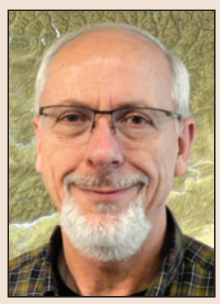
Petroleum news

Vol. 25, No. 25 • www.PetroleumNews.com | A weekly oil & gas newspaper based in Anchorage, Alaska | Week of June 21, 2020 • $2.50

page 7 Conoco aims to please shareholders financially, on climate

State receives 3 bids in first online sale, all for inlet tracts



TOM STOKES

The Alaska Department of Natural Resources Division of Oil and Gas posted results June 17 from its first online oil and gas lease sale, which offered tracts in two areas: Cook Inlet and the Alaska Peninsula.

It received three bids on Cook Inlet tracts, none on Alaska Peninsula tracts.

Hilcorp Alaska LLC was the sole bidder, bidding $26.76 an acre for a 5,590-acre tract south of Cosmopolitan and $18.76 an acre for two tracts, one 640 acres and one 916 acres, onshore on the west side of Cook Inlet on the Iniskin

see ONLINE SALE page 8

IEA boosts 2020 oil demand forecast by 500,000 barrels a day

As Petroleum News went to press Thursday morning, June 18, the most recent daily estimate from the Alaska Department of Revenue put Alaska North Slope crude at $41.91 per barrel at market close the day before, just above Brent crude, which had closed at $40.71.

By early Thursday morning Brent had crept up 18 cents, possibly on news that the Paris-based International Energy Agency had raised its 2020 oil demand forecast by 500,000 barrels per day to 91.7 million barrels.

While the oil market "remains fragile," IEA said in its monthly report, "the recent modest recovery in price suggests that the first half of 2020 is ending on a more optimistic note." New data show that "demand destruction in the early part of

see IEA FORECAST page 9

Statistical Review shows slowed oil consumption, rise in natural gas

Crude oil consumption grew by 0.9% in 2019, while natural gas consumption was up 2%, with primary energy consumption slowed to a 1.3% growth rate, less than half the 2.8% growth in 2018. Those were key findings of the bp Statistical Review of World Energy 2020, released June 17.

Slower growth in energy markets in 2019 was "in line with weaker economic growth and a partial unwinding of some of the one-off factors that boosted energy demand in 2018," the review said, with the slowdown "particularly evident in the U.S. Russia and India, each of which exhibited unusually strong growth in 2018." In the 2019 review, which covered 2018 data, the company said much of the demand growth in

see STATISTICAL REVIEW page 10

PTE Pipeline files for lower tariff to move Point Thomson oil

PTE Pipeline LLC, the Point Thomson Export Pipeline, which moves Point Thomson condensate 22 miles to a connection with the Badami Sales Oil Pipeline, is now carrying more oil than when the current tariff was put in place last year and the company has filed for a decrease from its current tariff of $12.80 per barrel to $8.77, based on the increased throughput. The current rate of $12.80 was effective beginning Jan. 1.

Rates for the line are based on a settlement agreement reached last August.

That settlement was reached after PTE Pipeline filed a revenue requirement study with the Regulatory Commission of Alaska in July 2018 proposing an increase for intrastate ship-

see PTE PIPELINE page 6

FINANCE & ECONOMY

Furie case closing?

3rd plan of reorganization calls for June 30 closing of sale to HEX C. I.

By STEVE SUTHERLIN
Petroleum News

The long and winding Chapter 11 bankruptcy case of Furie Operating Alaska LLC may soon come to a close, if an order filed in a motion for final decree by Furie June 15 in the U.S. Bankruptcy Court for the District of Delaware is granted in a July 7 hearing.

JOHN L. HENDRIX

The order would break up a trio of bankruptcy debtors consisting of Furie and related companies, Cornucopia Oil & Gas Company LLC and Corsair Oil & Gas LLC.

The order would close the Chapter 11 cases of Furie and Corsair, leaving Cornucopia to wrap up the business of the companies as the remaining debtor, to avoid imposing "significant costs on the debtors' estates."

Through the motion, Furie is requesting entry of an order closing the lead case, with all remaining matters to be administered in the Chapter 11 case of the remaining debtor. The caption in the remaining case would be modified to in re: Cornucopia Oil & Gas Company LLC, debtor, rather than Furie Operating Alaska LLC et al,

see FURIE SALE page 10

EXPLORATION & PRODUCTION

Seaview production phase

State approves Hilcorp plan of ops for facilities at Anchor Point gas discovery

By STEVE SUTHERLIN
Petroleum News

The Alaska Division of Oil and Gas approved a lease plan of operations June 15 for Hilcorp Alaska LLC to construct a new gas production facility at its existing Seaview pad located off the Old Sterling Highway 1.5 miles south of the town of Anchor Point on the lower Kenai Peninsula.

Hilcorp submitted a request April 3 for authorization to begin the development and production phase of the Seaview project, for ADL 392667. It includes installation of gas production infrastructure on the existing Seaview pad, as well as the drilling of up to two new gas wells.

The Seaview pad was constructed in 2018 within an existing gravel mine site on private surface

> *Hilcorp plans to install gas production facility infrastructure and modules and undertake Seaview 8 well completion beginning Aug. 1. The company plans to spud the Seaview 9 well Nov. 1, and to spud the Seaview 10 well Jan. 15.*

lands owned by Thomas H. Clark, Kenai Peninsula Borough tax parcels 16910237 and 16936040.

The Seaview exploration phase authorization included the drilling of the Seaview 8 and 9 wells, the division said. Seaview 8 has been drilled to approximately 10,500 feet. During development and production, the Seaview 9 and the proposed

see SEAVIEW PAD page 11

FINANCE & ECONOMY

Canada in the dumps

Capital spending plans take another setback, down almost C$14B from forecast

By GARY PARK
For Petroleum News

Leaders of the Canadian oil patch have been dragged into another downward spiral as the upstream oil sector again tries to redefine "bottom."

In revising its 2020 capital spending, the Canadian Association of Petroleum Producers estimates C$23.3 billion will be invested in the oil and natural gas production sectors, down from its C$27 billion forecast in January, which had projected a 6% increase over 2019, which was credited to a return to industry-friendly policies in Alberta and Saskatchewan.

But those hopes have been shattered despite a recent partial recovery in oil prices and a new

> *Since peaking at C$81 billion in 2014, combined Canadian oil and gas investment has plunged by 71% or C$57.7 billion and the loss of tens of thousands of jobs.*

agreement by OPEC and other producing countries to extend their 9.7 million barrels per day of production constraints through July.

Since peaking at C$81 billion in 2014, combined Canadian oil and gas investment has plunged by 71% or C$57.7 billion and the loss of tens of thousands of jobs.

However, the Alberta Energy Regulator has dangled a faint prospect of hope in the natural gas

see CAPITAL SPENDING page 8

● PIPELINES & DOWNSTREAM

Enbridge eyes new world

O&G pipeline giant turns attention to renewables, with special emphasis on offshore wind-power projects in Europe and North America

By GARY PARK

For Petroleum News

Calgary-based Enbridge, North America's largest carrier of oil and natural gas, believes it has seen the writing on the wall and it's actively engaged in carving out a new future by shuffling its asset mix to take advantage of the global energy transition.

Chief Executive Officer Al Monaco said that means changes to Enbridge's supply/demand balance from the current breakdown of generating 55% of its earnings from carrying liquids, 40% from natural gas transmission and almost 5% from renewable, primarily offshore wind projects in the United Kingdom and Germany and opportunities off the coast of France.

He said offshore wind opportunities have been identified in North America, although Enbridge believes Europe has the better supply chain and more attractive power-purchase agreements, including the "sheer know-how of how to deal with offshore wind projects."

"We also know that from a public policy perspective, Europe is quite advanced and we see very good commercial models there ... and that's where the big prize is for us at the moment."

"We think having a diversified approach, having a gradual approach to transition through natural gas and renewable makes a lot of sense." —Enbridge CEO Al Monaco

As Enbridge takes what Monaco describes as a "gradual" approach to transition, observers will be interested to see whether its decade-old rival, TC Energy (formerly TransCanada Pipelines) takes a similar route, especially if Joe Biden wins the U.S. presidential election and delivers on his pledge to shut down TC Energy's Keystone XL project.

Monaco said there is "still lots of runway for oil and natural gas, but it makes sense for us to mirror the global supply picture," with the International Energy Association forecasting a five-fold increase in solar and three-fold growth in wind power consumption by 2040.

"I think you'll find ... the vast majority of companies in our sector are positioned (to rely on the transportation of fossil fuels)," he said.

"We think having a diversified approach, having a gradual approach to transition through natural gas and renewable makes a lot of sense."

Enbridge currently lists the value of its assets at C$170 billion, including Canada's Mainline export oil pipeline which moves 2.9 million barrels per day from Western Canada primarily to refineries in the U.S. Midwest.

For 2020, it put price tags of C$3 billion on gas and utility projects, C$2 billion on oil and liquids pipelines and C$1 billion on renewable, indicating it is still taking a measured approach into a new world.

The IEA estimates the breakdown of global energy consumption stands at 32% for oil, coal at 28%, natural gas at 22%, biofuels at 9%, nuclear 5%, hydro at 2% and wind and solar at 1%. ●

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● EXPLORATION & PRODUCTION

US rig count drops to 279, another new low

By KRISTEN NELSON
Petroleum News

Baker Hughes' weekly count of rotary rigs drilling in the U.S. continues to drop, hitting a new low of 279 for the week ending June 12, down five from the previous week and down 690 from a year ago.

Prior to this year, the low count by the Houston oilfield services company, which has issued the count since 1944, was 404 rigs in May 2016.

New low records have now been set for six weeks in a row: 374 rigs on May 8 of this year; 339 rigs on May 15; 318 on May 22; 301 on May 29; 284 on June 5; and this week's new low of 279.

The count has been dropping steadily: down by five, 17, 17, 21, 35, 34, 64, 73, 62, 64, 44 and 20 rigs respectively, a total of 456, over the previous 12 weeks.

The company said 199 rigs targeted oil, down seven from the previous week and down 589 from a year ago, while 78 targeted gas, up two from the previous week and down 103 from a year ago. There were two miscellaneous rigs active, unchanged from the previous week and up by two from a year ago.

Twenty-two of the holes were directional, 246 were horizontal and 11 were vertical.

Alaska count unchanged

Pennsylvania (22) was up by two rigs the week ending June 12.

Rig counts were unchanged for Alaska (3), California (4), Colorado (6), Louisiana (34), Ohio (9) and Wyoming (1).

North Dakota (11), Oklahoma (10) and Texas (114) were each down by one rig from the previous week.

New Mexico (56) and West Virginia (6) were each down by two rigs.

Baker Hughes shows Alaska with three active rigs for the week ending June 12, down by two from a year ago.

The largest rig count drop by basin was in the Permian, which has the most active rigs at 137 and was down four from the previous week and down 304 from a year ago.

Baker Hughes has issued weekly rig counts for the U.S. and Canada since 1944 and began issuing international rig counts in 1975.

The U.S. rig count peaked at 4,530 in 1981. This week's count of 279 is a new low, surpassing lows set in the previous five weeks. Prior to that the previous low was 404 rigs in May 2016. ●

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● EXPLORATION & PRODUCTION

Division sees COVID production impacts

By KRISTEN NELSON
Petroleum News

COVID-19 will have both short term and long term impacts on Alaska's oil and gas production, according to slides prepared for a June 5 presentation to Commonwealth North's Energy Action Coalition by Alaska Department of Natural Resources, Division of Oil and Gas Deputy Director Justin Black.

Modeling assumptions for the low oil price scenario for the spring production forecast changed as a result of COVID-19, the slides say. The low price forecast in February-March for fiscal year 2020 was production of 519,011 barrels per day; in April, that had dropped to 506,143 bpd.

For fiscal year 2021, the February-March low price forecast was 512,430 bpd; in April it was 479,729 bpd.

Fiscal year 2020 ends June 30; fiscal year 2021 begins July 1.

Since BP and ConocoPhillips announced rig laydowns, modeling assumptions now include no new wells drilled through the end of the year, April through December, with rig laydowns the main drivers for the expected short term production decline, which is now estimated at 5.2% from FY2020 to FY2021.

The price used continues to be the state's official spring 2020 forecast price.

Exclusions

Some things were excluded, the presentation says, and they might make the estimated production impact from COVID-19 optimistic. The first is proration and production cut decisions — these are factors which will be considered by the Department of Revenue, not by DNR.

(Alyeska Pipeline Service Co. prorated production for portions of April and May in response to market conditions and ConocoPhillips cut its Alaska production for June by 100,000 bpd.)

The other exclusion that could make the projection optimistic is the impact of base production management activities, work which impacts rates of production.

Other factors

Other factors which could impact the production outlook include that some operators had drilled some 50% of their planned wells for fiscal year 2020 prior to rig laydown.

The division's presentation also noted that the rig laydown suggests no new rig workovers through the end of 2020, and lacking that work, and other base management work, the COVID-19 impacted production outlook could be optimistic.

While safety-related or regulatory-mandated work will not be deferred, deferrals on discretionary but rate-impacting work and potentially on planned maintenance turnarounds and some unplanned work could also impact production numbers.

While cost-cutting efficiency gains are a possibility, the division said much of that had already been done in the last three years due to price volatility.

There could also be an impact from ramp-up on base management and development activities going into 2021.

Historical perspective

Historically, production from new wells mitigates production decline, and laydown of rigs will exacerbate North Slope legacy field decline.

While it is uncertain how much higher decline will be, on average one year of drilling has mitigated first decline by some 5%.

The division said DNR's "illustrative outlook on production due to reduction in rig activities estimates" a decline of some 5.2% for FY2020 through FY2021, with that estimate including "high levels of uncertainty."

The analysis does not include any non-public information and uses public statements as of April 28 along with modeling assumptions, with the assumption that 2020 drilling will not exceed baseline development for all Slope operators over the recent past.

In the short term, the stop-work initiative by operators based on COVID-19 and low prices will be the main driver,

see **PRODUCTION IMPACTS** page 4

PIPELINES & DOWNSTREAM

RCA requires more info on pipeline deal

The Regulatory Commission of Alaska said in a June 12 order that it is requiring BP and Hilcorp to file more information on the proposed transfer of BP's Alaska midstream interests to Hilcorp subsidiary Harvest Alaska.

The commission has set a Sept. 28 date for its decision on the midstream transfers. Upstream transfers in the sale, which was announced last August, are being reviewed by the Alaska Department of Natural Resources. That portion of the deal is expected to close June 30.

The companies filed additional information requested by RCA Dec. 23.

That information, the commission said, included the purchase and sale agreement governing the acquisition of BP's Alaska assets. The commission said the parties requested, and it granted, confidential treatment of the purchase and sales agreement.

The companies have revised the financial terms, and RCA said it received a copy of the revised agreement May 4, but said while it appreciated the information, some of it "was not submitted in a manner that eases our review of issues we required into," and cited the purchase and sales agreement and the amendment as an example.

"The amendment replaces certain sections of the original purchase and sales agreement and includes over 400 pages of new exhibits. Rather than restating the purchase and sales agreement, the amendment adds 429 pages to the 395 pages of the original purchase and sales agreement. No concise narrative of the changes in the financial terms of the agreement was submitted with the revised purchase and sales agreement," RCA said.

The commission is now requesting detailed explanations of the amended purchase and sales agreement; detailed explanations of corporate guaranties; and detailed explanations of organizational information.

RCA is requesting additional detail related to the TAPS Carriers' liabilities for major expenditures and wants to be copied on continuing financial information which Harvest Alaska is required to provide to BP, and to receive copies of all previous and current versions of financial assurances agreements between Harvest and the Alaska Department of Natural Resources.

The deadline for providing the documents and responses is June 26.

—KRISTEN NELSON

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● NATURAL GAS

Pebble Mine to use 50 MMSCFD of gas

Electric: 270 megawatts to meet projected power requirements, sufficient peaking capacity, redundancy, excess power for communities

By STEVE SUTHERLIN
Petroleum News

Pebble Mine, as currently proposed, will draw 50 million standard cubic feet per day of natural gas through a 12-inch subsea and overland pipeline from the lower Kenai Peninsula to its site in southwest Alaska for power generation, Pebble spokesman Mike Heatwole told Petroleum News in a June 4 interview.

Heatwole said mine developer Pebble Partnership designed the pipeline and the powerplant to deliver more power than the proposed copper-gold-molybdenum-silver mine needs, in part to make power available to local residents.

"Both natural gas and electricity we would make available for the community should there be interest," he said. "For the power of course, that would be at cost; I don't know quite how it would be structured for the natural gas."

The communities in the region near the mine site currently rely largely on fuel oil or gasoline — which must be barged or flown in – for power generation.

"We've long said that our view is, one of the big opportunities that comes with a project such as Pebble is the infrastructure that of course comes with it, and we use the example of the hydroelectric power facilities down in Juneau where the mines put them in and eventually turned them over to the city for their electrical power," Heatwole said.

Pebble won't, however, deliver gas or electric directly to consumers.

"Of course, we don't want to be in the utility business, and local communities and other regional entities — probably the state — will have to work on how does that really come together," Heatwole said. "We work on getting the infrastructure in there and have both gas and electricity available; how it goes from there of course is largely a local decision."

270 megawatts capacity

Pebble plans a powerplant generating capacity of 270 megawatts to meet the projected power requirement while providing sufficient peaking capacity and redundancy, it said in a 2018 project description. One generating unit will be held in reserve for maintenance or emergency use. The plant will use high-efficiency combustion turbine generators operating in a combined-cycle configuration.

Gas-fired electrical generation eliminates the need to transport and store large amounts of diesel, Pebble said.

Waste heat from the power plant will be used to heat mine site buildings and to supply process heating to the water treatment plant, Pebble said. Low-pressure steam, through heat exchangers, will heat a closed loop glycol system to heat buildings, while warm water from the steam condenser discharge will be routed to the water treatment plant.

Construction of the gas line and the power facilities is expected to begin several years from now. Heatwole said the U.S. Army Corps of Engineers said it intends to publish the final environmental impact statement for the project near midsummer, followed by a record of decision 30 to 45 days later.

At that point Pebble will initiate plans for state permitting, process which could take two or three years, followed by the sanction decision on construction, he said.

Heatwole said Pebble did two days'

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PRODUCTION IMPACTS

with an estimated drop of some 13,000 bpd for FY2020 compared to the spring 2020 forecast developed in February, and a drop of some 32,000 bpd for FY2021.

For the long term, a downward adjustment of prices "is expected to affect economic viability of projects planned to come online in the medium to long term," with the analysis looking only at production impacts through year end 2021. ●

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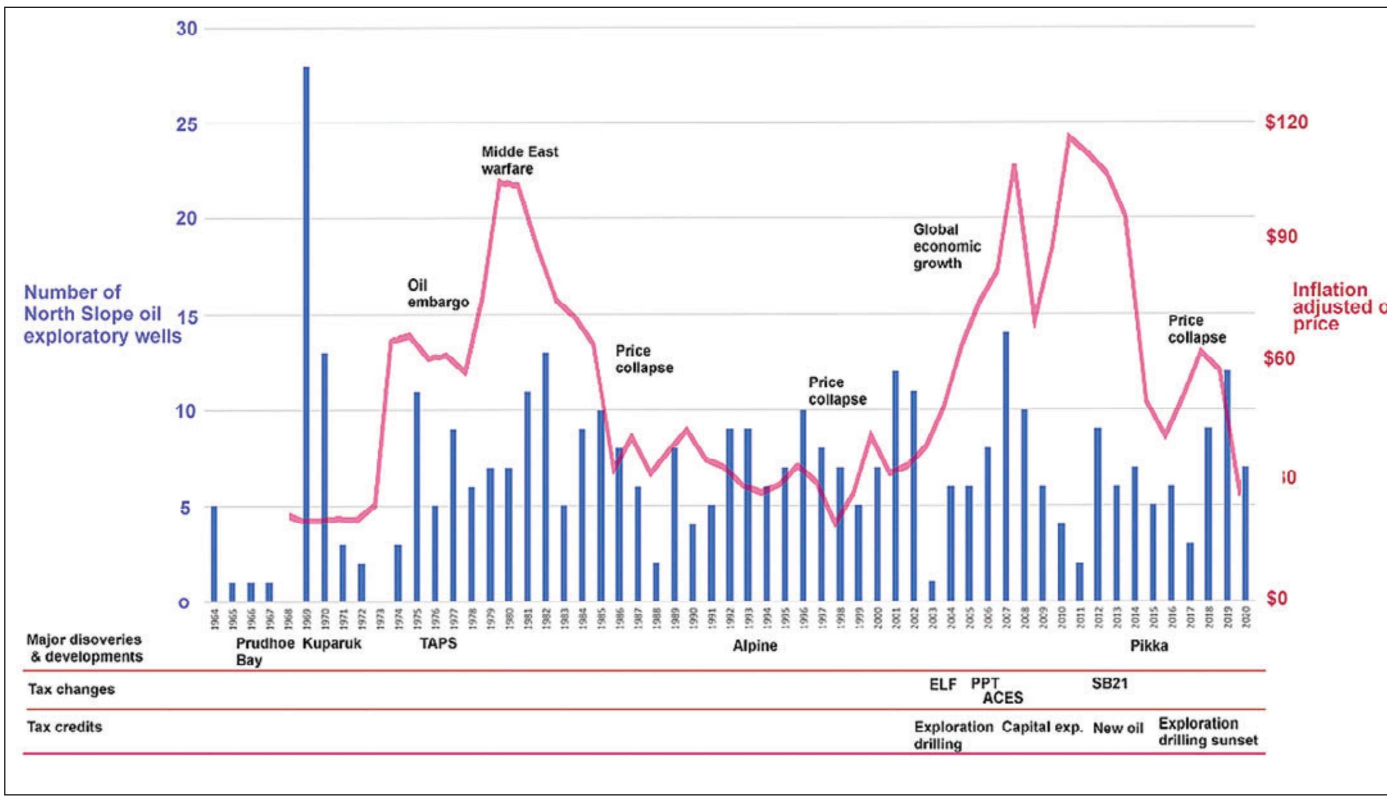
● EXPLORERS PREVIEW

What drives exploratory drilling?

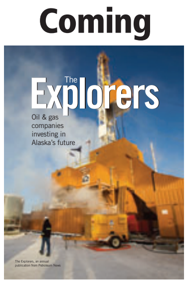
Examination of North Slope drilling history shows complex interrelationship with oil price, major discoveries and state tax changes

By ALAN BAILEY
For Petroleum News



The recent havoc in the oil market as a consequence of the COVID-19 pandemic, with the curtailed Alaska exploration drilling program last winter, has prompted interesting questions regarding the long-term impact of the oil price and oil market on exploration drilling on the North Slope. An analysis by Petroleum News of annual drilling levels, the market price of oil and other factors impacting the North Slope oil industry shows the complex interaction of a number of parameters.

Coming



August 2020

Drilling data for this analysis came from the Alaska Oil and Gas Conservation Commission — the AOGCC has complete records of all wells drilled in the state. However, the commission does not distinguish between exploration wells and oil prospect appraisal wells, with both types being categorized as "exploratory." The graphic accompanying this article shows the total number of exploratory wells drilled on the North Slope annually, since oil exploration started on the Slope in the 1960s. Excluded are gas wells and wells drilled by government agencies such as the U.S. Geological Survey. Since the AOGCC well data does not always include well spud dates, the dates used are the well completion dates — in most cases this corresponds to the year when the well drilling was initiated.

Major discoveries and oil prices

An immediate and obvious point of note is the correlation between some relatively high levels of drilling and major oil discoveries. In particular, the discovery of the giant Prudhoe Bay field in early 1968 was followed by a major peak in North Slope exploratory drilling. The Pikka oil discovery in the Nanushuk formation in 2005 also led to a flurry of exploration and appraisal drilling in subsequent years.

Layered on top of these features there appears to be some impact from oil price trends. The oil prices in the graphic come from the Energy Information Administration — they are the inflation-adjusted prices of oil imported into the United States and seem a reasonable proxy for the North Slope oil price. However, it is important to note that, while buoyant oil prices may encourage exploration activity, companies planning exploration must consider oil price expectations several years into the future.

Overall, there is zero statistical correlation between the oil price and the number of wells drilled since drilling started in the 1960s. However, across this entire timeframe, there were different periods when different factors came into play, with the oil price seeming to have different impacts at different times.

1970s market disruption

The Arab oil embargo of 1973 to 1974, followed by market disruption and an energy crisis triggered by the Iranian revolution and the Iran-Iraq war, caused oil prices to climb rapidly. This price climb and spike appear to correlate somewhat with a rise in North Slope drilling activity. The geopolitical events presumably also drove an interest in increased U.S. oil development.

The ending of the market disruption of the 1970s resulted in an oil glut and subsequent tumble in the oil price. The price peaked in 1980 and crashed by the mid-1980s. Alaska's economy saw a recession, as oil industry activity ground to a halt. And there was a corresponding sharp fall in the amount of exploratory drilling.

Statistically, the entire period from 1972 to 1988 saw quite a strong positive correlation between the annual number of wells drilled and the annual average oil price.

While the oil price remained relatively low for the next few years, it appears that the level of exploratory drilling on the North Slope recovered somewhat. Also, there were a number of appraisal wells drilled in this period, including wells associated with the major Alpine field, discovered in 1994. In the late 1990s there was a brief collapse in the price, as oil supplies exceeded demand. Although North Slope operators cut back on drilling, there appears to have been only a brief dip in exploratory drilling.

The upshot of all of this was a small negative correlation between the annual well count and the average price of oil between 1988 and 1998.

An oil price peak

Then, as the global economy grew, with the Chinese economy for example growing rapidly, oil demand started outstripping supply. The price of oil increased steadily, reaching a peak well over $100 before collapsing back in 2014 through 2016. Initially, the pace of North Slope exploratory drilling increased, much in line with the increasing oil price — between 1998 and 2007 there was a

see **EXPLORERS PREVIEW** *page 6*

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PTE PIPELINE

ments from $12.09 per barrel, a rate established by an earlier settlement, to $20.84 per barrel. PTE Pipeline also filed with the Federal Energy Regulatory Commission for an increase for interstate rates from $12.09 to $19.49 per barrel. The 2018 filing was based on a revenue requirement study based on a 2017 test year.

The proposed increases reflected what PTE Pipeline described as a substantial decrease in the pipeline's current and projected throughput compared to assumptions on which the 2016 settlement rate was based.

Field capacity 10,000 bpd

The Point Thomson field production facilities have a capacity design of 10,000 bpd, but equipment issues have typically kept production — and hence throughput on the line — well below that.

ExxonMobil Production, the Point Thomson field operator, has had compressor issues at the high-pressure field, which came online in April 2016, but told the state recently it was addressing issues with its gas injection equipment, had begun installing upgraded components and expected to receive and install remaining equipment during the 2020-21 plan of development period.

As noted in the April 19 issue of Petroleum News, two compressor trains are now reported to be operating at the field, with an increase in condensate production expected from approximately 5,000 bpd to 10,000 bpd, the rated facility capacity at the field, with each of the two trains capable of 5,000-6,000 bpd.

In April, the most recent month for which production data for Point Thomson is available from the Alaska Oil and Gas Conservation Commission, the field averaged 9,278 bpd, up from a March average of 7,601 bpd. The February average was 5,774 bpd, up from a January average of 5,292 bpd.

Average production from Point Thomson for the 12 months of 2019 was 5,968 bpd. Production for the first four months of 2020 averaged 6,986 bpd.

—KRISTEN NELSON

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PEBBLE POWER

worth of drilling work in April to study soil conditions near its gas compressor site along the Sterling Highway north of Anchor Point on the Kenai Peninsula. The work will inform the route of the pipeline which will be bored under the bluff and beach, rising to the seafloor and extending 75 miles across Cook Inlet to Ursus Cove on the west side.

Heatwole said he was not aware of talks with specific producers about buying gas for the project.

"Obviously there's a lot of talk about, 'could projects such as Pebble and Donlin facilitate more interest in what else is in the Cook Inlet basin in terms of gas beyond just what the Southcentral consumers are using?'" he said, adding, "but we haven't had those formal conversations." ●

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EXPLORERS PREVIEW

modest positive correlation between the well count and the oil price. However, the drilling activity subsequently disconnected from the oil price trend, presumably at least in part because of major changes in the laws governing Alaska oil production taxes.

Production tax changes

The oil production tax arrangements in Alaska remained unchanged from the early days of the North Slope industry until early 2005, when then Gov. Frank Murkowski increased the taxes by changing the rules for the "economic limit factor," or ELF. This change impacted legacy oil fields in the Prudhoe Bay unit and appears to have had little effect on the amount of exploratory drilling.

In 2006 the state Legislature passed then Gov. Sarah Palin's production profits tax, or PPT, a major rewrite of the tax law, changing the basis of tax assessments from taxing the wellhead value of oil to taxing the profits on oil production. This was later modified into Alaska's Clear and Equitable Share, or ACES, a tax passed in 2007 that retained the profits based arrangements of PPT while increasing the base tax rate and the tax progressivity at high oil prices.

The oil industry slammed the new tax laws, arguing that a resulting huge tax increase would have a significant negative impact on North Slope investment.

It is perhaps not coincidence that from 2008 to 2011 there was a continuous decline it the number of North Slope exploratory wells drilled, during a period of relatively robust oil prices.

In 2013 the Legislature passed Gov. Sean Parnell's Senate Bill 21, or SB 21, another major rewrite of the production tax statutes. SB 21 eliminated the progressivity of ACES while combining a flat tax rate with credits to encourage increased production. The industry has been supportive of SB 21.

There was a spike in North Slope drilling in 2012, the year prior to the passage of SB 21 — a peak in oil prices in 2011 and 2012 may have supported exploration enthusiasm.

Pikka discovery

Over the next four years exploratory drilling continued at a level of around five wells per year. A number of these wells were drilled in response to the Pikka discovery.

In 2014 the oil price started collapsing, sinking to an average of around $40 per barrel in 2016, as excess production flooded the market with oil. The oil market subsequently came into balance at prices around $60 to $70 per barrel. Until, that is, the COVID-19 pandemic arrived and, with it, the recent oil price disruption.

In 2014 the oil price started collapsing, sinking to an average of around $40 per barrel in 2016, as excess production flooded the market with oil. The oil market subsequently came into balance at prices around $60 to $70 per barrel. Until, that is, the COVID-19 pandemic arrived and, with it, the recent oil price disruption.

The winters of 2018 and 2019 saw particularly robust exploration drilling activity, with much focus on discoveries and prospects in the Nanushuk, in a business environment involving reasonable and seemingly stable oil prices.

However, across the entire period from 2007 to 2019 there was approximately zero statistical correlation between the number of wells drilled and the oil price — it appears that other factors such as new discoveries and the production tax situation were at play.

State tax credits

Another factor impacting exploratory drilling in Alaska has been the availability of state tax credits. Tax credits have proven a key parameter in the encouragement of new drilling in the Cook Inlet basin and in Alaska's Interior basins. Credits have also encouraged exploratory drilling on the North Slope.

The first tax credit, a credit for exploration drilling, was introduced by Gov. Murkowski in 2003. That may have impacted the rise in exploratory drilling between then and 2007. The PPT legislation included a capital expenditure credit that could benefit exploration drilling, although this credit was discontinued on the North Slope by the SB 21 legislation. SB 21 replaced the capital expenditure credit with a new oil credit, to encourage the development of new oil.

Companies involved in the exploration that led to the Pikka discovery have indicated that tax credits significantly motivated their drilling projects. That drilling led to further exploration in the Nanushuk play discovered at Pikka. It is also likely that the credits introduced in 2003 encouraged Caelus Alaska's drilling in Smith Bay in 2016 — those credits sunsetted shortly after that drilling was completed.

On the other hand, Gov. Bill Walker's veto in 2015, deferring some tax credit payments, also had a negative impact on the amount of new drilling done, in part by undermining confidence in investments in Alaska exploration. ●

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● FINANCE & ECONOMY

Conoco battles global warming

By KAY CASHMAN
Petroleum News

Shareholders are attracted to companies that offer consistent financial returns as well as a progressive position on climate change; specifically, global warming caused by human activities. ConocoPhillips' business strategy, initiated in late 2016, advanced its vision to be the E&P company of choice for investors and other stakeholders, leading to its being named to the Dow Jones Sustainability Index North America for the 13th consecutive year. That DJSI stock index captures the top 20% of the largest 600 stocks in the S&P Global Broad Market Index based on their environmental, sustainability and governance, or ESG, practices.


RYAN LANCE

In an interview in early June with IHS Markit's Daniel Yergin, ConocoPhillips Chairman and CEO Ryan Lance addressed ConocoPhillips' position on both returns to shareholders and global warming. Lance said ConocoPhillips alone has taken 7 million tons of equivalent CO2 out of its business over the last five to six years.

"We're about trying to reduce … emissions. We don't need regulations to do it because companies are voluntarily doing it today. We're trying to reduce the fugitive emissions. We're trying to reduce flaring and get that down and the CO2 footprint has come down in the United States, despite the fact that we've seen this dramatic growth in oil and gas production over time," Lance said.

"Companies are trying to do the right thing and trying to manage through this transition and improve the sustainability of the product we have. We are going after our Scope 1 and Scope 2 emissions," Lance said.

"The ESG, the transition discussion, is not going away," he said. "The world needs to transition to lower carbon fuels over time. But even then, there's space for oil and gas because it's so important for cheap reliable energy in all four corners of the world."

Scope 1 greenhouse gas emissions are direct emissions from owned or controlled sources, such as oilfield production facilities. Scope 2 GHG emissions are indirect, resulting from the generation of electricity, heat or steam owned or purchased by the company. Scope 3 includes all other indirect emissions occurring in a company's value chain.

Optimistic about future of oil and gas

Mike Sommers, CEO of the American Petroleum Institute, is also bullish on the future of oil.

In a recent virtual talk with Politico Playbook, Sommers expressed amazement that the world still consumes so much oil, despite being 30% off normal in May.

"The world was still demanding 70 million barrels of oil even during the worst economic crisis the world has ever seen," he said. "The world is going to continue to demand these products … post-pandemic."

And while Alaskans view ConocoPhillips' North Slope 750 million barrel Willow discovery as large, the world was using about that much oil in just over a week pre-pandemic.

For the world to stop using oil would require a massive and costly economic shift, which is one reason why solving global warming is so challenging, especially for third world economies in the early and middle stages of growth.

ConocoPhillips' Chief Economist Helen Currie is one of the people looking to help her company tackle global warming.

In a 2018 interview Currie said ConocoPhillips' position is that the world's need to drive down emissions doesn't mean oil demand will decline.

"We see oil demand continuing to grow for decades into the future — and in our view, it can continue to grow inclusive of climate change policies."

Political polarization latest challenge

"It seems to be a conversation about all or nothing, and there's no reasonable conversations going down the middle that say we can have these kinds of jobs, this incredible industry that's creating the security for our country (and that) we can do that sustainably with the climate in mind, with the planet in mind," Lance told Yergin regarding the challenges of political polarization vis-à-vis sustainability efforts. "There are middle grounds here."

ConocoPhillips is a founding member of the Climate Leadership Council and supports a tax on carbon to address Scope 3 emissions, Lance said. CLC is an international policy institute founded in collaboration with business and environmental interests to develop a carbon dividend plan. ●

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CAPITAL SPENDING

sector, noting that "with low gas prices, abundant supply and transitions towards cleaner burning fuels, demand for natural gas is expected to grow at all levels, provincial, national and global."

"Consumption in the oil sands, petrochemical energy diversification programs, the phase out of coal-fired electricity and Canadian liquefied natural gas export projects all have the potential to increase demand for Alberta's natural gas," the AER said.

AER suggests benchmark gas prices at Henry Hub could build to US$3.48 per million British thermal units and reach as high as US$4.63 in 2029, although that rate of increase depends on supply glut reductions in the United States, exports to Mexico, overseas LNG sales and a decline in byproduct gas flows from oil wells.

Alberta capex way down

For Alberta — the powerhouse of Canadian production — the AER said capital spending will slide into the range of C$14.6 billion-C$16.4 billion this year from C$18.9 billion in 2019, or 70% of CAPP's revised national outlay.

Alberta's crude oil output rose by 1% 2019 to 3.6 million bpd, stemming mainly from growth in upgraded and non-upgraded oil sands bitumen, AER reported.

The agency said further growth in oil sands production is expected to lift volumes to 4.4 million bpd by 2029.

The AER report noted that Alberta has produced a cumulative total of 14.4 billion barrels of oil, leaving 164 billion barrels of potential oil reserves to be recovered over time.

AER said the provincial industry "is expected to face significant headwinds in 2020 largely due to the effects" of COVID-19.

The regulator said that with pipeline expansions still bogged down in regulatory delays while oil markets remain unpredictable, it is not willing to predict when or if oil sands extraction will regain its key role as a driving force of the Alberta economy.

CAPP cites uncertainty

Ben Brunnen, CAPP's vice president of oil sands and fiscal policy, said it is "helpful that we are starting to see some global energy demand numbers indicating that the worst is behind us."

"The uncertainty about the future of COVID and whether subsequent waves will hit the economic recovery is what's holding back investor confidence. From an oil and gas perspective, it continues to be a struggle," he said.

Brunnen said Canadian producers have halted about 800,000 bpd of oil volumes because of weak prices, a number that could rise to 1.2 million bpd if rescheduled upgrader maintenance shutdowns (to convert raw oil sands bitumen into refinery-ready synthetic crude) are taken into account.

For many, especially hundreds of smaller service companies, the bleak outlook extends too far into the future for them to survive.

Their overheads represent a crushing burden that is likely to result in thousands more layoffs, especially in rural communities. ●

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ONLINE SALE

Peninsula, for a total of $178,779 for 7,146 acres.

In a press release after the sale results were posted, Division Director Tom Stokes said while the current low global prices and oversupply of oil were likely factors in reducing market interest in the sale, he was pleased that the sale demonstrated the value of the division's new online auction capabilities.

"We have been working hard to update the way the division does business, including providing scientific data, making lease offerings available globally, and conducting auctions online," Stokes said. "Today's experience, including sale results, validates our investment in this new way of doing business. It bodes well for our ability to conduct larger, more complex sales in the future that operate more efficiently at lower state cost."

Regulations changed

Since state lease sales began in the 1960s paper bid submissions have been required along with public bid openings. Last year the state changed oil and gas bidding regulations, allowing for online bidding.

The division contracted with EnergyNet Services LLC to use the company's Internet platform for the spring sales.

In announcing the changes last December, DNR Commissioner Corri Feige said the new regulations "will empower the Division of Oil and Gas to apply modern digital and technical solutions to provide efficient leasing services to the oil and gas industry." Feige said the relationship with EnergyNet promises to be a relationship which will enhance the state's ability to make its hydrocarbon resources available to broader markets.

This year's results are similar to recent sales in these areas: There have been no recent bids on Alaska Peninsula tracts and Cook Inlet has typically garnered a handful of bids.

Hilcorp holds the largest acreage position in the Cook Inlet basin, where it produces both oil and natural gas, and has been the only bidder in recent Cook Inlet sales, taking three tracts in the 2019 sale, eight tracts in the 2018 sale and six tracts in the 2017 sale.

—KRISTEN NELSON

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IEA FORECAST

the year was slightly less than expected, although still unprecedented. On the supply side, record output cuts from OPEC+ and steep declines from other non-OPEC producers saw global oil production fall by a massive 12 mb/d in May."

IEA said that in addition to a "9.4 mb/d decline in OPEC+ supply last month, output from non-OPEC countries outside the deal has fallen by 4.5 mb/d since the start of the year. To further speed up the market rebalancing, OPEC+ decided on June 6 to extend their historic output cut of close to 10 mb/d through July."

Increased mobility indicators for demand in the March-May period provided support: "in particular, China's strong exit from lockdown measures has seen demand in April almost back to year-ago levels," IEA said. "We have also seen a strong rebound in India in May, although demand is still well below year-ago levels."

In the second half of the year the "easing of lockdown measures in many countries should provide a boost. Even so, demand in 2020 is expected to be 8.1 mb/d lower than in 2019, with the biggest declines seen in the first half of the year," IEA predicted.

2021 demand still below norm

The agency's forecast for 2021 shows demand growing by 5.7 mb/d, which, at 97.4 mb/d, will be 2.4 mb/d below the 2019 level, IEA said.

This 2.4 mb/d gap between 2021 and 2019 is "largely explained by the dire situation of the aviation sector," IEA noted in its report.

"Data from the International Air Transport Association show that passenger traffic in 2020 will be nearly 55% lower than in 2019. The industry will continue to be a drag on oil demand through 2021, with our first estimate showing that, having fallen by 3 mb/d in 2020, jet/kerosene demand will rebound by only 1 mb/d in 2021, leaving it below the pre-crisis level," IEA predicted.

Global oil supply is set to tumble by a massive 7.2 mb/d on average in 2020, and stage only a 1.8 mb/d increase in 2021 assuming 100% compliance with OPEC+ cuts, IEA said. The recent improvement in oil prices that saw West Texas Intermediate oil, almost always below Brent and ANS crude, trading for a few days close to $40 a barrel is not enough to allow a significant increase in U.S. output, which in June is estimated to have fallen to 10.5 mb/d, down by 2.4 mb/d from a record high seen in November, IEA said.

In the meantime, high crude and product stocks will limit the scope for producers in many countries to sell more to refiners, the agency predicted. In the case of the U.S., it said, data from the Energy Information Administration show that commercial stocks of crude oil and products have increased by about 1 mb/d since the start of the year and are at an all-time high.

"In sporting terms, the 2020 oil market is now close to the half time mark. So far, initiatives in the form of the OPEC+ agreement and the meeting of G20 energy

see **IEA FORECAST** *page 11*

Petroleum news

Oil Patch Bits

Air Liquide signs contract with customer in South Korea

COURTESY PHOTO

Air Liquide Engineering & Construction said June 10, that it has signed a new contract with POSCO, a leading steel producer in South Korea, to design and build an air separation unit which will produce oxygen, nitrogen, and argon and have a production capacity of 1,700 tonnes per day of oxygen.

The new unit will be installed at POSCO's Pohang site in South Korea. The oxygen and argon produced will be used to transform iron into high quality steel and enable POSCO to improve efficiency of the production process.

This new air separation unit, replacing two existing units on the Pohang site, will be designed and built using Air Liquide's best-in-class cryogenics technologies, thereby maximizing energy efficiency and reducing environmental footprint.

POSCO, as the largest integrated producer in South Korea, delivers 41 million tons of crude steel per year. Founded in 1968 and privatized in 2000, POSCO has led the Korean steel industry for more than four decades.

Air Liquide has been working with POSCO for more than 30 years and has supplied 20 air separation units to POSCO's Pohang and Gwangyang sites.

LTI, Inc. Idaho drivers deliver groceries for WinCo

COURTESY PHOTO

As reported by Lynden News June 11, LTI Inc. drivers in Caldwell and Jerome, Idaho, answered the call this spring when the supermarket chain WinCo Foods was hit with an unprecedented demand for groceries due to the shelter-in-place orders. WinCo's daily freight volumes grew from 2.4 million to 7 million pounds of grocery products. "We agreed to help and quickly sent out trucks and drivers to the Boise, Idaho, distribution center," said LTI Inc. Operations Manager Gordy Sant. "Within the same day Caldwell drivers were hauling 400,000 pounds of groceries to several WinCo locations."

In all, LTI Inc. drivers hauled 3.4 million pounds of freight to various Idaho communities during the rush period. Jerome drivers also hauled loads to Salt Lake City, western Oregon or wherever products were needed. "Everyone at LTI Inc. pulled together to cover shifts for these drivers so we could assist in this emergency situation," Gordy said. "We continue to haul groceries for WinCo as needed. This is a great example of how Lynden and its people can quickly diversify and an opportunity to show our strength in an area outside of the milk industry."

Companies involved in Alaska's oil and gas industry

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

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STATISTICAL REVIEW

that year was weather related.

But China was an exception in 2019, the review said: its energy consumption accelerated in 2019, and as a result that country was the largest contributor to growth in all energy sectors except natural gas, where the U.S. narrowly exceeded China's growth.

COVID-19

The company highlighted the context in which the review is released.

"The COVID-19 pandemic may well turn out to be the most tragic and disruptive event that many of us will ever live through," Bernard Looney, the company's chief executive officer, said in the introduction. He acknowledged the deaths which have occurred and said: "The combined health and economic shock is bound to reshape the global economic, political and social environment in which we all live and work."

The pandemic may "accelerate emerging trends and create opportunities to shift the world onto a more sustainable path. But it also risks slowing progress if the short-term, domestic issues raised by COVID-19 are prioritized over long-term, global challenges, such as climate change."

Spencer Dale, bp chief economist, noted severe disruption in global energy markets in 2020 due to the pandemic, and said "bp's Statistical Review highlights the key energy trends emerging before Covid-19 and I hope will be a valuable source of information as the world emerges from the pandemic and transitions towards net zero."

BP has set a company goal of net zero in emissions by 2050.

2019 data

Statistical data gathered and analyzed in the report are for 2019.

The review cites a slow growth in carbon emissions in 2019 after a sharp increase in 2018 and credits a deceleration in primary energy consumption and an increased use of renewables and natural gas over coal. Carbon emissions from energy grew by 0.5%, less than half the 10-year average growth of 1.1%.

A 1.3% growth in primary energy consumption was driven by renewables and natural gas, the review says, with the two combined accounting for three quarters of the expansion. Apart from nuclear, all fuels grew at a slower rate than their 10 year averages.

While U.S. crude oil production grew by 1.7 million bpd, that growth was more than offset by a decline of 2 million bpd in OPEC production, led by declines in Iran, Venezuela and Saudi Arabia.

China accounted for more than three quarters of net global growth in primary energy consumption, followed by India and Indonesia.

The United States and Germany posted the largest declines.

Oil

Oil consumption grew by an average of 900,000 barrels per day, about 0.9%, led by China, with an increase of 680,000 bpd on average, and other emerging economies. Demand in Organization for Economic Cooperation and Development countries fell by 290,000 bpd.

While U.S. crude oil production grew by 1.7 million bpd, that growth was more than offset by a decline of 2 million bpd in OPEC production, led by declines in Iran, Venezuela and Saudi Arabia.

Crude oil production growth in the U.S. was the largest increase of any country for the third consecutive year, followed by significant increases in Brazil and Canada.

On the decline side, the 2 million bpd decline in OPEC production was its steepest decline in 2009, much of it driven by sanctions and economic difficulties in Iran and Venezuela, combined with the renewed OPEC+ production agreement, which resulted in a reduction of 430,000 bpd from Saudi Arabia.

By oil type, declines were concentrated in crude oil and condensate, down a combined 580,000 bpd, while natural gas liquids grew by 4.5%, up 520,000 bpd, following a trend, with NGL growth primarily in the U.S., 440,000 bpd, where NGL production doubled from 2012 to 2019 to 4.8 million bpd.

Natural gas

Natural gas consumption was up 2%, well below the 5.3% growth in 2018, but still enough to account for a 24.2% share, a record, of primary energy.

U.S. and Chinese natural gas consumption growth was slower than in 2018, "as the boost from weather effects and policy driven coal-to-gas switching in China faded."

Russia's drop in gas consumption, down 10 billion cubic meters, the largest of any country last year, was also partly attributable to fewer unusually hot and cold days.

Production of natural gas was up 3.4%, with almost two thirds of the increase from the United States. Australia and China were also key contributors.

The U.S. and Russia led liquefied natural gas supply growth, with most of the increased supplies going to Europe.

The review says the 2019 increase in natural gas production outpaced consumption growth, with storage levels rising in most regions and prices falling sharply as a result.

Coal

Consumption of coal was down by 0.6%, with its share of primary energy, 27%, at the lowest level in 16 years. Emerging economies, led by China and Indonesia, drove coal consumption, but that growth was offset by a sharp fall in OECD demand, the lowest level since the review began collecting that data in 1965.

Coal production rose 1.5%, with the only significant increases from China and Indonesia. The U.S. and Germany had the largest declines.

Renewables

There was a record increase in renewable energy, including biofuels, 3.2 EJ (exajoule, a quintillion joules). This was, the review says, "the largest increment for any source of energy in 2019."

Wind provided the largest contribution to that growth, 1.4 EJ, followed by solar at 1.2 EJ. The largest renewable contributor was China, up 0.8 EJ, followed by the U.S., 0.3 EJ, and Japan, 0.2EJ.

Hydroelectric consumption was up by 0.8%, led by China, Turkey and India, and nuclear consumption was up by 3.2%, led by China and Japan.

—KRISTEN NELSON

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FURIE SALE

debtors.

The debtors expect the effective date of the plan to occur on June 30, at which point the plan will have been substantially consummated, the June 15 motion said.

Third amended joint plan of reorganization confirmed

The motion to close the Furie and Corsair cases is made practicable by a signed order that arose from a June 11 hearing in the Wilmington court.

U.S. Bankruptcy Judge Laurie Selber Silverstein signed a confirmation order June 12, of Furie's third amended joint plan of reorganization, which sets forth the details of the sale of the debtors' assets in the Cook Inlet Kitchen Lights unit to Anchorage based Hex LLC, a company formed in November which is 100% owned by member manager John L. Hendrix.

Under the plan, Furie's secured term lenders will foreclose on Furie and related debtor companies, and subsequently sell the equity to Hex's designee, HEX Cook Inlet LLC for $5 million and other consideration.

The confirmation order authorizes the debtors to enter into and implement the "RWIO consent letter," which reflects a settlement with working interest owners — Giza Holdings LLC; Taylor Minerals LLC; Allen Lawrence Berry; the 2007 Allen Lawrence Berry Trust; and Danny Davis. The letter was filed as part of the amended plan April 19, as Exhibit C to the term sheet. The settlement will reduce the RWIO group's working interest from 20% to 10%, once the equity sale is complete, while preserving the group's overriding royalties.

Under the plan, Furie's secured term lenders will foreclose on Furie and related debtor companies, and subsequently sell the equity to Hex's designee, HEX Cook Inlet LLC for $5 million and other consideration.

The order also protects other royalty owners, stating that nothing in the plan or its documents "shall impact any rights, property, interests, claims or defenses that may exist under applicable nonbankruptcy law solely with respect to any valid overriding royalty interests in the oil and gas leases operated by the debtors."

The order addresses objections to the second amended plan of reorganization, filed June 6 by the United States on behalf of the U.S. Bureau of Customs and Border Protection, over $7.2 million owed on a prepetition Jones Act fine settlement between Furie and Customs.

"Notwithstanding any provision of the plan, this confirmation order, or any implementing or supplementing plan documents, the United States' setoff rights under federal law as recognized in Bankruptcy Code section 553, and recoupment rights, shall be preserved and are unaffected," the order said.

Other consideration: Tax credits, AIDEA financing keys to transaction

In addition to $5 million in cash from Hex — the acquirer, a $15 million debtor in possession, or DIP, refinancing loan will be issued, secured by a second priority lien behind ING Capital LLC on the State of Alaska tax credit priority collateral, also secured by a second priority lien on all of the assets or property of the reorganized debtors behind a first lien to Alaska Industrial Development and Export Authority debt, not to exceed $7.5 million in principal amount plus an additional $5 million in advances.

The first source of repayment for the DIP loan is State of Alaska tax credits already earned but unpaid to date.

Prepetition term loan lenders will receive shares of a $21 million new term loan issued by the reorganized Cornucopia Oil and Gas, secured by a third priority lien on the tax credit priority collateral.

Proceeds from the state tax credits are to be applied first to repay a new $60 million tax credit loan to ING until repaid in full; second, to repay the $15 million DIP replacement loan until repaid in full; third, to repay the $21 million new term loans, split 75% to the holders of the new term loans and 25% to the acquirer for every dollar; and fourth, the remainder, if any, to the acquirer. ●

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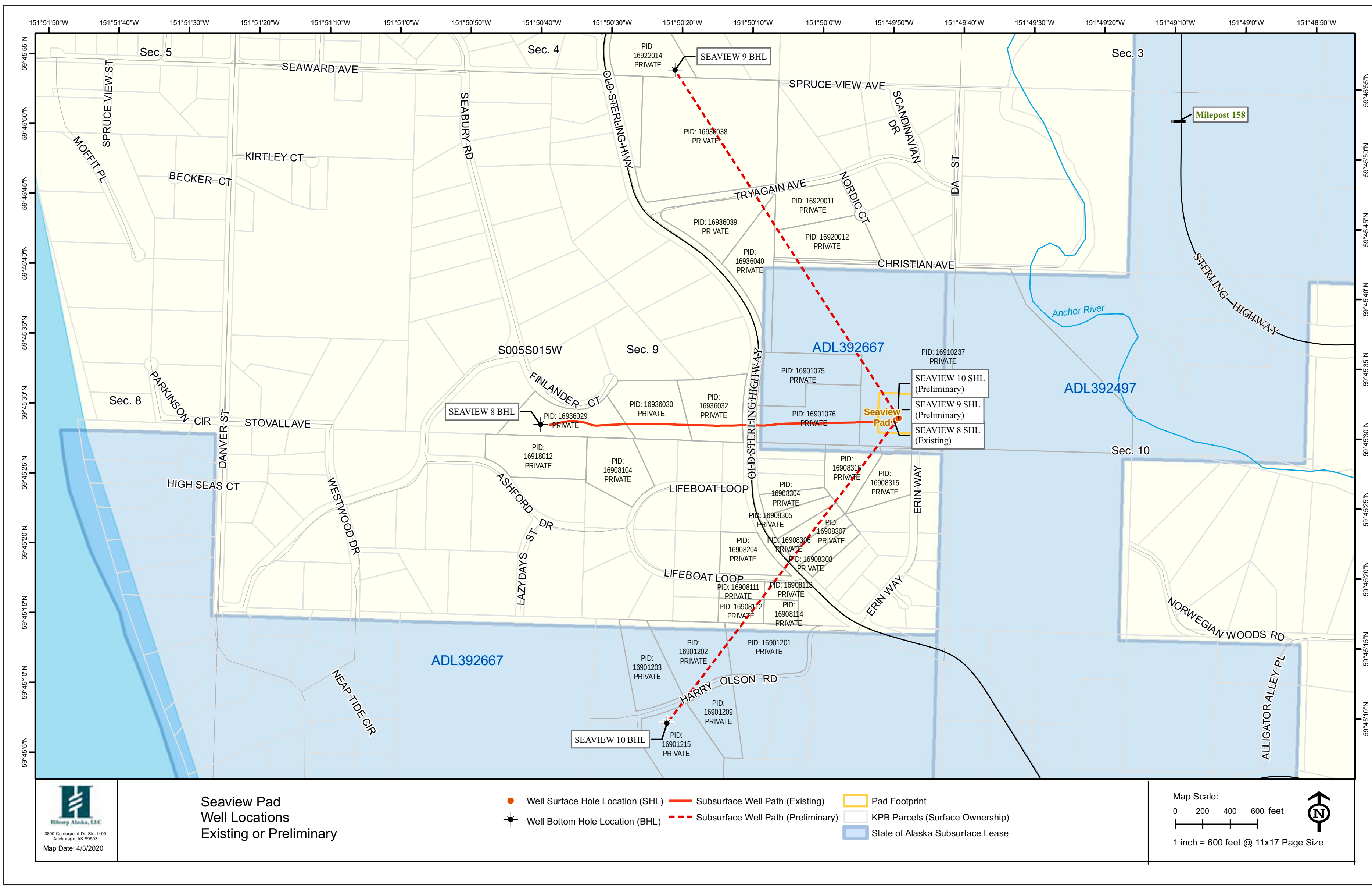

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SEAVIEW PAD

Seaview 10 wells will be drilled.

Hilcorp plans to install gas production facility infrastructure and modules and undertake Seaview 8 well completion beginning Aug. 1. The company plans to spud the Seaview 9 well Nov. 1, and to spud the Seaview 10 well Jan. 15.

The Seaview project includes metering facilities and pipeline infrastructure beyond the production facility, which will be authorized separately from the plan, the division said. It includes the installation of a 10-inch gas pipeline to transport produced natural gas from the Seaview pad to existing Enstar Natural Gas Co. pipeline infrastructure.

If authorization for the private non-exclusive easement is received, the Seaview project will also be entering the transportation phase upon completion of the natural gas pipeline, the division said. In considering the development and production phase, the division evaluated both the specific activities proposed under the plan as well as typical additional exploration, development, production and transportation activities that Hilcorp might propose for further development in the lease area.

Hilcorp will construct permanent gas production facility infrastructure on the Seaview pad including three heater separator unit skids, two compressor skids, two dehydration units, a vent stack with scrubber, control room, microturbine building, two 200-barrel double-walled produced water tanks and a meter building.

Electrical and instrumentation lines will be installed between each well and the control room.

Gas and produced fluids from wells will be conveyed via subgrade facility to an HSU skid located on the pad. Gas will be routed to a compressor module and a glycol dehydration module.

Produced fluid will be routed to two 200-barrel steel double-walled produced water tanks, pending transportation to an approved disposal well. The production modules have built-in secondary containment to capture liquids associated with processing gas, and to protect against an inadvertent release of production fluids.

Gas fever in Anchor Point

While Hilcorp employs a host of modern high tech and traditional exploration techniques, its study of drainage anomalies on the Kenai Peninsula led the way to the Anchor Point area.

The Swanson River field discovery by Richfield in the late 1950s is credited with sparking the modern oil industry in Alaska, which in turn built the case for statehood.

Soldotna Creek wraps around the main producing part of the Swanson River field, Hilcorp Senior Geologist Dave Buthman said in a presentation to the Alaska Geological Society March 17.

"It's hard to avoid seeing the importance of drainage anomalies when you see this," Buthman said. "A full half of the production of Swanson River has come from this circular drainage anomaly."

Happy Valley has a nosing drainage anomaly where Deep Creek flows that reveals a surface expression of the structure, he said.

"The discovery we just made at Seaview, you see the same sort of thing with the Anchor River," he said. "We don't have outcrops there, but we still see the same nosing."

Over the last few years, Hilcorp has been doing a brisk business to secure mineral rights around the Anchor River from the state as well as private mineral holders and public entities.

The company made news in late 2018 when it leased borough land mineral rights in Anchor Point, including the 1.7-acre site of the Anchor Point Volunteer Fire Dept. and Rescue. ●

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IEA FORECAST

ministers have made a major contribution to restoring stability to the market. If recent trends in production are maintained and demand does recover, the market will be on a more stable footing by the end of the second half" of 2020.

"However, we should not underestimate the enormous uncertainties," IEA cautioned.

Deutsche Bank chimes in

To keep us from getting too optimistic, a new report from Deutsche Bank analysts says there is at least a 33% chance that at least one of four disasters will occur in the next decade: an influenza pandemic killing more than 2 million people; a globally catastrophic volcanic eruption; a major solar flare; or a global war, with war being the most likely. If the timeframe is two decades, then there is a 56% chance of one of these disasters occurring, the analysts say. (Earthquakes were omitted because they are local events.)

—KAY CASHMAN

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