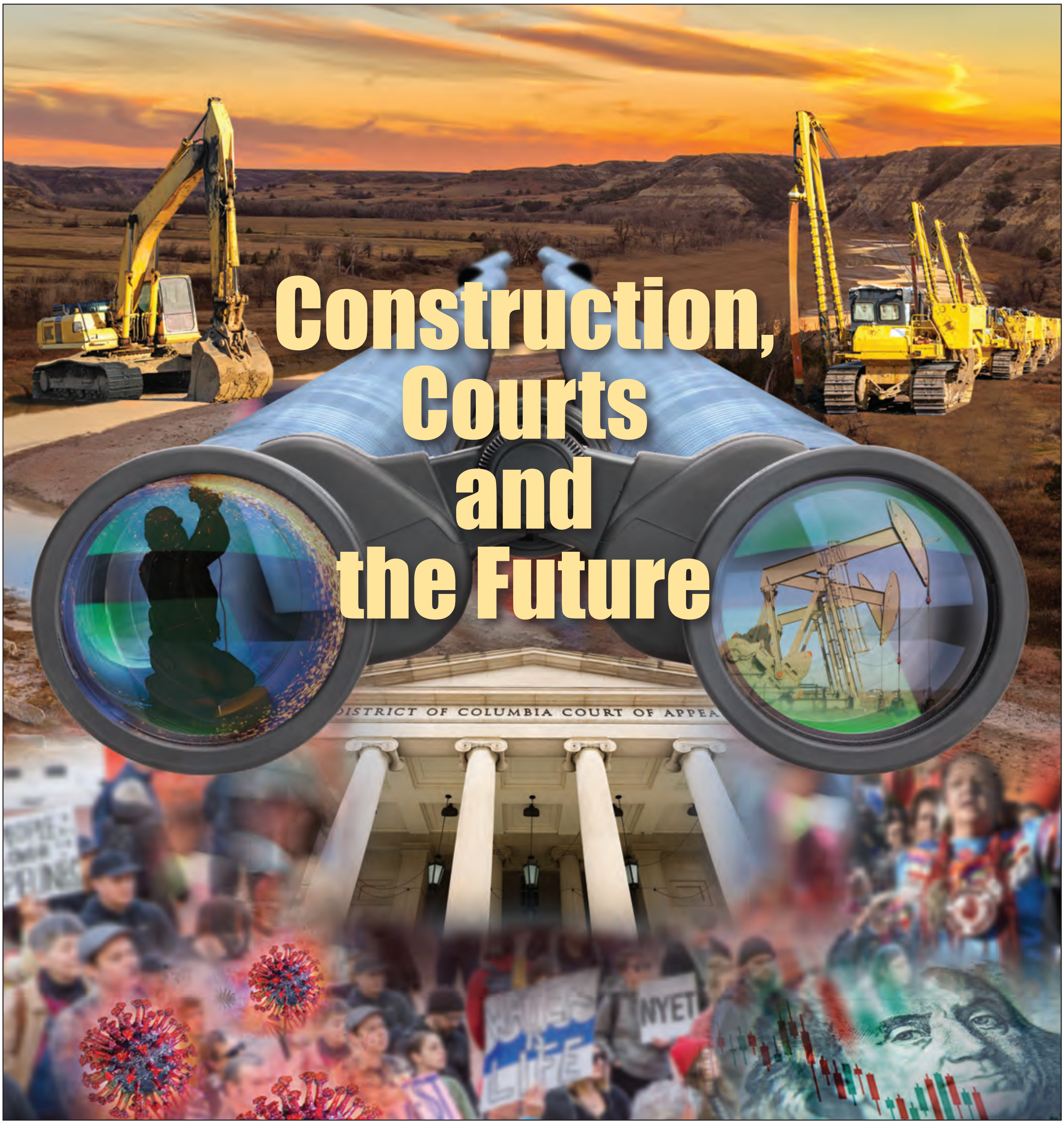
MIDSTREAM Business



A supplement to

Oil and Gas Investor

SEPTEMBER 2020

HARTENERGY

This announcement appears as a matter of record only.

Energy Spectrum Capital is pleased to announce the closing of its eighth midstream venture capital fund.

ENERGY SPECTRUM PARTNERS VIII LP

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The Fund provides venture capital to growth-oriented companies that acquire, develop and operate midstream energy assets in North America.

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MIDSTREAM Business

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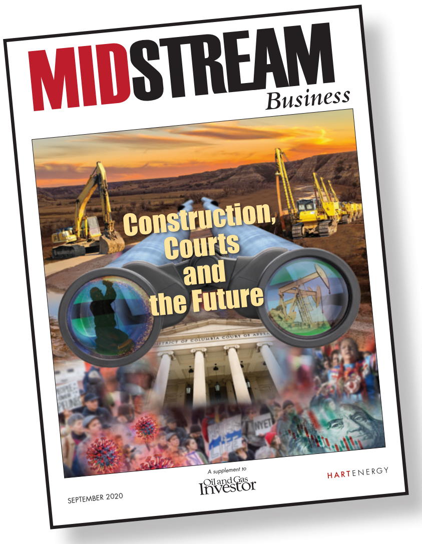


On the cover: As opponents use the courts more and more to slow progress on pipeline construction projects, rising costs threaten the future of vital projects. (Cover images courtesy of Shutterstock.com; Cover design by Alexa Sanders)

(Source: Hart Energy/Shutterstock.com)

DEALS

CNX Resources to Buy Out Midstream Affiliate in $357 Million Deal

CNX Resources Corp. agreed to buy out its midstream affiliate, creating the "lowest-cost Appalachia producer," the Pittsburgh-based E&P company said July 27.

Under a merger agreement, CNX Resources will purchase the remaining public stake, comprising about 42.1 million outstanding common units, of CNX Midstream Partners LP. Total consideration for the all-stock transaction, which is valued at roughly $357 million, is about $8.47 for each outstanding CNX Midstream unit.

The exchange ratio of 0.88 CNX shares per CNX Midstream unit represents a 15% premium to the 30-day average exchange ratio or a 28% premium to close on July 24, according to analysts with Tudor, Pickering, Holt & Co. (TPH).

"At first blush, valuation represents relatively low premium paid for a one-off transaction to bring cash cost savings in house," TPH analysts wrote in a July 27 research note.

CNX Midstream Partners is an MLP with gathering and other midstream energy assets to service natural gas production in the Appalachian Basin in Pennsylvania and West Virginia. The company formed in 2016, originally as CONE Midstream Partners, a joint venture (JV) between CNX Resources, operating as CONSOL Energy at the time, and Noble Energy Inc.

However, CNX Resources rebranded the company as CNX Midstream Partners in 2017 following the purchase of Noble's 50% interest in the midstream JV for $305 million in cash.

In a statement commenting on the transaction, CNX Resources CEO and President Nicholas J. DeIuliis said,"We expect the combined entity to be an even stronger company with a lower cost of capital and increased investable free cash flow."

Despite the expected cash savings, no changes were made to CNX Resources' current strategic plan to generate more than $3 billion in cumulative free cash flow over the next seven years.

"Following the completion of the transaction, CNX is expected to be the lowest cost producer in the Appalachian Basin, with increased operational flexibility and basin leading operational metrics," CNX Resources CFO Don W. Rush added in the company release.

CNX Resources expects to close the transaction in fourth-quarter 2020, at which time CNX Midstream common units will no longer be publicly traded. In aggregate, CNX will issue approximately 37 million shares in connection with the proposed transaction, representing approximately 17% of the total shares outstanding of the pro forma combined entity.

Following completion of the transaction, all senior notes of CNX Midstream will remain outstanding. No additional payments will be made to CNX in connection with the elimination of the incentive distribution rights transaction from January 2020.

The company said transaction terms were negotiated, reviewed and approved by the conflicts committee of the CNX Midstream board. The board of directors of CNX Resources and CNX Midstream also approved the merger agreement.

Citi is exclusive financial adviser to CNX for the transaction, and Latham & Watkins LLP is acting as the company legal adviser. Intrepid Partners LLC is exclusive financial adviser and Baker Botts LLP is legal adviser to the conflicts committee of the CNX Midstream board.

—*Emily Patsy*

DEALS

Montage Resources to Sell Noncore Ohio Utica Asset for $25 Million

Montage Resources Corp. is divesting a noncore asset sale in its Ohio Utica condensate development area to an international third party.

In a company release on July 22, Montage said it entered into a non-binding letter of intent for the sale of its existing noncore Ohio Utica wellhead gas and liquids gathering infrastructure in exchange for a cash payment of $25 million. The transaction is expected to close fourth-quarter 2020.

"We are extremely pleased to be working with this well-established third party on the sale of these noncore assets, and the proceeds will provide the company the ability to reduce leverage, enhance liquidity and maintain its already strong balance sheet," John Reinhart, president and CEO, said in a statement.

Montage Resources is an E&P company based in Irving, Texas, with approximately 195,000 net effective core undeveloped acres currently focused on the Utica and Marcellus shales of southeast Ohio, West Virginia and north-central Pennsylvania.

In April, the company shut in low-margin production in its liquids-rich producing areas, primarily impacting its

Utica condensate production, due to the historic crash in oil prices. However, on July 22, Montage said substantially all production had been returned to sales by June 1.

Additionally, Montage lowered its full-year 2020 capex guidance range to between $120 million and $140 million, from its previous $130 million to $150 million range. The company expects the capex adjustment won't impact its full-year 2020 production due to a "persistent" focus on cost and efficiency gains.

"Our demonstrated results continue to reinforce value-enhancing progress toward improvements in efficiency gains, cost reductions, shortened cycle times and ongoing well outperformance," Reinhart continued in his statement. "We believe the demonstrated capability of the team at Montage and the flexibility of the company's assets will enable us to maintain a relatively stable year-over-year production profile from a prudent amount of capital expenditures, while sustaining the company's commitment to debt reduction and cash flow generation."

—Hart Energy staff

TRENDS

Magellan Midstream Sees Lower Fuel Pipeline Volumes for Rest of 2020

Magellan Midstream Partners LP said its refined products pipeline volumes are expected to decline in the second half of this year as fuel demand remains depressed due to the pandemic.

Global oil demand plunged by about 30% in April as coronavirus-related lockdowns restricted travel worldwide and sent oil prices crashing.

Average base refined products pipeline volumes are expected to fall 6% for gasoline, 12% for distillate and 40% for aviation fuel compared to the second half of 2019, excluding the impact of expansion projects, Magellan said.

During the second quarter, lower drilling activity reduced distillate transportation volumes, CFO Jeff Holman said on an earnings call.

As oil prices collapsed, U.S. producers have slashed spending and curbed new drilling. The U.S. oil and gas rig count, an early indicator of future output, fell to an all-time low of 251 in late July.

Magellan said its West Texas refined products pipeline expansion began operations on July 1, with an additional 75,000 bbl/d of capacity now available. The related new refined products terminal in Midland, Texas, also began service this week, the company said.

The expansion of the Saddlehorn crude pipeline continues to progress, with an additional 100,000 bbl/d of capacity expected to be available by the end of 2020.

The Saddlehorn pipeline is currently capable of transporting 190,000 bbl/d of crude and condensate from the Denver Julesberg and Powder River shale basins to Cushing, Okla., the delivery point for benchmark U.S. crude futures.

Crude operating margins fell $34.9 million to $128.3 million and transportation and terminals revenue decreased $26.5 million in the second quarter in part due to lower third-party spot shipments on the Longhorn crude pipeline.

The spread between oil prices in the Permian Basin and Houston was not wide enough to encourage spot shipments on the line, Magellan said.

—Devika Krishna Kumar, Reuters

Bernard L. McNamee
(Source: FERC)

PEOPLE

FERC Commissioner McNamee to Step Down

Bernard L. McNamee, commissioner of the Federal Energy Regulatory Commission (FERC), announced he would step down on Sept. 4. His departure will likely leave FERC with only three of five commissioner positions filled.

McNamee, appointed by President Donald Trump, announced in January that he would not seek another term. He has served on the commission since his Senate confirmation in December 2018 and also served with the U.S. Department of Energy in multiple positions, including executive director of the Office of Policy and deputy general counsel for energy policy.

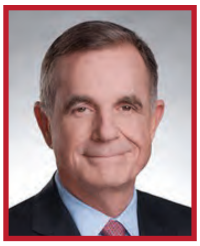
Sen. Joe Manchin (D-W.Va.), ranking member of the Senate Energy and Natural Resources Committee, released a statement noting that Congress did not intend for FERC to operate with only three commissioners instead of five.

"Currently, the Senate Energy and Natural Resources Committee lacks the necessary paperwork to hold a confirmation hearing for FERC nominees Allison Clements and Mark Christie," Manchin said. "I am hopeful the committee will act quickly to restore a fully seated FERC once we have the necessary paperwork."

The Trump administration on July 27 selected Clements, a Democrat, and Christie, a Republican, but has yet to submit the names to the Senate for confirmation. The committee previously warned the administration that it would not consider Republican nominees until a Democrat was chosen to replace Democratic Commissioner Cheryl LaFleur, who left FERC in March 2019.

—Joseph Markman

Dominion Energy plans to add 5,000 MW of offshore wind turbines in 15 years. (Source: Hart Energy/Shutterstock.com)



Thomas Farrell
(Source: FERC)

CLEAN POWER

Dominion's Farrell Stresses Role of Natural Gas in Clean Power Push

Natural gas will fuel power generation for years to come at Dominion Energy Inc., one of the largest U.S. utilities, even as it sells a huge pipeline network to Warren Buffett and adjusts to an aggressive clean power mandate in its biggest market.

Dominion, based in Virginia, has set out a goal of net zero emissions of CO_{22} and methane from power plants and gas infrastructure from 2050. Democrats in its home state this spring enacted a law requiring the company's local electric utility to use 100% carbon-free energy by 2045.

Yet natural gas, the fossil fuel with the lowest carbon emissions, would continue to be crucial to the company's power mix, said Thomas Farrell, chairman and CEO.

Farrell will become the company's executive chair, effective Oct. 1. In that role, he will continue to serve as chair of the board of directors.

Also, effective that date, Robert M. Blue, executive vice president and co-COO, will be promoted to president and CEO, reporting to Farrell. Diane Leopold, executive vice president and co-COO, will be promoted to Dominion Energy's sole COO, responsible for all the company's operating segments, reporting to Blue. Edward H. "Ed" Baine will be promoted to president-Dominion Energy Virginia. He will report to Leopold.

"In my opinion, for some considerable period of time, I don't know if it's 10 years, or 15 years, or 20, you're going to need fast-start gas-fired power plants that can help cover the needs of the economy when renewable power's not working," Farrell told the Financial Times in an interview following the announcement of his new post.

Solar and wind power depend on sunny days or strong breezes to operate. Maintaining reliable electric service requires resources available at any time, such as gas or nuclear generators. Battery storage is emerging as another option to back up renewables but remains in its infancy on the grid.

Partly in response to the Virginia law, the company this spring dramatically revised a long-term state resource plan that envisages adding more than 15,000 MW of solar capacity and 5,000 MW of offshore wind turbines in 15 years. More than 2,700 MW of storage resources also feature in the plan. Farrell said he was "rooting" for researchers working on batteries.

Dominion's resource plan also said the company would probably need to preserve thousands of megawatts of gas-fired generating capacity. It projects that gas would account for about 25% of power production in 2035, down from 42% in 2019.

In August, Dominion agreed to the $9.7 billion sale of its natural gas transmission and storage business to Buffett's Berkshire Hathaway. The same day, it canceled the pursuit of its proposed Atlantic Coast pipeline, even though the U.S. Supreme Court had days earlier ruled the project could receive a crucial federal permit.

Dominion and its project partner Duke Energy said other litigation presented new uncertainties for the Atlantic Coast project, the cost of which had ballooned to $8 billion from about $5 billion when first proposed in 2014.

A number of factors led to the sale of the gas transmission and storage business to Berkshire Hathaway, including changes to federal policy related to the financing of pipeline businesses, Farrell said.

"But it's also a recognition by us that we are a leader in clean energy among utilities, and we are going to be the leader," Farrell said.

—Gregory Meyer, Financial Times

PEOPLE

Midstream Equity Research Exec Ethan Bellamy Joins East Daley Capital

Ethan Bellamy joined East Daley Capital Advisors Inc., the provider of midstream energy asset-level data and analysis, to lead the firm's midstream energy market strategy.

Bellamy brings more than 15 years of experience in midstream equity research. He joins East Daley from Baird, where he most recently worked as a senior equity analyst covering energy infrastructure. Prior to Baird, he was the director of research for the Lehman Brothers MLP Opportunity Fund.

Having worked on the buy side, sell side and in private equity, Bellamy brings a deep experience in midstream investing and analytics, according to Jim Simpson, CEO and cofounder of East Daley Capital.

"We're pleased to expand our leadership team as we continue to grow our research and consulting practice in the North American midstream energy market," Simpson said in a statement.

At East Daley, Bellamy will work in his newly formed role as managing director of midstream strategy to expand the company's advisory capabilities, subscription services, marketing efforts, media relations and content development.

"As COVID-19 and commodity price turmoil create market volatility, a concise, comprehensive and bottoms-up understanding of asset level economics has never been more important in capital deployment," Bellamy said in a statement.

"I'm excited to show midstream professionals how East Daley's tools can help improve risk-adjusted returns," he added.

—Hart Energy staff

EARNINGS

Kinder Morgan Posts Quarterly Loss on $1 Billion Impairment Charge

U.S. pipeline operator Kinder Morgan Inc. posted a second straight quarterly loss as it took a $1 billion impairment charge after a steep fall in natural gas prices caused by the coronavirus crisis hurt the value of some of its assets.

Energy companies have been hard hit by the COVID-19 pandemic that slashed fuel demand by about 30%, hurting natural gas prices and leading to lower demand for crude to be refined into products.

"Sharp declines in crude oil and natural gas production along with reduced demand for refined products due to the economic shutdown in the wake of the pandemic clearly affected our business and will continue to do so in the near term," Kinder Morgan President Kim Dang said.

The company said two of its key natural gas projects remain on track despite the impact from the pandemic. It expects to start its Permian Highway Pipeline in Texas in early 2021 and the final three Elba Island LNG liquefaction plants this summer.

However, an industry source said on July 22 that a final investment decision on its proposed Permian Pass natural gas pipeline in Texas would likely get pushed out at least a couple of years.

The company said in March the pipeline faced an uncertain future because no customers for the project have been lined up in the current low-price environment.

The company's CO_2 segment, which ships CO_2 to oil fields for extracting crude, also came under pressure due to lower production and volatile oil prices.

Net loss attributable to the company stood at $637 million, or 28 cents per share, in the second quarter that ended June 30, compared with a profit of $518 million, or 23 cents per share, a year earlier.

Excluding items, the company reported a profit of 17 cents per share, in-line with Wall Street estimates, according to IBES Refinitiv data.

—Reuters

JOINT VENTURES

WhiteWater Midstream to Provide Permian Basin NGL Transportation Solutions

WhiteWater Midstream, MPLX LP and West Texas Gas Inc. (WTG) formed a joint venture (JV) on Aug. 6 to provide NGL takeaway capacity from MPLX and WTG gas processing plants in the Permian Basin to the NGL fractionation hub in Sweeny, Texas. WhiteWater Midstream's investment in the JV is backed by Ridgemont Equity Partners, Denham Capital Management and the Ontario Power Generation Inc. Pension Plan.

The JV will provide an optimized approach to pipeline transportation service for NGL primarily through the utilization of existing infrastructure with limited initial construction. The solution will facilitate future, capital-efficient expansions that meet customer demands in a recovering basin. The JV is supported by volumes from key processing plants with long-term commitments from top-tier Permian producers.

As part of this NGL transportation solution, the JV has entered into multiple capacity arrangements from Orla, Texas, to Sweeny, including an agreement with EPIC Y-Grade Pipeline LP (EPIC) to own an undivided joint interest in EPIC's existing 24-inch NGL pipeline from West Texas to the Eagle Ford Basin.

—Business Wire

Construction of the Mountain Valley Pipeline in West Virginia is projected to span approximately 303 miles. (Source: Malachi Jacobs/Shutterstock.com)

PROJECTS

Despite Permit Denial, MVP Southgate Remains on Track

The companies developing the Mountain Valley Southgate natural gas pipeline expansion from Virginia to North Carolina said on Aug. 12 they continue to target a 2021 startup for the project after North Carolina regulators denied a water permit.

The North Carolina Department of Environmental Quality (DEQ) denied the permit on Aug. 11 due to uncertainty around whether Equitrans Midstream Corp. will complete the $5.4 billion to $5.7 billion Mountain Valley Pipeline (MVP) from West Virginia to Virginia. A unit of Equitrans is leading the MVP project.

"We are disappointed by the decision," project spokesperson Shawn Day said, noting "Work on MVP is 92% complete and is targeted to enter service in early 2021."

MVP is one of several U.S. pipelines delayed by regulatory and legal fights with environmental and local groups that found problems with federal permits issued by the Trump administration.

Other projects similarly held up include Dominion Energy Inc.'s recently canceled $8 billion Atlantic Coast gas pipe from West Virginia to North Carolina.

"(Southgate) has always been an unnecessary project that poses unnecessary risks to our environment and given the uncertain future of the MVP Mainline. North Carolinians should not be exposed to the risk of another incomplete pipeline project," DEQ Secretary Michael Regan said in a statement. "North Carolina's clean energy future is not dependent on adding more gas infrastructure."

The North Carolina rejection caused some analysts to question whether Equitrans will be able to finish Southgate by the end of 2021, if ever.

—Reuters

METHANE

Enbridge Joins ONE Future Methane-reduction Coalition

Our Nation's Energy Future (ONE Future) announced that Enbridge Inc., the largest infrastructure company in North America, has joined the coalition, bringing the total number of member companies to 27.

"Enbridge has a storied history of providing safe, reliable energy to its customers across North America, and we're pleased they joined the ONE Future coalition," said Richard Hyde, executive director of ONE Future. "Their commitment to being a community partner is recognized through their many best practices; we are confident they will be an asset to the organization."

As a ONE Future member, Enbridge will report its 2019 methane results as part of the Transmission & Storage sector within the coalition and will hold a seat on ONE Future's board of directors. The 2018 Methane Intensity Report was released in the fall of 2019. In it, the coalition registered a 2018 methane intensity number of 0.326%, a decrease of 41% from 2017, demonstrating that the natural gas industry can minimize methane emissions and increase production and throughput while supplying much needed energy to the U.S. and around the globe for years to come.

"We are pleased to be part of a coalition that shares our commitment to reduce methane emissions," said Bill Yardley, executive vice president and president, gas transmission and midstream with Enbridge. "Enbridge takes this mission seriously. We recognize that climate change is a global issue, and we've undertaken many innovative and proactive initiatives to manage and reduce our emissions. We're focused on creating long-term value for all of our stakeholders." ■

—Hart Energy staff

Is 2020 Over Yet?

On the Gulf Coast, storage facilities and pipelines are moving forward. Elsewhere, COVID-19 and the courts are causing headaches.

By Joseph Markman

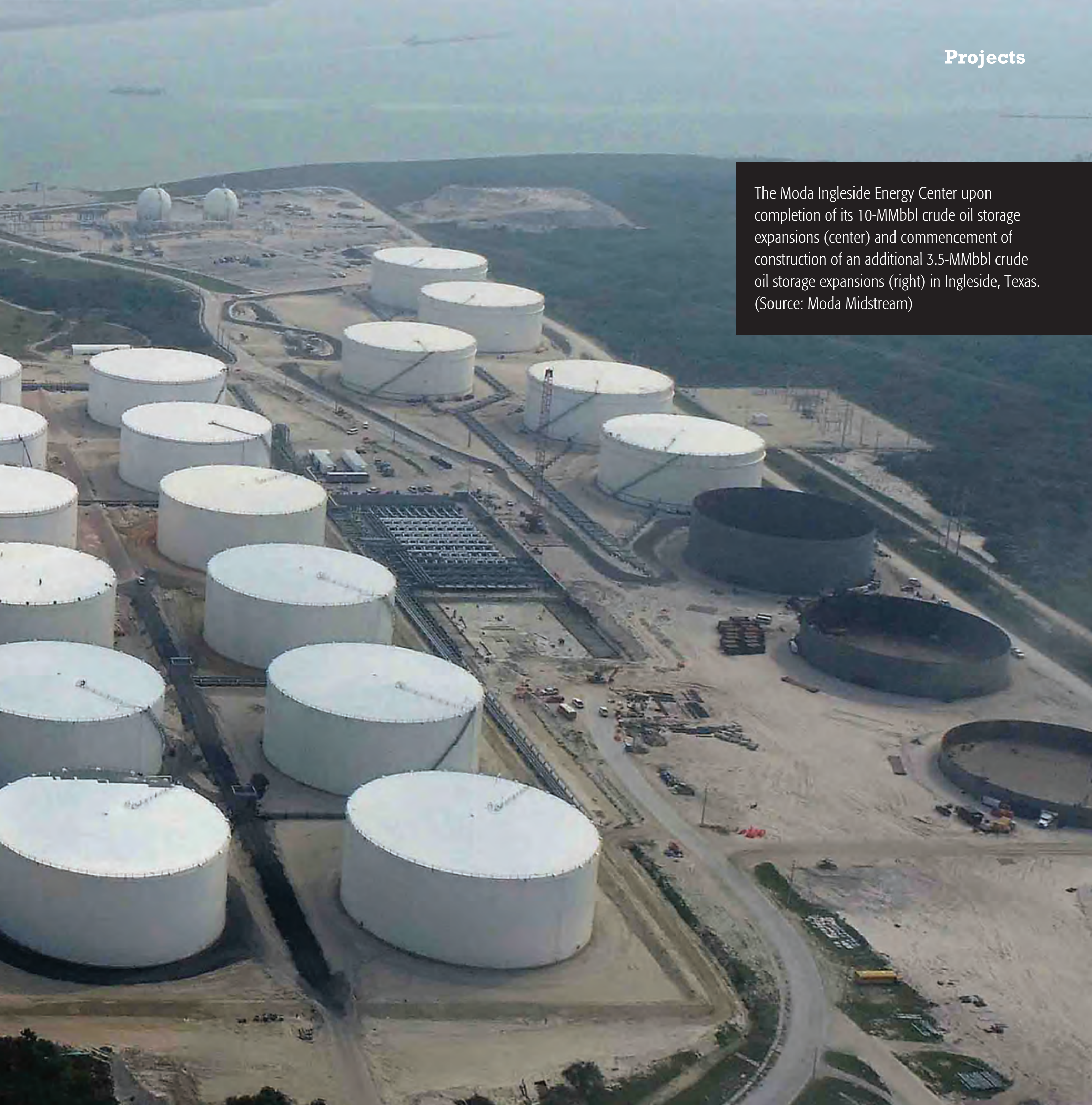
Energy Transfer Partners, as the kids would say, got "2020ed." The company's Dakota Access Pipeline (DAPL) was ordered to shut down in early July by a federal judge who ruled that the U.S. Army Corps of Engineers did not conduct an environmental impact statement as required before issuing a permit.

So, three years after DAPL went into operation to transport crude oil from the Bakken Shale to Patoka, Ill., a judge issued his decision based on a rule broken by a third party (the Corps). Three years. Now, friends, you know what it means to be 2020ed.

While that kerfuffle works itself out in court, it's worth noting that an actual project, the DAPL expansion, could be in doubt. The company planned to double capacity from 570,000 bbl/d to 1.1 MMbbl/d, but the oil price shock and loss of demand cut deeply into Bakken Shale producers' enthusiasm for the project.

"Honestly, [the DAPL expansion] is not needed," an anonymous E&P executive whose company committed to space on the expanded pipeline told Reuters. "Would I like to get out? Yes, for sure."

Those kinds of sentiments convinced Energy Transfer to declare force majeure to compel committed producers to stick with the project and honor their contracts. The federal court decision in early July didn't help.



The Moda Ingleside Energy Center upon completion of its 10-MMbbl crude oil storage expansions (center) and commencement of construction of an additional 3.5-MMbbl crude oil storage expansions (right) in Ingleside, Texas. (Source: Moda Midstream)

"We would assume an expansion would be off the table if DAPL is forced to close, but this is yet another loose end to tie up," Wells Fargo equity researchers said in a July 8 report. "For now, our estimates continue to assume a DAPL expansion."

Gulf Coast

The Gulf Coast again dominates the list of projects because demand has shifted down the value chain to storage and terminals, and away from wellhead-proximity needs like gathering and processing and pipelines.

In late April, Moda Midstream LLC completed the 10-MMbbl expansion of its Moda Ingleside Energy Center (MIEC) in Ingleside, Texas, and Moda Taft Terminal in Taft, Texas. Placing the final 495,000-bbl tank into service brought total storage capacity to 12 MMbbl.

"Bringing 10 million barrels of storage online in just over a year and a half is a major accomplishment," Moda's president and CEO, Bo McCall, said. The company, though, isn't done. Work has begun to add 3.5 MMbbl of crude storage at MIEC, bringing the total to 15.5 MMbbl when this expansion phase is completed, probably later this year. Other expansions are in the planning stages pending discussions with customers.

SELECTED CONSTRUCTION PROJECTS FOR APRIL–JULY 2020

Gulf Coast				
Operator/Developer	**Project**	**Location**	**Added Capacity**	**Status/Completion**
Moda Midstream LLC	Moda Ingleside Energy Center, Moda Taft Terminal	Ingleside and Taft, Texas	10 MMbbl	Moda placed its final 495,000-bbl tank into service in late April, bringing the total capacity of the expanded storage facilities to 12 MMbbl.
Venture Global LNG Inc.	Calcasieu Pass LNG export facility	Cameron Parish, La.	10 mtpa	Completed raising of second storage tank roof in May
Venture Global LNG Inc.	Plaquemines LNG export plant	Plaquemines Parish, La.	2.6 Bcf/d	The regulators approve construction to proceed.
Harvest Midstream Co.	Ingleside Pipeline	Ingleside and Taft, Texas	600,000 bbl/d	The 24-mile pipeline's completion was announced in June.
Harvest Midstream Co.	Harvest Midway Terminal	Taft, Texas	10 MMbbl	Phase one construction of the storage terminal is expected to be completed by the end of third-quarter 2020.
Buckeye Partners LP	South Texas Gateway Terminal	Port of Corpus Christi, Texas	Storage of 8.6 MMbbl	First vessel loaded with Permian Basin crude for export
NextDecade Corp.	Rio Grande LNG export facility	Port of Brownsville, Texas	17.61 mtpa	NextDecade delayed a final investment decision on the plant until 2021
Targa Resources Corp.	Targa NGL Pipeline	Kingfisher County, Okla., to Mont Belvieu, Texas	Dependent on open season results	Open season for 110-mile extension of the Grand Prix pipeline to Kingfisher County where it will connect with The Williams Cos. Inc.'s Bluestem Pipeline
Appalachia				
Operator/Developer	**Project**	**Location**	**Added Capacity**	**Status/Completion**
Dominion Energy Inc., Duke Energy Corp.	Atlantic Coast Pipeline	West Virginia to North Carolina	1.5 Bcf/d	Dominion and Duke canceled the project in early July, citing ongoing delays and cost uncertainty.
EQM Midstream Partners LP	Mountain Valley Pipeline	West Virginia to Virginia	2 Bcf/d	Expected completion delayed to early 2021, with estimated cost rising to $5.7 billion
The Williams Cos. Inc.	Leidy South project	Pennsylvania	582,400 Dth/d	FERC approved the project in mid-July. It includes construction of two compressor facilities.
PTT PCL	Ethane cracker	Ohio Valley	1.5 mtpa	Thai company PTT PCL delayed a final decision on whether to proceed with the $5.7 billion project in early June. In July, partner Daelim Chemical USA withdrew from the project.
Northwest				
Operator/Developer	**Project**	**Location**	**Added Capacity**	**Status/Completion**
Pembina Pipeline Corp.	Jordan Cove LNG	Coos County, Ore.	1.08 Bcf/d	DOE approved exports from the proposed terminal in early July.
Alaska Gasoline Development Corp.	Alaska LNG Export Termknal	Nikiski, Alasa	3.5 Bcf/d	In May, FERC authorized construction and operation of the $43.4 billion project.

Venture Global LNG Inc. was also in a hurry to complete its projects, raising the 1.8-MMlb tank dome and assembly of its second LNG storage tank at its Calcasieu Pass LNG export facility in Louisiana during a 1 hour and 20 minute operation in May, three months ahead of schedule. Installation of the gas-insulated switchgear was performed on schedule, too.

In mid-June, regulators gave the company a green light to move forward with limited site preparation of its proposed Plaquemines LNG export plant in Louisiana. A decision is expected later in the year, but if Venture Global chooses to proceed, it could be the only U.S. LNG project to begin construction in 2020 as coronavirus-related delays have pushed back plans of other developers. The $8.5 billion Plaquemines plant is scheduled to enter service in 2023.

Plaquemines is designed to produce up to 20 million tonnes per annum (mtpa) of LNG, equal to about 2.6 Bcf/d of natural gas. Analysts estimated the plant will cost about $8.5 billion.

Harvest Midstream Co. also kept an eye on the clock, completing its Ingleside Pipeline on time and providing customers with direct access to all three terminals in Ingleside.

"This is one of the fastest growing export centers on the Gulf Coast and we are excited to share this growth with our customers," Sean Kolassa, president of Harvest Midstream, said in June.

The 24-mile, 24-inch oil pipeline has a capacity of 600,000 bbl/d with Harvest Eagle Ford pipeline systems able to feed it with up to 380,000 bbl/d. It began transporting volumes to the Flint Hills Resources Ingleside Terminal first, followed by service to the South Texas Gateway Terminal and the MIEC.

The pipe originates at the Harvest Midway Terminal, which covers 160 acres in Taft, Texas. By the end of the third quarter, Phase 1 construction of the terminal is expected to be completed. The terminal could hold up to 10 MMbbl of crude storage.

Crude oil from the Permian Basin was loaded onto a vessel at the South Texas Gateway in July, a first for the Buckeye Partners LP-operated facility. The terminal is a joint venture, 50% owned and operated by Buckeye Partners. Phillips 66 Partners LP and Marathon Petroleum Corp. each have a 25% ownership interest.

When fully operational, South Texas Gateway's petroleum products storage capacity will total 8.6 MMbbl with the potential to expand to 10 MMbbl, and up to 800,000 bbl/d of throughput capacity at two deepwater docks.

Targa Resources Corp. announced an open season for an extension to its Grand Prix pipeline system. The 110-mile extension of Grand Prix will connect with Williams' Bluestem Pipeline in Kingfisher County, Okla., to move NGL to Mont Belvieu, Texas.

Not all of the news emanating from the Gulf Coast was as upbeat. In May, NextDecade Corp. said it will not decide whether to build the proposed Rio Grande LNG export plant in Texas until 2021. The company had announced it would make its final investment decision this year but backed off as it assessed demand destruction from the coronavirus to global LNG.

Appalachia

Dominion Energy and Duke Energy announced the cancellation of the Atlantic Coast Pipeline on July 5. The project costs, estimated at $4.5 billion to $5 billion when it began in 2014, had ballooned to at least $8 billion. The companies cited ongoing delays and increasing cost uncertainty, which threatened the pipeline's economic viability.

EQM Midstream Partners LP's Mountain Valley Pipeline, which is 92% complete, also experienced troubles. The project, originally expected to be finished

Northeast				
Operator/Developer	**Project**	**Location**	**Added Capacity**	**Status/Completion**
The Williams Cos. Inc.	Northeast Supply Enhancement natural gas pipeline	Pennsylvania to New York City	0.4 Bcf/d	In May, New York State regulators denied a water permit for the pipeline.
Canada				
Operator/Developer	**Project**	**Location**	**Added Capacity**	**tatus/Completion**
Enbridge Inc.	Line 3 replacement	Edmonton, Alberta to U.S. Midwest	390,000 bbl/d (Canada), 760,000 bbl/d (U.S.)	Minnesota Public Utilities Commission voted to allow the project to move forward.
TC Energy Corp,.	Keystone XL Pipeline	Alberta, Canada to U.S. Gulf of Mexico	830,000 bbl/d	A federal judge in Montana canceled an environmental permit for the pipeline, ruling that the Army Corps did not adequately consult with the U.S. Fish and Wildlife Service on risks to endangered species and habitat.
Mexico				
Operator/Developer	**Project**	**Location**	**Added Capacity**	**Status/Completion**
Mirage Energy Corp./ Northern Hemisphere Logistics Inc.	Isthmus Corridor project, other development	Mexico, South Texas	786 Bcf of storage	Mirage signed a $4 billion debt facility with Bluebell International LLC in mid-June.

The north LNG tank is located at Calcasieu Pass, La. (Source: Venture Global LNG Inc.)

in late 2018 at a cost of about $3.5 billion, was delayed to early 2021 with a new cost estimate of about $5.7 billion. Industry analysts, however, were skeptical that the company could meet the new deadline, noting the same legal issue concerning the Corps that tripped up DAPL is in play with Mountain Valley and other U.S. pipelines.

"Mountain Valley faces litigation risk on several upcoming permitting decisions," Height Capital Markets said.

A different project, PTT PCL's $5.7 billion ethane cracker in Ohio, also suffered a delay. The cause was the global economic slowdown and the accompanying demand collapse with an already saturated plastics market. The Thai chemical company had planned a final investment decision in the first half of 2020 but in early June put it off until first-quarter 2021.

Dominion Energy and Duke Energy announced the cancellation of the Atlantic Coast Pipeline on July 5. The project costs, estimated at $4.5 billion to $5 billion when it began in 2014, had ballooned to at least $8 billion.

In July, the company's partner, South Korea's Daelim Industrial Co. Ltd., withdrew completely.

The facility is planned to produce about 1.5 mtpa of ethylene.

Construction is expected to take four to six years.

Not all projects in Appalachia were in retreat. In late July, the Federal Energy Regulatory Commission granted approval for The Williams Cos. Inc. to move forward with its Leidy South Project. It is expected to increase natural gas pipeline capacity by 582,400 Dth/d for Atlantic Seaboard markets by the 2021-2022 winter heating season.

With the exception of two new compressor facilities, Leidy South's infrastructure addition will be relatively modest because it will rely on existing facilities in Pennsylvania. Alan Armstrong, president and CEO, stressed the clean energy aspect of the project in his announcement.

"There remain more than 80 coal plants in the states Transco serves that can potentially be displaced by clean, efficient and affordable natural gas," he said. ■

(Source: Alexa Sanders, Hart Energy)

Construction, Courts and the Future

Dominion Energy and Duke Energy canceled their $8 billion Atlantic Coast Pipeline project on July 5. One day later, a judge ordered the Dakota Access Pipeline to shut down. Even in a profoundly difficult year like 2020, these were tough days. But is the outlook for the midstream sector as bleak as it seemed at midyear? Perhaps not.

By Joseph Markman

The last twinkle of Fourth of July fireworks had barely faded from the television screens of a quarantined America when the country learned that the Atlantic Coast Pipeline (ACP) project, a key element in plans for its growing energy infrastructure, would be canceled.

How could this have happened? ACP, a joint project of Dominion Energy and Duke Energy, was as all-American as an industrial project can get. It possessed the American fondness for size: final cost estimate of $8 billion; length of 600 miles from West Virginia through Virginia to eastern North Carolina; and diameter of 42 inches (36 inches in North Carolina), allowing it to move about 1.5 Bcf/d of Marcellus Shale natural gas to generate electricity, and heat homes and businesses.

There was the love of money: communities along the route would collect as much as $30 million per year in property taxes, and electricity consumers in those three states would save about $377 million per year in energy costs.

And there was our workaholic nature: the economic activity from the pipeline would support an estimated 17,000 jobs—no small thing at any time but especially needed during a recession.

Presumably, those workers would at some point dine on hot dogs and apple pie as well. The only element of Americana missing from ACP was the rocket's red glare (due to the need to keep it a safe distance from the natural gas it would be transporting).

And then, with the sudden click on the "send" button for a press release, it was gone. This, despite $3.6 billion having been pumped into the project in the last six years. This, despite a 7-2 decision just three weeks earlier from the U.S. Supreme Court allowing the pipeline to cross below the Appalachian Trail. The anticipated litigation had injected so much financial uncertainty into the project that the economics no longer made sense and the partners called it quits.

Such was July 5. ACP was gone and consumers in three states would need alternative options for their natural gas, but at least it was a one-off disappointment for the pipeline sector. What more could crazy 2020 do to the oil and gas industry? Shut down an operating pipeline? Revisit the struggle over completion of the Dakota Access Pipeline (DAPL). No, things couldn't get that bad, could they? And after all, tomorrow was another day.

Then tomorrow arrived and the answer to what more 2020 could do to the industry came: DAPL was ordered to cease operations owing to an improper permit approval by the U.S. Army Corps of Engineers. Ouch.

A U.S. appeals court on Aug. 5 said DAPL does not have to be shut and drained per a lower court order, but a legal battle continues over the permit that allows the line to be finished. U.S. regulatory officials may still need to issue another environmental assessment for DAPL before deciding if the pipeline can keep operating, the U.S. Court of Appeals for the District of Columbia said.

'Different Animal'

It's too easy to lump the cancellation of ACP with the subsequent ordered shutdown of DAPL simply because of their proximity on the calendar.

"It's apples and oranges comparing operating pipelines with projects in development," Stacey Morris, director of research with Alerian, told Midstream Business. "Obviously, with production generally declining, there's not as much interest in building brand new pipelines at the moment compared to a couple years ago, which mutes some of the read-through to the industry from ACP's cancellation."

There was also the issue of Dominion's sale of its natural gas pipeline and storage assets to Berkshire Hathaway on July 6 for an enterprise value of $9.7 billion.

"I think there are a lot of unique circumstances surrounding that pipeline project as well, including the fact that the project was being led by utilities and Dominion was getting out of the pipeline business altogether," Morris said.

What struck Kenneth B. Medlock, senior director of the Center for Energy Studies at Rice University's Baker Institute for Public Policy, was that the plug was pulled on ACP after so much money had already been invested.

(Source: Rextag, a division of Hart Energy)

"At some point, you're so far in that you just want to see it finished," he told Midstream Business. "You need to recover something out of it. But I think the costs were mounting to the point where it was, 'We've got to do something in the interests of shareholders' and I think that's what drove the decision there."

External decisions made first by the Corps and then by the court, ambushed DAPL, not those made by operator Energy Transfer Partners.

"Dakota Access is a totally different animal because it was already operational," Medlock said. "It's one of those things that I don't think anybody expected to happen, and when it did, it kind of made you catch your breath a little bit because it does signal trouble on the horizon for lots of other potential infrastructure regardless of whether it's completed. It also signals that if you want to build something, you're going to do a lot of front-end work and you still might have a risk. As a developer, you might think you did everything you needed to do. You get the facility constructed and in operation and then there's something that's brought against one of the regulators involved in the process along the line."

Fighting Back

Judge James Boasberg of the U.S. District Court of the District of Columbia ordered Energy Transfer to shut and empty the 570,000-bbl/d line by Aug. 5, which would close the biggest pipeline moving crude oil from the Bakken Shale to Patoka, Ill. The ruling stated that the Corps violated the National Environmental Policy Act (NEPA) when it failed to complete an environmental impact review—"despite conditions that triggered such a requirement"—before granting the easement that allowed Energy Transfer to begin construction in 2017.

"Although mindful of the disruption such a shutdown will cause," the opinion read, "the Court now concludes that … Clear precedent favoring vacatur during such a remand coupled with the seriousness of the Corps' deficiencies outweighs the negative effects of halting the oil flow for the 13 months that the Corps believes the creation of an EIS [Environmental Impact Statement] will take."

A little more than a week later, the Council on Environmental Quality (CEQ) released its final rule to update NEPA regulations. The act was signed into law in 1970 and its regulations were last updated in 1978. "The final rule will make the NEPA process more efficient and effective, ensure consideration of environmental impacts of major projects and activities, and result in more timely decisions that support the development of modern, resilient infrastructure," said CEQ Chairman Mary B. Neumayr.

Energy Transfer countered swiftly. "We believe that the ruling issued this morning from Judge Boasberg is not supported by the law or the facts of the case," the company said in a statement that day. "Furthermore, we believe that Judge Boasberg has exceeded his authority in ordering the shutdown of the Dakota Access Pipeline, which has been safely operating for more than three years."

Energy Transfer filed a motion to stay the decision, arguing that regulations governing Corps property gives the Corps ultimate jurisdiction. The District Court rejected the motion but the U.S. Court of Appeals for the District of Columbia granted a stay on July 14. Native American tribes opposing the pipeline filed a response ahead of a hearing in late July.

How this plays out is uncertain. Wells Fargo Securities released a research note in early July citing Washington, D.C., consultants who believed it was unlikely that Energy Transfer would succeed in its appeal. However, Bloomberg reported that the company would not take action

(Source: Rextag, a division of Hart Energy)

to shut the pipeline while pursuing its legal strategy. Consider the logistics of shutting and emptying a major pipeline like DAPL, which could make it impossible for Energy Transfer to adhere to the Aug. 5 deadline. If the appeals process continues for the 13 months the Corps needs to complete its EIS, Wells Fargo mused, would the pipeline continue to operate in the interim?

Less Safe

If it turns out that the District Court's order is affirmed and DAPL must shut for the duration of the EIS, the impacts are myriad.

"It strands, potentially, resource in the Bakken," Medlock said. "When you shut that down, you start to run out of pipeline points of access out of that shale play, which means you're going to end up putting things on rail cars again. And that's a much more expensive proposition than moving by pipe, and that's going to change the economics of the wellhead for some players up there."

It's also not as safe, he said, adding that "the irony is that incidents are much higher when you increase the points of contact, and you have to when moving by rail car."

"Pipelines are the safest way to move crude. There are alternatives but they may not be as safe as putting crude into the pipeline."

–Stacey Morris, Director of Research, *Alerian*

The U.S. Energy Information Administration (EIA) data from April show the vast majority of crude-by-rail shipments in the country originating in the Midwest with 115,000 bbl/d moving to the East Coast and 157,000 bbl/d moving to the West Coast. Canada also ships more than 200,000 bbl/d of crude by rail to the U.S., most of which goes to the Gulf Coast.

Soon after the DAPL decision was announced, Crestwood Equity Partners assured customers of its Arrow gathering system in the Bakken that it was prepared to use the Hiland and Tesoro pipelines to get crude to market, and even use trucks to move oil to its COLT Hub in Epping, N.D.

"If DAPL is shut down, the industry will look at other options and ways to get that crude to market, but it certainly becomes more complicated," Morris said. "Pipelines are the safest way to move crude. There are alternatives but they may not be as safe as putting crude into the pipeline."

To a point, the loss of DAPL is mitigated in the overall market by the reduction of demand in an economy jolted by COVID-19. Higher breakevens in the Bakken in comparison with the Permian Basin mean many wells were shut in and will remain that way until oil markets recover.

"It's kind of a double-edged sword," Medlock said. "You might think, yeah, demand is down so price is down, so commercially it's not that attractive to drill new wells anyway. Even so, if I have to take existing production and start moving it to more expensive transport, that negatively impacts my price. There still is a negative commercial impact associated with this."

Wells Fargo estimated the cost basis in the use of rail rises by $10/bbl. Even in a world without the pandemic and its economic devastation, the higher price at the wellhead would be unlikely to fully compensate producers for the higher cost of rail or trucks in the absence of DAPL, he said. Either way, Bakken producers are going to hurt.

The EIA projected Bakken crude production of 1.095 MMbbl/d in July and 1.113 MMbbl/d in August. If DAPL is shut down, Wells Fargo expects production to decline to 1 MMbbl/d.

"It's possible that production could be constrained at the 1 MMbbl/d mark if basis widens to such a degree that incremental development in the Bakken becomes uneconomic," Wells Fargo analysts wrote. "Alternatively, if oil prices continue to increase, the impact to Bakken production may not be as significant as rail becomes economic."

That's a big if. The economic factors with a chokehold on the oil and gas industry are directly tied to the collapse of the global economy, which is tied to the advent of the COVID-19 pandemic. By midsummer, COVID-19 cases had surged to record levels in the U.S. and millions remained out of work.

Strategy of Delay

Not everyone was dismayed by the one-two punch to ACP and DAPL. The Sierra Club loved it.

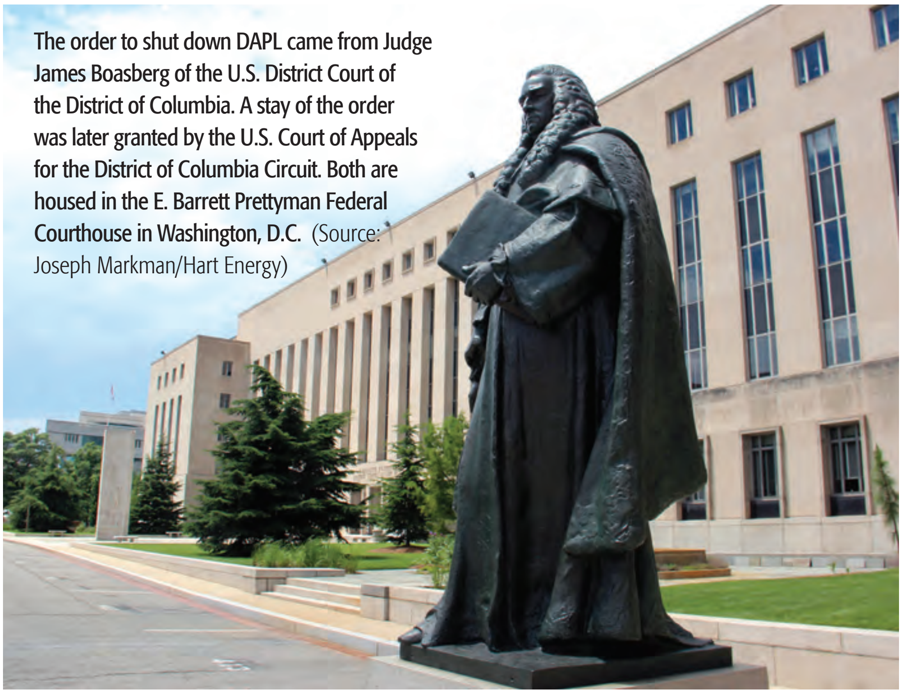
"This is a story of grassroots resistance," Kelly Martin, director of the Sierra Club Beyond Dirty Fuels Campaign, proclaimed during a July 6 press conference called to discuss ACP. "This is a story of relentless organizing. It is a victory for racial justice. It is a victory for environmental justice and for addressing the climate crisis. For six years, grassroots communities all along the proposed 600-mile route of the fracked gas Atlantic Coast Pipeline from West Virginia through Virginia into North Carolina have refused to give up. They held steadfast in their opposition to this ill-conceived, unnecessary, dirty and dangerous project. This is a story of holding agencies accountable for upholding environmental laws."

Tudor, Pickering, Holt & Co. analysts did not endorse Martin's heroic depictions but they did acknowledge the Sierra Club's strategy of persistence.

"While the decision does not have any direct read-throughs to other energy infrastructure projects under development," the analysts wrote, "it will likely embolden existing opposition and validates the strategy of delay."

This Isn't Over

The setbacks represented the difficulties of building new pipeline projects even when there is actual consumer demand for the projects, Dulles Wang, a director on Wood Mackenzie's North America gas team, said in an analysis. Of particular concern was a decision in April from a federal court in Montana involving Nationwide Permit 12 (NWP 12). The court ruled that the Corps violated the Endangered Species Act in reissuing NWP 12 for the crossing of the Yellowstone and Cheyenne rivers by



The order to shut down DAPL came from Judge James Boasberg of the U.S. District Court of the District of Columbia. A stay of the order was later granted by the U.S. Court of Appeals for the District of Columbia Circuit. Both are housed in the E. Barrett Prettyman Federal Courthouse in Washington, D.C. (Source: Joseph Markman/Hart Energy)

In Bachmanville, Pa., construction of an energy pipeline began in June 2017 in a rural part of the state. (Source: George Sheldon/Shutterstock.com)

The recent court battles over DAPL and ACP could set the tone for future litigation and delay tactics by opponents of pipeline construction. (Source: shinobi/ Shutterstock.com)

the Keystone XL Pipeline. The judge in the case vacated NWP 12 and ordered the Corps to reconsider its issuance based on compliance with the act.

"Northeast pipeline projects such as Mountain Valley and Penn East need to overcome NWP 12 hurdles," Wang wrote, "but Permian projects such as Permian Highway Project are not immune as well."

API expressed its displeasure in a statement from Mike Sommers, the organization's president and CEO: "Between the Atlantic Coast Pipeline cancellation and now the ruling to shut down the Dakota Access Pipeline, we are deeply troubled by these setbacks for U.S. energy leadership."

The following week, though, things were looking up from API's perspective.

"NEPA modernization will help America streamline permitting to move job-creating infrastructure projects off the drawing board and into development," Sommers said on July 15. "Today's action is essential to U.S. energy leadership and environmental progress, providing more certainty to jumpstart not only the modernized pipeline infrastructure we need to deliver cleaner fuels but highways, bridges and renewable energy."

Does that glimmer signal that perhaps the dark days of midstream's summer of discontent were not as dark as feared? Remember that since 2007, the U.S. has added almost 200 Bcf/d of natural gas pipeline capacity. Medlock urges some perspective because oil and gas opponents have not shown themselves to be absolute world beaters.

That is where we are—a country with a superabundance of natural gas on course to failing to meet future demand because it insists on binding itself in political knots.

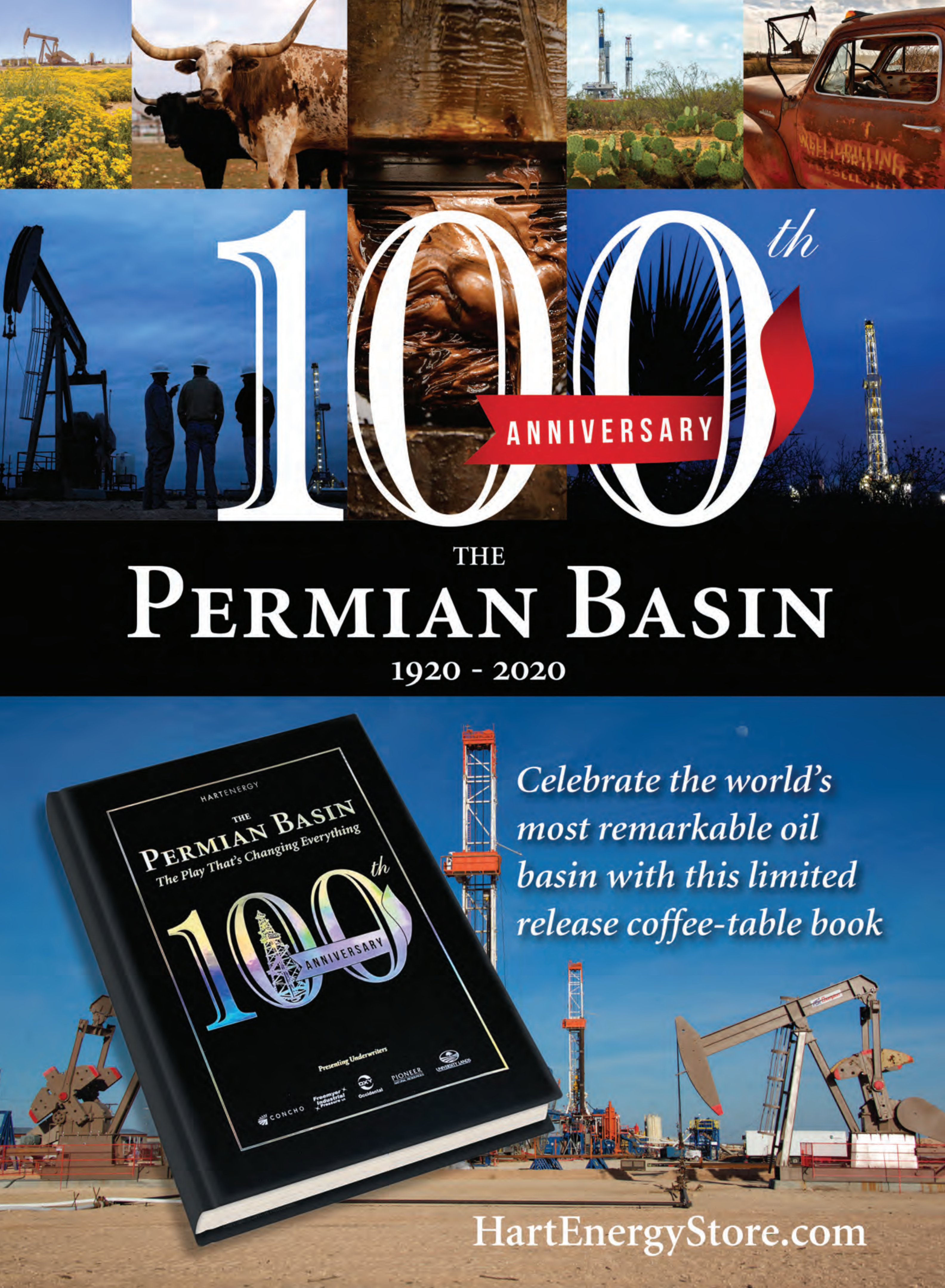
"So they shut down one, but we added a significant amount of infrastructure," he said. "I wouldn't want to trumpet [cancellation of ACP] as a massive success too much because if their goal is to stop all infrastructure then they're still lagging." Canceling projects invariably will lead to that familiar refrain of the shale revolution: pipeline constraints.

"I actually think there's going to be a point—when demand does begin to recover—when there's going to be some significant concern raised about availability of supply," he said. "We saw an indicator of this. You think back a year and a half ago [and] a lot of people in Washington were up in arms because an LNG tanker that had reloaded at the Isle of Grain in the U.K. with Russian molecules delivered gas to Boston."

Medlock was in Washington in February 2018, testifying before the Senate Committee on Energy & Natural Resources, and he was asked how the U.S. was forced to import from Russia. He explained to the senators how these markets work. If pipelines are not allowed to be built and the Jones Act prohibits U.S. tankers from delivering LNG, then the next least-cost opportunity is what's out there on the water. At that time in January 2018, it just so happened to be a cargo of gas that originated in Russia.

And that is where we are—a country with a superabundance of natural gas on course to failing to meet future demand because it insists on binding itself in political knots.

"That issue's not going away," Medlock said. "I think there's going to be an interesting to-ing and fro-ing on this for years to come. I don't think it's going away any time soon." ■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The Interview

This West Texas completion site shows Blackbuck Resources' pond management installation alongside treatment and transfer operations. (Source: Blackbuck Resources)

Justin Love
CEO, Blackbuck Resources

"Water midstream will be a hot place for investors to put money in. I think these companies will continue to grow and get more sophisticated," said Blackbuck Resources CEO Justin Love. (Source: Hart Energy)

Why the Water Midstream Business Won't Dry Up

Blackbuck Resources CEO Justin Love says being debt-free has helped his company through this tumultuous time and shares why opportunities for investors in the sector remain high.

By Jessica Morales

Blackbuck Resources LLC was founded in 2018 in response to water management solutions gaining momentum since the shale boom to design, build and operate water infrastructure in Texas and New Mexico. In a recent interview with Hart Energy, Blackbuck CEO Justin Love talked about the path forward for water midstream companies coming out of the current downturn. The following is a transcript of the video interview, which can be found at HartEnergy.com/videos.

Hart Energy: Justin, this has been a very challenging past few months. I know that goes without saying, but can you put into perspective for us how Blackbuck Resources finds itself in a different stage than some companies? Why is that?

Love: It's been a challenging couple of months. It's been very unpredictable, very volatile, especially for our sector. Blackbuck is fortunate in that timing is everything, and we have a unique background as a company in the midstream water space, in particular. We started formally in 2018 when we funded with our partners Crescent in Dallas, and we were basically evolving from a service company to a midstream company at that stage.

At the time, I had been thinking about water midstream for four years and followed water since the first shale boom. There was a bit of frustration that we may be a late entry, and we've been fortunate in that being a late entry has allowed us to focus on some greenfield projects and they kept us really busy through this tumultuous time.

While most of our competitors were out doing large M&A-style deals, we were focused on nuts and bolts services and then building our greenfield infrastructure. Through that timing and at this stage now, we've been able to learn from our peers' mistakes. The contract structures are continuously evolving; we're a very young sector. So we had the benefit of seeing these things play out.

We've also had the benefit of not doing large M&A [and] not taking on any debt—without debt in this market where the opportunities largely rely on M&A, [so] we're very well positioned to grow.

Hart Energy: How has the team at Blackbuck Resources come together in the past few months to develop a plan to solve near-term issues to keep on top, if you will?

Love: First and foremost, our focus was on keeping our employees safe during the pandemic. Early on we developed and adopted several policies and guidelines to ensure that we could operate [and] keep everybody safe while doing so. And then we focused on excellent execution.

We had drilling operations underway on a project in Culberson County and construction associated with that facility. We really just focused on getting it done once we had everybody under the new guidelines and procedures. Excellence in execution is how you help your customers, so that's what we did.

"We're in a very unique time. I think that the U.S. unconventional oil and gas business is particularly strong in the Permian. I think it's here to stay. I think we will see it bounce back as it always has."

Hart Energy: Speaking of helping customers, what is Blackbuck Resources doing to support customers as they're shutting in wells? What kind of water concerns do you have in the process of shutting in and during the shut-in?

Love: From a shutting-in perspective, what we've focused on was that we gather and dispose of produced water. We also treat produced water to be recycled in completions. So obviously that service kind of treatment side was first to slow as completion slowed down with the price environment. What we've really done is work with them very collaboratively on our cost structures. We've used the downtime, if you will, with lowered intensity of operations to focus on operational redundancy, which in a comeback will provide them with better flow assurance.

Hart Energy: It has really given you an unexpected time to reach a reset. What about when people are ready to restart their wells?

Love: When they're ready to restart, you have to be there to take away the water. And if you don't, then they can't produce the hydrocarbons. So we did use that time to focus on redundancy. We did a lot of operational testing, kind of like war games if you will, and we just so happen to be building our newest and largest state-of-the-art facility during that time. It was one of those things where you think it's misfortune, but it was actually a fortunate time for us to go in and enhance our ability to execute.

Hart Energy: Are you still able to find opportunities during this time? If so, where?

Love: We started as a services company, and I would say that, first off, those are largely diminished right now. Standalone services as related to water management are generally without contractual structures that lend themselves to continuing in this type of environment, but we do see opportunity particularly on the M&A side.

The operators that we partner with—the E&P companies—they were already in an environment where investors were demanding positive cash flow. And you couple that with the pandemic and the ensuing demand decrease, and they really were in a cash crunch.

Our opportunity to help them is through their divestiture of their water assets. Most E&Ps historically built their water infrastructure in-house, and that water infrastructure would largely be overbuilt for peaks and underutilized. They didn't focus on commercializing the water business. The water business was their business, and so you're not necessarily sharing with your peers.

For us, our biggest opportunity right now is to come in, find those captive assets that are underutilized and find ways to get cash to help correct and beef up the balance sheet of our customers, and focus on lowering their LOE over time so that they can return cash to investors as is expected.

Secondarily on the M&A front, again, I think all the opportunities today are largely M&A. We look at our peers, our competitors and there's some that have grown quite large, potentially taking on debt that they have to service and have contract structures that may have certain—I don't want to say weaknesses but—potential challenges in this type of unforeseen and unprecedented environment. We have the opportunity to kind of work hand in hand with them to say, 'Hey, do you have noncore assets over here? Let's help you with your balance sheet and let's help you with the debt.'

As I said, us not having debt right now and a very supportive private-equity group behind us, we're out looking to buy essentially.

Hart Energy: Have you seen an uptick on any water issues for customers or companies that are producing but neighboring wells have shut in?

Love: I hear things. I'm not a downhole person. I've heard things about shutting in wells and then turning them on. I haven't heard much about shutting in wells where your peers are producing or where your peers have shut in wells and you're producing.

Anecdotally, I can say that I was with a customer [recently] that runs a public E&P. They were saying that they have some data showing positive well results in terms of shutting in a well and then turning it back on [and] actually seeing better EURs and lower water cuts and better economics. That's just one datapoint. For me, that's not necessarily a good thing. I mean, if it's good for my customers, it's good for me, but obviously, less water [is] better for them [and] little bit worse for me as a company that sequesters that waste.

Hart Energy: If we can look into the very near future, what forward risks do you see as we head into the fall and the November election, but really just getting through these next few months?

Love: Just getting through these next few months, our industry and our sector as a whole faces risks every day, first and foremost being the safety of our employees and second being protection of the environment. So daily, we do everything we can to improve our ability to protect the environment and enhance the safety of our employees.

From an election perspective, there's definite risk out there. It's a bit disappointing to me, for the sector as a whole, given the reduction of emissions achieved through replacement of coal with natural gas [and] given the energy independence we've achieved through unconventional production over the last decade or so. I see a bit of vilification rhetoric out there on our industry as a campaign point. I'm a believer that science will prevail and that talking points and sound bites aren't necessarily always how things will play out, but it's not something that I think executives in our industry don't lose sleep over.

For us, moving into the election, we watch the issues closely. We have lobbyists. We have lawyers. We understand law and what an administration has the ability to do, what Congress has the ability to do and what state and local governments have the ability to do. So we stay on top of that and we try to operate in a safe and environmentally friendly way and do our best to improve that as we move forward every day.

Hart Energy: As a leader in our industry, what do you see as the path forward from here, for the water midstream sector but also the industry as a whole? What do you see or what do you tell your employees as we try to figure out how we move forward into 2021?

Love: I'll start with the broader industry. We're in a very unique time. I think that the U.S. unconventional oil and gas business is particularly strong in the Permian. I think it's here to stay. I think we will see it bounce back as it always has.

I think the makeup of the business may change a little bit, and we've seen this over the last several years as shale has kind of played out. You've seen what I call internally the corporatization of West Texas or the Permian (New Mexico included there). You see big, large-scale players that can do pretty well economically through economy of scale. Turning on shale production is still fantastic in terms of returns in a normal price environment. It's the best new production you can bring in terms of its economics and its efficiency. I think we'll see larger players, larger kind of factory-style operations as you hear it called in the media.

For the water midstream sector, it's a similar trajectory. We're obviously much younger as a sub-sector of a broader energy business. We're really only less than a decade old ourselves. What we've seen is that water historically has been seen as a service. E&Ps build the infrastructure. They operate their water. Like I said, the water business is their business.

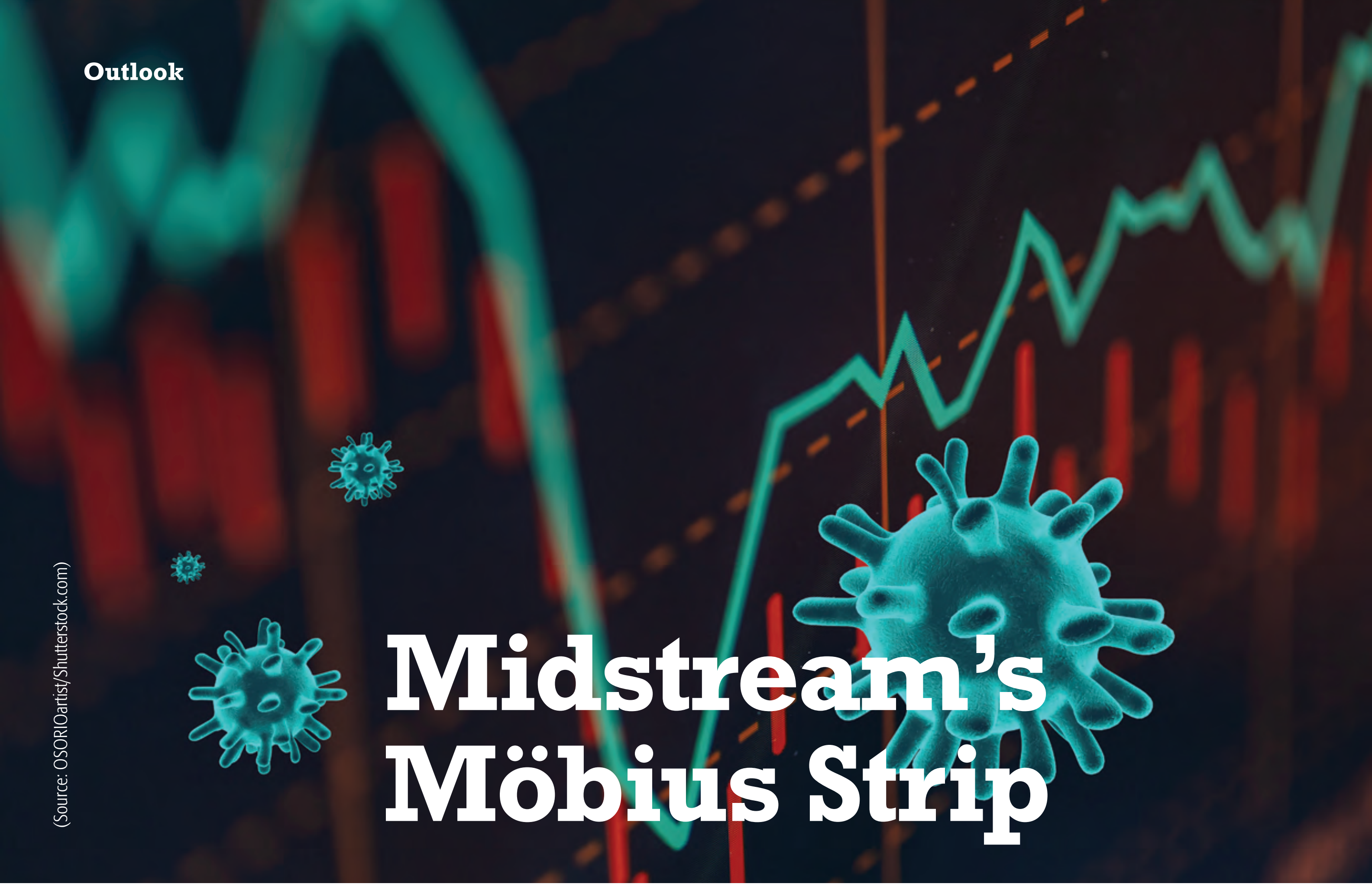
We're seeing a shift of increased sophistication, including us as an example of that. Our ability to evaluate from an E&P's perspective is, I think, second to none in the industry. We have an incredible team.

We run our own E&P analysis before we go into any deal, thinking about how we would manage the water. I think our competitors are going to be moving in the same direction. You're going to see larger water midstream companies that are more sophisticated and act more like your conventional G&P [gathering and processing] midstream.

I think from there you'll see potential IPOs. You'll see players that are long-term, low-yield investors coming into the mix for our business. You've seen some sovereign wealth come into business. There has been a lot going on just right ahead of this downturn, and I think as we come out of it that stuff will start back up.

Our business is unique in that we are tied to energy, but we are a green business, if you will. We sequester hazardous waste. We enhance E&Ps' ability to recycle water and preserve that water as a resource. So I think that if there's been any secular changes, water midstream will be a hot place for investors to put money in. I think these companies will continue to grow and get more sophisticated.

To watch the full video interview, visit to https://bit.ly/3ikOsEg. ■



(Source: OSORIOartist/Shutterstock.com)

Midstream's Möbius Strip

For years, the midstream sector has managed to stay strong in weak oil and gas markets, but the unforeseen impacts of COVID-19 and the OPEC+ oil price shock have had a deep impact.

By Darren Barbee and Emily Patsy

After years of being considered a refuge for oil and gas investors during a downturn, the midstream sector's ability to ride the waves of volatile commodity prices appears, this time around, headed toward a belly flop.

The midstream sector's crisscrossing thoroughfares, which transport commodities across the country and to the sea, have for years managed to stay strong even in weak oil and gas markets. Midstream's insulation was, in large part, thanks to unrelenting spending for new infrastructure. But after building out colossal infrastructure projects, companies within the midstream sector find themselves squeezed just as their assets were settling in for a comfortable middle age.

The unforeseen impacts of the pandemic and price shocks resulting from the OPEC+ supply war have dazed midstream companies. Decline, not growth, in EBITDA now seems possible for some companies. And their burden doesn't end with finances. Costly legal and regulatory battles have clouded once epic pipeline plans. And the 2020 election, in which a green energy-focused Democrat leads in the polls, adds even more uncertainty to the mix.

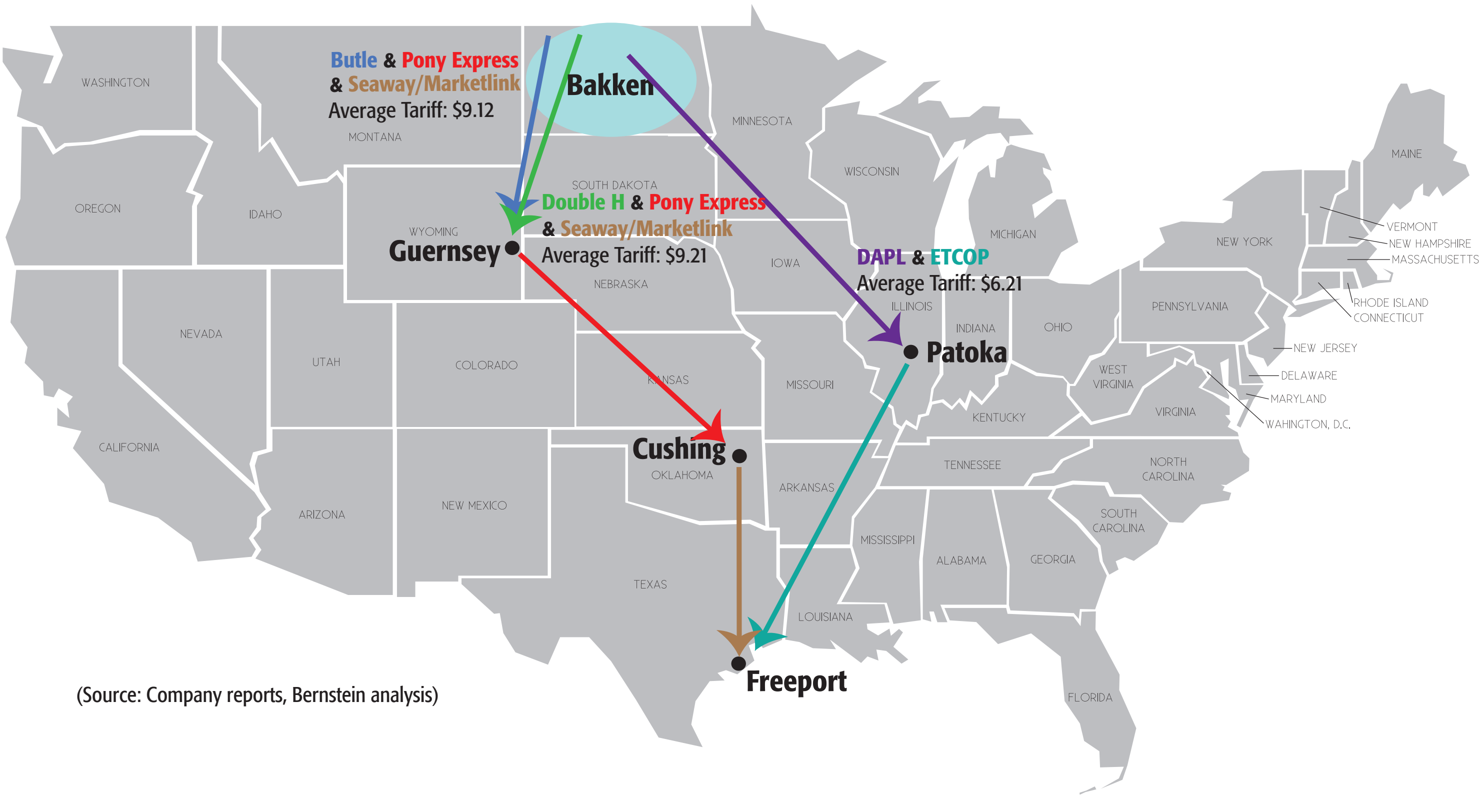
In a first, Moody's Investors Service said in June that it had changed its outlook to negative from stable, citing the twin shocks of falling demand and oversupply. Moody's predicted that EBITDA in the sector would decline by at least 5% in 2020.

Andrew Brooks, Moody's vice president and senior credit officer, said that, across the board, all sectors of the energy space are negative. However, midstream had previously fared well during prior downturns, including the price volatility of 2015-2016, which Brooks attributed to EBITDA growth from massive capital spending.

"Four years ago, the midstream space was in the midst of an enormous buildout of infrastructure and significant spending," he said. "It was pretty straightforward … growing EBITDA just as a result of all the spending and new projects that were being built."

Now a more mature sector, opportunities for rapid organic growth in midstream are scarce as infrastructure demands have met the needs of shale producers. Midstream spending is projected to be down roughly 20% to 30% or more in 2020 and through next year. Without high levels of spending, there's limited tailwind for the sector.

That's made the midstream space more susceptible to the weakness felt by upstream companies challenged by low oil prices, in particular. Still, underlying contractual agreements with upstream operators give midstream companies far more stability than oilfield services and independent E&Ps.



(Source: Company reports, Bernstein analysis)

While midstream "doesn't bear the full brunt of weakness upstream in terms of volumes and low commodity prices, nonetheless, there's enough to put a dent in EBITDA in the future together with just this significant decline in capital spending on new assets within the midstream space," Brooks said. "We haven't seen a decline in EBITDA performance in the midstream space up until now."

On Wall Street, midstream companies have taken a beating. Through July 15, the Alerian Midstream Energy Index fell 32% in 2020 compared amid a 38% drop in the S&P 1500 Composite Energy Index. Morgan Stanley analyst Stephen C. Byrd wrote in a July report that midstream operators are expected to announce better earnings and upward guidance revisions for the second quarter.

But, Byrd said, other factors would weigh down the sector.

Hang-ups

In a relatively short press release on July 5, Dominion Energy Inc. and Duke Energy Corp. jointly called it quits on the Atlantic Coast Pipeline—despite a definitive 7-2 win in the U.S. Supreme Court the previous month.

In bowing out, the companies cited ongoing legal challenges, a projected three-and-a-half-year delay until pipeline startup as well as inflated costs, which had doubled from roughly $4.75 billion to $8 billion.

"Recent developments have created an unacceptable layer of uncertainty," the companies said.

The next day, a federal court ordered closed the Dakota Access Pipeline (DAPL)—a conduit for Bakken crude operated by Energy Transfer LP—pending an extensive environmental review.

"The order, the first of its kind for an in-service oil pipeline, goes into effect in 30 days, although this ruling could still be appealed in higher courts. DAPL, as the project is known, carries roughly half a million barrels a day of crude from the Williston Basin to Midwest refineries," Raymond James analysts wrote on July 7.

Pointing to the DAPL and Atlantic Pipeline decisions, Morgan Stanley sees the continued threat of regulatory risk and the November election

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–Andrew Brooks, Vice President and Senior Credit Officer
Moody's Investors Service

starting to act as an overhang on the midstream sector.

"News flow collectively has increased concern that large-scale new midstream project development will be materially limited by legal and regulatory challenges," Byrd and Morgan Stanley analysts said. "Following the election in November, a potential [Joe] Biden administration could usher in a more stringent regulatory environment for new pipelines as well."

Brooks said regulatory challenges have long been a part of assessing risk in the midstream sector.

"Regulatory risk—whether it's at the federal level, whether it's state [or] local, whether it's grassroots opposition—it's always been there, but it's become more acute," he said. "Part of this is 'not [in] my backyard.' Part of this is just opposition to fossil fuels as a matter of principle, that we should be relying more on renewables and green energy. And part of it is kind of a backdoor opposition to fracking."

Opponents of pipelines and fossil fuels have also become more sophisticated in obstructing projects through legal and legislative mechanisms. Coupled with the volume of required regulatory filings, agencies involved to issue permits and other regulatory hurdles, project delays have become the norm.

Still, with the midstream sector already under strain, investors may need to shift future sector growth investment elsewhere. Recession and commodity uncertainty may encourage a flight to high-quality companies with strong balance sheets.

That sets up a scenario in which companies redirect cash flows to focus on a reduction of leverage and creation of free cash flow. Morgan Stanley argues that shifting to project high-grading, capital restraint and lower debt could result in expansion on de-risked funding strategies without growth.

"If managed conservatively, with a sober view of industry growth and caution around terminal value risk, we believe the more stable, cash-generative businesses within the sector could resonate with new groups of value investors over time," Byrd said.

"Different views on oil prices likely result in different views on what an asset is worth. From a midstream perspective, transactions will likely require visibility on expected throughput volumes."

–Stacey Morris, Director of Research
Alerian

But those companies still need E&P production, which is arguably the weakest link as producers struggle to maintain sustained cash flow. Compared to last year, U.S. producers have cut budgets by 47% and announced 1.5 MMbbl/d of supply curtailments.

Morgan Stanley expects investors to begin migrating toward companies with more secure balance sheets, actual demonstrated capital, limited exposure to regulatory risk and "comparatively stable EBITDA with advantaged or at least manageable exposure where it exists."

The firm recently upgraded Enbridge Inc. and Williams Cos. Inc. to overweigh. Enbridge benefits from a stable EBITDA profile and less regulatory risk for completion of one of its pipelines. Williams' already enjoys positive free cash flow generation and may benefit from the DAPL shutdown. The company has also begun to increase activity in the Marcellus and Haynesville.

With expectations of months of more recovery ahead, however, much of the midstream sector's fortunes rest on a solvent and active upstream sector that is already experiencing unprecedented hardships and potential bankruptcies.

Hiccups

Among the powerhouse producers in the Bakken, companies include Continental Resources Inc., Hess Corp., Marathon Oil Corp. and WPX Energy Inc.

Bernstein noted that it could take up to a year to get an environmental impact statement from the Army Corp. of Engineers, forcing some crude to be transported by rail. At those prices, many large producers may find differentials impassable. Elevated differentials in a $40 price environment would make Bakken oil revenues "barely enough to cover cash costs and not enough to incent new rigs."

Outside of the Bakken, oil production is also expected to be thin.

U.S. crude output is expected to fall by about 5% in 2020 to 11.6 MMbbl/d, according to a July 7 report by the U.S. Energy Information Administration (EIA). Next year, production is forecast to decrease by nearly 10%, or 1.2 MMbbl/d compared with 2019. The EIA noted its estimates were made before a court-ordered DAPL to cease operating by early August.

Beyond oil production, Morgan Stanley said midstream firms face the risk of the deteriorating credit quality of their E&P customers. During the 2015-2016 downturn, midstream contract rejects were not widespread. But markedly stressed E&P companies "will ratchet up demand for contractual concessions from the midstream operators, particularly if economic contraction deepens."

Through June 30, production companies have already sought bankruptcy protection for about $30.6 billion in debt—already eclipsing the total for each of the past three years, according to the Haynes and Boone LLP bankruptcy monitor.

Moody's has tallied "13 E&P bankruptcies in the E&P companies that we rate through mid-July," Brooks said adding, "We clearly haven't seen the end of that."

The potential of contract rejection by E&Ps going through bankruptcy is a risk for the midstream sector as well, according to Brooks.

"These are all executory contracts, which can clearly be rejected in bankruptcy," he said. "This time around, I think that, first of all, banks are less willing to help struggling E&P companies get through this downturn. So, there's a much shorter leash in terms of propping these companies up."

With multiple potential twists and turns—including rejecting contracts for better terms—Brooks said bankruptcy decisions are likely to be made "contract by contract."

"I think the risk is clearly there, and it's probably only going to increase as the upstream guys struggle through this difficult operating environment," he said.

As survival mode continues in E&P circles, a badly needed shot of confidence was delivered to the midstream sector on July 5. Berkshire Hathaway Inc., headed by investor Warren Buffett, agreed to buy Dominion Energy's natural gas transmission and storage assets for $9.7 billion, including $4 billion cash.

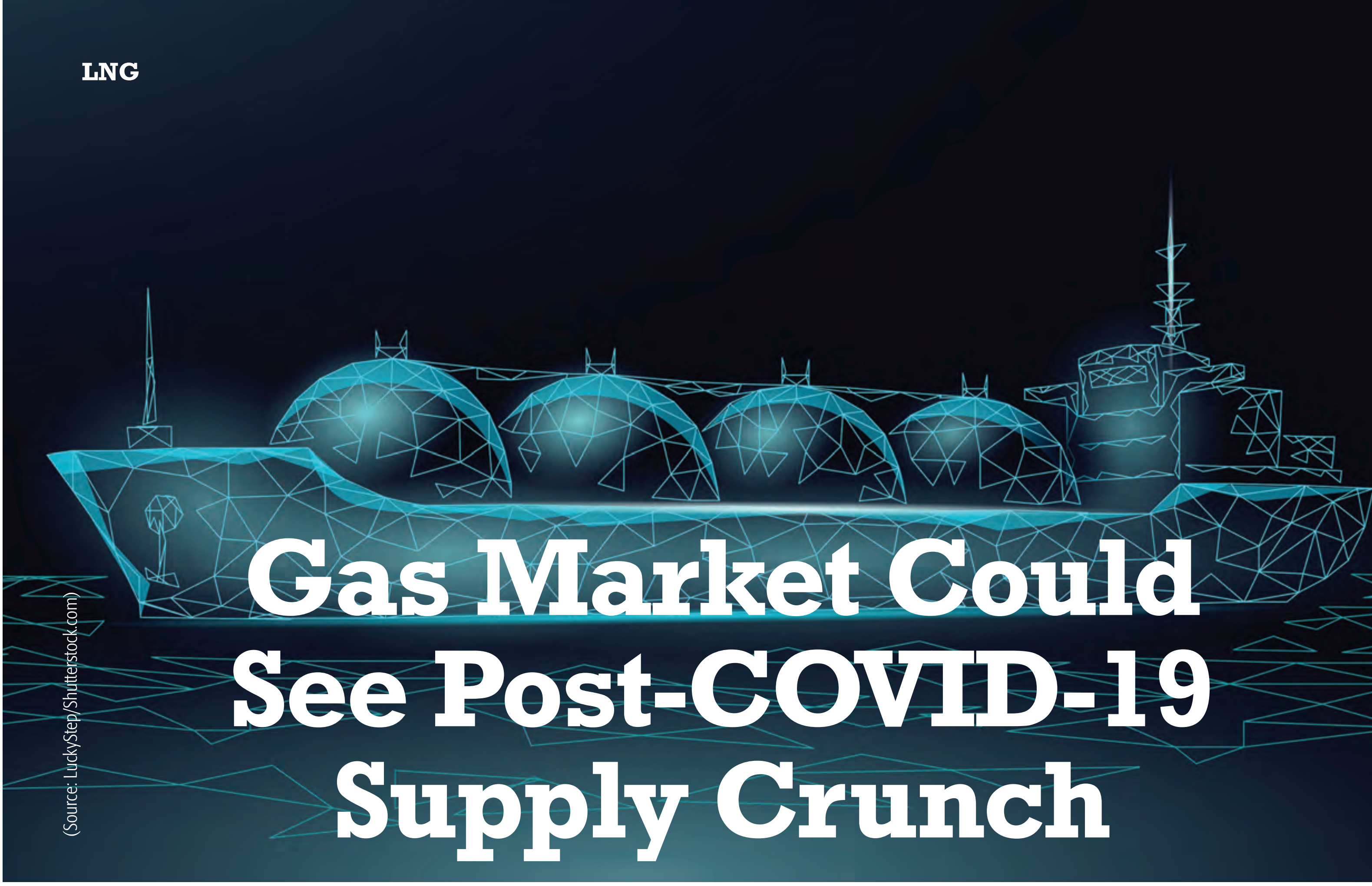
Despite its setbacks with the Atlantic Pipeline, Dominion is a formidable infrastructure company with more than 7,700 miles of natural gas transmission lines, 20.8 Bcf/d of transportation capacity and 900 Bcf of operated natural gas storage. The company also owns additional working storage capacity and partial ownership of an LNG export, import and storage facility.

Such deals may be difficult, generally, said Stacey Morris, director of research for Alerian.

"With the volatility in oil prices, it becomes harder to value oil-oriented upstream and midstream assets," she said. "Different views on oil prices likely result in different views on what an asset is worth. From a midstream perspective, transactions will likely require visibility on expected throughput volumes."

However, the implied EBITDA multiple for Dominion's assets was a "modest" 10x compared to midstream companies and those focused on natural gas pipeline transportation.

"While the transaction multiple is not rich, it is positive to see a large investment in midstream energy infrastructure by a renowned investor," she said. "Unfortunately, headlines surrounding the shutdown of DAPL, and to a lesser extent the cancellation of ACP, are shifting the focus in midstream today to regulatory and litigation risk." ■



(Source: LuckyStep/Shutterstock.com)

Gas Market Could See Post-COVID-19 Supply Crunch

Tellurian's Meg Gentle anticipates rising demand coinciding with slower production growth.

By Joseph Markman

Demand for LNG has started to turn around, according to a leading industry executive, but over the long term, the industry may struggle with a lack of supply.

"I'm probably more bullish on the long term than I was before and actually a little bit anxious because we are about to go into a bit of a supply shortage for the next four-ish years," Meg Gentle, president and CEO of Tellurian Inc., said during a webinar in July hosted by Rice University's Baker Institute for Public Policy.

That's because annual supply increases over the next four to five years will be significantly lower than the growth during the last four to five years.

"That's going to happen at a time when the market is used to $2 [per million British thermal unit (MMBtu)] LNG and really trying to grow, displace coal and displace transportation fuels to bring cleaner air," she said.

A former top executive at Cheniere Energy Inc., Gentle has been in the thick of the U.S. LNG sector's development from importer to exporter. Despite the setbacks experienced by the oil and gas industry this year, Gentle said she had been fascinated to watch the LNG market behave as a true, mature commodity and energy source and watching it balance.

As COVID-19 ravaged Asian economies earlier this year, European imports rose and even exceeded LNG purchases in 2019 for a time. That LNG largely filled storage in Europe and backed out pipeline gas from Russia, which ultimately was diverted to China.

European natural gas storage continues to build, though at a more moderate pace than it did in late May and June. That storage build has led to supply-side curtailment out of the U.S. and Australia, primarily, but also Russia and some of the other producing nations in smaller amounts, Gentle said.

''The U.S. balancing mechanism is very robust," she said. "We have some of the largest storage capacity in the world, and we're going into our own summer air conditioning season. We actually have increasing demand in this country for air conditioning load and, through the COVID quarantine keeping people at home, actually balanced out, and we have increasing gas usage in the U.S. for power gen and for coal displacement."

Ally of Renewables

Displacing coal was a recurring theme during the webinar for Gentle, who views natural gas as complementary to renewable sources of energy for power generation. She acknowledged the risk to the gas market by the anti-fossil fuel movement but noted CO_2 emissions from gas are half that of coal. Gas can also compensate for shortcomings in renewable supply, such as times when the wind doesn't blow and the sun doesn't shine.

"We have to work together in partnership to be able to increase our percentage of renewables, which we wholeheartedly support," she said. "In fact, natural gas can be that most reliable partner because it is a commodity now. It will have security; it has multiple producers and supply sources so that reduces the political risk on using it as a fuel."

The ability to store gas, either in liquid or gas form, means that it will be there when customers need it. And if somebody else needs it, LNG tankers can take it there.

"It's very flexible to allow renewable power and renewables in other sectors of energy to actually grow and flourish in a way that can be cost effective and can also be reliable for the grid," Gentle said.

"We actually have increasing demand in this country for air conditioning load and, through the COVID quarantine keeping people at home, actually balanced out, and we have increasing gas usage in the U.S. for power gen and for coal displacement."

–Meg Gentle, President and CEO
Tellurian Inc.

Partnership Approach

Financing major projects like Tellurian's Driftwood LNG facility in Lake Charles, La., is moving in new directions, Gentle said. At about $1,000 per metric tonne, a project with capacity of 27.6 metric tonnes per year carries a price tag of more than $27 billion. The traditional financing for such a facility is to convince project finance banks that the investment was secure by locking buyers into 20-year or 30-year contracts.

The business, however, has seen markets gain liquidity to the extent that cargoes are bought on a regular basis for delivery in a month's time or even six month's time. Buyers of LNG are reacting to the market price, like buyers of crude oil, and are less interested in 20-year deals.

"The challenge right now is: what is that business model that allows 70% of that project to get funded by the bank, and the bank to make sure that they're going to get paid back if there aren't 20-year contracts?" she said.

Tellurian pursued a joint venture approach. Equity partners in Driftwood will get their LNG at cost, which will be the best price on the market. That helps them move LNG into their market at competitive prices and allows Tellurian to move forward with the project as a partnership.

The concept extends to the feedstock as well, with Tellurian partnering with a gas producer in the Haynesville Shale. That cost moves to the plant at cost, where it is liquefied and loaded onto a tanker for $3.50/MMBtu. In this plan, the LNG can be delivered to Asian markets at $5/MMBtu or less.

The troublesome part of the plan has been COVID-19 and the economic wreckage it has wrought globally. The price of U.S. benchmark Henry Hub mid-morning on July 27 was $1.79/MMBtu, but the price on the Asian benchmark Japan Korea Mark on July 24 was $2.57/MMbtu. That's a long way from $5/MMbtu.

On June 16, Gentle announced during an investor presentation that Driftwood construction would be pushed back to first-half 2021 after its partnership agreement with Indian gas importer Petronet LNG did not come to fruition. Petronet returned to the table on July 21 and the two sides have until the end of the year to finalize the deal. Assuming sufficient agreements are in place, LNG production could begin in late 2024, with full capacity reached in 2026 or 2027.

The cyclical nature of the energy business bolsters the assumption that prices will rise again, and Gentle said in mid-June that she expects partnerships to finalize following COVID-19 when the Asian price climbs back above $5/MMBtu. The reliance on multiple markets speaks to the unique international nature of the LNG business.

"We work with our partners on that very low-cost basis and then the partnership becomes a very important component of geopolitical strengthening of ties," Gentle said, "making sure we are partners in business and partners as nations for many decades to come." ■

(Source: Wojciech Wrzesien, Shutterstock.com)

Pipelines Have a Place in Clean Energy

By Anne Bradbury

Editor's note: *The following opinion was originally published in The Financial Times. Opinions expressed by the author are her own.*

In early July, two U.S. energy groups gave up their six-year battle to build a natural gas pipeline, despite fighting all the way to the U.S. Supreme Court to obtain a permit.

Dominion Energy and Duke Energy canned the Atlantic Coast Pipeline just weeks after their high court victory. They estimated that constructing the 600-mile project, which would have stretched from West Virginia through Virginia to North Carolina, would have created 17,000 jobs and $2.7 billion in economic activity, and generated $28 million in annual property tax revenue for local governments.

And, once operational, the pipeline could have reduced energy costs for families and businesses across North Carolina and Virginia, as regional coal-fired electric plants were retired in favor of new ones powered by lower-cost natural gas, the companies said. This is especially important during our economic recovery.

But misguided opposition from environmental groups means the pipeline will not happen. That is a shame.

Green activists are wrong to insist that building pipelines is incompatible with improving the environment. Michael Shellenberger argues in an article summarizing his new book "Apocalypse Never" that it is unrealistic to expect that we can rely entirely on renewables because that would "require increasing the land used for energy from today's 0.5% to 50%."

We must replace dirtier fuels with clean ones. Natural gas, when combusted, has a lower emissions profile than coal, especially when it comes to pollutants that can make people sick at certain levels.

Increasing the use of natural gas has resulted in U.S. CO_2 emissions reaching their lowest levels in a generation, principally a result of coal-to-gas switching by power plants.

About half of all American homes already use natural gas for electricity, heating, cooking and other purposes. By cutting off the distribution of Appalachian natural gas by stopping the pipeline or seeking to ban it from new construction in New York, activists are prioritizing short-term wins at the expense of long-term reductions in emissions.

The demand for fuel will be filled, but not with renewables. One can see this in the northeast U.S., where LNG was imported from Russia in 2018 to meet power needs. Perversely, restricting natural gas supply is likely to lead some fuel users to switch back to coal, a clear loss for the environment.

Restricting natural gas supply is likely to lead some fuel users to switch back to coal, a clear loss for the environment.

The Atlantic Coast Pipeline and those like it across the nation are the infrastructure needed to continue to derive benefits from the U.S. shale revolution, which has powered our economy, supported good jobs and strengthened our national security.

Use of natural gas also has furthered actual improvements in the environment. According to the U.S. Energy Information Administration, American natural gas consumption increased by 3% in 2019, reaching a record 85 Bcf/d. Natural gas now accounts for the largest share of electricity generation, after first surpassing coal in 2016. Between 29,000 and 62,000 miles of new pipeline will be needed over the next 25 years to accommodate rising energy demand.

Yet the Atlantic Coast Pipeline experience shows that the U.S. will struggle to develop the necessary gas pipeline. In that case, the real losers will not be "big oil." Rather they are the consumers that will have fewer choices for their power sources and the environment, if more people turn to more polluting choices.

It is time to step back and reassess the way we are approaching this issue and hold a data-based debate grounded in the realities of the possible. Without it, we are delegating our environmental policy to activists who are singularly focused on what they do not want, rather than open to all options. ■

Anne Bradbury *is CEO of the American Exploration & Production Council, a U.S. industry body for oil and natural gas E&P.*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