Petroleum news

page 6 Stedman named to petroleum council; previously served 2014-15

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APSC completes marine transition from Crowley to Edison Chouest

The transition of marine services for the Valdez Marine Terminal from Crowley Marine Corp. to Edison Chouest Offshore were completed on schedule on July 1, Michelle Egan, Alyeska Pipeline Service Co. corporate communications director, has told Petroleum News.

"At midnight on July 1 we released the last Crowley vessel, so that all of the vessels in the system are now operated by Chouest," Egan said.

As the last of the Crowley vessels departed Valdez the new Edison Chouest tugs put on a water show, in recognition of the service that the Crowley fleet has provided.

"Those mariners have been really impressive over the years," Egan said.

see MARINE SERVICES page 10

NordAq completes P&As; AOGCC reduces fines, all bonding dropped

The Alaska Oil and Gas Conservation Commission has issued decisions and orders on reconsideration on fines and bonding requirements for plugging and abandoning the Shadura-1 and Tiger Eye Central-1 wells.

In June 29 orders the commission reduced the fines and said bonding was no longer necessary since both wells had been plugged and abandoned.

These Cook Inlet exploration wells were drilled by NordAq Energy Inc. — the Tiger Eye-1 on the west side of Cook Inlet and Shadura-1 on Cook Inlet Region Inc. lands on the Kenai Peninsula.

The commission fined the company and required bonding

see AOGCC ORDERS page 10

88 Energy suspends Icewine 2, begins HRZ farm-out process

Production testing has ended at Icewine 2 and the well was suspended June 30, West Perth, Australia-based 88 Energy said July 2, with demobilization of equipment completed over the June 30-July 1 weekend. The company said it believes results to date support potential economic viability of the HRZ shale play "and are within the range of outcomes achieved at other early stage unconventional plays, despite not achieving a flow rate that is representative of the capability of the reservoir."

The Icewine project was developed by 88 Energy in partnership with Burgundy Xploration, which began acquiring North Slope tracts south of Prudhoe Bay in 2013. 88 Energy's local operating company is Accumulate Energy Alaska.

Icewine 1 was drilled in 2015 and core extracted. Icewine 2 was drilled in 2017, both wells from the Franklin Bluffs gravel

see ICEWINE 2 page 11

Canada aims high with LNG, wants production cleaner, more efficient

JIM CARR

Canada is positioning itself to become the world's cleanest producer of LNG, using that fuel to displace dirtier sources of electricity around the world, especially coal-fired plants in Asia, said Natural Resources Minister Jim Carr.

He based that ambitious goal on a report from his own advisory council, consisting of 14 members from the energy sector, aboriginal communities and environmental groups who issued a report in late July targeting the environmental and economic benefits of shipping and burning oil and natural gas that is cleaner and more efficient.

see LNG GOALS page 9

FINANCE & ECONOMY

Swap involves Slope

ConocoPhillips gets BP's 39.2% of Kuparuk in exchange for share in UK field

By KRISTEN NELSON
Petroleum News

RYAN LANCE

ConocoPhillips and BP said July 3 that ConocoPhillips is acquiring BP's 39.2 percent interest in the Greater Kuparuk area, and BP's 38 percent interest in the Kuparuk Transportation Co. for an undisclosed price and is selling BP a subsidiary with a 16.5 percent interest in the Clair field in the United Kingdom. The Clair field sale is subject to regulatory approval; the Greater Kuparuk area acquisition is subject to co-owner pre-emption rights and both Kuparuk acquisitions are subject to regulatory approval.

ConocoPhillips said the transactions are inter-conditional and expected to close simultaneously. Excluding customary adjustments, the transaction prices are expected to be cash neutral to both companies. The effective date will be July 1.

"These transactions are significant for ConocoPhillips because they continue our strategy of coring up our legacy asset base in Alaska, while retaining an interest in the Clair Field in the U.K.," said ConocoPhillips Chairman and CEO Ryan Lance. "We have a long history of creating value in Alaska and an ongoing commitment to invest in

see BP-CONOCO SWAP page 11

EXPLORATION & PRODUCTION

Kuparuk sees bump in 2017

High performance from coiled tubing program offsets decline in drilling activity

By ERIC LIDJI
For Petroleum News

Despite an overall reduction of development activity, ConocoPhillips Alaska Inc. experienced a notable increase in oil production at the Kuparuk River unit in 2017.

The second-most productive unit in Alaska produced 109,100 barrels per day in 2017, up from an average of 103,000, according to a recent plan of development for the unit.

The main Kuparuk oil field produced 84,100 bpd in 2017, up from 78,100 bpd in 2016. The remaining oil production came from the four Kuparuk satellites, although only the West Sak satellite reported a slight increase last year.

For the current year, ConocoPhillips is planning a slight increase in drilling activity at the main Kuparuk field, with 17 coiled tubing sidetracks and five rotary wells.

ConocoPhillips attributed 7,500 bpd of incremental oil production to a 16-well (and 42-lateral) coiled tubing drilling program implemented at the Kuparuk oil field last year, down from a 20-well (and 55-lateral) coiled tubing program from 2016 that had been credited with only 3,500 bpd of incremental production. The company also drilled four

see KUPARUK BUMP page 12

PIPELINES & DOWNSTREAM

Line 3 gets regulatory OK

Enbridge clears major hurdle, but faces threats from indigenous tribes, enviros

By GARY PARK
For Petroleum News

Calgary-based Enbridge has edged closer to final government approval in Minnesota of its US$7 billion plan to restore capacity to 760,000 barrels per day on its aging line and equally closer to a threatened showdown with indigenous tribes and environmentalists.

The state's five-member Public Utilities Commission voted unanimously to approve plans to replace the corroded 50-year-old, 1,000-mile pipeline from Alberta to U.S. Midwest refineries in Minnesota and Wyoming, overriding concerns raised by Minnesota's Commerce Department and others that Enbridge had failed to demonstrate need for the expansion.

In a change from its original plans, Enbridge has pledged to remove segments of the old pipeline if asked to do so by landowners, while stopping short of offering to dig up the entire system at a cost of US$1.28 billion.

However, commission chairwoman Nancy Lange said Enbridge's rationing of demand from oil shippers for space on Line 3 was proof of the need to rebuild, although some commissioners voiced doubts that demand for crude oil and refined products would grow enough to warrant the project.

see LINE 3 page 10

● EXPLORATION & PRODUCTION

Month-over-month ANS crude steady in May

Northstar, Milne, Prudhoe have largest decreases from April; percentage gains led by increases at Badami, Oooguruk, Nikaitchuq

By KRISTEN NELSON
Petroleum News

Alaska North Slope crude oil production averaged 515,464 barrels per day in May, up 0.4 percent, 1,938 bpd, from an April average of 513,257 bpd, and down 2.2 percent from a May 2017 average of 527,055 bpd.

Production data is from the Alaska Oil and Gas Conservation Commission, which provides volumes by well on a month-delay basis.

The largest month-over-month percentage increase was at Badami, operated by Glacier Oil and Gas Corp. subsidiary Savant Alaska, which went from 698 bpd in April up 203 percent, a difference of 1,419 bpd, to a May average of 2,117 bpd (and up 144.7 percent from a May 2017 average of 865 bpd).

What happened between April and May this year? The company put the B1-07, its Starfish exploration well, on line in mid-May. Carl Giesler, Glacier CEO, told Petroleum News in early June that the well had tested at production rates of more than 2,500 bpd.

Cook Inlet production averaged 15,952 bpd in May, down 0.9 percent, 143 bpd, from an April average of 16,095 bpd.

Nikaitchuq and Oooguruk also had healthy month-over-month percentage increases.

The Eni-operated Nikaitchuq field averaged 19,441 bpd in May, up 42.4 percent, 5,789 bpd, from an April average of 13,652 bpd and up 10.3 percent from a May 2017 average of 17,628 bpd, while the Caelus Alaska-operated Oooguruk field averaged 12,680 bpd in May, up 56.9 percent, 4,597 bpd, from an April average of 8,083 bpd and up 0.4 percent from a May 2017 average of 12,635 bpd.

Point Thomson, operated by ExxonMobil Production Co., averaged 5,734 bpd from its single well in May, up 8.4 percent, 443 bpd, from an April average of 5,291 bpd, and produced for all 31 days of the month, in contrast to April when the well was only online for 18 days. Production at the field was up 29.8 percent from a May 2017 average of 4,419 bpd.

Endicott, operated by Hilcorp Alaska, averaged 6,557 bpd in May, up 4.2 percent, 262 bpd, from an April average of 6,295 bpd, and down 16.2 percent from a May 2017 average of 7,826 bpd.

Production from the ConocoPhillips Alaska-operated Kuparuk River field held steady, averaging 113,057 bpd in May, up just 10 bpd from an April average of 113,047 bpd and up 3.3 percent from a May 2017 average of 109,462 bpd. In addition to the main Kuparuk pool, Kuparuk produces from satellites at Meltwater, Tabasco and Tarn, and from West Sak.

Northstar, Prudhoe, Milne, Colville all down

The Hilcorp-operated Northstar field had the largest month-over-month percentage decline, down 5.3 percent, averaging 8,768 bpd in May, down 489 bpd from an April average of 9,257 bpd. The field, however, was up 17.5 percent from a May 2017 average of 7,461 bpd.

Milne Point, also operated by Hilcorp, averaged

see **ANS PRODUCTION** page 3

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ON THE COVER

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● NATURAL GAS

Interior Energy Project into next phase

With the Fairbanks utilities consolidated into a single entity, work will focus on new LNG tanks and expanding the gas supply

By ALAN BAILEY
Petroleum News

The Alaska Industrial Development and Export Authority's Interior Energy Project has now moved into a new phase, following the completion of the purchase by the Interior Gas Utility of Pentex Natural Gas Co. from AIDEA. The purchase has achieved the consolidation of IGU with Fairbanks Natural Gas to form a single gas utility in Fairbanks, Gene Therriault, IEP team leader, confirmed to the AIDEA board on June 28. FNG is a subsidiary of Pentex. IGU's integration plan for the utilities indicates that the combined utilities would adopt FNG's management structure, with Dan Britton, CEO of FNG, becoming CEO of the combined utility, Therriault said.

The purpose of the IEP is to facilitate an expanded supply of affordable natural gas for the Fairbanks region, to alleviate the high cost of energy in the area and to reduce air pollution resulting from the use of wood burning stoves to heat buildings.

With IGU's purchase of Pentex, the newly consolidated Fairbanks utility will now move into the driver's seat for moving the IEP forward. Through Pentex the utility also owns the Titan liquefied natural gas plant near Point Mackenzie and a trucking operation for transporting LNG to Fairbanks. However, since the Pentex purchase was funded through AIDEA Sustainable Energy Transmission and Supply, or SETS, loans, AIDEA will have financial oversight of major expenditure on advancing the IEP.

Gas distribution infrastructure

FNG already has an established gas supply service in central Fairbanks. SETS funding enabled both FNG and IGU to build some new gas distribution infrastructure in the city in 2015. Therriault commented that FNG has been laying some additional gas distribution piping in conjunction with road construction projects in Fairbanks. The IGU board has approved capital expenditure of $350,000 for further pipe laying of this nature in fiscal year 2019, Therriault said, adding that the new pipe laying has already brought to light six light industrial businesses interested in obtaining a gas supply.

Key to using the new distribution infrastructure, and hence signing up more gas customers, is the provision of increased LNG storage capacity in Fairbanks. LNG storage expansion would enable summer-produced gas to be stockpiled for use during high winter demand, thus enabling more customers to be served without necessarily increasing the daily LNG production capacity.

Key to using the new distribution infrastructure, and hence signing up more gas customers, is the provision of increased LNG storage capacity in Fairbanks.

LNG storage

In December, an IEP initiative, also funded through AIDEA loans, started the construction of a large new LNG storage facility in Fairbanks. The expectation is to have that facility completed in the fall of 2019. Therriault told the board that the storage project is proceeding on time and within budget. The last of the large concrete panels that will form the outer skin of the LNG tank has just been put in place, he said.

The financing for the facility construction assumes the availability of a state tax credit to cover part of the cost — there is some uncertainty regarding how the IEP will fit into the funding stream for tax credit payments, Therriault said. However, legislation passed to address the payment of a tax credit backlog increases the likelihood of the tax credit system working for the project, he said.

IGU has also purchased an option on land in North Pole, with the objective of being able to move one of FNG's existing LNG tanks in central Fairbanks out to North Pole. The concept is to do this in time to qualify for a tax credit for that project, Therriault said. To qualify for a credit a tank has to be operational and in use by Jan. 1, 2020.

Expanding the supply

Ultimately, the idea is to increase the overall supply of gas to Fairbanks, to support further expansion of the gas distribution infrastructure in the region. The agreement for the sale of Pentex to IGU assumes that the supply increase will be achieved through an expansion of the Titan LNG plant. However, the terms of the agreement accommodate the possibility of an alternative plan: IGU is also considering a concept put forward by manufacturing company Siemens, in conjunction with Knikatnu Corp., the Native village corporation for the Knik and Wasilla area, to build a new LNG plant next to the Alaska Railroad near Houston. Presumably, at some stage IGU will issue a request for proposal, seeking bids for the development of a means of increasing the LNG supply.

Converting to gas

The key to the overall economics of the IEP will ultimately be the number of Fairbanks residents and businesses that convert to the use of natural gas for the heating of buildings — the higher the gas demand, the lower the unit cost of producing LNG and delivering gas to the consumers. The current approved budget for FNG includes the hiring of someone who will conduct customer outreach, to facilitate gas conversions, Therriault said.

The state Legislature has passed legislation enabling the on-bill financing of conversions, to ease the pain of the conversion costs. An on-bill financing arrangement enables the payment of the conversion costs though installments added to a consumer's monthly gas bills. The Legislature had previously passed legislation enabling the implementation of Property Assessed Clean Energy, or PACE, arrangements that can bring low cost financing to businesses wishing to convert to natural gas use. ●

Contact Alan Bailey at abailey@petroleumnews.com

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ANS PRODUCTION

21,064 bpd in May, down 3.2 percent, 706 bpd, from an April average of 21,770 bpd and up 7.1 percent from a May 2017 average of 19,667 bpd.

The BP-operated Prudhoe Bay field, the Slope's largest, averaged 259,387 bpd, down 3.2 percent, 8,528 bpd, from an April average of 267,915 bpd and down 10 percent from a May 2017 average of 280,900 bpd. In addition to the main Prudhoe oil pool, Prudhoe Bay production includes Aurora, Borealis, Lisburne, Midnight Sun, Niakuk, Polaris, Point McIntyre, Put River, Raven and Schrader Bluff.

The ConocoPhillips-operated Colville River field averaged 66,390 bpd in May, down 1.3 percent, 859 bpd, from an April average of 67,249 bpd and up 0.3 percent from a May 2017 average of 66,192 bpd. In addition to oil from the main Alpine pool, Colville production includes satellite production from Fiord, Nanuq and Qannik.

Cook Inlet

Cook Inlet production averaged 15,952 bpd in May, down 0.9 percent, 143 bpd, from an April average of 16,095 bpd.

Hilcorp's Beaver Creek field averaged 86 bpd, down 4.4 percent from an April average of 90 bpd.

Granite Point, also operated by Hilcorp, averaged 2,869 bpd in May, up 0.7 percent, 21 bpd, from an April average of 2,848 bpd.

Hansen field, the Cosmopolitan project, operated by BlueCrest, averaged 841 bpd in May, up 9.9 percent, 76 bpd, from an April average of 765 bpd.

Hilcorp's McArthur River field, Cook Inlet's largest, averaged 5,246 bpd in May, down 0.7 percent, 37 bpd, from an April average of 5,283 bpd.

Middle Ground Shoal, also operated by Hilcorp, averaged 1,515 bpd in May, up 2.2 percent, 32 bpd, from an April average of 1,483 bpd.

Redoubt Shoal, operated by Glacier Oil and Gas subsidiary Cook Inlet Energy, averaged 1,204 bpd, down 11.9 percent, 163 bpd, from an April average of 1,367 bpd.

Hilcorp's Swanson River field averaged 1,560 bpd, up 3.7 percent, 55 bpd, from an April average of 1,505 bpd.

Trading Bay, also operated by Hilcorp, averaged 1,731 bpd, down 1.3 percent, 23 bpd, from an April average of 1,754 bpd.

Glacier's West McArthur River averaged 900 bpd, down 10 percent, 100 bpd, from an April average of 1,000 bpd.

ANS crude oil production peaked in 1988 at 2.1 million bpd; Cook Inlet crude oil production peaked in 1970 at more than 227,000 bpd. ●

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● EXPLORATION & PRODUCTION

Seismic results at Greater Point McIntyre

BP's latest plan of development for six Prudhoe Bay participating areas makes frequent reference to 2014-15 North Prudhoe seismic

By KRISTEN NELSON
Petroleum News

BP Exploration (Alaska) has submitted plans of development for six participating areas in the Greater Point McIntyre area to the Alaska Department of Natural Resources, Division of Oil and Gas: Lisburne, combined Niakuk, Point McIntyre, Raven, North Prudhoe Bay and West Beach.

Combined, these PAs contributed an average of 30,850 barrels per day of production in the 12 months from April 1, 2017, to March 31, 2018.

The PODs note that the Lisburne Production Center continues to be gas constrained — there are mentions in the PODs that the facility is at maximum capacity given the constraint.

BP said these are mature areas where production is expected to continue to decline, but also noted that the areas were covered by the North Prudhoe seismic shot in 2014-15. Processing was completed on that seismic in September 2016, BP said, with interpretation focused on improving structure mapping over the entire area, "and now detailed analysis of substructures will begin for prospect identification into 2019."

> *Point McIntyre is the most productive participating area of the group, averaging 14,800 bpd in 2017-18.*

Lisburne

The Lisburne participating area is one of the most productive at Greater Point McIntyre, averaging 13,800 barrels per day over the April 1, 2017, to March 31, 2018, period covered in the POD.

BP said the Lisburne Production Center continues to be gas constrained. Seawater injection into the Lisburne gas cap continues to supplement gas injection for oil recovery. Lisburne gas cap water injection began in 2008 as a pilot and the Alaska Oil and Gas Conservation Commission approved it for permanent injection in January 2017. BP said the injector was shut-in during most of the reporting period awaiting repair, which is planned during the current POD plan year.

The gas cap water injection has resulted in gas-oil-ratio suppression, and several previously uncompetitive wells are being brought back on at L5 Pad, pending gas lift installs, the company said.

One well was drilled and completed during the previous plan period and another was in the process of being completed, and 25 additional Lisburne wells had a total of 30 rate-adding interventions.

Current plans include the possible drilling of three additional wells, and the company said several additional Lisburne drilling locations are being considered for possible future drilling, contingent on continued performance of the 2015-17 drilling program and performance of new wells that may potentially be drilled.

Combined Niakuk participating area

The combined Niakuk PA averaged 1,200 bpd in the 2017-18 reporting period. "This rate, combined with production from the other GPMA fields, fully utilized available Lisburne Production Center (LPC) capacity, within reservoir management constraints," BP said.

BP said there was technical work to assess potential infill and peripheral drilling during the 2017-18 reporting period, with an updated integrated subsurface project underway utilizing the 2014-15 North Prudhoe seismic survey. The survey was completed in April 2015, final pre-stack depth migration processing was completed in September 2016. "A new interpretation of the data was utilized for an update to the reservoir description of the Niakuk field," BP said.

The company said "Niakuk development well targets are under technical and commercial evaluation," based on the updated reservoir description.

Point McIntyre PA

Point McIntyre is the most productive participating area of the group, averaging 14,800 bpd in 2017-18.

A rate-adding surface project involved the STP 36-inch pipeline, which had been taken out of service in November 2011. Until October 2016, all Point McIntyre production went to the Lisburne Production Center but following completion of the STP-36 project in that month, all PM-2 pad production went to Gathering Center 1, "resulting in increased production at LPC," the company said. The project restored the STP-36 line to service by combining the usable portion of the STP 36 line with an existing common line. Previously PM-2 production had been split between LPC and GC1.

There is a tertiary recovery process at Point McIntyre with alternating cycles of miscible gas injection and water injection. Miscible gas injection started in October 2000, with 293 billion cubic feet of MI gas injected into the reservoir to date.

Point McIntyre was covered in the 2014-15 North Prudhoe seismic survey with interpretation focused on improving structure mapping and understanding subsurface areas of interest — the Kuparuk, Sag, Ivishak, Lisburne and Alapah intervals.

"The seismic has resulted in a better understanding of flank opportunities, and coil sidetracks are currently being evaluated," BP said.

A project to expand MI to the PM-1 pad is planned for 2018, the company said, similar to the project that expanded the volume of MI to PM-2 in the previous plan year.

Raven PA

The Raven participating area averaged 1,050 bpd in 2017-18.

NK-14B was spudded at Raven in March 2017. BP said it is an extension well delineating the extent of the Raven oil pool and is being produced on a tract operation basis as information is gathered. NK-14B is a horizontal well completed in the Sag River formation.

NK-15Ai was spudded in February and completed as an injector at a new location in the Raven pool.

BP said technical evaluations of Raven drilling options are using the 2014-15 North Prudhoe seismic survey, and those "evaluations combined with drilling results will form the basis for potentially expanding the Raven PA."

North Prudhoe, West Beach

Two of the participating areas, North

see SEISMIC RESULTS page 5

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● GOVERNMENT

GAO reviews Strategic Petroleum Reserve

Changing scenarios for usage and aging crude oil storage infrastructure give rise to challenges over long-term plans for facility

By ALAN BAILEY

Petroleum News

The U.S. Government Accountability Office has reported the results of its investigation into the operation of the U.S. Strategic Petroleum Reserve and has recommended some ways of better ensuring that the reserve can continue to fulfill its role. The reserve, by storing large volumes of crude oil, provides the United States with an oil supply buffer capable of mitigating oil supply disruptions. The reserve also enables the country to meet its commitment to maintain emergency oil reserves under the terms of the International Energy Agency's International Energy Program. The U.S. Department of Energy manages the reserve.

Congress authorized the creation of the Strategic Petroleum Reserve in 1975 in response to the Arab oil embargo of 1973 to 1974. The bulk of the reserve, currently amounting to about 665 million barrels, is stored in underground salt caverns at four major sites on the Gulf Coast. In addition, as part of the SPR, the Northeast Gasoline Supply Reserve holds 1 million barrels of gasoline. The Northeast Home Heating Oil Reserve also holds 1 million barrels of ultra-low sulfur distillate, although this is not part of the strategic reserve.

Changing priorities

The original concept behind the strategic reserve was to protect the United States from disruption to oil imports. And, under the IEA's rules for its International Energy Program, each oil importing country that is an EIA member must hold a reserve representing at least 90 days of net oil imports. Those reserves can be in the form of crude oil or petroleum products such as gasoline or diesel fuel. And the reserves can be held by the government or by private industry or by some combination of the two.

Although the U.S. has been able to use its strategic reserve to meet its international obligations for the holding of reserves, the U.S. has tended to use the reserve to guard against fuel supply disruption within the country as a consequence of catastrophic events such as earthquakes and hurricanes, the GAO report says. And changes in the global oil market have impacted the reserve requirements. In particular, the recent upsurge of U.S. oil production has reduced U.S. oil imports, a factor that has resulted in the volume of oil stored in the reserve climbing well above that 90-day minimum limit.

To help fund the modernization, in fiscal year 2017 the agency raised about $323 million from the sale of oil in the reserve.

The increased importance of the strategic reserve as a contingency against internal U.S. oil supply disruption has raised some issues. In particular, the location of the reserves storage site on the Gulf Coast may make it difficult to support a supply disruption in some other part of the country. Moreover, since the supply disruption may impact the availability of refined products, the availability of crude oil from the strategic reserve may be of limited usefulness, the GAO report says.

Aging infrastructure

Also, much of the infrastructure at the storage sites on the Gulf Coast is now of an age beyond its serviceable life. There are growing concerns about the system's ability to continue to operate as intended, and there have been equipment failures, including a pipeline leak.

Any addition or reduction of the volume of oil held in the strategic reserve requires Congressional approval. But, although DOE has examined the economic benefits of a range of reserve sizes, the agency has not determined an optimum size for the reserve, the GAO report says. In addition, DOE has not determined whether additional regional reserves of petroleum products should be added to the strategic reserve, to support internal U.S. supply disruptions, the report says.

Modernization program

The DOE has a modernization program

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SEISMIC RESULTS

Prudhoe Bay and West Beach, had no production in 2017-18.

In upcoming plans, which cover Oct. 1 this year through Sept. 30, 2019, BP did not propose bringing those two PAs back into production. North Prudhoe Bay produced from a single well completed in 1993; the well was shut-in in February 2000 due to safety concerns and BP said it has reviewed the condition and history of the well and concluded "that the well is not currently in condition to bring on line and flow."

There are also issues with a 6-inch line in the area that will require an internal pipeline integrity inspection and once that work has been completed, expected to be in 2019, "additional prospects will be evaluated for development in the North Prudhoe Bay PA," BP said.

West Beach production began in 1993. BP said the field has been delineated with 11 penetrations — seven wells and four sidetracks — and has produced a total of 3.37 million barrels of crude, with some 92 percent from the original WB-04 well.

Oil production at West Beach was suspended in the second quarter of 2001 due to increasing gas oil ratio and declining reservoir pressure. BP detailed attempts which have been made to put West Beach back into production through 2010 and said production through West Beach production lines will not be restarted until an internal pipeline integrity inspection is made, with engineering studies of the pad underway and assessment of the current conditions of the pipeline and surface kit expected to be complete in 2019. This is the same line which is impacting North Prudhoe Bay production. ●

Contact Kristen Nelson at knelson@petroleumnews.com

GOVERNMENT

Stedman named to petroleum council

Alaska state Sen. Bert Stedman, R-Sitka, said June 28 that he will serve on the National Petroleum Council. He was named to the council by Rick Perry, secretary of the U.S. Department of Energy.

The National Petroleum Council is an advisory board to the secretary of Energy on oil and natural gas issues. Stedman's role will be to represent the views of the states in public policy decision making.

BERT STEDMAN

Stedman previously served on the council in 2014 and 2015, and said he looks "forward to again representing Alaska's unique position on oil and gas issues as the only true Arctic state in the U.S."

"During my prior service on NPC I was very engaged in a comprehensive study looking at the potential development of oil and gas deposits in Alaska's arctic," Stedman said. That study, published in 2015, is available on the council's website at www.npcarcticpotentialreport.org/.

The council was established in 1946 by President Truman.

Its website shows 218 members, representing integrated, refining and oil and gas production companies; midstream and retail oil and gas companies; support services companies; electric companies and other large consumers; and non-industry and not-for-profit members.

Three Alaskans currently serve on the council — all in the non-industry and not-for-profit category: Richard Glenn of the Arctic Slope Regional Corp.; Alaska Commissioner of Natural Resources Andrew Mack; and Stedman, representing The Energy Council. The Energy Council, an organization in which Alaska legislators have regularly participated, describes itself on its website as "the world's leading members platform for direct engagement between investors, asset owners, developers and government stakeholders."

—KRISTEN NELSON

● UTILITIES

Moving toward a more unified approach

Alaska Railbelt electric utilities have made significant progress in coordinating their operations but much remains to be done

By ALAN BAILEY
Petroleum News

Over the past month or so the Regulatory Commission of Alaska has held a series of public meetings to review progress by the Alaska Railbelt electric utilities in moving towards a more unified approach to managing and operating the Railbelt electrical system. The meetings have demonstrated significant progress towards efficiency gains though inter-utility coordination. However, some key milestones in the unification process have yet to be reached.

Fragmented system

The Railbelt electrical system, a product of the manner in which the more populous regions of the state have evolved, is owned and operated by six independent utilities. The state of Alaska also owns a sector of the electricity transmission grid. Thus, given the state's relatively low population, the six utilities in total serve a customer base and electrical load much smaller than those of most individual utilities elsewhere in North America. The balkanized nature of the system ownership and operation leads to inefficiencies in terms of how the system as a whole operates. And that impacts the cost of electricity.

In June 2015 the RCA issued a series of recommendations for a more unified approach to the operation of the Railbelt electrical system. Essentially, those recommendations consisted of the need to implement merit-ordered economic dispatch on the system; the formation of a single transmission company, or transco, to operation the transmission grid; and the implementation of a single set of enforceable reliability standards. These unification efforts also require the formation of some form of unified operator, to oversee how the entire electrical system is managed.

The overall objective is to minimize the cost of electricity for consumers while maintaining an acceptable level of supply reliability.

Voluntary efforts

The RCA has encouraged the utilities' voluntary efforts to meet its recommendations. The recent commission public meetings were convened to review the status of those efforts — the commission anticipates reporting to the state Legislature this year on how much progress has been made. And some stakeholders in the electrical system have expressed frustration at what they regard as slow progress. The utilities have commented on the complications involved: Each utility has its own contractual arrangements, its own assets that need to be paid for, and its own consumers to satisfy. And a change that may have a net benefit for the system as a whole, may work to the detriment of an individual utility.

American Transmission Co., a Wisconsin transco, has been assisting the six Railbelt utilities in figuring out how a transco could be implemented in the Railbelt.

Economic dispatch

Economic dispatch, the first of the issues to be addressed, involves the continuous use of the cheapest available power generation. For some years the utilities have been interchanging power through power sales to each other, but full economic dispatch involves doing this on a more continuous, minute-by-minute basis. One complication is the layout of the Railbelt transmission grid: Power demand regions on the Kenai Peninsula and in the Fairbanks area are each connected by a single transmission intertie to the major demand center in Southcentral Alaska. So, although the utilities can and do interchange power across the entire system, those single interties represent single points of failure, a factor that requires power generation self sufficiency on both the peninsula and in Fairbanks, to assure continuity of power supplies.

In January 2017 the three Southcentral utilities, Chugach Electric Association, Municipal Light & Power and Matanuska Electric Association, formed an agreement to jointly implement economic dispatch in Southcentral. Given the complications involved, that initiative is taking longer than the utilities had originally anticipated. In one of the recent RCA meetings the utilities said that they now anticipate finalizing agreements for the power pool by the end of September, with full implementation of the new arrangements in March 2019 following RCA approval.

That would lead to the possibility of

see RAILBELT UNIFICATION page 8

● EXPLORATION & PRODUCTION

Commission receives 2 commingle requests

BP applies to commingle Put River, Prudhoe oil pool production; Hilcorp applies for single-well Beluga, Tyonek gas pool commingling

By KRISTEN NELSON
Petroleum News

The Alaska Oil and Gas Conservation Commission has received two applications for commingling of production in wellbores, one from BP Exploration (Alaska) and one from Hilcorp Alaska.

Prudhoe, Put River oil pools

BP is the Prudhoe Bay field operator. In its June 20 application the company requests amendment of commission conservation orders for the Prudhoe oil pool and the Put River oil pool to allow pool wide downhole commingling.

In its application BP said Put River oil pool appraisal activities in 2005 identified oil and gas condensate in the western and central lobes of the Put River oil pool, but further development of those lobes "was not pursued at that time in part due to low flow rates that resulted in significant operational challenges and associated down-time due to hydrate deposition."

BP said there are several wells that penetrate both the Prudhoe and Put River oil pools and could be completed in both pools. The company said that commingling production in the same well bore would increase fluid rate and velocity, "resulting in higher flowing wellhead temperatures and reduced production problems associated with hydrate formation," allowing for recovery of a greater quantity of Put River oil and gas condensate.

Commingling would not cause waste, BP said, and told the commission there are several potential wells in which existing Ivishak production from the Prudhoe oil pool could be commingled with Put River production. The company told the commission that production from the separate wells can be properly allocated.

Beluga, Tyonek gas pools

Hilcorp applied June 21 for downhole commingling of production from the Beluga and Tyonek gas pools in the same wellbore in well SRU 14-15 in the Swanson River field. Without commingling approval, the company said, it would plug and abandon the well.

Hilcorp said SRU 14-15 was drilled by Standard Oil Co. in July 1959 and initially produced oil from the Hemlock formation. The well was shut-in and temporarily abandoned in 1963 after producing a total of some 14,300 barrels.

"The well is currently shut-in in hopes to add perforations in the Beluga and Tyonek formations which may result in adding production in commercial quantities," the company told the commission.

Union Oil Company of California perforated and tested the Tyonek formation in the well for gas in June 2001 but did not find commercial quantities. Hilcorp perforated and tested the Tyonek sands in November 2017, detecting a small amount of gas, but without enough reservoir pressure to sustain flow.

"The well is currently shut-in in hopes to add perforations in the Beluga and Tyonek formations which may result in adding production in commercial quantities," the company told the commission.

The federal Bureau of Land Management has already granted commingling and allocation approval from the Beluga formation in SRU Tract 2 and the Tyonek participating area in the SRU-14-15 well, based on a May 14 application, Hilcorp told the commission.

"To extend the productive life of this wellbore, Hilcorp now requests that the AOGCC grant a waiver of the requirement to provide complete separation of flow streams from different pools as specified in 20 AAC 25.210 for commingling of production within the same wellbore from the Beluga Gas Pool and the Tyonek Gas Pool. Hilcorp plans to add bypassed production in the Beluga and Tyonek formations without isolating existing perforations within the Tyonek formation, in order to return SRU 14-15 to production," the company said.

The commission has tentatively scheduled hearings on the applications (Aug. 6 on the BP request, Aug. 7 on the Hilcorp request), but said in both cases that if hearings are not requested per its notices it may issue orders without holding hearings. ●

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GAO REVIEW

to address the age of the strategic reserve facilities, but the scope of the modernization program has undergone several changes in response to changing conditions and requirements. To help fund the modernization, in fiscal year 2017 the agency raised about $323 million from the sale of oil in the reserve. And Congress has approved the draw down and sale of up to $350 million worth of oil in fiscal year 2018. DOE has been moving forward with the modernization program, and the first major construction is scheduled for fiscal year 2019.

DOE now assumes that the strategic reserve will in future store some 405 million barrels of oil, a figure well below the facility's design capacity of about 713 million barrels. In response, DOE may close one of the strategic reserve sites, the GAO report says. DOE could also consider leasing excess storage capacity to other countries, the report says.

But long-term uncertainty regarding the required scale and configuration of the strategic reserve hampers mid- to long-range planning efforts for the modernization project, the report says. And DOE does not have the authority to pursue options for the use of excess capacity in the strategic reserve facilities, the GAO report says.

Four recommendations

In response to the issues that the strategic reserve faces, the GAO has made four recommendations.

First, the DOE should supplement its current strategic view of the reserve, taking into account the response of the private sector, oil market projections and the costs and benefits of a range of strategic reserve sizes. Second, the agency needs to periodically review and provide to Congress its analysis of potential reserve sizes. Third, the agency should analyze the benefits of holding regional reserves of petroleum products. And fourth, as part of its analysis of oil sales mandated by Congress, the agency should consider a full range of options for handing the resulting excess storage assets.

DOE has partly agreed with the first recommendation, saying that it would supplement its current long-term strategy but commenting that a full cost-benefit of the strategic reserve may not be meaningful, since most of the costs of the system have already been incurred. However, the agency did concur with the recommendation for regular reporting to Congress.

The agency disagreed with the third recommendation, citing a number of concerns including a view that the operation of government owned and/or operated regional reserves of petroleum products would be inefficient and expensive. With the U.S. having the world's most robust oil refining system, it would be preferable to provide reserve supplies of crude oil to refineries in the event of disruption to the supply of refined products, DOE said.

DOE told the GAO that it concurs with GAO's fourth recommendation, saying that the agency has already begun a study into the disposition of excess or underused petroleum reserve assets. ●

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LAND & LEASING

Preliminary BIF out for Cook Inlet sales

The Alaska Department of Natural Resources, Division of Oil and Gas, has issued a preliminary best interest finding for Cook Inlet areawide oil and gas lease sales from 2019-2028. The division said the director has preliminarily found that Cook Inlet oil and gas lease sales from 2019-28 are in the best interests of the state.

The preliminary BIF, published June 29, is available on the division's website at http://dog.dnr.alaska.gov/.

The division will be taking public comments through Aug. 30 and said the finding will be revised as needed and any relevant information and issues brought up during the public comment period will be incorporated into the final finding as necessary.

The BIF would cover sales for 10 years with the issuance of annual supplements as needed.

The division said in the preliminary BIF executive summary that while Cook Inlet has rock sequences with proven oil and gas potential, it is a mature producing basin which has been under exploration and development for 60 years. "The chances of finding major undiscovered petroleum reservoirs are reduced due to the extensive exploration that has already taken place," the division said.

It did note that while many of the basin's oil and gas fields are considered mature, "there has been an increase in activity. New companies have entered the basin, employing new seismic exploration and drilling technology. In many cases, development drilling programs in existing fields have focused on previously unrecognized pay zones."

—PETROLEUM NEWS

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RAILBELT UNIFICATION

Fairbanks-based Golden Valley Electric Association joining the "tight pool." Homer Electric Association on the Kenai Peninsula, on the other hand, has indicated that it sees little benefit in joining the pool.

Transmission company

The establishment of a transco for the transmission grid could in particular address a couple of current problems: the cost of "wheeling" electricity over multiple grid sectors, each with its own transmission fees; and the difficulty of a single utility investing in grid upgrades that benefit multiple utilities, and not just itself.

American Transmission Co., a Wisconsin transco, has been assisting the six Railbelt utilities in figuring out how a transco could be implemented in the Railbelt. The idea is that the transco would operate the transmission infrastructure, set a unified tariff for transmission system usage, and act as a conduit for investment in the transmission infrastructure.

In May the utilities told the commission that they have made substantial progress in agreeing on how the transco would operate: Essentially the utilities would continue to maintain the sections of the transmission grid within their service areas but would do so under contract to the transco. And the transco would maintain a non-discriminatory tariff, allowing anyone access to the grid. However, an acceptable method of allocating operating costs between the utilities, especially given different utilities' different ownership and usage of the system, has yet to be determined. Nor have the utilities agreed on the structure of a transco management team. The utilities told the commission that they now anticipate filing a transco decision by the end of this year.

Reliability standards

The utilities have in the past operated under two different sets of reliability standards but have recently worked on unifying those standards. In April the utilities filed a unified set of standards with the commission. However, the standards need to address cybersecurity, an issue of significant and growing concern involving the potential for malware to bring down the computer and information systems that are used to operate the electrical system. The utilities have told the commission that they have formed a cybersecurity working group and that this group is making rapid progress, anticipating the implementation of cybersecurity standards in the first quarter of next year, following regulatory approval.

System operator

The reliability standards would presumably be enforced by a system operator, overseeing the entire Railbelt system. There has been significant controversy over various ideas for the potential role of an operator, and in particular how the operator should be governed. Independent power producers, including producers of renewable energy, want to see independent governance that can assure open access to the electrical system for anyone meeting required operating standards. Utilities want to see governance decisions take adequate account of the utilities' technical expertise.

From various operator concepts that have emerged in recent months, it appears that there has been some convergence in the governance concepts. The utilities have commissioned GDS Associates to facilitate what they are calling the Railbelt Reliability Council. The RRC, regulated by the RCA, would oversee the reliability standards, open access to the transmissions system, and the planning of expansions to the power generation and transmission arrangements. However, GDS has recommended that the RRC should not initially be responsible for the oversight of economic dispatch in the Railbelt — given the cost of implementing economic dispatch, the RRC should first conduct some modeling to assess the costs and benefits, GDS recommends.

Some stakeholders have expressed concern, saying that a Railbelt system operator must manage economic dispatch in the system. In addition to the RRC, two other operator concepts have been floated, one by the Alaska Energy Authority and one in a bill in the state Legislature.

The utilities are in the process of finalizing a memorandum of understanding for RRC formation, probably for filing with the commission in August. RCA approval of the MOU would presumably be followed by RRC formation, although the regulatory mechanism for the entity would need to be clarified. ●

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LNG GOALS

Carr said the report shows that oil and gas, which will be a vital part of the energy mix "for quite a while," can over time be extracted "more sustainably than ever. We are on the road to accomplishing that."

He said the report's advice is closely aligned with a recent consensus reached by G20 energy ministers on how to move the world off the dirtiest sources of energy and will form the basis of Canada's national energy strategy that will be developed more fully in August at a meeting of federal and provincial energy ministers.

But not everyone is buying into Carr's view, with Keith Stewart, a senior energy strategist at Greenpeace, arguing that the report has failed to establish a vision for moving off fossil fuels entirely in line with its Paris agreement goal of net zero emissions.

Others, however, reject the arguments of some environmentalists that the development of LNG in British Columbia is incompatible with provincial GHG reduction targets.

"Natural gas might be better than coal, but it's still pretty greenhouse gas intensive," he told The Canadian Press.

Others, however, reject the arguments of some environmentalists that the development of LNG in British Columbia is incompatible with provincial GHG reduction targets.

Rod Seeley, president of E3 Merge Consulting, wrote in the National Post that British Columbia is poised to become a world leader in LNG facility performance.

He said the province's climate policies, including a C$35 per metric ton carbon tax that will increase to C$50 by 2022, and a 45 percent reduction in methane emissions from oil and gas are setting a standard for the rest of the world.

Lowest GHG emissions

Seeley said LNG facilities that meet British Columbia's performance requirements will have the lowest GHG emissions anywhere, producing 50 percent fewer emissions than the average global LNG facility and 30 percent fewer than the best LNG plants currently in operation.

But he cautioned that British Columbia needs to "find the right balance between climate policy to ensure that significant opportunities like LNG investments being proposed in B.C. don't go to other countries that have little or no GHG policy and are more carbon intensive (than B.C.)."

B.C. has the ability to develop its wealth of natural resources "in a sustainable manner, provide jobs and economic opportunity for the province and deliver products to the world that have the lowest carbon intensity," Seeley said.

He estimated that output from one LNG plant in B.C. exported to Asia could provide enough energy to replace or displace up to 40 coal-fired power plants with cleaner-burning natural gas.

That, Seeley estimated, could reduce global GHG emissions by 60 million to 90 million metric tons a year of carbon dioxide — an amount roughly equal to 10 percent of Canada's annual GHG emissions.

—GARY PARK

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Petroleum news Oil Patch Bits

Sorensen named 2018 Alaska Truck Driver of the Year

COURTESY LYNDEN

Lynden Transport recently announced that Jack Sorensen was named the 2018 Alaska Truck Driver of the Year by the Alaska Trucking Association. Lynden drivers have been named driver of the year four out of the past five years. Lynden Transport driver John Schank received the award twice — in 2014 and 2017 — and Alaska West Express driver Brian Ambrose was recognized in 2016. Ambrose was named second place overall champion in this year's competition, as well as taking first place in the sleeper truck class.

"We are extremely proud of the professionalism and commitment our drivers exhibit every day on the job, but also the knowledge and skills they bring to the annual ATA truck driving championships," says Lynden Transport President Paul Grimaldi. "These drivers are the best of the best. They must complete a written knowledge test, a pre-trip inspection and a skills course as part of their participation."

Sorensen has earned many first-place finishes in the annual driving competition in Anchorage and has maintained an accident-free record for 34 years. He has traveled to the national truck driving competition seven times over his long driving career.

ASRC announces industrial services acquisition

Arctic Slope Regional Corp. said June 28 that it is pleased to announce the acquisition of Hudspeth & Associates by its wholly owned subsidiary ASRC Industrial Services LLC.

Headquartered in Englewood, Colorado, with a satellite office in Rifle, Colorado, Hudspeth provides environmental remediation, demolition, dismantlement and civil site services throughout the Rocky Mountain region. Hudspeth serves a diverse customer portfolio made up of industrial and commercial enterprises, state and local governments, as well as federal agencies. Since the company's founding in 1998, Hudspeth has differentiated itself from competitors via its relentless focus on safety and willingness to partner with customers to overcome complex challenges with unique, innovative solutions.

"Today's announcement of the acquisition of Hudspeth is another exciting day in the pursuit of the AIS strategy that ASRC initiated in September 2016," said Rex A. Rock Sr., president and CEO of ASRC. "On behalf of ASRC's board of directors, I am pleased to welcome the management team and talented employees of Hudspeth to the ASRC family of companies. I am confident the addition of Hudspeth to the AIS platform will contribute to delivering durable, enduring benefits to ASRC shareholders."

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

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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LINE 3

In a separate 3-2 decision the commission approved Enbridge's preferred route for the new line south of the existing corridor, recommending only slight changes, meaning that the company could avoid further delays and added costs.

Prospect of clashes

Despite those gains, Enbridge faces the prospect of clashes with Native Americans, who oppose the project because of concerns about spills and the impact on tribal wild rice harvesting areas and interrupted the commission hearings with shouts of "Shame on you, you cowards."

Winona Laduke, an Ojibwe and executive director of Honor the Earth, said the regulatory decision is "an act of aggression by the Minnesota government and we will do what we need to legally protect our land," while the Fond du Lac tribe has vowed to appeal the commission's decision.

In a change from its original plans, Enbridge has pledged to remove segments of the old pipeline if asked to do so by landowners, while stopping short of offering to dig up the entire system at a cost of US$1.28 billion.

The company had no immediate comment on the outcome of a regulatory process that has lasted four years, although Chief Executive Officer Al Monaco has made it clear that Line 3 is a vital part of Enbridge's C$22 billion growth plan and its strategy for reducing a debt burden.

Flow could begin in 2019

Enbridge has indicated that crude could flow on the new line by late 2019 but warned that any further changes ordered by the state to the company's preferred route could extend the completion over "multiple construction seasons."

Public utilities commissioner Matt Schuerger said that regardless of Enbridge apportionment of space on the existing line refineries are "clearly" still getting oil and have "zero" idle capacity at their facilities.

Eric Swanson, a Minneapolis-St. Paul attorney for Enbridge, said railroads have been supplying crude to the region's refineries because of rationing by Enbridge.●

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MARINE SERVICES

Tanker damaged

A problem did occur on June 27 when one of the new tugs, the Ingot, bumped into the tanker Florida when the tug was coming alongside the tanker to assist with the docking at a berth. There was a hard landing, with metal-to-metal contact, causing a dent about 20 inches long, six inches wide and three inches deep in the tanker's hull, Egan said. However, the Florida was able to depart on June 28, after an inspection by the American Bureau of Shipping and clearance by the U.S. Coast Guard, Egan said.

Although tugs and tankers come into contact and scrapes can occur, Alyeska is concerned about the scale and location of this particular damage. Egan said that the company immediately launched an investigation and has ruled out mechanical issues or vessel design as contributing factors. There have been meetings between the tug captain, the marine pilot and the tanker master, with a resulting agreement over increased levels of communication during the docking an undocking of tankers, and over the need to reduce the speeds of both tankers and tugs as they come alongside, Egan said.

The marine services

Alyeska's Ship Escort/Response Vessel System, known as SERVS, manages the marine services, which provide tug assistance for tankers berthing at the Valdez Marine Terminal, while also supporting oil spill prevention and contingency plans for the terminal and the tanker operations. As part of the spill prevention program, tugs escort tankers through the Valdez Narrows at the entrance to Port Valdez, and across Prince William Sound between Port Valdez and the Gulf of Alaska.

The marine transition results from a decision by Alyeska, operator of the trans-Alaska pipeline and the marine terminal, to put the contract for the marine services to competitive bid — in August 2016 Alyeska announced that it was awarding the contract to Edison Chouest.

A huge project

The transition has been a huge, complex project: Edison Chouest built five new tugs, purpose designed for escorting tankers; four general purpose tugs; and four new barges, purpose built for oil spill response. The new oil spill response barges were specifically designed for use in Valdez and are equipped with new state-of-the-art oil skimmers. The project has required training for the Edison Chouest crews, and demonstrations that the new vessels can perform their required tasks in the challenging sea conditions of Prince William Sound and the Port of Valdez.

The introduction of new oil spill prevention and response equipment and vessels has necessitated changes to the oil spill contingency plans, both for the marine terminal and for the tanker operations. The Alaska Department of Environmental Conservation has to approve the plans. Both of the contingency plans are in hand, and all of the training, exercises and demonstrations required to date have been completed, Egan said. ADEC has cleared all essential vessels for use, she said.

As is normal with the marine services, there will be continuing training and demonstrations, Egan said.

Improved efficiency

In addition to being designed specifically for use in support of the Valdez tanker operations, the vessels have consistent designs, a factor that enables improved operational efficiency. And the response barges have been designed with decks almost clear of equipment and piping, and with command modules elevated for maximum visibility of the barge operations.

The new vessels started arriving in Valdez in March. Since then, there have been more than 100 deployments and demonstrations in Prince William Sound, including the docking and undocking of tankers, Egan said. Incoming crews of experienced mariners have completed more than 35,000 training hours in total and have demonstrated their capabilities in Prince William Sound operation and with Crowley mariners, she said.

"I think we're just happy to be celebrating this transition," Egan said. "The system is better than it's ever been."

—ALAN BAILEY

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AOGCC ORDERS

for plugging and abandoning the wells because the leases on which the wells were drilled had expired and plugging and abandonment are required prior to lease expiration. NordAq told the commission that the wells had not been initially plugged and abandoned because there were other uses for the wells and the company believed that other companies were interested in using the wells.

But other companies did not take over the wells.

Shadura

In late 2016 the commission proposed the following for Shadura: a $621,000 civil penalty and a requirement that NordAq provide a $1.2 million check to the commission, the commission's projected cost to plug and abandon the Shadura well if NordAq did not perform that work. The well was drilled in 2011.

After the commission public noticed a hearing for April 4, 2017, NordAq contacted the commission with a plan to P&A the Shadura well, a plan the commission approved in February 2017.

After the April hearing, the commission issued a revised notice of proposed enforcement action changing the requirement for the $1.2 million check to a bond in that amount in favor of the commission. The civil penalty was reduced $100,000. NordAq was required to P&A the well and have the location cleared within one year of the May 24, 2017, revised notice.

NordAq requested reconsideration and oral argument, which were held Sept. 20, 2017. At that time the company told the commission the well would be plugged and abandoned by Feb. 28, 2018.

NordAq admitted to a violation of regulations but said a $10,000 civil penalty would be more reasonable.

The commission said in its June 29 order that the Shadura well was plugged and abandoned March 19, 2018.

The commission reduced the civil penalty to $25,000 and rescinded the requirement for the $1.2 million bond.

Tiger Eye

The commission initially proposed a civil fine of $150,000 for the failure to plug and abandon Tiger Eye and required that NordAq provide a $1.3 million check, the commission's proposed cost to plug and abandon the well if the company did not do that work. Tiger Eye was drilled in 2012 and suspended. The commission said the well, on the west side of Cook Inlet, is only accessible during summer months.

The well's bottom hole location is on a state lease which expired in October 2016. A portion of the well crosses a CIRI lease, which was terminated in July 2015.

After the commission scheduled a public hearing for April 2017, NordAq contacted the commission with a proposed plan to P&A Tiger Eye, a plan which the commission approved in early March 2017.

After the April 2017 hearing the commission issued a revised notice of proposed enforcement action, lowering the civil penalty to $100,000 and changing the requirement for the $1.3 million check to a bond in that amount in sole favor of the commission. The notice specified that the bond would be forfeited if Tiger Eye had not been permanently plugged and abandoned and cleared the well location within a year of the revised notice.

After an informal review requested by NordAq, the commission reduced the civil penalty to $100,000 and reduced the required bond amount to $800,000, requiring proof of the bond within 30 days.

NordAq requested an extension of time to file an application to reconsider the requirement for the surety bond and later requested reconsideration and oral argument, held in September.

At the oral argument NordAq advised the commission that Tiger Eye had been plugged and abandoned earlier in September and argued for reduction of the civil penalty to $10,000.

The commission said the well was plugged and abandoned Sept. 9, 2017.

In its June 29 order the commission rescinded the requirement for the $800,000 bond and reduced the civil penalty to $25,000.

—KRISTEN NELSON

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BP-CONOCO SWAP

our legacy assets, as well as in the development of our recent exploration success. Likewise, we are committed to maximizing the value of our assets in the U.K. North Sea, including continued investment in our operated assets in the Central North Sea," Lance said.

ConocoPhillips is already the majority working interest owner at Kuparuk, where it is the operator, at 55.3 percent, followed by BP at 39.2 percent, Chevron at 4.9 percent and ExxonMobil at 0.6 percent, giving ConocoPhillips 94.5 percent at Kuparuk once this deal closes.

BP focus at Prudhoe

BP retains its 26.4 percent interest at Prudhoe Bay which it operates.

"This is a further step in focusing our portfolio around core assets and developments which have the potential for significant growth," said BP Upstream Chief Executive Bernard Looney. "Clair is a key advantaged oilfield for our North Sea business, a giant resource whose second phase is about to begin production and which holds great potential for future developments."

Current Clair partners are BP, operator, 28.6 percent; ConocoPhillips, 24 percent; Shell UK Ltd., 28 percent; and Chevron North Sea Ltd. 19.4 percent.

As a result of this agreement, BP will hold a 45.1 percent interest in Clair and ConocoPhillips will retain a 7.5 percent interest.

"In Alaska, this transaction will increase our focus on managing our deep resource base at the massive Prudhoe Bay oilfield and help enable a more competitive and sustainable business for BP," Looney said.

The interests BP is selling in Alaska are non-operating, while the Clair field, the company said, is a core asset of its North Sea business in the U.K.

Interests in the west side

ConocoPhillips has a strong position on the western North Slope and has been steadily moving west.

In partnership with Anadarko Petroleum ConocoPhillips developed the Alpine field in the Colville River unit west of Kuparuk and farther west is in the process of developing Greater Mooses Tooth in the National Petroleum Reserve-Alaska, where it has also announced a large discovery at Willow.

The company recently closed on its acquisition of Anadarko's 22 percent interests in western North Slope properties, including Anadarko's non-operated interest in the western North Slope and its interest in the Alpine pipeline for $400 million; that transaction had an effective date of Oct. 1, 2017.

The acquisition of BP's Kuparuk interests, including BP's ownership position in the Kuparuk Pipeline, which moves oil to the trans-Alaska oil pipeline, solidifies ConocoPhillips's position on the western North Slope.

Substantial amounts of North Slope crude oil are involved.

The most recent production data by field, from May, shows 66,390 barrels per day from the Colville River unit, some 13 percent of Slope production, and 113,057 bpd at Kuparuk, 22 percent of Slope production. ConocoPhillips also holds a 36 percent working interest ownership at the BP-operated Prudhoe Bay field, the Slope's largest, where May production averaged 259,387 bpd, 50 percent of Slope production. ●

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ICEWINE 2

pad off the Dalton Highway.

The company said suspension of the well has been designed to allow future use of the wellbore, including a horizontal sidetrack with multi-stage stimulation.

More work required

88 Energy said it believes a more significant work program is required to de-risk the HRZ play further "and that the data obtained to date is sufficient to attract a farm-in partner to undertake this program," a plan the company said is consistent with development progression "in all other unconventional resource plays."

Work at Icewine 2 included acquisition of a more sophisticated logging suite to complement the core obtained from Icewine 1. Results included quantitatively proving overpressure of the HRZ, 88 Energy said.

Results from the well "provide the requisite data to confidently design a horizontal well with a multi-stage stimulation that can access the entire height of the formation," the company said.

Joint venture partners are "in the process of engaging with an experienced service provider to provide state of the art analysis and quality control of the existing dataset, undertake additional work and put together an appropriate forward work program to present to potential farminees," 88 Energy said.

—KRISTEN NELSON

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KUPARUK BUMP

rotary wells in 2017 at the Kuparuk participating area (and another six as part of its West Sak development), compared with eight rotary wells at Kuparuk in 2016.

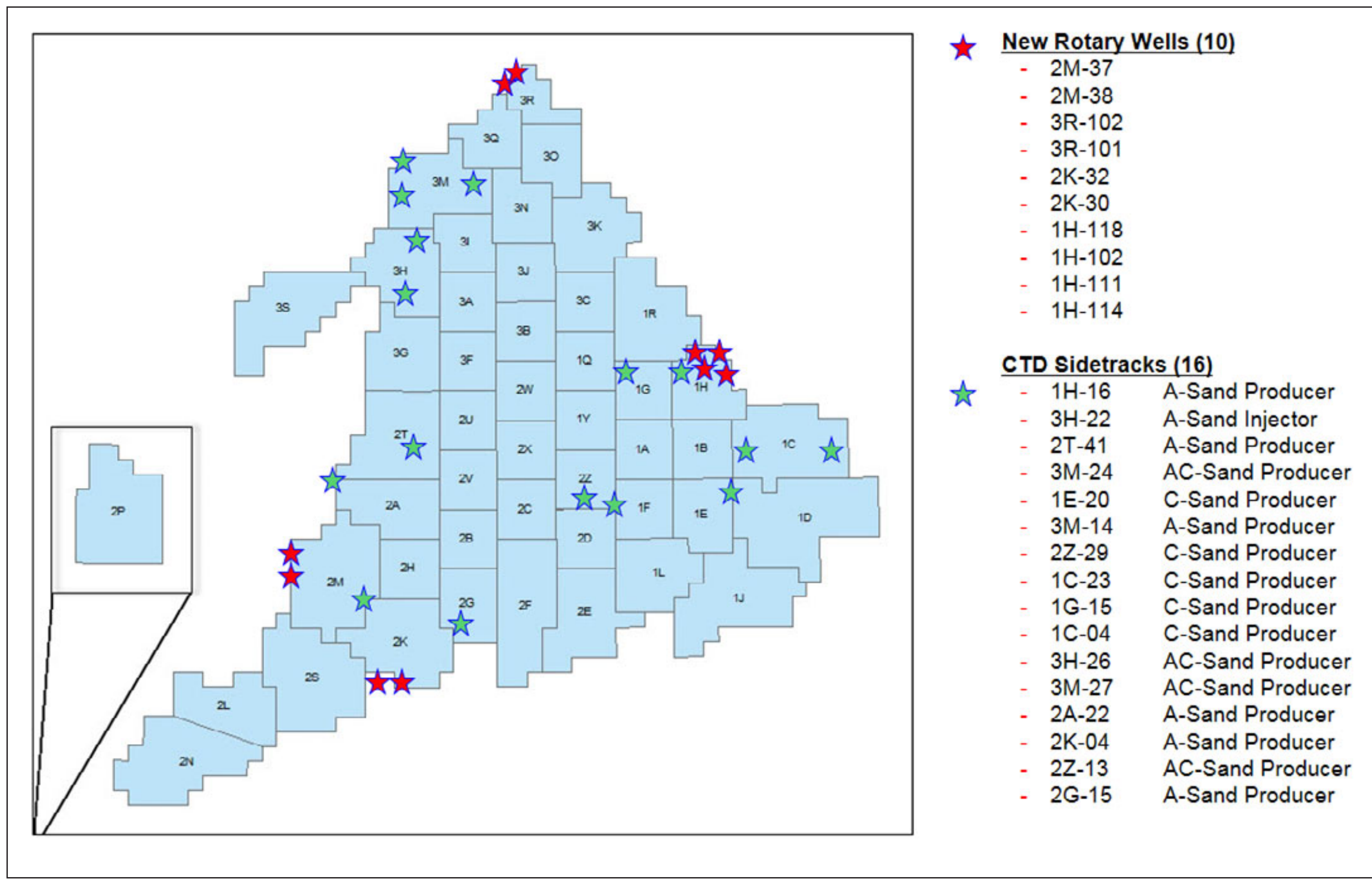
An associated workover program at the Kuparuk field yielded no increase over last year. The company attributed 2,000 bpd to a rigged workover program and another 8,000 bpd to non-rig well work at the Kuparuk field, compared with 1,600 bpd for rigged well and 10,700 bpd from non-rig work in 2016.

For the current year, ConocoPhillips is planning a slight increase in drilling activity at the main Kuparuk field, with 17 coiled tubing sidetracks and five rotary wells. The company is currently developing the main Kuparuk field from 866 active wells — 471 producers and 395 injectors, including 116 water-alternating-gas injectors — equivalent to 2016.

The recent activity at the Kuparuk field reflects the results of the Kuparuk West Sak 3-D seismic program from 2005 and the Western Kuparuk 3-D seismic program from 2011.

But the company has also been engaging in a broader infrastructure-led exploration strategy, where exploration targets close to existing production are given higher priority.

Among those projects is a program targeting the Cretaceous Brookian Moraine interval from Drill Site 3S. The company has been monitoring the reservoir for years from a pair of wells — 3S-613 and 3S-620 — and intends a drill a follow-up pair in 2019. Another exploration project involves 17,920 acres near Drill Site 2S, added in December 2017.



Location of 2017 CTD and rotary drilling projects

Through the end of 2017, the Kuparuk field had produced 2.44 billion cumulative barrels.

West Sak

The only other production bump came from the West Sak satellite

West Sak produced 13,818 bpd from 119 active wells — 60 producers and 59 injectors — in 2017, up from 13,701 bpd from 112 active wells in 2016.

The increase in wells came largely but not entirely from the Drill Site 1H program brought online last year. ConocoPhillips drilled two producers — the 3R-101 and 1H-102 multilaterals — and four injectors — 3R-102, 1H-111, 1H-114 and 1H-118. (Figures from the Alaska Oil and Gas Conservation Commission indicate an additional injection well.)

Through the end of 2017, West Sak had produced 88.6 million cumulative barrels of oil.

The company expects to continue Drill Site 1H development this year. The total 2017-18 program calls for four horizontal multilateral producers and 15 vertical injectors.

A subsequent phase planned for 2019 will target viscous oil at Drill Site 3R. Additional viscous oil opportunities at West Sak exist at Drill Site 1C, Drill Site 1D, Drill Site 3K and Drill Site 3N. Opportunities also remain at Drill Site 1H and Eastern NEWS.

Meltwater, Tabasco, Tarn

The remaining three Kuparuk satellites all experienced production declines last year.

The Meltwater satellite southwest of the main field produced 947 bpd in 2017, down from 1,326 bpd in 2016. The satellite was being developed from 15 active wells in 2017 — nine producers and six injectors — down one injector from 2016.

Through the end of 2017, Meltwater had produced 19.7 million cumulative barrels of oil.

The decline in oil production came, in some measure, from increased natural gas production. A three-week shut-in of the satellite in June 2017 measured back pressure to determine how much oil was being backed out of a common production line due to natural gas production and placed the total at approximately 900 bpd.

West Sak produced 13,818 bpd from 119 active wells — 60 producers and 59 injectors — in 2017, up from 13,701 bpd from 112 active wells in 2016.

While gas flooding remains an efficient tool for enhanced recovery at Meltwater, the increasing gas-to-oil ratio is threatening the economics of some wells, according to ConocoPhillips. The company plans to convert to water flood in late 2018 or early 2019.

The Tabasco satellite produced 1,380 bpd in 2017, down from 1,430 bpd in 2016 from a similar profile of active wells — four producers and two injectors.

Through the end of 2017, Tabasco had produced 20.1 million cumulative barrels of oil.

The Tarn satellite produced 7,800 bpd in 2017, down from 8,400 bpd in 2016, despite an identical active well profile — 39 producers and 24 injectors.

Through the end of 2017, Tarn had produced 121.6 million cumulative barrels of oil. ●

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