Oil and Gas News Briefs
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More nuclear restarts in Japan will reduce need for LNG imports

(Reuters; Aug. 31) - Japan's consumption of liquefied natural gas is set to fall as the country's nuclear reactors restart with output from atomic power set to reach its highest level since the aftermath of the 2011 Fukushima disaster. Kansai Electric will restart the 870-megawatt No. 4 reactor at its Takahama station on Aug. 31, a spokesman said. The Kansai restart follows Kyushu Electric bringing back its 890-megawatt No. 2 reactor at its Sendai plant on Aug. 29. Kyushu now has four reactors running.

Each returning reactor will cut demand for LNG by as much as 1 million tonnes a year, said Kosho Tamura, a gas analyst at Japan Oil, Gas and Metals National Corp. While the savings is a positive for Japan's utilities, the loss of Japanese demand could undermine the outlook for the global market. Japan is the world's biggest buyer of LNG. Kansai will have three units operating and expects to have another reactor at Takahama restarted in November, its spokesman said. Operating the first three units will save about $1.5 billion in fuel costs each year, the Kansai spokesman said.

Restarting Kyushu's nuclear units will save the company about $2.2 billion in annual costs based on current LNG prices, its spokeswoman said. With two more reactors likely to restart by the end of the year — when Japan enters its peak demand period — as much as 9 million tonnes of LNG demand could be replaced by nuclear power. Before the Fukushima disaster Japan had the world's third-largest reactor fleet which provided about one-third of its electricity.

PetroChina plans to boost domestic gas production

(S&P Global Platts; Aug. 30) - PetroChina is aiming to grow its natural gas output at a much faster rate than oil over the next five years as producers rush to meet Beijing's call for cleaner fuels, while aging reserves limit its ability to produce more oil. But despite the anticipated growth in oil and gas production by China's biggest upstream company, the incremental volumes will fail to close the gap with China's growing need for energy resources, said the company's vice chairman Zhang Jianhua.

PetroChina is aiming to annually grow its gas output by about 4 to 5 percent over the next five years, while annual oil production would grow by a modest 1 percent over the same period, company officials said. PetroChina's domestic proven and developed crude oil reserves fell below 9 billion barrels by the end of 2008. The downward trend has continued since then, hitting 5.18 billion barrels by the end of 2016, although it recovered slightly to 5.59 billion barrels at the end of 2017.

And although PetroChina plans to boost its gas production, it is lagging behind the country's demand growth, an indication that China will be more dependent on imports. China's gas consumption surged 17.5 percent year on year in the January-June to 4.76 trillion cubic feet, while PetroChina's gas production was 1.65 tcf, about 60 percent of the country’s total output. PetroChina imported 850 billion cubic feet of pipeline gas from central Asia in the first half of the year, 78 bcf from Myanmar and 331 bcf as LNG.

Yamal LNG coming on stream faster than expected

(Reuters; Aug. 31) - Liquefied natural gas exports from Novatek’s Yamal terminal in the Russian Arctic have come on stream faster than expected this summer and exceeded volumes from Russia’s only other LNG facility, Sakhalin-2, for the first time in August. The pace of commissioning the $27 billion project has surprised a market used to chronic delays. Novatek said earlier this week it had begun commissioning Yamal’s third train, and that its first two trains are running at full capacity of 11 million tonnes a year.

Full production from the two trains at Yamal and two trains at Sakhalin doubles Russia’s output to just over 20 million tonnes per year, making the country the fifth-largest LNG exporter in the world. Yamal loaded its first cargo at the end of last year. The second train started producing LNG in late July with normal operations by Aug. 9. Barring any technical glitches, Yamal’s third train should be producing LNG by November, far ahead of the scheduled first quarter of 2019 and market expectations of mid-next year.

There were already signs that Yamal was moving ahead with speed when two LNG shipping companies said they would expedite the delivery of Arctic-class LNG carriers. Dynagas, an LNG shipping company specializing in carriers able to navigate the icy waters of the Arctic, said Aug. 27 it had delivered a carrier three months early on Aug. 14. Teekay LNG, one of the world’s largest LNG shipping companies, said it sought to provide two Arctic-class carriers to Yamal early, noting the ahead-of-schedule start-up.

Nova Scotia LNG project slows down spending amid uncertain market

(Cape Breton Post; Nova Scotia; Aug. 29) - The company proposing to build a gas pipeline in conjunction with a liquefied natural gas export terminal in Bear Head, Nova Scotia, said its reduced spending is due to changes in global energy markets since it first applied for a permit. Its 2018 benefits report to the provincial Utility and Review Board showed total spending in Nova Scotia in the first half of the fiscal year at just below $500,000, down substantially from $5.4 million in 2016 and $1.2 million in 2017.

“These market condition changes include a substantial imbalance in the current LNG supply-demand situation, deferral of long-term purchase commitments by the market and instability in energy pricing including LNG,” wrote Paul MacLean, strategic and regulatory affairs adviser with Bear Head LNG. “For these reasons, the time necessary to obtain binding LNG agreements required to underpin the construction program for the project is proving longer than expected.”

“We’ve been spending more time in Calgary working with pipeline companies as well as western basin producers to secure the (gas) supply necessary for our feedstock,” MacLean said. Securing a gas supply is essential for a final investment decision on the LNG plant. MacLean declined to give a timeline for the decision. The project would produce 8 million tonnes per year of LNG. Bear Head is a subsidiary of Australia-based Liquefied Natural Gas Ltd., which also proposes to build an LNG terminal in Louisiana.

Mexican utility plans to stop LNG imports after pipelines enter service

(Argus Media; Aug. 30) - CFEnergia, the generating fuels subsidiary of Mexico's state-owned utility CFE, will halt all liquefied natural gas imports into the Manzanillo (Pacific side) and Altamira (Gulf of Mexico) regasification terminals by early 2019 when new pipelines will be able to handle higher volumes of U.S. gas deliveries. Though a dozen new gas lines are in operation, seven more are under construction and three are held up by legal action initiated by indigenous communities.

Once all the new lines are in service, pipeline gas import capacity will about double. CFEnergia imports an average of 65 LNG cargoes each year to the Altamira and Manzanillo terminals, many from the United States, but once the Sur de Texas-Tuxpan and the Manzanillo-Guadalajara pipelines come online next year, the company expects to import only the rare LNG cargo "to keep the terminal cold," said CFEnergia director Guillermo Turrent.

While LNG imports have been traditionally used as a complement to pipeline supply to Mexico, LNG imports have steadily increased since April last year. This followed delays to the scheduled start of a series of new import pipelines. Mexico’s LNG imports averaged 840 million cubic feet per day in May, while pipeline gas imports averaged 4.3 billion cubic feet per day that same month.

LNG export terminal in Savannah, GA, to start up fourth-quarter 2018

(Savannah Now; GA; Aug. 30) - A $2 billion export addition to the 1978 Elba Island liquefied natural gas import terminal is nearing completion on the Savannah River about five miles downstream from downtown Savannah, Georgia. Initial start-up is expected in the fourth quarter of 2018, with the final liquefaction units coming online by the third quarter of 2019. When complete, Elba will be able to export 350 million cubic feet per day of gas, about 2.6 million tonnes of LNG per year.

The project uses a new technology, developed by Shell, called the Movable Modular Liquefaction System. The terminal will include 10 small-scale liquefaction units, called trains. There has been little activity at the import terminal in recent years as U.S. shale gas production put an end to the need for LNG imports. The terminal owners, Kinder Morgan and EIG Global Energy Partners, saw exports as a way to revive the facility. Shell holds a 20-year contract for 100 percent of the terminal's liquefaction capacity.

Elba will be the third U.S. LNG export facility to come online, joining Cheniere Energy's Sabine Pass, Louisiana, terminal that opened in 2016 and Dominion Energy's Cove Point, Maryland, terminal that started up in March. If needed, Elba will be able to import LNG, said a Kinder Morgan spokeswoman. "Based on market conditions, the facility will have the ability to handle both imports and exports at the customer's discretion."

FERC allows work to resume on $3.7 billion gas pipeline

(The Roanoke Times; VA; Aug. 29) - Federal regulators are allowing work to resume along most of the Mountain Valley Pipeline's 303-mile route through West Virginia and Virginia. Federal Energy Regulatory Commission authorization comes less than a month after it ordered a halt to work on the project. In its Aug. 29 letter, FERC cited a new analysis by the U.S. Bureau of Land Management concluding that the line's earlier approved route through the Jefferson National Forest is the best of several alternatives.

BLM had been faulted for inadequately considering all potential route alternatives when the 4th U.S. Circuit Court of Appeals struck down two key approvals for the gas pipeline to pass through the forest. The only exceptions to FERC's Aug. 29 authorization to resume construction are for a 3.5-mile stretch of the pipeline through the national forest — for which Mountain Valley still must obtain a new permit from the U.S. Forest Service — and a segment in Braxton County, West Virginia, that also crosses federal land.

Mountain Valley has pushed its projected completion date for the $3.7 billion project from early 2019 to the fourth quarter of 2019. The line will move up to 2 billion cubic feet a day of West Virginia gas to market, linking to an existing line near the Virginia-North Carolina border. Since construction ramped up in April, however, regulators in Virginia and West Virginia have warned Mountain Valley that it was failing to keep muddy runoff from flowing off construction sites and into nearby streams.

FERC approves Cheniere's $1 billion Oklahoma gas pipeline

(The Oklahoman; Aug. 30) - Cheniere Energy hopes to begin work on its $1 billion Midship Pipeline soon, now that it has obtained approval from the Federal Energy Regulatory Commission. The 200-mile-long gas line will start in Kingfisher County in Oklahoma and head south and east to the Oklahoma/Texas line, where it will hook into the nation's interstate pipeline system. Once it becomes operational in the third quarter of 2019, it will have the capacity to carry about 1.44 billion cubic feet of gas per day.

The new pipeline will move production from Oklahoma's SCOOP and STACK fields in the Cana Woodford Basin, which is the third most active oil and gas field in the country, according to Baker Hughes. The area had 65 active rigs last week. Cheniere said the supply will provide a ready source of gas that ultimately can be exported through the liquefied natural gas terminals the company owns in Louisiana and Texas. Lacking pipeline capacity, STACK and SCOOP producers have been selling gas at a discount.

Permian drillers have a water problem — too much of it

(Bloomberg; Aug. 30) - In the dry plains of West Texas, home to America's most prolific oil play, the problem isn't too little water, it's too much of it. ''If we don't have a water solution we can't produce the well, it's as simple as that,'' said Will Hickey, CEO of producer Colgate Energy. With fracking, explorers blast water, sand and chemicals down wells to crack open the shale below. As oil is pumped up, so is salt-laden water from underground reservoirs that would devastate farmland if released on the surface.

With as many as four barrels of water produced for every barrel of oil from the Permian Basin, it's a disposal nightmare that could add as much as $6 a barrel to company break-evens by 2025, according to a recent Wood Mackenzie study. Overall, the region will pull up enough water this year alone to cover all of Rhode Island nearly a foot deep. Spending on water management in the Permian is likely to nearly double to more than $22 billion in just five years, according to industry consultant IHS Markit.

Drillers generally inject excess water back into the ground, often after trucking it to areas such as the San Andres, a region largely drilled-out early in the shale boom. But now, with the boom hitting historic levels, that system is running into headwinds. In the San Andres, wells sunk to gather oil deeper within the play are collapsing as a result of the increased pressure from water injections, causing dozens to be closed and the loss of miles of pipe, according to Andrew Hunter, a drilling engineer at Guidon Energy.

At the same time, earthquakes in the Permian have more than tripled to 62 with at least a 2.5 magnitude in the past year, from just six two years earlier. Environmentalists are quick to blame the water injections, pointing to studies on similar activity in Oklahoma.

Permian flared 320 million cubic feet a day of gas in 2nd quarter

(Wall Street Journal; Aug. 29) - In America's busiest oil field, roughly $1 million worth of gas is burned away every day. Shale drillers in the Permian Basin of Texas and New Mexico say they have no way to move the gas — a byproduct of oil drilling — to market because there aren't enough pipelines. Instead they get rid of the excess gas by setting it on fire, known as flaring. Companies flare about 3 percent of the gas they extract in the Permian, producing greenhouse-gas emissions equivalent to 2 million cars.

Shale drillers are flaring with the consent of state regulators. Until more gas pipelines and storage facilities are added, the only alternative to burning gas would be to reduce some of the area's lucrative oil production, which has helped boost U.S. crude output to a record 11 million barrels a day. Texas officials say they expect the issue to resolve itself eventually once infrastructure is built. "There's nothing for us to do," said Ryan Sitton, a member of the state agency that regulates oil and gas operations.

The Wall Street Journal reviewed data on the more than 20,000 permit requests that companies submitted to Texas to flare gas over the past five years. None was denied as of early August, the data show. Permian production has soared to 3.3 million barrels of oil a day and nearly 11 billion cubic feet of gas in June, according to federal statistics. Flaring topped 320 million cubic feet a day in the second quarter, according to analysis of public data compiled by Rystad Energy, an energy consulting and research firm.

Without stricter rules "the economic driver to do something with it is not strong," said a consultant for the World Bank's Global Gas Flaring Reduction Partnership.

Colorado will vote in November to severely limit oil and gas drilling

(Wall Street Journal; Aug. 29) – Coloradans in November will consider banning oil and gas drilling within 2,500 feet of homes, businesses and many green spaces, essentially prohibiting drilling in most of the seventh-largest oil-producing state. Fracking opponents collected enough signatures to put the issue on the ballot, setting the stage for a heated battle in a state where suburban sprawl and oil and gas production have encroached on one another. Colorado's top politicians have largely come out against the measure.

Colorado requires oil and gas wells to be located at least 500 feet from buildings and 350 feet from recreation areas like playgrounds. The ballot initiative to expand setbacks to 2,500 feet would ban drilling on 85 percent of the state's non-federal land, according to an analysis by state regulators. Activists have campaigned for years for such limitations in Colorado, where wells commonly abut densely populated areas. Similar statewide initiatives failed to make the ballot in 2014 and 2016.

Since then, however, oil production has increased 44 percent in Colorado. That surge coincided with growth in the suburban communities north of Denver where drilling is most prevalent. “Our strategy is to have a ground game that spans the entire state and particularly areas that are impacted, areas where folks tend to vote,” said Suzanne Spiegel of Colorado Rising, the group behind the measure. Many of the homeowners whose houses flank oil and gas drilling don’t own the mineral rights that would entitle them to royalties. The initiative is widely expected to face legal challenges if it passes.

Court rules insufficient consultation with First Nations for oil line

(Financial Post; Canada; Aug. 30) - The Canadian government has vowed to build the Trans Mountain expansion project despite a major setback Aug. 30 from a Federal Court of Appeal decision overturning the oil pipeline’s construction permits. The court ruled that the government did not adequately carry out its duty to consult with First Nations on the project and that the National Energy Board’s environmental review was flawed because it did not fully consider increased tanker traffic along the B.C. coast.

The court said the consultation process was insufficient because it was “missing a genuine and sustained effort to pursue meaningful, two-way dialogue.” The project now will need to undertake new reviews if it is to move forward. The decision is not what the Calgary oil patch was expecting. Opposed Indigenous groups along the route, however, celebrated the decision. Union of British Columbia Indian Chiefs President Stewart Phillip called it “one in a long line” of decisions recognizing Indigenous title and rights.

Finance Minister Bill Morneau, who negotiated Canada’s C$4.5 billion deal to buy the pipeline and 710-mile expansion project from Kinder Morgan in May to ensure it would be built despite provincial opposition in British Columbia, said the federal government remains committed to the project to expand the line’s capacity to move Alberta oil to a coastal export terminal. Near term, Kinder Morgan is preparing to halt construction. The court ruling is expected to delay the project and drive up costs, previously estimated at C$7.4 billion with a potential escalation to C$9.3 billion if completion is delayed to 2021.

Alberta premier wants emergency law to clear the way for oil line

(The Canadian Press; Aug. 31) - Alberta Premier Rachel Notley said an Aug. 30 federal court decision striking down regulatory approval of the contentious Trans Mountain oil pipeline expansion is a national crisis — and she is pulling her province out of the federal climate plan until Ottawa fixes it. Notley also said her government has not ruled out acting on recent legislation that allows it to cut the flow of oil to other provinces to drive home the importance of Alberta’s bedrock industry to the rest of Canada.

“Albertans are angry. I’m angry,” Notley said Aug. 30. “Alberta has done everything right and we’ve been let down. The current state of affairs in Canada right now is such that building a pipeline to tidewater is practically impossible.” The court overturned federal approval of the pipeline project, which would have almost tripled the line’s capacity from Alberta to an export terminal on the British Columbia coast. The court cited inadequate Indigenous consultations and the regulator’s’ failure to fully consider tanker traffic.

Notley called on the federal government to appeal the decision to the Supreme Court; properly consult with Indigenous peoples; and recall Parliament so that it can pass emergency legislation making it clear that the National Energy Board does not have to inquire into marine shipping impacts as part of its mandate. Until then, she said Alberta is pulling out of the national climate plan, meaning the province won’t agree to raise its current price on carbon from $30 tonne to $40 tonne in 2021 and $50 a tonne by 2022.

Shell expects its Gulf production will return to 450,000 barrels a day

(S&P Global Platts; Aug. 29) - Shell is fast expanding its Gulf of Mexico oil business and should return next year to its past record production level of about 450,000 barrels per day in the region, upstream director Andy Brown told S&P Global Platts. Brown said Shell had brought on stream a well a week in the Gulf of Mexico over the past three months. The Appomattox platform, due online next year, he said, would enable additional production from several fields.

The company believes capacity at the platform, originally designed for 175,000 barrels per day, can reach 240,000 with debottlenecking. Further out, Shell will bring the Vito hub on stream in 2021, while this year's Whale discovery with Chevron should justify another oil hub, Brown said.

Shell said last November it aimed to increase its worldwide deepwater production to more than 900,000 barrels of oil equivalent a day by 2020 from under 800,000 currently. In addition, the company aims to roughly double its Permian shale basin production to 200,000 barrels a day by 2020, split evenly between oil, gas, and natural gas liquids.

Public-private partnership plans oil export terminal in Louisiana

(ICIS; Aug. 29) - Tallgrass Energy and Drexel Hamilton Infrastructure Partners are planning to build a crude oil export terminal on the Mississippi River in Plaquemines Parish, Louisiana, the state’s economic development agency confirmed Aug. 29. The proposed Plaquemines Liquids Terminal, with storage for up to 20 million barrels of oil, could be fully operational by mid-2020, the agency said.

The terminal would be fed by an 800,000-barrel-per-day pipeline from the Cushing oil hub in Oklahoma. Tallgrass also plans an offshore pipeline extension to give the terminal the added capability of loading very large crude carriers, the state agency said. The pipeline and terminal project will require a capital investment of about $2.5 billion.

The project is planned as a public-private partnership, with multiple deepwater docks along the river to be furnished by the Plaquemines Port Harbor & Terminal District. The facilities will provide terminal operators with the ability to load and unload the larger-capacity vessels now traversing the expanded Panama Canal, the agency said.

Indian Railways signs up to start using gas at its workshops

(Reuters; Aug. 30) - Indian Railways on Aug. 30 signed a preliminary deal with natural gas distributor GAIL India, part of a drive by the world's third-biggest oil consumer to gradually shift to cleaner fuels. India is building infrastructure, including gas pipelines and liquefied natural gas import facilities, to raise the share of gas in its energy mix to 15 percent in next few years from the current level of about 6.5 percent.

Using natural gas will be about 25 percent cheaper than the alternative fuels used by the railways at its workshops and production units, said Ashwani Lohani, chairman of Indian Railways' board. He said the company would strive to shift all 54 of its shops to gas by June 2019. Indian Railways annually consumes almost 19 million barrels of diesel, said Chetram, chief administrative officer of Indian Railways Organisation for Alternate Fuels. Only a fraction of that will be replaced by natural gas, he added.

"The objective of this memorandum of understanding is … we will be supplying natural gas to the Indian Railways," said B.C. Tripathi, chairman of GAIL India.