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Coal Retirement Analysis

Highlights

- Decreasing fuel supply as producers shift to other markets has increased the degree of volatility in the entire coal supply chain. This volatility is expected to grow as United States' power producers continue to transition away from coal-fired generation.
- Dynamic natural gas prices, combined with coal retirements, transportation constraints, pipeline constraints and the addition of significant natural gas fired generation have contributed to large swings in the actual and forecasted burn in coal and gas generation.
- The Companies performed an updated coal retirement analysis for each Energy Transition Pathway as well as an analysis without carbon constraints to identify the most economic timing of coal retirements based on the availability of replacement resources. The updated coal retirement analysis was developed based upon Carolinas Resource Plan assumptions including the substantial increase in the load forecast and updated planning reserve margin.
- The updated coal retirement analysis weighs the continued operational benefits to the system of each coal unit as well as the costs to operate and maintain the units over time based on, for example, unit-specific maintenance schedules. The analysis also optimizes unit retirement dates based on the availability of new capacity additions and other considerations to ensure an orderly transition that maintains or improves system reliability, prudently manages risks and uncertainties, and enables the Companies to meet the growing energy needs of customers. These planning considerations support minor adjustments to the model-selected retirement dates for certain units to allow for more orderly and executable retirement schedules.

A Changing Energy Landscape – Impacts of Industry Exit from Coal

Changing Economics of Coal

As discussed in Chapter 1 (Planning for a Changing Energy Landscape), economics and environmental regulations are driving a decline in the coal industry and its supporting infrastructure. The transition away from coal generation by electric utilities has impacted every aspect of domestic coal production and supply transportation. This changing environment, coupled with current inflationary pressures, results in risks and uncertainties, described in more detail below, for coal supply assurance and reliable operations of the Companies coal generation facilities. 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. Although the coal market experienced an unexpected boost in demand and prices during calendar years 2021 and 2022 due to an economic resurgence following the COVID-19 pandemic, rising natural gas prices and Russia's invasion of Ukraine, prices have since retreated to close to pre-pandemic levels. Accelerating coal facility retirements, as well as competition from natural gas, and increasing renewable capacity have also put renewed downward pressure on domestic coal demand. Inflationary cost increases to mining operations including, but not limited to, labor, equipment and fuel have further impacted the coal industry's ability to respond to changes in market demand and its ability to compete with natural gas and renewables. The downward pressure on domestic coal demand and pricing coupled with rising coal production costs poses increasing risks to coal producers' ability to maintain financial stability. Finally, increasing competition for labor resources in coal-producing regions, coupled with increased post-COVID-19 era personnel retirements and an overall shift away from mining to positions with greater longevity and more favorable work conditions, are also expected to maintain production pressure on producers and further limit their ability to respond to shifts in demand.

The financial challenges of coal companies have direct implications on the Companies' ability to obtain low-cost and reliable coal supply through planned coal facility retirements. The United States coal sector continues to face challenges with accessing capital due to concerns about the industry's environmental impacts and long-term viability. None of the publicly traded coal mining companies operating in the United States currently have an investment-grade credit rating, substantially increasing their borrowing costs in the current interest rate environment. As demand for coal and the ability to obtain capital continues to decrease, there is potential for further consolidation of producers, leading to increased risks of non-performance, higher prices and less flexibility. Future financial instability of producers could result in fuel cost volatility and increased unavailability risk, which can impact electricity costs and reliability. International demand will also factor into future production and pricing volatility.

Similarly, long-term declines in demand for coal in the utility sector are also driving rail transportation providers 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 ability to respond timely to significant changes in scheduling demand due to lead times needed for adding crews and locomotive equipment. Additionally, there is competition for the same resources between the domestic and international coal supply chain as historically international export coal trains receive priority service. These factors, combined with increasing scrutiny surrounding railcar maintenance and inspections following the highly publicized derailment in East Palestine, Ohio, are expected to put increased pressure on rail transportation providers' ability to respond to demand volatility and increase the risk of higher customer costs.

Coal Supply and Transportation Constraints

Coal Supply

The coal supply chain relies on relatively ratable coal deliveries to drive efficiencies, maintain labor resources and protect financial viability. Longer term commitments priced above the cost to produce help to retain and support the labor force, plan future mining needs and ensure future revenue. Most coal producers have limited, if any, ability to respond timely to rapid changes in coal demand driven by the real-time switching between fuels due to labor constraints and the inability to absorb delivery shortfalls. Unexpected coal delivery decreases and disruptions due to decreased demand reduce coal producers expected revenues. Many coal producers have limited opportunity to store coal and the stored commodity is not generating cash flow. The producer's inability to withstand lulls in coal demand has the potential to result in further consolidation or deterioration of the coal supply.

Of most immediate concern to Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, the "Companies") is the reduction in Central Appalachian ("CAPP") thermal coal production. Much of the reduced thermal production 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 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.[1] CAPP thermal coal has lower sulfur dioxide ("SO_2") than other domestic coals and is critical to the coal units meeting their environmental permitting and operating design specifications. Without adequate future CAPP supply, non-traditional sources of lower SO_2 CAPP-like coals could be required for reliability.

Coal Transportation

The magnitude of the volatility of coal demand continues to be larger than the coal transportation supply chain can effectively support. This degree of volatility is expected to continue and perhaps worsen as more and more United States power producers begin transitioning away from coal-fired generation. This volatility makes it much more difficult for the Companies' transportation providers, particularly the Class I railroads, to plan for resources around crews (personnel) and equipment (locomotives). Like coal producers, coal transportation providers have a need for a reasonably steady level of monthly coal shipments to retain and support their labor force and plan for locomotive usage. Historically, the railroads have had a difficult time timely accommodating significant delivery demand shifts resulting from the Companies' burn volatility. The lead times for attaining the appropriate number of crews (railroad personnel) have not historically aligned with the utilities' demand needs. Railroad

[1] IHS Markit, US Coal Market Briefing, February 2022, IHS Subscription Portal.

response time for training conductors and engineers typically takes a minimum of four to six months. This length of time has proven to be too long to support periods of increased coal delivery needs. By the time the appropriate number of crews are trained, certified and positioned where needed, the increased need for coal deliveries has most likely already occurred.

In the foreseeable future, declining CAPP coal supply may require the Companies' operating stations to shift coal basins to meet supply needs; however, coal basin shifts can take up to 12 months to establish effectively given the need to establish or right-size railroad crew bases and position equipment.

All the DEC and DEP coal supply is delivered by rail to its facilities. As a result, any disruptions in rail service due to labor and resource constraints, weather, maintenance and rail system demand, or derailments can significantly impact station deliveries.

While the Companies lease their own rail cars for use in transporting coal, the Companies do not have the unilateral right to add additional rail sets into service. The serving railroad approves both whether and how many rail sets may be added based on network traffic at the time of the request. The Companies have been denied the request to add equipment from time to time based on already high network traffic.

Lastly, during 2021 and 2022, the availability of coal cars from third party suppliers shrunk to "zero" as the surge in coal demand, a nationwide liquidation of coal cars over the previous decade, and longer-term lease contracts by other utilities basically removed all available coal cars from the market. Given the declining demand for domestic coal, manufacturers are not planning on building additional railcars to replace the cars that have been scrapped over the last decade.

Based on the transportation constraints discussed above, the Companies expect continued issues with the ability of the railroads to respond timely to changing demand along with limited availability of coal car transportation equipment to continue, all of which increases the risk of reliable supply and higher customer costs.

Evolving Coal Unit Generation and Dispatch Equation

Dynamic natural gas prices, combined with coal retirements, regional transportation constraints, pipeline constraints, and the addition of significant natural gas fired generation and growing energy contributions from fuel-free solar have contributed to large actual and forecasted burn swings in Duke Energy coal and gas generation. In many parts of the Eastern and Southern United States, natural gas generation competes with the delivered cost of coal. The range of competing dispatch prices between coal and natural gas generation is dynamic based on market prices and real-time switching of natural gas for coal in the generation dispatch stack is common.

In addition, the United States Energy Information Administration announced that electricity generated from renewables surpassed coal in the United States for the first time in 2022. However, until new dispatchable zero carbon 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.

With limited elasticity of supply, coal is 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, and that these higher marginal costs will contribute to longer-term higher customer costs. Therefore, it has become increasingly important to redefine the time horizon of least-cost economic dispatch to reflect the true cost of ensuring reliability of coal supply through to the final coal generation plant retirement. 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, has been a necessary evolution in least-cost economic dispatch to support coal supply assurance through to planned station retirements.

Policies and Regulations Impacting Coal

Increasing environmental regulations regarding coal ash, wastewater and air-borne emissions have put significant pressure on the viability of aging coal units to remain both cost-effective and compliant over time. Indeed, as seen in the May 2023 Environmental Protection Agency's ("EPA") Clean Air Act ("CAA") Section 111 Proposed Rule discussed further below, regulations are likely to become even more stringent. While the electric industry largely exits coal generation, it is becoming even less economically viable and increasingly risky to attempt to invest in and maintain coal units into the late 2030s and into the 2040s. In parallel, the majority of states have energy goals in the form of renewable or clean energy portfolio standards or greenhouse gas emission reductions mandates,[2] and Congress has created incentives such as the Inflation Reduction Act of 2022 and the Infrastructure Investment and Jobs Act for other types of resources and technologies, further driving an exit from coal. During this critical period of the energy transition, the increasing pressure on the coal industry poses challenges for the important role these units play in system reliability and adequacy, particularly during extreme weather events unless replaced with equally reliable resources before they retire.

Implications for the Companies' Coal Facilities

Continuing to maintain the Companies' coal fleet presents challenges due to availability of a qualified workforce and maintaining aging equipment. Maintaining a qualified workforce is more difficult today due to limited career opportunities in a declining industry that does not have long-term job security. As the current employees reach retirement, it is very challenging to attract new workers given the short remaining life of the U.S. coal fleet. This leads to higher costs to maintain an adequate workforce to operate and maintain coal plants. Also, the current coal generation workforce is looking at other areas/industries to work that will provide more future security. The higher costs can be attributed to the need to attract employees not looking at the coal industry or the increased need for contract labor to meet gaps. The Companies do have a program, Transitional Resource Support Group, in place to assist employees with increasing their skillsets to find employment opportunities within the

[2] NARUC, State Clean Energy Policy Tracker, accessed May 17, 2023, available at https://www.naruc.org/nrri/nrri-activities/clean-energy-tracker/.

Companies. This is helpful, but many employees would like to have security and prefer to exit the industry prior to retirement.

There are many challenges that affect a utility's ability to maintain an aging coal fleet. One challenge is being able to get materials in a timely manner and secure equipment that is becoming obsolete. Companies are no longer supporting the declining coal industry as they have in the past causing these supply chain issues. Materials that could previously be secured in days, now can take weeks or months. Another challenge is making funding decisions with uncertainty of retirement, which requires agility in the planning process to respond to changing conditions to balance the right amount of investments in plants with limited future life while striving to maintain reliability. Some of the Companies' coal plants have the capability to burn both coal and natural gas. This provides operational flexibility and reduces fuel costs for customers. Having certainty of retirement dates supports an orderly transition and provides employees with a level of certainty on the path forward.

As noted above, an additional challenge potentially impacting coal-fired electricity generation nationally is the EPA's efforts to regulate carbon emissions. On May 23, 2023, EPA published a suite of proposals under CAA section 111 ("EPA CAA Section 111 Proposed Rule") regulating carbon dioxide emissions from fossil fuel-fired power plants. The EPA CAA Section 111 Proposed Rule addresses existing coal and gas (under section 111(b)) and new gas (under section 111(d)). The potential impact on coal-fired generating units is modest — Duke Energy is planning to retire remaining coal units by the end of 2035, pending regulatory approval and adequate dispatchable replacement generation. As the rule is currently crafted, the impacts would be limited to coal-only units that operate beyond the end of 2031. To the extent resource planning concludes any of these units are needed beyond 2031 for reliability support, a 20% annual capacity factor limitation will be imposed.

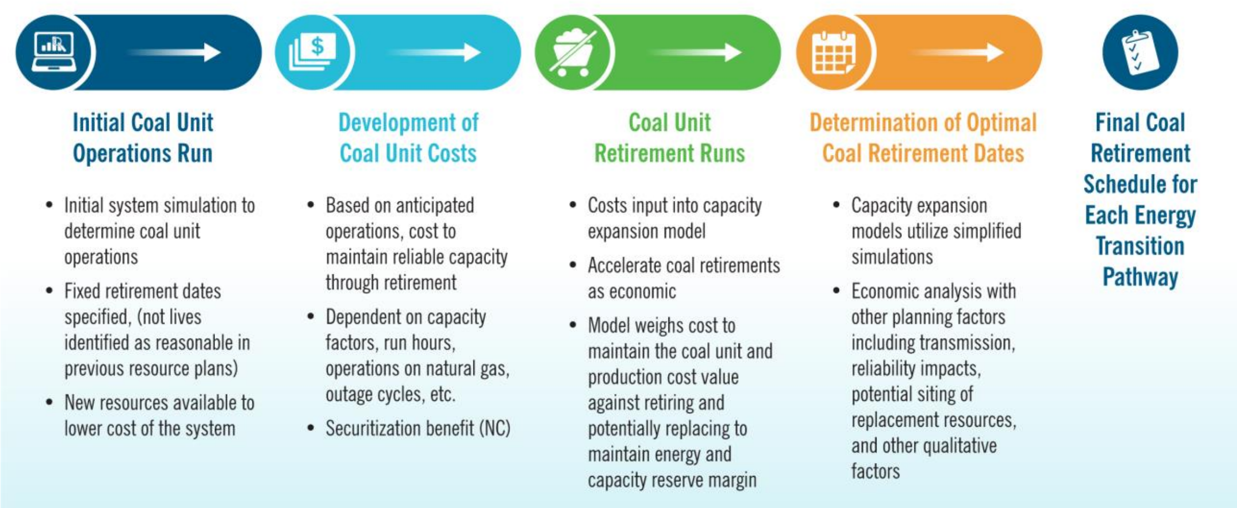
Coal Retirement Analysis

Considering the substantial increase in the load forecast and update to the planning reserve margin from previous long range planning cycles, DEC and DEP conducted a new coal retirement analysis for the 2023 Carolinas Resource Plan (the "Plan" or "the Resource Plan"). Given the capacity expansion modeling capabilities and enhancements described in Appendix C (Quantitative Analysis), the Companies performed the coal retirement analysis endogenously within the capacity expansion model, optimizing the retirement dates with the expected availability of replacement resources. As described in Chapter 2 (Methodology and Key Assumptions), the Companies performed coal retirement analysis for each Energy Transition Pathway, and for informational purposes in a scenario without carbon constraints. The modeling and analysis to determine the final coal retirement schedule consisted of several steps, including development of the analytical assumptions, capacity expansion modeling, and final determination of optimal coal retirement dates considering results of the modeling and other relevant quantitative and qualitative planning factors.

The Plan utilized the capacity expansion model to identify economic timing of future coal retirements, endogenously optimizing retirements with available capacity and expected energy replacement resources. The capacity expansion model weighed the continued operational benefits to the system and costs to operate and maintain the coal units over time against the retirement and replacement of the coal units by selection of available supply-side resources, while also meeting the operational and planning constraints of the system, including achievement of emissions reductions targets.

Importantly, retirement dates selected by the endogenous analysis are limited to a single and static view of assumptions and costs and, therefore, should be treated as representative and directional in nature (rather than determinative) due to these limitations. To more accurately reflect the complex interdependencies of resource additions and retirements, the coal retirement analysis consists of multiple steps, in addition to the endogenous analysis, to determine costs to operate and maintain each unit, evaluate model-identified potential economic retirement dates, and then consider the modeling results in the context of real-world planning considerations to determine optimal retirement dates for each unit. Specifically, the Companies' Coal Retirement Analysis Process presented below in Figure F-1 and discussed in greater detail below accounts for the dynamic nature of costs associated with maintaining each coal unit, and used the endogenously identified retirement dates, along with considering other qualitative planning factors.

Figure F-1: Coal Retirement Analysis Process



Analytical Assumptions for Maintaining Existing Coal Assets

To perform the capacity expansion modeling with endogenous selection of coal retirements, the model weighs the costs to continue to operate and maintain the coal units, and the production cost and emissions of the system against the cost and production cost benefits of resources that can be brought online while meeting the requirements of the system. These incremental resources selected provide energy and capacity to the system previously provided by the coal resources. To the extent that the aggregate resource additions can reliably replace the coal capacity and energy in a cost-effective manner, the model can economically select to retire these units.

For the capacity expansion model to complete this complex analytical balancing act, the Companies must specify to the model the parameters for retirements including costs to operate and maintain the coal units, the years the coal can be selected for retirement, and other quantitative factors to reflect real-world practicalities to retiring the units and maintaining the operational efficiency and reliability of the grid.

First, the Companies identified which units would be assessed in the coal retirement analysis. The Companies included all coal units for DEC and DEP, with the exception of Allen 1 and 5 and Cliffside 6. Allen 1 and 5 are planned for near-term retirement by the end of 2024. Because these units are already progressing towards near-term retirement, these retirements were not reoptimized as part of the retirement analysis. In the case of Cliffside 6, this unit is already capable of operating on 100% natural gas, as indicated in prior IRPs. The Companies assume Cliffside 6 ceases coal operations by the end of 2035 and operates exclusively on natural gas thereafter. Therefore, this unit was not included in the retirement analysis, as retiring this unit, and replacing it would be suboptimal given its current natural gas operating capabilities.

Initial modeling coal retirements dates were then specified to the model for each unit. This initial retirement date provided the model with the basis for economically accelerating retirements. As discussed earlier in this Appendix, the risks of continuing to operate coal capacity through the mid-2030s significantly increases as headwinds from supply availability, transportation constraints and environmental regulations combine with challenges to reliably maintain and operate these resources, ultimately increasing reliability and cost risks for customers. Therefore, all units were assumed to be retired by no later than the start of 2036 to mitigate exposing customers to the significant coal fuel supply risks discussed above. The Companies then relied on depreciable lives date as the latest date the unit could be retired, consistent with depreciation studies from the previous planning cycle. In limited cases for Marshall 1 and 2, which are among the oldest coal units still on the system, the latest date the unit could be retired was established with near-term projects to leverage generator replacement for the retirement of these units with new replacement resources. A summary of these initial coal retirement dates (retired by January 1 of the year listed), and other coal unit statistics, are shown in Table F-1 below.

Table F-1: Coal Unit Statistics and Initial Modeling Coal Retirement Dates

Unit	Location[1]	Unit Capacity [Winter MW]	In-Service Date	Initial Modeling Coal Retirement Dates[2]
Belews Creek 1	NC	1,110	1975	2036
Belews Creek 2	NC	1,110	1975	2036
Cliffside 5	NC	546	1972	2033
Marshall 1	NC	380	1965	2029
Marshall 2	NC	380	1966	2029
Marshall 3	NC	658	1969	2035
Marshall 4	NC	660	1970	2035
Mayo 1	NC	713	1983	2036
Roxboro 1	NC	380	1966	2029
Roxboro 2	NC	673	1968	2029
Roxboro 3	NC	698	1973	2034
Roxboro 4	NC	711	1980	2034
Total MW	**-**	**8,019**	-	-

Note 1: All the Companies' remaining coal units are located in North Carolina and serve customers in both South Carolina and North Carolina.

Note 2 : Initial Modeling Coal Retirement Dates assumed by beginning of the year (Jan. 1).

As a means of acknowledging the operational efficiencies of operating and retiring units together and to limit the complexities of simultaneously determining coal retirements with replacement resources within the capacity expansion model, the Companies leveraged coal unit groupings to retire pairs of units where reduced costs of common operations and equipment are realized with retiring both units simultaneously compared to isolated retirements. These groupings are listed below in Table F-2.

Table F-2: Coal Retirement Analysis Unit Groupings

	Unit Group Capacity (Winter MW)
Belews Creek 1 & 2	2,220
Cliffside 5	546
Marshall 1 & 2	760
Marshall 3 & 4	1,318
Mayo 1	713
Roxboro 1 & 2	1,053
Roxboro 3 & 4	1,409

Finally, to allow the endogenous analysis within the capacity expansion model to assess the economic coal retirements, the Companies had to develop the costs for maintaining the reliability of these units through their remaining lives. The Companies developed these costs utilizing projected operational factors including operations on natural gas, projected costs to reliability operate the units and comply with known and quantifiable environmental regulations and projected major maintenance cycles necessary to maintain the resources for their anticipated remaining lives. The analysis further included other potential benefits and costs of retirement including securitization benefits of a portion of the units' projected net book value for accelerated retirement for subcritical coal units (as permitted under North Carolina law), and transmission costs that may need to necessarily be incurred to upgrade the transmission system to maintain reliability if the coal units were retired. Table F-3 below summarizes some of the key coal unit characteristics impacting continued operations costs.

Table F-3: Coal Unit Characteristics Impacting Continued Operations Costs

Coal Unit Grouping	Steam Generator Technology	Natural Gas Co-Firing Capability
Belews Creek 1 & 2	Supercritical	50%
Cliffside 5[1]	Subcritical	40%
Marshall 1 & 2[1]	Subcritical	40%
Marshall 3 & 4	Supercritical	50%
Mayo 1	Subcritical	0%
Roxboro 1 & 2	Subcritical	0%
Roxboro 3 & 4	Subcritical	0%

Note 1: Cliffside 5 and Marshall 1 and 2 are capable of co-firing on natural gas at 40% capacity. However, these units are only able to do so when the other units at these sites are not fully utilizing their natural gas capability. In the Carolinas Resource Plan modeling, Cliffside 5 assumes 10% natural gas co-firing capability and Marshall 1 and 2 remove natural gas co-firing as a simplifying model computational assumption for site natural gas availability.

Endogenous Coal Retirement Modeling

Initial Coal Unit Operations Runs

The costs to operate and maintain generation units over time as discussed in the previous section, are determined by how long the unit is expected to remain in the resource portfolio and how much the unit will run over that time. Investments are generally driven by operational characteristics dictated by how a unit is utilized and how much it is utilized. To accurately reflect the operations of these units, given the constraints of the system, an initial set of capacity expansion and production cost models ("Initial Coal Unit Operations Runs") were completed for each Energy Transition Pathway and in a supplemental scenario without carbon constraints or penalties. This initial modeling yielded unique projected coal unit operations for each Pathway and the no carbon constraints scenario and along with the associated additional resources needed to meet the requirements of the system. The simulation of the system provides the inputs needed to develop the costs of maintaining and investing in these coal units over the projected remaining lives of the assets, as discussed in the previous section. These Initial Coal Unit Operations Runs utilized fixed retirement dates consistent with the dates shown in Table F-1.

Development of Coal Unit Costs

As discussed above, the costs for operating and investing in these units over time to maintain reliable operations over the projected lives of the resources were developed based on the unit-specific operational results of the Initial Coal Unit Operations Runs. Each run provided a representation of how the coal units might be utilized over the planning horizon, should they continue to operate through their initial modeling retirement date. The operations of the units may change from one Pathway to another based on the other resources added to the portfolio necessary to meet the energy and capacity needs of the system. Based on these operational projections, including capacity factors, operations hours and operation on natural gas at the Companies' natural gas co-fired coal units, the Companies developed cost projections for each coal retirement scenario that corresponds to an Energy Transition Pathway and the no carbon constraints portfolio. These sets of investments and ongoing maintenance and operation costs could then be put back into the capacity expansion model to determine economic retirement dates endogenously.

Coal Unit Retirement Runs

Once the cost projections for each coal unit for Energy Transition Pathway and the no carbon constraints coal retirement scenario had been input into the capacity expansion model, the Companies conducted the "Coal Unit Retirement Runs." These model runs, performed within the capacity expansion screening model, assessed potential to economically accelerate the retirement of the coal units while simultaneously optimizing the selection of new resources and maintaining reliability meeting the energy and capacity needs of the system, and solving for the emissions reductions targets, as applicable for Pathways 1, 2 and 3.

The model's objective function is to minimize the cost of the system over time while adhering to constraints such as reliability, energy and capacity requirements of the system, and emissions targets as they apply to Pathways 1, 2 and 3. The model will weigh the cost of accelerating the retirement of the unit and avoiding the operations and maintenance cost of maintaining the coal unit with the costs and benefits of accelerating replacement resources. If the model deems it is lower cost to retire the coal capacity, avoiding the future investments in these units and to incur potential cost for adding incremental resources to maintain the planning reserve margins of the system, the model has the option to do so.

Determination of Optimal Coal Retirement Dates

While the capacity expansion model was used to endogenously identify retirement dates economically on a level comparison with new resources to meet the requirements of the system, relying exclusively on results from the capacity expansion model is not appropriate for resource planning, neither for selecting resource additions nor retirements, especially with respect to executing the retirements and planning for an orderly transition. As discussed in Appendix C, the capacity expansion model is a screening model. The capacity expansion model's system simulation simplifications can provide high-level resource selection indications if a resource is generally beneficial to the portfolio. However, the capacity expansion model's inability to reflect dynamic costs associated with each unit's ongoing operations and maintenance schedule, and to assess such costs for units with different projected retirement dates, is an inherent limitation that cannot be captured with static cost inputs into the model. Furthermore, in line with the Plan's planning objectives, and as identified by the Companies in prior resource planning proceedings, the coal retirements are often contingent on a number of factors and must be executable to ensure the reliability of the system upon retirement. These contingencies include the timing of new resource additions, load growth and planning reserve margin requirements, transmission constraints and the ability to leverage sites for future development. To optimize unit retirement dates based on the availability of new capacity additions while considering an orderly transition that maintains or improves system reliability, prudently manages risks and uncertainties, and ensures the Companies can meet the growing energy needs of customers, the Companies made minor adjustments to the coal retirement dates for certain units to allow for more orderly and executable retirement schedules contributing to the continuing reliability of the system. Tables F-4 through F-7 below show the economic retirement dates identified by the capacity expansion screening model and the optimal retirement dates given the endogenous modeling results and planning considerations described above, all dates reflecting a beginning of year basis.

Table F-4: Energy Transition Pathway 1

Coal Unit Grouping	Model Selected Retirement Date	Optimal Retirement Date
Belews Creek 1 & 2	2030	2030
Cliffside 5	2029	2029
Marshall 1 & 2	2029	2029
Marshall 3 & 4	2034	2034
Mayo 1	2029	2029
Roxboro 1 & 2	2029	2029
Roxboro 3 & 4	2030	2030

The Companies did not adjust any of the coal unit retirement dates in Energy Transition Pathway 1. The challenges of achieving the interim emissions reduction targets in the Pathway may be further exacerbated by further adjusting the retirements economically selected by the capacity expansion model. To be clear, retiring approximately 6,700 megawatts ("MW") of firm winter capacity in a two-year span would require a significant and practically infeasible amount of replacement resources to maintain adequate planning reserve margins for the Companies in an extraordinarily compressed and accelerated timeline which could unduly jeopardize the reliability of the system. However, consistent with the Pathway, the level of replacement resources to enable retirement would be significant on an accelerated and compressed timeline needed to achieve the reduction targets and allow for the retirement of these resources.

Table F-5: Energy Transition Pathway 2

Coal Unit Grouping	Model Selected Retirement Date	Optimal Retirement Date
Belews Creek 1 & 2	2032	2036
Cliffside 5	2031	2031
Marshall 1 & 2	2029	2029
Marshall 3 & 4	2034	2032
Mayo 1	2032	2031
Roxboro 1 & 2	2029	2029
Roxboro 3 & 4	2033	2033

The model selected retirement dates for Energy Transition Pathway 2 were adjusted slightly when determining the optimal retirement dates to be used for the development of the Pathway's portfolios. Retirement dates for Cliffside 5, Marshall 1 and 2, Roxboro 1, 2, 3 and 4 were unadjusted from the model's identified dates. The capacity expansion model identified the retirement date for Mayo in 2032. However, given the retirement dates of Roxboro 1 and 2 selected in 2029, and Roxboro 3 and 4 selected in 2033, accelerating the economically identified Mayo 1 retirement from 2032 to 2031 provides for an orderly transition by scheduling two years between retirements of each of the DEP unit groups. The Mayo unit, at just over 700 MW, is more easily retired and replaced on a slightly accelerated timeline compared to the Roxboro 3 and 4 two unit grouping totaling 1,409 MW. In DEC, Belews Creek 1 and 2 were economically selected for retirement in 2032 and Marshall 3 and 4 were economically selected for retirement in 2034. Considering the large size of both unit groupings, the Companies identified that Marshall 3 and 4 may be more optimally suited for generator replacement at the site, and with an accelerated timeframe for retirement, economies of scope and scale may be able to be leveraged with retirement dates of these units closer to the retirement dates of Marshall 1 and 2 in 2029. For Belews Creek 1 and 2, in part because this site is well suited for and being pursued as the first early site permit for advanced nuclear, the Companies delayed the retirement of these units to 2036. This timeline is generally consistent with the timing planned for the first advanced nuclear small modular reactor unit coming online. Furthermore, the delay of Belews Creek with the acceleration of Marshall 3 and 4, provides slightly more capacity through the transition relative to the economically selected date, providing added reliability to the system.

Table F-6: Energy Transition Pathway 3

Coal Unit Grouping	Model Selected Retirement Date	Optimal Retirement Date
Belews Creek 1 & 2	2036	2036
Cliffside 5	2033	2031
Marshall 1 & 2	2029	2029
Marshall 3 & 4	2032	2032
Mayo 1	2036	2031
Roxboro 1 & 2	2029	2029
Roxboro 3 & 4	2034	2034

The model selected retirement dates for Pathway 3, some of which were adjusted slightly when determining the optimal retirement dates for this Pathway. Retirement dates for Marshall 1, 2, 3 and 4; Belews Creek 1 and 2; and Roxboro 1, 2, 3 and 4 were unadjusted from the model's identified dates. The model economically selected Cliffside 5 in 2033. When compared to the retirement dates of Marshall 3 and 4, it was determined that accelerating the retirement of Cliffside 5 to 2031 was optimal timing for this unit. Cliffside 5 is a subcritical coal unit with limited availability for operating on lower carbon emission natural gas with the dual fuel optionality. Given that Marshall 3 and 4 are supercritical units that are more efficient than Cliffside 5 and have more natural gas co-firing capability, the Companies decided to accelerate the retirement of Cliffside 5 ahead of Marshall 3 and 4, without adjusting the model selected retirement date for Marshall 3 and 4. In DEP, Mayo was selected for retirement by the capacity expansion model in 2036. Mayo is among the most expensive of the coal units to operate. Given the lack of operational efficiency for the single unit site and the low capacity factor and run hours projected by the model in the 2030s, the Companies determined the optimal retirement date for Mayo should be accelerated to 2031. This provides for consistent progress toward reducing coal generation risks to customers, while having little impact to the cost of operating the system.

Table F-7 below summarizes the final coal retirement schedule used for each of the Pathways for the development of Core Portfolios, Portfolio Variants and Sensitivity Portfolios under each Pathway.

Table F-7: Coal Unit Retirements (effective by January 1 of year shown)

Unit	Utility	Winter Capacity (MW)	Effective Year by Pathway (Jan 1)		
			Pathway 1	Pathway 2	Pathway 3
Allen 1[1]	DEC	167	2025	2025	2025
Allen 5[1]	DEC	259	2025	2025	2025
Belews Creek 1	DEC	1,110	2030	2036	2036
Belews Creek 2	DEC	1,110	2030	2036	2036
Cliffside 5	DEC	546	2029	2031	2031
Cliffside 6[2]	DEC	849	2049	2049	2049
Marshall 1	DEC	380	2029	2029	2029
Marshall 2	DEC	380	2029	2029	2029
Marshall 3	DEC	658	2034	2032	2032
Marshall 4	DEC	660	2034	2032	2032
Mayo 1	DEP	713	2029	2031	2031
Roxboro 1	DEP	380	2029	2029	2029
Roxboro 2	DEP	673	2029	2029	2029
Roxboro 3	DEP	698	2030	2033	2034
Roxboro 4	DEP	711	2030	2033	2034

Note 1: Allen 1 & 5 retirements are planned by December 31, 2024. Retirements were not included in the Coal Retirement Analysis due to near-term planned retirement dates.
Note 2: Cliffside 6 is assumed to continue operating on 100% on natural gas beyond 2035 and was not included in the coal retirement analysis for the Carolinas Resource Plan.

Supplemental Scenario Analysis

As discussed above, the Companies developed coal retirement schedule that is optimized without CO2 constraints. This portfolio is used in Supplemental Portfolios for informational purposes as discussed in Chapter 2, Chapter 3 (Portfolios), and Appendix C. The result of this analysis is presented below in table F-8.

Table F-8: No Carbon Constraints Scenario

Coal Unit Grouping	Model Selected Retirement Date	Optimal Retirement Date
Belews Creek 1 & 2	2036	2036
Cliffside 5	2033	2033
Marshall 1 & 2	2029	2029
Marshall 3 & 4	2035	2035
Mayo 1	2036	2036
Roxboro 1 & 2	2029	2029
Roxboro 3 & 4	2034	2034

The Companies did not adjust any of the coal retirement dates in the no carbon constraints scenario, as this analysis was performed as part of the supplemental scenario analysis. The resulting coal retirement dates leave this scenario exposed to economic and reliability risks and disruptions, as explained earlier in this Appendix, by waiting until the mid-2030s to retire the majority of the Companies' coal fleet. Similar to Pathway 1, retiring approximately 6,200 MW of firm winter capacity in a compressed, four-year span would require significant replacement resources in a short time frame to maintain adequate planning reserves. Furthermore, this supplemental and informational scenario relies heavily on coal generation to serve load through the remaining lives of these units, which leaves this scenario significantly exposed to risks of more stringent restrictions on fossil generation in the future. If a disruption in the coal industry were to materialize before this scenario begins transitioning out of coal, the scenario has few directions to turn to replace the energy and capacity needed by the system to maintain reliability. Finally, it is not practical to run these coal units indefinitely as the industry inclusive of labor markets, equipment suppliers, coal mining and coal transportation become increasingly obsolescent. As the components within these units age and the parts and workforce to reliably operate the coal fleet become increasingly harder to obtain, the Companies are further at risk of requiring significant investment to keep these units reliable for a potentially short remaining life.

Moving from Planning to Execution

The coal retirement analysis is a critical component of the Carolinas Resource Plan. The assessment of economic and optimal coal retirement dates in the Plan allows the Companies to account for the changing energy landscape, including evolving economic factors, load growth in the region and continued headwinds facing the coal industry. The analysis affords the Companies the ability to check and adjust to ensure customers' expectations for reliable and affordable service are met throughout the energy transition.

As subcritical coal units are retired from the Companies' supply portfolio, the Companies will continue to assess the benefits of securitization of a portion of the units' projected net book value for accelerated retirement for subcritical coal units (as permitted under North Carolina law). As stated previously in this Appendix, the coal retirement analysis conducted for the Carolinas Resource Plan accounts for this benefit in the overall economics of retiring the subcritical coal units. The Companies also estimated the benefits of securitization for the customer and have included those benefits in the bill impact calculations.

The Companies will also continue to pursue the replacement resources necessary to fill the energy and capacity gap from remaining coal retirements that have reliably and affordably served customers over the last six decades. The approach of replacing before retiring ensures the Companies have adequate resources at the time of retirement to ensure the reliability of the system after these units is retired. Recognizing the changing energy landscape as the Companies progress closer to retirement, it will be essential that the dates reflected in this Carolinas Resource Plan are used as representative guides based on the best information available at the time of the development of the plan. As projected net load, the state of the coal industry and environmental regulations continue to evolve over time, the Companies will continue to check and adjust to maintain affordability and system reliability. The Companies are committed to mitigating risks associated with the continued operation of the coal fleet, while providing a reliable and increasingly clean resource mix, and an orderly transition away from coal is essential to those objectives.