Petroleum news

page 3 EIA: lower inventories driving higher prices; consumption up through 2050

Vol. 28, No. 42 • www.PetroleumNews.com A weekly oil & gas newspaper based in Anchorage, Alaska Week of October 15, 2023 • $2.50

Lagniappe files exploration plan for eastern North Slope acreage

On Oct. 4, Nate Lowe, VP of Land & Business Development for Armstrong Oil & Gas Inc. and manager of Lagniappe Alaska LLC filed a land use permit application with Alaska's Division of Oil and Gas for the "Lagniappe Exploration Program" on Alaska's eastern North Slope.

BILL ARMSTRONG

Exploration activity for the multi-year (up to 5 years) permit is expected to begin on Nov. 15. Lagniappe will drill six wells with a maximum of three wells per year. The wells will be drilled on the Lagniappe-operated lease block south of the Badami unit, which encompasses 148 leases on 270,000 acres. Indications are that the company hopes the exploration program will take no more than two consecutive years.

The first winter mobilization, expected to be this winter, will transport and deliver the Doyon 141 drilling rig to the King Street-1 well, the Nabors 105 drilling rig to the Voodoo-1 well, and Sockeye-1 well.

Winter mobilization will be conducted via an overland ice

see EXPLORATION PLAN page 6

19 wells planned at Prudhoe Bay western satellites in 2024 POD

Hilcorp North Slope, the Prudhoe Bay operator, is planning 19 wells at the Prudhoe Bay unit western satellites in 2024, comparable to numbers for this year, which Hilcorp reported as 14 wells completed with an additional four pending execution.

The numbers are from the 2024 plan of development for the PBU western satellites, which Hilcorp submitted to the Alaska Department of Natural Resources' Division of Oil and Gas on Oct. 2. The 2024 POD covers the 2024 calendar year.

Hilcorp submitted the plan on behalf of itself and the other PBU working interest owners: ConocoPhillips Alaska, ExxonMobil Alaska Production and Chevron U.S.A. ExxonMobil is the largest WIO at Prudhoe, holding 36.4%, followed by ConocoPhillips at 36.08%, Hilcorp North Slope at 26.36% and Chevron at 1.16%.

Average daily oil production from the western satellites for the 2022 calendar year was 33,139 barrels per day, Hilcorp said, with Orion averaging 11,329 bpd, Borealis 8,755 bpd, Polaris 7,435

see HILCORP WELLS page 6

Hilcorp looks to convert injector at PTU Central Pad to producer

Point Thomson unit operator Hilcorp Alaska is evaluating converting one of two injectors at Point Thomson into a producer, as production continues to decline from PTU-17, the field's sole producer.

In a plan of development for Point Thomson covering 2024-25, submitted to the Alaska Department of Natural Resources' Division of Oil and Gas on Oct. 2, Hilcorp said gas and condensate are produced from the initial participation area at Point Thomson, with the producer, PTU-17 on West Pad and two injectors, PTU-15 and PTU-16, on Central Pad.

Hilcorp Alaska took over as operator at Point Thomson in October 2021. ExxonMobil Production Alaska, the previous operator, holds 62.36% of working interest in Point Thomson, Hilcorp Alaska holds 36.99% and a combined group of smaller working interest owners hold 0.65%.

Hilcorp said from Jan. 1, 2022, through Aug. 30, 2023, condensate production averaged 7,300 barrels per day, with a

see INJECTOR CONVERSION page 6

UTILITIES

Railbelt renewables

Electric utilities talk to the RCA about their policies and experiences

By ALAN BAILEY
For Petroleum News

During a Sept. 13 meeting of the Regulatory Commission of Alaska several Alaska electric utilities overviewed their experience of implementing and using renewable energy sources. The commission held the meeting to gather information about the use of renewable energy in Alaska, in conjunction with an information docket on the topic — the commission anticipates providing testimony to the state Legislature over Senate and House bills proposing the implementation of a renewable portfolio standard in Alaska. An RPS would mandate the rate at which a utility must implement renewable energy sources.

1 2 SERIES

Part 1 of this two-part series of articles overviewed reports at the meeting by Cordova Electric Cooperative and Kotzebue Electric Association. This part overviews reports by Alaska Railbelt utilities Chugach Electric Association, Homer Electric Association and Matanuska Electric Association.

Chugach Electric

Arthur Miller, chief executive officer of Chugach Electric Association, told the commission that his utility's power generation mix currently

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FINANCE & ECONOMY

Hamas attack roils oil

Oct. 9 crude price spike just a blip on downtrend from Sept. 27 highs

By STEVE SUTHERLIN
Petroleum News

A surprise attack on Israel by Hamas militants over a Jewish holiday weekend put the Middle East on edge, and edgy crude traders reacted, sending oil futures some 4% skyward on Monday Oct. 9.

Alaska North Slope crude for West Coast delivery rose Oct. 9 as well, up $1.83 to close at $89.59 per barrel, as West Texas Intermediate leapt $3.59 to close at $86.38 and Brent leapt $3.57 to close at $88.15.

The Oct. 9 spike interrupted a general trend lower for oil prices as demand concerns pared away at 2023 highs set Sept. 27, which saw ANS just a dollar and change away from $100.

Israel declared war on Hamas as the weekend progressed, engaging Hamas fighters on the ground and launching retaliatory air strikes.

Tensions remained elevated Oct. 9, as the world rushed to get a handle on the scope of the combat, and whether Hamas acted alone or if other nations or groups were complicit.

Israel is not a major crude producer in the area, with two refineries processing some 300,000 barrels per day, but if the conflict were to spread to Iran — which has supported Hamas — global oil supplies could be materially impacted.

Crude markets were calmer on Oct. 10. ANS added 22 cents on the day to close at $89.81, but WTI reversed lower by 41 cents to close at $85.97 and

see OIL PRICES page 7

EXPLORATION & PRODUCTION

BlueCrest files 10th POD

Innovative C.I. producer seeks funding for oil drilling & gas project

By KAY CASHMAN
Petroleum News

BlueCrest Alaska Operating, the company with the largest known underdeveloped structure in Alaska's Cook Inlet basin, recently filed its 10th plan of development for state leases ADL018790, ADL384403, ADL391903 and ADL391904 which make up the Cosmopolitan unit. The 10th POD will run from Jan. 1 through Dec. 31, 2024.

JOHN MARTINECK

The first well the company plans to drill is the H10 Trident Fishbone.

This multi-lateral well will allow BlueCrest to drill the equivalent of 21-24 wells on 800-foot spacings CFO John Martineck told Petroleum News earlier this year.

The Cosmopolitan unit's Hansen field is 3 miles offshore the southern Kenai Peninsula and 5 miles north of the community of Anchor Point.

Accessed from its onshore pad using directional drilling, its wells extend from the pad under Cook Inlet into state of Alaska submerged lands.

Production is primarily oil but there is an associated gas component to it.

Production is processed on site and oil is trucked off location for sale, while BlueCrest sells its natural gas to local utilities.

The company owns a drilling rig, which will be

see BLUECREST POD page 7

● EXPLORATION & PRODUCTION

Amaroq focuses on gas at Nicolai Creek

In latest POD, company says it is considering grassroots well; working licensed 3D for offshore acreage, focused on gas, not oil

By KRISTEN NELSON
Petroleum News

In the 50th plan of development for Nicolai Creek, Amaroq Resources President Scott Pfoff told the Alaska Department of Natural Resources, Division of Oil and Gas that the company is working to attract additional investment to develop "upside potential for conventional oil and gas, unconventional gas, and storage development" at the field.


SCOTT PFOFF

Pfoff said if the company is unable to attract additional investment it would begin to plan for field abandonment in two to three years.

Nicolai Creek is a small gas field on the west side of Cook Inlet, with acreage onshore and offshore.

In its 2022 approval of the 49th POD, the division said Nicolai Creek first produced gas in 1968. Alaska Oil and Gas Conservation Commission records show sporadic production through 1977 and then a long break until production, initially sporadic, began again in 2001, when Aurora Gas succeeded Union Oil Company of California as operator. After Aurora Gas filed for reorganization in federal bankruptcy court, Aurora Exploration acquired the field and became operator Jan. 1, 2018, later changing its name to Amaroq Resources.

2024 POD

The 50th POD covers the 2024 calendar year.

Pfoff said in the 12 months from Sept. 1, 2022, through Aug. 31, 2023, Nicolai Creek produced 108,369 thousand cubic feet, mcf, a decrease of 8.5% year over year.

AOGCC records show an average daily production of 353 mcf in August, the most recent month for which data is available. Nicolai Creek is among the smallest Cook Inlet natural gas fields, accounting for 0.2% of August production.

Pfoff listed six wells at the field, five producers and one injector, with an additional five abandoned by previous operators.

Nicolai Creek Unit 2, NCU 2, "is produced from time to time, pressure permitting," he said, accounting for 4,042 mcf over the year.

NCU 3 remains shut-in "due to formation sand and silt plugging the tubing," and will probably require a coiled tubing cleanout to reestablish production.

NCU 9 is on production and produced 108,369 mcf from September through August.

NCU 10 is shut-in "due to excessive water production."

NCU 11 is shut-in due to insufficient pressure but did produce 112 mcf for the year.

Work underway, planned

Pfoff said installation of a booster compressor at the south production facility is planned focused on NCU 2 and NCU 11. He said by boosting pressure in those wells, the company expects additional gas from NCU 9. That work is expected to occur in the first half of 2024.

Increased pressure is being encountered during injection at NCU 1B, the injection well, and the company wants to identify the cause and remedy the situation. Pfoff said the work will require a wireline unit and the company is pursuing options to fund that work.

There is a tentative work plan and AFE for a rig workover at the NCU 10, but Pfoff said the company is evaluating an alternative: a grassroots well which could produce "most or all of the remaining reserves" at the NCU 10 and NCU 3. That well would require third-party funding.

Additional 3D data has been licensed covering Nicolai Creek's offshore acreage and there is a work plan for analysis of that data, with priority to "be given to identifying natural gas bearing formations as opposed to the deeper potentially oil bearing formations," Pfoff said, with options for funding in progress.

It is in long-range plans that he discusses upstream for Nicolai Creek. He said additional investment is needed to pursue upsides, conventional oil and gas and storage, among them.

If additional investment is attracted, Pfoff said, "the field would likely remain in operations for years to come."

Without additional investment to develop upsides, he said he foresees the field being abandoned in two to three years. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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● FINANCE & ECONOMY

Lower inventories drive higher prices

EIA sees inventory causing price rise; through 2050 energy consumption expected to rise on population growth, living standards

By KRISTEN NELSON
Petroleum News

Crude oil prices are up on reduced global inventories and long term — through 2050 — global energy consumption is expected to increase, driven by population growth, manufacturing and higher living standards, the U.S. Energy Information Administration said Oct. 11 in its October Short-Term Energy Outlook and International Energy Outlook 2023.


JOE DECAROLIS

In the STEO, EIA said global petroleum inventories are forecast to decrease by some 280,000 barrels per day in the second half of the year due to reduced OPEC+ production targets and Saudi Arabia's continued voluntary production cut. As oil supplies decrease, prices are expected to be higher in 2024, with Brent averaging $95 per barrel.

"We expect crude oil prices to rise in response to lower global inventories, although significant uncertainty persists around global demand for oil products," said EIA Administrator Joe DeCarolis.

In the U.S., winter heating costs are expected to be lower this winter.

"Natural gas prices this year have been consistently lower than in 2022. Even if this winter is colder than forecast, we still expect households heated by natural gas to pay less to heat this winter," DeCarolis said.

Prices and supply

Brent averaged $101 in 2022 and is forecast to average $84 this year, rising to $95 in 2024, EIA said. The price of natural gas at Henry Hub averaged $6.42 per million British thermal units in 2022 and is forecast to average $2.61 per million Btu this year and $3.23 in 2024.

Brent averaged $94 per barrel in September, increasing after Saudi Arabia extended its production cuts through the end of the year and U.S. commercial crude inventories fell to the lowest level since early 2022.

EIA said it expects global oil inventories, which fell by some 0.2 million bpd in the second half of the year, to continue to drop at that pace through the first quarter of 2024 and then to be balanced for the remaining three quarters of the year "as global oil consumption growth generally slows while production growth accelerates."

The agency said while recent attacks on Israel do not impact physical oil markets, "they raise the potential for oil supply disruptions and higher oil prices."

Global liquid fuels production is forecast to increase by 1.3 million bpd this year and by 0.9 million bpd in 2024, EIA said, with non-OPEC production forecast to increase by 2.2 million bpd this year, more than offsetting OPEC production declines.

"Production growth outside OPEC is driven by new project starts in North America and South America," the agency said, with non-OPEC production forecast to grow by 1 million bpd next year "as new projects in Guyana and Brazil continue to add supply and the United States and Canada increase production."

Natural gas

EIA is forecasting that U.S. natural gas exports will set a record this year and continue to grow, with net U.S. exports this year increasing 20% from 2022 to average 12.8 billion cubic feet per day.

Gross U.S. liquefied natural gas exports were 10.6 bcf per day in 2022 and are forecast to average 13.2 bcf per day in 2024. EIA said the U.S. exported more LNG than any other country in the first half of this year, averaging 11.6 bcf per day. After averaging 12.7 bcf for the first three quarters of 2024, EIA expects exports to average almost 15 bcf per day in the fourth quarter of 2024 "as a result of three new export projects that are set to begin operations and expand U.S. export capacity."

In addition to LNG, the U.S. exports natural gas by pipeline to Canada and Mexico, exports which are expected to increase by 9% this year, as U.S. natural gas imports decline by 6%, with less natural gas needed from Canada with warmer weather in the northern U.S.

International Energy Outlook 2023

In its International Energy Outlook 2023, IEO2023, EIA is projecting that global consumption and energy-related CO2 emissions will increase through 2050 in most cases modeled.

The agency said while it "expects zero-carbon technology — renewables and nuclear — will meet the bulk of new energy demand through 2050, that growth is not sufficient to decrease global energy-related CO2 emissions in most cases under current laws and regulations" according to its projections.

EIA said in most IEO2023 cases, "Western Europe and Asia continue to import natural gas through 2050, while the Middle East and North America continue to produce and export more natural gas."

EIA Administrator Joe DeCarolis said: "IEO2023 fills an important niche among global outlooks by focusing on a plausible but sober assessment of global energy trends through the first half of the century. There is considerable uncertainty in the energy landscape over the next 30 years, and the IEO provides a set of policy neutral baselines that will help guide sound decision-making."

Population, income increase

EIA said both population and income are increasing, and those increases "offset the effects of declining energy and carbon intensity on emissions."

Energy consumption is expected to grow fastest in residential and industrial sectors, the agency said, with liquid fuels consumption growing most rapidly in industrial applications.

And, as economic growth drives increased disposable income, there is more demand for transportation.

What about the shift to renewables?

That, EIA said, "is driven by regional resources, technology costs, and policy."

From 2022, electric power generation capacity globally increases 55% to 108% by 2050, with electricity generation increasing 30% to 76%, with renewables, nuclear and battery storage accounting for most of the growth in capacity and generation.

"Renewables become an increasingly cost-competitive source of electricity and grow the fastest in cases that assume high economic growth and greater electricity demand," DeCarolis said.

In some countries a transition from fossil fuels is hastened by concerns for energy security, while that concern drives increased fossil fuel consumption in other countries, EIA said.

Resource demand

EIA said it found that global demand for oil increases between 3% and 10% by 2030, compared with 2022, and between 6% and 42% by 2050, depending on the case, with growth in demand greatest in the high economic growth case.

Demand for natural gas increases 2% to 10% by 2030, depending on the case, and between 11% and 57% by 2050, increasing most in the high economic growth case.

EIA said in most IEO2023 cases, "Western Europe and Asia continue to import natural gas through 2050, while the Middle East and North America continue to produce and export more natural gas." ●

Contact Kristen Nelson at knelson@petroleumnews.com

● EXPLORATION & PRODUCTION

Baker Hughes US rig count down 4 to 619

Texas had largest change, down 7, with New Mexico up by 4; international count down 12 from September, led by offshore rigs

By KRISTEN NELSON

Petroleum News

The Baker Hughes' U.S. rotary drilling rig count was 619 for the week ending Oct. 6, down by four rigs from the previous week, and down by 143 from 762 a year ago. This is the third consecutive week of declining counts, with six of the last eight weeks seeing declines in the number of active rigs, a downward trend dominant since the beginning of May.

A drop of 17 on May 12 was the steepest drop since June of 2020, during the first year of the COVID-19 pandemic. The Oct. 6 count is the lowest since Feb. 4, 2022, when the count was 613. The count dropped below 700 the week ending June 2, the first time it has been below 700 since April 2022. This week's count is down from a high so far this year of 775 on Jan. 13. The high for 2022 was a count of 784 rigs at the beginning of December.

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.

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.

Baker Hughes shows Alaska with nine rotary rigs active Oct. 6, unchanged from the previous week and down by one from a year ago.

The Oct. 6 count includes 497 rigs targeting oil, down by five from the previous week and down by 105 from 602 a year ago, with 118 rigs targeting natural gas, up by two from the previous week and down 40 from 158 a year ago, and four miscellaneous rigs, down one from the previous week and up by two from a year ago.

Fifty-three of the rigs reported Oct. 6 were drilling directional wells, 553 were drilling horizontal wells and 13 were drilling vertical wells.

Alaska rig count unchanged

New Mexico (106) was up by four rigs from the previous week and Oklahoma (37) was up two.

Texas (297) was down by seven rigs week over week.

North Dakota (30) and Wyoming (19) were each down by a single rig.

Rig counts in other states were unchanged from the previous week: Alaska (9), California (5), Colorado (16), Louisiana (43), Ohio (10), Pennsylvania (20), Utah (14) and West Virginia (8).

Baker Hughes shows Alaska with nine rotary rigs active Oct. 6, unchanged from the previous week and down by one from a year ago. Eight of the Alaska rigs were onshore, unchanged from the previous week, with one rig working offshore, also unchanged.

The rig count in the Permian, the most active basin in the country, was down by three rigs from the previous week at 309 and down by 36 from 345 a year ago.

International count down by 12

Baker Hughes' international rig count for September, issued Oct. 6, is down by 12 rigs from August at 940, with land rigs down one to 716 and offshore rigs down 11 to 224. Compared to the September 2022 count of 879, this September's international count is up by 61, with land rigs up by 56 and offshore rigs up by five.

Baker Hughes began providing a monthly international rig count in 1975. The international count excludes North America, which is included in the company's worldwide figures.

The Middle East accounted for the most rigs in the international totals for September, 327, followed by Asia Pacific with 216, Latin America with 175, Europe with 115 and Africa with 105.

The U.S. rig count averaged 632 in September, down 15 from August, and down 131 from September 2022, while the Canadian count for September averaged 188, down by one from August and down by 23 from September 2022.

Worldwide the rig count was 1,760 in September, down 28 from 1,788 in August and down 93 from 1,853 last September. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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Kay Cashman	PUBLISHER & FOUNDER
Mary Mack	CEO & GENERAL MANAGER
Kristen Nelson	EDITOR-IN-CHIEF
Susan Crane	ADVERTISING DIRECTOR
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Allen Baker	CONTRIBUTING WRITER
Judy Patrick Photography	CONTRACT PHOTOGRAPHER
Forrest Crane	CONTRACT PHOTOGRAPHER
Renee Garbutt	CIRCULATION MANAGER

ADDRESS
P.O. Box 231647
Anchorage, AK 99523-1647

NEWS
907.522.9469
publisher@petroleumnews.com

CIRCULATION
281.978.2771
circulation@petroleumnews.com

ADVERTISING
Susan Crane • 907-250-9769
scrane@petroleumnews.com

Petroleum News and its supplement, Petroleum Directory, are owned by Petroleum Newspapers of Alaska LLC. The newspaper is published weekly. Several of the individuals listed above work for independent companies that contract services to Petroleum Newspapers of Alaska LLC or are freelance writers.

OWNER: Petroleum Newspapers of Alaska LLC (PNA)
Petroleum News (ISSN 1544-3612) • Vol. 28, No. 42 • Week of October 15, 2023

Published weekly. Address: P.O. Box 231647 Anchorage, AK 99523-1647
Subscription prices in U.S. — $118.00 1 year, $216.00 2 years
Canada — $206.00 1 year, $375.00 2 years
Overseas (sent air mail) — $240.00 1 year, $436.00 2 years

"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News, P.O. Box 231647 Anchorage, AK 99523-1647.

UTILITIES

RRC files proposed budget, work plan

The Railbelt Reliability Council has filed with the Regulatory Commission of Alaska its draft budget and work plan through to the end of 2024. In September 2022 the RCA granted an electric reliability organization certificate to the RRC, which will maintain and mandate reliability standards for the Railbelt's high voltage electrical system; administer rules for open access to the transmission grid; and conduct Railbelt-wide integrated resource planning. The RRC is in the process of establishing its organization and infrastructure, in preparation for going into operation.

According to the draft budget, the organization's total estimated operating costs for 2024 total $6.5 million. The RRC will recover this cost from the Railbelt utilities. Ultimately the improved efficiencies in the Railbelt electrical system that the RRC will enable are expected to more than compensate for the costs of operating the new organization. The RRC is holding a public work session on Oct. 24 to discuss comments received on its budget.

The RRC told the RCA that its budget is based on an assumption that the organization will hire a chief executive officer by Dec. 4 — the organization currently soliciting CEO candidates.

According to the RRC's draft work plan, the development of an integrated resource plan is anticipated to start in November of this year and should be completed by November 2027. The development of reliability standards will likely take place over a period running from June 2024 to February 2028. The organization is also going to move ahead with setting up its office arrangements and hiring staff.

Meanwhile the Railbelt utilities are having to address some urgent issues relating to the potential availability of federal grants for upgrades to the Railbelt electricity transmission system and to the need to address likely future shortfalls in the availability of Cook Inlet natural gas for power generation. Presumably at some point these efforts will need to be coordinated with the planning that the RRC will be conducting. There is also an active debate regarding the speed at which renewable energy generation systems can and should be implemented in the Railbelt.

—ALAN BAILEY

continued from page 1

RAILBELT RENEWABLES

consists of approximately 82% natural gas fueled generation, 15% hydropower and 3% wind power. And last year the utility's board approved a goal of reducing the utility's power generation carbon intensity by at least 35% by 2030 and by at least 50% by 2040, provided that these targets can be achieved without a significant negative impact on electricity rates. It is also critically important that a high level of electricity supply reliability can be maintained, Miller said.

Miller's comments related to both Chugach Electric's legacy business and the business it acquired from its purchase of Anchorage utility Municipal Light & Power in 2020.

Dispatchable and non-dispatchable energy

Renewable energy supplies can be characterized as dispatchable or non-dispatchable. Dispatchable resources can be increased or reduced in synchronization with fluctuating electricity demand, or with fluctuations in the outputs from other power generation systems. Non-dispatchable resources are intermittent, because, for example, of fluctuating wind strengths at wind farms.

Miller said that Chugach Electric has seen significant success with obtaining power from its dispatchable renewable sources, consisting of the Bradley Lake, Cooper Lake and Eklutna Lake hydropower systems. The utility's main non-dispatchable energy source is a wind farm on Fire Island, offshore Anchorage. The Fire Island system came online in the fourth quarter of 2012, Miller said.

Chugach Electric has also seen an increasing proliferation of non-dispatchable renewable energy generation at the customer level, such as the implementation of rooftop solar systems on customers' houses. However, so far the amount of this type of generation, referred to as net metered projects, has not reached a level that might impact the reliability of the electrical system, said Allan Rudeck, Chugach Electric chief strategic officer. But it will be important to monitor and take account of the impact of long-term growth in the sector, Rudeck said.

Avoided costs

Miller said that a key parameter in evaluating a renewable energy system is the electricity generation costs that can be avoided through the replacement of non-renewable generation with renewable generation. Chugach Electric has determined that the cost of power from the three hydropower systems has come in at or below the avoided cost of gas power generation, while the Fire Island wind power has come at a cost significantly higher than the avoided cost.

However, there is an issue regarding the manner in which avoided costs are determined, Miller commented. For the short-term displacement of energy from operational gas-fired power generation systems, Chugach Electric uses the cost of the most expensive fuel gas as the avoided cost. However, looked at over a longer term, to include the fixed costs of the generation facilities, the avoided cost would clearly be higher.

Hydropower systems

In terms of dispatchable, renewable power, Chugach Electric shares the used of Bradley Lake, in the southern Kenai Peninsula, with the other Railbelt utilities and has an entitlement to 56% of the power from the system, Andrew Laughlin, Chugach Electric chief operating officer, told the commission. The utility fully owns the Cooper Lake power plant and is entitled to about 64% of the output from the Eklutna Lake system.

One benefit of the Cooper Lake and Eklutna Lake systems is that the large sizes of the lakes enable the lakes to be used to store water during the wetter months of the year, for use for power generation during the winter, when power demand peaks, Laughlin said.

In recent years, especially since the acquisition of ML&P, Chugach Electric has been able to vary its power supplies from Bradley Lake to regulate the variable power output from the Fire Island wind farm, thus largely eliminating any need to curtail acceptance of any Fire Island power output, Laughlin said.

And the use of hydroelectric power has resulted in savings in the use of 2.5 billion to 4 billion cubic feet of fuel gas annually, he said. In 2022, for example, that represented an estimated average savings of about $20 million in short and long-term marginal costs, he said.

Fire Island wind

In terms of non-dispatchable power, the performance of the Fire Island wind farm has matched, or even done slightly better than, projections that were made before the project was commissioned. However, although the volume of gas saved from the use of the wind power has proven close to what had been predicted, the price of the gas has so far been less than had been anticipated, Laughlin said. On average, the use of Fire Island wind has increased electricity bills by about 1.5%, he said.

Regulating variable power

Rudeck commented that Chugach Electric is evaluating ways to regulate variable power generation, as the amount of non-dispatchable generation in the system increases. It is possible to regulate the power by varying the power output of gas fired power generation. However, this approach is limited by physical constraints in the gas supply chain and commitments made to gas pipeline companies and gas suppliers. Chugach Electric is exploring the possibility of installing onsite gas storage for its gas fired generation plants, to facilitate the use of the plants for regulating the power supplies, Rudeck said. The utility is working with MEA to install a 40-megawatt hour battery system that will come online later this year. But high penetrations of renewable energy will require days, weeks and seasons of energy storage, Rudeck commented.

Matt Clarkson, Chugach Electric chief legal officer, cautioned about the possibility of some confusion in regulatory approval standards for renewable energy projects causing complications in the approval of new renewable energy projects.

Rudeck said that Chugach Electric is currently evaluating two proposed, new renewable energy projects: the 122-megawatt Little Mount Susitna Wind Project and the 120-megawatt Ranger Power Midnight Sun Project in the Susitna Valley. The utility also wants to bring a community solar project proposal to the commission later this year, he said.

Homer Electric Association

Larry Jorgensen, director of power fuels and dispatch for Homer Electric Association, told the commission that HEA's primary renewable energy source is the Bradley Lake hydropower facility in the southern Kenai Peninsula — HEA typically receives about 60,000 megawatt hours of power annually from Bradley Lake, Jorgensen said.

The Battle Creek diversion project, completed a few years ago, increased the power output from the Bradley Lake system. Another potential expansion, the Dixon Diversion development, is being considered by the Alaska Energy Authority and the Railbelt utilities.

Currently HEA is working with two independent power producers on renewable energy projects, Jorgensen said. A grant from the Alaska Energy Authority will enable the Railbelt utilities to build some meteorology towers, to collect wind data and, thus, enable an evaluation of available wind resources, he said. HEA is also pursuing federal Powering Affordable Clean Energy, or PACE, funding, as a possible means of partially funding power purchase agreements, Jorgensen said.

Jorgensen commented that, while economies of scale in new power generation can drive costs down to competitive levels, the limited ability to move power across the Railbelt's electricity transmission system renders it difficult to implement large renewable energy systems.

Significant net metering

HEA does have a significant level of net metering, in which HEA customers operate their own wind and solar electricity generation. About 7% of the electricity used in HEA's service area comes from net metering, with almost all of the new net metering installations using solar energy, Jorgensen said. He commented that a point of contention is that current rate structures for net metering do not take into account the cost of the electricity grid services that a net metering customer is using.

In January 2022 HEA implemented a large new battery storage system, to help regulate the power supplies in its electricity grid. The system responds very quickly to variations in power supply and demand, providing adequate reserves of power to bolster the system, Jorgensen said. The battery system has proven particularly effective in dampening any oscillations in power output from Bradley Lake, he said.

Matanuska Electric Association

Ed Jenkin, chief operations officer for Matanuska Electric Association, told the commission that MEA currently obtains 17% of its power from renewable sources, primarily from the Bradley Lake and Eklutna Lake hydro facilities. The utility also obtains electricity from a 1.2 megawatt solar farm at Willow, and from a recently opened 6 megawatt solar farm at Houston. Most of the rest of the utility's power comes from natural gas fueled power generation.

Tony Izzo, chief executive officer of MEA, commented that the opening of the new solar farm at Houston has brought MEA to the upper limit of the utility's capacity to regulate the variable power output from renewable energy systems such as wind and solar farms without incurring additional costs. Jenkin said that the cost of power supply regulation could also increase if there are increases to the small amount of net metered power currently provided by customers in MEA's service area. In addition, a utility cannot assume that power will always come reliably from a net metered source and, so, must have adequate supply capacity for situations when that source is not available, Jenkin commented.

Carbon emissions reduction

Jenkin said that a past objective of MEA had been to achieve a 28% reduction in carbon emissions by 2030. It turned out that the utility achieved that goal in 2022, primarily as a consequence of the improved efficiency of gas fired power generation, both at MEA's Eklutna Generation Station and from power obtained through MEA's power pool with Chugach Electric.

Looking to the future, MEA is working with Chugach Electric on the implementation of a battery energy storage system, and on how to regulate the power supply frequency and enable more use of wind power, Jenkin said. The use of hydropower is a key component of future goals, he said. The two utilities have been evaluating options for wind, hydro and nuclear energy at large scales, and for solar and geothermal energy at a smaller scale, he said. There are studies that have looked into wind power, in particular a study presented by the National Renewable Energy Laboratory. However, NREL has not yet identified the cost of integrating the wind systems into the electrical system, nor the cost of regulating the wind power, Jenkin said.

Jenkin also referenced the state Renewable Energy Fund grant that will support the installation of around five meteorological towers for determining wind resources in the region.

MEA sees micro grids as a possible means of solving power supply reliability issues at some remote locations. For example, the utility is considering putting a microgrid at the end of a long distribution line to the Chulitna River, with the possibility of installing river generation units to bolster supply reliability in that area.

More clean energy needed

Jenkin also commented that MEA is experiencing load growth and, as more load comes into the system, more clean energy will be needed to meet MEA's clean energy goals — MEA prefers to refer to the promotion of clean energy in general, rather than just renewables. Currently, the utility has an aspirational goal of 50% clean energy by 2050, he said.

Preliminary studies have focused on the use of wind and hydro, with nuclear power also being a future possibility, he said. A micronuclear power facility, for example, would not be considered renewable energy, but would not emit carbon dioxide.

The utility is also looking at the future installation of further battery storage — currently the primary purpose of battery capacity is to ensure frequency stability in the electrical system.

Izzo commented that, with the focus of the majority of the utility's customers being on reducing electricity rates, and certainly not increasing rates, the 50% clean energy goal needs to be achieved without a significant negative impact on rates.

The importance of reliability

Jenkin emphasized the importance of electricity supply reliability, given that the Railbelt electrical transmission system has very little redundancy. Batteries can help maintain the electricity frequency for up to around two hours. So, it is necessary to have a firm fuel source, or transition to firm generation that is available year-round, whether that is hydro or potentially nuclear, Jenkin said. MEA is also very interested in potential long duration energy storage solutions, he said. And moving power from larger wind facilities or other generation facilities such as hydro will require an appropriately capable transmission system, he said.

Izzo commented that he sees current uncertainty over future gas supplies from the Cook Inlet as a crisis situation for electricity generation reliability, especially given the likelihood that the timeframe for siting, permitting and building a large wind farm, for example, would extend beyond the current timeframe for gas supply certainty. MEA is in the process of assigning some people in its organization to specifically address this problem, he said. ●

Contact Alan Bailey at abailey@petroleumnews.com

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EXPLORATION PLAN

road route originating from the existing gravel Endicott Road. A 500-foot by 785-foot temporary staging and offroad pad, constructed of ice, will be built near the origin of the project ice road to support mobilization efforts. A semi-circular ice road turnout, approximately 200 feet long by 20 feet wide, will be constructed on the north side of Endicott Road (at the Lagniappe ice road origin) to support wide vehicle turn access.

The existing permanent single-lane bridge on the west fork of the Sagavanirktok River near Deadhorse is not adequate to support Lagniappe's rig move; therefore, Lagniappe proposes to build a bypass ice bridge, between the ramp to the H2MHill yard and the ramp to Drillsite 17. The bridge will be approximately 1.4 miles long, 200 feet wide, and 7-8 feet deep.

The land use permit will authorize off-road travel, ice construction, and associated activities in support of oil and gas activities using approved vehicles on state land between the Canning and Colville rivers. This is a general permit; individual activities will be reviewed and authorized on a case-by-case basis under the permit.

Previously reported

In line with its Alaska strategy to focus on the big Pikka development west of the central North Slope, Santos said Sept. 19 that it is "farming down" half of its working interest in the 148 lease block it shares with Lagniappe on the eastern North Slope.

Once an agreement with APA Corp. (holding company for Apache Corp.) and Armstrong Oil & Gas's Lagniappe is executed, Santos' working interest will be 25%.

Under the terms of the deal, initial activities during the exploration phase will be undertaken without cost to Santos.

A spokesperson for APA's Apache Corp. told Petroleum News that Bill Armstrong's Lagniappe Alaska will be the operator of the acreage.

The lease block, Santos said, contains "multiple prospects in the late Cretaceous Brookian and Schrader Bluff formations."

Although Bill Armstrong will not comment on the Sept. 19 agreement with Santos and APA, on March 30 after Lagniappe had begun permitting for the area, he told Petroleum News in a text that the exploration wells will target Brookian objectives — "Pikka look-a-likes that are defined off of high effort, reprocessed modern 3D. Really exciting stuff. Big targets."

There has been "virtually no prior drilling in the area. The wells that have been drilled have great shows and some have bypassed pay on old logs," Armstrong added.

—KAY CASHMAN

Contact Kay Cashman at publisher@petroleumnews.com

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INJECTOR CONVERSION

total of 4.4 million barrels of condensate delivered to the trans-Alaska oil pipeline during that period.

This average includes a number of months in 2022 when production averaged more than 9,000 bpd, but production has been declining, highlighted earlier this year when PTE Pipeline repeatedly applied to the Regulatory Commission of Alaska for increases in the tariff rate on the pipeline to reflect lower production and thus a higher cost per barrel. PTEP runs 22 miles from the central processing facility at Point Thomson to a connection with the Badami Sales Oil Pipeline.

Facilities at the field, which came online in 2016, are rated to produce up to 10,000 barrels per day. It took time to approach that rate as then-operator ExxonMobil struggled with injection issues based on leading-edge technology employed at the high-pressure condensate field, with liquids removed at the surface and gas reinjected.

By 2020, production averaged more than 9,000 bpd in some months, but by 2022 there were fewer months which reached that production average.

The tariff for 2023, set in late 2022, was $7.86 per barrel, but on May 30 PTEP filed for an increase to $12.49 per barrel, based on the 2019 Settlement Agreement between the state and PTEP which provides that the rate can be changed during the year if additional data results in at least a 10% increase or decrease in the maximum rate.

PTEP told RCA in May that through the first five months of the year actual throughput had been significantly lower than the projected throughput used to calculate the $7.86 per barre rate.

In June, when PTEP filed to increase the tariff to $25.08 per barrel, it said "throughput has continued to decline and is expected to remain low for the remainder of 2023."

A third filing, on Aug. 30, was an increase to $36.94 per barrel.

In August, the most recent month for which Alaska Oil and Gas Conservation Commission production data is available, Point Thomson averaged 2,363 bpd, down 11.1% from July and down 72.1% from August 2022, when production averaged 8,467 bpd.

Single production well

AOGCC filings show Hilcorp has been working on PTU-17, the producing well, in an effort to increase production since at least early 2022.

In its 2024-25 POD the company told the division:

"Productivity has been declining in producer PTU-17 since field startup. The current operable wellstock at Point Thomson is unable to cycle 200 MMSCFD gas and fill the IPS facilities to capacity. Additional wells would be required to fill the IPS to capacity. Hilcorp will continue to evaluate drilling opportunities during the 2024-2025 POD Period."

The company said current production "will be maintained in line with historical decline," and said it plans to convert PTU-15, one of the two injector wells, to production, "pending results of internal review."

PTU-15 and PTU-16, the injector wells at the field, are on the Central Pad, while PTU-17, the producer, is on West Pad.

As for exploration/delineation plans, Hilcorp said it will review and evaluate "internal interpretive data to establish future development plans for lands comprising 'Area F' of the PTU."

—KRISTEN NELSON

Contact Kristen Nelson at knelson@petroleumnews.com

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HILCORP WELLS

bpd, Aurora 4,898 bpd and Midnight Sun 723 bpd. These are crude volumes — the most recent comparable numbers for Prudhoe, from August Alaska Oil and Gas Conservation Commission data, is an average of 209,302 bpd. Prudhoe also produces natural gas liquids; Hilcorp shows no NGL volumes for the western satellites.

Hilcorp took over as operator in mid-2020 said that since then, the company said, it "has focused on returning idle wells to service, optimizing production through the existing surface infrastructure, targeting reservoirs that had been under-developed, improving voidage replacement, maximizing MI utility, improving operational efficiency, and a strong drilling program which together led to a 21% (2,127Mbb) year-on-year increase in overall oil production rate from the Western Satellites from the period January 1, 2021-December 31, 2021 to January 1, 2022-December 31, 2022."

2023 POD focus on Orion

There are five participating areas: Aurora PA, Borealis PA, Midnight Sun PA, Orion PA and Polaris PA.

The majority of wells drilled during the 2023 POD were at Orion, primarily from L Pad, with six wells completed and producing or injecting, one anticipated for completion and injection in the fourth quarter and three anticipated to be drilled in the fourth quarter. On Z Pad, two wells are online and injecting.

Three wells were drilled at Polaris, all at W Pad, with one well converted from a producer to an injector and two wells drilled and online — one producing and one injecting.

Two coiled tubing sidetracks were drilled at Borealis, one from L Pad and one from V pad, with one online injecting and the other pending a post-drill frack.

A single CTD sidetrack was drilled at Aurora, and while the desired oil column was found, the work string is stuck in hole and the well is unable to flow.

No wells were drilled at Midnight Sun.

While no wellwork or workovers were planned, a number took place: four at Aurora; two at Borealis; one at Midnight Sun; two at Orion; and two at Polaris.

2024 POD

Hilcorp said that in the 2024 POD period it anticipates drilling at four of the PAs: approximately five producers at Aurora; approximately one producer and one injector at Borealis; approximately one producer and one injector at Orion; and approximately 10 wells, evenly split between producers and injectors, at Polaris.

No wellwork or workovers are planned, but "will be executed to maintain and enhance production/injection as needed."

Construction of the EWE LDT twin pipeline phase 1 will begin in 2024 and continue into 2025.

Hilcorp said it continues to evaluate future drilling opportunities and potential undeveloped reservoirs, and "plans to evaluate new pad development options" and "is currently evaluating pad options, facility layouts, and surface development schemes for west-end development."

Additional pipelines are being evaluated to reduce header pressure and increase gas lift pressure at four pads: I, V, W and Z.

Western satellite reservoirs

Aurora development began in 2000 with production starting in November 2000 and water injection in December 2001, Hilcorp said. Prudhoe Bay miscible gas for water-alternating-gas, WAG, injection has been used for tertiary recovery.

Borealis development began in 2001 with production starting in November 2001 and water injection in June 2002, followed by Prudhoe Bay miscible injectant, MI, for WAG starting with a pilot project in June 2004.

Midnight Sun development began in 1997 and production began in October 1998, with water injection in October 2000 and MI in 2006.

Orion development began in late 2001 with production in April 2002 and water injection in December 2002. Prudhoe Bay MI for WAG has been used for tertiary recovery since October 2006.

Polaris development began in November 1997 with production in November 1999 and water injection in May 2003. Prudhoe Bay MI for WAG was used briefly in 2006 and in November 2009 began again for tertiary recovery.

—KRISTEN NELSON

Contact Kristen Nelson at knelson@petroleumnews.com

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OIL PRICES

Brent shed 50 cents to close at $87.65.

On Oct. 11, the American Petroleum Institute announced a massive expansion of 12.940 million barrels in U.S. commercial crude inventories for the week ending Oct. 6. Analysts had called for a build of just 1.3 million barrels.

U.S. commercial crude inventory data from the U.S. Energy Information Administration was not available as Petroleum News went to press Oct. 12, having been delayed by the Columbus Day holiday on Oct. 9.

The Department of Energy said Oct. 9 that crude oil inventories in the Strategic Petroleum Reserve were unchanged for the week ending Oct. 6. At 351.3 million barrels, the SPR is near a 40-year low. The Biden Administration has purchased only 4 million barrels since commencing a buyback program to replace a record 180 million barrels it released in 2022 to lower domestic gasoline prices prior to the mid-term elections.

ANS dropped $1.88 Oct. 11 to close at $87.93, while WTI plunged $2.48 to close at $83.49 and Brent dropped $1.83 to close at $85.82.

In trading prior to the Hamas attack, ANS added 33 cents Oct. 6 to close at $87.76, as WTI rose 48 cents to close at $82.79 and Brent rose 51 cents to close at $84.58.

On Oct. 5, ANS fell $1.38 to close at $87.43, WTI fell $1.91 to close at $82.31 and Brent fell $1.74 to close at $84.07.

From Wednesday to Wednesday, ANS fell 88 cents from its Oct. 4 close of $88.81 to $87.93 on Oct. 11.

ANS traded at a $2.99 premium to Brent on Oct. 11.

War with Iran could boost prices

Pioneer Natural Resources CEO Scott Sheffield said oil prices could skyrocket if Iran gets involved in the war between Hamas and Israel.

"If Iran enters the war, we're going to see much higher oil prices, obviously," Sheffield told CNBC's "Squawk Box" Oct. 10.

"It's going to be up to (Prime Minister Benjamin) Netanyahu, I believe," Sheffield said. "Depends on how much evidence he has that they're behind it and whether or not he decides to do anything about it."

To date no evidence has surfaced to link the attacks to Iran, according to the Biden administration.

"Iran is complicit in this attack in a broad sense because they have provided the lion's share of the funding for the military wing of Hamas, they have provided training, they have provided capabilities, they have provided support, and they have had engagement and contact with Hamas over years and years," national security adviser Jake Sullivan said in an Oct 10 press briefing.

The New York Times reported that U.S. intelligence indicated the assault by Hamas took senior Iranian officials by surprise.

But the Wall Street Journal in an Oct. 8 report said Iranian security officials helped plan the raid and gave the green light for the attack at an Oct. 2 meeting in Beirut, according to senior members of Hamas and Hezbollah, another Iran-backed militant group.

Officers of Iran's Islamic Revolutionary Guard Corps had worked with Hamas since August to devise the air, land and sea incursions — the most significant breach of Israel's borders since the 1973 Yom Kippur War — the people said, according to the report. ●

Contact Steve Sutherlin
at ssutherlin@petroleumnews.com

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BLUECREST POD

used for the H10 Trident well.

During the ninth POD BlueCrest planned to maintain production, conduct hot oil treatments and continue planning for drilling of the Hl0 well and potential offshore natural gas development.

These operations were completed as planned.

The company also completed an overhaul and engine exchange on its LP#l compressor.

BlueCrest installed hot oil treatment equipment onsite to allow it to perform treatments on demand and not rely on a third-party contractor. The company has been performing the treatments every three to four weeks. This helped with maintaining production levels in the facility.

BlueCrest was prepared to drill the Hl0 well, but due to lack of investment funding, will not be drilling the Hl0 well in 2023. However, the company spent a considerable amount of time refining the Hl0 well design, reworked the Hl0 AFE, and laid out the complete onshore oil drilling program.

In addition, BlueCrest explored/engineered alternatives to the offshore gas drilling campaign, looking at the possibility of drilling shallow ERD gas wells from onshore vs. installing a platform in the Cook Inlet to drill the gas wells.

BlueCrest's Hansen field averaged 703 barrels of oil per day in August, unchanged from July, and down 7.5% from an August 2022 average of 760 bpd.

Untapped gas reserves

Currently BlueCrest is producing less than 1% Cook Inlet's natural gas.

BlueCrest President and CEO Benjamin Johnson told the Alaska House Special Committee on Energy on Feb. 21 about the huge natural gas reserves that have been discovered in the Cosmopolitan unit.

The Tyonek gas sands, which lie above the oil reservoirs the company is currently producing, look to be too shallow to be reached from onshore wells, he said.

Multiple wells have been drilled through the gas zones, which have a proved but undeveloped volume of 234 billion cubic feet with flow tests confirming high productivity, and the size and shape of the structure documented by 3D seismic.

Johnson said the gas zones are similar to the Ninilchik field, some 15 miles to the north and the largest Cook Inlet gas producer.

The gas at Tyonek was discovered in the Starichkof State 1 drilled in 1967 and confirmed in the Cosmopolitan State 1 drilled in 2013, both drilled by jack-up rigs, with flow tests done at the 2013 well.

Johnson said there are 12 gas sands at the Cosmopolitan Tyonek gas field.

Because of the requirement for a platform, it will cost hundreds of millions to develop that resource, Johnson said, but it could produce up to 50 million cubic feet per day.

He said this is dry gas, with no liquid hydrocarbons. It would require a 3-mile subsea pipeline to the company's onshore facility, and he said recent seafloor surveys confirm a safe pipeline route, while the onshore facility is already connected to the Enstar pipeline system.

The design of platform and facilities and cost estimates are largely completed, he said, with the platform gas wells to be done with standard Cook Inlet drilling and completion.

From funding to first gas would be 30 to 40 months, Johnson said.

Plans for 2024

BlueCrest's 10th POD is a repeat of the ninth POD. The company is actively looking for investment dollars to restart its onshore oil drilling with the H10 Trident Fishbone drilling program in the 2024 calendar year.

The company is also looking for investment dollars for its offshore gas development. The imminent gas shortage in Southcentral Alaska has made this objective a top priority for BlueCrest.

Parent BlueCrest Energy is a privately held oil and gas development company based in Fort Worth, Texas. Subsidiary BlueCrest Alaska Operating has a local office in Anchorage. ●

Contact Kay Cashman
at publisher@petroleumnews.com

Congratulations

Congratulations Santos & Lagniappe!

Operator Lagniappe Alaska will drill as many as three exploration wells this coming winter

Consistent with its Alaska strategy to focus on the Pikka development west of the central North Slope, Santos said Sept. 19 that it will “farm-down” half of its working interest in 148 state of Alaska exploration leases on the eastern North Slope in an agreement with Armstrong Oil & Gas’ Lagniappe Alaska and investor APA, the holding company for Apache Corp.

Bill Armstrong’s Lagniappe Alaska will be the operator of the 270,000-acre block and all indications are exploration will begin in the upcoming winter with two rigs and as many as three wells.

We offer all three companies our congratulations.

Kevin Gallagher

Bill Armstrong

ABR, Inc.
Acuren
AES Electric Supply, Inc.
Airgas, an Air Liquide Company
Airport Equipment Rentals
Alaska Air Cargo
Alaska Dreams
Alaska Frontier Constructors (AFC)
Alaska Fuel Services
Alaska Marine Lines
Alaska Materials
Alaska Railroad
Alaska Steel Co.
Alaska Textiles
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ASTAC (Arctic Slope Telephone Assn. Coop, Inc)
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