4

Execution Plan

Highlights

- The Execution Plan represents a deliberate evolution of short-term action planning in previous resource plans, providing near-term and intermediate-term actions across major aspects of the Carolinas Resource Plan: existing supply-side resources, new supply-side resources, transmission system planning, Grid Edge and customer programs.
- The Execution Plan is an integrated plan across all resources of the Companies' interconnected electric systems that meets long-term planning objectives and facilitates an orderly and risk-balanced energy transition — exiting from coal-fired generation and ensuring equally reliable replacement resources.
- The Near-Term Actions Plan represents reasonable and prudent steps during the near-term 2023–2026 timeframe that are generally consistent with the Carolinas Resource Plan's Core Portfolio P3 Base to develop and procure the resources needed to advance critical aspects of the Companies' orderly energy transition.
- Executing resource plan activities in a changing energy landscape requires monitoring risks and signposts to "check and adjust" plans as conditions change and as opportunities arise.

Successful execution of the Carolinas Resource Plan (the "Plan" or "the Resource Plan") will require prudent and intentional planning and timely regulatory approvals to deliver the resource additions, retirements and system transformation needed to ensure that reliability is maintained or improved. The next 10 to 15 years is a critical execution phase in Duke Energy Carolinas, LLC's ("DEC") and Duke Energy Progress, LLC's ("DEP" and together with DEC, the "Companies") orderly energy transition as the Companies plan for significant load growth, execute the retirement of 8,400 megawatts ("MW") of aging coal units in North Carolina (which serve all of the Companies' customers) and replace this significant retiring dispatchable capacity with equally reliable resources. As the Companies navigate the changing energy landscape, a detailed Execution Plan is essential for a reliable and orderly energy transition. Plan execution necessitates the need to consider lead times for regulatory actions, siting and permitting, procurement and construction as well as fuel supply and transmission dependencies needed to meet future energy requirements.

The Execution Plan presented in this Chapter provides a detailed roadmap and reflects an intentional evolution of the short-term action plan framework presented in past Integrated Resource Plans ("IRPs").[1] First, the Execution Plan introduces the execution planning horizons, with information on monitoring risks and signposts to navigate uncertainty. Second, the Companies present their plan for near-term actions through 2026 that includes the critical and reasonable steps needed to support the energy transition in the short term. Third, the Chapter presents detailed Execution Plans outlining significant near-term and intermediate-term actions across all major Plan components, including actions in the 15-year Base Planning Period[2] to advance longer lead-time resources and breakthrough technologies. The major components of the Plan include: 1) Existing Supply-Side Resources, 2) New Supply-Side Resources, 3) Transmission System Planning and 4) Grid Edge and Customer Programs. In addition, at the end of this Chapter, the Companies have provided information and a proposed timeline on the potential merger of DEC and DEP utility operations.

Many of these actions are interdependent on one another to achieve the planning objectives of complying with applicable laws and regulations, while maintaining or improving upon the reliability of the system, increasing power supply diversity, reducing emissions, and balancing the costs and risks of an orderly energy transition and industry exit from coal. Therefore, the activities in this Execution Plan should be viewed as a complete plan that work together in concert to facilitate a risk-balanced and orderly transition of the Companies' systems to meet the challenges described in Chapter 1 (Planning for a Changing Energy Landscape). Finally, in addition to the identified activities outlined in this Chapter, the Companies continually evaluate emerging opportunities to pursue prudent incremental supply-side and Grid Edge projects that can meet growing customer needs while conforming with planning objectives outlined in Chapter 2 (Methodology and Key Assumptions) and Chapter 3 (Portfolios).

Execution Planning Horizons and Navigating Uncertainty

To organize the Companies' execution activities, the Planning Period has been divided into three temporal execution and planning periods: near-term, intermediate-term and long-term, as defined

[1] The Companies first presented the concept of an Execution Plan in the 2022 proposed Carbon Plan, and both near-term action planning as well as identifying resources for selection by the North Carolina Utilities Commission ("NCUC") are now required by Proposed Rule R8-60A(C). This is the Companies' first opportunity to present the more detailed Execution Plan to the Public Service Commission of South Carolina ("PSCSC", together with NCUC ("Commissions")).

[2] As explained in Chapter 2 (Methodology and Key Assumptions), the 15-year base resource planning period meets North Carolina and South Carolina long-term planning requirements.

below. This Chapter identifies activities in the near term and intermediate term. Long-term actions are outlined in the specific resource appendices.

Near-Term Actions are the measures required in the 2023 to 2026 timeframe to enable the immediate development, procurement and integration of resources identified as needed and in the best interest of customers. The Companies view these near-term actions as prudent and necessary to advance the energy transition.

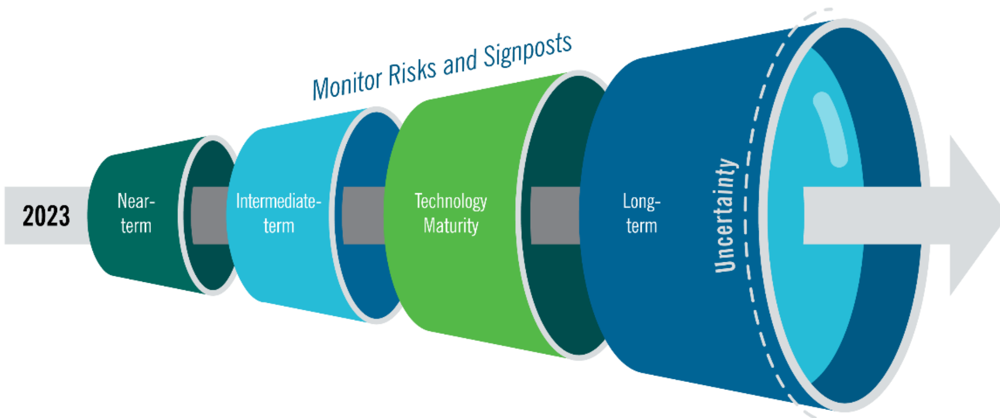
Intermediate-Term Actions are activities between 2027 and 2032 that are likely needed to further advance an orderly energy transition, considering relevant lead times such as regulatory, permitting, or construction activities.

Long-Term Planning occurs in 2033 and beyond, involving high-level qualitative project planning and sign-post monitoring to ensure the Companies remain on the least-cost path to providing affordable, reliable and increasingly clean electricity to the Carolinas. Long-term Planning recognizes that there will be intervening, iterative planning cycles and regulatory proceedings to ensure the Companies remain on track during the energy transition.

Navigating Uncertainty

The Carolinas Resource Plan requires the Companies to implement substantial near-term actions while monitoring risks and signposts across all planning horizons. While the long-term planning and modeling processes can assess many of these risks and signposts to make informed planning decisions, such modeling presents a resource planning "snapshot in time" and relies on numerous assumptions that become increasingly difficult to predict out into future years as the band of uncertainty widens regarding technology, cost, policy, consumer trends and economic conditions. Proactive risk and signpost monitoring will provide key information that will be used to navigate uncertainty by checking and adjusting future plans, as illustrated in Figure 4-1 below and described later in this Chapter. Timeliness of regulatory actions and decisions will be particularly important to provide certainty related to the execution of short-term actions as the Companies advance important components of the energy transition.

Figure 4-1: Navigating Uncertainty Across Planning Horizons



Optimizing For Execution

The Carolinas Resource Plan is a long-term plan based on reasonable, but generic, planning unit quantities and annual dates for modeling purposes. As the Companies begin detailed development and siting for specific resources, there will be refinements and modifications to quantities and timing as the Companies optimize for execution considering a multitude of practical factors that are beyond the scope of the long-term planning process presented in the Plan. These quantity and timing adjustments could be based on pricing and economics, sourcing, technology specifications, supply chain availability (e.g., materials, labor), permitting timelines and other evolving factors. It should be expected that quantities and timing of resource execution activities may vary from the Plan's generic planning units and annual dates while the Companies seek to meet the intended resource needs recommended through long-term planning models.

Critical Execution Phase in the Energy Transition

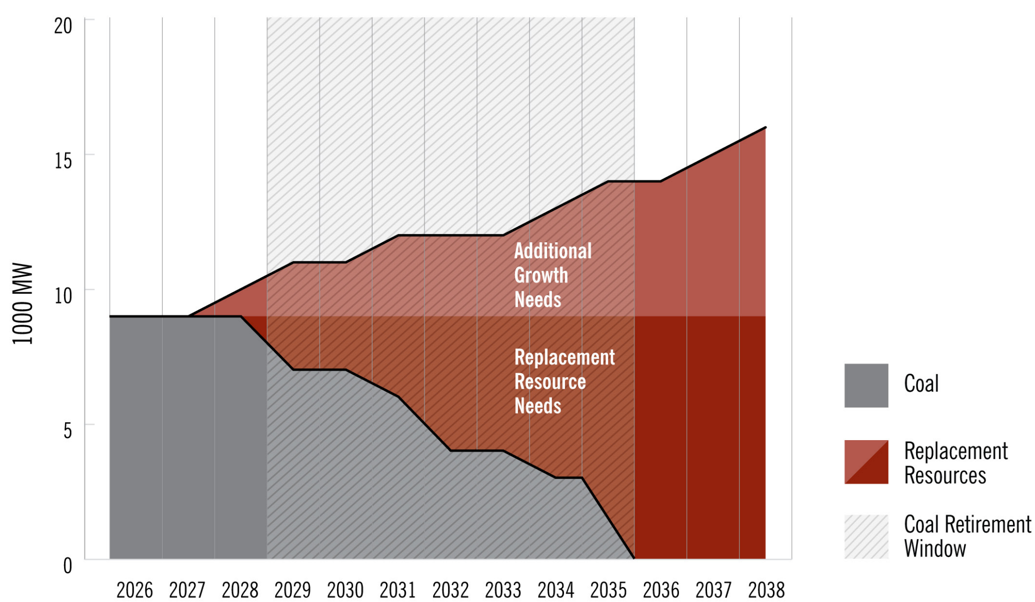
The Companies and other utilities across the country are developing plans for the energy transition that are designed to maintain reliability for customers in a changing energy landscape. The President and Chief Executive Officer of the North American Electric Reliability Corporation ("NERC") recently stated that the reliability risk profile for customers is increasing due to the "disorderly transformation of the generation resource base," performance issues with resources replacing conventional baseload generation, increased demand due to electrification, and extreme weather events.[3] Working with the Commissions and stakeholders in a collaborative, constructive and stable regulatory construct, the

[3] Testimony of North American Electric Reliability Corporation President and Chief Executive Officer James B. Robb before the United States Senate Committee on Energy and Natural Resources on June 1, 2023.

Companies are in a strong position to control the pace and composition of the energy transition to preserve reliability — thus ensuring an orderly energy transition for customers.

This next decade is a critical execution phase for the Companies' electric system. As coal units retire, a set of adequate and diverse replacement resources that are equally or more reliable must be developed and enter commercial operation in time to maintain or improve system reliability, shown below in Figure 4-2. This complex reality creates added emphasis on the Companies' current Execution Plans and requires taking decisive and reasonable steps in the near term that appropriately considers lead times for regulatory actions, siting and permitting, procurement and construction, fuel and transmission dependencies needed to retire coal capacity and implement the replacement resources and demand-side tools necessary to maintain reliability. These execution realities could potentially challenge meaningful progress in executing the energy transition, thereby amplifying risks related to the industry's exit from coal and to meeting growing energy demand while maintaining or improving reliability.

Figure 4- 2: Critical Execution Phase in the Energy Transition



Recent Progress Executing the Energy Transition

Over the past year, the Companies have made steady progress in advancing the energy transition, including issuing the Carolinas' largest-ever solar procurement and first-ever solar paired with storage ("SPS") procurement, developing new gas generation and battery storage at retiring coal unit sites and other strategic grid locations, working with other Transmission Providers and stakeholders on strategic and needed transmission expansion, evaluating the Carolinas' opportunity for both onshore and offshore wind, and advancing development of Bad Creek II and small modular reactor ("SMR") nuclear, among others. Table 4-1 below provides a summary status of activities taken by the Companies related to supply-side resources and transmission. In addition, the Companies have an active set of energy efficiency ("EE"), demand-side and customer program options in various stages of development. Figure 4-3 below further shows what actions are currently underway for demand-side activities and which regulatory dockets capture elements of their execution.

Supply-Side and Transmission Progress Update

Table 4-1 below summarizes at a high level the status of supply-side activities since resource plans were last updated.

Table 4-1: Supply-Side and Transmission Recent Developments

Activities	Recent Developments
Advance Subsequent License Renewals ("SLR") for existing Nuclear Units	Filed Oconee's SLR application and expect Nuclear Regulatory Commission ("NRC") approval in 2024. Preparing Robinson Unit 2 SLR application for submittal to NRC in 2025.
Launch Early Site Permit ("ESP") Activities	Pursuing advanced nuclear site options and preparing initial ESP for preferred Site 1. Evaluating reactor technologies.
Solar and SPS Procurements	2022 Solar Procurement completed procuring 964.7 MW, and seeking PSCSC approval of same.[4] 2023 Solar and SPS Request for Proposals ("RFP") issued August 2023 to procure 1,435 MW solar (approximately 700 MW of which would be paired with 260 MW battery storage).
Onshore Wind Stakeholder Engagement and Site Assessment	Completed initial onshore wind siting analysis. Completed initial stakeholder engagement with onshore wind developers, including market intelligence RFI — additional engagement is ongoing.
Offshore Wind Energy Areas ("WEA") Evaluation	Completed the Offshore Wind Energy Area comparative evaluation.
Red Zone Expansion Projects (RZEP)	All 14 RZEP 1.0 projects are underway — 13 projects planned to be in-service by end of 2026 with the final remaining project in service in 2027.
Gas Generation	Generator Replacement Requests ("GRRs") for DEP Person County (Roxboro) Combined Cycle ("CC") (1,360 MW) and DEC Marshall Combustion Turbines ("CTs") (900 MW) submitted in March 2023. Interconnection requests for additional capacity beyond GRR submitted in June 2023. The Companies plan to file pre-Certificate of Public Convenience and Necessity ("CPCN") applications with the North Carolina Utilities Commission ("NCUC") before year-end 2023. The Companies also intend to make informational filings with PSCSC.
Hydrogen	Submitted U.S. Department of Energy ("DOE") application for Southeast Regional Hydrogen Hub. Developing clean hydrogen studies and demonstration projects.

[4] See PSCSC Docket Nos. 2022-239-E & 2022-240-E.

Activities		Recent Developments
	Pumped Storage Hydro Development	Bad Creek II (1,680 MW) interconnection request progressing in DEC 2022 Definitive Interconnection System Impact Study ("DISIS") Process. RFP for major equipment issued.
	Battery Development	Interconnection Requests for 800 MW of standalone storage projects entered 2022 (300 MW) and 2023 (500 MW) DISIS Process.

Grid Edge and Customer Programs Recent Progress Update

Figure 4-3 below summarizes the status of in-flight and proposed regulatory actions associated with Grid Edge and other demand-side activities. The exploration of additional demand response options and expansion of the customer pool are areas under strategic development. Additional details on demand-side activities can be found in Appendix H (Grid Edge and Customer Programs).

Figure 4-3: Grid Edge and Customer Programs Activities Status Update

Grid Edge and Customer Programs Short Term Action Plan

ACTION / DOCKET	NC NOTES	SC NOTES
"As Found" Savings	Duke Energy filed The Smart Saver Early Replacement and Retrofit Program in Dockets E-7 Sub 1278 and E-2 Sub 1308 on 9/27/2022	Filed in SC in Docket 2013-298-E for DEC and 2016-149-E for DEP on 4/26/2023
Tariff on Bill Repayment	Duke Energy filed Tariffed On-Bill Program Tariff in Dockets E-7 Sub 1279 and E-2 Sub 1309 on 9/28/2022	Duke Energy is currently developing a pilot program for DEP, in collaboration with stakeholders, to test on-bill repayment of energy efficiency upgrades and has committed to filing for approval before 12/31/23
Smart Saver Solar EE Program	On 3/23/2023, the NCUC denied Duke Energy's application in Dockets E-7 Sub 1261 and E-2 Sub 1261. The NCUC ordered creation and filing of solar plus storage pilot to be recovered through NC REPS. Duke Energy filed PowerPair℠ Program consistent with NCUC Order on June 21, 2023 in Docket Nos. E-2 Sub 1287 and E-7, Sub 1261.	On 4/3/2022, the PSCSC denied Duke Energy's application in Docket Nos. 2021-143-E and 2021-144-E.
Initiation of Review of EE/DSM Cost Recovery Mechanism *"As Found" Savings* *Updating Utility System Benefit Valuation Accelerated Pilot Process* *Expansion of Low-Income Program Eligibility*	On 4/27/23, Duke Energy filed a letter in Dockets E-7 Sub 1032 and E-2 Sub 931 to initiate a review of the EE/DSM Cost Recovery Mechanism. Duke Energy has shared its proposed modifications intended to address each of the targeted areas with stakeholders, and a stakeholder meeting on the proposed modifications was held June 30, 2023. Internal work has been done to develop a new method to determine the inputs for the system benefits	Potential future changes being reviewed with EE Collaborative, and Duke Energy will review the need to revisit the Mechanism in the future.
Low Income Program Expansion	On 3/1/23, the NCUC approved the DEC Income Qualified High Energy Usage Pilot in Docket E-7 Sub 1272 and the DEP Weatherization Program in Docket E-2 Sub 1299	DEP Weatherization was approved in Docket No. 2022-266-E. Duke Energy is currently developing an Income Qualified High Energy Use Pilot in DEP and has committed to filing the pilot for approval before 12/31/2023 per settlement in Docket No. 2022-254-E.
Additional Demand Response Option	Evaluating heat strip, duel-fuel heating, water heater and storage options as well as more effective targeting/marketing to low-income customers	Evaluating heat strip, duel-fuel heating, water heater and storage options as well as more effective targeting/marketing to low-income customers

Filed *Approved* *Strategy Under Development* *Denied*

Overview of Near-Term Actions

The Companies identified near-term execution actions that are generally consistent with recommended Core Portfolio P3 Base, with resource additions and interim actions deemed reasonable steps to advance the energy transition. The Companies organized these activities into near-term action plans ("NTAP"), which are summarized in Table 4-2 below and broken out by technology in the detailed Execution Plans section of this Chapter. The Companies then developed these plans to highlight execution activities for the Commissions' consideration. The accelerated time frame to deliver new resources underscores the importance of the Commissions' support for near-term activities in the Carolinas Resource Plan and related constructive stakeholder and regulatory actions to advance Execution Plan components.

Optimizing Existing Supply-Side Resources

All portfolios require retiring coal units, expanding the flexibility of existing gas units, and advancing SLRs and power uprates ("PURs") for existing nuclear generation units that today provide over 10,000 MW of zero-carbon, cost-competitive capacity to support the energy transition to enable coal unit retirements that are dependent upon equally reliable replacement capacity that maintains or improves system reliability.

New Supply-Side Resources

Transitioning the fleet while maintaining or improving system reliability and keeping cost increases reasonable will require a blend of many different resource types, even expanding beyond the Companies' current fleet. The Companies expect significant growth of new natural gas, solar, SPS, and standalone storage with increasing durations. Wind energy is new to the Carolinas but is a valuable system resource that complements solar energy profiles, as further addressed in Appendix I (Renewables and Energy Storage). The Companies have long been leaders in successful nuclear operations, with the first nuclear plant beginning commercial operation more than 50 years ago in 1971. The Companies' 11 reactors have operated for 24 consecutive years with a greater than 90% capacity factor, a testament to their reliability. The Companies believe that advanced nuclear will be critical to providing reliable, long-term, clean energy in the Carolinas. Similar to its nuclear success, the Companies have over four decades of experience with pumped storage hydro, making the Companies well-positioned to double the hourly output of the Bad Creek facility. Duke Energy also has extensive experience developing new gas turbine assets at brownfield sites to facilitate coal retirements while ensuring adequate dispatchable capacity. With the increasing potential for future hydrogen use, the Companies have included new gas assets in the Resource Plan that will have capabilities to cofire hydrogen. (See Table K-1 in Appendix K (Natural Gas, Low-Carbon Fuels and Hydrogen)).

Importantly, many of these actions are interdependent of one another to comply with laws and regulations while maintaining or improving the adequacy and reliability of the system. For example, coal facilities cannot be retired independent of the timely in-service of adequate replacement capacity, along with any needed upgrades to the transmission system to ensure bulk power system reliability is maintained. Though near-term Execution Plan activities can be organized in independent categories, many are interrelated to fully achieve Plan targets and objectives. Finally, the Carolinas Resource Plan is a long-term plan, so the dates and quantities in the portfolios should be considered directional and not exact. The specific resources (technology, design, capacity) to be developed and optimal in-service dates will be refined through the development and siting processes as Plan components are executed, considering a multitude of practical factors that are beyond the scope of the long-term planning process presented in the Plan. As more information is gathered through execution, the Companies will keep the Commissions apprised of material developments through Carolinas Resource Plan updates, as well as through seeking resource-specific regulatory processes or approvals (e.g., a CPCN proceeding).

Table 4-2 below presents a consolidated view of new supply-side resources and near-term actions that are either under development today or planned to be developed in the near-term period through 2026. This “NTAP Table” presents targeted capacity amounts for development and procurement on or just prior to the in-service capacity years on a beginning of year (“BOY”) basis identified as needed in the Companies’ recommended Core Portfolio P3 Base. The NTAP Table then identifies activities targeted for completion in 2023 as well as ongoing development and procurement activities over the near-term period (2024–2026).

As discussed earlier, generic unit quantities and annual dates used for long-term planning purposes to develop resource needs are optimized for execution considering many practical factors, while continuing to align with the intended overall resource needs defined in planning. Importantly, the capacity amounts presented in the NTAP Table represent installed capacity additions and certain resource types (i.e., solar, battery energy storage, onshore wind) that require initial development activities in excess of the levels identified or on an accelerated schedule to ensure timely execution and commercial operation of needed new capacity resources amounts considering attrition through the development phases.

Table 4-2: Supply-Side Near-Term Actions Plan 2023 to 2026

Resource	Proposed MW Amount, In-Service BOY		Activities Targeted for Completion Through 2023	Proposed Near-Term Actions 2024–2026
Solar	6,000	2031	- 2022 Solar Procurement achieved 964.7 MW of new solar[1] - The in-flight 2023 procurement targeting 1,435 MW[1] of new solar (700 MW of which will be paired with 260 MW of storage).	- Continue RZEP 1.0 projects and advance RZEP 2.0 projects.[2] - 2024: Procurement targeting 1,435 MW of solar and SPS (approximate 2028 in-service date). - 2025 and 2026: Procurements targeting approximately 2,700 MW to 3,150 MW of solar and dependent on RZEP 2.0 (approximate 2029-2030 in-service date).
Battery Storage[3]	2,700	2031	- Progressing development and interconnection of 1,000 MW[4] of stand-alone battery storage. - 2023 Solar RFP targeting 260 MW SPS.	- 2024 to 2026: Develop and study additional 650 MW stand-alone battery storage. - 2024 to 2026: Target procurement of 790 MW of SPS.
Onshore Wind	1,200	2033	- Carolinas site screening evaluation.	- Select development partner(s), perform site feasibility studies and begin activities associated with siting development for 300, 450 and 450 MW per year (for 1/2031, 1/2032 and 1/2033 in-service, respectively) of onshore wind projects.[5] - Submit interconnection requests into 2025-2026 DISIS interconnection clusters.
CT[6]	1,700	2032	- Interconnection request, pre-CPCN for 2 CTs totaling 900 MW and identify sites and progress planning for additional CT capacity.	- 2024: File CPCN for 2 Marshall Advanced CTs at 900 MW (BOY 2029 in-service), submit air permits, begin transmission build-out engineering/modifications - 2024: Evaluate siting options and submit Interconnection Study requests for 425 MW CT (BOY 2030 in-service) - 2025: File CPCN for 425 MW CT (BOY 2030 in-service) - 2026: Submit interconnection requests/GRR and CPCN for replacement 425 MW CT (BOY 2032 in-service)
CC[6]	4,080	2031	- Interconnection request, pre-CPCN for 1 CC totaling 1,360 MW. - Execute gas contracts for fuel supply. - Identify sites and progress planning for 2 additional CCs.	- 2024: File CPCN for Person County Advanced CC1 at 1,360 MW (BOY 2029 in-service), submit air permits, begin transmission build-out engineering/ modifications. - 2024: Evaluate siting options and submit Interconnection Requests for 2 additional CCs (1,360 MW each; BOY 2030 & 2031 in-service). - 2025: File CPCNs for 2 CCs (1,360 MW each; BOY 2030 & 2031 in-service).

Resource	Proposed MW Amount, In-Service BOY		Activities Targeted for Completion Through 2023	Proposed Near-Term Actions 2024–2026
Pumped Storage Hydro	1,700	2034[7]	- Entered 2022 interconnection queue. - Issued RFP for major equipment. - Prepared initial construction estimates. - Continued FERC license activities.	- 2024: Sign Interconnection Agreement and begin transmission work, file SC Certificate of Environmental Compatibility and Public Convenience and Necessity ("CECPCN"), design major equipment. - 2025 and 2026: File NC Out of State CPCN, file final FERC application, prepare for construction.
Advanced Nuclear	600	2035	- Evaluating advanced nuclear reactor technologies. - Developing Early Site Permit ("ESP") for Site 1.	- Site 1 – 2023 to 2026: Choose reactor technology, submit ESP, develop construction permit/license application, contract with reactor vendor, and order long-lead equipment. - Site 2 – 2025 to 2026: Develop and submit ESP, begin construction permit/license application.
Offshore Wind	Evaluate potential resource need in Base Planning Period (2033 or later)		- Evaluated 3 WEAs off North Carolina coast. - Submit WEA evaluations. - Partnered with NC State Energy Office for submittal of Infrastructure Investment and Jobs Act ("IIJA") funding application for offshore wind-enabling transmission.	- Continue partnership with NC State Energy Office to pursue IIJA funding. - Actively monitor United States market and supply chain development to inform optionality. - Continue to evaluate potential earlier resource need (0 to 1,600 MW) and make recommendation on offshore wind RFP in 2025 or sooner based on the market conditions and need.

Note 1 : 2022 Solar Procurement quantity includes added MW from earlier competitive procurement of renewable energy ("CPRE") procurements that were unawarded as of Q3 2022. 2023 Solar Procurement target includes some added volumes for terminated CPRE contracts and for 2022 Solar Procurement selected winners that declined to execute contracts.

Note 2 : RZEP 2.0 projects subject to local transmission planning process requirements. See Appendix L (Transmission System Planning and Grid Transformation).

Note 3 : Total Battery Storage amount includes a combination of stand-alone battery development and SPS amounts. Some amount of attrition is expected in development process. Annual target quantities, timing of in-service and ratio of stand-alone and SPS may be adjusted during development process.

Note 4 : Includes stand-alone storage resources currently in advanced development.

Note 5 : In order to achieve the target placed in service capacities of 300, 450, 450 MW, a multiple of each year's target capacity will need to be sited and initial development executed. Not all sited projects are expected to be built; some projects may be terminated due to interconnection costs, permitting issues, Federal Aviation Administration ("FAA") or military conflicts, etc. As such, the Companies would seek to site three to four times the targeted capacity.

Note 6 : The exact amounts, models, and configurations of gas-fired generation (e.g., simple cycle versus CC) chosen for Plan execution will depend on the specific needs of the system at the time of development — optimizing for multiple factors including but not limited to cost, efficiency, supplier specifications, site parameters and fuel supply. This may also include adjustments to new CT or CC project activity timing for optimization and assurance of timely commercial operation, particularly as it relates to enabling coal unit retirements.

Note 7 : Bad Creek II Pumped Storage Hydro is projected to come into service by mid-2033; for planning purposes, the modeling reflects this resource coming into all resource portfolios at beginning of year 2034.

Transmission System Planning and Grid Transformation

Critical enabling transmission assumptions are integrated into this Plan to facilitate the supply-side additions presented in the Near-Term Actions Plan. Further details on transmission execution planning are presented below in the detailed Execution Plan section and Appendix L (Transmission System Planning and Grid Transformation).

Grid Edge and Customer Programs

Grid Edge and customer programs will continue to advance EE and demand-side options that allow for overall demand reduction and demand optimization, ramping up forecasted contributions growth rate through the 15-year Base Planning Period (see details in Chapter 2) — helping to shrink the overall challenge of the energy transition. Details on those activities that occur through other stakeholder and regulatory proceedings are found in Appendix H.

Merger of DEC and DEP

The Companies plan to initiate regulatory proceedings in the near term to merge DEC and DEP, which will consolidate the Companies' system operations functions, to facilitate a more cost-effective and efficient energy transition for customers. Additional detail for the merger of DEC and DEP can be found later in this Chapter.

Detailed Execution Plans: Existing Supply-Side Resources

The detailed Execution Plans in this section outline the critical and reasonable steps needed in the near term to move the energy transition forward in an orderly way and also identifies further actions required over the intermediate term to advance longer lead-time resources and breakthrough technologies, such as SMRs, that are planned to achieve commercial operation in the mid-2030s.

The location of future solar, onshore wind, SPS and even advanced nuclear assets (whether DEC or DEP) will be heavily dependent on future evaluation criteria, bids, ability to permit and other factors not yet fully known. Therefore, the tables below are combined DEC and DEP, noting that locations will be refined through the execution phase.

Retiring Existing Coal

Planning for Coal Unit Retirements in the Generation Transition

Reducing risk for customers through an orderly energy transition requires careful planning and diligent, yet flexible, execution of continued retirement of the Companies' remaining coal units across North Carolina, which have provided reliable service to the Companies' customers in both states for decades. As discussed in Chapter 3, all portfolios result in a full exit from coal-fueled generation by 2035 (retiring over 8,400 MW of coal capacity). Executing on these coal unit retirements must be coordinated with the development of replacement resources, their fuel supply, where applicable, and transmission system improvements to maintain resource adequacy and reliability for customers. The Companies will also actively evaluate opportunities to repurpose infrastructure and add new replacement generation and energy storage resources at retiring coal sites, where cost-effective to do so.

In the near-term, existing Allen 1 & 5 coal units are planned to retire by December 31, 2024 pending internal approvals. To preserve system stability, it is paramount that the Companies have adequate dispatchable generation in place prior to coal retirements to ensure system capacity and reliability. Lincoln Unit 17, the first advanced class CT with a capacity exceeding 400 MW, will become a Company asset on January 1, 2024 pending NCUC approval of DEC's request to amend its existing CPCN for the unit.

In the near term, the Companies will continue to plan their intermediate- and longer-term coal unit retirement strategy, including performing necessary transmission evaluations, as outlined in Appendix L, to identify any necessary system improvements that are needed to allow coal unit retirements while ensuring bulk power system reliability is maintained. The Companies will also continue to monitor the changing economics of coal including coal supply and transportation constraints, the evolving impacts on coal unit commitment and dispatch resulting from these constraints, impacts of increased policies and regulations and the implications for the Companies' coal facilities as detailed in Appendix F (Coal Retirement Analysis).

Table 4-3 below describes the Companies' near-term and intermediate-term Execution Plan for coal retirements. Additional information on how coal retirements were evaluated in Plan modelling is provided in Appendix C (Quantitative Analysis) and Appendix F. Dates are generally aligned with recommended Core Portfolio P3 Base and it should be noted that most retirement dates are dependent upon successfully executing replacement generation plans. Therefore, it should be expected that retirement dates may be adjusted to optimize execution planning (construction synergies, GRR use, gas capacities, transmission timing, etc.).

Table 4-3: Execution Plan – Coal Retirements

Near-Term Actions (2023–2026)	
2024	• Retire Allen 1 & 5 units by December 31, 2024 assuming approvals gained and permission granted to take care, custody, and control of Lincoln 17 on January 1, 2024.
Intermediate-Term Actions (2027–2032)	
2028–2029	• Retire Roxboro Units 1 & 2 and Marshall 1 & 2 after their respective in-flight hydrogen-enabled natural gas assets are placed in-service at existing sites.
2031	• Approximate BOY time frame for Cliffside 5 retirement pending equally reliable replacement resources exist to allow retirements.
2031	• Approximate BOY time frame for Mayo retirement pending equally reliable replacement resources exist to allow retirements.
2032	• Approximate BOY time frame for Marshall 3 & 4 retirements pending equally reliable replacement resources exist to allow retirements.

Expanding Flexibility of the Existing Gas Fleet

As coal units are retired and the integration of renewable resources increases, the flexibility of dispatchable gas-fired resources is essential for maintaining system reliability in a least-cost manner. Today, the Companies' gas-fired generation fleet consists of 55 CTs, nine CC units, and one combined heat and power ("CHP") unit, having a combined total capacity of 11,891 MW. To increase the flexibility of the existing gas-fired fleet, the Companies will need to equip a number of its CC/CT stations to support more flexible operational capabilities, such as lower load operations, increased ramp rates, and the ability to cycle more often to respond to increased variability in the output of renewable resources. In fact, flexibility/uprate projects are currently being engineered for two existing CCs: H.F. Lee and Smith Power Block 4.

In the near and intermediate terms, the Companies will complete the planning phase and implement gas unit control upgrades and equipment changes, which will require regulatory approvals for operational and air permit changes. In addition to increased flexibility, the proposed projects also provide limited additional dispatchable capacities. See Table K-2 in Appendix K for details.

Table 4-4 below outlines the Companies' near-term and intermediate-term Execution Plan to increase the flexibility of the existing gas fleet, and additional information on the existing CC fleet is provided in Appendix K.

Table 4-4: Execution Plan – Existing Gas Fleet

Near-Term Actions (2023–2026)	
2023–2026	• Ensure long-term fuel security for existing CC fleet. • Implement unit flexibility/uprate projects on four existing CCs (H.F. Lee, Smith PB4, Sutton & W.S. Lee). Work includes engineering, air permit revisions, DISIS submittals and execution.
Intermediate-Term Actions (2027–2032)	
2024–2028	• Implement unit flexibility/uprate projects on three existing CCs (Buck, Dan River, Smith PB5). Work includes engineering, air permit revisions, DISIS submittals and execution.

Extending the Life of Existing Nuclear Fleet

Extending the life of the Companies' existing nuclear fleet is a bedrock assumption for the Plan, providing for the continuation of a major source of reliable, zero-carbon, cost-competitive power. Accomplishing this important objective requires federal regulatory approval of 20-year SLRs for the 11 existing nuclear generation units operating at six nuclear stations across the Carolinas, totaling 10,773 MW of generation. The current operating licenses will begin to expire in the 2030s, and the regulatory process may take up to four years per SLR application. The NRC accepted the Companies' first SLR application (Oconee) for review in mid-2021 and is currently in the process of requesting additional information to support its review. The Companies plan to develop and submit an SLR application for each nuclear station, with the remaining submittals tentatively planned for 2025, 2027, 2030, 2031 and 2035.

In addition to extending the operating licenses at each site, Duke Energy continues to optimize the use of PURs where cost-effective to improve or maintain system operability and reliability. A Measurement Uncertainty Recapture ("MUR") project allows more accurate measurements of parameters in the plant resulting in additional incremental power output. MUR Uprates to the Oconee Nuclear Station are currently underway and will result in an additional 15 MW per unit when completed in 2024. Several of the Companies' nuclear facilities (Harris, Robinson and Brunswick) have already been uprated while the remaining facilities (Oconee, McGuire and Catawba) are currently being evaluated for major PURs to increase their power output. These evaluations investigated required component replacements, cost and timing of the potential projects. Based on current evaluations, PURs for McGuire Units 1 and 2 and Catawba Unit 1 are feasible to move forward at this time. The Brunswick Nuclear Plant is also pursuing an increased power output for both units by implementing an MUR project.

In addition to the PUR and MUR projects, projects are being planned at the five reactors at Catawba, Harris and McGuire to extend their fuel cycle lengths from 18 months to 24 months ("24-month fuel cycles or 24MFC"). This work has already been completed for the Brunswick, Oconee and Robinson units. Extension of fuel cycle length reduces the number of refueling outage days and therefore increases capacity factor and total MWhs over the remaining life of the plant.

Table 4-5 below outlines the Companies' near-term and intermediate-term Execution Plan to extend the life of the existing nuclear fleet, and additional information is provided in Appendix J (Nuclear). Pursuing SLRs, PUR, MUR and 24MFC projects will allow Duke Energy's existing nuclear fleet to continue to provide clean, carbon-free baseload power to the Carolinas, at the optimal power output, well into mid-century.

Table 4-5: Execution Plan – Existing Nuclear

Near-Term Actions (2023–2026)	
2023–2025	• Prepare the SLR application for the Robinson Nuclear Plant.
2025	• Submit the SLR application for the Robinson Nuclear Plant.
2024–2027	• Prepare the SLR application for the Brunswick Nuclear Plant.
2023–2026	• Develop 24MFC design change packages and license submittals for Catawba and McGuire. • Develop PUR/MUR balance of plant ("BOP") design change packages. • Develop PUR/MUR license submittals.
Intermediate-Term Actions (2027–2032)	
2027	• Submit the SLR application for the Brunswick Nuclear Plant.
2028–2030	• Prepare the SLR application for the McGuire Nuclear Station.
2030	• Submit the SLR application for the McGuire Nuclear Station.
2029–2032	• Prepare the SLR application for the Catawba Nuclear Station.
2031	• Submit the SLR application for the Catawba Nuclear Station.
2027–2028	• Continue development of PUR/MUR BOP design change packages. • Submit PUR/MUR license submittals.
2027–2030	• Conduct PUR major equipment purchases. • Develop 24MFC design change packages and license submittal for Harris. • Submit 24MFC license submittals.
2027–2032	• Perform PUR/MUR implementation of BOP modifications. • Implement 24MFC (all implemented by 2031).
2032	• All PURs fully implemented.

Detailed Execution Plans: New Supply-Side Resources

The identifies the need for a diverse portfolio of generating assets across all portfolios. This section addresses the actions that the Companies intend to commence immediately in the near term and to continue over the intermediate term relating to the development and procurement of new supply-side resources. Note that each of the resources has an associated Appendix that provides further technical background regarding the resource.[5]

Supply-Side Asset Development, Acquisition and Procurement Approach

Execution of the Carolinas Resource Plan will include a range of procurement methods. Foundational to the procurement activities outlined below is the need to preserve customer value by pursuing the most reasonable, least cost solution across each procurement action the Companies undertake. Specific avenues of procurement include utility self-development, asset acquisitions and, for solar and SPS, solicitations for controllable power purchase agreements. In all cases, the information gained through the procurement process will be used to inform and refine future Carolinas Resource Plan analyses and filings. This iterative process involving subsequent procurement efforts and their associated regulatory proceedings informing future Plan updates will provide the Commissions and the Companies with opportunities to adjust the pace and volumes of procurement activities in response to changing market conditions relative to planning assumptions at any given point in time.

Self-Development

In some cases, the Companies anticipate leveraging utility self-development for projects that are location-specific and for long lead-time resources that the Companies have evaluated for the best combination of siting, fuels, transmission and timing to meet customers' future needs. Self-development will leverage the Companies' existing property, station workforce, electric and/or gas transmission, access to water, permits, etc. to the benefit of customers. For self-developed projects, the Companies will be responsible for project siting and development, managing permitting as well as obtaining engineering, procurement and construction ("EPC") services. The Companies have substantial self-development experience with internal processes to competitively bid major equipment and EPC services to ensure the best value for customers considering project-specific costs and risks. The Companies may also pursue joint development projects in which a third-party development partner shares in the responsibility for project siting, development, permitting and engineering, but the Companies will have responsibility for procurement and construction activities. The Companies would also competitively bid construction services for joint development projects.

Asset Acquisition

The Execution Plan anticipates the potential for acquisition of resources from third-party developers and potentially existing asset owners. Asset acquisitions can be accomplished through procurements

[5] See Appendix I (Renewables and Energy Storage), Appendix J (Nuclear), Appendix K (Natural Gas, Low-Carbon Fuels and Hydrogen) for additional information.

or bilateral negotiations and are generally utilized when there is flexibility as to where the assets are located and the market for development is more mature. Specific types of acquisitions for new assets include asset transfers, asset transfers plus EPC services, Build-Transfers and acquisition of operating assets. Details of each type of acquisition are further detailed below:

Asset Transfer: A third-party developer proposes to sell a fully developed project and is responsible for, but not limited to, project siting, land control, development, site investigation, surveying, title work, permitting, limited engineering and all interconnection studies. The developer assigns or transfers all assets, rights, etc. to the Company upon satisfaction of all development and closing conditions, which generally occurs prior to the start of construction. The utility is responsible for final EPC of the facility.

Asset Transfer Plus EPC: A third-party developer proposes to sell a fully developed project and is responsible for, but not limited to, project siting, land control, development, site investigation, surveying, title work, permitting, engineering, all interconnection studies and all procurement and construction of the facility pursuant to an EPC Agreement. The developer and utility enter into an agreement in which the developed project assigns or transfers all assets, rights, etc. to the utility upon satisfaction of all development and closing conditions, which generally occurs prior to the start of construction. The parties also enter into an EPC Agreement in which the developer is responsible for final EPC of the facility.

Build-Transfer: A third-party developer proposes to sell a fully developed and constructed turn-key facility. The developer is responsible for all project development activities, including but not limited to, project siting, land control, development, site investigation, surveying, title work, permitting, engineering and all interconnection studies. The developer and utility enter into a Build-Transfer Agreement ("BTA") in which the developer is responsible for all development scope, EPC of the facility. The facility is assigned to the utility at BTA closing, which is generally between mechanical completion and placed in-service milestones.

Acquisition of current operating facilities: A third-party asset owner agrees to sell an existing facility already constructed and in operation by the facility owner to the utility.

Solar and Solar Paired with Storage Procurements for Controllable Purchased Power Agreements

The Companies will continue to leverage established and evolving competitive procurement processes to secure a reasonable balance of controllable Purchased Power Agreements ("PPAs") from third-party owners of solar and SPS resources. The Companies support a balanced approach to the competitive procurement of solar and SPS resources as prudent and in the best interest of customers in both states and have developed robust experience with procuring new third-party-owned controllable solar resources. That balanced approach is consistent with North Carolina law requiring that 45% of new solar generation selected by the NCUC as part of the Carolinas Resource Plan be owned by third parties and delivered to the Companies under controllable PPAs.[6] The Companies

[6] N.C.G.S. § 62-110.9(2)b.

recently completed the 2022 Solar Procurement[7] as well as received approval for the Resource Solicitation Cluster to be used for the 2023 Solar and SPS RFP ("2023 Solar RFP"). Specific procurement actions including the anticipated development method are discussed in further detail in their respective resource subsections that follow.

Procurement/Development Execution Approach by Resource

To procure the diverse set of resources outlined in the Carolinas Resource Plan while pursuing the most reasonable, least cost resources for customers, the Companies have tailored their near-term approach based on the resource type. Table 4-6 below summarizes the procurement/development strategy for each resource outlined in this Execution Plan.

Table 4-6: Procurement / Development Execution Approach by Resource

Resource	Procurement / Development Approach
Gas	Self-development with competitive bidding of major equipment and EPC services as appropriate.
Solar	The Companies intend to leverage established dual-state and evolving competitive procurement processes to self-develop projects, acquire solar and SPS resources and contract for solar and SPS resources under controllable PPAs with third-party owners.
Advanced Nuclear	The Companies will choose a vendor based on the selected technology and will negotiate a contract for long-lead items. Sites 1 and 2 are planned to be identical technology.
Onshore Wind	Self-development and/or strategic partnerships with onshore wind developers.
Offshore Wind	The Companies would seek NCUC and PSCSC directives prior to any procurement activities. A procurement plan would be developed based on the selected portfolio (timing, size, commercial arrangement, WEA, etc.).
Pumped Hydro Storage	Self-development with competitive bidding of major equipment and EPC services as appropriate.
Energy Storage	Self-development for stand-alone battery storage. SPS procured in conjunction with solar RFPs.

[7] Detailed information on the results of the 2022 Solar Procurement is available in the RFP Post-Solicitation Report filed July 31, 2023, in NCUC Docket Nos. E-2, Sub 1297 and E-7, Sub 1268, and will also be filed in PSCSC Docket Nos. 2022-239-E and 2022-240-E.

Significantly Expanding Utility-Scale Solar

The addition of controllable solar capacity is a key component of the Companies' NTAP and longer-term recommended P3 Base portfolio. In total, the Companies are planning to add 6,000 MW of new incremental solar resources to their systems by 2031 and over 14,000 MW by the end of the Base Planning Period in 2038.

The Companies have recently successfully completed the 2022 Solar Procurement, procuring approximately 965 MW of new solar resources and recently issued the 2023 Solar RFP with a target to procure 1,435 MW between DEC and DEP (targeting 735 MW of solar only and 700 MW of solar paired with 260 MW of storage, subject to volume adjustments based on price and market depth). The Companies are currently seeking a public interest determination of the 2022 Procurement framework and competitive bidding results from the PSCSC at the time of the filing of the Resource Plan, and the 2023 Procurement may be filed with the PSCSC at a future date.[8] These in-flight 2023 solar procurement resources are expected to come online in 2027 or beyond. Additional detail on the 2022 Solar Procurement and 2023 Solar RFP is further described in Appendix I. Future annual procurements for both solar and SPS resources are planned in 2024 and beyond to procure needed solar resources to be installed under moderately aggressive to extremely aggressive interconnection timelines that are dependent on the outcome of planned transmission investments, as well as on the timeliness and execution of developers, as further described in Appendix L. Table 4-7 below outlines the Companies' plan to significantly expand controllable utility scale solar in the Carolinas.

[8] See PSCSC Docket Nos. 2022-239-E & 2022-240-E.

Table 4-7: Execution Plan – Solar

Near-Term Actions (2023–2026)	
2023	• Executed 2022 Solar Procurement procuring 964.7 MW of controllable solar and awaiting PSCSC decision on public interest finding. • Issue and execute 2023 Solar RFP to procure next tranche of solar and SPS resources (1,435 MW targeted with volume adjustment mechanism up to 1,600 MW), which may require additional filings in SC. • Stakeholder engagement in preparation for 2024 Solar Procurement, as needed.
2024	• Establish 2024 Solar RFP Procurement schedule and target volume (Q1 2024). • Selection of and contracting with 2023 Solar RFP winners (Q2–Q3 2024). • Finalize and issue 2024 Solar RFP by Q3 2024.
2025–2026	• Issue additional dual state Solar Procurements, with targets based on IRP modeling results for solar coming online in 2029–2030.
Intermediate-Term Actions (2027–2032)	
2027–2030	• Issue subsequent solar procurement RFPs in alignment with then-approved resource plan.

Increasing System Flexibility and Maintaining Reliability with Energy Storage

Energy storage capacity in the Carolinas will play an increasingly critical role to provide dispatchable capacity and to help manage fluctuations in net load due to intermittent generation such as wind and solar and to match generation with fluctuating demand. The nature of energy storage allows energy to be injected back onto the grid when it is needed most to support system reliability.

Specific to expanding pumped storage hydro though a second powerhouse at Bad Creek, the Companies have issued an RFP for centerline equipment bids and the project continues to be studied in the 2022 DISIS process, which moved into Phase 3 study in June 2023. Table 4-8 below outlines the Companies' plan to advance pumped storage hydro in the near and intermediate terms toward commercial operation of the planned Bad Creek II project in 2033. Additional detail on pumped storage hydro can be found in Appendix I.

Table 4-8: Execution Plan – Pumped Storage Hydro

Near-Term Actions (2023–2026)	
2023	• Issued Major Equipment RFP. • Completed Third-Party Cost Estimate Review. • Release EPC RFP. • Determine EPC strategy for Bad Creek II.
2024	• Bad Creek Unit 4 Uprate completed (80 MW). • Sign Interconnection Agreement. • Begin DISIS cluster transmission work. • Major equipment design & model testing. • File for SC Certificate of Environmental Compatibility and Public Convenience and Necessity. • Major Equipment engineering design.
2025	• File for NC Out-of-State CPCN. • File Final Federal Energy Regulatory Commission ("FERC") Application.
2026	• Prep for construction.
Intermediate-Term Actions (2027–2032)	
2027	• Receive FERC License. • Order Major Equipment.
2027–2032	• Bad Creek II Construction.
2033	• Commission and place Bad Creek II in-service.

In addition to executing the Bad Creek I uprate and continuing planning and development for the new Bad Creek II Powerhouse project, the Companies are also planning and executing the deployment of grid-connected battery storage on the DEP and DEC systems in the near term. As further discussed in Appendix I, the Companies are taking prudent and reasonable steps to develop stand-alone battery storage resources and to procure batteries paired with new solar resources in the 2023 Solar RFP:

- progressing development of approximately 300 MW of stand-alone battery storage projects in the 2022 DISIS cluster;
- submission of an additional approximately 500 MW as part of the 2023 DISIS cluster;
- integration of the Companies' first transmission-connected battery in the Carolinas;

- execution of Duke Energy's first advance procurement agreements for supply-constrained and battery-specific components to support future development of stand-alone battery projects; and
- soliciting procurement of 240 MW of battery storage paired with new solar resources in the 2023 Solar RFP.

While there are various types of storage technologies that may be available in the future to support the Companies — in the near term — are executing on plans to integrate megawatt-scale electrochemical batteries through partnerships with diverse suppliers who provide the latest battery technology expertise and resources as further discussed in Appendix I.

The Companies believe that modeled results justify a need to procure an additional 2,400 MW of batteries (including the 300 MW assumed in all portfolios) for a total of 2,700 MW of battery energy storage resources in-service by BOY 2031. The Companies plan to develop standalone battery storage facilities through self-development with competitive procurement of EPC while continuing to procure SPS via solar RFPs. Similar to other project development activities, the Companies anticipate the need to perform preliminary development work of higher levels than these targets to account for potential project attrition.

Table 4-9 below outlines the Companies' plan to advance new battery energy storage. Additional detail on energy storage can be found in Appendix I.

Table 4-9: Execution Plan – Energy Storage

Near-Term Actions (2023–2026)	
2023–2026	• Test and study non-lithium and long duration technologies at the research and development scale. • Procure, construct and interconnect projects in advanced stages of development which are assumed in all modeled portfolios. • Continue development activities, including filing of interconnection requests and procurement of necessary long-lead equipment for stand-alone battery energy storage projects at strategic grid locations. • Finalize procurement strategy and initiate relevant procurement activities to support addition of 1,650 MW of standalone energy storage being placed in-service by beginning of 2031. • Finalize procurement strategy and initiate relevant procurement activities to support addition of 1,050 MW of battery energy storage that is paired with solar by beginning of 2031.

Intermediate-Term Actions (2027–2032)	
2027–2032	• Procure, construct and interconnect energy storage selected in Resource Plan. • Continue development activities, including filing of interconnection requests, for battery energy storage projects at strategic grid locations to allow for upward flexibility in future resource plans as well as preparation for projects to be connected beyond the 2032 intermediate-term time horizon

Planning for New Wind Energy Resources

Onshore Wind

The market for onshore wind generation is still new to the Carolinas, with no operational or under-development onshore wind facilities within the Companies' balancing authority areas. However, the Carolinas Resource Plan demonstrates that onshore wind development could be an important component of the Carolinas' energy transition and recommended Core Portfolio P3 Base identifies a system need for 1,200 MW of new onshore wind resources to be developed and placed into service by 2033. As further described in Appendix I, significant early-stage development activities are required in the near term to develop this amount of new resources in the Carolinas. Table 4-10 below outlines the Companies' efforts to advance the development of onshore wind in the Carolinas and plan for the development of up to 1,200 MW of new onshore wind capacity to be installed by 2033.

The Companies retained DNV Energy, an experienced consultant in wind energy project development, to support completion of an initial screening study, which indicates there are viable wind capacity areas in both South Carolina and North Carolina. The Companies continue to recommend pursuit of onshore wind development through partnerships with established developers. Robust stakeholder engagement will be essential to gauge the interest of customers and residents impacted by the siting of onshore wind projects. As further described in Appendix I, development of this new to the Carolinas resource will require significant early-stage siting, permitting and development work, and not all sited projects are expected to be built. Some project sites may be terminated due to interconnection costs, permitting issues, FAA or military conflicts, etc. In order to achieve the target onshore wind capacities identified below in Table 4-10, a multiple of three-to-four times each year's target capacity will need to be sited and initial development executed. Additional detail on onshore wind can be found in Appendix I.

Table 4-10: Execution Plan – Onshore Wind

Near-Term Actions (2023–2026)	
2023–2024	• Select and contract with strategic development partner(s); continue engagement with industry partners and local areas where siting could occur
2024–2026	• With a goal of 300 MW onshore wind placed in-service by BOY 2031 (Tranche 1), advance siting studies & activities, continue engagement, execute lease and/or easements agreements for targeted project sites, begin development/siting activities. Submit interconnection requests into 2025 DISIS cluster.
2025–2026	• With a goal of 450 MW onshore wind placed in-service by BOY 2032 (Tranche 2), advance siting studies & activities, execute lease and/or easement agreements for targeted project sites, begin development/siting activities. Submit interconnection requests into 2026 DISIS cluster.
2026	• With a goal of 450 MW onshore wind placed in-service by BOY 2033 (Tranche 3), advanced siting studies & activities, establish site control, begin development/siting activities. Submit interconnection requests into 2027 DISIS cluster.
Intermediate-Term Actions (2027–2032)	
2027–2030	• Advance development of Tranche 1 projects (interconnection studies & agreements, environmental studies, wind resource campaign, local/state/federal permitting). Begin procurement of equipment and EPC services.
2030	• Commission and place Tranche 1 projects in-service.
2027–2031	• Advance development of Tranche 2 projects (interconnection studies & agreements, environmental studies, wind resource campaign, local/state/federal permitting). Begin procurement of equipment and EPC services.
2031	• Commission and place Tranche 2 projects in-service.
2027–2032	• Advance development of Tranche 3 projects (interconnection studies & agreements, environmental studies, wind resource campaign, local/state/federal permitting). Begin procurement of equipment and EPC services.
2032	• Commission and place Tranche 3 projects in-service.

Offshore Wind

The offshore wind market is a new and developing industry in the United States with very few operational wind turbines. As further addressed in Appendix I, the Companies do not currently own offshore wind development assets, including a WEA lease, and as directed by the NCUC, have been evaluating potential resource availability in the Carolinas, timeline for achieving commercial operation, as well as the costs and risks of deploying offshore wind. As identified in the NTAP and addressed in the Executive Summary and Chapter NC (2023-2024 CPIRP Update), offshore wind was not selected in the Companies' recommended Core Portfolio P3 Base through the end of the Base Planning Period by 2038 (though needed for long-term carbon neutrality), and the Companies' near-term actions do not include obtaining a lease and proceeding with more significant initial development activities required to make offshore wind available in the Carolinas in the early 2030s. Table 4-11 below presents limited proposed near-term planning and development activities relating to continuing to explore the possibility of developing or procuring offshore wind resources in the Carolinas and maintaining future optionality.

Dependent upon market conditions and receipt of regulatory support from state regulators, the Companies will continue to evaluate the role of offshore wind in providing increasingly clean, diverse power to customers in the Carolinas. Onshore transmission projects that enable offshore wind optionality also support the integration of additional renewable resources such as solar and SPS and will continue to be evaluated in the near-term. As discussed in Appendix I, to competitively bid and execute 1,600 MW of offshore wind, the Companies would need supportive decisions by the NCUC and PSCSC by December 31, 2024 to pursue an offshore wind RFP in order to potentially achieve a 2033 in-service date. Future consideration of offshore wind in the next comprehensive resource plan filings with NCUC and PSCSC would likely result in an offshore wind development timeline that supports a 2035 or later in-service date.

Table 4-11: Execution Plan – Offshore Wind

Near-Term Actions (2023–2026)	
2023	• Submit findings of WEA comparative Analysis.
2024–2026	• Actively monitor United States market and supply chain development to inform optionality. • Re-evaluate need for offshore wind project in future resource plans. • Make recommendation on Offshore Wind RFP in next Carolinas Resource Plan filings with NCUC and PSCSC or sooner based on market conditions or need.
Intermediate-Term Actions (2027–2032)	
2027–2032	• Execute updated offshore wind-related actions based on guidance from Commissions in next resource plan proceedings

Advanced Nuclear Strategy

Table 4-12 below outlines the Companies' near-term actions to progress development of advanced nuclear resources in the Carolinas. The actions support the initial SMR in-service date for the first quarter 2034, and an in-service date in the first quarter 2035 for the first SMR unit at a second site. Subsequent units at each site are assumed to follow in 18-month intervals as determined to be needed in future resource plans. Additional details on advanced nuclear energy can be found in Appendix J.

Table 4-12: Execution Plan – Advanced Nuclear

Near-Term Actions (2023—2026)	
2023–2024	• Perform SMR technology assessment and due diligence review.
2023–2025	• Prepare an advanced nuclear ESP application for the Belews Creek site (SMR Site 1). • Choose an SMR technology for Belews Creek SMR site 1.
2025	• Submit ESP application for the Belews Creek site to the NRC.
2025–2026	• Develop ESP application for Site 2.
2025–2027	• Develop a construction permit application ("CPA") or combined construction & operating license application ("COLA") for SMR Site 1.
2026	• Submit ESP application for Site 2 to the NRC. • Enter contract with a reactor vendor of choice and order long-lead equipment for Site 1. • Begin CPA or COLA for Site 2.
Intermediate-Term Actions (2027–2032)	
2027–2030	• Develop Site 3 ESP application, if ESP path determined to be the necessary route.
2027	• Submit a CPA or COLA to the NRC for Site 1.
2028	• Submit a CPA or COLA to the NRC for Site 2.
2028-2030	• Submit a CPCN application for Site1 and a CPCN application for Site 2

Intermediate-Term Actions (2027–2032)	
2027–2032	• Enter contract with reactor vendor and order long-lead equipment for Sites 2-5; Advanced Reactors may be chosen beginning with Site 4. • Begin development of an ESP application for Site 4 and Site 5 if ESP path determined to be the necessary route. • Begin CPA or COLA for Sites 3–5. • Begin site preparations in accordance with the limited work authorization for Site 1, 2 and 3.
2030–2033	• Construction period for Site 1, Unit 1.
2031–2034	• Construction period for Site 2, Unit 1.
2032	• Commence construction period for Site 3.
2032–2034	• Construction period for Site 1, Unit 2.

Transitioning with Additional Dispatchable Natural Gas Resources

New dispatchable natural gas-fueled resources are needed under all Energy Transition Pathways and Portfolios to retire coal, reliably integrate renewables and maintain system reliability. The Companies' plan for dispatchable new hydrogen-capable natural gas resources, outlined in Table 4-13 below, presents an aggressive development timeline designed to enable the Companies to achieve commercial operation of additional natural gas resources by 2028, with additional CC and CT capacity planned for 2029 through the early 2030s. On January 1, 2024, Duke Energy will take ownership of the largest single CT as developed by Siemens at Lincoln station.

CPCN Applications are currently being finalized to leverage retired coal plant sites for new generation, and the Companies are working on a request for authorization to construct hydrogen-enabled gas assets in North Carolina (approximately 900 MW CTs at Marshall station located in Terrell, NC and 1,360 MW CC at Person County Energy complex located in Semora, NC) both of which were selected by the NCUC in the initial 2022 Carbon Plan,[9] and which are also consistent with past IRPs filed with the PSCSC. Additional detail on new natural gas capacity and its important role in the Companies' orderly energy transition and ensuring power system reliability can be found in Appendix K and Appendix M (Reliability and Operational Resilience).

[9] Order Adopting Initial Carbon Plan and Providing Direction for Future Planning, Docket No. E-100, Sub 179 (Dec. 30, 2022) ("initial 2022 Carbon Plan").

Table 4-13: Execution Plan – Natural Gas Assets

Near-Term Actions (2023–2026)	
2023	• Contract for incremental interstate firm transportation to support additional fuel supply needs. • GRR as well as interconnection requests for incremental capacity submitted into 2023 DISIS for two Marshall CTs and Person County CC1. • Request turbines bids (with Hydrogen capability adders). • Submit pre-CPCN applications for two Marshall Advanced CTs and Person County Advanced CC1. • Contract for intrastate firm transportation to support Marshall Advanced CTs and Person County Advanced CC1 gas redelivery from interstate pipelines.
2024	• Submit CPCN and air permit applications for Marshall Advanced CTs and Person County Advanced CC1. • Receive Marshall Advanced CTs and Person County Advanced CC1 Interconnection Agreement and CPCN orders. • Commence detailed design and engineering for Marshall Advanced CTs and Person County Advanced CC1. • Begin transmission build-out engineering/modifications for Marshall Advanced CTs and Person County Advanced CC1. • Submit interconnection requests (DISIS/GRR as applicable) for two CCs (BOY 2030 & 2031 in-service) and one CT (BOY 2030 in-service).
2025	• Submit CPCNs and air permits for CC2 and CC3 (BOY 2030 and 2031 in-service) and one CT (BOY 2030 in-service).
2026	• Submit interconnection requests (DISIS/GRR as applicable) for one CT (BOY 2032 in-service). • Submit CPCN for one CT (BOY 2032 in-service).

Intermediate-Term Actions (2027–2032)	
2028	• Submit interconnection requests (DISIS / GRR as applicable) for two CTs (BOY 2034 in-service). • Commission and place Marshall Advanced CTs in-service. • Commission and place Person County Advanced CC1 in-service.
2030	• Commission and place one CT (BOY 2030) and CC2 in-service (BOY 2030).
2031–2032	• Commission and place CC3 (BOY 2031) and one CT (BOY 2032) in-service.

Intermediate-term actions identified in Table 4-13 are based on the ability to execute the Core Portfolio P3 Base and reflect adjustments for gas, transmission, GRR/DISIS, construction site synergies, etc. The exact size, blend and timing of CTs and CCs will vary depending on many factors influencing overall project executability.

Assessing the Viability of Hydrogen Resources

The emergence and integration of hydrogen can be a key component to maintaining flexibility of the resource portfolio going forward while leveraging clean energy resources in the Companies' service territories. Likewise, the DOE, via the regional Hydrogen Hubs, and the Environmental Protection Agency ("EPA"), via the Clean Air Act ("CAA") Section 111 Proposed Rule, have recognized hydrogen as a key cornerstone to their desired energy transition plans. The Companies have been researching and evaluating hydrogen for years and see its potential to allow continued use of CT/CC assets while reducing carbon dioxide emissions at such time the technology is adequately demonstrated. While hydrogen is a promising zero carbon fuel, the Companies are monitoring risks associated with the necessary infrastructure to manufacture, buy, and deliver sufficient quantities of hydrogen to gas generation facilities not being available, especially on the timetable in EPA's CAA Section 111 Proposed Rule. This proposal will require larger high-capacity factor CCs (greater than 45%–55%) to burn 30% hydrogen by volume by 2032 and 96% hydrogen by volume for these CCs by 2038. The Companies will continue to meaningfully engage with the EPA and states as the rule progresses toward a potential final issuance in mid-2024.[10] Table 4-14 below outlines the Companies' plan to participate in the necessary studies and demonstrations to advance the understanding and development of hydrogen production, storage, transportation and utilization in electric generation to

[10] Comments of Duke Energy, EPA New Source Performance Standards For Greenhouse Gas Emissions From New, Modified, And Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines For Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; And Repeal Of The Affordable Clean Energy Rule, Docket ID No. EPA-HQ-OAR-2023-0072, 88 Fed. Reg. 33,240 (May 23, 2023), submitted on regulations.gov, Aug. 8, 2023.

build operational experience with this pivotal carbon free fuel. Additional information is provided in Appendix K.

Table 4-14: Execution Plan – Hydrogen

Near-Term Actions (2023–2026)	
2023–2024	• Develop clean hydrogen studies and demonstration projects. • Submit information and proposals for potential federal funding to offset costs where appropriate. • Leverage work to date on Clemson CHP Hydrogen study to continue preparing toward a potential operational demonstration project. • Understand and map hydrogen opportunities. • Support and develop storage technology research and demonstrations with appropriate recovery mechanisms. • Collaborate with academic and industry research partners to advance low-carbon hydrogen production technologies. • Support of CT manufacturers development of 100% hydrogen capable dry low-emission combustion. • Improve hydrogen production, hydrogen transportation and hydrogen storage cost projections. • Develop regulatory support for future hydrogen transport and storage infrastructure. • Commence approved studies and demonstration.
2023–2024	• Determine hydrogen readiness scope for new unit turbine builds. • Plan for new CT/CC units built with hydrogen feasibility.
2025–2026	• Assess opportunities for clean hydrogen studies and demonstration projects with appropriate recovery mechanisms
Intermediate-Term Actions (2027–2032)	
2027–2028	• Develop opportunities for clean hydrogen studies and demonstration projects with appropriate recovery mechanisms.
2027–2032	• Complete approved studies/projects and commence operations of demonstrations. Incorporate learnings into future planning.

Transmission System Planning and Grid Transformation

Identifying, planning for, and constructing needed transmission infrastructure is a common critical path component to the resource plan portfolios presented in the Carolinas Resource Plan as the Companies integrate new generating resources and plan for the orderly retirement of aging coal generation while ensuring adequate and reliable electric service is maintained. This transformation includes transmission planning and investments required to retire existing coal-fired generation and interconnect new solar, SPS, pumped storage hydro, stand-alone storage, wind, SMRs, and gas generation. Seeking strategic and alternative paths to reducing the cost of transmission upgrades and new infrastructure such as leveraging the generation replacement process for interconnecting replacement generation at retired coal generation sites as well as information on how the Companies prudently plan and reliably operate their transmission systems is described in Appendix L.

Enabling Coal Unit Retirements

Each of the resource portfolios includes the retirement of existing coal units. Locating replacement generation at the same site as retiring coal-fired generation can provide the grid support necessary to ensure continued system reliability and reduce transmission network upgrade costs. The Execution Plan includes a near-term action to leverage the GRR study process to ensure efficient, timely and cost-effective interconnection of new generation planned to be sited at retiring coal-fired generation locations. These locations currently include DEC's Marshall Plant and DEP's Roxboro Plant, with additional potential sites being evaluated for replacement generation to be sited in the future.

For DEC, the completion of construction of transmission infrastructure will enable the retirements of both remaining Allen Units 1 and 5 by December 31, 2024. Transmission planning studies completed to date have not identified major transmission impacts from the retirement of Cliffside Unit 5 by the end of 2030. Intermediate-term actions include the assessment and construction of additional transmission system upgrades to enable coal-fired generation retirements in the late 2020s and early 2030s. Retirement of the Marshall coal units 1 & 2 will be enabled through the GRR process with Advanced CT generation replacing these two coal units. DEC plans to evaluate transmission upgrades to enable retirements as the Belews Creek mid-2030s planned retirement date approaches; preliminary analysis suggests that transmission upgrades will be required to retire this capacity if it is not replaced with new generation on-site and coincident with the retirement.

For DEP, the retirement of the Roxboro and Mayo coal units will cause the need for additional transmission projects unless this generation capacity is replaced sufficiently at the Roxboro and/or Mayo sites and coincident with the retirements. DEP plans to leverage the generation replacement process for replacing Roxboro generation with new gas assets and Mayo, potentially with storage.

Intermediate-term actions include the continued assessment and construction of any transmission system upgrades needed to enable coal unit retirements. Additional detail on transmission planning assessments to support coal unit retirements is addressed in Appendix L.

Renewable Enabling Transmission

The Execution Plan also includes a near-term action to construct renewable enabling transmission projects necessary to allow for substantial incremental solar resource interconnections in existing "Red Zone" areas of DEC and DEP, as further described in Appendix L.

In the intermediate-term, more extensive transmission network upgrades will be required to integrate remote interconnected resources and ensure safe and reliable energy delivery to load centers under various grid conditions. Upgrades of existing transmission lines, although very successful with enabling interconnections of initial phases of resource plan portfolios, will not be sufficient to interconnect later phases of incremental resources identified in the Plan's portfolios. In addition to the initial upgrades of existing transmission, new transmission infrastructure with new rights of way will be required at some point in the future as more resources are integrated to replace retiring coal generation and reliably serve increasing load.

Table 4-15 below outlines the Companies' near-term and intermediate-term Execution Plan to advance the grid needs critical to the resource plan portfolios described in the Carolinas Resource Plan.

Table 4-15: Execution Plan – Transmission System Planning and Grid Transformation

Near-Term Actions (2022–2027)	
2023	• Incorporate the Camden-Camden Dupont 115 upgrade into the 2023 Local Transmission Plan. • File revisions to the Open Access Transmission Tariff ("OATT"), Attachment N-1, Local Transmission Planning Process with FERC to address increased transparency and coordination as well as a multi-value strategic transmission planning process. • Introduce RZEP 2.0 projects in the Resource Plan. • Continue assessment of network transmission needs for wind, solar, and SPS through DISIS and 2023 North Carolina Transmission Planning Collaborative studies. Pursue IIJA funding and continue assessment of wind enabling transmission.
2024	• Upon FERC approval of OATT Attachment N-1 changes to the Local Transmission Planning Process, implement the revisions to the process including development of the first multi-value strategic transmission plan, and adding steps for transparency and coordination with stakeholder meetings.
2023–2027	• Continue to identify and implement interconnection process improvements and monitor impacts of improvements against objectives.
2025–2027	• Continue to identify transmission infrastructure needs for implementing the Carolinas Resource Plan including enabling coal generation retirements and ensuring sustained reliability with planning studies conducted through the DISIS process, the Carolinas Transmission Planning Collaborative, and the Southeastern Regional Transmission Planning group. • Complete construction of the 14 RZEP projects identified as needed to replace aging transmission infrastructure and implement near-term actions provided in the initial 2022 Carbon Plan
Intermediate-Term Actions (2027–2032)	
2027–2032	• Develop and start execution of long-term strategic transmission expansion plan.

Grid Edge and Customer Programs

As discussed in Appendix H, the Companies' Grid Edge and customer programs are intended to provide customers with a variety of options to manage their electric use to both reduce monthly bills and provide value to the electric grid. Grid Edge refers to technologies, programs and investments that advance a decentralized, distributed, and two-way grid. The “edge” refers to the edge of the electricity network, or grid, where the Companies’ electricity reaches customers’ homes and businesses. Grid Edge programs include EE and demand-side management (“DSM”) programs, certain rate designs, voltage control efforts, renewable energy programs, behind-the-meter generation and storage, and electric transportation programs. These customer-owned energy-related technologies continue to develop and mature, providing customers the opportunity to leverage the value that adopting these technologies adds to the utility system.

The Companies continue to identify and investigate opportunities to “shrink the challenge” through aggressively pursuing Grid Edge and customer programs. Over the past year, the Companies have worked to address market barriers, garner stakeholder feedback, and make the necessary regulatory filings to implement enablers that can increase the impacts that can be achieved. Detail on the Companies’ execution activities related to Grid Edge and customer programs is shown below in Table 4-16.

Table 4-16: Execution Plan – Grid Edge and Customer Programs

Near-Term Actions (2023–2027)	
2023	**Energy Efficiency** • Obtain NCUC approval of On-tariff Bill Repayment Pilot for Multi-Family New Construction and On-tariff Bill Repayment Program (DEC/DEP five-year rollout). • Obtain PSCSC approval of On-tariff Bill Repayment Pilot (DEP SC) • Obtain PSCSC and NCUC approval of Smart $aver Early Replacement and Retrofit Program. • Seek and obtain approval to update Smart $aver Program to include education, outreach, and technical support for new construction market. • Work with stakeholders to obtain NCUC approval to update the inputs underlying the determination of the utility system benefits in the Companies’ approved DSM/EE Cost Recovery Mechanism. • Work with stakeholders to obtain NCUC approval of Efficiency Innovation Program for inclusion in the approved DSM/EE Cost Recovery Mechanism. • Obtain NCUC approval of a process to identify the use of an “as found” savings baseline for certain EE measures and programs in the Companies’ approved DSM/EE Cost Recovery Mechanism. **Demand Response Programs** • Obtain approval of PowerPair℠ Solar and Battery Installation Pilot Program Expand Heat Strip program in DEP.

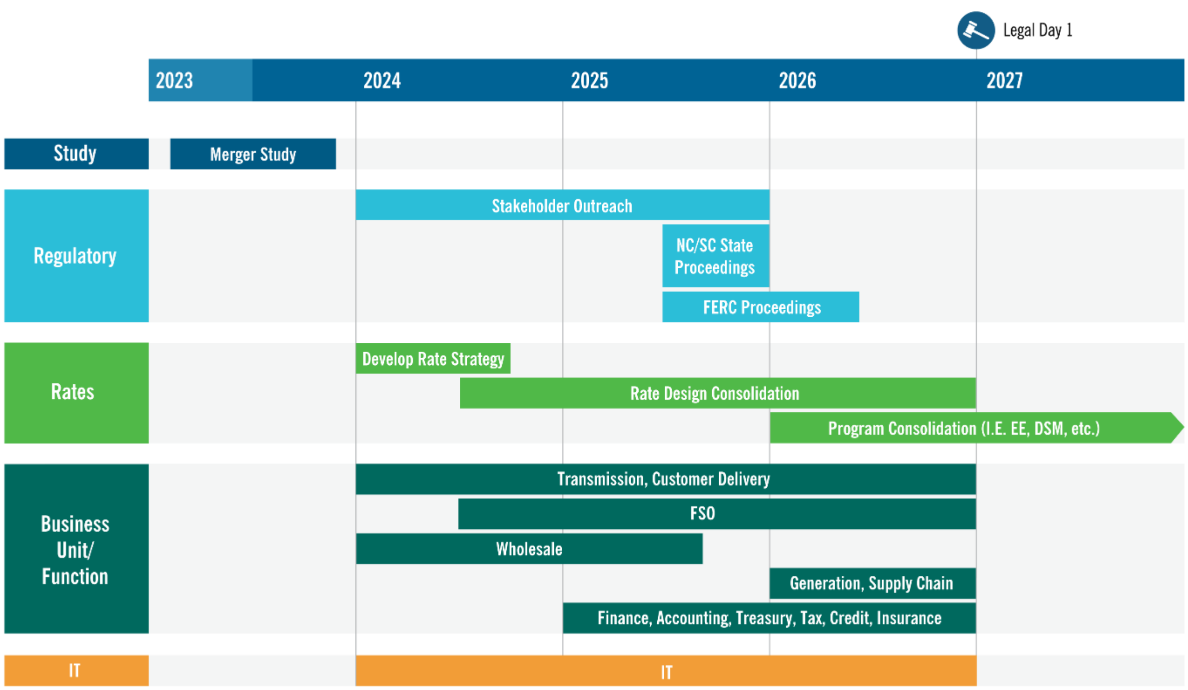
Near-Term Actions (2023–2027)	
2023	• Seek and obtain approval of an Income Qualified demand response program to allow switches and thermostats to be installed during and after Neighborhood Energy Saver visits. • Better Integration with EE offers — Demand Response programs are being incorporated as part of the electric heat customer experience within EE programs. • Seek and obtain approval of a residential battery program. • Seek and obtain approval of an additional PowerShare option that will provide DEC with firm reduction capability. **Rapid Prototyping for Non-DSM/EE Programs** • Complete Rapid Prototyping stakeholder process for non-DSM/EE pilot programs and file a formal proposal as ordered by the NCUC. **Transportation Electrification** • Obtain approval for Electric Vehicle (“EV”) Supply Equipment Tariffs. • Launch approved Managed Charging Pilot with EV Manufacturers.
2023–2024	**Clean Energy Customer Programs** • Obtain approval for Green Source Advantage Choice and Clean Energy Impact Programs. • Seek and obtain approval of Clean Energy Connection, a shared solar program. **Demand Response Programs** • Expand outreach to increase adoption of existing thermostat programs. • Seek and obtain approval for behavioral demand response program to encourage dynamic rate adoption through communicating directly with customers through My Home Energy Report. **Rate Design** • Seek and obtain approval for enhanced Hourly Pricing program. **Transportation Electrification** • Begin execution of Vehicle- to-Grid pilot program. • Continue to support customers and stakeholders in siting EV charging infrastructure through engagement with government agencies to inform on the deployment of IIJA and other available funding. • Analyze the impacts of Time-of-Use rates on residential EV charging.

Near-Term Actions (2023–2027)	
2023-2024	• Seek and obtain approval for off peak credit managed EV charging programs. • Continue to identify, analyze and plan for emergence of electrified fleet load clusters.
2025	**Energy Efficiency** • Seek and obtain approval of increased incentives for non-lighting measures. **Rate Design** • Contingent on both NCUC and PSCSC approvals and implementation of new distributed energy technology supportive rate designs (DEC/DEP implementation). • Seek and obtain approval for updated pricing structures to reflect a change in hourly energy costs due to increased solar penetration. • Seek and obtain approval for behavioral demand response program and supporting infrastructure to encourage dynamic rate adoption. **Grid Edge** • Seek and obtain approval for new locational grid pilots (including regulatory framework) and measures. **Electric Transportation** • Complete and review findings for the North Carolina EV School Bus Phase 1 (approved in 2020 but extended until mid-2025). **Voltage Optimization** • Complete DEC Integrated Volt-Var Control ("IVVC")/Conservation Voltage Reduction ("CVR") Phase 1 rollout to 73% of eligible DEC circuits.
2026	**Voltage Optimization** • Complete DEP Distribution System Demand Response CVR software implementation.
Intermediate Term Actions (2027-2032)	
2028	**Voltage Optimization** • Seek and obtain approval for Phase 2 expansion of DEC IVVC/CVR to 90% of eligible circuits.

Pursuing Duke Energy Carolinas and Duke Energy Progress Merger

As the Companies transition the generating fleets, the combining of DEP and DEC into one operating utility company will provide value to customers. The Companies have launched a costs/benefits study of a potential utility merger between DEC and DEP. While DEC and DEP consolidated system operations is modeled in the Plan as discussed in Chapter 2 and Appendix C, a fully merged DEC and DEP is not explicitly part of this Execution Plan. Consideration of a fully merged DEC and DEP is related to the energy transition as the Companies believe there are aggregate systems savings that could be achieved for customers. Merging DEC and DEP to operate as one utility would harmonize future resource costs across DEC and DEP during the energy transition. The Companies have projected January 2027 (Figure 4-4 below) for possible merger completion, pending stakeholder activities and necessary regulatory approvals separate from long-term resource planning processes and proceedings. While this Resource Plan does not at this time assume fully merged utilities; future long-term planning assumptions will be appropriately aligned as the workstream progresses.

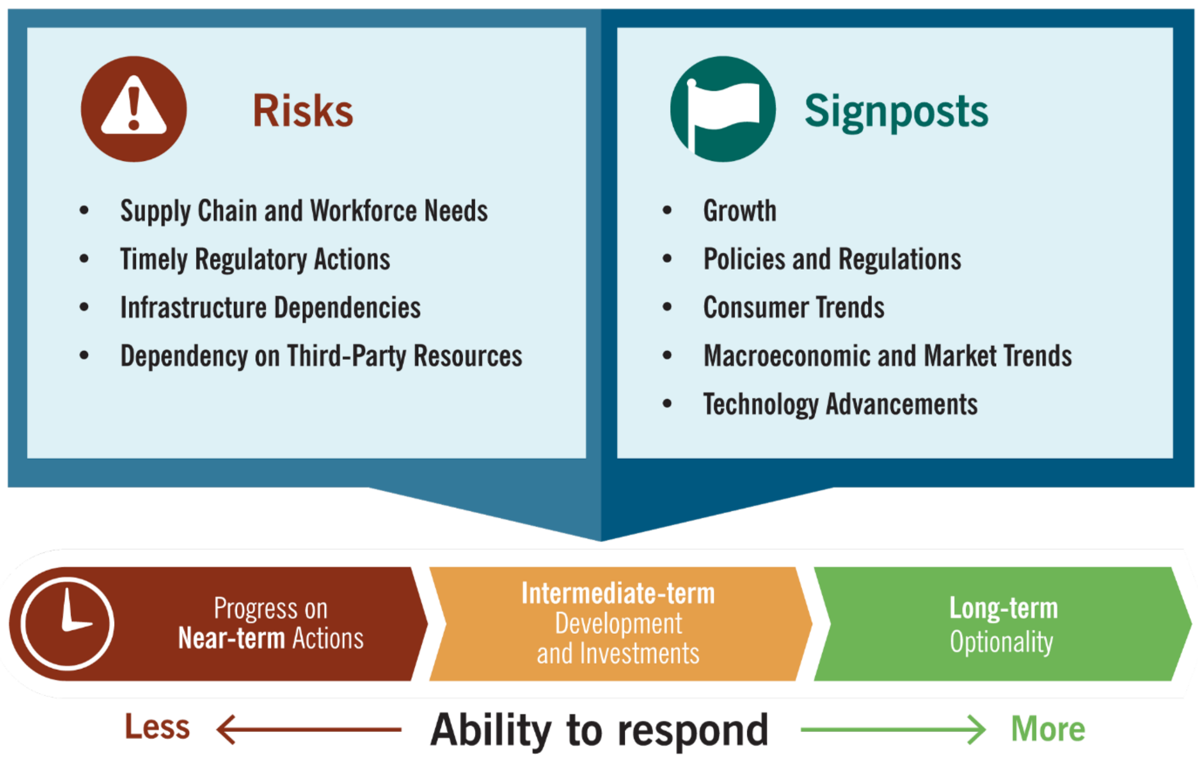
Figure 4-4: Example DEC and DEP Merger Timeline



Checking and Adjusting in Response to a Changing Energy Landscape

The Companies will continue to monitor risks and signposts related to an orderly energy transition across all planning horizons. The timing or level of impact of specific risks or signposts indicates how much time the Companies have to adjust or respond to the changing condition that potentially impacts progress on near-term actions, commitments and investments in the intermediate term, or the ability to retain technology optionality in the long term (Figure 4-5 below). This creates a level of uncertainty that may be particularly impactful during this critical execution phase of the energy transition. As the energy transition progresses, the Companies will be focused on the linkage between on-the-ground execution and long-term planning to be responsive to changes such as supply chain factors, siting and permitting activities, cost adjustments, and project dependencies. The signposts noted below apply to all areas of the Companies' resource planning efforts. Details on the risks the Companies are currently monitoring relating to a planning area or technology can be found in the Appendices to the Plan.

Figure 4-5: Execution Risks and Signposts



Risks

Integral to Plan execution is the identification and monitoring of risks to determine when external factors require the Companies to take mitigating actions, consider alternative strategies or pivot to alternative options to achieve planning objectives. The risks also inform the Commissions' decision-making regarding the optimal timing and generating resource mix. Execution risk categories are outlined below, and the Appendices provide additional information on risks specific to the planning area or technology.

Supply Chain and Workforce Needs: Material and equipment supply chain disruptions may lead to construction delays or inability to develop certain types of programs or projects on the timeline identified or at the costs or amounts assumed in the modeling. Shortages in qualified craft and engineering labor may cause delays or increased costs in constructing new energy resource facilities and supporting infrastructure or implementing new programs.

Timely Regulatory Actions: The ability to receive timely regulatory decisions from all required authorities and jurisdictions for proposed activities is essential to meet load growth, maintain reliability and have an orderly energy transition. Inability to receive timely decisions to authorize, site and receive permits and environmental reviews for new energy resource facilities and supporting electric transmission and gas pipeline infrastructure may impair or slow advancement of execution activities. Additionally, timely regulatory decisions regarding Grid Edge and customer programs enables clarity on advancement of proposals contributing to the Plan.

Infrastructure Dependencies: Coordinated proactive transmission planning and timely construction of the significant transmission that will be needed to interconnect new resources present a key interdependency and timing risk. Future uncertainty or inability to secure additional interstate pipeline firm transportation causes increased fuel assurance risk, increased customer fuel cost exposure and potentially delayed coal retirements. Also, the inability to secure flexible coal supply through coal unit end of life may accelerate the need for their capacity replacement.

Dependency on Third-Party Resources: Procurement of third-party developed resources introduces contract default risk. Through solar and SPS competitive procurement processes, the Companies make awards to the lowest-cost, highest-ranked sites and target a balanced mix of utility-owned and third-party-owned resources. However, the Companies have recently experienced contracted resources delaying commercial delivery dates or terminating their PPAs and dropping from the interconnection queue. This risk could leave the Companies short of annual in-service targets and delay interconnection of other resources if restudies are required.

Signposts

To navigate disruptive or longer-term uncertainties such as policy shifts, statutory or regulatory changes, innovation, or economic trends, the Companies will actively monitor the following signposts that could impact plan trajectory to guide their long-term planning assumptions and necessary future adjustments. As these signposts emerge and evolve, the Companies will update planning assumptions, adjust for any new requirements or constraints, and integrate into future modeling to determine whether modification is required to successfully meet planning objectives.

Growth: Continued load growth in the Carolinas due to economic development, population increase, electrification trends and EV adoption has the potential to impact the Plan as the Companies work to meet customer needs and ensure reliability.

Policies and Regulations: Federal policies and regulations can influence the timing, costs and technical requirements for complying with mandated carbon reduction at least cost. Similar to national policies, state energy law and regulations can influence energy resource planning decisions. Recent examples of this signpost include the IIJA, the Inflation Reduction Act of 2022, EPA's CAA Section 111 Proposed Rule and the Fiscal Responsibility Act.

Consumer Trends: Consumers across all customer classes can be influential in the energy transition journey and dictate the adoption curve for certain technologies such as electric transportation, distributed solar, electric heat pump conversions and investment in renewables.

Macroeconomic and Market Trends: Duke Energy will monitor macroeconomic trends and indicators that could require adjustments to ensure the Plan continues to remain the most reasonable, least cost. Macroeconomic indicators are measures that can be influenced by national or global economic conditions, including energy commodity prices, inflation and interest rates, taxes or other added costs, supply chain disruptions, labor shortages and other national or global disruptions due to macro-economic policies or geopolitical influences impacting the energy industry.

Technology Advancements: The maturity and efficacy of emerging clean energy technologies and grid technologies are critical to the Companies' ability to execute an orderly energy transition. Meeting planning objectives will likely require reliance on breakthrough technologies and design changes in existing technologies, such as increased storm resiliency for offshore wind, that are still in the development and demonstration phase and have not yet achieved widespread commercial availability and economies of scale.