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page 2 This month in history: ConocoPhillips dominates 2004 winter exploration

ANS production down 0.6% from fall in Spring Revenue forecast

ADAM CRUM

The Alaska North Slope oil price forecast in the Spring 2024 Revenue Forecast, released March 13, is up $1.69 per barrel for the current 2024 fiscal year from the fall forecast and up $2 per barrel for fiscal year 2025, Commissioner of Revenue Adam Crum said in introducing the forecast, while the ANS production forecast is down by 2,800 barrels per day for FY24 and up 13,100 bpd for FY25.

Crum said as a result of the revised outlooks for oil price and production, the forecast for unrestricted general fund revenue — before transfer from the Permanent Fund Earning Reserve — is up $58 million for FY24 and up $140 million for FY25.

The price difference, $73.49 per barrel in the spring forecast compared to $71.64 in the fall forecast, is an increase of

see **SPRING FORECAST** *page 8*

Keithley: Importing LNG would stimulate inlet gas production

Why isn't more Cook Inlet natural gas being found and produced?

Because the economics don't support it at present prices, Brad Keithley told the House Resources Committee March 15.

He said if the market is allowed to set the price, more natural gas will be brought to market while current prices only support production from existing fields, not the investment required to find and bring new volumes online.

Bringing in liquefied natural gas would increase the price enough to make more Cook Inlet gas exploration and development economic.

Committee Chair Tom McKay has expressed the concern that importing liquefied natural gas would drive out the oil and gas industry in Cook Inlet, but Keithley said LNG imports wouldn't drive out Cook Inlet natural gas but would reset the price, providing producers the economics they need to go after more natural gas. And if limited LNG is targeted for import, those imports would be scalable, he said, so if a large discovery was made in the inlet, LNG supplies could be scaled back or eliminated.

see **GAS ECONOMICS** *page 8*

Grassroots wells OK'd at 2 inlet gas fields, Beluga, Cannery Loop

The Alaska Department of Natural Resources' Division of Oil and Gas has approved applications from Hilcorp Alaska for grassroots wells at two Cook Inlet gas fields, Beluga River and Cannery Loop. Beluga River, among the inlet's largest gas fields, is on the west side and Cannery Loop, one of the smaller, is on the Kenai Peninsula.

At Beluga River, which Hilcorp operates on behalf of itself and majority working interest owner Chugach Electric Association, the division approved two wells and associated infrastructure March 18 in an amendment to the lease plan of operations for the unit. Both wells will be at J Pad.

The division said the wells will tie into existing J Pad gas production infrastructure. Work will include four flowlines, three instrumentation and electrical lines, a produced water line, six separator packages and three headers, with an existing line heater building to be removed and associated piping and electrical lines to be abandoned below grade.

The division said there will be trenching on the pad for

see **GAS FIELDS** *page 6*

EXPLORATION & PRODUCTION

Narwhal appeals

Court action against DNR says Shell holding unit 2 years past default

By KAY CASHMAN
Petroleum News

JOHN BOYLE

On March 4, independent Narwhal LLC filed an appeal in Alaska Superior Court against the state of Alaska, Department of Natural Resources, alleging DNR Commissioner John Boyle "acted in violation of Alaska law by failing to find Shell Offshore Inc. in default of the current Plan of Exploration for the West Harrison Bay unit" and further failed to "demand cure where Shell has been in default of the unit's POE since Dec. 31, 2022."

Basically, Narwhal claims Shell has strung DNR along with promises to explore West Harrison Bay since getting approval to form the unit in 2020.

Operator and 100% working interest owner of the nearshore West Harrison Bay unit, Shell says it has been "diligently" looking for a partner, or partners, to buy into the unit to share the exploration cost and risk — and to take over the role of operator.

In 2022 the company told the division that it "had made solid progress toward that objective prior to the Covid-19 pandemic and the resulting collapse in oil prices."

see **NARWHAL APPEALS** *page 5*

FINANCE & ECONOMY

ANS hits upper $80s

Up week for crude despite hawkish Fed as China economy shows resilience

By STEVE SUTHERLIN
Petroleum News

Alaska North Slope crude took a dive into uncertain waters March 20 shedding $1.03 to close at $85.55 per barrel, as an ambiguous Fed became coy over its plans for benchmark interest rates as American consumers remained resilient in the face of higher prices.

ANS held its toehold in the upper $80s despite the bloodbath.

WTI was hit harder March 20 than ANS, but WTI maintained a foothold in the $80s, plunging $1.79 to close at $81.68. Brent slid $1.43 to close at $85.95.

U.S. Federal Reserve Chairman Jerome Powell's press conference March 20 kept the Fed policy rate steady in a range of 5.25%-5.5% and made no major changes to its policy statement. The committee also maintained its forecast for three rate cuts this year.

A surge in Chinese demand may send ripples through Pacific markets, including West Coast markets where most ANS crude trades.

Powell's press conference, statement and economic forecasts all point to three rate cuts starting in June, said Krishna Guha, vice chairman of

see **OIL PRICES** *page 7*

ALTERNATIVE ENERGY

Railbelt renewables?

NREL report indicates increased wind, solar power could be cost effective

By ALAN BAILEY
For Petroleum News

The National Renewable Energy Laboratory has published a report evaluating potential costs associated with the expanded use of renewable energy for power generation in the Alaska Railbelt. The report indicates that a significant increase in the use of renewable energy, in particular wind power, could prove substantially cheaper than continuing the current high dependence on natural gas fueled power generation.

NREL's study considered three scenarios: no additional renewable energy capacity; a least cost mix of energy resources, including renewables; and a resource mix driven by a renewable portfolio standard, with a requirement for 80% of power generation from renewables by 2040. The Alaska Legislature has been considering bills that would impose an RPS with that 80% renewables target.

The study assumed that a planned second electricity transmission line between the Kenai Peninsula and load centers in the Anchorage region would be built.

Least cost with 76% renewables

The study found that the least cost scenario

see **NREL REPORT** *page 4*

● THIS MONTH IN HISTORY

ConocoPhillips dominates Alaska exploration

20 years ago this month: Company has drilled or participated in 43 exploration wells in 6 years, acquired more than a million acres

Editor's note: This story first appeared in the March 21, 2004, issue of Petroleum News.

By KRISTEN NELSON

Petroleum News

ConocoPhillips Alaska plans as many as four exploration wells on Alaska's North Slope this winter, 2003-04. Three wells have spud — Carbon and Scout No. 1 in the National Petroleum Reserve-Alaska — and Placer on the western edge of the Kuparuk River unit. A third NPR-A well is planned, using one of the two rigs already drilling there, Rick Mott, ConocoPhillips Alaska's vice president of exploration and land, told Petroleum News March 4, 2004, and a second well at Placer has been permitted as a contingency, depending on results from the first Placer well.

Mott said ConocoPhillips has drilled or participated in 43 exploration wells in Alaska in the last 6 years, "which is just a very significant proportion of the total number of wells." The 43 include the wells being drilled this winter season.

In addition, the company has shot some 3,400 square miles of 3D seismic in those 6 years, including this winter's work.

"And we've leased over 1 million acres of exploration acreage," he said.

"There's no one else in the industry that comes close in my opinion to that sort of commitment to Alaska."

RICK MOTT

In NPR-A, Mott said, ConocoPhillips has interests in 1.1 million acres, 750,000 acres if you look at just ConocoPhillips' share of the leases. Its other federal acreage is Minerals Management Service leases on the outer continental shelf, some 99,000 acres, Mott said, "almost all Beaufort Sea," with just some 2,000 acres in Cook Inlet.

The company's interest in state exploration acreage is approximately 446,000 acres, 88,000 acres of which is offshore.

Well count can be misleading

Mott noted that some people track the company by the number of exploration wells it drills.

But, he said, that's misleading, because the number of wells is not a measure of what the company is spending on exploration.

Mott said the company does not release its exploration budget for Alaska, but "this is a fairly typical year, with respect to budget years for Alaska. What changes from year to year, though, is what our working interest is in wells and where they're located."

For example, a few years back, he said, the company had a 20% interest in the Trailblazer well in NPR-A, with partners Chevron and BP. In this winter's wells, however, ConocoPhillips has a 78% working interest.

> *But the expense of drilling in Alaska should be of concern to Alaskans, Mott said, because once prospects are identified, ConocoPhillips looks at reserve size, risk and "the value per barrel and the cost."*

Because of the higher working interest, Mott said, one of the company's wells this year would be the equivalent of its cost to participate in four Trailblazer wells.

The company's exploration investment in Alaska is not down, he said, "it's our working interest that varies from year to year."

Location is also an important cost factor.

Compared to a well within a field, a well "maybe 5 miles away" will cost twice as much.

"If you go more than 20 miles away, you're probably talking about four times as expensive."

At 50 miles away, he said, the cost can be 10 times that of a well within a field.

"And if you go offshore. you're talking about 20 times as expensive."

People who want to play the well-count game, Mott said, "should look at where the wells are located."

For instance. at Puviaq, in northwestern NPR-A, the company moved equipment by rolligon from both Deadhorse and Barrow, driving "over 26,000 miles in rolligons at 10 miles an hour," he said.

Mott said what really drives Alaska costs home to him

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● EXPLORATION & PRODUCTION

Baker Hughes US rig up by 7 to 629

By KRISTEN NELSON

Petroleum New

The Baker Hughes' U.S. rotary drilling rig count was 629 for the week ending March 15, up by seven rigs from 622 the previous week, and down by 125 from 754 a year ago, reversing after a drop of seven last week. The rig count increased in five of the last eight weeks and decreased in three, with a gain of 20 against a loss of 11 over the period, bucking a downward trend dominant since the beginning of May.

A drop of 17 to 731 on May 12, 2023, was the steepest weekly drop since June of 2020, during the first year of the COVID-19 pandemic, when the count also dropped by 17 to 284 on June 5, following drops as steep as 73 rigs in one week in April. The count continued down to 251 at the end of July 2020, reaching an all-time low of 244 in mid-August 2020.

For 2023, the count hit its low point Nov. 10 at 616, down from a high of 775 on Jan. 13, 2023. In 2022, the count bottomed out at 588 Jan. 1, reaching a high for the year of 784 on Nov. 23.

When the count dropped to 244 in mid-August 2020, it was the lowest the domestic rotary rig count had been since the Houston based oilfield services company began issuing weekly U.S. numbers in 1944.

Baker Hughes shows Alaska with 13 rotary rigs active March 15, unchanged from the previous week and up by three from a year ago when the count was 10.

Prior to 2020, the low was 404 rigs in May 2016. The count peaked at 4,530 in 1981.

The count was in the low 790s at the beginning of 2020 prior to the COVID-19 pandemic, where it remained through mid-March of that year when it began to fall, dropping below what had been the historic low in early May with a count of 374 and continuing to drop through the third week of August 2020 when it gained back 10 rigs.

The March 15 count includes 510 rigs targeting oil, up by six from the previous week and down 79 from 589 a year ago, with 116 rigs targeting natural gas, up by one from the previous week and down 46 from 162 a year ago, and three miscellaneous rigs, unchanged from the previous week and unchanged from a year ago.

Fifty-four of the rigs reported March 15 were drilling directional wells, 562 were drilling horizontal wells and 13 were drilling vertical wells.

Alaska rig count unchanged

Louisiana (48) was up by five rigs from the previous week.

Texas (294) gained three rigs week over week and New Mexico (107) and West Virginia (9) were each up by a single rig.

Pennsylvania (22) was down by two rigs and Oklahoma (44) was down by one.

Rig counts in other states were unchanged from the previous week: Alaska (13), California (6), Colorado (16), Kansas (1), North Dakota (32), Ohio (12), Utah (12) and Wyoming (11).

Baker Hughes shows Alaska with 13 rotary rigs active March 15, unchanged from the previous week and up by three from a year ago when the count was 10. Twelve of the Alaska rigs were onshore, unchanged from the previous week, with one rig working offshore, unchanged from the previous week.

The rig count in the Permian, the most active basin in the country, was up by three from the previous week at 316 and down by 34 from 350 a year ago. ●

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HISTORY

is a comparison with costs at the company's prospects worldwide.

Offshore West Africa, ConocoPhillips can drill a well "in 2,000 feet of water depth less expensively than we can drill a well, say, 50 miles out in the NPR-A. Significantly less expensively — like two-thirds the cost."

Costs a concern

Alaska is a sanctioned exploration play for ConocoPhillips, Mott said, but that doesn't mean cost isn't a factor.

The company looks "at the opportunities in plays and basins" and does "screening-level evaluations of those basins and those plays."

There are only a handful of sanctioned plays in the world.

"It's not like Alaska is number 28 out of 50," he said, there are "only a few in the world."

"So, Alaska's very important to ConocoPhillips in its exploration program."

"And in essence that gives us a hunting license, if you will, that we can go out and look for opportunities in those plays because we think they have economic potential to be interesting to us."

But the expense of drilling in Alaska should be of concern to Alaskans, Mott said, because once prospects are identified, ConocoPhillips looks at reserve size, risk and "the value per barrel and the cost."

We can't impact the reserve size, we "have to take what the basin gives us."

Technology and the skill of its people enable the company "to try and understand the risk … and reduce it to the irreducible point."

Then there is the element of cost. ConocoPhillips' engineering and drilling staff work on the most cost-effective way to go after a prospect.

But, Mott said, "the attractiveness of the basin will also be driven by the natural logistics problems of Alaska and … by the cost of our contractors."

The bottom line, he said, is that "we all have a stake in cost" and ConocoPhillips needs the "help and assistance and cooperation" of its contractors in the cost area.

When the value per barrel is evaluated, engineering has a role to play, but "we do have a natural challenge" — an 800-mile pipeline and "then a several-thousand-mile boat trip to get to market." And both contractors and state government have a role there.

ConocoPhillips will "continue to try to be creative and we'll work on our job part and try and find significant reserves and minimize the risk, and we'll try and be smart in our engineering approaches to drive down cost, but we need the help of our contractors and certainly state government."

Because, Mott said, "If costs go up … or value goes down, value per barrel goes down (and) it makes Alaska less attractive."

"It sounds like a political statement," he said, "but it's not a political statement — it's reality."

Right now, Alaska is still one of ConocoPhillips' "favorite plays and favorite localities in the world. And we hope everyone will work with us to keep it that way." ●

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NERL REPORT

would involve growing the renewable portfolio to around 76% of power generation by 2040, with wind energy providing about 51% of the total power. Adding further renewables to meet the RPS standard would have little impact on the overall cost savings, the study found. However, the study did not consider the possibility of adding any major new hydropower facilities to the power supplies. The study also excluded the possibility of implementing tidal power systems. However, the possibility of the development of a geothermal power system was included in the evaluation.

NREL used weather conditions and power generation profiles from 2018 to conduct its modeling for the scenarios. However, the study took account of possible increased electricity demand relating to the potential increase in the use of electric vehicles.

As part of their power supply modeling the researchers also evaluated possible sites for renewable energy facilities, in particular wind farms. Solar farms are feasible but are unlikely to be as productive as wind farms in Alaska's environment, the researchers found.

Gas fueled power generation still needed

Both scenarios involving the increased use of renewables assumed that the existing gas fueled power generation plants would remain in operation, to ensure adequate power supplies when renewable energy generation drops, because, for example, of a lack of wind power. The study also assumed that Golden Valley Electric Association's Healy Unit 1 coal fired plant would continue to operate, while Healy Unit 2 would close.

The buildup of renewable energy production would, on average, significantly reduce the usage of the gas fueled plants, thus increasing the unit cost of power from the plants. However, this increased unit cost of gas fueled generation would be more than offset by the relatively low cost of the renewable generation, the study found. Existing hydropower would also be used to ensure the reliability of power supplies.

Important assumptions

During a presentation about the study to the Regulatory Commission of Alaska on March 13 Paul Denholm, a power system engineer from NREL, commented that the study had made a number of assumptions. For example, the researchers assumed that some form of centralized management of power planning and dispatch would be required for the entire Railbelt, with power being shipped across the transmission lines as necessary to ensure maximum efficiency in power generation. The use of major amounts of renewable energy would dramatically change the manner in which the Railbelt transmission system is used, given potentially rapid fluctuations in the amount of wind and solar power generation, Denholm commented.

The study assumed that a planned second electricity transmission line between the Kenai Peninsula and load centers in the Anchorage region would be built. However, the study also assumed that no upgrades would be made to the northerly transmission intertie between Willow and Healy.

But the manner in which the system is operated needs to take account of the possibility of either of the major transmission interties between the south, central and northern sectors of the system going out of action, Denholm cautioned.

Essentially, assuming the use of the federal investment tax credits, around $3 billion would be invested in renewable and other infrastructure, to avoid $4.3 billion in fuel and other costs, Denholm said.

Federal investment tax credits

A key assumption in estimates of the cost of renewable energy is that the construction of new renewable energy facilities would qualify for federal investment tax credits of 40%. The study also assumed that the cost of natural gas for Southcentral Alaska would continue to increase — there would be a need to import liquefied natural gas, starting at around 2028 or 2029, at a cost at around $12 per million Btu. And, in estimating the cost of renewable energy, the study had factored in the additional cost relative to the Lower 48 likely to be involved in building renewable power plants in Alaska.

One question relating to the need for gas fueled power to underpin power supply reliability revolves around the need for sufficient gas storage, to ensure adequate gas deliverability during periods of high gas fueled power demand. The analysis factored in the cost of additional gas storage as part of the cost of implementing the renewables, but it is very uncertain how much additional storage would actually be needed, Denholm said.

The study also assumed a need for additional battery storage of electrical power, to help stabilize the system, he said.

The likelihood of cost savings

Given the projected cost of imported LNG, signing a long-term contract for the delivery of renewable power at $100 per megawatt hour or less would likely save money, Denholm said. Thus, given the high and increasing cost of LNG coupled with the declining cost of renewables, the study found that renewables would be a cost effective means of reducing gas consumption in the gas fueled power plants — the bottom line is that cumulative savings could amount to more than $1 billion over the timeframe of the least cost scenario.

Essentially, assuming the use of the federal investment tax credits, around $3 billion would be invested in renewable and other infrastructure, to avoid $4.3 billion in fuel and other costs, Denholm said. ●

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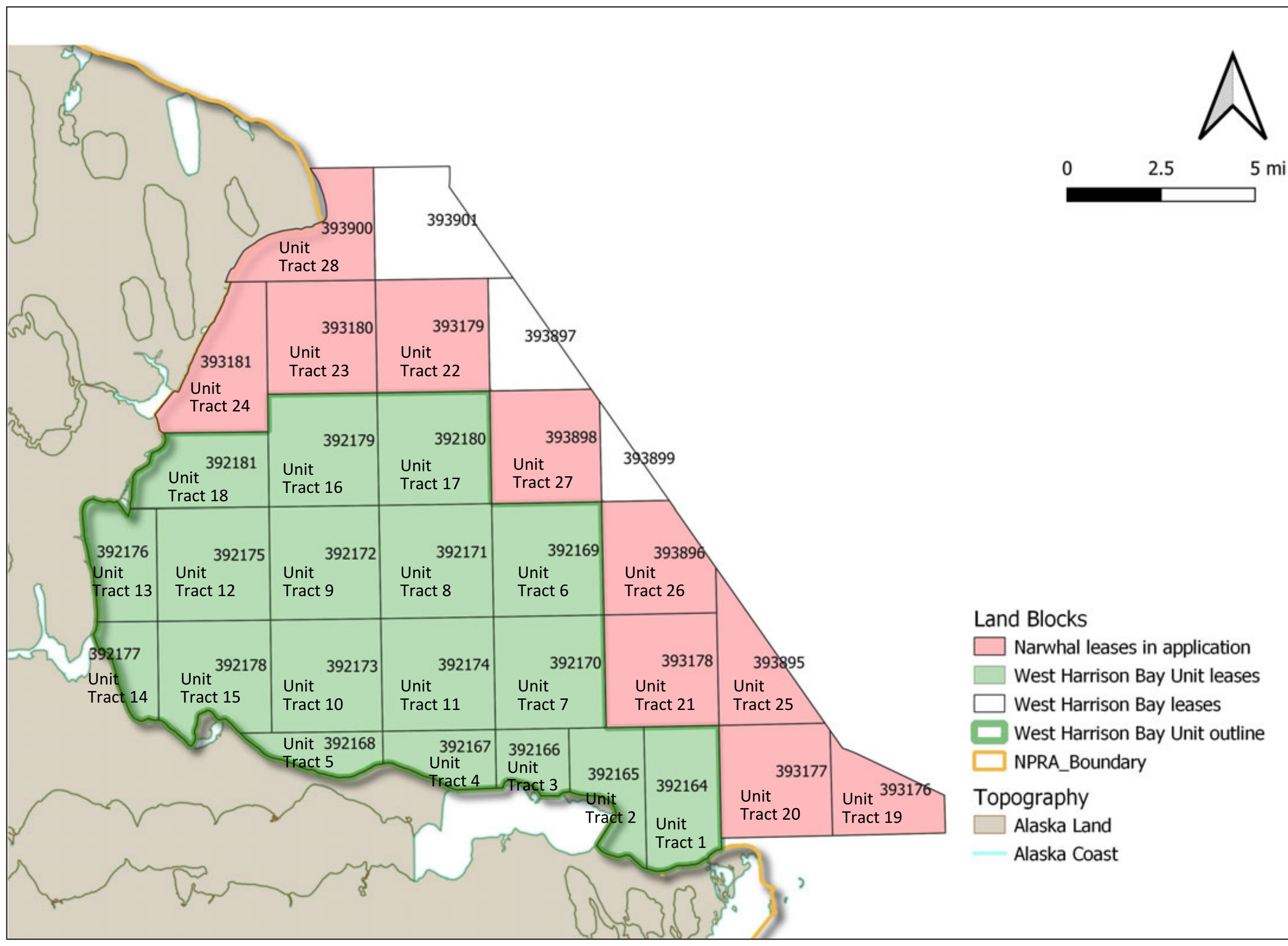
NARWHAL APPEALS



Prime location

The Nanushuk formation is the hottest play west of the central North Slope.

The 81,000-acre West Harrison Bay unit lies northwest of Santos' Pikka unit, a 1 billion barrel discovery currently under development, and approximately 7 miles directly north of ConocoPhillips Alaska's Bear Tooth unit, which holds the big Nanushuk Willow discovery in the National Petroleum Reserve-Alaska.

Narwhal's options

On Dec. 20, 2022, Anchorage-based Narwhal asked DNR's Division of Oil and Gas to expand Shell's West Harrison Bay unit to include Narwhal's leases. On May 23, 2023, division Director Derek Nottingham denied that request.

Narwhal's proposed West Harrison Bay unit expansion area, which includes Narwhal's leases, is roughly 50,180 acres for a total of 131,311 acres in the shallow state waters.

Because Narwhal had no direct interest in the West Harrison Bay, or WHB, unit, and because the activities proposed by Narwhal in its plan of exploration on its leases can be conducted on a lease-by-lease basis or Narwhal can apply to form a separate unit comprised of its own leases, expansion of the WHB unit is unnecessary, Nottingham said in his decision.

On April 6, 2023, Shell International Exploration & Production, parent of Shell Offshore, emailed comments to the division about Narwhal's proposed expansion.

In Nottingham's words, Shell said that: "Narwhal has not conducted its own seismic survey, but rather appears to rely on the same 2D and 3D seismic survey datasets used by Shell in its application to form the WHB unit. Narwhal is not seeking to voluntarily unitize the leases to aid exploration or production, instead, Narwhal's unprecedented proposal involves the forced creation of a joint venture with Shell, the removal of Shell as the operator of the unit, and a new plan of exploration. … Narwhal has failed to satisfy the criteria of 11 AAC 83.303. … Involuntary expansion is contrary to the department's statutory scheme. … Although Narwhal has reached out to Shell with multiple commercial proposals, including lease combinations, and proposals to purchase Shell's leases; these proposals were considered in depth by Shell, but Shell declined these offers."

Narwhal's points

In a Jan. 23 letter to Boyle, Narwhal asked for reconsideration of a Jan. 3 DNR decision regarding an amendment to the second POE and an extension of the WHB unit agreement that invited further discussions with Shell.

Per Narwhal's letter, on Sept. 22, 2023, Shell submitted a proposed amendment to DNR to the second POE, requesting to extend the unit term. The proposed amendment was not submitted by Shell until eight months and 22 days after Shell defaulted on the contractual obligations in the current POE, which requires it to, among other things, (1) finalize commercial arrangements with other prospective market participants and designate a new unit operator on or before Dec. 31, 2022, and (2) complete the first of two wells during the 2023-2024 winter drilling season.

DNR's elected not to deny Shell's request to amend the POE and extend the unit term, not to issue a notice of default and demand to cure, and not to demand release of the performance bond put in place to secure Shell's commitment to develop the leases, Narwhal wrote.

The decision "violates DNR's statutory and constitutional obligations under Alaska law to develop resources in accordance with the public interest, is not supported by the 11 AAC 83.303 criteria or factors, violates the equal protection clauses of the Alaska Constitution and reflects blatant favoritism of Shell compared to similarly situated smaller oil and gas operators in Alaska," and more, Narwhal wrote.

"As DNR is aware… Narwhal holds leases adjacent to the WHB unit and has made multiple attempts to work cooperatively with Shell to spur development" of the WHB leases. "DNR's refusal to enforce Shell's contractual obligations and stop Shell from warehousing its leases in the WHB unit in violation of the WHB unit agreement and second POE has resulted in … damages to Narwhal by preventing it from bidding on and acquiring the WHB unit leases in a competitive areawide lease sale or pursuing a cooperative and coordinated exploration, appraisal, and development program with a lessee that is actually willing to drill the hydrocarbon accumulations in the WHB that are shared with Narwhal in a manner that maximizes the economic and physical recovery of the natural resources."

DNR's decision affects leases held by Shell in the WHB unit (ADLs 392164, 392165, 392166, 392167, 392168, 392169, 392170, 392171, 392173, 392174, 392175, 392176, 392177, 392178, 392179, 392180, 392181) and adjacent leases held by Narwhal (ADLs 393176, 393177, 393178, 393179, 393180, 393181, 393895, 393896, 393897, 393898, 393899, 393900). ●

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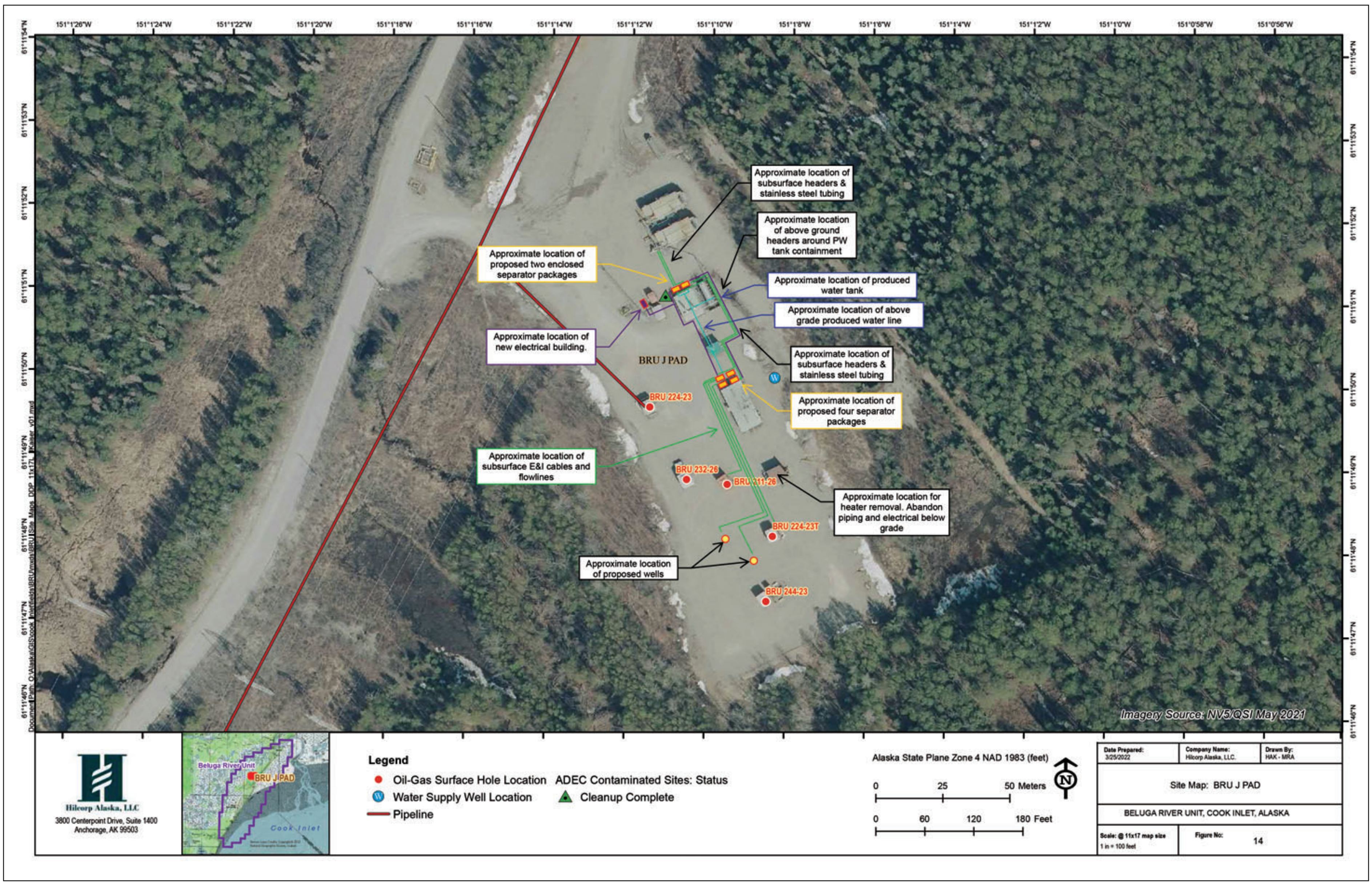

Beluga River, among the inlet's largest gas fields, is on the west side and Cannery Loop, one of the smaller, is on the Kenai Peninsula.

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GAS FIELDS

new flowlines, instrumentation and electrical lines, and for subsurface headers, with all work to be done on J Pad, which is some 2 miles south of the mouth of the Beluga River.

Plan work includes:

•Installation of separator packages and flowlines.

•Installation of produced water lines, instrumentation and electrical lines, cellars and conductors and headers.

•Drilling of two grassroots wells.

•Tying in wells with existing infrastructure.

•Installation of heat trace and insulation.

At Cannery Loop, the division approved an amendment to the unit plan of operation on March 15.

One grassroots well, CLU 16, will be drilled on Pad 1, and associated infrastructure will be installed, including flowlines, electrical instrumentation, well cellar and a conductor, with work to include:

•Preparing for drilling activities.

•Drilling and testing the well.

•Installing facility piping and electrical and instrumentation lines tying the well into existing CLU Pad 1 production infrastructure.

*Production of gas from CLU-16.

—KRISTEN NELSON

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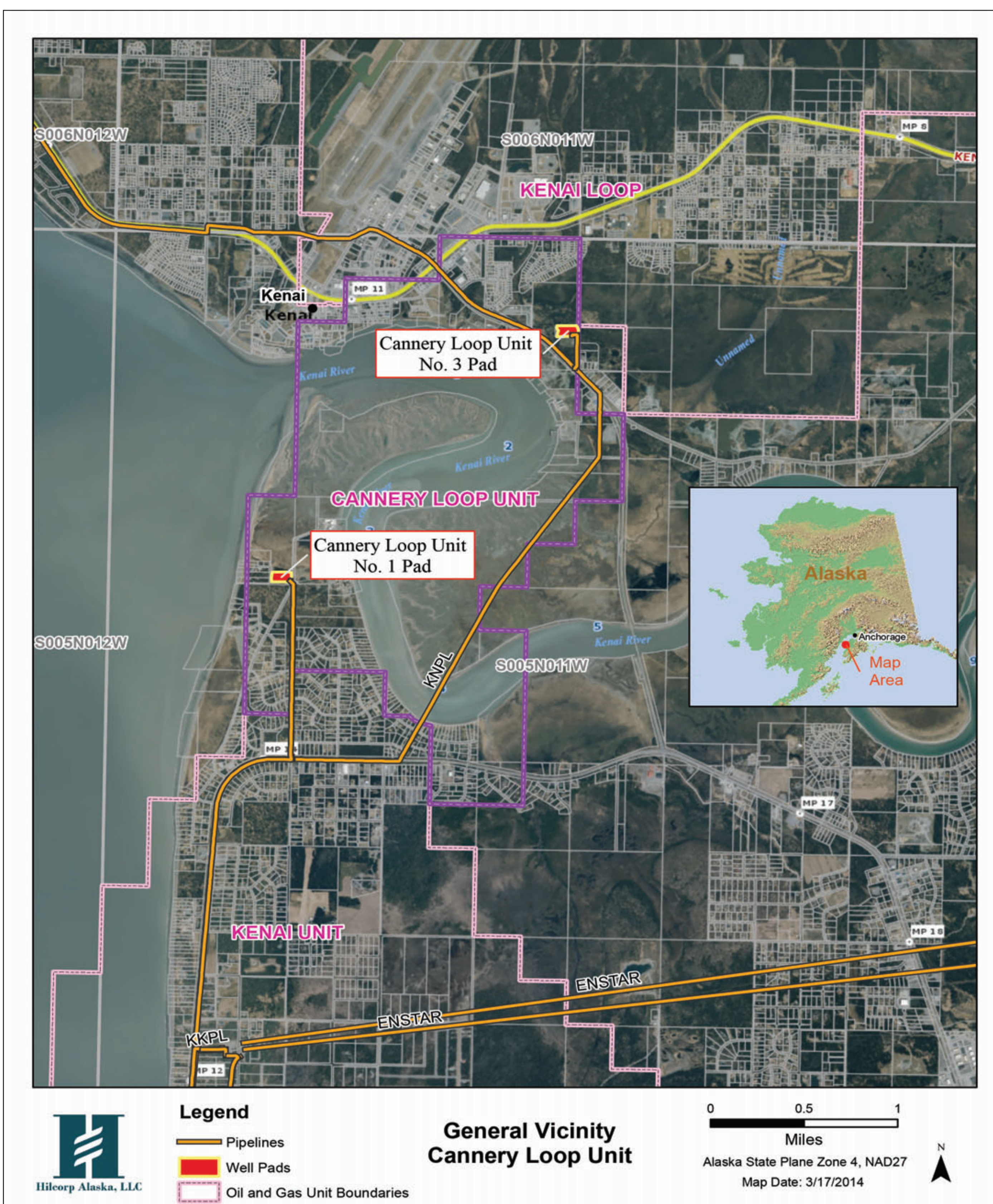

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OIL PRICES

Evercore ISI, quoted in MarketWatch.

"This is a Fed that wants to cut rates — not before it is responsible to do so, but as soon as it is responsible to do so, with June and three cuts this year still it's quite sticky base case," Guha said.

Earlier in the year, traders were much more bullish on a radical movement to lower interest rates, some expecting a half dozen rate changes moving the Fed to a more accommodating stance.

So far, however, the economy is exhibiting some heat, and in that atmosphere, stimulus doesn't deliver the punch it does in a weakening economy.

But it isn't just a robust consumer driving the economy, business investment is ramping up.

An explosion of spending on Artificial Information floats a promise of a more efficient, more intelligent, more humane, and instinctual way of doing business — it is a revolution.

AI could reduce pollution and waste by eliminating the inefficiencies of doing business in the old fangled way, it is hoped.

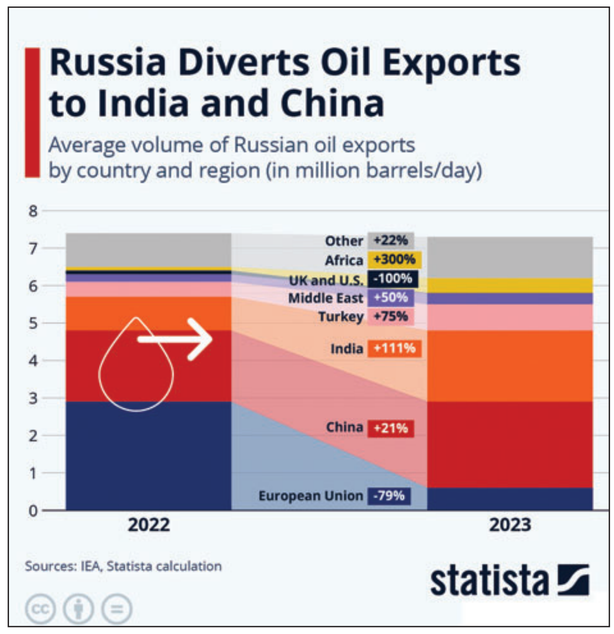
Working harder with greater efficiency may serve us better — particularly in the near term, than a total redesign of our industrial capacity chasing someone's idea of a greener process.

AI needs energy and it needs energy that is available on a reliable and economic basis. Energy also is the lifeblood of the construction and trade that a revolution engenders.

Using what is at hand efficiently will be necessary to balance the energy supply as demand explodes.

U.S. crude production presently leads the world, and a sophisticated refining industry tirelessly turns out a blinding array of fuels, lubricants and products … from toys to pharmaceuticals.

As such, oil didn't stay down in the wake of the Fed minutes. Oil traded in the green in early Asian trade as Petroleum News went to press March 21.



U.S. crude oil levels took a surprise dive the week ending March 15 according to data released March 20 by the U.S. Energy Information Administration.

Commercial crude oil inventories excluding the Strategic Petroleum Reserve dropped 2 million barrels to 445 million barrels — 3% below the five-year average for the time of year, the EIA said. Analysts answering a Wall Street Journal poll predicted crude stockpiles would decrease by 1.2 million barrels.

SPR levels rose by 750,000 barrels to 362.3 million barrels.

Total motor gasoline inventories staged a bullish 3.3 million barrel decrease on the week, reaching 230.8 million barrels — 2% below the five-year average for the time of year.

ANS rose 35 cents March 19 to close at $86.58, as WTI jumped 75 cents to close at $83.47 and Brent added 49 cents to close at $87.38.

Prices leapt higher March 18. ANS jumped $1.49 to close at $86.23, WTI leapt $1.68 to close at $82.72 and Brent popped $1.55 to close at $86.89.

ANS added 5 cents March 15 to close at $84.74, but WTI fell 22 cents to close at $81.04 and Brent edged 8 cents lower to close at $85.34.

ANS advanced $1.27 March 14 to close at $84.69, while WTI leapt $1.54 to close at $81.26, and Brent jumped $1.39 to close at $85.42.

China goes pop!

A surprise pop in Chinese industry and retail cheered bullish crude traders March 18.

China's factory output and retail sales bested expectations for January-February, according to official data.

Industrial output rose 7% for the period — the quickest growth in almost two years, Reuters reported, adding that retail sales slowed to 5.5% from 7.4% in December but slightly beat forecasts.

Chinese stocks closed at a record for the year, recapturing 12% of a lull that started in February, Reuters said. Global stocks and U.S. futures rose on the news.

"The impact of a punchier Chinese economic rebound on global oil and commodities comes at a critical juncture for inflation-watchers, central banks and bond markets," Reuters said.

A surge in Chinese demand may send ripples through Pacific markets, including West Coast markets where most ANS crude trades.

Due to lower refinery runs, some additional Russian crude is available on the world market as Ukraine mounts strikes on Russian oil assets.

A Reuters analysis found Ukrainian attacks have idled some 7% of Russian refining capacity in the first quarter. A March 16 strike sparked flames at the 170,000 barrel-per-day Slavyansk refinery in Krasnodar.

But China will have to compete with fast-growing India for crude. Since Russia invaded Ukraine in 2022, India has increased its imports of Russian crude by 111%, according to International Energy Agency data. ●

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Petroleum News — Oil Patch Bits

Calista board of directors appoints unit 6 interim director

As reported by Calista Corp. News March 4, the Calista board of directors has appointed Chris Kolerok as the unit 6 interim director.

Kolerok is a Calista shareholder with ties to Mekoryuk. He graduated from the University of Alaska Anchorage with a bachelor's degree in economics and received a master's degree in public policy from Harvard University's John F. Kennedy School of Government. He currently works for the Cook Inlet Housing Authority in Anchorage.

The unit 6 director position became vacant with the resignation of Jolene John last year, after which the board opened an application period for qualified Calista shareholders to apply for the position.

The board appointed Kolerok after reviewing applications submitted by eligible shareholders with ties to the unit 6 villages of Chefornak, Mekoryuk, Newtok (Mertarvik), Nightmute, Toksook Bay, Tununak and Umkumiute. The deadline to apply was Jan. 5.

Pursuant to the Calista bylaws, "any vacancy on the board of directors may be filled by the affirmative vote of a majority of the remaining directors." The board selected Kolerok after reviewing applications at its February 2024 meeting.

Kolerok will serve the remainder of the unit 6 term, which will be up for election at the 2025 annual meeting of shareholders.

CHRIS KOLEROK

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SPRING FORECAST

2.6%, while the difference in forecast production levels is a decrease of 0.6% for FY24, followed by a 2% increase, 13,000 bpd, for FY25.

In presenting the spring forecast in the Senate Finance Committee March 14, Revenue Chief Economist Dan Stickel said the increase of $58.4 million in unrestricted revenue for FY24 in the forecast is primarily driven by oil price, although the $140.1 million increase for FY25 also reflects a forecast increase in production. On oil price he said that the forecast price was increased by $1 to $3 per barrel over the 10-year forecast period.

FY24 production

By field, changes in the production forecast are not particularly large: Prudhoe is down, but production from Prudhoe satellites is up, and the Greater Point McIntyre area at Prudhoe is down. At Kuparuk, production from the main field is up, while that from Kuparuk satellites is down. Endicott is down, Alpine is up and the fields summed up under offshore — primarily Nikaitchuq, Northstar and Oooguruk — are up. National Petroleum Reserve-Alaska production is up, while Point Thomson is down.

Total North Slope production is now forecast at 467,600 bpd in FY24, down from 479,400 bpd in FY23, and down from a fall forecast of 470,300 bpd. Cook Inlet, which averaged 9,000 bpd in FY23, is down from a fall forecast of 8,200 bpd for FY24 to 8,200 bpd.

FY25 production

For FY25, beginning July 1, ANS production is now forecast at 476,800 bpd, up 2.8%, from a fall FY25 forecast of 463,800 bpd.

The production forecast is unchanged for Prudhoe Bay and Alpine and there are some decreases, the largest for offshore fields, now forecast at 23,700 bpd, down from 25,600 bpd.

Increases in the forecast are for NPR-A, up from 11,600 bpd to 18,700 bpd; Kuparuk, up from 45,700 bpd to 49,300 bpd; Kuparuk satellites, up from 45,700 bpd to 49,300 bpd; Prudhoe Bay satellites, up from 87,100 bpd to 88,200 bpd; and Point Thomson up from 2,800 bpd to 3,400 bpd.

The most significant increases in the forecast, reflecting new fields coming online, are at the end of the forecast period, with FY33 showing 640,200 bpd. Beginning in FY26, production climbs, forecast at 482,000 bpd in that year, and continues to increase, crossing the 600,000 bpd mark in FY32.

Allowable lease expenditures

Stickel said an increase is expected in allowable lease expenditures, which he characterized as a barometer of industry activity in Alaska with large investments reflecting new field development.

Capital expenditures are forecast at more than $4 billion in FY24, he said, with further increases in FY25 and FY26. Operating costs also increase, and a graph in Stickel's presentation shows capital expenditures expected to peak in FY26 before declining and surpassed by operating costs by FY30.

The spring forecast shows FY23 deductible North Slope operating expenditures at $2.26 billion and capital expenditures at $4.23 billion, increasing in FY24 to $2.74 billion for operating expenditures and $2.82 billion for capital expenditures, and rising again in FY25 to $2.82 billion in operating expenditures and $3.06 billion in capital expenditures.

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GAS ECONOMICS

Utilities' study

Keithley said the study produced by the utilities, "Alaska Utilities Working Group Phase I Assessment: Cook Inlet Gas Supply Project," provides the best assessment of the economics of Cook Inlet natural gas. One of the options presented there, based on the reuse of existing Kenai LNG facilities, would provide the lowest cost LNG over time — $12 to $13.60 per mcf, thousand cubic feet — compared to a potential long-term cost of $9.30 to $25.50 per mcf for Cook Inlet gas, with a timeline of 3-4 years.

With Cook Inlet gas currently at some $9 per mcf, a price in the $12-range would be an increase, but the Kenai LNG option compares favorably to larger LNG projects and to the long-term price of Cook Inlet natural gas. And while the price of gas would be just $4-$5 per mcf from full development of a North Slope export LNG project, with a pipeline to Nikiski connected to a large new LNG facility, there are no commitments for that project and it has the longest timeline, 7-8 years.

The range of prices for Cook Inlet natural gas was cited in a March 4 presentation by McKay's staff, who noted that prices for Cook Inlet gas would rise as less economic volumes were brought into production. (See story in March 17 issue of Petroleum News.)

In the utilities' study by Berkely Research Group the Kenai LNG option is described as "retrofitting the Kenai LNG export facility located in Nikiski (owned by Marathon) to be utilized as an LNG import and regasification facility for a broader group of customers than the Kenai refinery as currently proposed by Marathon," and would use the existing pier and storage tanks, with LNG coming in by tanker, "stored in the existing storage tanks, and then vaporized and injected into the Kenai Beluga Pipeline system." The study pegged the required capital investment at $768 million.

Keithley said Enstar and the Chugach Electric Association are trying to keep the price of natural gas down because consumers want the price low. The utilities are concerned they will be questioned by the Regulatory Commission of Alaska if prices rise and want to find another way to get more supply.

Why is the price too low?

Keithley said Enstar and the Chugach Electric Association are trying to keep the price of natural gas down because consumers want the price low.

The utilities are concerned they will be questioned by the Regulatory Commission of Alaska if prices rise and want to find another way to get more supply. RCA has ample authority to be involved and needs to be part of the discussion, he said, because RCA's obligation is to ensure that the utilities meet their obligations. Both Enstar and Chugach Electric have said they can't meet their obligations without more supply.

The problem, he said, it that it takes a higher price to bring in more supplies and cited the situation in the Lower 48 in the 1970s when the natural gas price was regulated at such a low level that there was a perceived gas shortage; with a higher price, competition grew, more gas was brought to market and ultimately enough gas was produced that the price came down.

Consumers did complain when the price went up, but the result was adequate supply.

Keithley said he sees supply as the tradeoff for a higher price. You can have $9 gas, he said, but the supply isn't guaranteed. Adding $12 LNG guarantees the supply, and since LNG would initially make up a small portion of the supply, there would be less of an immediate impact on utility bills.

No subsidies

The Legislature is looking at various bills to incentivize Cook Inlet gas development, from bringing in another jack-up rig to royalty reductions and other financial incentives.

Keithley said any action taken by the Legislature should have the lowest overall cost statewide. If there are subsidies, it should be clearly understood who is paying for them and who benefits from them, he said.

He argued that previous subsidies, enacted during the earlier perceived shortage of Cook Inlet natural gas, ultimately lowered the permanent fund dividend, thus having a statewide impact primarily on middle- and lower-income families, while benefits for Cook Inlet gas were received primarily by Southcentral residents.

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