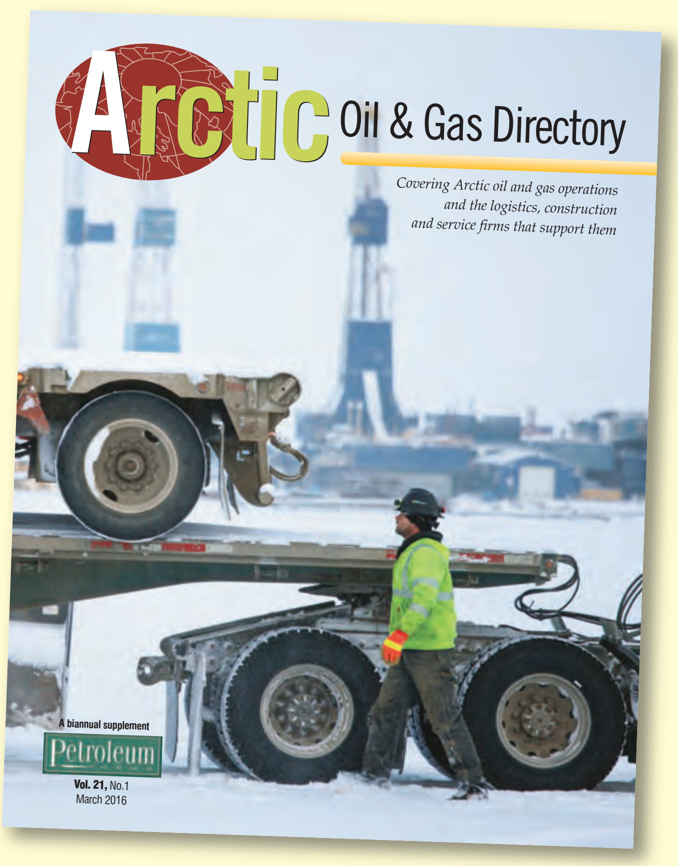
Latest Arctic Directory released



House Resources moves committee substitute for oil tax credit bill

The House Resources Committee moved a committee substitute for House Bill 247 March 22, dropping a good many of the proposals included in the administration bill, including most of the revenue-generating changes to the state's oil and gas tax credit system proposed by Gov. Bill Walker.

Over some 20 hearings, and discussions of amendments to the CS, views of committee members appeared to split between concerns about encouraging future oil and gas development in a time of low returns for the industry and low revenues for the state and a focus on reducing state support for oil and gas exploration and development provided by tax credits and increasing taxes on the oil and gas industry.

In an overview of CS changes, Tax Division Director Ken

see **TAX CREDIT** *page 24*

Alberta-Alaska link gets prod; feasibility study in the works

Promoters of a rail-and-pipeline connection from the Alberta oil sands to Valdez are about to launch a feasibility study of the C$34 billion venture to move about 1 million barrels per day of bitumen for export to Asia, starting in 2020.

Matt Vickers, chief executive officer of G Seven Generations, told an Arctic Oil & Gas symposium in Calgary that the first stage will be early engagement with aboriginal communities along the proposed rail route of almost 1,500 miles.

He said that to date there has been strong backing from indigenous peoples, with Canada's influential Assembly of First Nations endorsing the concept.

"If you don't have early engagement at that level — regardless of whose land you're on or where you are in the world — I

see **LINK STUDY** *page 19*

page 3 Q&A: Wielechowski expresses concern over credit bill, status of AKLNG

EXPLORATION & PRODUCTION

A continuing effort

Prudhoe Bay going beyond 12.4B barrels of oil recovered; gas now dominates

By ALAN BAILEY
Petroleum News

Although the original estimate of 22.4 billion barrels of oil in place for the Prudhoe Bay field on Alaska's North Slope has remained unaltered since field development first began, the anticipated ultimate oil recovery from the field has climbed over the years, as new development and production techniques have teased more oil out of the field reservoir, Scott Digert, BP's Prudhoe Bay East Area development manager told the Alaska Geological Society on March 15.

To date the field operators have recovered about 12.4 billion barrels of oil from the field, a figure that represents 55 percent of the oil in place. Ultimate recovery could reach 60 percent, a volume of 14 billion barrels, depending on whether the future oil price is high enough to make economic the increasingly expensive development of the more elusive oil in the reservoir.

> *And nowadays, 50 percent of the oil being produced exists in the gas phase in the reservoir, whereas at field startup almost all of the oil existed underground in liquid form, Digert said.*

"That would take clear seas and a tailwind, and oil prices much above where they are today," Digert said, commenting that the breakeven price of oil for viable Prudhoe Bay production today is

see **PRUDHOE BAY** *page 22*

FINANCE & ECONOMY

Oil back to the future?

Not hardly, Herrera says of Wood Mac report, but recovery might begin in 2017

By KAY CASHMAN
Petroleum News


ROGER HERRERA

Whether it's the Wall Street Journal, the Financial Post or Wood Mackenzie's March 7 recent oil price report, people seem bent on making comparisons between the 1986 oil price collapse and today's crisis.

But Roger Herrera — Petroleum News' favorite oil price guru because of his accurate predictions — sees the comparisons as superficial; a nonsensical basis for predicting what will happen to oil markets in the months and years ahead.

Nonetheless, Wood Mackenzie's prediction of an oil price recovery starting in 2017 is possible, Herrera said, but not because of the reasoning used in the consultancy's March report.

The title of the report, Oil Markets in 2016: Back to the future II, is a take on the 1986 movie, "Back to the Future."

Various projections for life in 2015 in the film have come true — video conferencing, movie sequels, handheld tablets and wall mounted widescreen televisions. But it will be sheer chance if Wood Mac's oil price prediction comparisons prove true, energy observer Herrera told Petroleum News.

"In 1986, Saudi Arabia had been deliberately keeping its production low while its OPEC partners

see **OIL FUTURE** *page 23*

PIPELINES & DOWNSTREAM

TAPS needs more throughput

Alyeska's Barrett: Federal regulatory environment discourages increased oil flow

By ALAN BAILEY
Petroleum News


JUDY PATRICK
TOM BARRETT

Faced with ever more difficult issues relating to ice formation and wax precipitation, the trans-Alaska oil pipeline needs more oil production from the North Slope to stave off declining oil throughput, Tom Barrett, president of Alyeska Pipeline Service Co, told a meeting of the Resource Development Council on March 17. Alyeska operates the pipeline on behalf of the oil companies that own the line.

"We live and breathe on (oil) throughput," Barrett said. "The lower the throughput, the harder our job is and the more challenging it is."

Essentially, as oil throughput declines and slows, the oil becomes colder on its way down the line, resulting in increased wax precipitation from the oil and the possibility of ice formation.

Using current approaches to dealing with the ice and wax issues, the pipeline can safely operate down to 300,000 barrels per day — Alyeska does not currently have a solution for dealing with flow rates below that level, Barrett said. In 2015 the pipeline handled on average just over 500,000 barrels per day.

Barrett commented that the regulatory climate,

see **TAPS THROUGHPUT** *page 19*

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GOVERNMENT

Concerns over credit bill, AKLNG status

Sen. Wielechowski, an Anchorage Democrat, says Alaska needs a tax credit system that doesn't cost the state more than it earns

By STEVE QUINN
For Petroleum News

Sen. Bill Wielechowski got a quick look at the Department of Revenue's spring forecast and didn't seem surprised that the news of the state's deficit got worse. The Anchorage Democrat and Senate Resources Committee member says he understands the chronically low oil prices are driving many of the problems, but he insists the Legislature can make changes to sections of the tax law he believes unfairly favors the oil industry, such as the tax credits system. Wielechowski spoke to Petroleum News on the prospects of a change to the tax credits as well as the status of the AKLNG project.

Petroleum News: The governor released a preliminary spring forecast, which cites greater deficit linked to low oil prices than previously expected. What are your initial thoughts on the report?

Wielechowski: In a word? Depressing.

A couple of things jumped out at me. The money coming into the state continues to go down, and that's a huge concern. A few other things jumped out at me. I looked at the production numbers and saw oil production numbers are up slightly then it starts tracking down slightly in the outward years.

The other thing that I noticed was the tax credits, up to $825 million and we now under water $771 million — paying out $771 million more than we are receiving in oil production taxes. When you add all the unrestricted revenue in the state from petroleum — whether it's income taxes, property taxes, royalties — we are actually for the first time in the state's history underwater. We are paying the oil industry more than we receive. Now that's unrestricted. We take in slightly more when you take in restricted revenue, but it just goes to show you the tremendous dependence on the oil industry, and a situation financially that is unsustainable for the state.

Petroleum News: Let's talk about production. It goes up slightly then works its way back down. What do you make of that?

Wielechowski: I'm always happy when we see the production numbers go up. As you went out to 2025 there is a slight decline, so it's relatively flat. It's a little disconcerting because during the SB 21 debate, we were promised more production. We stopped the drop. Remember that mantra? Unfortunately, when you look at every production forecast has shown declines in long-term production. So that's troubling. This is even when the price of oil $100 a couple of years ago after the passage of SB 21 and that's very concerning.

Petroleum News: At the very least, it has seemed to level out. Are there some provisions in SB 21 that are working?

Wielechowski: I think it's working for the producers. For the state of Alaska, it's financially hurting the state long term. ACES needed improvement; there was no doubt about it. The tax credits, we've known that's been an issue. Under ACES, we took too much at the high end. We had a lot promises under SB 21: more jobs, more revenue, save the Permanent Fund, increased production. We are just not seeing that happening at this point.

SEN. BILL WIELECHOWSKI

Petroleum News: So how much of that is SB 21 and how much of that is the market?

Wielechowski: I think oil was on a decline and there was probably nothing that was going to stop it in Alaska. Certainly not SB 21. I think there are other things that could have been done to stem the tide and we sponsored legislation to do that. We had projected decline when oil was $90 and $100 a barrel. Nothing has changed. You're dealing with a resource that's on a long-term decline. A lot of promises were made that we knew were not going to be kept and they are not being kept. I think there are ways to spur more production on the North Slope but SB 21 was not the way to do it.

Petroleum News: The Senate has first crack at a bill to place two members of the Legislature on the AGDC board as non-voting members. What are your thoughts on that?

Q AND A

Wielechowski: I don't support the legislation for a few reasons. I think there are some legal issues with it number one. There is an attorney general opinion which says it's unconstitutional and that's a huge issue. I think from a practical standpoint, we need to remove the politics from the gas line. I've said that for years now. We have this body that we've created, the AGDC. The governor appoints, we approve and I think we need to address it at that point. We give general legislative guidance but I think for us to politicize it even more by having legislators on it is just the wrong approach.

Petroleum News: So where do you stop. Any appointment by the governor is a political appointment, so it's already there.

Wielechowski: The appointees get questioned vigorously after the governor appoints them, and they should. Once we appoint them to this position, we shouldn't be micromanaging it as a Legislature. To the extent that's possible, we need to get the politics moved out of it. They have been appointed by the governor and approved by the Legislature, they are very contentious hearings, but to make it even more political to have legislators

see WIELECHOWSKI Q&A page 21

● FINANCE & ECONOMY

Spring revenue forecast down $300M from fall

Oil price is lower, although North Slope production higher, but overall state will be taking in less money than projected last year

By KRISTEN NELSON
Petroleum News

A preliminary spring revenue forecast for Alaska, released March 21, drops fiscal year 2016 general fund unrestricted revenue to $1.3 billion, down almost $300 million from the fall forecast. The GFUR forecast for FY 2017 is $1.2 billion.

Revenue Commissioner Randall Hoffbeck said the forecast is typically released in early April, a week after the annual oil production returns which are due March 31, "but because of potential budget implications of sustained low oil prices, we wanted everyone to know the effects on the current revenue outlook as soon as possible."

The big driver for the change is the oil price, Hoffbeck said, which was projected at $50 per barrel for FY 2016 in the fall revenue forecast, and is now projected at $40 per barrel. He said forecast prices over the next 10 years have also been reduced, reflecting a slower gain in oil prices, which the department is now estimating won't reach $60 per barrel until FY 2021.

The FY 2016 and FY 2017 forecasts are based on the expectation of oil in the $30 to $40 per barrel range for the next 15 months and oil production of at least 500,000 barrels per day. The preliminary forecast says North Slope crude oil production has been revised upward for FY 2016 from 500,200 bpd to 517,700 bpd, a 3.5 percent increase from the fall forecast. Non-North Slope production, however, is now forecast at 17,300 bpd for FY 2016, down 2.85 percent from a fall forecast of 17,800 bpd.

For the 10-year forecast period, North Slope production ranges from 517,700 bpd in FY 2016 to 300,500 bpd in FY 2025, compared to the fall forecast which ranged from 500,200 bpd in FY 2016 to 302,100 bpd in FY 2025. For all fiscal years except FY2016 and FY2017, the spring forecast for North Slope production is lower than the fall forecast.

Cumulative unrestricted petroleum revenue, based on revenue beginning in FY 1959, is $115.83 billion and estimated to grow to a cumulative $124.386 billion by FY 2025.

Lease expenditures

Combined operating and capital lease expenditures for the North Slope, which were $7.431 billion in FY 2015, are trending down from the fall forecast, which projected $6.889 billion for fiscal year 2016, a number now estimated at $6.55 billion for FY 2016 in the spring forecast. For FY 2017 the fall forecast was $6.454 billion, with the spring forecast at $6.046 billion.

Oil and gas production tax is projected at $133.4 million in FY 2016, dropping to $45.6 million in FY 2017, and bottoming out at $10.7 million in FY 2019, then rising to $274.1 million by FY 2025.

Overall unrestricted petroleum revenue (including petroleum property tax, petroleum corporate income tax, production tax, oil and gas hazardous release, oil and gas royalties net of Permanent Fund Corp. and CBRF deposits and bonuses, rents and interest) is estimated at $780 million in FY 2016, dropping to $690.6 million in FY 2017, and then increasing through most of the forecast period to $1.075 billion in FY 2025.

Cumulative unrestricted petroleum revenue, based on revenue beginning in FY 1959, is $115.83 billion and estimated to grow to a cumulative $124.386 billion by FY 2025. ●

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EXPLORATION & PRODUCTION

Hilcorp permitting Greystone pad

Hilcorp Alaska LLC is permitting an exploration project in the southern Kenai Peninsula.

If the subsidiary of the Houston-based independent proceeds with the project, it would be the first exploration venture for the company outside of its existing units in Alaska.

The proposed Greystone pad would be on Cook Inlet Region Inc. leases between the Deep Creek and Nikolaevsk units, which are both producing fields operated by Hilcorp.

To date, Hilcorp has focused almost exclusively on development since arriving in Alaska and has only pursued exploration opportunities within existing units when required to retain acreage. That approach has yielded wells at the Deep Creek and Ninilchik units.

A public notice from the Alaska Department of Environment Conservation said Hilcorp would begin construction on Greystone in the second quarter and drill at least one well.

—ERIC LIDJI

● GOVERNMENT

Not-so-neighborly

Alberta and British Columbia lock horns over issues of pipeline access to Pacific Coast and BC hopes of selling surplus power

By GARY PARK

For Petroleum News

The simmering showdown between Canada's two most western provinces over energy megaprojects is coming to the boil, with British Columbia trying to sell surplus hydroelectric power to its neighbor and Alberta Premier Rachel Notley spurning the offer unless British Columbia allows construction of an oil pipeline across its territory to the Pacific Coast.

"We're not necessarily going to have that much demand for that much electricity if we can't find someone to sell our product to," Notley told reporters.

"We have to get our product to other markets."

She said that if provinces such as British Columbia and Manitoba want to talk about power lines crossing provincial borders they need to understand that is no different from Alberta's efforts to get support for its desperate efforts to get crude pipelines built to export terminals.

There was an even more direct statement by Alberta Energy Minister Marg McCuaig-Boyd, who said her government would "do what's best for Albertans and Alberta's economy. We won't be buying more power if we can't get our resources to market."

Different views

British Columbia Energy Minister Bill Bennett said he did not have a problem with Alberta linking a potential power deal to pipeline support.

"We have a long, very positive history of cooperating with Alberta, so I don't see this as a big problem. I think we can work through this and find a way to do business together," he said.

Bennett said British Columbians mostly want to ensure that that any pipelines carrying heavy crude are built to the highest standards, based on the five conditions it has set to protect land, air and sea.

Successive Alberta governments have a different view of that relationship, having spent much of the last decade trying to get British Columbia to sign off on Enbridge's Northern Gateway and Kinder Morgan's plans to triple capacity of its Trans Mountain system, both designed to get oil sands bitumen to Asian markets.

British Columbia Chamber of Commerce President Jon Garson lifted the curtain on the cross-border tensions by urging the governments to ensure political rhetoric does not interfere with enhancing trade and building both economies.

The gulf between the two provinces was reflected in a new poll by the Angus Reid Institute which showed 60 percent of British Columbians oppose the Trans Mountain project, while 80 percent of Albertans support the proposal.

"It's a tale of two neighbors with very little in common," said Shachi Kuri, executive director of Vancouver-based Angus Reid.

In the midst of the cross-border push-and-shove, British Columbia Premier Christy Clark is seeking C$1 billion in federal money to upgrade British Columbia Hydro transmission lines to support electricity shipments to Alberta.

She said "it's great" Alberta has "finally" decided to phase out coal-fired electricity plants, adding "we can help them with energy so they can find a way to shut those coal plants."

But Clark showed little understanding that Alberta already has access to its own sources of clean power — wind, solar and natural gas.

For Clark there is pressure to strike a deal with Alberta now that construction is underway on the Site C hydroelectric dam in northeastern British Columbia — a C$9 billion project with capacity of 1100 megawatts that was partly designed to support exploration, production and transportation of gas for LNG plants on the Pacific Coast.

How much, if any of the Site C power will be needed for LNG is now a matter of doubt as projects hang by the slenderest of threads, leaving British Columbia with the prospect of a vast surplus, including an existing transmission line into Alberta that is already underutilized.

Call to define benefits

Scott Thon, chief executive officer of Alberta's largest electricity transmission provider and chairman of the Canadian Electricity Association, told the Financial Post that Clark's plan fails to establish the benefits of her scheme to Alberta consumers.

"What we need first is to define the benefit, then we can talk about what we need to capture the benefits, versus saying 'Let's go and build something and hope there are benefits.'"

British Columbia government officials have issued estimates that a hydro link would eliminate up to 6 million metric tons of carbon emissions, underpinning the province's target for reducing its carbon output.

George Heyman, an opposition member of the British Columbia legislature, said Clark is pushing the idea mostly to justify Site C, adding "she's locked into the project and is trying to convince people there's a market for the power."

British Columbia Chamber of Commerce President Jon Garson lifted the curtain on the cross-border tensions by urging the governments to ensure political rhetoric does not interfere with enhancing trade and building both economies.

He said political squabbling will only generate a "lot of bad blood that will get in the way of people doing business."

Bennett insisted British Columbia's pipeline conditions are "not unreasonable ... they manifest exactly the same values that Albertans have and I think we can work through that together," acknowledging that the export of raw materials benefits all of Canada. ●

Contact Gary Park through publisher@petroleumnews.com

LAND & LEASING

Canadian rights go begging

The latest auction of oil and gas exploration land in British Columbia drew a blank, one of the clearest signs yet that upstream companies are keeping their powder dry.

For the first quarter of this year, sales in the province have fetched barely C$200,000 compared with C$2.8 million in the same period of 2015, which itself was one of the worst on record.

The trend has been copied in Alberta, where sales in the first two months fetched C$11 million, compared with C$63 million a year earlier.

RBC Capital Markets reported that successful bids across the wider Western Canadian Sedimentary basin hit a 23-year low in 2015, with upfront, lump-sum payments known as bonuses sliding to C$351 million from C$1.07 billion in 2014.

Total acquisitions of exploration land rose 24 percent to 4.3 million acres in 2015, but that was primarily the result of first-quarter optimism that oil prices were heading for a strong recovery.

Prediction of lease expirations

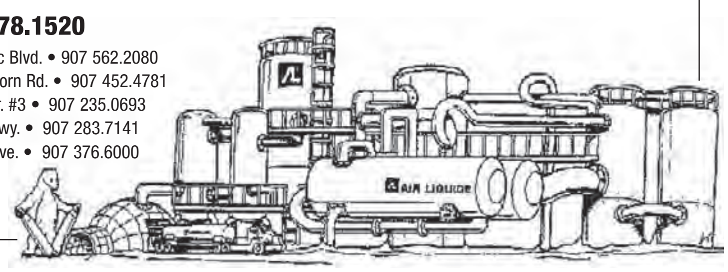
Gregg Scott, president of Calgary-based Scott Land & Lease, told the Financial Post that many companies are choosing to drill wells at a loss just to preserve their five-year leases, although others are opting to let their permits expire.

He predicted that leases covering hundreds of thousands of acres will continue to expire until oil firms up at about US$50 a barrel, when a scramble to secure rights will resume.

Hardest hit have been junior- and intermediate-sized producers who are unable to raise the capital to invest in land.

For now, the downturn has been dramatic, with land prices in Western Canada slumping 73 percent to an average C$81 per acre in 2015 compared with C$308

see AUCTION SALES page 7



● ENVIRONMENT & SAFETY

The fate of oil on Arctic beaches

New research indicates rapid evaporation but slow degradation of hydrocarbons, with some oil persisting and difficult to remove

By ALAN BAILEY
Petroleum News

Recent laboratory research at the University of Alaska Fairbanks, with funding assistance from the Bureau of Ocean Energy Management, suggests that some oil spilled on an Arctic beach would likely evaporate quite quickly, but that biodegradation of the oil would be relatively slow. Depending on how sandy a beach is, wave and tidal action may remove much of the oil. Longer chained hydrocarbons would tend to persist in the beach and would be relatively difficult to remove.

The researchers concluded that within a few weeks about 40 percent of the spilled oil would disappear from the beach sediment, mostly from evaporation, with the ambient temperature having little impact on this outcome.

Two lab settings

A report on the research says that the researchers conducted experiments in two laboratory settings using beach material from Barrow, on the northern coast of Alaska.

In the first setting, the beach material was placed in jars and soaked in water at two salinity levels to simulate beach conditions. Nutrient from fertilizer was also placed in each jar. Different amounts of crude oil were put into different jars. Some jars were then held at a temperature of 20 degrees C for six weeks, while other jars were kept at 3 degrees C for nine weeks. As a measure of biodegradation of the oil, the scientists measured the amount of carbon dioxide emitted. Volatile hydrocarbon material released from the oil was also measured. The scientists measured the amount of crude oil remaining in the sediments after the experiments, and they estimated the quantity of microbes in the sediments.

In the second setting, beach sediments, together with crude oil, were put into columns constructed from PVC piping, and water was flushed through the material every 12 hours over durations ranging from three to 18 days, to simulate tidal action. Solid or liquid fertilizer was added to some columns as a nutrient. As before, experiments were conducted at temperatures of 3 degrees C and 20 degrees C. Released carbon dioxide and volatile material were measured, and after experiment completion, samples from different levels of the column were analyzed.

Experimental results

The experiments using the jars showed that, although higher levels of oil degradation to carbon dioxide took place at the higher temperature, less than 10 percent of the oil biodegraded at either temperature level. However, at both temperatures about 40 percent of the oil evaporated, with most of this vaporization happening during the first week. Increasing the amount of oil in the sediment increased the amount of vaporization but reduced the percentage of the oil vaporized. On average after six weeks about 70 percent of the original oil remained in the sediment.

In the PVC column experiments the water flush moved the oil through the sediment, with only background levels of hydrocarbon left in pebbly sediments after 18 days. Considerably higher hydrocarbon levels remained in sandy gravel. On the other hand, over time, biodegradation in sandy gravel exceeded that in the pebbly material. And oil degradation over 18 days was higher in the higher temperature experiments. Fertilizer had little impact on the degradation.

Key findings

The researchers concluded that within a few weeks about 40 percent of the spilled oil would disappear from the beach sediment, mostly from evaporation, with the ambient temperature having little impact on this outcome. Relatively little biodegradation would take place during this period, although more biodegradation would be likely over longer timeframes. Bioremediation through nutrient application is unlikely to have much impact. The longer chain hydrocarbons that tend to remain in the sediments would be more difficult to remove.

In situations where a beach is subject to tidal and wave actions, most of the hydrocarbons would wash out of the pebbly sediments within an 18-day period. Oil in sandy sediments, on the other hand, would be much more resistant to this type of wash out. And, in general, sandy beaches would be much more difficult to clean up than pebbly beaches, the researchers concluded. ●

Contact Alan Bailey at abailey@petroleumnews.com

● GOVERNMENT

Alberta grasps economic nettle

By GARY PARK

For Petroleum News

The Alberta government is confident it can succeed where its predecessors have stumbled and failed over more than 40 years by engineering a radical shift in the province's economic oil and natural underpinning.

RACHEL NOTLEY

In opening a new session of the legislature, the New Democratic Party administration of Premier Rachel Notley pledged it would not sit back and "do nothing" as Alberta plunges ever-deeper into financial trouble.

"We have a very, very difficult economic situation here in Alberta as a result of a do-nothing approach in the past," Notley, who was elected last May, told reporters. "We are here to act as a shock absorber."

She said the government will create an Energy Diversification Advisory Committee to "look at a wide range of initiatives that could enhance value-added efforts in Alberta."

Through the EDAC, the government will seek advice on creating more incentives for upgrading oil sands bitumen into synthetic crude, for an expanded petrochemical sector and for other "value added" industries, indicating it is ready to "enhance the economics" of related projects.

Notley said the province's recent allocation of C$500 million in royalty tax credits for companies building petrochemical plants is one example of the of government incentives, including for the 50,000 barrels per day, C$8.4 billion first stage of the North West Redwater Partnership's refinery under construction near Edmonton that the NDP heavily criticized while it was in opposition.

Value-for-dollar analysis

She said the EDAC will analyze the value-for-dollar the plant will generate for taxpayers and may consider "tweaking it to come up with better."

Notley declined to speculate on how the government would react if the EDAC recommends direct investment in private industry, but she did concede that the oil price shock battering Alberta does not allow her administration to sit back and wait.

"I would reject the notion that we simply cover our ears, cover our eyes, cross our fingers and sit in the corner hoping the economy recovers," she said.

Provincial assistance in the 1960s and 1970s helped the establishment of a commercial oil sands industry, but Alberta also has a long list of failed ventures in telecommunications, banking, resource processing and agriculture that ran up losses of about C$2.2 billion.

More details are expected in the 2016-17 budget due for release on April 14.

"If economic diversification happened completely on its own, Alberta would not be in the position it currently is today," said Economic Development Minister Deron Bilous. "Government has a role in setting the right conditions that will help attract investment." ●

Contact Gary Park through publisher@petroleumnews.com

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AUCTION SALES

in 2014, RBC said.

The average price in Alberta for the January-February period was C$32.34 per acre, compared with almost C$100 in 2014, while British Columbia posted a more dramatic decline to C$32.85 this year from C$1,043 in 2014.

RBC said companies such as Birchliff Energy, Paramount Resources, Seven Generations Energy and PrairieSky Royalty have dominated buyers by acquiring up to two-thirds of the 240,000 acres of leases offered for sale in the past two years.

—GARY PARK

Contact Gary Park through publisher@petroleumnews.com

EXPLORATION & PRODUCTION

Testing new drilling rules

Canadian Natural Resources, the largest producer of heavy oil in Canada, is trying an end run by seeking a combined regulatory approval for 47 wells in Alberta.

The application to the Alberta Energy Regulator will put to the test a new pilot program that allows producers to bundle multiple activities.

If approval is granted CNR will be able to drill and complete the wells on six multi-well pads and one single-well pad, while combining the drilling with seven bitumen crude batteries, access roads and associated gas pipelines to supply needed fuel.

If approval is granted CNR will be able to drill and complete the wells on six multi-well pads and one single-well pad, while combining the drilling with seven bitumen crude batteries, access roads and associated gas pipelines to supply needed fuel.

The company said all of the prospective lands are located about 25 miles northwest of Cold Lake in eastern Alberta.

A spokeswoman for CNR said in a letter to the regulatory agency that the process will "improve the effectiveness and efficiency" of discussions with stakeholders by allowing them to consider potential development plans for the area over the next five years.

But the argument also clashes with the anticipated results of an AER investigation into four bitumen leaks from a CNR oil sands project in 2013 that has already saddled the company with C$40 million in cleanup costs.

An AER spokeswoman said the CNR application is the second under the new regulations since Suncor Energy applied for a similar approval at its Meadow Creek thermal oil sands project about 30 miles south of Fort McMurray.

She said the agency is ready to consider single applications for multiple activities, allowing Albertans and the AER to weigh the combined environmental impacts.

However, Duncan Kenyon, a director of the Alberta-based Pembina Institute, an environmental watchdog, said the AER should have issued a public report on the positives and negatives of an earlier pilot program before extending it to other areas of the province.

—GARY PARK

PIPELINES & DOWNSTREAM

Rail boss: fossil fuels 'probably dead'

Fossil fuels are "probably dead," although the transition to renewable energy sources is a long way off, said Hunter Harrison, the man who turned around both of Canada's largest railroads.

He predicted to a transportation conference in New York in mid-March that investments in traditional energy sources will dry up because of environmental hurdles.

"I think it's a challenge going forward, but rails have historically dealt with those changes really well through the years and continue to survive and make it," Harrison said.

He noted that adjusting to a shift to alternative energy will require the rail industry to follow its own example in the 1990s when the U.S. Clean Air Act wiped away 29 percent of the business at Illinois Central Railway that he ran at the time.

Harrison later occupied the chief executive officer's post at Canadian National Railway before moving to the top job at Canadian Pacific Railway three years ago.

His mandate in all cases has been to turn the companies into leaner operations and modernize them.

Last year CP Rail rewarded him with C$19.9 million in compensation, even though its share values dropped over the period.

Reference to trend

A company spokesman said Harrison was referring in New York to an "overwhelming trend" towards sustainable energy and the need for all segments of the economy to acknowledge the ever-changing landscape.

"I'm not maybe as green as I should be," Harrison acknowledged, but added "the climate is changing and they're not going to fool me anymore."

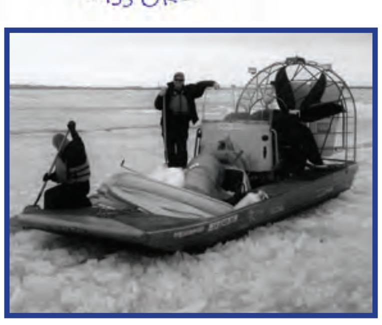
Greenpeace welcomed Harrison's view, saying it marked a reversal from the 1990s when railroads denied global warming because they relied too much on coal shipments.

Keith Stewart, the organization's head of climate and energy campaigns, said Harrison is "just recognizing the new realities and looking to where the puck is going rather than where it has been."

He said Canada's political leaders would "do well to recognize that renewable energy is the way of the future and we need to be looking at how we can prepare for a world that is going beyond fossil fuels."

CP Rail has reported a recent decline in shipments of crude oil due to declining demand brought on by the fall in commodity prices, while thermal coal shipments have also waned.

—GARY PARK



● NATURAL GAS

Pacific NorthWest LNG stalled again

Regulator, government, need another 3 months to get through public comments, emission documents before recommendation

By GARY PARK

For Petroleum News

The shaky hope of an imminent final approval for British Columbia's Pacific NorthWest LNG project has been dealt another setback by the Canadian government.

Environment Minister Catherine McKenna and the Canadian Environmental Assessment Agency added another three months to the targeted March 22 deadline for a regulatory verdict because they need more time to examine the potential greenhouse gas emissions from the entire project.

McKenna said the operator Petronas provided "significant new information" regarding the project that "must be analyzed and included in the final assessment report."

She said it would be premature to speculate on whether she will even refer the application to the federal cabinet for approval.

Change of direction

That is a sharp change of direction from a draft report by the CEAA in February that concluded the liquefaction plant and tanker terminal near Prince Rupert could be built without major environmental impacts.

However, the CEAA said it is now reviewing 34,000 public comments and 11,000 pages of technical data in addition to the new information from Petronas that estimates total GHGs, including upstream emission estimates from gas extraction and pipelines.

The CEAA said it "recognizes the importance of timely decisions, while balancing the need for a fair and thorough process that is grounded in science."

It promised to work "diligently with the technical working group for the project, including indigenous groups and federal experts, to review the information and finalize the environmental assessment report and conditions."

The company said its updated projection is for less than 5 million metric tons per year of carbon dioxide.

British Columbia Natural Gas Development Minister Rich Coleman said he is confident a recommendation can be made to the federal cabinet sometime in April and suggested the government's final decision should be swayed by the project's huge economic benefits for Canada.

"All in all, it's C$36 billion," he said. "That's about two percentage points of the entire Gross Domestic Product of Canada. It's probably 7,000 to 8,000 construction jobs and another 3,000 to 4,000 on the pipeline."

John Stephenson, chief executive officer of the Toronto-based investment firm of Stephenson & Co., said the final ruling on Pacific NorthWest "is going to be widely watched as a barometer of the government's interest in supporting what is the driver of the Canadian economy, which is energy."

He said if there is any "hiccup" on the government's part he would not be surprised to see Petronas and its Asian partners abandoning the scheme.

To date, there have been six delays in the regulatory process, adding more than one year to the two years that industry officials originally anticipated.

Conditional Lax Kw'alaams support

There was one shred of positive news for the proponent when the Lax Kw'alaams First Nation said in a letter to the CEAA that it would conditionally support the project subject to certain conditions, notably the creation of an environmental performance committee.

The community's stand, if implemented, would remove a key obstacle to what could be British Columbia's first large-scale LNG export operation.

It represents a complete turnaround by the Lax community from a year ago, although it does insist that an environmental committee would have the authority to monitor compliance with conditions and recommend enforcement measures to the government.

However, some hereditary leaders of

see LNG PROJECT page 10

COURTESY BLUECREST ENERGY

Under construction: BlueCrest Energy's 38-acre Cosmopolitan drill site and production facility just north of Anchor Point on Alaska's Kenai Peninsula has been under construction for the last two years and is now in its final phase. Startup of oil production is expected in April, although the company won't hold an official startup ceremony until later this summer.

● EXPLORATION & PRODUCTION

Forty-nine years to production

Independent close to bringing Cosmopolitan offshore Cook Inlet oil field online six operators and 49 years after discovery

By KAY CASHMAN
Petroleum News

Forty-nine years after it was discovered, the Cosmopolitan oil prospect offshore Alaska's lower Kenai Peninsula will likely be brought online in April by BlueCrest Energy Inc.

The Texas independent is the sixth operator of the field and the first to bring it to commercial oil production; with shallower natural gas development likely to follow once the company secures a jack-up rig and sets platforms.

"At this point, we are fairly certain that we will start up the first oil production in April," although no official ceremonies are planned until "later in the summer," J. Benjamin Johnson, president and chief executive officer of BlueCrest, told Petroleum News in a March 22 email.

"So far, everything has tested out, and we are progressing very well toward a start-up mid-month," he said.

Johnson was raised in Kenai and worked in Cook Inlet and on the North Slope in his youth. Later, with ARCO Alaska, he created the first Kuparuk full-field development model and coordinated the first waterflood surveillance plans for Prudhoe Bay.

BlueCrest is bringing in a large land-based drilling rig to develop the Cook Inlet accumulation, using extended reach wells drilled from an onshore pad (see photo).

JUDY PATRICK

J. BENJAMIN JOHNSON

The company has already started shipping parts of the huge rig to Alaska, Johnson said, providing a March 18 photo of BlueCrest Rig No. 1 at the factory in Liberty.

"We are just now finishing construction of the new rig in Texas. We have already begun shipping some of the components (the entire rig will require approximately 115 large truckloads), and we will be running the final tests of the rig over the next two weeks. The entire rig will not arrive in Alaska until probably late May and will begin drilling in early July," Johnson said in an email.

"The wind-walls for winterization have been removed and are already en-route. You can see the massive size of the rig and all the associated equipment. The entire system moves on large rails from well to well on the drill site and can complete a move in a few hours, compared to days or weeks required for moving traditional rigs," he said, noting the 3,000 horsepower rig is "capable of lifting 1.5 million pounds of pipe in the well and can simultaneously stack over 24,000 feet of drill pipe in the derrick. It was designed specifically for the extended-reach Cosmopolitan wells but could also be used for almost any other large field in Alaska in the future."

BlueCrest has been working on its 38-acre Cosmopolitan drill site and production facility just north of Anchor Point for the last two years.

Cosmo well history

The 12,112-foot Starichkof State No. 1 discovery well was drilled by Pennzoil in 1967.

ARCO Alaska began a second Cosmopolitan exploration effort in the 1990s.

In 2001, after acquiring the Alaska assets of ARCO, Phillips Inc. drilled the Hansen No. 1 well directionally to an offshore target. Following a merger, ConocoPhillips Alaska assumed operatorship and in 2003, drilled Hansen No. 1A, a sidetrack of the earlier Phillips well.

see **COSMOPOLITAN** *page 10*

COURTESY BLUECREST ENERGY

Huge new land rig coming: BlueCrest Energy is bringing in a rig to develop the Cook Inlet oil accumulation, using extended reach wells drilled from onshore. The derrick, which will hold simultaneously 24,000 feet of drill pipe, is pictured here on March 18 in front of the factory in Liberty, Texas. The company has already started shipping rig components to Alaska. It will require 115 large truckloads.

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COSMOPOLITAN

ConocoPhillips subsequently brought in Pioneer Natural Resources, which acquired the remaining working interest at Cosmopolitan and became operator.

In 2007, Pioneer plugged the original Starichkof and Hemlock completions on the Hansen No. 1A sidetrack and drilled Hansen No. 1A-L1, another sidetrack off the original Hansen well.

In 2010, Pioneer fracture stimulated the interval from Hansen No. 1A-L1. An extended flow-test produced 250 barrels of oil per day and more than 33,000 barrels, cumulatively, which the company trucked to the Tesoro refinery under a pilot program.

In 2011, Pioneer relinquished three Cosmopolitan leases to the state of Alaska and sold two leases held by oil wells to operator Buccaneer and its minority partner, BlueCrest.

The state offered the three relinquished leases under special terms. They were picked up by Apache Corp. but regulatory delays over its basin-wide seismic program prompted Apache to sell the three leases to Buccaneer and BlueCrest.

*“At this point, we are fairly certain that we will start up the first oil production in April,” although no official ceremonies are planned until “later in the summer.” **—J. Benjamin Johnson, BlueCrest president and CEO***

BlueCrest took a 75 percent working interest in the field and helped fund the 7,599-foot Cosmopolitan No. 1 delineation well in May 2013.

When Buccaneer began selling properties, BlueCrest acquired the remaining 25 percent interest and became operator of Cosmopolitan. As of mid-August, BlueCrest held 22,535.69 acres of Cosmopolitan leases, 14,423 of which were unitized.

Walker bill endangers development

Further development of Cosmopolitan’s oil and natural gas, however, partially hinges on stopping the passage of House Bill 247 and its companion bill in the Senate, Johnson told legislators in testimony March 1.

Gov. Bill Walker’s proposed legislation would harm the investment climate in Southcentral Alaska by eliminating tax credits for development of previously discovered proven reserves — tax credits that made development of Cosmopolitan possible after 49 years.

Johnson said the credits benefit the state because it breaks even on credits at $35 oil and at $65 oil gets twice what it invested. He compared that to the state’s investment in the Permanent Fund, telling legislators the credits are a better investment for the state than the Permanent Fund as long as oil averages $44 per barrel over the next 40 years.

Privately held BlueCrest is based in Fort Worth and has regional offices in Houston and Anchorage. ●

Contact Kay Cashman at publisher@petroleumnews.com

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LNG PROJECT

the First Nation say they have been “betrayed” by their elected council and “will fight this to the end, whether the council is on our side, or not.”

If the project gets a green light, the Lax people stand to collect an initial payment of C$28 million and annual payments starting at C$13 million, rising to C$50 million in 40 years.

Coleman said the Lax “have been clear any development must not harm the environment, especially fish and fish habitat, which is also a core priority of the government of British Columbia and we look forward to working together on this should the federal government reach a positive decision.”

On the downside, Katherine Spector, a commodities strategist with CIBC World Markets, raised questions about how competitive Canada can be in the global LNG marketplace as supply gluts form and demand slows in Asia at a time when Australia and the United States make an aggressive push to secure buyers.

For now, Prime Minister Justin Trudeau is coming under pressure from British Columbia Premier Christy Clark who told him in February that “LNG can be the biggest contribution Canada can make to global climate change if we can help displace coal in China.” ●

Contact Gary Park through publisher@petroleumnews.com

NORTH OF 60 MINING news

page 12 Freeman finds grains of hope amid grim exploration results

www.MiningNewsNorth.com The weekly mining newspaper for Alaska and Canada's North Week of March 27, 2016

NORTHERN NEIGHBORS

Compiled by Shane Lasley

SKEENA RESOURCES LTD.

Skeena secures option to acquire historic, high-grade Snip gold mine

Skeena Resources Ltd. March 23 reported the signing of an agreement with Barrick Gold to acquire the historic high-grade Snip gold mine in northwestern British Columbia, an operation that produced roughly 1 million ounces of gold from ore averaging 25 grams per metric ton gold. Under terms of the agreement, Skeena may acquire a 100 percent interest in the Snip property by: issuing up to 3.25 million Skeena shares to Barrick; investing C$2 million on Snip within the first 30 months of the agreement, including C$500,000 within the first 12 months. Barrick will retain a 1 percent net smelter return royalty on the Snip property. If Skeena exercises the option, upon delineating 2 million ounces of gold, Barrick may exercise a back-in right to purchase a 51 percent interest in the property in return for a payment of three times Skeena's cumulative expenditures, following which the parties will form a joint venture. "The Snip option agreement is an important step forward in our strategy to consolidate and develop high-quality assets in British Columbia," said Skeena President and CEO Walter Coles. "The Snip property strongly complements Skeena's Spectrum and GJ projects, which are also located in the Golden Triangle. We appreciate Barrick's confidence in our team and their willingness to allow us to go back and explore on one of our chairman, Ron Netolitzky's, earliest successes in the region. We intend to be very aggressive about advancing this asset." Snip, which operated from 1991 to 1999, was burdened by the high cost of being a stand-alone operation restricted to fly-in servicing, augmented with support by a hovercraft from Wrangell, Alaska, requiring high grades to ensure economic viability. Compounding this, mining costs nearly doubled over the mine life while the gold price fell to US$300 per ounce by 1999. The prospects for re-developing the Snip property have improved dramatically, given today's substantially higher gold prices, subsequent improvements to the infrastructure and access in the Golden Triangle region of northwestern B.C. "This acquisition gives us an opportunity to re-examine historic drill intercepts on the Snip property that may indicate mineralization that would be economic with the recent construction of nearby infrastructure and at today's higher gold prices," said Netolitzky. "We are excited to renew exploration for additional mineralized shoots in a large shear structure which already demonstrated the presence of a million-ounce, high-grade deposit." Netolitzky is a 2015 Canadian Mining Hall of Fame inductee, an honor largely due to his contributions to the discoveries of the Snip and Eskay Creek gold mines in the Golden Triangle.

Millrock Resources grows Golden Triangle portfolio with LNT option

Millrock Resources Inc. March 21 said it has assumed an

see **NORTHERN NEIGHBORS** *page 14*

TECHNOLOGY METALS

A round Graphite Creek

Graphite One focuses on forming battery-grade graphite from Alaska deposit

By SHANE LASLEY
Mining News

Tesla Motors is on the cusp of unveiling its Model 3, an affordable mid-size sedan that is the key to the company's goal of producing 500,000 all-electric vehicles per year by 2017 – welcome news for those who want to own a Tesla but can't afford the two more luxurious models released by the company.

A half-million Teslas rolling off of assembly-lines each year also could be good news for Graphite One Resources Inc., a junior mining company aspiring to supply some of the roughly 27,000 metric tons of coated spherical graphite needed in the batteries of these electric autos.

"With the United States presently 100 percent import-dependent for all of its (natural) graphite, reliable access to high-purity product will be a key factor in the United States' ability to build sustainable industries in clean-tech and other high-tech applications," said Graphite One President and CEO Anthony Huston.

To this end, Graphite One is focusing its efforts on demonstrating that the spherical graphite needed to store power in lithium-ion batteries can be produced from material mined at the enormous deposit identified at its Graphite Creek property in western Alaska.

"With America's largest natural flake deposit, and the advanced processing capabilities we are now working towards validating, Graphite One is systematically developing critical components of a North American clean-energy supply chain," added Huston.

Spherical graphite

Graphite One is in the midst of a five-phase program designed to prove that graphite mined from its huge deposit north of Nome can be transformed into a high-quality anode material for the lithium-ion batteries used to power electric vehicles and the growing myriad of other devices being powered by these mobile electric storage cells.

Carbon-coated spherical graphite is the finished product used in lithium-ion batteries. The spherical shape allows the graphite to be more efficiently packed into battery cells, while the coating extends the graphite's lifetime capacity.

Graphite One has teamed up with Tru Group Inc. – a technology metals consultant with expertise along the entire graphite-graphene supply chain – to complete a five-phase program designed to produce this specialized battery component from Graphite Creek material.

In 2015, Tru had identified characteristics of the Graphite Creek deposit that may make the material a good fit for many of the high-tech and green energy sectors that are driving a large part of the growing market for graphite.

As identified by TRU, these distinguishing features can be described as spheroidal, thin, aggregate and expanded. The consultant postulated that these distinctive characteristics could lend to different specialized applications with minimal processing.

These unique and naturally occurring properties

GRAPHITE ONE RESOURCES INC.

A section of massive graphite cut during the 2013 drill program at the Graphite Creek project near Nome, Alaska. Graphite One Resources is now working out the process of producing the spherical graphite used as anode material in the lithium-ion batteries that power electric vehicles and other mobile electronic devices.

have prompted Graphite One to apply for the trademark, STAX, to describe Graphite Creek graphite.

"From the time we identified the unique mineralization of our STAX graphite, we've observed a number of potential performance advantages," said Huston.

Following up on its initial theories, Tru has tested various means of milling and purifying Graphite Creek STAX material, all of which resulted in creating graphite purities above the 99.95 percent requirement for battery quality graphite.

"Now, with the first three phases of our product development program complete, we have been able to validate the assumptions we made in terms of the purity we could achieve," the Graphite One CEO added.

Tru is now working on producing carbon-coated spherical graphite from the purified STAX. These potato-shaped spheres will be used to manufacture coin cells, where the final electrochemistry of the Graphite Creek anode material will be tested.

Ultimately, Graphite One wants to have samples of carbon-coated spherical graphite made from its Alaska deposit that could be evaluated by potential end users.

Driving graphite demand

While Graphite One has not evoked the name Tesla Motors as a potential end user of its STAX graphite, the growing electric car manufacturer is driving the demand for lithium-ion batteries and all of the ingredients needed to make them.

To achieve its goal of manufacturing 500,000 electric vehicles per year, Tesla is erecting a 10-million-square-foot plant in Nevada to produce the batteries that will power the cars and crossover SUVs.

"The Gigafactory is an important step in advancing the cause of sustainable transportation and will enable the mass production of compelling electric vehicles for decades to come," said Tesla Motors Chairman and CEO Elon Musk.

While not scheduled to be fully operational until 2020, the gigafactory is on pace to produce its first battery cells before the highly anticipated Model 3 goes into production.

see **GRAPHITE CREEK** *page 14*

● COLUMN

Mining sees another dismal year in 2015

Hit with declining commodity prices and shrinking budgets, industry places worldwide exploration sector on life support

By CURT FREEMAN

For Mining News

As in the recent past, the state of the world's exploration industry was summarized in SNL Metal & Mining's annual "Corporate Exploration Strategies" publication, released at the Prospectors and Developers Association of Canada convention in Toronto earlier this month. Not surprisingly, it painted a grim picture of 2015, the worst year for exploration since 2009.

The statistics indicate that worldwide exploration expenditures declined a further 19 percent to $9.2 billion compared with to $11.4 billion in 2014 and a far cry from record expenditures of $21.5 billion in 2012. The combined double whammy of commodity prices decreasing since 2011 and decreasing exploration budgets since 2012, have left the exploration industry on life support around the globe. Producing companies continue to fight falling average grades, falling commodity demand, falling commodity prices and shareholder pressure for leaner, more efficient organizations, all of which require cuts in exploration spending, down 18 percent in 2015, the third straight year the majors have cut exploration spending. In the junior sector, exploration spending plummeted a whopping 26 percent last year, this after an even steeper year-over-year decline of 29 percent in 2014. The desire for less risky exploration (more successful exploration), increased near-mine exploration to 34 percent of total exploration in 2015, with grassroots exploration accounting for only 29 percent of the sector's total spending, while advanced stage exploration pulled in 37 percent. On a commodity basis, all of the major metals saw reduced exploration in 2015, raising concerns about future production from a project pipeline that has fewer and fewer new projects in it. Gold-directed exploration fell 14 percent, platinum fell 33 percent and uranium fell 34 percent year-on-year. From a geographic standpoint, Latin America's share of the global total increased to more than 28 percent of worldwide exploration expenditures, the region's highest share since the bottom of the last downturn in 2001. Exploration budgets in Africa and Pacific/Southeast Asia were hit hard,

see FREEMAN page 13

The author

CURT FREEMAN

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FREEMAN

declining 30 percent and 28 percent, respectively. Looking into my crystal ball for 2016, I have been able to track announced and estimated budgets for about two dozen Alaska exploration projects and come up with a dismal $42 million in estimated exploration expenditures for the year. By comparison, that would be the lowest level of expenditures for exploration since 2003. Despite all the gloom and doom, several of SNL Metals & Mining's recent economic indicators suggested that the mining industry may be at or near the bottom of this cycle. Hope that is true because Alaska did well in the recent Fraser Institute "Survey of Mining Companies, 2015", a fact we all hope will be remembered when the markets pick up. We placed 2nd of 109 jurisdictions worldwide behind Western Australia in the Mineral Potential Index (using best management practices), and 6th in the Investment Attractiveness Index, behind Western Australia, Saskatchewan, Nevada, Ireland and Finland. Although Alaska rose in the Policy Potential Index about 10 percentile points over its ranking in 2014, we still placed a disappointing 23rd. However, if history is any gauge of the future, the mining industry is willing to take risk if the potential for new mineral discoveries exists, and such discoveries cannot occur unless, like Alaska, a jurisdiction's mineral endowment is top-flight.

Western Alaska

GRAPHITE ONE RESOURCES INC. announced that it has completed the first three phases of its five-phase exploratory product development program to produce carbon-coated spherical graphite from its Graphite Creek deposit on the Seward Peninsula. The test work used "STAX" graphite from the project. (STAX is an acronym for graphite that is Spheroidal, Thin, Aggregate and eXpanded.) The tests achieved a minimum purity level of greater than 99.98 percent graphitic carbon in three samples totaling 3,000 grams. The graphite purity from all runs exceeds the threshold requirement of 99.95 percent graphitic carbon for preparing spherical graphite and was assessed by assaying for both impurity and graphite content. The three phases of the product development work now completed include a 300-gram phase 1 graphite concentrate use to test air milling characteristics. Results indicate that 66 percent less air pressure is required to achieve size reduction in STAX graphite than what is typically observed for conventional flake graphite. In Phase 2, the 300-gram trial sample was purified to greater than 99.99 percent graphitic carbon by non-acid methods at a U.S.-based purification facility. In Phase 3, an air-milled 2,400-gram trial sample and a 300- gram unmilled trial sample were each given the same purification treatment as the sample in phase 2, and the results were independently verified as achieving a graphite purity of greater than 99.98 percent graphitic carbon and greater than 99.99 percent graphitic carbon, respectively. Phase 5 will be dedicated to manufacturing and generating electrochemical performance data for the coin cells (coated spherical graphite) and evaluating the spherical graphite quality and performance as battery anode material. In addition, mineral processing test work is underway to validate the mineral processing flowsheet for the project, including the generation of 5 kilograms of high-purity concentrate. The results from mineral processing and second-stage product development will form the basis for the Graphite Creel preliminary economic assessment expected out later this year.

Alaska Range

MIRANDA GOLD CORP. and JV partner **GOLD TORRENT, INC.**, announced an updated mineral resource for their Willow Creek gold project near Hatcher Pass. The updated mineral resource estimate includes measured and indicated mineral resources of 121,500 ounces of gold contained in 206,500 metric tons grading an average of 18.3 grams per metric ton gold. An additional inferred mineral resource includes 35,150 ounces of gold contained in 59,000 metric tons grading an average of 18.5 g/t gold. All of the estimated mineral resources are based on a cutoff of 5.0 g/t gold. An updated model has been expanded to include a portion of the Lucky Shot area. In total, mineral resources at the Willow Creek project include eight veins in the Coleman area and two veins in the Lucky Shot area. The mineral resource estimate is based on information from 174 drill holes. Potential exists to increase the mineral resources at the project through drilling down-dip extensions of the Coleman and Lucky Shot area, and the exploration targets in the War Baby and Murphy areas along strike to the east. Completion of the updated mineral resource estimate for the project allows Gold Torrent to move forward with its planned preliminary feasibility study, anticipated to be released during the first half of 2016.

Southeast Alaska

UCORE RARE METALS INC. provided an update on the preparations for utilizing their rare earth separation pilot plant using raw ore from their Bokan-Dotson rare earth elements project. **IBC ADVANCED TECHNOLOGIES** of American Fork, Utah, has completed construction of all Molecular Recognition Technology superstructure, processing architecture, automation systems, and initial water testing of the rare earth separation pilot plant. The plant is now in a pre-production quality control and testing phase. The next stage of the pilot plant process is the commissioning phase, scheduled to commence this month, which will include the initial start-up of the processing systems and further water testing, followed by the receiving of pregnant leach solution. Each section of the plant will be water-tested prior to testing with actual pregnant leach solution. The pilot plant program will entail the following components: 1) rare earth separation, in which all rare earths, as a group, are isolated from the waste materials in the pregnant leach solution; 2) removal of scandium, a valuable rare earth element used in advanced aluminum alloys for the aerospace sector; 3) class separation of the light rare earth elements (lanthanum to neodymium plus yttrium) and the heavy rare earth elements (samarium to lutetium); and 4) separation of individual rare earth elements, including the pilot program separation of terbium and europium at more than 99 percent purity, plus dysprosium at 99.99 percent purity. The remaining heavy rare earth element solution, consisting of holmium to lutetium, gadolinium and samarium; as well as the light rare earth elements solution, consisting of lanthanum to neodymium and yttrium, will be retained for future work. ●

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GRAPHITE CREEK

The United States Geological Survey estimates that once in full production the Gigafactory will "require 93,000 tons of flake graphite for use as anode material." This compares to a total of 54,400 tons of graphite consumption in the United States during 2015, according to the USGS Mineral Commodities Summaries 2016.

All of the natural graphite used in the United States last year was imported, with 97 percent coming from China, Mexico, Canada, Brazil, and Madagascar.

The USGS noted Graphite One's Graphite Creek project and Alabama Graphite's Coosa project as potential domestic sources of this anode ingredient of increasing importance.

Located about 37 miles north of Nome, the Graphite Creek deposit boasts 17.95 million metric tons of indicated resource averaging 6.3 percent (1.13 million metric tons) graphite; and 154.36 million metric tons of inferred resources averaging 5.7 percent (8.76 million metric tons) graphite.

Whether or not Graphite One sells directly to the gigafactory, the massive graphite need of the one facility adds to the overall demand for products from world-class deposit of carboniferous materials like the one at Graphite Creek.

"As the green technology economy grows, driving continued adoption of electric vehicles and smart grid power storage devices, graphite will increasingly be a key material – a factor already present in rising demand projections," said Huston.

Once the product development and mineral processing test work is complete, Graphite One plans to finalize a preliminary economic assessment for the Graphite Creek project. ●

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NORTHERN NEIGHBORS

option agreement on the Lord Nelson Tenures in northwestern British Columbia from Geofine Exploration Consultants. Also known as the LNT property, these mineral tenures are owned by Teuton Resources Corp. and have been under option to Geofine since 2010. Situated immediately to the south of Millrock's Poly property, LNT sits at a juncture between the Del Norte mineralized trend to the south and a volcanogenic massive sulfide horizon (X zone) on Poly. With the addition of the 2,450-hectare (6,050 acres) LNT property, the expanded Poly project now covers 9,770 hectares (24,140 acres) of prospective ground in the Golden Triangle region of British Columbia. The target area at LNT hosts stream sediment, soil and rock samples that are anomalous in gold, silver, copper, lead, zinc and pathfinder elements. One rock sample collected from a large boulder is reported to contain 6.55 g/t gold. An historical electromagnetic anomaly extends to the north from the Del Norte trend and has never been drill-tested on the LNT property. Rapidly receding glaciers have exposed new mineral showings and alteration zones in recent years. Systematic geochemical sampling and geological mapping will be needed prior to selecting targets for drill testing. By assuming the option, Millrock has the right to earn a 100 percent interest in the LNT property by incurring C$898,405 in exploration expenditures and providing option payments of C$120,000 over a four-year period. The next option payment of C$15,000 is due in November and the exploration expenditures may be completed any time prior to November 2019. Teuton retained a 2 percent net smelter return royalty with a C$50,000 advance royalty starting in 2020. There has been no up-front cost to Millrock for the assumption. Located 34 kilometers (21 miles) northeast of Stewart, the LNT property is bisected by Highway 37A and the Stewart Power Line.

Junior tests for gold veins above Klondike placers

Klondike Gold Corp. March 18 said it plans to complete 1,500 meters of drilling in 20 shallow holes during an initial phase of 2016 exploration at its Lone Star and Dominion properties near Dawson City, Yukon Territory. The C$350,000 program also will include geophysics, soil geochemistry, trenching, prospecting and mapping to advance additional target areas for future drilling. Field work is expected to begin in April with drilling planned to start in June. Based upon its evolving orogenic gold model of source mineralization for placer gold in the region, Klondike Gold has identified numerous areas to test for high-grade gold-bearing quartz veins. The company said the target mineralization is associated with, and controlled by, newly identified fault and extensional structures and certain lithologic parameters. "We now understand how these veins form, where they may be located, the controlling major structures and their implied geologic age," said Klondike Gold CEO Peter Tallman. "Going forward, we will use drilling to discover as many gold-bearing veins as possible and to systematically test the best of them to determine length, depth, and grade characteristics." Contingent upon continued positive drill results and funding, the company is anticipating a second phase of drilling this year.

Kennady North boasts fourth kimberlite find

Kennady Diamonds Inc. March 17 said exploration drilling at its Kennady North diamond project in Nunavut has encountered a third kimberlite body at the high-grade Faraday kimberlite cluster. Following the completion of ice-based infill drilling at the Faraday 1 kimberlite, the rig was moved to a geophysical target some 80 meters to the southwest where indications of the presence of kimberlite were discovered during the winter. Three exploration holes have been completed at the Faraday 3 discovery within the past week with the latest hole intersecting more than 55 meters of kimberlite. Kennady Diamonds President and CEO Patrick Evans said, "Faraday 3 is the fourth kimberlite body that we have discovered at Kennady North over the past three years. Methodical exploration over the Kelvin – Faraday kimberlite corridor has increased our confidence in the potential for the discovery of further kimberlite bodies within the corridor." Additionally, 300 metric tons of kimberlite were recovered as part of the Kelvin North Lobe bulk sampling program. The company's target is to recover some 500 metric tons, which is expected to result in the recovery of more than 1,000 carats of diamonds. The diamond parcel will be used for revenue modeling of the Kelvin North Lobe. ●

● GOVERNMENT

State moves royalty oil sale to Tesoro

By KRISTEN NELSON

Petroleum News

The Department of Natural Resources has issued a final best interest finding and determination for a sale of Alaska North Slope royalty crude oil to Tesoro Refining and Marketing Co.

In the finding the DNR commissioner proposes to sell 20,000 to 25,000 barrels per day of the state's royalty oil in-kind to Tesoro for processing at its Nikiski refinery under a five-year contract.

DNR said in a statement that deliveries are estimated to start Aug. 1 and continue until July 31, 2021.

In the finding the department said the sale of royalty oil in-kind will maximize revenue to the state, help meet in-state need for crude and facilitate continued operation of the Nikiski refinery.

Under the terms of the contract the state will receive no less than the amount it would receive, on average, from keeping its royalty in-value.

Almost a billion barrels

DNR said in the best interest finding that between November 1979 and October 2015 the state disposed of 918.8 million barrels of royalty oil through in-kind sales, approximately 45 percent of its North Slope royalty oil. The state has sold its royalty oil to in-state refineries through competitive and non-competitive sales and has occasionally auctioned royalty oil to customers in the Lower 48.

The state's royalty oil has declined as North Slope production has declined, with the volumes of royalty oil available for sale in the five-year contract period estimated to be between 37,000 and 54,000 bpd. The amount in the Tesoro contract is some 45 percent to 68 percent of those volumes.

The best interest finding says there are three considerations in taking royalty oil in-kind.

The state wants to keep a small percentage as royalty in-value, where the lessees market the state's share with their own production and pay the state the value of its royalty share, because there are higher royalty values for some leases and to obtain pricing and other information from RIV dispositions for comparison purposes.

The second consideration is that royalty oil is based on a production forecast that has at times been "quite optimistic," the finding said. The third consideration is that royalty forecasts provide expected daily volumes, while production varies over the year, highest in winter and lowest in summer.

The value to the state is that it receives more revenue from RIK sales than from RIV sales.

The finding says the state received more revenue from each barrel of RIK oil than RIV oil in 83 months of the 94 months from January 2008 to October 2015. Since March 2011 the difference has been some $1.94 per barrel. In that period the state sold some 95.14 million barrels of RIK oil under three different contracts, with $106.11 million of additional revenue over what would have been realized under RIV. ●

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● FINANCE & ECONOMY

TransCanada pulling out the stops

Assets sales, mostly generation, help finance US$13 billion takeover of Columbia Pipeline; plan to ship natural gas to LNG terminals

By GARY PARK

For Petroleum News

TransCanada Chief Executive Officer Russ Girling described his company's US$13 billion deal to buy Texas-based Columbia Pipeline Group as "truly transformational" and wasted no time demonstrating what he meant.

A 704-megawatt natural gas-fired power complex bought for US$657 million from Talen Energy only six weeks ago was immediately put back on the block.

RUSS GIRLING

That is among a basket of U.S. Northeast power assets TransCanada is putting up for sale to pay for its Columbia acquisition.

Chief Financial Officer Don Marchand said the plans also include selling a gas- and oil-fired generation plant in New York bought for US$2.9 billion in 2009, hydroelectric power holdings in New England, a wind power operation in Maine, gas generation facilities in Rhode Island and its natural gas pipelines in Mexico.

The assets will land on the market just as interest in power plants is heating up, said Jeff Bodington, with an investment banking firm Bodington & Co.

In the interim, TransCanada said it has credit facilities in place to cover up to C$10.3 billion worth of debt to finance the Columbia transaction, which is separate to the C$4.2 billion share issue.

> *The company was also forced to back out of plans to deliver huge volumes of Arctic gas to southern markets from Canada's Mackenzie Delta and Alaska's North Slope.*

Focus shift

But beyond looking for ways to help finance its blockbuster deal, along with its C$4.2 billion share issue which many sources said was heavily oversubscribed, TransCanada is also gearing up to dramatically shift its focus from Western Canada to the eastern United States.

For decades, TransCanada established its business around moving gas from Alberta to Ontario and Quebec through a massive pipeline network that has been in rapid decline.

Natural gas production in Western Canada has dropped about 20 percent in the last 15 years to 13.5 billion cubic feet per day, while Canadian exports to the United States have been slashed in half.

The company was also forced to back out of plans to deliver huge volumes of Arctic gas to southern markets from Canada's Mackenzie Delta and Alaska's North Slope.

Edward Kallio, an independent energy consultant in Calgary, said TransCanada held out too long for Alaska and Mackenzie gas to fill its pipelines.

Now, he told the Globe and Mail, it has recognized that the "fundamentals really drive where the pipes are going to go and where they are going to thrive."

Marcellus shale

That is where Columbia entered the picture, with its extensive delivery systems from the Marcellus shale, where production has quadrupled to 20 bcf per day since 2010 and is expected to add another 10 bcf per day in the next 15 years. The nearby Utica shale also plays a key role.

Dirk Lever, an analyst with AltaCorp Capital, said a lot of the Marcellus and Utica gas is competing with Alberta and Texas gas.

Now, Girling said, his company will gain a pipeline link in Pennsylvania and adjoining states, providing a "rare and attractive" opportunity that will position TransCanada to be the main shipper of natural gas to LNG operations across North America.

It is not yet clear whether that strategy is intended to offset the apparent defeat of its Keystone XL crude pipeline from Alberta to the Texas Gulf Coast and possibly its Energy East project across Canada should that falter. ●

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LAND & LEASING

Date set for spring areawide lease sales

By KRISTEN NELSON
Petroleum News

The state has set May 4 as the date for bid opening in its Alaska Peninsula areawide 2016 and Cook Inlet areawide 2016W oil and gas lease sales.

The Alaska Division of Natural Resources, Division of Oil and Gas, said in a March 18 statement that in-person bid submission for the sales would be May 2 from 9 a.m. to 4 p.m. at suite 800 of the Atwood Building, 550 West 7th Avenue, Anchorage, with the public bid opening beginning at 9 a.m. May 4 in suite 108 of the Atwood Building.

The state has not received bids for recent Alaska Peninsula areawide lease sales, an area of some 4 million gross onshore acres and 1.75 million offshore acres. The Alaska Peninsula sale includes 1,047 tracts from 640 to 5,760 acres on the north side of the Alaska Peninsula from the Nushagak Peninsula in the north and then south and west to the vicinity of Cold Bay.

Alaska Peninsula tracts have a $5 per acre minimum bid, carry a 12.5 percent royalty and have a 10-year term. The annual rental rates are $1 per acre in the first year, and increase by 50 cents per acre to $3 in the fifth year.

Cook Inlet

Cook Inlet bid activity has varied widely in recent years. That sale area covers some 4.2 million gross acres, 815 tracts ranging from 640 to 5,760 acres, in the Municipality of Anchorage, the Matanuska-Susitna and Kenai boroughs. The acreage is in the Matanuska and Susitna river valleys generally south and west of Houston and Wasilla, the Anchorage bowl and the western shore of Cook Inlet from Beluga River to Harriet Point, and includes tide and submerged lands in upper Cook Inlet from Knik Arm and Turnagain Arm south to Anchor Point and Tuxedni Bay.

The minimum per-acre bid for Cook Inlet tracts is $10 and tracts carry a 10-year primary term and a 12.5 percent royalty. Rental is $10 per acre in years 1 through 7, increasing to $250 per acre in years 8 through 10, except that beginning in the year after the year in which sustained production begins, or the state determines that the lessee has exercised reasonable diligence in exploring and developing the list, the state may, at its sole discretion, set the annual rental at $10 per acre or fraction of an acre. In evaluating a request for decreased rental the state will consider funds expended by the lessee to explore and develop the lease and the types of work completed by or on behalf of the lessee on the lease.

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

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GOVERNMENT

BOEM proposes new air quality regs

Agency says new rule would modernize and strengthen regulations while providing consistency in managing industry emissions

By ALAN BAILEY
Petroleum News

The Bureau of Ocean Energy Management is proposing new regulations for air emissions from offshore oil and gas activities on the U.S. outer continental shelf. In 2011 the U.S. Congress transferred jurisdiction for outer continental shelf air quality from the Environmental Protection Agency to the Department of the Interior. Previously Interior had only been responsible for air quality in part of the Gulf of Mexico.

The regulations would require an offshore operator to aggregate for analysis the emissions from closely spaced activities and facilities, regardless of whether the activities fall within a single plan.

Rather than issuing air quality permits, BOEM, an agency within Interior, requires air emissions specifications to be documented within exploration and development plans that BOEM approves. The new regulations spell out new standards that will need to be met in approved plans.

"This proposal takes a balanced approach to modernize BOEM's regulations and ensure compliance with today's air quality standards," said Janice Schneider, BOEM assistant secretary, land and minerals management, on March 17 when announcing the proposed regulations. "These proposed improvements will minimize harm to human health and the environment from oil and gas activities."

Cross-reference with EPA

BOEM says that the new regulations, which will target the emission of volatile organic compounds, nitrogen oxides, sulfur dioxide, carbon monoxide and particulate matter, will cross-reference BOEM's standards for air pollutants to those of EPA. The regulations would modernize and strengthen the requirements for identifying, modeling, measuring and tracking pollutant emissions, BOEM says. And instead of measuring pollution impacts onshore from the coastline, impacts would be measured landward from a state's seaward boundary, typically three nautical miles offshore.

The regulations would require an offshore operator to aggregate for analysis the emissions from closely spaced activities and facilities, regardless of whether the activities fall within a single plan. And, while current regulations only consider emissions from support vessels located within 25 miles of a facility, the proposed regulations would require consideration of emissions from a support vessel during its entire transit.

The rule includes a schedule for ensuring the compliance of all plans, including previously approved plans, with the new regulations. And the new regulations will provide BOEM with a single, consistent set of requirements, appropriate to both the Gulf of Mexico and the Arctic offshore, BOEM says.

The public will have 60 days to comment on the proposed regulations following publication in the Federal Register.

"Informed by our longstanding relationship with operators, this proposal incorporates key aspects of today's practices into our regulations, while also bringing our regulations up to speed with the best available science," said Abigail Ross Hopper, BOEM director. "We will review public comments and conduct rigorous stakeholder engagement before finalizing the regulations." ●

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● INTERNATIONAL

North Sea industry faces perfect storm

Workers face end of jobs at declining fields, with thousands of jobs at risk; 1/3 of UK North Sea fields could close within 5 years

By DANICA KIRKA
Associated Press

It's Thursday night and the Spider's Web pub is packed with beefy guys in windproof jackets and massive backpacks. The exhausted oil rig workers pile their bags against the wall, play pool or just slump in the leather seats, knocking back pints of beer.

But despite the drink, there's not much laughter. It's not work that bothers them, but the prospect that the work will end.

"I'm worried," says Fraser Jamieson, an engineer who has spent the past 20 years on North Sea oil rigs. "We're all worried."

The North Sea oil industry, the biggest and oldest in Europe, is struggling with a toxic combination of aging, drying wells and the recent plunge in oil prices, which is forcing companies to rethink investments and putting thousands of jobs at risk. Estimates suggest more than a third of some 330 oil fields in the U.K. North Sea will close in the next five years.

"There is a sort of perfect storm," said Dorrik Stow, director of the Institute of Petroleum Engineering at Heriot-Watt University in Edinburgh, Scotland. "Those cumulative factors are going to negatively impact on the North Sea unless there is a fairly significant upsurge in the price of oil."

Low Brent, US production growth

Brent crude, the benchmark for international oil, hit a 12-year low of $27.10 a barrel in January amid slowing economic growth in China and increased production in the U.S. That's down from more than $100 a barrel as recently as September 2014. While prices have recovered somewhat, Brent traded for about $42 March 18 and most experts don't expect a significant rebound soon.

Low prices are causing turmoil internationally in an industry that has been going through booms and busts ever since 1859, when the first drilling rig was built in Titusville, Pennsylvania.

For the North Sea, each new bust accelerates its downward spiral, hurting the countries that tap it — Britain, Norway and to a lesser extent the Netherlands.

Norway on March 17 slashed interest rates in a bid to help the economy manage the oil sector's drop. In Britain, the government the week ending March 18 offered tax relief to oil companies to protect jobs and stem a decline in government income. Tax revenue from the industry dropped to 2.1 billion pounds ($3 billion) last year from 10.9 billion pounds in 2011-12.

Platforms dismantled

Some of the biggest platforms are being dismantled as the industry forecasts production will drop to 45 million tons of oil equivalent this year, less than a third of the 150 million tons produced in 1999. Shell, for example, has started the process of decommissioning the Brent oil field — which has produced 3 billion barrels of oil equivalent since 1976 and gave its name to the international crude oil benchmark.

Oil companies are expected to invest about 1 billion pounds ($1.4 billion) in new projects this year, compared with a recent average of 8 billion pounds, industry association Oil & Gas U.K. says.

And it is hitting workers hard. Some 5,500 people have lost their jobs, or 15 percent of the 36,600 directly employed in the industry at the end of 2013, according to Oil & Gas U.K. The group estimates that total direct and indirect employment supported by the industry has fallen to 375,000 from a peak of 440,000.

Shell, for example, has started the process of decommissioning the Brent oil field — which has produced 3 billion barrels of oil equivalent since 1976 and gave its name to the international crude oil benchmark.

If the oil price remains around $30 a barrel for the rest of 2016, almost half of the North Sea fields "are likely to be operating at a loss, deterring further exploration and capital investment," according to Oil & Gas U.K.

"2016 is going to be quite pivotal," said Fiona Legate, a research analyst at Wood MacKenzie. "We will see distress sales, and it will be make or break for a lot of companies."

Doldrums in Cromarty Firth

The doldrums are evident in the port of Cromarty Firth, a small deepwater estuary near the Scottish town of Inverness at the back door of the central North Sea. In the past, the port usually housed two rigs at a time as they underwent periodic maintenance. Now it hosts 10 — split roughly between rigs that are expected to be dismantled and those that are parked in hopes that higher oil prices will mean new contracts.

It's tough for a community in which rig maintenance meant good jobs. The port's chief executive, Bob Buskie, believes this downturn is unlike others because there isn't likely to be a boom after the bust.

"We have to realize that what's gone on in the past is in the past, and for the industry to survive in the future the whole model has to change to some extent," he said.

For Buskie that means getting work decommissioning the platforms once built and maintained in Cromarty Firth. It also means looking for new business. He's trying to attract more cruise ships packed with tourists who want to take in the delights of the Scottish Highlands, complete with bus tours of nearby Loch Ness and local whisky distilleries.

"There is a new normal," Buskie said. "We have to find out what the new normal is."

Uncertainty

And in the period of transition, there is uncertainty for those who depend on oil for their livelihoods.

In Aberdeen, the Scottish city at the heart of North Sea oil, restaurants are empty at lunchtime. Hotel parking lots are barren. Helicopters once busy ferrying workers are parked on the tarmac.

It's common to hear conversations about people who have been laid off or are barely hanging on. Retired engineer Ken Forbes, 70, suggests the high-fliers made rich by oil are "coming down to Earth with a big bang."

At the cozy Sanddollar cafe on the Aberdeen seafront, the lunchtime crowd clears quickly despite the prospect of luscious lemon cake and hot tea. Waiter Piotr Kowalski, 23, said he's noticed that people are much more careful about what they order.

"They spend less," he said, noting the downturn. "They don't go out so often in the first place."

Tommy Campbell, a regional organizer at the Unite union's Aberdeen headquarters, sees the pain every day. Just last week one worker told him the entire team on his rig — some 30 people — had been put on notice for redundancy.

He argues oil companies have responsibilities not just to shareholders, but to the communities that support them. He says the union is "organizing and speaking up with our demand for a U.K. summit," that would bring companies, politicians and the community together to think creatively about what's next rather than just cutting headcounts. Otherwise the pain will just continue.

"We're throwing rattles out of the prams," he said. "Everybody is losing out." ●

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TAPS THROUGHPUT

particularly on the federal side, is challenging in Alaska, with regulation tending to impede badly needed oil development. And the oil industry in the state needs a stable fiscal environment he said, commenting that Great Britain has recently reduced its tax rates for offshore oil and gas production, to help the industry through the current period of low oil prices.

Barrett made comparison between federal regulation in Alaska and government regulation in Norway. A senior Norwegian government official recently commented that the government of Norway supports offshore oil development, because of the economic benefits that the development brings, he said. And, while the Norwegian regulatory regime is based on a partnership culture between government and industry, the command-and-control approach to regulation in the United States is highly prescriptive. In Norway, the government sets performance standards and then works with industry to figure out how to meet those standards, Barrett said.

Moreover, the United States has moved in a direction of tending to criminalize mistakes rather than seeking solutions, Barrett commented. If an engineer makes a mistake, for example, the government wants to lock him up as part of the command and control approach to industry oversight.

"Don't breathe unless you get a permission slip and, by the way, if you make a mistake you're going to jail," Barrett said when characterizing his view of the U.S. government attitude.

But that is not how to conduct business, he said, commenting that taking pride in work and having regulators and industry working together is a more effective approach.

A need for trust

The industry also needs to ensure that it can be trusted, by working in a safe and reliable manner, Barrett said. He commented on Alyeska's safety record.

"Last year we had the safest year we ever had on TAPS," Barrett said. "We don't want anyone going home hurt. That's our mantra."

TAPS pipeline reliability in 2015 stood at 99.5 percent, with two scheduled shutdowns for the carrying out of essential maintenance work being the reason for the reliability level coming in fractionally below perfect. In fact, Alyeska has now completed a four-year testing program on all 176 of the pipeline's mainline valves, an exercise involving the tricky operation of conducting valve tests without stopping the flow of oil through the line, Barrett said.

Responsibility and transparency

Increasingly, the public now expects corporate social responsibility and transparency. And, to be successful, a business needs the trust of its customers, of the public and of the regulators, Barrett said. In March Alyeska was named by the Ethisphere Institute, for the fifth year in a row, as one of the world's most ethical companies. The company received a large operator environmental performance award from the American Petroleum Institute. The Alaska SeaLife Center gave the company its 2015 Alaska Ocean Leadership Award for the company's fishing vessel spill response fleet program in Prince William Sound. The company has also received the governor's safety award.

And Alyeska employees perform many activities in support of local communities, Barrett said.

When it comes to environmental stewardship, Alyeska had a successful year in 2015, despite some significant flooding issues along the Dalton Highway during the spring breakup, and despite have to live with wildfires in the Interior during the summer. Both Alyeska and the Alaska Department of Transportation have been working pro-actively to build gravel and snow berms, to more effectively handle any flooding that may happen this year, Barrett said.

Addressing low flow

Meanwhile, Alyeska continues to conduct testing and take action to deal with the growing challenge of low oil flow in the pipeline. The company has now staged contingency supplies of methanol at certain points along the line, to act as antifreeze in the oil in the event of a winter pipeline shutdown. However, given the problems that the methanol would create for the refineries that process the oil, the staging of methanol does not provide a simple solution, Barrett said.

Alyeska runs scraper pigs, torpedo shaped devices that fit inside the line, to clean deposited wax off the pipeline interior. The company is evaluating a new European technology that sweeps precipitated wax by circulating fluid at high pressure. However, this technology has yet to be used in a 48-inch pipeline, similar to the TAPS main line, Barrett said

For some time Alyeska has been adding heat to the oil in the pipeline, in particular by recirculating the oil at some of the pump stations. The company has installed a point source heating system at one of the remote gate valves and is planning to install another of these systems at pump station eight, Barrett said. Rather than simply siting the heating systems at pump stations, the company has found it to be more effective to heat the oil at points along the line where the oil becomes especially cold during the winter, Barrett said.

Looking to the future, as the company's legacy workforce ages, the company is actively bringing in new people, many of whom have TAPS experience through work for Alyeska's contractors, Barrett said. The company has about 800 employees and uses hundreds of contractors. About 95 percent of the workforce is Alaska based, and 70 percent of the company's contractors are headquartered in Alaska, Barrett said. About 20 percent of the company employees are Alaska Native, 30 percent are women and 33 percent are minorities, he said. ●

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Dropping of Crowley a matter of business

The fact that Crowley Maritime Corp. is no longer in the running for the next contract for maritime support services at the Valdez Marine Terminal results from a new competitive bidding procedure for the services, Tom Barrett, president of Alyeska Pipeline Service Co., told a meeting of the Resource Development Council on March 17. Alyeska operates the terminal on behalf of the terminal owners.

"It's business, basically," Barrett said.

Crowley has provided the support services, including tanker escort tugs, docking tugs and spill response support vessels, for the past two 10-year service contract cycles.

For the next contract cycle, Alyeska started the contract bidding three years in advance of the expiry date for the current contract, Barrett explained. The idea was to make the bidding more competitive by giving the company that is awarded the contract time to build any equipment they might need to provide the contracted services, he said. The company might need, for example, a different set of escort tugs. Barrett confirmed that, although the new contract has not yet been settled, Crowley is no longer in the bidding.

—ALAN BAILEY

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LINK STUDY

don't believe the project is going to work," Vickers said.

A preliminary study released by the independent Van Horne Institute concluded that with a C$1.8 million grant from the Alberta government, the idea has merit.

Route study to get underway

The detailed feasibility study that will narrow down the rail's exact route is scheduled to get underway by early spring, with the company undertaking an aerial survey.

The trains would carry heated bitumen, which would allow a relatively straightforward cleanup in the event of a spill, Vickers said.

He said the substance would come out of the tanker cars like molasses and could be cleaned up with shovels.

The regulatory review process would be

see **LINK STUDY** *page 24*

Petroleum news

Oil Patch Bits

Crowley unsuccessful in bid for services contract

COURTESY CROWLEY

Crowley Marine Services will not be providing oil spill prevention and response services in Valdez and Prince William Sound when its contract expires June 30, 2018. Crowley has provided marine services in Prince William Sound since 1990.

Despite bidding aggressively for the SERVS contract extension, Crowley was not chosen by Alyeska to retain the entire scope of the current contract.

Crowley is fully committed to continued professional service and full compliance as the marine service provider until the end of June 2018, and will be engaged in any transition process. Participants in the bidding process are restricted from disclosing details.

"We bid this contract very aggressively and are extremely disappointed that we were not selected to retain this business," said Tom Crowley, company chairman and CEO. "We have been assured that this outcome is the result of a very competitive landscape and is not a reflection of Crowley's qualifications or record. We will continue to work constructively with Alyeska through the duration of our contract. Crowley and Alyeska agree that there is nothing more important than the continued protection of Prince William Sound."

There are currently 17 vessels, 230 highly trained mariners and 17 shore side administrative personnel working together to provide world-class service to Alyeska in Valdez.

Guess & Rudd says Kristin Bryant named shareholder

KRISTIN BRYANT

Guess & Rudd P.C. is pleased to announce that Kristin Eagen Bryant has become a shareholder of the firm. Since joining Guess & Rudd in 2011, Bryant has represented insurance companies, corporations, municipal governments, small businesses, aircraft overhaulers and individuals in a broad range of litigation matters. These include aviation accident liability, product liability, insurance bad faith and coverage issues, underinsured/uninsured motorist claims, premise liability, automobile liability, professional liability claims and employment law claims. Bryant has tried cases in both federal and state court. In addition, she works on a variety of estate planning and disposition matters. Bryant attended Seattle Pacific University where she received a 4-year gymnastics scholarship. She is a graduate of Gonzaga University School of Law in Spokane, Washington.

AECOM most admired company for second consecutive year

AECOM, a premier, fully integrated global infrastructure firm, announced recently that it has been named to Fortune magazine's list of the world's most admired companies for the second consecutive year.

From an annual survey conducted by Fortune and global management consulting firm Korn Ferry Hay Group, top executives, directors and financial analysts identify the companies with the strongest reputations within their industries and across industries.

"Being included on Fortune's world's most admired companies list for a second year in a row is an outstanding achievement that highlights the growth and fundamental

see OIL PATCH BITS page 22

Companies involved in Alaska and northern Canada's oil and gas industry

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

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WIELECHOWSKI Q&A

sitting on the board knowing full well the Legislature controls their purse strings. Having even more power is just the wrong approach.

Petroleum News: On the pipeline, what are your thoughts on the status of AKLNG right now?

Wielechowski: The commodity costs are at a cyclical low. If you can secure commitments, now is the time to do it. Most experts believe the price for oil and gas will rebound. Now is the time. If you can take advantage to get low-cost contracts to build now is the time to do it.

Petroleum News: Are you OK with the governor's handling of it with his announcement?

Wielechowski: Obviously I was disappointed like all Alaskans. We are in a partnership we don't have sole control over this. That's one of the reasons why I opposed the gas line bill that Gov. Parnell set up a few years ago. I didn't want to put our fate, our destiny in the hands of three or more producers or pipeline builders. By passing that bill we've lost a lot of our ability to control our destiny. Sure with the producers, it's a tough time for them. They don't want to commit the funds to the project and they have the votes. We have 25 percent. So yeah in some ways this is a byproduct of the legislation passed where we have turned over our sovereignty.

Petroleum News: Do you ever foresee a gas line being built?

Wielechowski: You know I've asked this question of people who I trust and I've asked this question of the experts who appear before us. I think there is a very strong argument for an Alaska gas pipeline and an LNG project. The advantages that we have here are location, cold weather, the infrastructure that we have in place, that fact that we have known supplies of gas in large quantities. We have lots of things going in or favor. It is going to take a commitment by everyone. Again, we've put our destiny in the hands of others and that's a challenge at this point.

Petroleum News: What's the alternative to putting your destiny in the hands of others?

Wielechowski: I would like to have seen an exploration of going out to the market, like the governor had proposed and trying to get contracts, then seeing if we can get the funds to build it. You go to Tokyo, you go to Korea, you go to China and get companies that desperately need the gas and work together with them and get the financing to build a project. So the state would be the lead agent. The state would be taking control. Now we've got a producer built pipeline. If you remember going back decades this is a discussion we had eight or nine years ago saying how there are AG opinions saying that it's not in Alaska's best interest, it's not in our country's best interest to have a producer-owned pipeline. There are a lot of issues associated with that. We've had many, many hearings about this over the years.

It's sort of like we are reliving our mistakes. Here we are again, we've put our faith, our destiny in the hands of others and I certainly understand these are tough financial times for everyone. This is our economic future and I would have liked to have seen an exploration, going out to the market to see if we could finance a project that way.

Petroleum News: So what would you like to hear from the governor by the end of the year on the LNG project?

Wielechowski: The problem that we have now is we are locked into this gas line bill, locked into this strategy to get a gas line. It puts our fate into the hands of others. I don't know how you get out of that — until the Legislature acts to get us out of that situation, which I don't see happening. The governor is stuck in that position. He opposed that situation also. You've got a Legislature that wants to stick with that broken formula for building the pipeline. So how do you get out of that? Unless the Legislature realizes we are not going anywhere with this.

Petroleum News: So what would you like to hear from the producers, the partners in this project?

Wielechowski: I'm sympathetic to the partners' financial situation. This is tough financial times. At the same time, this is what happens in the oil industry. They made $45 billion in the six or seven years we had ACES in place. Now they have a couple of years where they are not making money. The hope for them is you make enough money in the good times that you can weather the bad times.

So I can't fault them for saying look, times are tough financially for us, we can't go through with this. I can fault the Legislature for getting us in this situation that some of us had predicted. Would I like to see the oil industry come forward and say this is a top priority, we are going to go ahead and finance this, and try to get these low costs steel contracts when prices are low. Sure. Is that realistically going to happen? Probably not.

Petroleum News: So do you believe the spring forecast changes your outlook on the prospects of the AKLNG project?

Wielechowski: I look at these forecasts with a grain of salt. I really do. Two years ago we were forecasted to have $100 to $120 a barrel oil for the next 10 years. Today's it's $30 to $60 oil for the next 10 years. The one thing I can tell you about predicting the price of oil is no matter what price you predict, you are going to be wrong. There are so many different variables. You don't know what somebody is going to blow up a pipeline in Nigeria or war is going to break out in the Middle East. These are things we don't have sufficient knowledge of. The one thing I have said is we shouldn't be overreacting when you are at a cyclical low. I feel pretty confident that the price of oil will go up over the next several years. We have to be careful as a state not to overreact when the prices are too low and not to overreact when the prices are too high. I've seen that over and over again in this building. This mindset that sets in that oil is $40 and it's going to be that way forever or oil is going to be $100 and it's going to be that way forever. It's just not how it works. It's not how it happens. So I think we need to be measured in what we do. We need to have a long-term vision on the pipeline and I don't think the current framework gets us to where we want to get. I understand it's a complex process, but I think we would be better off having one entity, that being the state or AGDC, managing this, going out and trying to get contracts. The demand for gas is projected to rise in the future. Asia needs natural gas: Japan, Korea, China need natural gas — LNG. Countries like to diversify where they get natural gas. We've got a long track record of delivering natural gas from Nikiski. I still think it's possible to make this happen. I don't know if it's possible under the current frame work though.

Petroleum News: OK, onto a bill that is expected to make its way to your committee — eventually. It's HB 247. You were on the steering committee that looked at the tax credits. What were your takeaways from the working group first?

Wielechowski: It seemed to me there was a general consensus that something needed to change. We certainly had industry members there fighting for the industry and supporting the industry. I get that. I think people of Alaska and people of the committee in general agreed we can't sustain where we are going on oil tax credits. It's reached a point now as the revenue forecast points out that we are paying out $771 million more in tax credits than we get in production taxes. That's just not sustainable.

I asked Revenue why did the numbers go up so much? What is happening is companies realize this is coming to an end and everyone is out there exploring and we are paying them 85 percent to go do the exploration. In some cases, it could be more than 100 percent that we are paying them.

If a company is looking at investing in Alaska versus another state, they will say well Alaska is paying us 85 percent, even 100 percent. Yeah, we get the nod but at the same time it's crushing to our treasury. You've got speculation going on and companies are saying I can drill this well for practically nothing. I can gold plate it. There is disincentive for companies to act rationally. I think there are wild bets being made.

Petroleum News: OK, so onto the bill, what's your sense of how the bill is looking?

Wielechowski: I think everybody recognizes we have a problem with tax credits and everybody realizes we have a problem with finances in general. All the interest groups are coming out very, very strongly and opposing virtually everything. I can't tell you how many industry groups I've had come to my office and say we've got to do something but don't tax me. It's the same with the tax credits. I think companies and people recognize it's a problem but nobody wants to be the one to lose their tax credits or have to pay a little bit more in taxes. The question is will the Legislature have a little more will power to do that.

Petroleum News: Occasionally there has been some discussion, however briefly, there seems to be more people talking about new oil, whether it should be sunsetted or not. That was a concern you had during the SB 21 debate. Is that a concern for you?

Wielechowski: It's a huge concern. Ultimately all oil is going to be considered new oil and that means ultimately we get no taxes from it. There was an amendment run in the House to limit it to I think seven years. That failed by a few votes. To make it unlimited is irresponsible of the state. What our experts have testified to over the years is that after five to seven years companies have recouped their costs. So I think five years probably gives companies more than enough time to recover costs.

What I think we should do is look at how do we truly

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PRUDHOE BAY

in the high $30s.

Gas dominates

Digert also said that, today, Prudhoe Bay is operating more like a gas field than an oil field, with gas production volumes massively exceeding those of oil — most of the gas is injected back into the field reservoir for pressure support and to drive more oil out of the reservoir. In 2014 gas constituted 97 percent of the fluid volume going through the production facilities; 2 percent was water; and just 0.4 percent was oil, Digert said. And nowadays, 50 percent of the oil being produced exists in the gas phase in the reservoir, whereas at field startup almost all of the oil existed underground in liquid form, he said.

Over the years there have been many plans for major gas sales from the field, but now does seem the time to start moving the gas to market, Digert said. While there may be a billion barrels of oil, or perhaps a bit more, to produce from the field, gas sales could amount to more than 3 billion barrels of oil equivalent, he said. Original gas in place in the field was estimated at 40 trillion cubic feet, although only a portion of this could in practice be produced.

At field startup in 1977 the field owners anticipated ultimate recovery of 9.6 billion barrels of oil, with oil production

Development of the Prudhoe Bay field has now reached a point where BP has been designing a series of distinct plays for producing oil in a number of different situations at different locations in the field reservoir.

continuing until the late 1980s. At that point major gas sales would blow down the field's gas cap, with the field's life coming to an end in the early 2000s, Digert says. But the field operators coasted through those original expectations, with the field now 40 years into its life, longevity well beyond the field's original 30-year design life, he said.

Ivishak reservoir

Most of the oil from the Prudhoe Bay field has come from the field's massive Ivishak reservoir, which contained a huge gas cap above an equally large oil rim, with an aquifer below the oil. Across much of the field a layer of heavy oil tar seals the oil rim from the underlying aquifer, Digert said. The reservoir thickness between the oil-water contact at the base and the upper edge of the gas cap at the top exceeds 400 feet, he said.

Although the reservoir consist of four distinct zones, each with particular rock characteristics, fluid communication through the reservoir is, in general, good, allowing the vertical migration of fluids and the gravity segregation of fluids of different densities: Oil will tend to flow down through the reservoir, while gas will go to the top and water will sink to the bottom, Digert said.

As a consequence, a primary oil production technique over the years has been gravity drainage, in which the oil has drained down through the reservoir towards production wells, pushed down by gas in the gas cap. After several decades of oil production, the gas has moved most of the way down through the reservoir, so that oil production wells today are mostly producing from near the bottom of the oil column, Digert said. And, with the gas pushing downward in the main central part of the field, a waterflood technique is used around the edges, using injected water to flush oil sideways towards the production wells.

Gas and water injection

With gas reaching the production wells and being produced along with the oil, BP injects the gas back into the crest of the reservoir. This gas injection both helps maintain the fluid pressure inside the reservoir and, by flowing back down inside the reservoir, sweeps remnant oil towards the production wells, Digert said. The system works a little like blowing warm air over wet clothing — the lean gas vaporizes the relic oil in the rock pores, enabling the recovery of perhaps 20 percent of the oil left behind from the original oil production, he explained. The injected lean gas can also push out the original gas in place, which contains condensate, a mixture of light hydrocarbons.

The waterflood operations from the edges of the reservoir leave an oil saturation of about 35 percent in place. Consequently, BP alternates water injection with the injection of miscible injectant, a cocktail containing natural gas and natural gas liquids, to flush more oil from the rock pores. That can reduce the oil saturation of the rock pores to perhaps 5 percent, Digert said. But the efficiency of the technique can be relatively low in terms of the volume of oil produced because the water and miscible injectant tend to take different routes through the rock. Consequently, it is necessary to move the production and injection locations around, to improve the contact between the injected fluids and the relict oil.

Also a trademarked technique called BrightWater, involving the injection of polymer particles that expands and blocks already flooded sections of the reservoir, can divert newly injected water into areas where waterflood can be most effectively used.

With oil and some gas being removed from the field reservoir, the reservoir pressure decays over time. Consequently, for the last 10 years BP has been injecting water into the gas cap, to slow down the reservoir pressure decline. The injected water tends to flow down through the reservoir, at the risk of trapping oil or producing water rather than oil from production wells. However, so far the gas cap water injection technique has proved very effective, with more gained than may have been lost, Digert said. The gas cap water injection probably adds 15,000 to 16,000 barrels to the field's daily production, he said.

Drilling techniques

In the effort to extract more oil from the field reservoir, drilling techniques have evolved over the years. Early wells were drilled vertically through the near-surface permafrost, then deviated out at a 40 degree angle before being curved back into a near vertical profile through the field reservoir. Horizontal wells, drilled laterally for 5,000 to 7,000 feet from a steep well bore have since come into use. And in the late 1980s and early 1990s coiled tubing came into use as a cost effective means of drilling lateral wells from existing well bores. Coiled tubing involves the use of a continuous length of flexible, relatively narrow bore steel drill pipe, with a motor driven drill bit at the downhole end.

While there 800 to 850 usable wells in the field at present, there need to be some 650 to 660 producing wells in operation to keep up the full production rates, Digert said.

New plays

Development of the Prudhoe Bay field has now reached a point where BP has been designing a series of distinct plays for producing oil in a number of different situations at different locations in the field reservoir. One play, for example, involves drilling a well along the bottom of an area where oil is trapped, with the far end of the well bent upwards into the gas accumulation above the oil. The upward directed end section of the well enables measurement of the oil thickness, while perforations in this section of the well pipe allow gas to enter the well, to help lift oil to the surface from the section of the well in the oil pool.

Another play, in the waterflood area of the field, involves sidetracking a well to sweep the reservoir rock above and below a region where the rock has previously been flooded with water.

BP has also been making moves to develop the Sag River, a relatively thin reservoir unit above the main Ivishak reservoir and originally containing perhaps 1.5 billion barrels of oil in place. Having poorer reservoir quality than the Ivishak, the Sag River has not received much attention until relatively recently. BP is now trying the use of long horizontal wells and hydraulic fracturing techniques, similar to those used for shale oil development in the Lower 48, to produce Sag River oil. At this stage test drilling has successfully demonstrated production, although at today's oil prices economic success is not certain, Digert said. And the reservoir quality is quite variable from one part of the Sag River to another, he said. ●

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OIL PATCH BITS

strengths of our business and the transformative work we do globally," said AECOM Chairman and CEO Michael S. Burke. "This recognition is another reflection of the dedication and expertise of our employees who make it possible for all of us to deliver a better world."

According to Fortune, the world's most admired companies list is considered to be the definitive report card on corporate reputation. The companies featured on the list represent "the pinnacle of excellence" in nine key performance areas: Ability to attract and retain talented people, quality of management, social responsibility to the community and the environment, innovativeness, quality of products or services, wise use of corporate assets, financial soundness, long-term investment value, effectiveness in doing business globally.

The world's most admired companies list and details on the methodology can be found on the Fortune website. The list also appears in the magazine's Feb. 22 print edition.

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

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OIL FUTURE

and the rest of the world produced more or less all they could.

"This inevitably meant that the Saudis were quickly losing market share. They therefore deliberately induced the price collapse by very rapidly increasing their production volume — which at that time they alone could do — and thereby lowering the price of crude by about the same percentage as it has declined today," Herrera said.

His perception of today's price collapse is "radically different" and "was certainly not induced by Saudi Arabia. … All the Saudis have done is to keep their production more or less stable and watched while the U.S. tight oil revolution flooded the world with excess oil," Herrera said.

"The causes in 1986 and now are very similar, but the catalysts are completely different," he said.

"Why are people so unwilling to recognize that the … flood of tight oil from the U.S. has been the main cause of the price collapse?" Herrera asked, clearly frustrated.

"Obviously, the politics of the Middle East and perhaps the China economy, together with Putin's extreme need for petroleum income, have had important effects, but, fundamentally, it has been the U.S. evolution of tight oil technology, in particular, that has been the reason for the price collapse."

Nobody, Herrera said, has read Saudi Arabia correctly.

"Everyone thought the Saudis would continue to control the price by acting as the swing producer," he said. "Welcome to the new world!"

Googling the 1986 crisis "you will read lots of commentators who recognize many similarities between the two events (1986 and 2015 oil price collapses), but I would argue that the world is totally different today than 30 years ago and if the parallels turn out to be exact, it is luck rather than inevitability that make them so," Herrera said.

"I have always believed that every one, everywhere, wanted to benefit from abundant energy, especially oil. I think that this is truer today than it was 30 years ago because the benefits of energy are so instantly translated into a more pleasant lifestyle and a longer and healthier life," he said.

About half of mankind, he said, still wants such changes, so the demand for oil will only continue to increase.

Can't rely on history repeating itself

"What I am trying to say is that it is very misleading and dangerous to forecast the world's oil future by assuming that the 1986 price fall is a template for today."

Despite the similarities between the 1986 and current oil price collapses, "now is not like then, so we can't rely on history repeating itself," Herrera said.

If the Organization of Petroleum Exporting Countries no longer functions in its traditional way, "one can argue that the price of oil will mainly be influenced by supply and demand."

"In fact, that is perhaps exactly what is happening today — affected, of course, by politics and wars," Herrera said.

"Without new energy breakthroughs, which could happen quickly and at any time," he said it is "reasonable" to expect demand to outstrip supply.

"So, the price of oil will go up," he said.

Hopefully it will happen slowly, Herrera said, and not because of revolution or war.

In January, Herrera predicted crude at a solid $40 a barrel by the end of the year, "if everything goes better than expected."

Because low oil prices are good for the general public and businesses outside the oil industry, they eventually translate into more development, which increases the demand for oil, causing oil prices to increase.

That said, he did not see development catching up

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IEA more bullish

In its monthly report on oil markets, the International Energy Agency said in March there were "signs that prices might have bottomed out."

The Paris-based IEA pointed to several reasons behind its assertion, including supply outages in Iraq, Nigeria and United Arab Emirates; drops in non-OPEC crude supplies; weakness in the U.S. dollar; soft but nonetheless steady demand; and the possibility that OPEC would take stronger action to boost prices, despite the fact member supply reductions seemed unlikely.

In its February report, IEA said it was "very hard to see how oil prices can rise significantly in the short term."

Since then, oil prices have rallied more than 35 percent, but that had more to do with perception than actual crude supply and demand.

Still, the fundamentals have improved, the agency noted, with exports from Iraq falling by 220,000 barrels per day in February and Iran's return to the market being less dramatic than the Iranians said it would be.

Also, U.S. oil production is nearing 9 million barrels per day, with IEA forecasting it will fall 530,000 barrels per day in 2016. (The Department of Energy's Energy Information Agency predicted a more robust decline of 700,000 bpd.)

IEA also reduced output predictions for Brazil, Colombia and other non-OPEC countries by a total of 750,000 bpd.

On the other hand, the agency saw crude consumption growing by only 1.2 million bpd in 2016, in sharp contrast to the 1.8 million bpd average in the past five years.

IEA attributes that drop to flat or reduced demand from China, the U.S, France, Japan and Brazil.

But the agency predicted continued growth in demand from India and a few other emerging markets, noting global demand was sound, but "not rock-solid."

Any uncertainty, IEA said, could be expected to be "skewed to the downside."

—KAY CASHMAN

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WIELECHOWSKI Q&A

encourage new oil to be produced. If a company had already planned, they shouldn't get tax credits for new oil. If a company made investments in certain areas, and a tax credit isn't going to incentivize them, then they shouldn't get tax breaks for it. You want to design it in a way that you truly incentivize companies to go out and invest in areas and develop new oil, and do it in areas you wouldn't do it absent of the tax credit.

Petroleum News: You know a few weeks ago President Obama and Prime Minister Trudeau were both speaking to the Arctic with a climate change bent. Many worry this could ultimately jeopardize the chances of ever developing ANWR. Do you support drilling there?

Wielechowski: I do support it and always have. I think there is a way you can do it that both sides can support. I think one of the ways we've heard is you get at it from state land and drill diagonally. I don't think you'll see it at $40 or $50 oil, but I think the next time oil spikes again and you go up to over $100.

I think as the price of oil rises, more people will be supporting it. So in the future, I think it's important for us as a state to keep pushing for it. There are massive amounts of oil there. There is good quality, light oil. The one thing I want to ensure is we get a fair share for it. Because it's on federal land, we don't get federal royalties for it. ●

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TAX CREDIT

Alper said the revenue impact of the original bill was $500 million to the state in fiscal year 2017, while the impact of the CS was $45 million, although he said those numbers were based on the fall revenue forecast. Impacts to the state under the original bill were projected at $425 million in FY18 and $250 million in FY19; impacts of the CS would be $60 million in FY18 and $55 million in FY19.

The CS eliminates hardening the production tax floor and increasing that minimum tax from 4 percent to 5 percent, eliminates extension of the minimum tax to “new” oil and eliminates a provision which would not have allowed the small producer credit to reduce tax payments below the floor.

Alper said proposed changes to the system under Senate Bill 21 which had been retained were the GVR, the new oil value reduction, can no longer be used to increase the size of a net operating loss and a municipality which owns production and sells a portion can only deduct the share of expenses for the portion it sells against revenue.

Alper said the CS also preserved a fix which provides for compound interest on underpayments and assessments, although the CS removed a proposed increase in the interest rate.

The original bill repealed two Cook Inlet credits effective July 1; the CS phases out the two credits, one by phases in 2017 and 2018, the other in 2022. The Cook Inlet net operating loss is reduced from 25 percent to 10 percent in 2017.

The CS also creates a legislative working group to evaluate Cook Inlet tax credits and develop a new Cook Inlet tax regime for consideration by the 2017 Legislature.

Cook Inlet benefits retained

Janak Mayer of enalytica, the consultants employed by the Legislature to evaluate oil tax changes, noted the $25 million cap on per-company credits had been increased to $200 million, which would protect against the potential liability for a major new development, such as the proposed Armstrong development at Pikka.

The big difference between the North Slope and Cook Inlet — with the majority of refundable credits going to Cook Inlet producers — would be retained in the CS, Mayer said.

The reduction in Cook Inlet benefits, he said, would reduce spending support for new developments to 30 percent, vs. 55 percent under the status quo and 25 percent in the original bill, and reduce spending support for current production to 20 percent, vs. 30 percent under the status quo and zero in the original bill.

North Slope major producers would see no change at any price under the CS, he said, while for North Slope new or smaller producers there would be no change at higher oil prices, but if the company has an operating loss, the gross value reduction cannot be used to increase the size of the loss to earn a larger net operating loss credit.

For North Slope new project developers, there would be no change at any price, although Mayer did note very large new projects would be limited by the $200 million per company cap, which at a 35 percent net operating loss would require a bit over $570 million a year in capital spending for a single company to reach that limit.

In a statement released after the bill passed the committee, Resources Co-chair Ben Nageak, D-Barrow, said: “These are difficult times for Alaska and industries operating in Alaska.” He said the committee “worked hard to maintain a balanced resource policy between exploration and production. The committee realized that exploration success over the next three to five years becomes the production for the next 20 years and into the future.”

House Speaker Mike Chenault, R-Nikiski, an alternate committee member, called the bill “one of the biggest issues we’ll face this session” and said he looked forward to the work the House Finance Committee would do on the bill.

Geran Tarr and Andy Josephson, Democratic committee members from Anchorage, said in a statement that changes made in the bill removed $450 million in savings and new revenue.

“The current oil tax credit system is not sustainable,” Tarr said. Josephson said with the state “staring a recession square in the eye” it can no longer afford the oil tax credit system.

—KRISTEN NELSON

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OIL FUTURE

with the world’s crude supply this year, and only beginning to next year.

It is a gradual process, he said, and the current gap between development and supply is very wide — and because cheap oil isn’t yet causing an appreciable decrease in the cost of living.

“This time, they seem to be taking their own sweet time,” Herrera said about the cost of goods and services.

It’s a slow process, but “maybe — maybe — in five years we’ll see a return to $100 oil,” he said.

“What we’ve created is a situation that is quite unique. We’ve never had an excess of oil in the world to this extent. .. Development sort of kept up,” Herrera said.

Even if crude prices return to the $100 level in five years or less, he feared the world would be a much different place at that time.

“Lower oil prices could destabilize the governments of Russia and Saudi Arabia, which are heavily reliant on oil,” Herrera said in January. ●

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LINK STUDY

different from pipelines crossing provincial borders, with the lead role in Canada being played by Transport Canada rather than the National Energy Board, while the Alaska segment would be handled by United States authorities.

Vickers said the Alaska governor and Valdez mayor are both keen on the plan, which should help avoid the headwinds encountered by TransCanada’s Keystone XL system.

Yukon Energy, Mines and Resources Minister Scott Kent agreed that the permitting process should be less complicated that what keystone experienced.

“There’s not as many landowners as you’d find in a project like Keystone XL,” he said.

“But that said, all of these projects would require environmental screening and have to undergo that scrutiny so that we can manage any environmental risks.”

—GARY PARK