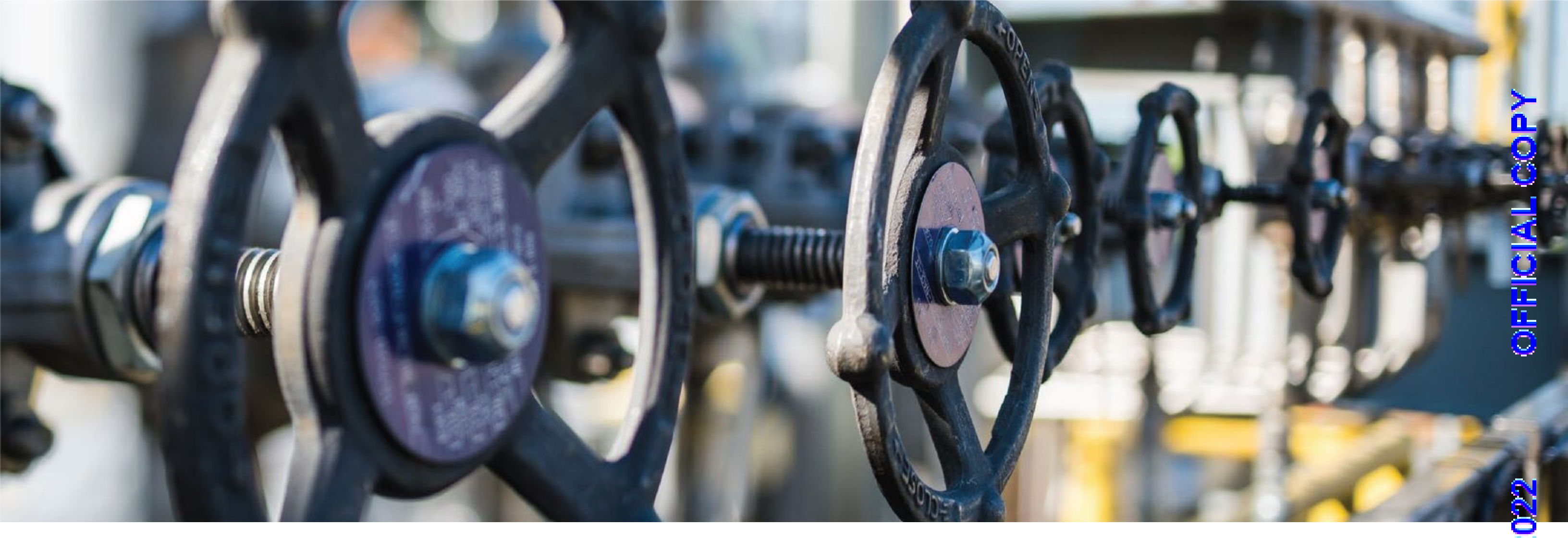

N Fuel Supply

Decarbonization of the Duke Energy Carolinas, LLC (“DEC”) and Duke Energy Progress, LLC (“DEP” and, together with DEC, “Duke Energy” or the “Companies”) power generation fleet has significant implications on the Companies’ long-term fuel supply strategy. DEC and DEP customers have long benefited from a secure and diverse fuel portfolio of coal, natural gas, diesel and other energy sources. Until new dispatchable carbon-free fuel technologies become economically viable for utility-scale use to maintain reliability, traditional fossil fuels will be required to maintain least-cost and reliable operations. There are two primary areas of focus to sustain adequate fuel supply through the generation transition:

1. Obtain sufficient coal supply to provide reliability through the likely end-of-coal consumption in the 2030s.

2. Obtain the additional natural gas interstate firm transportation required to support renewable integration, maintain cost-effective and reliable energy and achieve lower system carbon emissions.

Coal Supply Assurance

There have been significant coal generation retirements across the nation as power generators transition their fleets to lower carbon energy sources, such as renewables and natural gas. Additional planned retirements for the nation's aging coal facilities contribute to the continuing deterioration of the domestic coal supply chain. Customer fuel cost and unavailability risks increase as coal production continues to decrease. These declines in supply flexibility and market uncertainty create future risks for coal supply assurance and ultimately create risks for customers. While the Companies continue to focus on coal supply assurance, these affordability and reliability risks support retiring coal facilities and developing new advanced generation dispatch methodologies to manage the transition.

Coal market volatility has increased due to several factors, all of which increase risks to coal supply assurance for Duke Energy:

- Deteriorated financial health of coal suppliers due to declining domestic demand for coal;

- Natural gas price volatility;

- Uncertainty around proposed, imposed and stayed environmental regulations for power plants;
- Shifting production from thermal coal to metallurgical coal to maximize limited capital resources;
- Increased U.S. physical coal competition from global demand markets;
- Increased domestic supply pricing influence from volatile international markets;
- Tightened access to investor financing and deteriorating credit quality increases the overall financing costs for coal producers; and
- Increasing external labor and resource constraints.

The financial challenges of coal companies could have direct implications on the Companies' ability to obtain low-cost and reliable coal supply through planned coal facility retirements. The U.S. coal sector faces challenges with accessing capital due to concerns about the industry's environmental impacts and long-term viability. Increasing Environmental, Social and Corporate Governance ("ESG")-related activity has made accessing financing more difficult for coal producers. In addition, none of the publicly traded U.S. coal mining companies currently have an investment grade credit rating. A growing list of banks and insurance companies have made pledges to exclude transactions with coal companies, limiting the sector's ability to go to the bond market or bank lenders.[1]

A primary risk of coal supply lies within a producer's ability to maintain financial stability through downward cycles of pricing pressure and decreased demand. While in early 2022 the coal market was in an upward commodity price cycle, this trend is unlikely to sustain through the 2030s. Accelerating coal facility retirements, continued competition from natural gas, and increasing renewable capacity are expected to continue to put downward pressure on domestic coal demand. With no new greenfield U.S. thermal coal mines expected the risk of further reduced production at existing mines or premature closures continue to weigh on the long-term coal production outlook. Of most immediate concern to the Companies is the reduction in Central Appalachian ("CAPP") thermal coal production, much of which is due to producers shifting to the domestic and export metallurgical coal markets as suppliers look to maximize limited capital and labor resources. According to Information Handling Services Markit ("IHS Markit"), in 2021 approximately 66% of total CAPP production was metallurgical coal as it increasingly becomes the primary driver of coal production in Central Appalachia.[2] CAPP thermal coal has lower sulfur dioxide ("SO_2") than other domestic coals and is critical to several Duke Energy coal units meeting their design specifications. Without adequate future CAPP supply, non-traditional sources of lower SO_2 CAPP-like coals could be required for reliability.

[1] Shut off from conventional capital, US coal companies seek creative options. June 2021. S&P Global Market Intelligence.
https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/shut-off-from-from-conventional-capital-us-coal-companies-seek-creative-options-64515285.
[2] US Coal Market Briefing. February 2022. IHS Subscription Portal. *IHS Markit*.

Reductions in capital expenditures and shifts away from thermal coal production will continue to limit suppliers' operational flexibility and their ability to respond to ongoing shifts in power generation demand. Increasing competition for labor resources in coal-producing regions coupled with increased post-COVID-19 era personnel retirements is also expected to maintain production pressure on producers and further limit their ability to respond to shifts in demand. Once capital and human resources leave the coal industry, they are unlikely to return. Future financial instability of producers could result in fuel cost volatility and increased unavailability risk, which can impact electricity costs and reliability. This risk is likely not accounted for in third-party fundamental forward-commodity pricing; however, the Companies are planning to protect their customers through appropriate contracting and reduced volumetric exposure to coal over time. Strategic longer-term contracts that provide certainty to both supplier and consumer should provide fuel security through the fleet transition but will limit flexibility to treat coal as an unlimited resource.

U.S. coal facility retirements continue to accelerate. IHS Markit projects the size of the coal-generation fleet to fall by more than 70% over the next 10 years from about 210 GW to 65 GW.[3] As a result of declining U.S. demand due to retirements, U.S. thermal coal production volumes are expected to continue to decline. Figure N-1 below shows that forecasted decline, specifically of CAPP and Northern Appalachian ("NAPP") thermal coals, which are the most consumed by DEC and DEP's generation fleet.

Figure N-1: Annual United States Coal Production

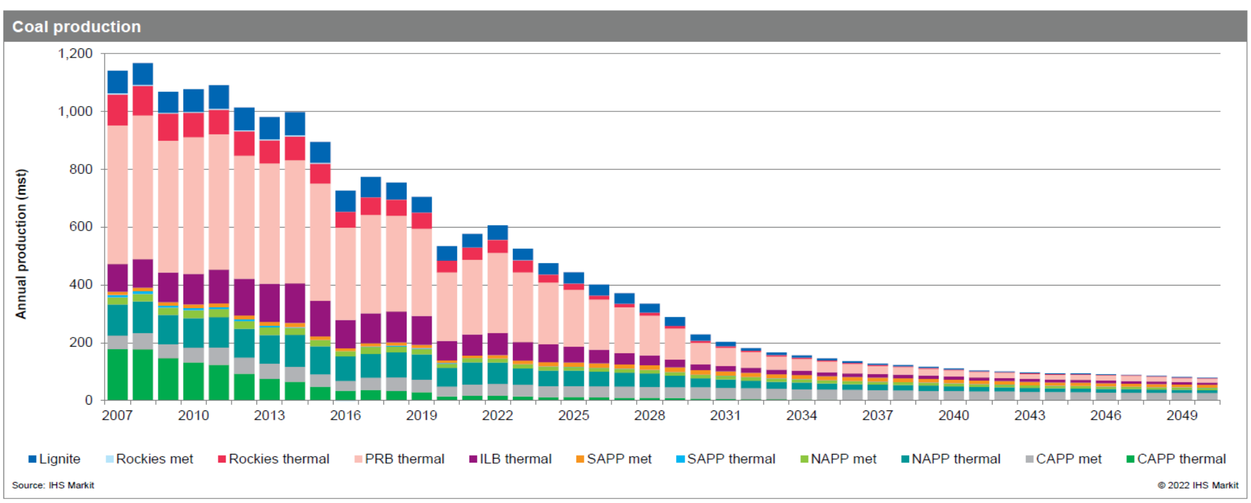

Figure source: US Coal Market Briefing. February 2022. IHS Subscription Portal. *IHS Markit*

While domestic natural gas production has export limitations from operational liquefaction capacity to produce liquefied natural gas ("LNG"), domestic coal has lower export barriers. Over the years, the U.S., with excess production and export terminal capacity, has typically been a swing supplier of coal in the global market. Going forward, U.S. coal producers are likely to align a higher percentage of their

[3] US Coal Market Briefing. February 2022. IHS Subscription Portal. *IHS Markit*.

production to international markets as domestic utility demand decreases; this could result in decreased supply availability and increased price volatility for domestic coal consumers. If domestic producers fail to increase their exposure to higher priced markets like Europe and Asia, additional U.S. mine closures could be expected. The supply chain stressors of attracting labor and investment capital could also drive suppliers to consolidate, and transportation providers to resize operations and capital allocations. The decreasing domestic supplier base could result in reduced supply tonnage and declines in market liquidity, further increasing customer price exposure and reliability risks. These risks are even further complicated by the European Union's April 2022 ban of Russian coal imports, which could increase demand for U.S. coal production.

Remaining domestic coal demand will also have to increasingly compete with larger Asian demand markets for U.S. production, even though the U.S. is currently not a driving force in the global coal supply market. Table N-1 below shows the top 10 coal consumers from 2020 and their "growth" or "decline" change from the previous year.

Table N-1: 2020 Top Coal Consumers

Top 10 Consumers	2020 Exajoules	Global Share	Change from 2019
China	81.7	51.7%	2.3%
India	18.6	11.8%	0.3%
U.S.	11.3	7.2%	-14.6%
Japan	4.9	3.1%	-1.7%
South Africa	3.8	2.4%	1.4%
Russia	3.6	2.3%	0.0%
South Korea	3.4	2.2%	-5.3%
Indonesia	3.4	2.2%	20.0%
Germany	2.3	1.5%	-20.7%
Vietnam	2.1	1.3%	30.2%

Table source: Global Coal Consumption is Being Driven by Developing Countries. July 19, 2020. *Forbes*

Figure N-2: Global Coal-Fired Capacity Addition by Year

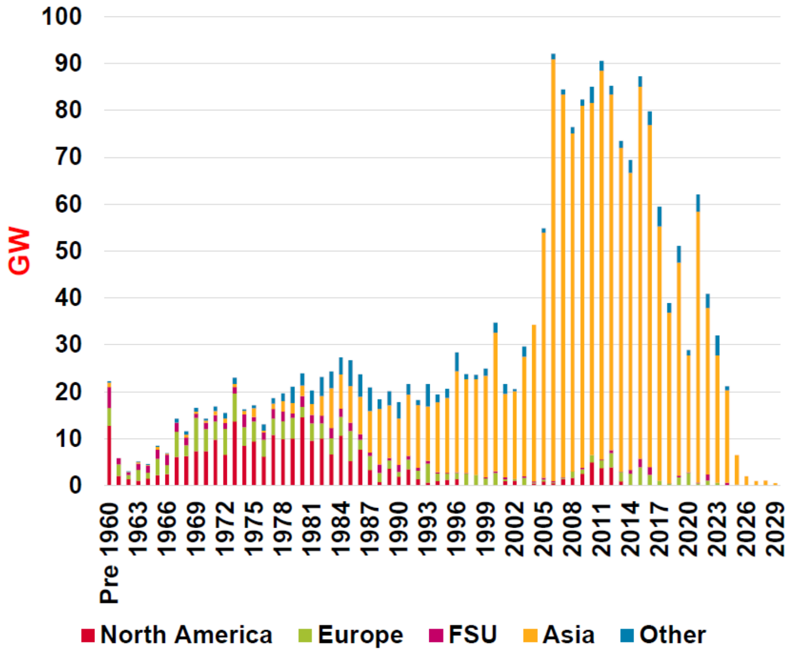

Figure source: Breakout 5D: Pathways – Platts Analytics Weighs In on a Low-Carbon Future with Fossil Fuels. October 13, 2021. *S&P*

Additions to global coal-fired capacity over the last several decades are most notable in Asia, as seen above in Figure N-2 above. China's coal-fired power generation capacity is more than five times larger than the U.S.' coal capacity. The International Energy Agency ("IEA") estimated in December 2021 that coal-fired power generation through 2024 is expected to increase 4.1% in China, 11% in India and 12% in Southeast Asia.[4] During the same time, the United States (-21%) and European Union (-30%) are expected to decline. China's coal consumption hit an all-time high in 2021 and is expected to continue to rise through at least 2024. China currently produces less coal than it consumes, so its additional consumption has implications on the international coal market.

In the future, if domestic coal supply becomes limited or unreliable, international supply imports may be necessary to ensure generator availability. International supply assumptions are not currently included in Duke Energy's long-term modeling. If they were to be included, the cost of coal supply would significantly rise. International coal prices hit an all-time record high in 2021 exceeding $400/ton, which was approximately quadruple the domestic Appalachian pricing at the time. Given current U.S. coal market illiquidity, as the coal market further deteriorates, a coal dispatch methodology that utilizes U.S. coal market commodity curves may not fully account for the true cost to ensure fuel security and manage volatile burns.

[4] IEA Coal 2021: Analysis and forecast to 2024. December 2021. *International Energy Agency* https://www.iea.org/reports/coal-2021.

Importing coal from the global market would also require more complex logistic requirements, further reducing operational flexibility and increasing costs. It could be challenging to find adequate logistics networks to deliver coal from an import vessel to a power plant. Currently, all of the DEC and DEP coal supply is delivered by rail to its facilities. Railroad transportation was designed for consistent baseload consumption, but declining demand for coal in the utility sector has caused rail providers to modify their business models to be less dependent on coal-related transportation revenues. Although rail transportation providers are required to provide rail service, the Companies' rail transportation providers have limited resources to adapt to significant changes in domestic coal burn profiles. Because the coal industry supply chain is not designed to have assets waiting for demand spikes, it can take weeks to months to respond to changing market conditions or supply and demand disruptions. With these changes in transportation usage, railroad companies could reassess the coal shipment structure and railroad rates could increase.

With limited elasticity of supply, coal will become a constrained resource, requiring new dispatch protocols that optimize long-term economic value to customers subject to limitations on supply and transportation. The Companies anticipate any remaining supply elasticity will reflect the high marginal costs of increasing or decreasing production and transportation. These high marginal costs of coal burn volatility will contribute to longer-term higher customer costs. Developing advanced dispatch methodologies to manage a more defined and decreasing volume of coal across intra-year and inter-year burn volatilities in a manner that provides the highest value to customers while maintaining reliability of coal supply for critical periods will be a necessary evolution in least-cost economic dispatch to support coal supply assurance.

Additional Firm Gas Transportation

As coal facility retirements have increased in recent years, the Companies have used significantly less coal than in the past and have instead increased utilization of renewable and natural gas resources. This trend of increased natural gas consumption will likely persist to maintain system reliability while increased volumes of renewables are integrated into the Carolinas' changing generation mix. With the transition from non-intermittent coal to intermittent renewables, firm generator capacity and operational flexibility provided by natural gas generation will play an important role in mitigating increasing reliability risks. As quoted in Appendix M (Natural Gas), the North American Electric Reliability Corporation ("NERC") President and CEO Mr. James Robb testified to Congress in 2021 about the critical role that natural gas plays in the U.S. power grid. This is further exhibited in NERC's December 2021 Long-Term Reliability Assessment:

> Prioritizing reliability during the grid's transformation and as governmental policies are developed will support a transition that assures electric reliability in an efficient, effective, and environmentally sensitive manner. However, recognition of the challenges that the system faces during this transition requires action on key matters.

> Natural gas is the reliability "fuel that keeps the lights on," and natural gas policy must reflect this reality.[5]

Currently, the Companies' natural gas generation stations rely on interstate pipeline firm transportation or on-site coal and diesel dual-fuel capability for fuel security; however, the Companies' combined cycle fleet is currently deficient of interstate pipeline firm transportation capacity due to the cancellation of Atlantic Coast Pipeline ("ACP"). Looking ahead, current and future gas turbines could transition to hydrogen or other low- or zero-carbon fuels. Although promising, hydrogen still requires additional production and generation technology development to be widely utilized as a utility fuel. As discussed in Appendix O (Low-Carbon Fuels and Hydrogen), the Companies will continue to closely follow hydrogen technology in preparation for its potential future use as a substitute for natural gas. Regardless of the future utilization of natural gas, renewable gas or hydrogen as the fuel, there is still a need for additional pipeline capacity in the Carolinas.

Firm pipeline transportation is essential to manage the natural gas supply security needed for reliable cost-effective generation. Not only does interstate firm transportation allow access to lower cost natural gas supply, but it provides the intraday flexibility necessary to support intermittent renewable energy and maintain reliability through increased fuel security of dispatchable gas generation. Operationally, interstate firm transportation is necessary to balance the system's hourly gas demand swings that inherently accompany intermittent renewable generation. The Electric Power Research Institute ("EPRI") released a whitepaper in November 2021 noting a key finding that additional gas generation enables carbon reduction by providing the flexibility needed to balance variable renewable resources and meet hourly system needs.

> "New natural-gas-fired capacity helps offset coal retirements, providing firm capacity to aid in balancing variable renewables, ensuring that supply can meet growing demand in every hour, minimizing electricity cost increases, and reducing system operational changes."[6]

Meeting gas generation's fuel needs requires a flexible and reliable gas supply. To meet this requirement, the Companies need additional firm transportation capacity on interstate pipelines because there is no natural gas underground storage or production in the Carolinas. All gas supply is dependent on interstate pipelines transporting gas from the Appalachia and Gulf Coast production regions. The Transco pipeline, the primary interstate gas infrastructure through the Carolinas, is fully subscribed and constrained during times of high utilization, an issue raised several times by stakeholders in the Carbon Plan stakeholder meetings. Over the past decade in the Carolinas, natural gas demand growth has outpaced increases in gas delivery capacity. Given the need for increased interstate firm transportation and the current litigious environment for building new pipeline capacity, the Companies have developed two scenarios for incremental firm transportation capacity as

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[5] NERC Long Term Reliability Assessment. December 2021. *North American Electric Reliability Corporation.* https://www.nerc.com/pa/RAPA/ra/Reliability Assessments DL/NERC_LTRA_2021.pdf.

[6] Strategies and Actions for Achieving a 50% Reduction in U.S. Greenhouse Gas Emissions by 2030. November 2021. *Electric Power Research Institute.* EPRI-Whitepaper-Strategies-and-Actions-for-US-GHG-Reduction.pdf.

discussed in Appendix E (Quantitative Analysis). These scenarios are centered around the ability to obtain a limited amount of additional firm transportation for access to lower cost gas from the Appalachia region. These two Fuel Supply Cases are: (1) a primary case with limited new Appalachian gas, and (2) an alternate case with no new access to Appalachian gas.

On July 5, 2020, Dominion Energy and Duke Energy announced the cancellation of ACP citing anticipated delays and increasing cost uncertainty due to ongoing permitting and legal challenges. Cancellation of ACP left the Companies with a considerable remaining need for interstate firm transportation for existing generation. The need for additional firm transportation and diversity of gas supply, which formed the basis of the ACP project, have not changed. The Carolinas Carbon Plan (the "Plan" or "Carbon Plan") assumes the same additional interstate firm transportation volumes for existing generation, as assumed in both the ACP project and the Companies' 2020 Integrated Resource Plans ("IRP"), which are required to cost-effectively and reliably support the existing natural gas generation fleet. Without additional firm transportation for both existing and incremental generation, there would likely need to be a substantial increase in the gas fleet's volume of on-site fuel storage for reliability.

Due to the cancellation of ACP, the Companies have significantly less generation gas supply requirements covered by interstate firm transportation than other peer southeast electric utilities and also have the risk of sole-sourced pipe supply, whereas other peer utilities have multiple pipeline sources. These risks expose the Companies to increased challenges if there are market disruptions or supply constraints. As the Carolinas' gas demand peaks during the winter, it must compete for any available delivered gas supplies with natural gas local distribution companies and other end-users to serve peak demand periods. Lacking additional firm transportation that accesses Appalachia, the Companies' customers will fail to gain the benefits of improved gas availability and price stability, particularly during the winter.

In March 2022, the U.S. Energy Information Agency released a "No Pipes" report in addition to its reference case for its 2022 Annual Energy Outlook.[7] This federal government agency's "No Pipes" report has several important findings that are relevant to the Carbon Plan:

- The no pipeline builds case shows a direct correlation to increased natural gas commodity costs for customers;
- The case shows the Carolinas and Georgia region being one of the highest impacted nationally by no pipelines being built. Restricting new pipeline capacity into the region decreased the forecasted gas flows from the base case. Specifically, these were north-to-south gas flows primarily from Appalachia; and
- The no pipeline builds case results in coal replacing a quarter of the energy through 2050 that would have been natural gas if pipelines had been built.

[7] AEO2022 Issues in Focus: Exploration of the No Interstate Natural Gas Pipeline Builds case. March 30, 2022. *US Energy Information Agency*. https://www.eia.gov/outlooks/aeo/IIF_pipeline/.

Charles Rivers Associates also recently performed a modeling exercise that shows no new pipeline infrastructure in the U.S. could cost natural gas consumers $26 billion annually.[8] Specifically for the Carolinas, that would result in an annual average price increase of 33% for delivered natural gas in 2030.

Conclusion

Without additional interstate pipeline firm transportation, the Companies have increased fuel assurance risk, increased customer fuel cost exposure and increased risk of delayed coal retirements. In addition, the Companies would continue to have a firm transportation portfolio that is less than half of its current combined-cycle design capacity need and less than a quarter of the current gas fleet's historical peak gas burn. Alternative fuel supply case scenarios $P1_A$, $P2_A$, $P3_A$, and $P4_A$ discussed in Appendix E (Quantitative Analysis) illustrate resource planning options that do not require additional Appalachian interstate firm transportation to meet the Carbon Plan targets. However, these options create additional costs, executability challenges and reliability risks for customers.

[8] The Relationship Between Energy Infrastructure and Consumer Costs. April 6, 2022. *Charles River Associates*. https://www.crai.com/insights-events/publications/the-relationship-between-energy-infrastructure-and-consumer-costs/.