North Carolina Transmission Planning Collaborative

Report on the NCTPC 2022–2032 Collaborative Transmission Plan

February 21, 2023
FINAL REPORT

2022 – 2032 NCTPC Transmission Plan
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I. Executive Summary

The North Carolina Transmission Planning Collaborative ("NCTPC") was established to:

1) provide the Participants (Duke Energy Carolinas ("DEC"), Duke Energy Progress ("DEP"), North Carolina Electric Membership Corporation ("NCEMC"), and ElectriCities of North Carolina ("ElectriCities") and other stakeholders an opportunity to participate in the electric transmission planning process for the areas of North Carolina and South Carolina served by the Participants;

2) preserve the integrity of the current reliability and least-cost planning processes;

3) expand the transmission planning process to include analysis of increasing transmission access to supply resources inside and outside the Balancing Authority Areas ("BAAs") of DEC and DEP; and

4) develop a single coordinated transmission plan for the Participants that includes reliability, economic, and public policy considerations while appropriately balancing costs, benefits and risks associated with the use of transmission and generation resources.

Attachment N-1 of the Joint Open Access of DEC, DEP, and Duke Energy Florida LLC ("Joint OATT")[1] reflects the Local Transmission Planning Process for DEC and DEP approved by the FERC for compliance with Order Nos. 890 and 1000, and is effectuated through the NCTPC Process. The overall NCTPC Process is performed annually and includes the Reliability Planning and Local Economic Study Planning Processes, which are intended to be concurrent and iterative in nature. The NCTPC Process is designed such that there will be considerable

[1] Joint Open Access Tariff of Duke Energy Carolinas, LLC, Duke Energy Florida, LLC, and Duke Energy Progress, LLC, at 1084, available at http://www.ferc.duke-energy.com/Tariffs/Joint_OATT.pdf.

feedback and iteration between the two processes as each effort's solution alternatives affect the other's solutions.

The 2021–2031 Collaborative Transmission Plan (the "2021 Collaborative Transmission Plan" or the "2021 Plan") was published in January 2022. That plan received a mid-year update in August 2022.

This report documents the current 2022 – 2032 Collaborative Transmission Plan ("2022 Collaborative Transmission Plan" or the "2022 Plan") for the Participants. The initial sections of this report provide an overview of the NCTPC Process as well as the specifics of the 2022 reliability planning study scope and methodology. The NCTPC Process document and 2022 Study scope document are posted in their entirety on the NCTPC website at http://www.nctpc.org/nctpc/.

The scope of the 2022 reliability planning process is focused on the annual base reliability study. The base reliability study assesses the reliability of the transmission systems of both DEC and DEP in order to ensure reliability of service in accordance with North American Electric Reliability Corporation ("NERC"), SERC Reliability Corporation ("SERC"), and DEC and DEP requirements. The purpose of the base reliability study is to evaluate the transmission systems' ability to meet load growth projected for 2022 through 2032 with the Participants' planned Designated Network Resources ("DNRs").

Based on the reliability study's input assumptions, the 2022 Study identifies any new system impacts not currently addressed by existing transmission plans, in which case solutions were developed. The 2022 Study also adjusts existing plans where necessary.

The NCTPC reliability study results affirm that the planned DEC and DEP transmission projects identified in the 2021 Plan continue to satisfactorily address the reliability concerns identified in the 2021 Study for the near-term (5 year) and the long-term (10 year) planning horizons. The 2022 Plan is detailed in Appendix C which identifies the new and updated projects planned with an estimated cost of greater than $10 million.

The total estimated cost for the 24 reliability projects included in the 2022 Plan is $936 million as documented in Appendix C. This compares to the original 2021

Plan estimate of $694 million for 16 reliability projects. In-service dates and cost estimates for some projects that are planned or underway have been revised based on updated information. An update to the 2021 plan was provided in the 2021 mid-year update published in August 2022 with an updated cost estimate of $748 million. See Appendix G for a detailed comparison of this year's Plan to the updated 2021 Plan.

The list of major projects will continue to be modified on an ongoing basis as new improvements are identified through the NCTPC Process and projects are placed in-service or eliminated from the list. Appendix D provides a more detailed description of each reliability project in the 2022 Plan.

For the purposes of this report the following definitions are used:

- Construct – greenfield project that is new
- Reconductor – existing structures will support new conductor and attachments
- Rebuild – new structures required
- Upgrade – generic – may include upgraded structures, upgraded conductor, upgraded relay protection, upgraded attachments, upgraded CTs, line traps, etc.

The 2022 Plan, relative to the 2021 Plan, includes no new reliability projects for DEP and 9 new DEC reliability projects:

Project ID	Project Name
0061	Wateree 100 kV Line (Great Falls-Wateree), Upgrade
0062	Silas 100 kV Line (Mocksville-Idols Tap), Upgrade
0063	North Greenville 230 kV Tie Station, Upgrade
0064	Wylie 100 kV Line (Wylie-Arrowood Retail), Upgrade
0065	Morning Star 230 kV Tie Station, Upgrade
0066	Davidson River 100 kV Line (North Greenville-Marietta), Upgrade
0067	Harley 100 kV Line (Tiger-Campobello), Upgrade
0068	Sandy Ridge 230 kV Line (Newport-Morning Star), Upgrade
0069	Skybrook 100 kV Line (Winecoff-Eastfield Retail), Upgrade

There are revised in-service dates, estimated cost changes, and/or scope changes for the following DEC and DEP projects in the 2022 Plan relative to the 2021 Plan:

Project ID	**Project Name**	**Cost Change**	**Timeline Change**
0039	Asheboro–Asheboro East 115 kV North Line, Reconductor	↑	⋙
0046	Windmere 100 kV Line (Dan River–Sadler), Construct	↓	⋙
0048	Wilkes 230/100 kV Tie Station, Construct	↓	⋙
0050	Craggy–Enka 230 kV Line, Construct	↑	⋘
0051	Cokesbury 100 kV Line (Coronaca–Hodges), Upgrade	↑	⋙
0052	South Point 100 kV Switching Station, Construct	↓	⋙
0053	Wateree Hydro Plant, Upgrade	↑	⋘
0054	Carthage 230/115 kV Substation, Construct	↑	▬
0056	Castle Hayne–Folkstone 115 kV Line, Rebuild	↑	⋘
0057	Holly Ridge North 115 kV Switching Station, Construct	↓	▬
0059	Monroe 100 kV Line (Lancaster-Monroe), Upgrade	↓	⋙
0060	Westport 230 kV Line (McGuire-Marshall), Upgrade	↑	▬

Each year, the Oversight Steering Committee (“OSC”) of the NCTPC determines if there are any public policies driving the need for local transmission upgrades. Through this process the OSC requests input from the Transmission Advisory Group (“TAG”) participants to identify any public policy impacts to be evaluated as part of the NCTPC Local Planning Process. The OSC may itself identify public policies to be evaluated.

This year, in addition to the NCTPC reliability study, the OSC recognized the evolving carbon reduction plan (“Carbon Plan”) under development by the North Carolina Utilities Commission (“NCUC”) pursuant to N.C.G.S. § 62-110.9, as enacted by S.L. 2021-165, as a public policy potentially driving the need for local transmission system upgrades. In response to this evolving public policy and the need to assess providing increasing transmission access to supply resources inside the BAAs of DEC and DEP, Duke Energy initiated a special supplemental study to address the NCUC Public Staff concerns regarding the impact on the DEC and DEP network transmission systems to support the interconnection of significant renewable resources as specified in prior Integrated Resource Plans and in the more recent proposed Carbon Plan pathways filed by DEC and DEP. On December 30, 2022, the NCUC issued an order supporting the inclusion of the projects identified by the study in the 2022 Plan. The OSC has reviewed the study analysis and agrees with the study results and inclusion of the projects in the 2022 Plan. The total estimated cost for these 14 proposed projects included in the 2022 Plan is $554 million as documented in Appendix E.

The 2022 Plan includes 4 new DEC projects resulting from the Local Public Policy Planning Process:

Project ID	**Project Name**
0080	Lee 100 kV Line (Lee-Shady Grove), Upgrade
0081	Piedmont 100 kV Line (Lee-Shady Grove), Upgrade
0082	Newberry 115 kV Line (Bush River-DESC), Upgrade
0083	Clinton 100 kV Line (Bush River-Laurens), Upgrade

and 10 new DEP projects resulting from the Local Public Policy Planning Process:

Project ID	**Project Name**
0070	Cape Fear – West End 230 kV Line, Rebuild
0071	Erwin – Fayetteville East 230 kV Line, Rebuild
0072	Erwin – Fayetteville 115 kV Line, Rebuild
0073	Fayetteville – Fayetteville Dupont 115 kV Line, Rebuild 3.2-mile section[2]
0074	Milburnie 230 kV Substation, Upgrade
0075	Weatherspoon – Marion 115 kV Line, Upgrade
0076	Camden Junction – Wateree 115 kV Line, Rebuild
0077	Robinson – Rockingham 115 kV Line, Rebuild
0078	Robinson – Rockingham 230 kV Line, Rebuild
0079	Fayetteville – Fayetteville Dupont 115 kV Line, Rebuild 4.9-mile section

[2] This project has recently been moved to the base reliability plan.

Appendix F provides a more detailed description of each project in the 2022 Plan to integrate additional generation and proposed for compliance with public policy.

For a variety of reasons (such as load growth, generation retirements, or power purchase agreements expiring), LSEs may wish to evaluate other resource supply options to meet future load demand as part of the Local Economic Study Process. These resource supply options can be either in the form of transactions or some hypothetical generators which are added to meet the resource adequacy requirements for this study.

In 2022, the OSC decided to examine the impacts of fourteen different hypothetical transfers into, out of, and through the DEC and DEP systems under the Local Economic Planning Process. The results of the fourteen different hypothetical transfers under the Local Economic Planning Process are documented in Section VI.

In this 2022 NCTPC Process, the Participants validated and continued to build on the information learned from previous years' efforts. Each year the Participants will look for ways to improve and enhance the planning process. The study process confirmed again this year that the joint planning approach produces benefits for all Participants that would not have been realized without a collaborative effort.

II. North Carolina Transmission Planning Collaborative Process

II.A. Overview of the Process

The NCTPC Process was established by the Participants to:

1) provide the Participants (DEC, DEP, NCEMC, and ElectriCities) and other stakeholders an opportunity to participate in the electric transmission planning process for the areas of North Carolina and South Carolina served by the Participants;

2) preserve the integrity of the current reliability and least-cost planning processes;

3) expand the transmission planning process to include analysis of increasing transmission access to supply resources inside and outside the Balancing Authority Areas of DEC and DEP; and

4) develop a single coordinated transmission plan for the Participants that includes reliability, economic, and public policy considerations while appropriately balancing costs, benefits, and risks associated with the use of transmission and generation resources.

The NCTPC Process is a coordinated Local Transmission Planning process conducted on an annual basis. The Local Transmission Plan will identify local transmission projects (Local Projects). A Local Project is defined as a transmission facility that is (1) located solely within the combined DEC–DEP transmission system footprint and (2) not selected in the regional transmission plan for purposes of regional cost allocation.

The Local Planning Process addresses transmission upgrades needed to maintain reliability and to integrate new generation resources and/or loads. The overall Local Planning Process includes several components:

- Reliability Planning Process
- Resource Supply Options Process
- Local Economic Study Process
- Local Public Policy Process

An overview of the NCTPC Process Flow is included in Appendix A.

The Reliability Planning Process (base reliability study) evaluates each Transmission System's ability to meet projected load with a defined set of resources as well as the needs of firm point-to-point customers, whose needs are reflected in their transmission contracts and reservations. The Resource Supply Options Process is conducted to evaluate transmission system impacts for other potential resource supply options to meet future load requirements.

The overall Local Planning Process is designed such that there will be considerable feedback and iteration between the Reliability Planning Process and Resource Supply Options Process. This is necessary as the alternative solutions from one process affect the alternative solutions in the other process.

The Local Economic Study Process allows the TAG participants to propose economic upgrades to be studied as part of the Local Planning Process. This process evaluates the means to increase transmission access to potential supply resources inside and outside the Balancing Authority Areas of DEC and DEP.

The Local Public Policy Process identifies if there are any public policies that are driving the need for local projects. Either the OSC or the TAG could identify those public policies that may drive the need for new local transmission projects.

The OSC manages the NCTPC Process. The Planning Working Group ("PWG") implements the development of the NCTPC Process and coordinates the study development. The TAG provides advice and makes recommendations regarding the development of the NCTPC Process and the study results.

The final results of the Local Planning Process include summaries of the estimated costs and schedules to provide any transmission upgrades and/or additions needed to maintain a sufficient level of reliability necessary to serve customers. Throughout the Local Planning Process, TAG participants (including TAG participants proposing transmission solutions, generation solutions, and solutions utilizing demand resources) may participate.

The purpose of the NCTPC Process is more fully described in the current Participation Agreement which is posted at http://www.nctpc.org/nctpc/.

II.B. Reliability Planning Process and Resource Supply Options Process

The Reliability Planning Process has traditionally been used by the transmission owners to provide safe and reliable transmission service at the lowest reasonable cost. Through the NCTPC, this was expanded to include the active participation of the Participants and input from other stakeholders through the TAG.

The OSC approves the scope of the reliability study, oversees the study analysis being performed by the PWG, evaluates the study results, and approves the final reliability study results. The Reliability Planning Process begins with the incumbent transmission owners' most recent reliability planning studies and planned transmission upgrade projects.

In addition, the PWG solicits input from the Participants for different scenarios on where to include alternative supply resources to meet their load demand forecasts in the study. This is known as the Resource Supply Options Process. This step provides the opportunity for the Participants to propose the evaluation of other resource supply options to meet future load demand due to load growth, generation retirements, or the expiration of purchase power agreements. The PWG analyzes the proposed interchange transactions and/or the location of generators to determine if those transactions or generators create any reliability criteria violations. Based on this analysis, the PWG provides feedback to the Participants on the viability of the proposed interchange transactions or generator locations for meeting future load requirements. Note that new or modified interchange or generation must go through official FERC, NC, or SC Generator Interconnection or Transmission Service processes, which may find different results than the NCTPC study process. The PWG coordinates the development of the reliability study and the resource supply option study based upon the OSC approved scope and prepares a report with the recommended transmission reliability solutions.

The overall Local Planning Process is designed such that there will be considerable feedback and iteration between the Reliability Planning Process and the Resource Supply Options Process. This is necessary as the alternative solutions from one process may affect the alternative solutions in the other process.

The results of the Reliability Planning Process include summaries of the estimated costs and schedules to provide transmission upgrades and/or additions needed to: (i) maintain a sufficient level of reliability necessary to serve the native load of all Participants and (ii) reliably support the resource supply options studied. The reliability study results are reviewed with the TAG, and the TAG participants are given an opportunity to provide comments on the results. All TAG feedback is reviewed by the OSC and PWG for consideration for incorporation into the final Collaborative Transmission Plan.

For the 2022 Study, the NCTPC evaluated resource supply scenarios that modeled hypothetical transfers across the NCTPC interface with neighboring systems.

II.C. Local Economic Study Process

The Local Economic Study Process allows the TAG participants to propose hypothetical economic transfers to be studied as part of the Local Planning Process. The Local Economic Study Process provides the means to evaluate the impact of potential supply resources inside and outside the BAAs of the Transmission Providers. This local economic analysis provides the opportunity to study what transmission upgrades would be required to reliably integrate new resources.

The Local Economic Study Process begins with the TAG members proposing scenarios and interfaces to be studied, which are then compiled by the PWG and evaluated by the OSC to determine which ones will be included for analysis in the current planning cycle.

The OSC approves the scope of the local economic study scenarios (including any changes in the assumptions and study from those used in the reliability analysis), oversees the study analysis being coordinated by the PWG, evaluates the study results, and approves the final local economic study results.

The PWG coordinates the development of the local economic studies based upon the OSC approved scope and prepares a report which identifies recommended transmission solutions that could increase transmission access.

The results of the Local Economic Study Process include the estimated costs and schedules to provide the increased transmission capabilities. The local economic study results are reviewed with the TAG, and the TAG participants are given an opportunity to provide comments on the results. All TAG feedback is reviewed by the OSC for consideration for incorporation into the final Local Transmission Plan.

Some planning cycles may only focus on the Reliability Planning Process if stakeholders do not request any economic study scenarios for a particular planning cycle.

For the 2022 Study, the NCTPC received four local economic study requests to evaluate hypothetical resource transfers in various amounts (500 MW and 750 MW) from DUK and PJM to SCPSA in 2029. The PWG analyzed two of the four local economic studies as part of the resource supply analysis, DUK-to-SCPSA 750 MW and PJM-to-SCPSA. In total, the PWG examined the impacts of 14 different hypothetical transfers into, out of, and through the DEC and DEP systems. See Section VI for detailed study results.

II.D. Local Public Policy Process

Each year, the OSC seeks input from the TAG participants to determine if there are any public policies driving the need for local transmission upgrades to be evaluated as part of the Local Planning Process. The OSC may itself identify public policies to be evaluated. The OSC will use the criteria below:

- The public policy must be reflected in state, federal, or local law or regulation (including order of a state, federal, or local agency).
- There must be existence of facts showing that the identified need cannot be met absent the construction of additional transmission facilities.

For the 2022 Study, the NCTPC received two Public Policy Requests, one to evaluate the potential impacts of the development of PJM off-shore wind on the NC transmission system, and another to evaluate 9 GW of solar resources being incorporated into the NC transmission system. The details of the disposition of these two requests are covered in Section V.

II.E. Local Transmission Plan

Once the reliability and local economic studies are completed, including any evaluations due to public policies, the OSC evaluates the results and the PWG recommendations to determine if any proposed economic projects, public policy projects, and/or resource supply option projects will be incorporated into the Local Transmission Plan. If so, the initial plan developed based on the results of the reliability studies is modified accordingly. This process results in a single Local Transmission Plan that appropriately balances the costs, benefits and risks associated with the use of transmission and generation resources. This plan is reviewed with the TAG, and the TAG participants are given an opportunity to provide comments. All TAG participant feedback is reviewed by the OSC for consideration to be incorporated into the final Local Transmission Plan.

The annual Local Transmission Plan information is available to Participants for identification of any alternative least cost resources for potential inclusion in their respective Integrated Resource Plans. Other stakeholders can similarly use this information for their resource planning purposes.

III. 2022 Reliability Planning Study Scope and Methodology

The scope of the 2022 Reliability Planning Process was focused on the annual base reliability study. The base reliability study assessed the transmission systems of both DEC and DEP in order to ensure reliability of service in accordance with North American Electric Reliability Corporation ("NERC"), SERC Reliability Corporation ("SERC"), and DEC and DEP requirements. The purpose of the base reliability study was to evaluate the transmission systems' ability to meet load growth projected for 2027 summer through 2032 summer with the Participants' DNRs. The 2022 Study allowed for identification of any new system impacts not currently addressed by existing transmission plans in which case solutions were developed. The 2022 Study also allowed for adjustments to existing plans where necessary.

III.A. Assumptions

1. Study Year and Planning Horizon

The 2022 Plan addressed a ten-year planning horizon through 2032. The study years and seasons chosen for the 2022 Study are listed in Table 1.

Table 1
Study Years

Study Year / Season	Analysis
2027 Summer	Near-term base reliability
2027/2028 Winter	Near-term base reliability
2032/33 Winter	Long-term base reliability

2. Network Modeling

The network models developed for the 2022 Study included new transmission facilities and upgrades for the 2027, 2027/2028, and 2032/33 models, as appropriate, from the current transmission plans of

DEC and DEP and from the 2021 Plan. Table 2 lists the planned major transmission facility projects (with an estimated cost of $10 million or more each) included in the 2027, 2027/2028, and 2032/33 models. Table 3 and 4 lists the major generation facility additions and retirements included in the 2027, 2027/2028, and 2032/33 models.

Table 2
Major Transmission Facility Projects Included in Models

Company	Project ID	Project Name	2027S	2027/ 2028W	2032/ 2033W
DEC	0046	Windmere 100 kV Line (Dan River–Sadler), Construct	Yes	Yes	Yes
DEC	0048	Wilkes 230/100 kV Tie Station, Construct	Yes	Yes	Yes
DEC	0051	Cokesbury 100 kV Line (Coronaca–Hodges), Upgrade	Yes	Yes	Yes
DEC	0052	South Point 100 kV Switching Station, Construct	Yes	Yes	Yes
DEC	0058	Coronaca 100 kV Line (Coronaca-Creto), Upgrade and Construct	Yes	Yes	Yes
DEC	0059	Monroe 100 kV Line (Lancaster-Monroe), Upgrade	No	No	Yes
DEC	0060	Westport 230 kV Line (McGuire-Marshall), Upgrade	No	No	No
DEC	0061	Wateree 100 kV Line (Great Falls-Wateree), Upgrade	Yes	Yes	Yes
DEC	0062	Silas 100 kV Line (Mocksville-Idols Tap), Upgrade	Yes	Yes	Yes
DEC	0063	North Greenville 230 kV Tie Station, Upgrade	Yes	Yes	Yes
DEC	0064	Wylie 100 kV Line (Wylie-Arrowood Retail), Upgrade	Yes	Yes	Yes
DEC	0065	Morning Star 230 kV Tie Station, Upgrade	No	No	Yes

Company	Project ID	Project Name	2027S	2027/ 2028W	2032/ 2033W
DEC	0066	Davidson River 100 kV Line (North Greenville-Marietta), Upgrade	No	No	Yes
DEC	0067	Harley 100 kV Line (Tiger-Campobello), Upgrade	No	No	No
DEC	0068	Sandy Ridge 230 kV Line (Newport-Morning Star), Upgrade	No	No	No
DEC	0069	Skybrook 100 kV Line (Winecoff-Eastfield Retail), Upgrade	No	No	Yes
DEP	0034	Sutton–Castle Hayne 115 kV North Line, Rebuild	Yes	Yes	Yes
DEP	039	Asheboro–Asheboro East 115 kV North Line, Reconductor	Yes	Yes	Yes
DEP	0050	Craggy–Enka 230 kV Line, Construct	Yes	Yes	Yes
DEP	0053	Wateree Hydro Plant, Upgrade	Yes	Yes	Yes
DEP	0054	Carthage 230/115 kV Substation, Construct	No	No	No
DEP	0055	Falls 230 kV Sub, Upgrade	No	No	No
DEP	0056	Castle Hayne–Folkstone 115 kV Line, Rebuild	No	No	No
DEP	0057	Holly Ridge North 115 kV Switching Station, Construct	No	No	No

Table 3

Major Generation[3] Facility Additions in Models

Company	Generation Facility	2027S	2027/ 2028W	2032/ 2033W
DEC	Lincoln County CT (525 MW)	Included	Included	Included
DEC	Apex PV (30 MW)	Included	Included	Included
DEC	Aquadale PV (50 MW)	Included	Included	Included
DEC	Bear Branch PV (35 MW)	Included	Included	Included
DEC	Beaverdam PV (42 MW)	Included	Included	Included
DEC	Blackburn PV (61.7 MW)	Included	Included	Included
DEC	Broad River PV (50 MW)	Included	Included	Included
DEC	Brookcliff PV (50 MW)	Included	Included	Included
DEC	Healing Springs PV (55 MW)	Included	Included	Included
DEC	High Shoals PV (16 MW)	Included	Included	Included
DEC	Hornet PV (75 MW)	Included	Included	Included
DEC	Lick Creek PV (50 MW)	Included	Included	Included
DEC	Misenheimer PV (74.4 MW)	Included	Included	Included
DEC	Oakboro PV (40 MW)	Included	Included	Included
DEC	Olin Creek PV (35 MW)	Included	Included	Included
DEC	Partin PV (50 MW)	Included	Included	Included
DEC	Pelham PV (32 MW)	Included	Included	Included
DEC	Pinson PV (20 MW)	Included	Included	Included
DEC	Quail PV (30 MW)	Included	Included	Included
DEC	Speedway PV (22.6 MW)	Included	Included	Included
DEC	Stanly PV (50 MW)	Included	Included	Included
DEC	Stony Knoll PV (22.6 MW)	Included	Included	Included
DEC	Sugar PV (60 MW)	Included	Included	Included
DEC	Two Hearted PV (22 MW)	Included	Included	Included

[3] Major Generation Threshold is 10 MW or greater and connected to the transmission system

Company	Generation Facility	2027S	2027/ 2028W	2032/ 2033W
DEC	West River PV (40 MW)	Included	Included	Included
DEC	Westminster PV (75 MW)	Included	Included	Included
DEP	Cabin Creek Solar (70.2 MW)	Included	Included	Included
DEP	Gold Valley Solar (78.8 MW)	Included	Included	Included
DEP	Nutbush Solar (35.0 MW)	Included	Included	Included
DEP	Camp Lejeune Battery (11.0 MW)	Included	Included	Included
DEP	Sapony Creek Solar (23.4 MW)	Included	Included	Included
DEP	Loftins Crossroads Solar (75.0 MW)	Included	Included	Included
DEP	Roxboro CC Units 1-2 (2700 MW)	Not Included	Not Included	Included
DEP	Mayo CC Unit 1 (80 MW)	Not Included	Not Included	Included

Table 4

Major Generation[4] Facility Retirements in Models

Company	Generation Facility	2027S	2027/ 2028W	2032/ 2033W
DEC	Allen 1-5 (1083 MW)	Retired	Retired	Retired
DEC	Cliffside 5 (574 MW)	Retired	Retired	Retired
DEC	Lee 3 (120 MW)	Retired	Retired	Retired
DEP	Darlington Co 1-4,6,7,8,10 (514 MW)	Retired	Retired	Retired
DEP	Blewett CTs 1-4 and Weatherspoon CTs 1-4 (232 MW)	Retired	Retired	Retired
DEP	Roxboro Units 1-4 (2462 MW)	Not Retired	Not Retired	Retired
DEP	Mayo Unit 1 (746 MW)[5]	Not Retired	Not Retired	Retired

[4] Major Generation Threshold is 10 MW or greater and connected to the transmission system.

[5] To meet winter peak demand, a hypothetical CC unit was modeled at Mayo to balance the case. This was 80 MW for the w2032_33 case. The Mayo CC unit was modeled at a higher output value for some of the hypothetical transfer scenarios requiring additional MWs needed for export from DEP.

3. Interchange and Generation Dispatch

Each Participant provided a resource dispatch order for each of its DNRs for the DEC and DEP BAAs. Generation was dispatched for each Participant to meet that Participant's load in accordance with the designated dispatch order.

DEC models distribution-connected generation as being netted against the load at the transmission bus. Transmission-connected generation is modeled if it is either in-service or has an executed generator interconnection agreement at the time the models are built. Because only transmission-connected generation is modeled explicitly, the following assumptions do not apply to distribution-connected generation. Solar generation is available for dispatch up to the generator interconnection agreement value but is only dispatched at 80% of that value in summer models. Facilities with storage may be dispatched up to 100% of the generator interconnection agreement value depending on the amount of storage associated with the facility. The level of solar generation dispatch is jurisdiction-specific and is supported by operating data that can be reflective of various factors such as geography and plant design. Solar generation is not dispatched in winter models. The dispatch assumptions reflect the expected solar generation output coincident with the DEC peak load. DEC models 1,602.8 MW of transmission-connected solar generation available for dispatch, dispatched consistent with the previous dispatch assumptions.

DEP models solar generation in its power flow cases that is either in-service or has an executed generator interconnection agreement at the time the models are built. This includes transmission-connected as well as distribution-connected solar generation. The current 2027 summer power flow case has 1,363 MW of transmission-connected and 1,987 MW of distribution-connected solar generation for a total of 3,350 MW. In its summer peak cases, DEP scales the solar generation down to 50% of its maximum capacity to approximate the amount of solar generation that will be on-line coincident with the DEP peak load. This level of dispatch is jurisdiction-specific and is supported by operating data reflective of various factors such as geography and plant design.

Facilities with storage may be dispatched up to 100% of the generator interconnection agreement value depending on the amount of storage associated with the facility. For winter peak studies, DEP assumes that no solar generation will be available at the time of the winter peak. DEP models all transmission upgrades that are determined necessary by the respective generation interconnection studies.

III.B. Study Criteria

The results of the base reliability study, the resource supply option study, and the local economic study were evaluated using established planning criteria. The planning criteria used to evaluate the results include:

1) NERC Reliability Standards;
2) SERC requirements; and
3) Individual company criteria.

III.C. Case Development

The base case for the base reliability study was developed using the most current 2021 series NERC Multiregional Modeling Working Group ('MMWG") model for the systems external to DEC and DEP. The MMWG model of the external systems, in accordance with NERC MMWG criteria, included modeling known long-term firm transmission reservations. Detailed internal models of the DEC and DEP East/West systems were merged into the base case, including DEC and DEP transmission additions planned to be in service by the period under study. In the base cases, all confirmed long-term firm transmission reservations with roll-over rights were modeled.

III.D. Transmission Reliability Margin

NERC defines Transmission Reliability Margin ("TRM") as:

> *The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.*

DEP's reliability planning studies model all confirmed transmission obligations for its BAA in its base case. Included in this is TRM for use by all LSEs. TRM is composed of contracted VACAR reserve sharing and inrush impacts. DEP models TRM by scheduling the reserved amount on actual reserved interfaces as posted on the DEP Open Access Same-time Information System (“OASIS”).

In the planning horizon, DEC ensures VACAR reserve sharing requirements can be met through decrementing Total Transfer Capability (“TTC”) by the TRM value required on each interface. Sufficient TRM is maintained on all DEC-VACAR interfaces to allow both export and import of the required VACAR reserves. DEC posts the TRM value for each interface on the DEC OASIS.

Both DEP and DEC ensure that TRM is maintained consistent with NERC requirements. The major difference between the methodologies used in planning by the two companies to calculate TRM is that DEP uses a flow-based methodology, while DEC decrements previously calculated TTC values on each interface.

III.E. Technical Analysis and Study Results

Contingency screenings on the base cases and scenarios were performed using Power System Simulator for Engineering (“PSS/E”) power flow or equivalent. DEC and DEP each simulated its own transmission and generation down contingencies on its own transmission system.

DEC created generation down cases that assume a major unit is removed from service and the system is economically redispatched to make up for the loss of generation.

Generation down cases were developed for the following units:

Bad Creek 1	Cliffside 6	McGuire 2
Belews Creek 1	Dan River CC	Mill Creek 1
Broad River 1	Jocassee 1	Nantahala
Buck CC	Kings Mountain CC	Oconee 1
Catawba 1	Lee CC	Oconee 3
Cherokee Co-gen	Lincoln 1	Rockingham 1
Cleveland 1	Marshall 1	Rowan CC
Cliffside 5	McGuire 1	Thorpe

Additionally, generation down cases for transmission-connected solar sites were created. These cases reflected one of two assumptions: 1) an individual solar site being unavailable or 2) a group of solar sites being unavailable. For the latter, engineering judgement was used to group transmission-connected solar sites in common geographic areas.

Outages involving one or more of the following transmission-connected solar sites were considered:

Apex	Hornet	Pinson
Apple 2	Hunters Cove	Quail
Apple 3	Lick Creek	Ruff
Aquadale	Maiden Creek	Rutherford
Ayrshire	McBride	Speedway
Bear Branch	Misenheimer	Stanly
Beaverdam	Mocksville	Stony Knoll
Broad River	Monroe	Sugar
Brookcliff	Newberry	Sun Edison
Gaston	Oakboro	Two Hearted
Healing Springs	Partin	West River
High Shoals	Pelham	Westminster

DEP created generation down cases which included the use of TRM, as discussed in Section III.D. DEP TRM cases model interchange to avoid netting against imports, thereby creating a worst-case import scenario. TRM cases were developed for the following units:

Brunswick 1	Robinson 2
Harris	Asheville CC1

To understand impacts on each other's system, DEC and DEP have shared their transmission contingency and monitored elements files in order for each company to simulate the impact of the other company's contingencies on its own transmission system. In addition, each company coordinated generation adjustments to accurately reflect the impact of each company's generation patterns.

The technical analysis was performed in accordance with the study methodology. The results from the technical analysis for the DEC and DEP systems were shared with all Participants. Solutions of known issues within DEC and DEP were discussed. New or emerging issues identified in the 2022 Study were also discussed with all Participants so that all are aware of potential issues. Appropriate solutions were developed and tested.

The results of the technical analysis were discussed throughout the study area based on thermal loadings greater than 90% for base reliability, and greater than 80% for resource supply options and local economic studies to allow evaluation of project acceleration.

III.F. Assessment and Problem Identification

DEC and DEP performed an assessment in accordance with the methodology and criteria discussed earlier in this section of this report, with the analysis work shared by DEC and DEP. The reliability issues identified from the assessments of both the base reliability cases and the local economic study scenarios were documented and shared within the PWG. These results will be reviewed and discussed with the stakeholder group for feedback.

III.G. Solution Development

The 2022 Study performed by the PWG confirmed base reliability problems already identified (i) by DEC and DEP in company-specific planning studies performed individually by the transmission owners and (ii) by the 2021 Study. The PWG participated in the review of potential solution alternatives to the identified base reliability problems and to the issues identified in the resource supply option analysis. The solution alternatives were simulated using the same assumptions and criteria described in Sections III.A through III.E. DEC and DEP developed planning cost estimates and construction schedules for the solution alternatives.

III.H. Selection of Preferred Reliability Solutions

For the base reliability study, the PWG compared solution alternatives and selected the preferred solution, balancing cost, benefit and risk. The PWG selected a preferred set of transmission improvements that provide a reliable and cost-effective transmission solution to meet customers' needs while prudently managing the associated risks.

III.I. Contrast NCTPC Report to Other Regional Transfer Assessments

For both the DEC and DEP BAAs, the results of the PWG study are consistent with SERC Long-Term Working Group ("LTWG") studies performed for similar timeframes. LTWG studies have recently been performed for the 2027 summer timeframe. The limiting facilities identified in the PWG study of base reliability have been previously identified in the LTWG studies for similar scenarios. These limiting facilities have also been identified in the individual transmission owner's internal assessments required by NERC reliability standards.

IV. Base Reliability Study Results

The 2022 Study verified that DEC and DEP have projects already planned to address reliability concerns for the near-term (5 year) and long-term (10 year) planning horizons. There were no unforeseen problems identified in the reliability studies performed on the base cases.

The 2022 Plan is detailed in Appendix C which identifies the new and updated projects planned with an estimated cost of greater than $10 million. Projects in the 2022 Plan are those projects identified in the base reliability study. For each of these projects, Appendix C provides the project status, the estimated cost, the planned in-service date, and the estimated time to complete the project.

The total estimated cost for the 24 reliability projects included in the 2022 Plan is $936 million as documented in Appendix C. This compares to the original 2021 Plan estimate of $694 million for 16 reliability projects. In-service dates and cost estimates for some projects that are planned or underway have been revised based on updated information. An update to the 2021 Plan was provided in the 2021 Mid-Year Update published in August 2022 with an updated cost estimate of $748 million. See Appendix G for a detailed comparison of this year's Plan to the updated 2021 Plan.

V. Local Public Policy Study Results

For the 2022 Study, the NCTPC received two Public Policy Requests, one to evaluate the potential impacts of the development of PJM off-shore wind on the DEC and DEP transmission systems, and another to evaluate 9 GW of solar resources being incorporated into the DEC and DEP transmission systems. After review and discussion with each of the sponsors requesting the studies, the PJM offshore wind request was put on hold. In regard to the 9 GW solar Public Policy Request, due to difficulties in providing projected locations and MW sizes for solar resources, the requestor agreed with the NCTPC to instead utilize the results of supplemental studies performed by Duke to address NCUC Public Staff concerns regarding impact on the DEC and DEP network transmission systems to support the interconnection of significant renewable resources as specified in prior Integrated Resource Plans and in the more recent proposed Carbon Plan filed by DEC and DEP. If the solar requestor desires to submit an updated Local Public Policy Request in 2023, they agreed to provide more detailed input information for conducting an NCTPC study.

During the 2022 Study, the OSC recognized the evolving Carbon Plan as a public policy potentially driving the need for local transmission system upgrades. In response to the NCUC Public Staff concerns regarding this evolving public policy and the need to assess increasing transmission access to supply resources inside the BAAs of DEC and DEP, Duke Energy initiated the special supplemental study.

The results of the supplemental study and cost-benefit analysis (CBA) for the RZEP projects were presented to the TAG stakeholder group on October 18, 2022 for comment and feedback. The CBA for the RZEP projects consisted of the following process:

- Evaluation using an industry wide application, the Interruption Cost Estimate or “ICE” Calculator data based on the probability of failure.
- ICE calculates reliability benefits based off asset deterioration curves and measures customer impact of an outage utilizing the ICE data for the probability of failure.
- Utilization of the asset replacement value model to quantify the

reliability benefits from replacing aging infrastructure resulted in each of the RZEP projects scoring a 5.1 positive benefit to cost ratio or higher.

- These CBA scores do not ascribe any value to carbon reduction.

Following the October 18, 2022 TAG meeting, no additional comments or feedback were received from TAG participants by the requested November 4, 2022 date aside from the South Carolina Office of Regulatory Staff asking for the basis of the CBA numbers. That information from NCUC filed testimony was provided to the SC Office of Regulatory Staff.

DEC and DEP requested acknowledgement from the NCUC, within the Carbon Plan Order, that the 14 RZEP projects are needed in order to interconnect at the fast pace and large volume of new renewables specified in the Carbon Plan. On December 30, 2022, the NCUC issued its Carbon Plan Order[6] supporting the inclusion of the 14 RZEP projects in the 2022 Plan that were identified by the supplemental study, and indicated that the projects are necessary to achieve the carbon dioxide emission reduction mandates of the North Carolina General Assembly law HB 951 in a least cost manner. The NCUC's conclusion is in keeping with the directive from the North Carolina General Assembly that the NCUC consider transmission as an element of the Carbon Plan. N.C.G.S. § 62-110.9(1).

Consistent with Section 4.3.2.1 of Section N-1 of the OATT, the criteria for determining whether a public policy drives local transmission need includes a requirement that the "public policy must be reflected in state, federal or local law or regulation (including order of a state, federal, or local agency)." Enactment of the North Carolina General Assembly law HB 951 and the subsequent NCUC Carbon Plan Order provides support for these 14 RZEP projects being included as public policy projects in the Local Transmission Plan. The OSC has reviewed the supplemental study analysis and agrees with the study results and supports inclusion of the RZEP projects in the 2022 Plan.

[6] *Order Adopting Initial Carbon Plan and Providing Direction for Future Planning* ("Carbon Plan Order") issued December 30, 2022, in NCUC Docket No. E-100, Sub 179.

The total estimated cost for these 14 proposed RZEP projects in the 2022 Plan is $554 million as documented in Appendix F.

The results of the supplemental studies show completion of the 2022 RZEP projects will potentially allow the interconnection of approximately 3,759 MW of solar generating facilities in Duke's territory — 2,778 MW in DEP and 981 MW in DEC.

Throughout the consideration of these public policy projects by the NCTPC and during the NCUC Carbon Plan proceeding, various parties raised concerns regarding the appropriate cost allocation of these projects, including the potential disproportionate nature of the anticipated costs to be incurred by DEC and DEP, and the benefits to be received by their respective retail and wholesale customers. The NCUC recognized this issue and directed Duke to mitigate exacerbation of the rate disparity between DEC and DEP attributable to the Carbon Plan.

Parties also noted other cost allocation considerations including, but not limited to: (1) the potential unfavorable consideration of Duke's Carbon Plan expenditures, including public policy projects; (2) the different approaches to the allocation of network upgrade costs under state and federal interconnection procedures; and (3) the potential for cost increases and overruns beyond the estimates on which the analysis of the RZEP projects were based, including affected system costs for other LSEs.

Inclusion of the 14 RZEP projects in the 2022 Plan should not be viewed as an indication of any NCTPC OSC member's position on cost recovery or support for any specific cost allocation approach. Inclusion of the 14 RZEP projects as public policy projects should not be viewed as limiting the consideration of other benefits in cost recovery or cost allocation. Each LSE reserves the right to continue to advocate that the allocation of costs is done in a fair and equitable manner, and to ensure that only reasonable costs are eligible for recovery.

VI. Local Economic Study Results

In 2022, the PWG also analyzed, as part of the local economic planning studies, cases that represent 14 different hypothetical transfers into, out of, and through the DEC and DEP systems, listed in Table 5. Each of these transfers were examined individually, and not in combination with other transfers. Where issues requiring solutions within the applicable planning window were identified, alternative solutions were discussed, and a primary set of solutions was determined. All issues identified were either previously identified by the base reliability studies or can be mitigated with ancillary equipment upgrades.

Table 5
Local Economic Planning Studies
Resource Supply Options
2032/33 Winter Hypothetical Transfer Scenarios

ID	Resource From	Sink	Test Level (MW)
1	PJM	DUK[1]	1,000
2	SOCO	DUK	1,000
3	CPLE[2]	DUK	1,000
4	TVA[3]	DUK	1,000
5	PJM	CPLE	1,000
6	DUK	CPLE	1,000
7	DUK	SOCO	1,000
8	PJM	DUK / CPLE	1,000 / 1,000
9	DUK / CPLE	PJM	1,000 / 1,000
10	CPLE	PJM	1,000
11	DUK	PJM	1,000
12	DUK[4]	TVA	1,000
13	DUK	SCPSA	750
14	PJM[5]	SCPSA	500

[1] DUK is the Balancing Authority Area for DEC.

[2] CPLE is the eastern Balancing Authority Area for DEP.

[3] This hypothetical transfer is intended to evaluate the impact of a 1,000 MW TVA transaction through the SOCO transmission system into DUK.

[4] This hypothetical transfer is intended to evaluate the impact of a 1,000 MW DUK transaction through the SOCO transmission system into TVA.

[5] This hypothetical transfer is intended to evaluate the impact of a 500 MW PJM transaction through the DUK transmission system into SCPSA.

VII. Collaborative Transmission Plan

The 2022 Transmission Plan includes 24 reliability projects and 14 public policy projects with an estimated cost of $10 million or more each. The reliability projects are listed in Appendix C with detailed project descriptions in Appendix D. The total estimated cost for the 24 reliability projects is $936 million. This compares to the original 2021 Plan estimate of $694 million for 16 reliability projects. In-service dates and cost estimates for some projects that are planned or underway have been revised based on updated information. An update to the 2021 Plan was provided in the 2022 mid-year update published in August 2022 with an updated cost estimate of $748 million. The 14 public policy projects are listed in Appendix E with detailed project descriptions in Appendix F. The total estimated cost for the 14 public policy projects is $554 million. The total for all the projects included in the 2022 Transmission Plan is $1.49 billion.

The detailed project descriptions in Appendix D and E includes the following information:

1) Project ID: Description of the project.

2) Issue Resolved: Specific driver for project.

3) Status: Status of development of the project as described below:

    a. In-Service – Projects with this status are in-service.
    b. Underway – Projects with this status range from the Transmission Owner having some money in its current year budget for the project to the Transmission Owner having completed some construction activities for the project.
    c. Planned – Projects with this status do not have money in the Transmission Owner's current year budget and the project is subject to change.
    d. Conceptual – Projects with this status are not Planned at this time but will continue to be evaluated as a potential project in the future.
    e. Deferred – Projects with this status were identified in the 2021 Report and have been deferred beyond the end of the planning horizon based on the 2022 Study results.

f. Removed - Project is cancelled and no longer in the plan.

4) Transmission Owner: Responsible equipment owner designated to design and implement the project.

5) Projected In-Service Date: The date the project is expected to be placed in service.

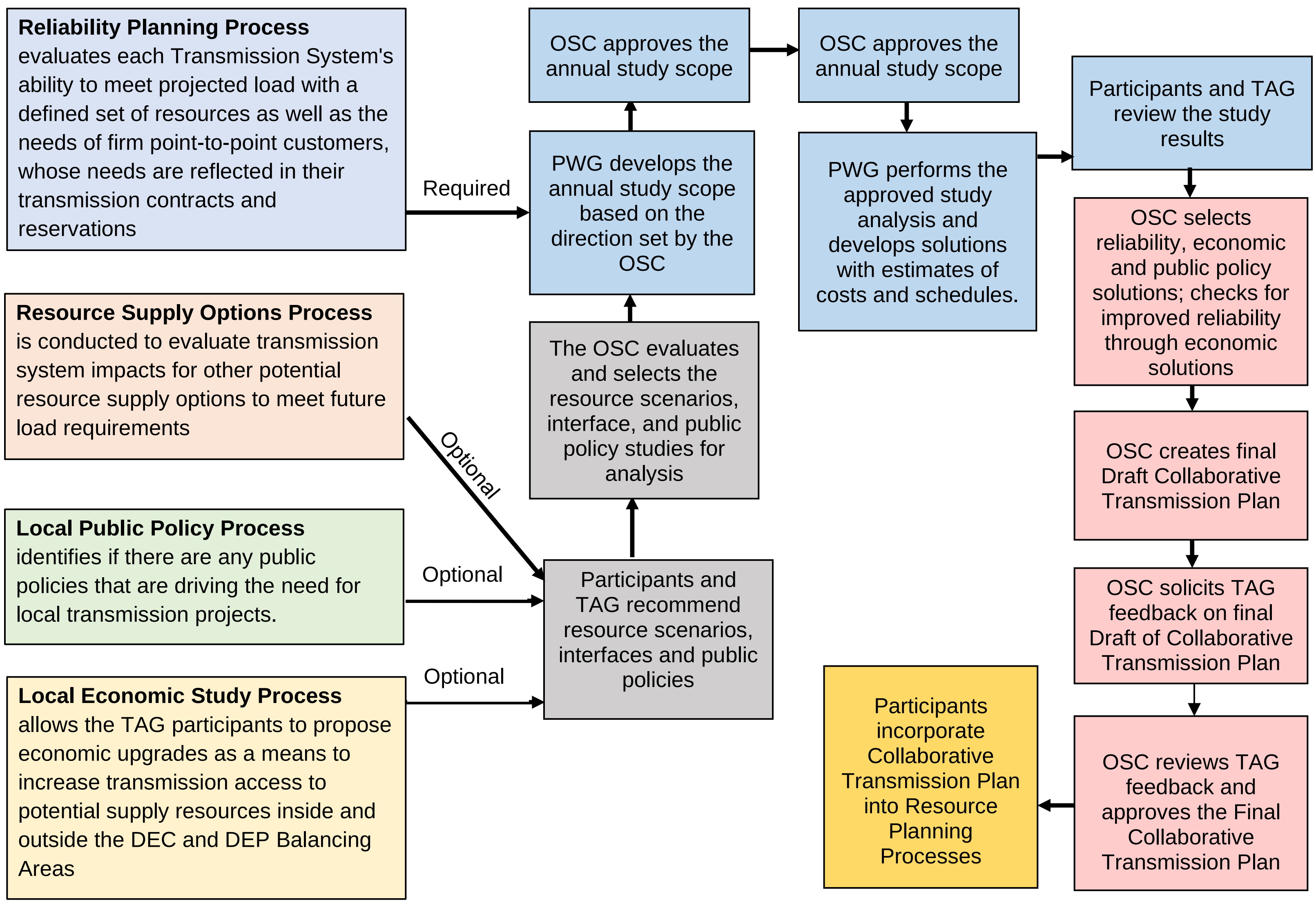
6) Estimated Cost: The estimated cost, in nominal dollars, which reflects the sum of the estimated annual cash flows over the expected development period for the specific project (typically 2 – 5 years), including direct costs, loadings and overheads, but not including AFUDC. Each year's cash flow is escalated to the year of the expenditures. The sum of the expected cash flows is the estimated cost.

7) Project lead time: Number of years needed to complete project. For projects with the status of Underway, the project lead time is the time remaining to complete construction of the project and place the project in service.

See Appendix G for a detailed comparison of this year's Plan to the updated 2021 Plan. The list of 2022 Transmission Plan projects will continue to be modified on an ongoing basis as new improvements are identified through the NCTPC Process and projects are placed in-service or eliminated from the list.

Appendix A
NCTPC Process Flow Chart

2022 NCTPC Process Flow Chart



Appendix B
Interchange Tables

2027 SUMMER PEAK, 2027/2028 WINTER PEAK, 2032/2033 WINTER PEAK

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE (BASE)

Duke Energy Carolinas Modeled Imports – MW

	27S	27/28W	32/33W
CPLE (NCEMC–Hamlet)	165	165	165
PJM (DVP/PJM)	2	2	2
SCEG (Chappells)	2	2	2
SCPSA (PMPA)	195	84	98
SCPSA (Seneca)	29	26	27
SEPA (Hartwell)	181	181	181
SEPA (Thurmond)	113	113	113
SOCO (NCEMC)	44	44	44
Total	**731**	**617**	**632**

Duke Energy Carolinas Modeled Exports – MW

	27S	27/28W	32/33W
CPLE (Broad River)	875	875	875
CPLE (Cleveland)	196	196	0
CPLE (KMEC)	87	87	87
CPLE (NCEMC–Catawba)	307	307	307
CPLE (Rowan)	376	370	0
PJM (NCEMC–Catawba)	100	100	100
SCEG (KMEC)	5	5	5
SCPSA (Haile)	20	20	20
Total	**1966**	**1960**	**1394**

Duke Energy Carolinas Net Interchange – MW

	27S	27/28W	32/33W
	1235	**1343**	**762**

Note: Positive net interchange indicates an export and negative interchange an import.

2027 SUMMER PEAK, 2027/2028 WINTER PEAK, 2032/2033 WINTER PEAK

DUKE ENERGY PROGRESS (EAST)

DETAILED INTERCHANGE (BASE)

Duke Energy Progress (East) Modeled Imports – MW

	27S	27/28W	32/33W
PJM (NCEMC–AEP)	100	100	100
PJM (NCEMC)	75	75	75
DUK (Broad River)	875	875	875
DUK (Cleveland)	196	196	0
DUK (NCEMC–Catawba)	307	307	307
DUK (KMEC)	87	87	87
DUK (Rowan)	376	370	0
PJM (SEPA–KERR)	95	95	95
Total	**2111**	**2105**	**1539**

Duke Energy Progress (East) Modeled Exports – MW

	27S	27/28W	32/33W
CPLW (Transfer)	0	150	200
PJM (NCEMC–Hamlet)	165	165	165
DUK (NCEMC–Hamlet)	165	165	165
Total	**330**	**480**	**530**

Duke Energy Progress (East) Net Interchange – MW

	27S	27/28W	32/33W
	-1781	**-1625**	**-1009**

Note: Positive net interchange indicates an export and negative interchange an import.

2027 SUMMER PEAK, 2027/2028 WINTER PEAK, 2032/2033 WINTER PEAK

DUKE ENERGY PROGRESS (WEST)

DETAILED INTERCHANGE (BASE)

Duke Energy Progress (West) Modeled Imports – MW

	27S	27/28W	32/33W
CPLE (Transfer)	0	150	200
SCPSA (Waynesville)	22	22	22
TVA (SEPA)	14	14	14
Total	**36**	**186**	**236**

Duke Energy Progress (West) Modeled Exports – MW

	27S	27/28W	32/33W
–--	---	---	---
Total	**---**	**---**	**---**

Duke Energy Progress (West) Net Interchange – MW

	27S	27/28W	32/33W
	-36	**-186**	**-236**

Note: Positive net interchange indicates an export and negative interchange an import.

2027 SUMMER PEAK, 2027/2028 WINTER PEAK, 2032/2033 WINTER PEAK

DUKE ENERGY PROGRESS (WEST), DUKE ENERGY PROGRESS (EAST)

DETAILED INTERCHANGE (TRM)

Duke Energy Progress (West) Modeled Imports – MW

	27S, 27/28W, 32/33W
AEP (TRM)	69
DUK (TRM)	191
TVA (TRM)	20
Total	**280**

Duke Energy Progress (East) Modeled Imports – MW

	27S, 27/28W, 32/33W
AEP (TRM)	100
DUK (TRM)	773
DVP (TRM)	427
SCEG (TRM)	200
SCPSA (TRM)	326
Total	**1826**

Note: Imports and exports for TRM are in addition to Base transfers

Appendix C Transmission Plan Major Project Listings – Reliability Projects

2022 Collaborative Transmission Plan – Reliability Projects (Estimated Cost > $10M) Items identified in red are changes from the previous report.						
Project ID	Reliability Project	Status[1]	Transmission Owner	Projected In-Service Date	Estimated Cost ($M)[2]	Project Lead Time (Years)[3]
0024	Durham–RTP 230 kV Line, Reconductor	Conceptual	DEP	TBD	20	4
0039	Asheboro–Asheboro East 115 kV North Line, Reconductor	In-service	DEP	12/1/2022	28	-
0046	Windmere 100 kV Line (Dan River-Sadler), Construct	Underway	DEC	6/1/2024	26	1.5
0048	Wilkes 230/100 kV Tie Station, Construct	Underway	DEC	12/1/2024	53	2

2022 Collaborative Transmission Plan – Reliability Projects (Estimated Cost > $10M) Items identified in red are changes from the previous report.						
Project ID	Reliability Project	Status[1]	Transmission Owner	Projected In-Service Date	Estimated Cost ($M)[2]	Project Lead Time (Years)[3]
0050	Craggy–Enka 230 kV Line, Construct	Underway	DEP	12/1/2024	104	2
0051	Cokesbury 100 kV Line (Coronaca–Hodges), Upgrade	Planned	DEC	6/1/2025	22	2.5
0052	South Point 100 kV Switching Station, Construct	Underway	DEC	12/1/2025	96	3
0053	Wateree Hydro Plant, Upgrade	Underway	DEP	6/1/2023	15	0.5
0054	Carthage 230/115 kV Substation, Construct	Underway	DEP	12/1/2025	28.5	3

2022 Collaborative Transmission Plan – Reliability Projects (Estimated Cost > $10M) Items identified in red are changes from the previous report.						
Project ID	Reliability Project	Status[1]	Transmission Owner	Projected In-Service Date	Estimated Cost ($M)[2]	Project Lead Time (Years)[3]
0055	Falls 230 kV Sub, Upgrade	Conceptual	DEP	12/1/2028	45	4
0056	Castle Hayne–Folkstone115 kV Line, Rebuild	Underway	DEP	12/1/2025	95.5	3
0057	Holly Ridge North 115 kV Switching Station, Construct	Underway	DEP	12/1/2026	12	4
0058	Coronaca 100 kV Line (Coronaca-Creto), Upgrade and Construct	Planned	DEC	6/1/2026	18	3.5
0059	Monroe 100 kV Line (Lancaster-Monroe), Upgrade	Underway	DEC	12/1/2027	53	5

1

2022 Collaborative Transmission Plan – Reliability Projects (Estimated Cost > $10M) Items identified in red are changes from the previous report.						
Project ID	Reliability Project	Status[1]	Transmission Owner	Projected In-Service Date	Estimated Cost ($M)[2]	Project Lead Time (Years)[3]
0060	Westport 230 kV Line (McGuire-Marshall), Upgrade	Conceptual	DEC	TBD	65	4.5
0061	Wateree 100 kV Line (Great Falls-Wateree), Upgrade	Underway	DEC	12/1/2023	10	1
0062	Silas 100 kV Line (Mocksville-Idols Tap), Upgrade	Underway	DEC	6/1/2025	22	2.5
0063	North Greenville 230 kV Tie Station, Upgrade	Underway	DEC	12/1/2026	20	4
0064	Wylie 100 kV Line (Wylie-Arrowood Retail), Upgrade	Underway	DEC	12/1/2026	15	4
0065	Morning Star 230 kV Tie Station, Upgrade	Planned	DEC	6/1/2028	36	4

2022 Collaborative Transmission Plan – Reliability Projects (Estimated Cost > $10M) Items identified in red are changes from the previous report.						
Project ID	Reliability Project	Status[1]	Transmission Owner	Projected In-Service Date	Estimated Cost ($M)[2]	Project Lead Time (Years)[3]
0066	Davidson River 100 kV Line (North Greenville-Marietta), Upgrade	Conceptual	DEC	TBD	30	4
0067	Harley 100 kV Line (Tiger-Campobello), Upgrade	Conceptual	DEC	TBD	45	4
0068	Sandy Ridge 230 kV Line (Newport-Morning Star), Upgrade	Planned	DEC	12/1/2028	60	6
0069	Skybrook 100 kV Line (Winecoff-Eastfield Retail), Upgrade	Conceptual	DEC	TBD	17	4
TOTAL					**936**	

[1] Status: ***In-service****:* Projects with this status are in-service. This status was updated as of 12/1/2022.

Underway*:* Projects with this status range from the Transmission Owner having some money in its current year budget for the project to the Transmission Owner having completed some construction activities for the project.

Planned*:* Projects with this status do not have money in the Transmission Owner's current year budget; and the project is subject to change.

***Conceptual**:* Projects with this status are not p*lanned* at this time but will continue to be evaluated as a potential project in the future.

***Deferred**:* Projects with this status were identified in the 2021 Report and have been deferred beyond the end of the planning horizon based on analysis performed to develop the 2022 Collaborative Transmission Plan.

Removed: Project is cancelled and no longer in the plan

[2] The estimated cost is in nominal dollars which reflects the sum of the estimated annual cash flows over the expected development period for the specific project (typically 2 – 5 years), including direct costs, loadings and overheads; but not including AFUDC. Each year's cash flow is escalated to the year of the expenditures. The sum of the expected cash flows is the estimated cost.

[3] For projects with a status of Underway, the project lead time is the time remaining to complete construction and place in-service.

Appendix D
Transmission Plan
Major Project
Descriptions –
Reliability Projects

Table of Contents

Note: The estimated cost for each of the projects described in this Appendix D is in nominal dollars which reflects the sum of the estimated annual cash flows over the expected development period for the specific project (typically 2 – 5 years), including direct costs, loadings and overheads; but not including AFUDC. Each year's cash flow is escalated to the year of the expenditures. The sum of the expected cash flows is the estimated cost.

Project ID and Name: 0024 – Durham–RTP 230 kV Line, Reconductor

Project Description
Reconductor approximately 10 miles of 230 kV line with 6–1590 ACSR conductor.

Status	Conceptual
Transmission Owner	DEP
Planned In-Service Date	TBD
Estimated Time to Complete	4 years
Estimated Cost	$20 M

Narrative Description of the Need for this Project
With Harris Plant down, a common tower outage of the Method (DEC)–East Durham and the Durham–Method 230 kV Lines will cause an overload of the Durham 500 kV Sub-RTP 230 kV Switching Station Line.

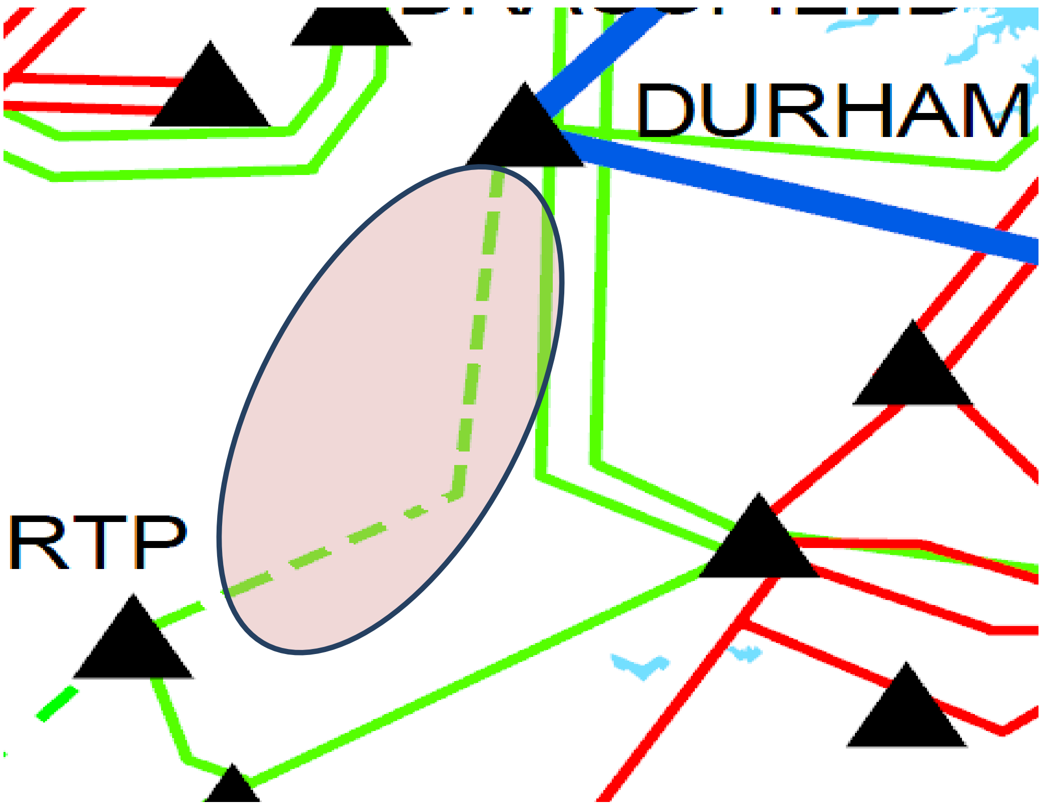
Other Transmission Solutions Considered
Construct a new line between Durham and RTP 230 kV subs.

Why this Project was Selected as the Preferred Solution
Cost and feasibility. Reconductoring is much more cost effective.

D–1

Durham–RTP 230 kV Line

- **NERC Category P3 Violation**
- **Problem:** With Harris Plant down, a common tower outage of the Method (DEC)–East Durham and the Durham–Method 230 kV Lines will cause an overload of the Durham 500 kV Sub-RTP 230 kV Switching Station Line.
- **Solution:** Reconductor approximately 10 miles of 230 kV line with 6-1590 ACSR conductor.



Project ID and Name: 0034 – Sutton–Castle Hayne 115 kV North Line, Rebuild

Project Description
This project consists of rebuilding the Sutton Plant – Castle Hayne 115 kV North Line using 1272 MCM ACSR conductor or equivalent (approximately 8 miles). The line traps at both Sutton and Castle Hayne terminals will be removed in conjunction with the installation of OPGW. The 800 A current transformers at both line terminals will have to be uprated as part of this project.

Status	In-service
Transmission Owner	DEP
Planned In-Service Date	6/1/2021
Estimated Time to Complete	Completed
Estimated Cost	$30 M

Narrative Description of the Need for this Project
By 2021, with all area generation online, the loss of the Sutton Plant–Castle Hayne 115 kV South Line will cause the Sutton Plant–Castle Hayne 115 kV North Line to exceed its thermal rating.

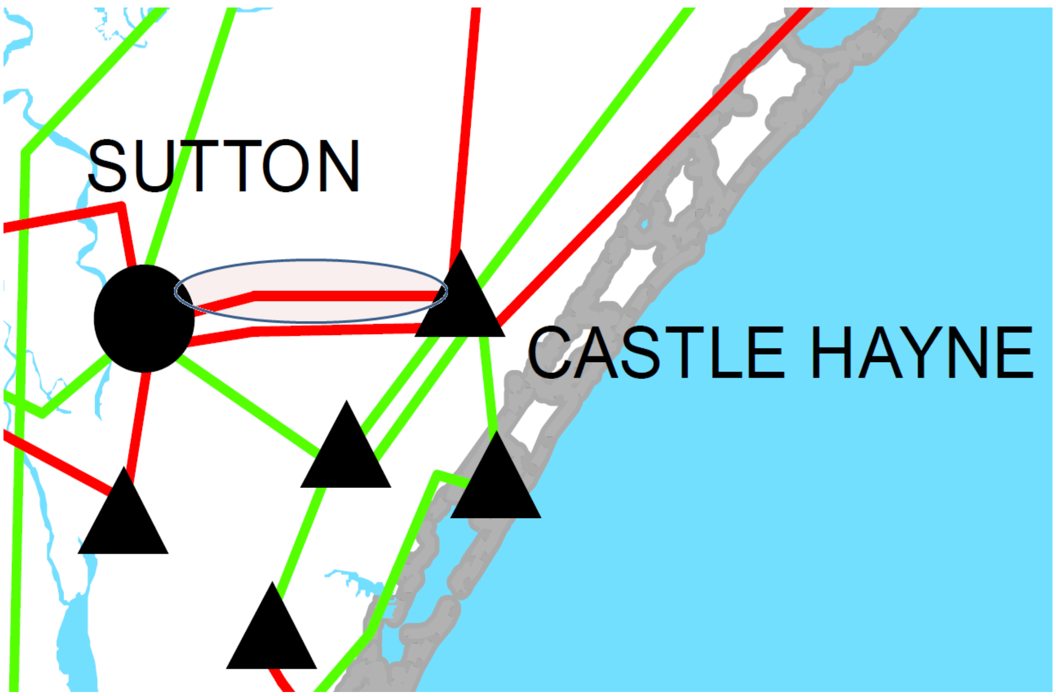
Other Transmission Solutions Considered
Convert 115 kV line to 230 kV.

Why this Project was Selected as the Preferred Solution
Cost and feasibility are much improved with selected alternative.

D–2

Sutton–Castle Hayne 115 kV North Line, Rebuild

- **NERC Category P1 violation**
- **Problem:** By 2021, with all area generation online, the loss of the Sutton Plant–Castle Hayne 115 kV South Line will cause the Sutton Plant–Castle Hayne 115 kV North Line to exceed its thermal rating.
- **Solution:** Rebuild 115 kV line.



Project ID and Name: 0039 – Asheboro–Asheboro East 115 kV North Line, Reconductor

Project Description
This project consists of rebuilding/reconductoring approximately 6.5 miles of the existing 115 kV line using 3-1590 or equivalent conductor. This project requires the replacement of disconnect switches at Asheboro 230 kV and the replacement of the breaker, the disconnect switches, and the 115 kV east bus at Asheboro East 115 kV associated with this line. Both ends of the line will also require CT/metering equipment upgrades such that they are not the limit to the line rating. The upgraded equipment for this line should be 2000 amp minimum.

Status	Underway
Transmission Owner	DEP
Planned In-Service Date	6/1/2022
Estimated Time to Complete	0.5 years
Estimated Cost	$28 M

Narrative Description of the Need for this Project
This project is needed to alleviate loading on the Asheboro–Asheboro East 115 kV North line under the contingency of losing the Asheboro–Asheboro East 115 kV South line with Harris Plant down.

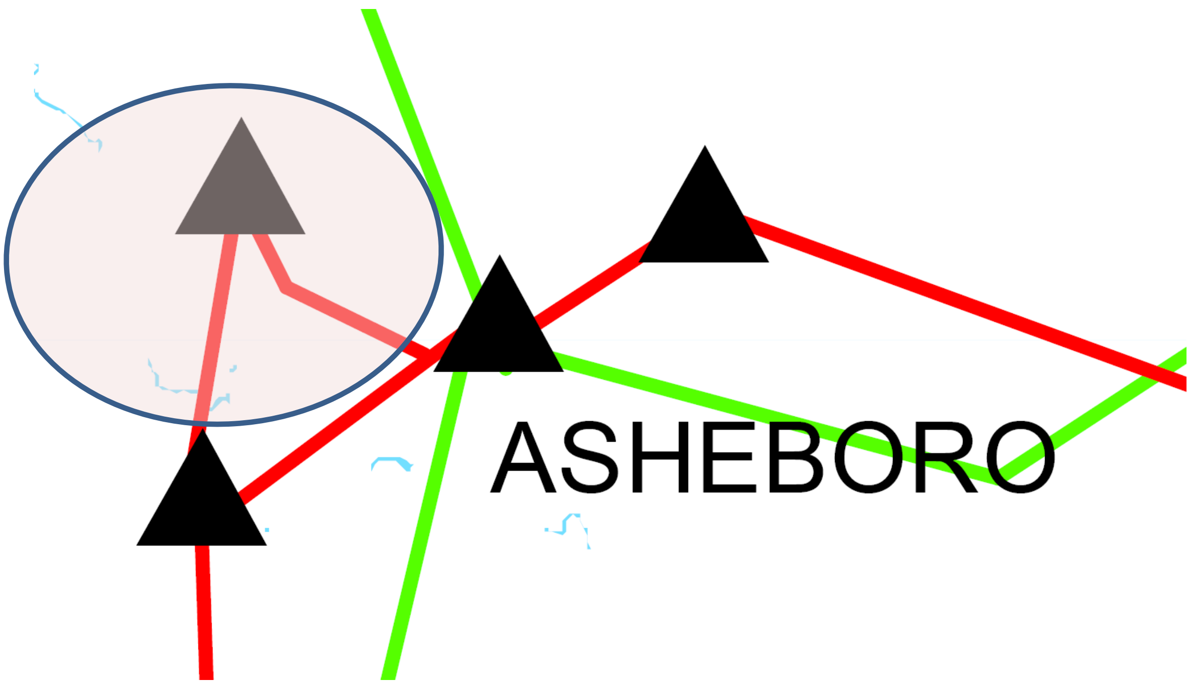
Other Transmission Solutions Considered
Construct a new 115 kV line from Asheboro to Asheboro East.

Why this Project was Selected as the Preferred Solution
Cost and feasibility.

D–3

Asheboro–Asheboro East 115 kV North Line, Reconductor

- **NERC Category P3 violation**
- **Problem:** By the summer of 2022, with Harris down, the loss of the Asheboro–Asheboro East 115 kV South line will cause the Asheboro–Asheboro East 115 kV North line to overload.
- **Solution:** Rebuild/reconductor the Asheboro–Asheboro East 115 kV North Line and upgrade equipment.



Project ID and Name: 0046 – Windmere 100 kV Line (Dan River–Sadler), Construct

Project Description
This project consists of building a new 100 kV line (954 ACSR) along an existing ROW.

Status	Underway
Transmission Owner	DEC
Planned In-Service Date	6/1/2024
Estimated Time to Complete	1.5 years
Estimated Cost	$26 M

Narrative Description of the Need for this Project
The Reidsville and Wolf Creek 100 kV lines (Dan River–Sadler) can become overloaded for the loss of any of the circuits between Dan River and Sadler.

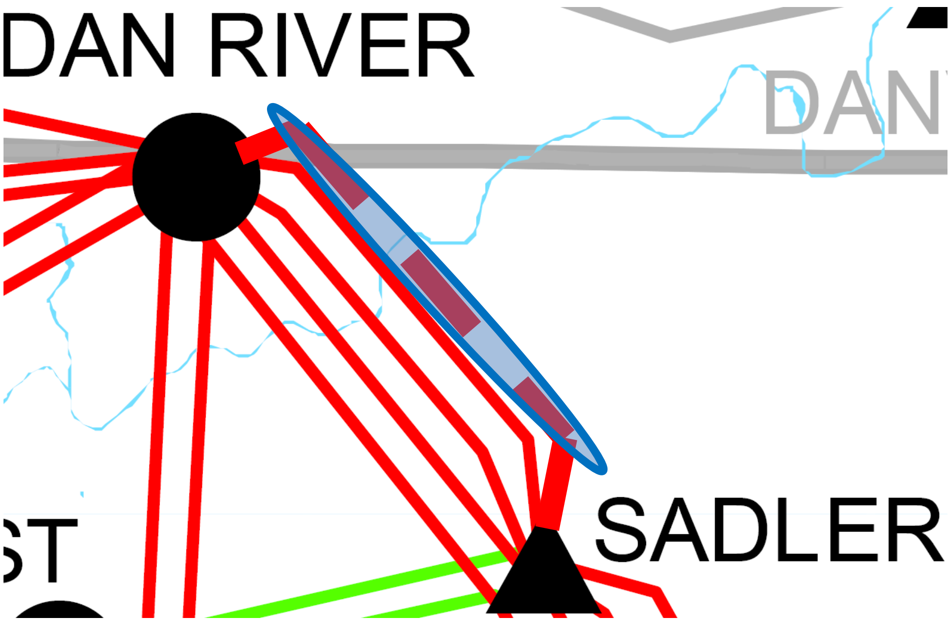
Other Transmission Solutions Considered
Rebuilding both double circuit 100 kV lines (≈8 miles each) between Dan River and Sadler.

Why this Project was Selected as the Preferred Solution
Greater operational flexibility in the area.

D–4

Windmere 100 kV Line (Dan River–Sadler), Construct

- **NERC Category P3 violation**
- **Problem:** Loss of any of the four existing 100 kV circuits between Dan River and Sadler and can overload the remaining circuits.
- **Solution:** Construct new 100 kV line.



Project ID and Name: 0048 – Wilkes 230/100 kV Tie Station, Construct

Project Description
This project consists of building a new 230/100 kV Wilkes tie station and re-routing local transmission lines.

Status	Underway
Transmission Owner	DEC
Planned In-Service Date	12/1/24
Estimated Time to Complete	2 years
Estimated Cost	$53 M

Narrative Description of the Need for this Project
The primary driver for this project is to increase support in the area around Wilkesboro NC. Contingencies, especially in the winter, have the tendency to drop voltage in the area as well as some thermal loading concerns with the loss of the Oxford 100 kV line. The secondary driver is to alleviate the need to rebuild N Wilkesboro Tie as a result of the need to install a bus junction breaker at N Wilkesboro Tie. Presently, loss of the single N Wilkesboro bus takes out six 100 kV lines, causes loss of load and low voltage problems in the area. Installation of a bus junction breaker would also cause thermal loading issues requiring a line upgrade. This project also makes use of 230 kV transmission lines that pass adjacent to the new 230/100 kV tie station.

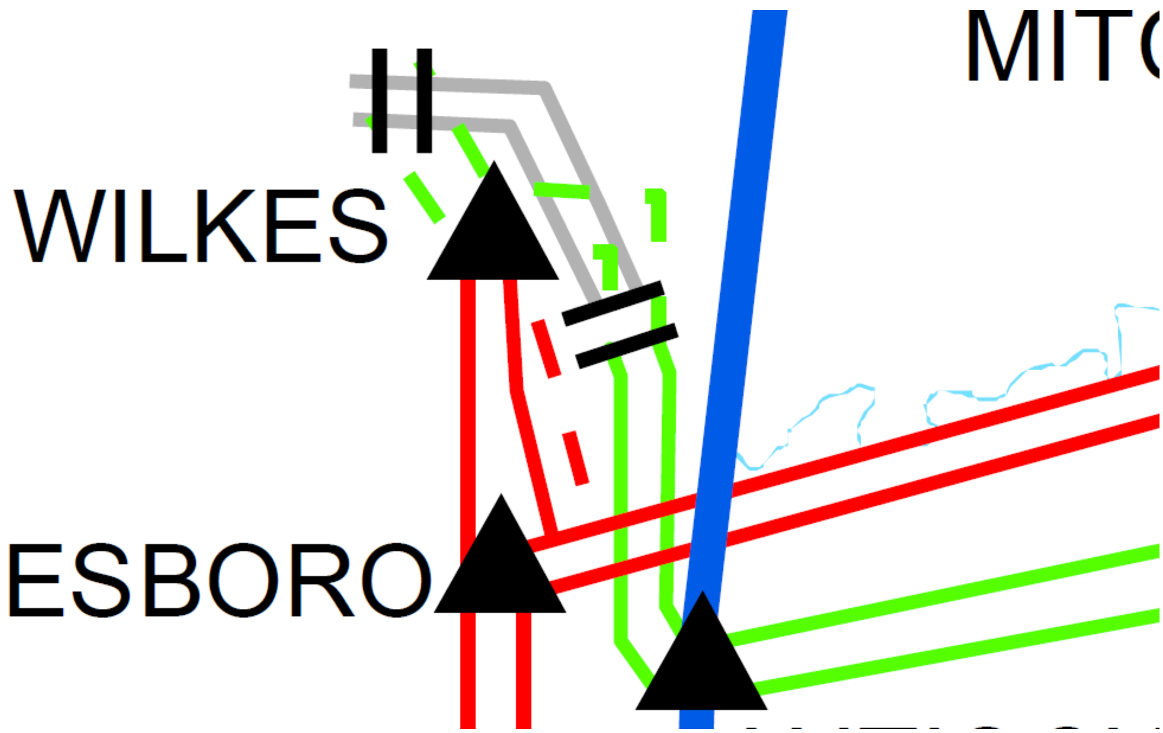
Other Transmission Solutions Considered
Rebuild N Wilkesboro Tie to allow installation of a bus tie breaker.

Why this Project was Selected as the Preferred Solution
Greater long-term value to system and operational flexibility in the area.

D–5

Wilkes 230/100 kV Tie Station, Construct

- **NERC Category P1, P2, & P3 violation**
- **Problem:** Contingency events in the Wilkesboro, NC area cause thermal loading issues, loss of load and low voltage problems in the area.
- **Solution:** Construct new 230/100 kV tie station.



Project ID and Name: 0050 – Craggy-Enka 230 kV Line, Construct

Project Description
This project consists of constructing approximately 10 miles of new 230 kV transmission line between the Craggy and Enka Substations.

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	12/1/2025
Estimated Time to Complete	4 years
Estimated Cost	$104 M

Narrative Description of the Need for this Project
Opening the Asheville end of the Oteen 115 kV West line overloads the Enka – West Asheville 115 kV line. Also, a NERC P6 outage of Craggy–Enka 115 and Asheville–Oteen 115 West lines has no viable operating procedure beginning 12/1/2025. Outage of the West Asheville 115 kV bus overloads the Craggy–Enka 115 kV line.

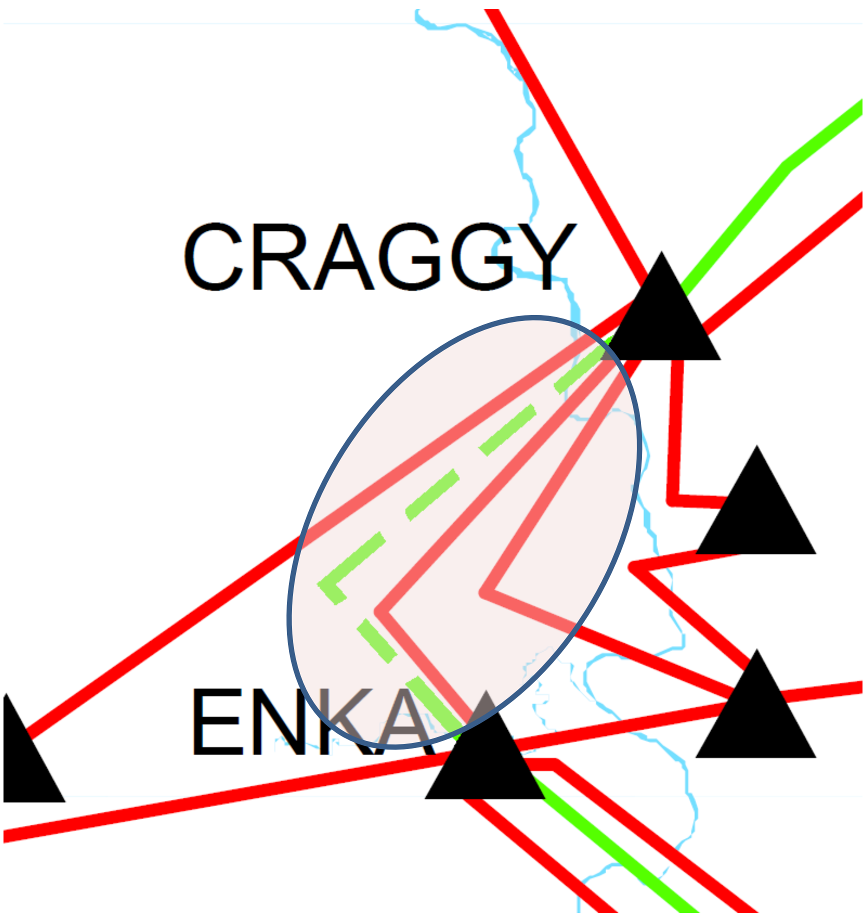
Other Transmission Solutions Considered
Reconductoring multiple transmission lines. These include the Enka–West Asheville 115 kV Line, the Craggy–Enka 115 kV line, the Canton–Craggy 115 kV Line, and the Asheville–Oteen 115 kV East Line.

Why this Project was Selected as the Preferred Solution
Cost and feasibility.

D–6

Craggy–Enka 230 kV Line, Construct

- **NERC Category P3 & P6 violation**
- **Problem:** Opening the Asheville end of the Oteen 115 kV West line overloads the Enka – West Asheville 115 kV line. Also, a NERC P6 outage of Craggy–Enka 115 kV and Asheville–Oteen 115 kV West lines has no viable operating procedure beginning 12-2025. Outage of the West Asheville 115 kV bus overloads the Craggy–Enka 115 kV line.
- **Solution:** Construct the Craggy–Enka 230 kV Line.



Project ID and Name: 0051 – Cokesbury 100 kV Line (Coronaca–Hodges), Upgrade

Project Description
This project consists of rebuilding 9.2 miles of the existing 477 ACSR conductor with 1272 ACSR.

Status	Planned
Transmission Owner	DEC
Planned In-Service Date	6/1/25
Estimated Time to Complete	2.5 years
Estimated Cost	$22 M

Narrative Description of the Need for this Project
These lines may become overloaded for loss of one of the circuits.

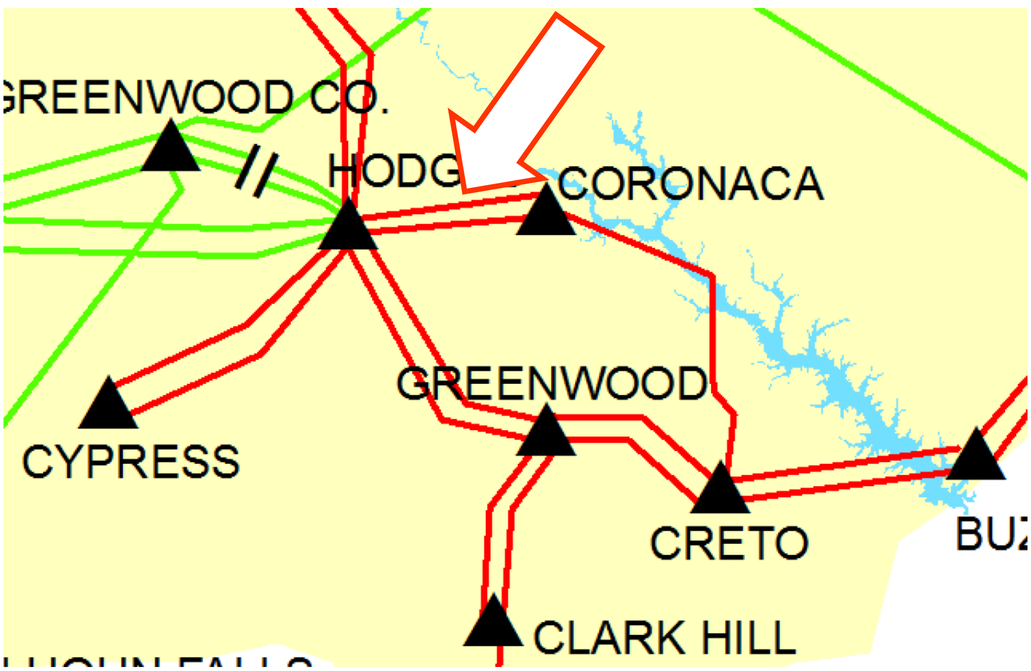
Other Transmission Solutions Considered
New transmission line(s).

Why this Project was Selected as the Preferred Solution
New transmission line(s) would require additional right-of-way, adding to the cost of the project.

D–7

Cokesbury 100 kV Line (Coronaca–Hodges), Upgrade

- **NERC Category P3 violation**
- **Problem:** Loss of one of the Greenwood–Hodges 100 kV lines may overload the remaining line.
- **Solution:** Rebuild 100 kV lines with higher capacity conductors.



Project ID and Name: 0052 – South Point 100 kV Switching Station, Construct

Project Description
This project consists of replacing (in a new location) the 100 kV switchyard at Allen Steam Station and upgrading the existing 230/100 kV transformers.

Status	Underway
Transmission Owner	DEC
Planned In-Service Date	12/1/25
Estimated Time to Complete	3 years
Estimated Cost	$96 M

Narrative Description of the Need for this Project
The transformers may become overloaded for loss of the other transformer, and there are obsolescence issues with the existing switchyard at Allen Steam Station.

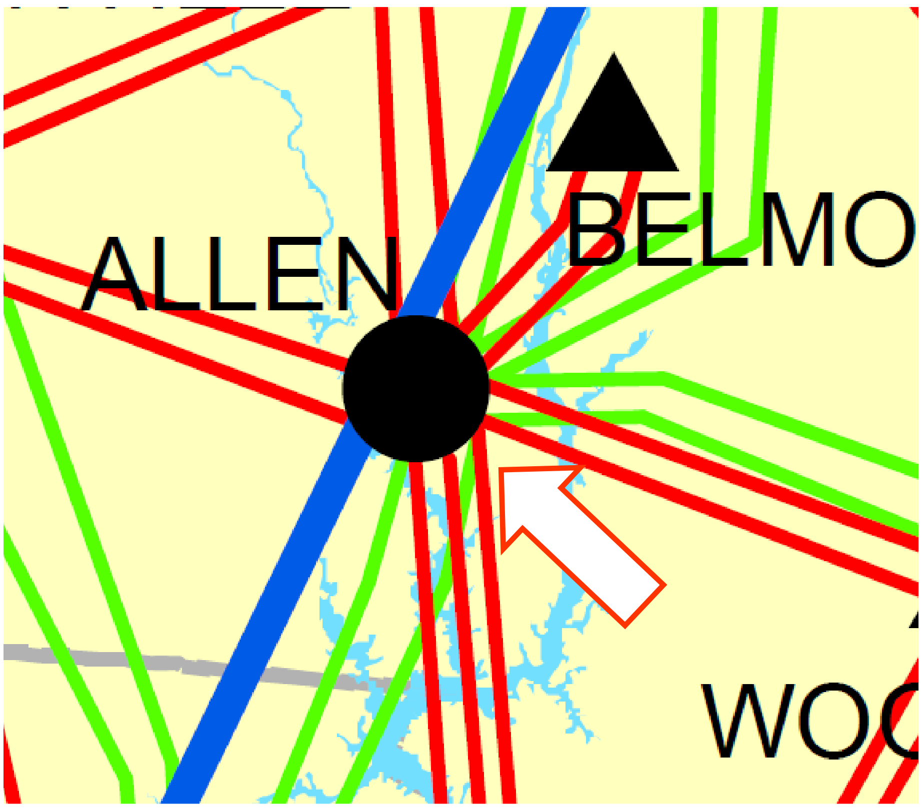
Other Transmission Solutions Considered
Convert Wylie Switching Station to 230/100 kV. Rebuild Allen Steam Station in its current location and replace existing 230/100 kV transformers at Allen Steam Station.

Why this Project was Selected as the Preferred Solution
Cost and timing

D–8

South Point 100 kV Switching Station, Construct

- **NERC Category P3 Violation**
- **Problem:** Post-generation retirement at Allen Steam Station, loss of one 230/100 kV transformers at Allen may overload the remaining transformer.
- **Solution:** Upgrade to larger transformers



Project ID and Name: 0053 – Wateree Hydro Plant, Upgrade

Project Description
This project consists of replacing the two existing 115/100 kV autotransformers at Wateree Plant with two new 168 MVA 115/100 kV autotransformers. While the two existing 115/100 kV Wateree transformers share a single breaker, the new transformers will be separately breakered so that either one can trip out with the other bank still transferring power between DEP and DEC. (The Wateree Plant is owned by DEC, but the existing 115/100 kV transformers and the 115 kV bus are owned by DEP.)

Status	Underway
Transmission Owner	DEP
Planned In-Service Date	12/1/2023
Estimated Time to Complete	2 years
Estimated Cost	$15 M

Narrative Description of the Need for this Project
By winter 2023-24, the NERC P3 outage of Robinson Nuclear plus outage of either the Richmond–Newport 500 kV line or the Camden–Lugoff 230 kV line causes an overload of the existing Wateree 115/100 kV transformers. In addition, the existing Wateree 115/100 kV transformers have reached end of life based on analysis from Asset Management.

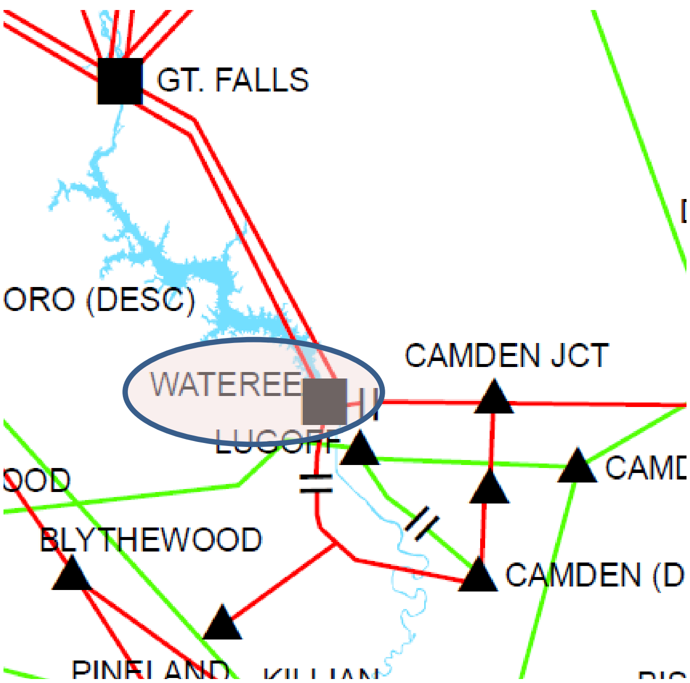
Other Transmission Solutions Considered
New transmission lines.

Why this Project was Selected as the Preferred Solution
The cost and construction feasibility are much better with selected alternative.

D–9

Wateree Hydro Plant, Upgrade

- **NERC Category P3 violation**
- **Problem:** By winter 2023-24, the NERC P3 outage of Robinson Nuclear plus outage of either the Richmond–Newport 500 kV line or the Camden–Lugoff 230 kV line causes an overload of the existing Wateree 115/100 kV transformers. In addition, the existing Wateree 115/100 kV transformers have reached end of life based on analysis from Asset Management.
- **Solution:** Upgrade existing transformers.



Project ID and Name: 0054 – Carthage 230/115 kV Substation, Construct

Project Description
Construct a new 230/115 kV substation near the existing Carthage 115 kV substation. Loop in the existing Cape Fear–West End 230 kV line and West End–Southern Pines 115 kV feeder. The new Carthage 230–West End 115 kV line will be normally open at Carthage 230.kV.

Status	Underway
Transmission Owner	DEP
Planned In-Service Date	12/1/2025
Estimated Time to Complete	4 years
Estimated Cost	$28.5 M

Narrative Description of the Need for this Project
By winter 2025-26, the NERC P1 outage of one West End transformer overloads the other and voltage at Southern Pines 115 kV drops below criteria.

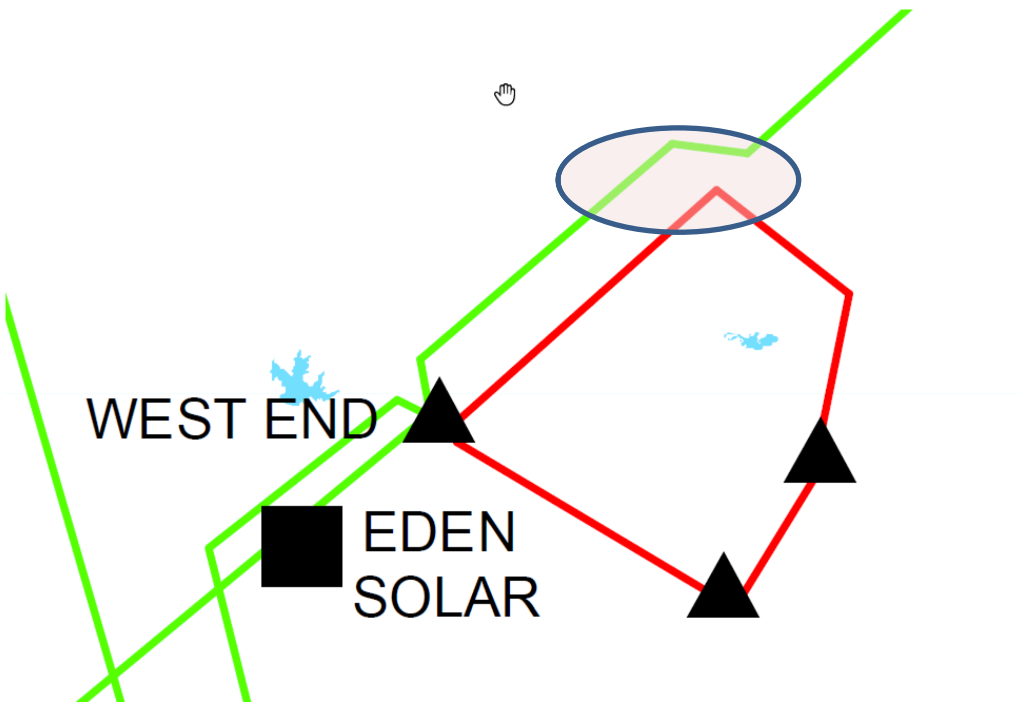
Other Transmission Solutions Considered
Convert several 115 kV substations to 230 kV.

Why this Project was Selected as the Preferred Solution
The cost and construction feasibility are much better with selected alternative.

D–10

Carthage 230/115 kV Substation, Construct

- **NERC Category P1 violation**
- **Problem:** By winter 2025-26, the NERC P1 outage of one West End transformer overloads the other and voltage at Southern Pines 115 kV drops below criteria.
- **Solution:** Construct new 230/115 kV substation in the Carthage area.



Project ID and Name: 0055 – Falls 230 kV Sub, Construct

Project Description
At Falls 230 kV Substation add a 300 MVAR 230 kV Static Var Compensator (SVC).

Status	Conceptual
Transmission Owner	DEP
Planned In-Service Date	12/1/2028
Estimated Time to Complete	4 years
Estimated Cost	$45 M

Narrative Description of the Need for this Project
With the future retirement of Roxboro and Mayo plants, several DEP areas were observed to have significant contingency voltage depression.

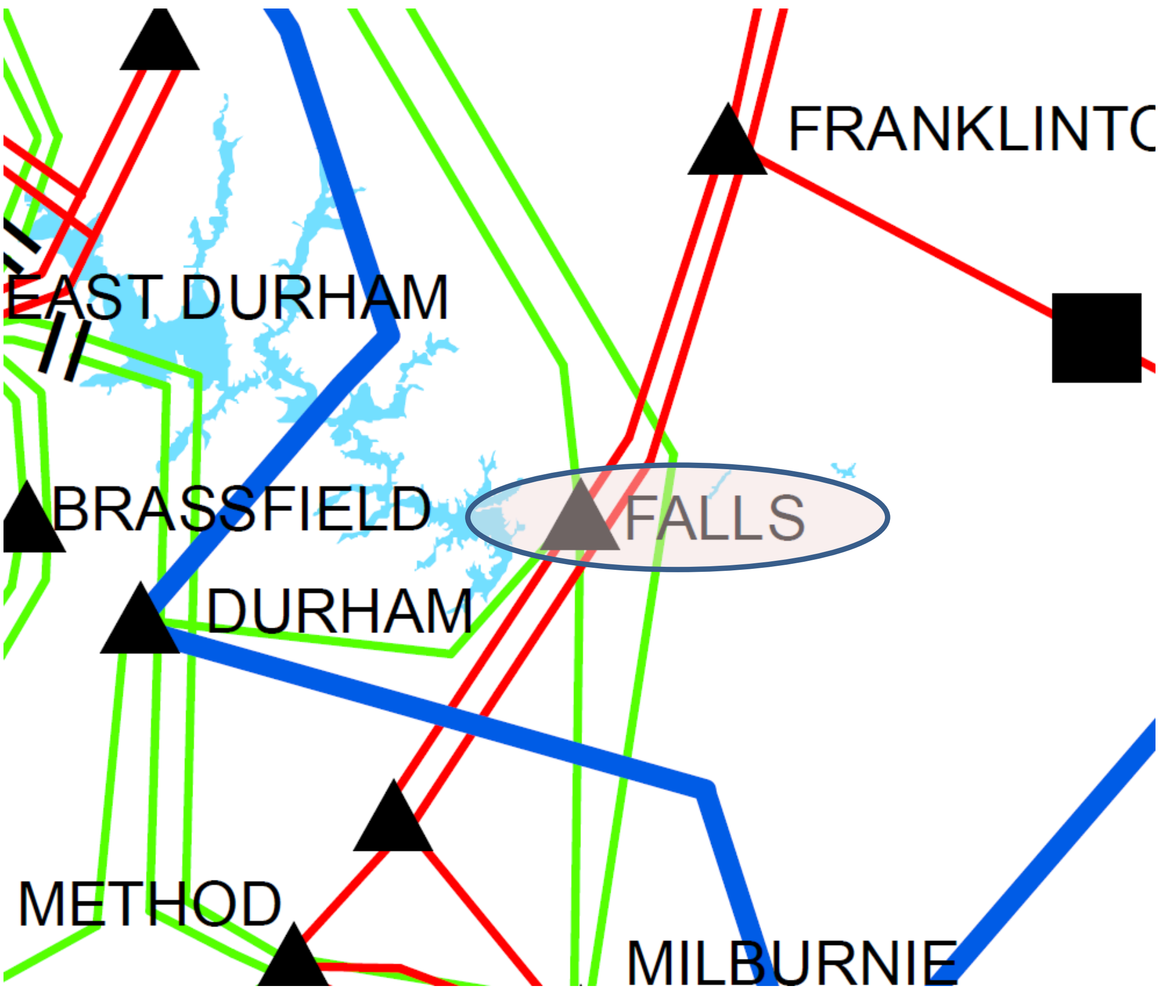
Other Transmission Solutions Considered
Replacement generation in the Roxboro area.

Why this Project was Selected as the Preferred Solution
The cost and construction feasibility are much better with selected alternative.

D–11

Falls 230 kV Sub, Construct

- **NERC Category P1 violation**
- **Problem:** With the future retirement of Roxboro and Mayo plants, several DEP areas were observed to have significant contingency voltage depression.
- **Solution:** Add 300 MVAR SVC at the Falls 230 kV Substation.



Project ID and Name: 0056 – Castle Hayne–Folkstone 115 kV Line, Rebuild

Project Description
Rebuild approximately 25.91 miles of 115 kV line (Castle Hayne 230 kV Sub to structure #251) with 1272 MCM ACSR or equivalent.

Status	Underway
Transmission Owner	DEP
Planned In-Service Date	12/1/2026
Estimated Time to Complete	4 years
Estimated Cost	$95.5 M

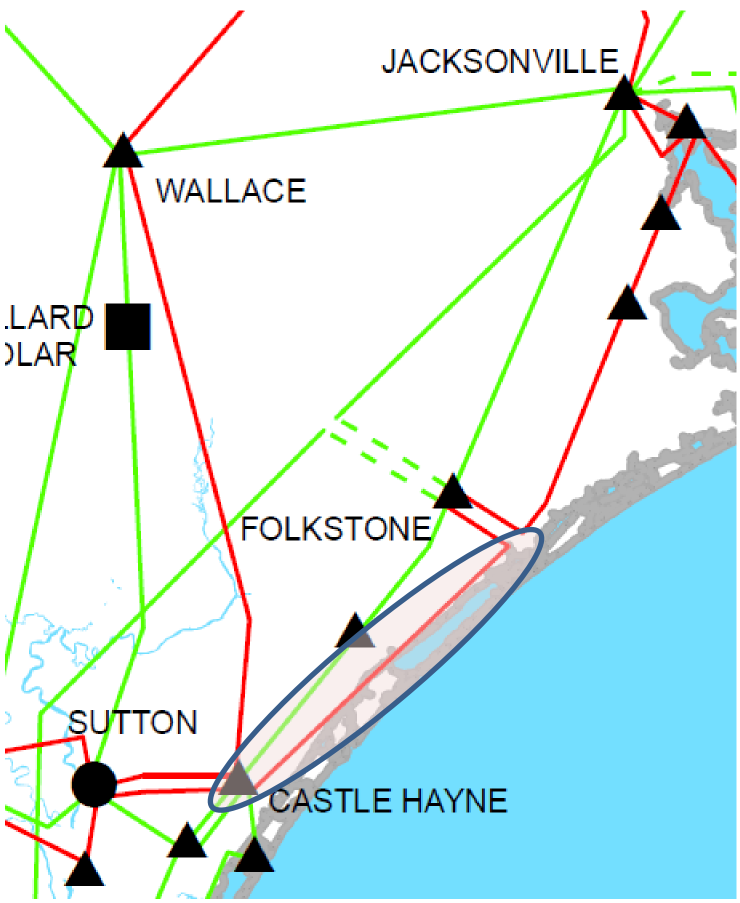
Narrative Description of the Need for this Project
By winter 2026/27, an outage of the Castle Hayne – Folkstone 230 kV line will cause the Castle Hayne 230 kV Sub-Folkstone 115 kV line to overload. This project will mitigate the overload problem.

Other Transmission Solutions Considered
New 230 kV transmission lines.

Why this Project was Selected as the Preferred Solution
The cost and construction feasibility are much better with selected alternative.

Castle Hayne–Folkstone 115 kV Line, Rebuild

- **NERC Category P1 violation**
- **Problem:** By winter 2026/27, an outage of the Castle Hayne–Folkstone 230 kV line will cause the Castle Hayne 230 kV Sub-Folkstone 115 kV line to overload. This project will mitigate the overload problem.
- **Solution:** Rebuild approximately 25.91 miles of 115 kV line (Castle Hayne 230 kV Sub to structure #251) with 1272 MCM ACSR or equivalent.



Project ID and Name: 0057 – Holly Ridge North 115 kV Switching Station, Construct

Project Description
Construct a new 115 kV Switching Station northeast of Holly Ridge, NC where the Castle Hayne–Folkstone 115 kV and Folkstone–Jacksonville City 115 kV lines come together. Construct a new 115 kV feeder from the new switching station to Jones–Onslow EMC Folkstone POD.

Status	Underway
Transmission Owner	DEP
Planned In-Service Date	12/1/2026
Estimated Time to Complete	4 years
Estimated Cost	$12 M

Narrative Description of the Need for this Project
By winter 2026-27, the NERC P2-1 opening of the Folkstone end of the Castle Hayne–Folkstone 115 kV line results in low voltages at stations on this line.

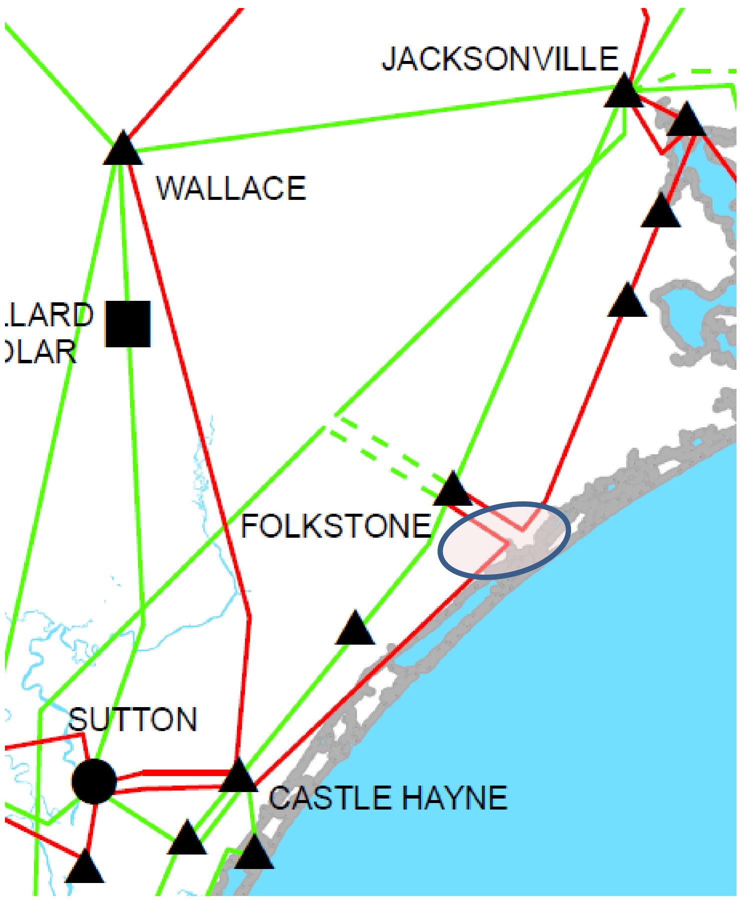
Other Transmission Solutions Considered
New 230 kV transmission lines.

Why this Project was Selected as the Preferred Solution
The cost and construction feasibility are much better with selected alternative.

D–13

Holly Ridge North 115 kV Switching Station, Construct

- **NERC Category P2-1 violation**
- **Problem:** By winter 2026-27, the NERC P2-1 opening of the Folkstone end of the Castle Hayne – Folkstone 115 kV line results in low voltages at stations on this line.
- **Solution:** Construct new 115 kV switching station northeast of Holly Ridge.



Project ID and Name: 0058 – Coronaca 100 kV Line (Coronaca-Creto), Upgrade and Construct

Project Description
This project consists of rebuilding 8.9 miles of the existing 477 ACSR conductor with 954 ACSR and adding a second 954 ACSR circuit.

Status	Planned
Transmission Owner	DEC
Planned In-Service Date	6/1/26
Estimated Time to Complete	3.5 years
Estimated Cost	$18 M

Narrative Description of the Need for this Project
These lines may become overloaded for loss of both Coronaca-Hodges 100 kV circuits.

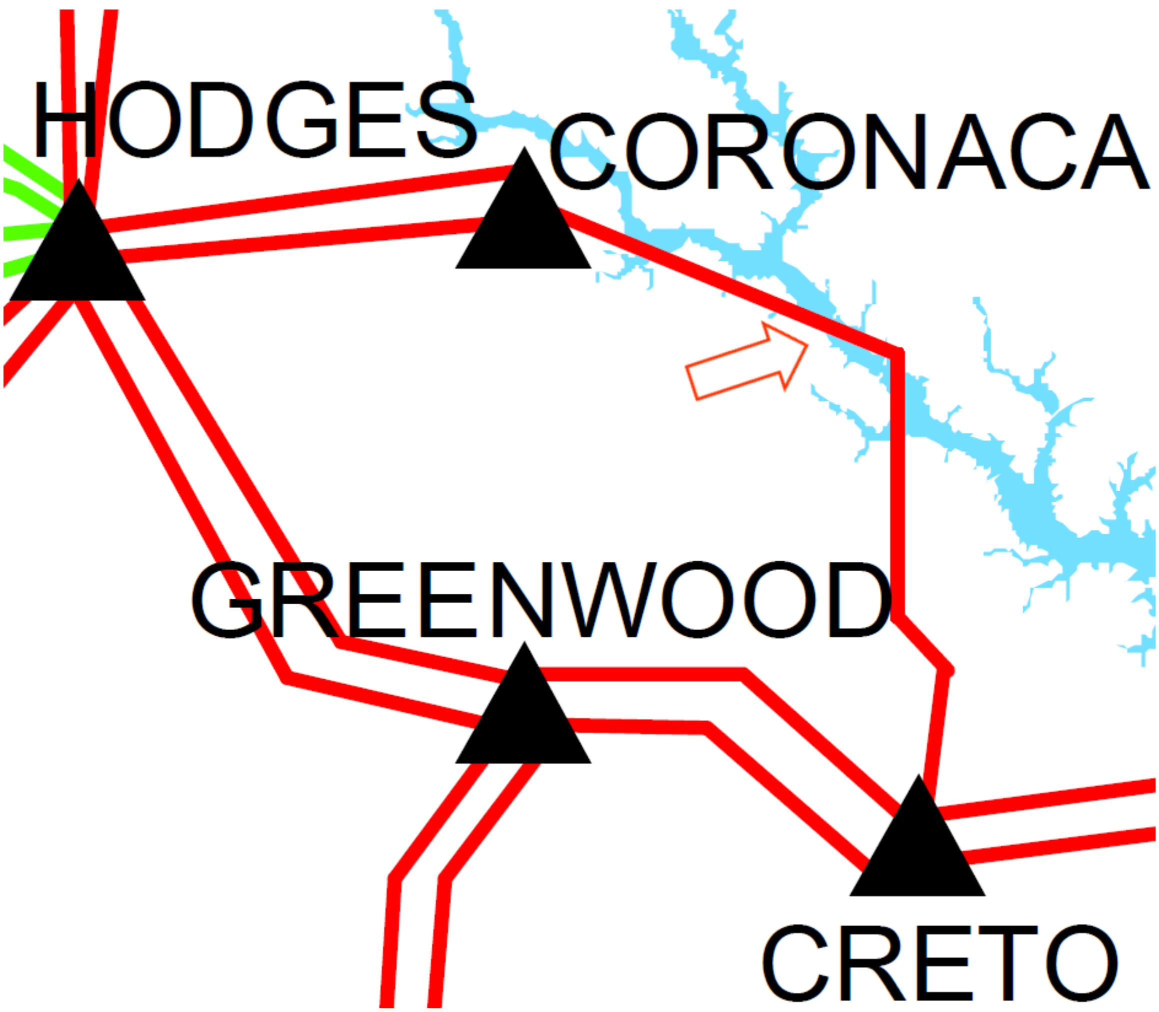
Other Transmission Solutions Considered
New transmission line(s).

Why this Project was Selected as the Preferred Solution
New transmission line(s) would require additional right-of-way, adding to the cost of the project.

D–14

Coronaca 100 kV Line (Coronaca-Creto), Upgrade and Construct

- **NERC Category P6 & P7 violation**
- **Problem:** Loss of both Coronaca-Hodges 100 kV lines may overload the Coronaca-Creto line.
- **Solution:** Rebuild 100 kV lines with higher capacity conductors and add second circuit.



Project ID and Name: 0059 – Monroe 100 kV Line (Lancaster-Monroe), Upgrade

Project Description
This project consists of rebuilding 23.8 miles of the existing 2/0 Cu conductor with 1158 ACSS/TW.

Status	Underway
Transmission Owner	DEC
Planned In-Service Date	12/1/27
Estimated Time to Complete	5 years
Estimated Cost	$53 M

Narrative Description of the Need for this Project
These lines may become overloaded for loss of one of the circuits.

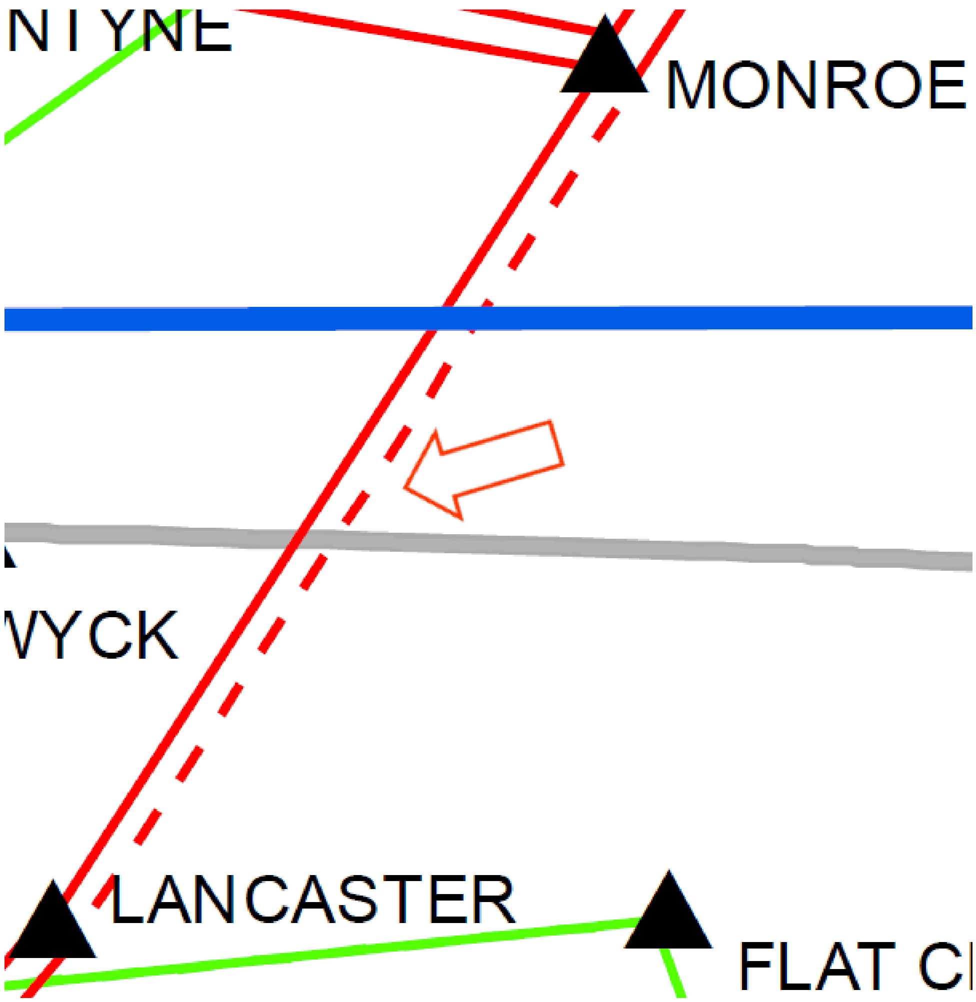
Other Transmission Solutions Considered
New transmission line(s) into Monroe Main.

Why this Project was Selected as the Preferred Solution
New transmission line(s) would require additional right-of-way, adding to the cost of the project.

D–15

Monroe 100 kV Line (Lancaster-Monroe), Upgrade

- **NERC Category P3 violation**
- **Problem:** Loss of one of the Lancaster-Monroe 100 kV lines (black circuit) may overload the remaining line (white circuit). Loss of a transformer at Morning Star may also overload existing 100 kV lines.
- **Solution:** Rebuild 100 kV lines with higher capacity conductors.



Project ID and Name: 0060 – Westport 230 kV Line (McGuire-Marshall), Upgrade

Project Description
This project consists of rebuilding 13.8 miles of the existing 1272 ACSR conductor with 1533 ACSS/TW.

Status	Conceptual
Transmission Owner	DEC
Planned In-Service Date	TBD
Estimated Time to Complete	5 years
Estimated Cost	$65 M

Narrative Description of the Need for this Project
These lines may become overloaded for loss of one of the circuits.

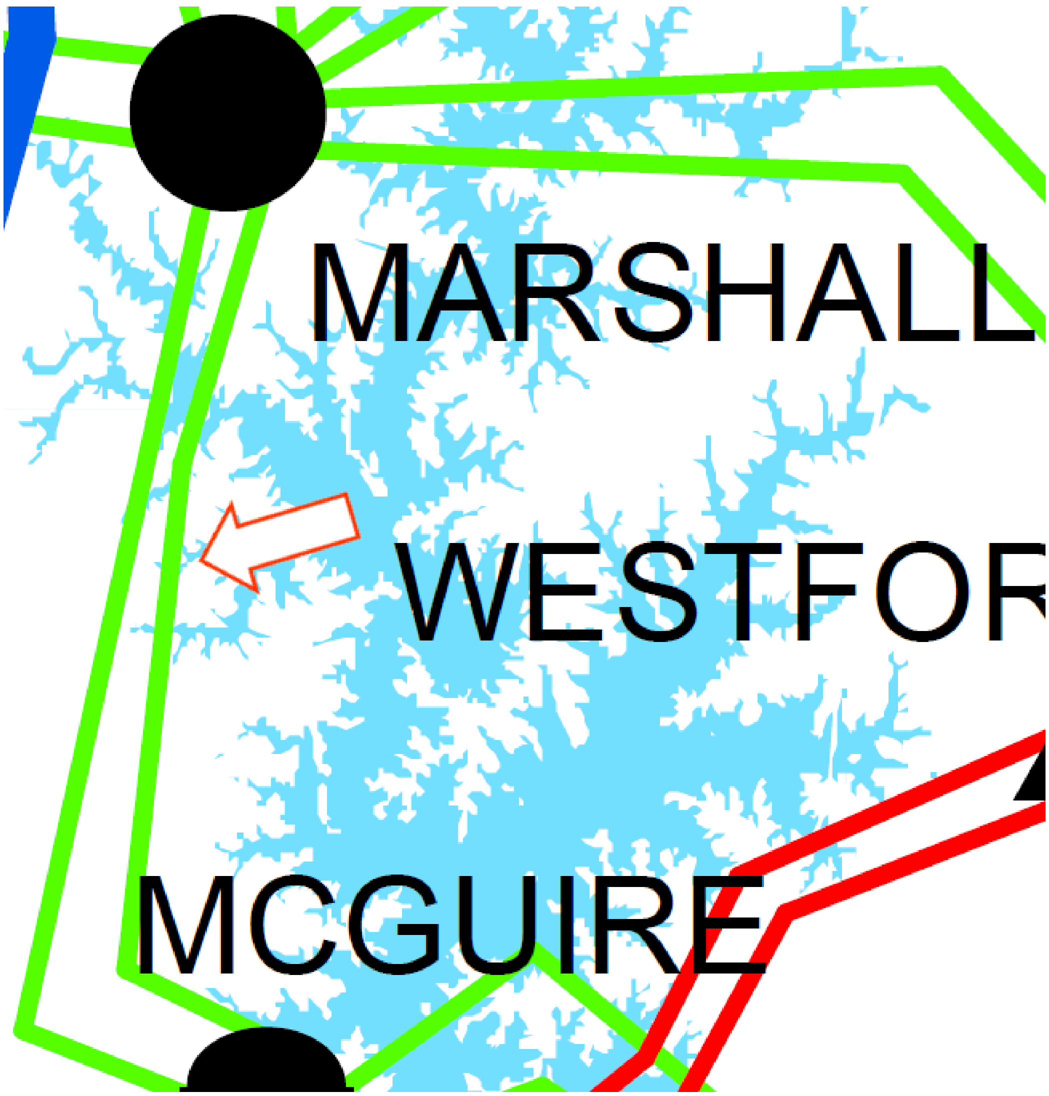
Other Transmission Solutions Considered
Series line reactors.

Why this Project was Selected as the Preferred Solution
Line reactors would drive the upgrade of a different, longer set of 230 kV lines.

D–16

Westport 230 kV Line (McGuire-Marshall), Upgrade

- **NERC Category P3 violation**
- **Problem:** Loss of one of the McGuire-Marshall 230 kV lines may overload the remaining line.
- **Solution:** Rebuild 230 kV lines with higher capacity conductors.



Project ID and Name: 0061 – Wateree 100 kV Line (Great Falls-Wateree), Upgrade

Project Description
This project consists of six-wiring 19.8 miles of the existing 2/0 Cu conductor.

Status	Underway
Transmission Owner	DEC
Planned In-Service Date	12/1/2023
Estimated Time to Complete	1 year
Estimated Cost	$10 M

Narrative Description of the Need for this Project
The loss of either circuit can overload the remaining the circuit.

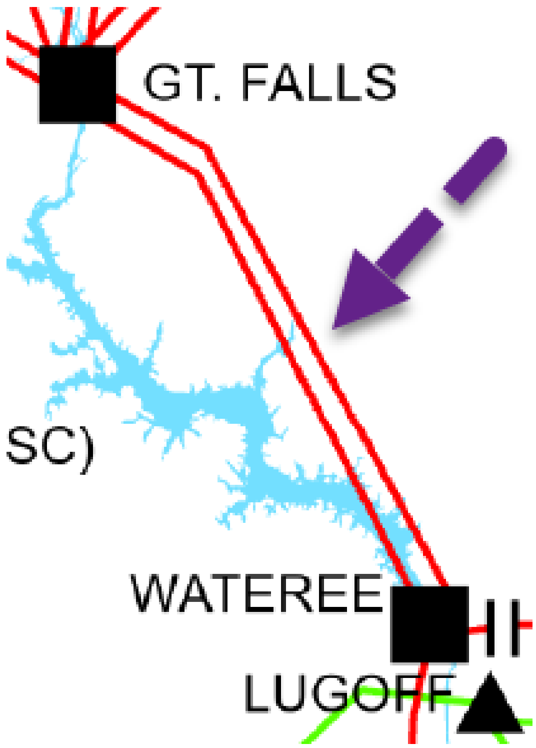
Other Transmission Solutions Considered
Rebuild 19.8 miles of double circuit 100 kV. New transmission line(s).

Why this Project was Selected as the Preferred Solution
Cost and difficulty of rebuilding the existing double circuit 100 kV line. Quickest, low-cost option to resolve DEC/DEP local issues around Wateree.

D–17

Wateree 100 kV Line (Great Falls-Wateree), Upgrade

- **NERC Category P2/P3/P5/P7 violation**
- **Problem:** The loss of either circuit can overload the remaining the circuit.
- **Solution:** Six-wire existing double circuit 100 kV line.



Project ID and Name: 0062 – Silas 100 kV Line (Mocksville-Idols Tap), Upgrade

Project Description
This project consists of rebuilding 11.4 miles of the existing 2/0 Cu and 477 ACSR conductor with 1272 ACSR.

Status	Underway
Transmission Owner	DEC
Planned In-Service Date	6/1/2025
Estimated Time to Complete	2.5 years
Estimated Cost	$22 M

Narrative Description of the Need for this Project
This line may become overloaded for various contingencies involving facilities on the path between Stamey Tie and Winston Tie.

Other Transmission Solutions Considered
New transmission line. Dropping load.

Why this Project was Selected as the Preferred Solution
Replaces aging transmission infrastructure and provides additional transmission capacity in area at a lower cost than constructing additional facilities.

Silas 100 kV Line (Mocksville-Idols Tap), Upgrade

- **NERC Category P2/P4/P5/P6/P7 violation**
- **Problem:** This line may become overloaded for various local transmission contingencies.
- **Solution:** Rebuild 100 kV line with higher capacity conductors.

Project ID and Name: 0063 – North Greenville 230 kV Tie Station, Upgrade

Project Description
This project consists of installing a 230 kV series bus junction breaker, replacing 10 breakers, replacing a 230/100/44 kV transformer, and upgrading ancillary equipment on a local 100 kV line.

Status	Underway
Transmission Owner	DEC
Planned In-Service Date	12/1/2026
Estimated Time to Complete	4 years
Estimated Cost	$20 M

Narrative Description of the Need for this Project
Primarily Asset Management driven upgrades to address aging infrastructure, with some of the breaker replacements and the bus junction breaker installation being driven by TPL

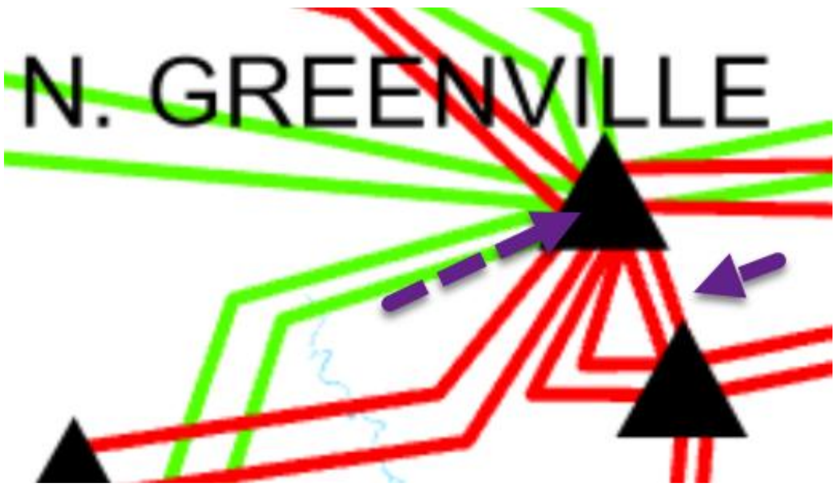
Other Transmission Solutions Considered
Upgrading multiple transmission lines that may overload under contingency. Reacting to equipment failure versus proactively replacing breakers due to condition.

Why this Project was Selected as the Preferred Solution
Cost, reliability, and safety.

D–19

North Greenville 230 kV Tie Station, Upgrade

- **NERC Category P5 violation**
- **Problem:** Asset Management identified the need to replace transmission equipment, and TPL studies indicated lines that may overload under contingency.
- **Solution:** This project consists of installing a 230 kV series bus junction breaker, replacing 10 breakers, replacing a 230/100/44 kV transformer, and upgrading ancillary equipment on a local 100 kV line.



Project ID and Name: 0064 – Wylie 100 kV Line (Wylie-Arrowood Retail), Upgrade

Project Description
This project consists of rebuilding 7.9 miles of the existing 477 ACSR conductor with B-477 ACSR.

Status	Underway
Transmission Owner	DEC
Planned In-Service Date	12/1/2026
Estimated Time to Complete	4 years
Estimated Cost	$15 M

Narrative Description of the Need for this Project
This line may become overloaded for various local transmission contingencies.

Other Transmission Solutions Considered
Dropping load

Why this Project was Selected as the Preferred Solution
Reliability

Wylie 100 kV Line (Wylie-Arrowood Retail), Upgrade

- **NERC Category P2/P3/P4/P5/P6 violation**
- **Problem:** Local transmission contingencies involving facilities associated with Allen Steam Station, Newport Tie and/or Woodlawn Tie may overload this line.
- **Solution:** Rebuild 100 kV lines with higher capacity conductors.

Project ID and Name: 0065 – Morning Star 230 kV Tie Station, Upgrade

Project Description
This project consists of replacing (3) 230/100 kV transformers and converting the station to breaker-and-a-half.

Status	Planned
Transmission Owner	DEC
Planned In-Service Date	6/1/2028
Estimated Time to Complete	4 years
Estimated Cost	$36 M

Narrative Description of the Need for this Project
The transformers can become overloaded for various contingencies involving facilities associated with Morning Star Tie Station.

Other Transmission Solutions Considered
Dropping load. Add 4th 230/100 transformer.

Why this Project was Selected as the Preferred Solution
Reliability. Age of existing transformers.

D–21

Morning Star 230 kV Tie Station, Upgrade

- **NERC Category P2/P4/P6 violation**
- **Problem:** Various contingencies involving facilities at Morning Star Tie Station may cause one or more of the transformers to become overloaded.
- **Solution:** Replace existing 230/100/44 kV transformers with larger transformers and convert the station to breaker-and-a-half.

Project ID and Name: 0066 – Davidson River 100 kV Line (North Greenville-Marietta), Upgrade

Project Description
This project consists of rebuilding11.5 miles of the existing 250 Cu / 477 ACSR conductor with 1272 ACSR.

Status	Conceptual
Transmission Owner	DEC
Planned In-Service Date	TBD
Estimated Time to Complete	4 years
Estimated Cost	$30 M

Narrative Description of the Need for this Project
This line may become overloaded for contingencies involving facilities associated with Shiloh Switching Station.

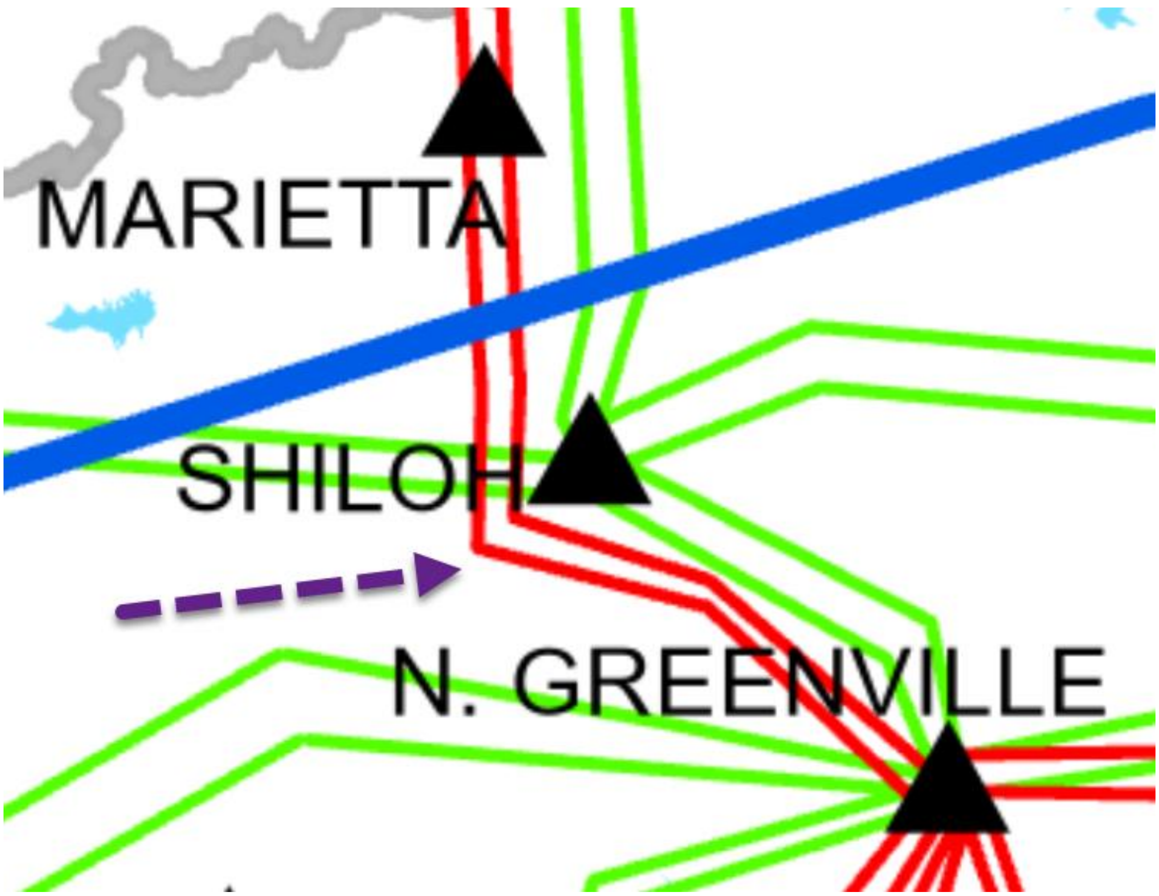
Other Transmission Solutions Considered
Dropping load. Curtailing transfers to CPLW.

Why this Project was Selected as the Preferred Solution
Reliability

D–22

Davidson River 100 kV Line (North Greenville-Marietta), Upgrade

- **NERC Category P5/P6/P7 violation**
- **Problem:** This line may become overloaded due to contingencies of facilities associated with Shiloh Switching Station.
- **Solution:** Rebuild 100 kV line with higher capacity conductors.



Project ID and Name: 0067 – Harley 100 kV Line (Tiger-Campobello), Upgrade

Project Description
This project consists of rebuilding 11.8 miles of the existing 336 ACSR conductor with 1272 ACSR.

Status	Conceptual
Transmission Owner	DEC
Planned In-Service Date	TBD
Estimated Time to Complete	4 years
Estimated Cost	$45 M

Narrative Description of the Need for this Project
This line may become overloaded for local contingencies.

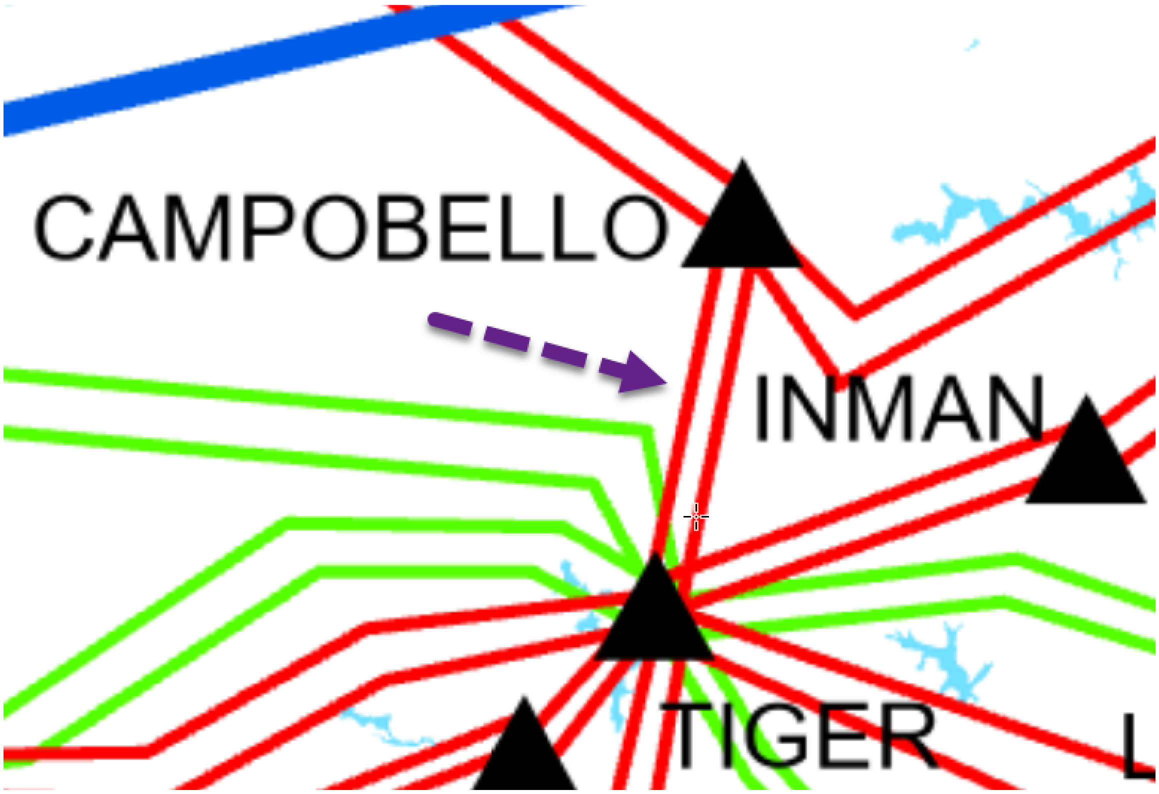
Other Transmission Solutions Considered
New tie station

Why this Project was Selected as the Preferred Solution
Lower cost and increased capacity on older transmission facility.

D–23

Harley 100 kV Line (Tiger-Campobello), Upgrade

- **NERC Category P2/P3/P6/P7 violation**
- **Problem:** Loss of local transmission facilities may overload the 100 kV line.
- **Solution:** Rebuild 100 kV line with higher capacity conductors.



Project ID and Name: 0068 – Sandy Ridge 230 kV Line (Newport-Morning Star), Upgrade

Project Description
This project consists of adding a second circuit to a 33.6 mile 230 kV line and several associated projects needed to accommodate the circuit addition.

Status	Planned
Transmission Owner	DEC
Planned In-Service Date	12/1/28
Estimated Time to Complete	4 years
Estimated Cost	$60 M

Narrative Description of the Need for this Project
This line may become overloaded for loss of a 500 kV tie line between DEC and DEP or other local contingencies.

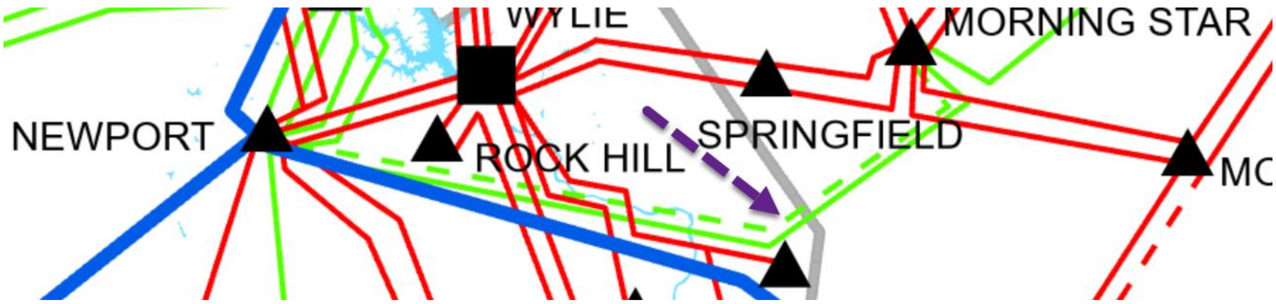
Other Transmission Solutions Considered
Upgrade existing 230 kV circuit. Line reactors.

Why this Project was Selected as the Preferred Solution
Utilization of existing 230 kV corridor increases transmission capacity and ability to reliably serve local load. Capability of existing structures to support a second 230 kV circuit.

D–24

Sandy Ridge 230 kV Line (Newport-Morning Star), Upgrade

- **NERC Category P1/P2/P3/P6/P7 violation**
- **Problem:** Loss of local transmission facilities may overload the existing 230 kV circuit
- **Solution:** Add second 230 kV circuit between Newport and Morning Star.



Project ID and Name: 0069 – Skybrook 100 kV Line (Winecoff-Eastfield Retail), Upgrade

Project Description
This project consists of rebuilding 7.9 miles of the existing 477 ACSR conductor with 1272 ACSR.

Status	Conceptual
Transmission Owner	DEC
Planned In-Service Date	TBD
Estimated Time to Complete	4 years
Estimated Cost	$17 M

Narrative Description of the Need for this Project
This line may become overloaded for local contingencies.

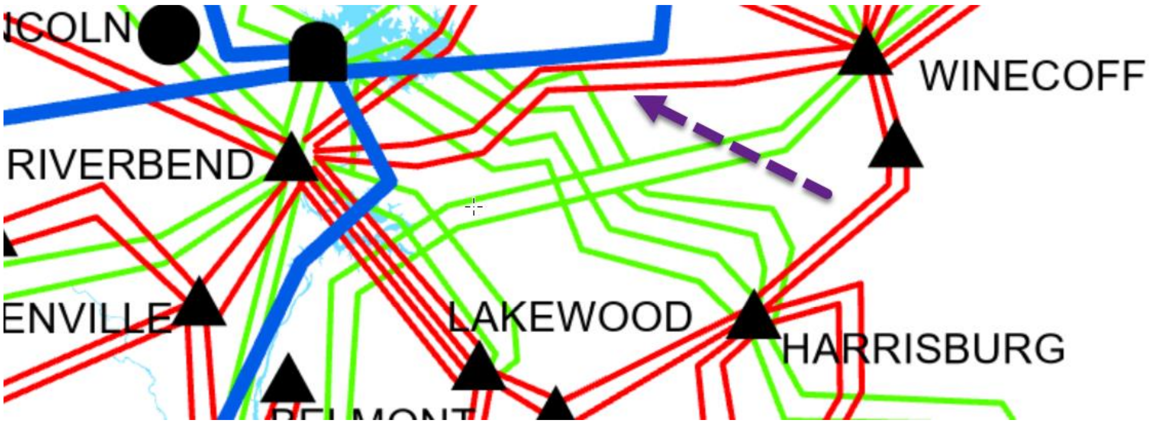
Other Transmission Solutions Considered
Dropping load.

Why this Project was Selected as the Preferred Solution
Reliability

D–25

Skybrook 100 kV Line (Winecoff-Eastfield Retail), Upgrade

- **NERC Category P6/P7 violation**
- **Problem:** Loss of local transmission facilities may overload this line
- **Solution:** Rebuild 100 kV line with higher capacity conductors.



Appendix E Transmission Plan Major Project Listings – Public Policy Projects

2022 Collaborative Transmission Plan – Public Policy Projects						
Project ID	**Public Policy Project**	**Status[1]**	**Transmission Owner**	**Projected In-Service Date**	**Estimated Cost ($M)[2]**	**Project Lead Time (Years)[3]**
0070	Cape Fear – West End 230 kV Line, Rebuild	Planned	DEP	6/5/2026	70	2.5
0071	Erwin – Fayetteville East 230 kV Line, Rebuild	Planned	DEP	6/5/2026	84	2.5
0072	Erwin – Fayetteville 115 kV Line, Rebuild	Planned	DEP	6/5/2025	21	2.5
0073	Fayetteville-Fayetteville Dupont 115 kV Line, Rebuild 3.2-mile section	Planned	DEP	12/26/2024	16	2.5
0074	Milburnie 230 kV Substation, Upgrade	Planned	DEP	4/2/2026	4	2.5

2022 Collaborative Transmission Plan – Public Policy Projects						
Project ID	Public Policy Project	Status[1]	Transmission Owner	Projected In-Service Date	Estimated Cost ($M)[2]	Project Lead Time (Years)[3]
0075	Weatherspoon-Marion 115 kV Line, Upgrade	Planned	DEP	12/12/2025	13	2.5
0076	Camden Junction-Wateree 115 kV Line, Rebuild	Planned	DEP	12/11/2026	10	2.5
0077	Robinson Plant-Rockingham 115 kV Line, Rebuild	Planned	DEP	11/18/2027	38	2.5
0078	Robinson Plant-Rockingham 230 kV Line, Upgrade	Planned	DEP	6/5/2026	43	2.5
0079	Fayetteville-Fayetteville Dupont 115 kV Line, Rebuild 4.9-mile section	Planned	DEP	4/16/2026	14	2.5

2022 Collaborative Transmission Plan – Public Policy Projects						
Project ID	Public Policy Project	Status[1]	Transmission Owner	Projected In-Service Date	Estimated Cost ($M)[2]	Project Lead Time (Years)[3]
0080	Lee 100 kV Line (Lee-Shady Grove), Upgrade	Planned	DEC	12/1/2026	45	4
0081	Piedmont 100 kV Line (Lee-Shady Grove), Upgrade	Planned	DEC	12/1/2026	45	4
0082	Newberry 115 kV Line (Bush River-DESC), Upgrade	Planned	DEC	12/1/2026	42	4
0083	Clinton 100 kV Line (Bush River-Laurens), Upgrade	Planned	DEC	12/1/2026	109	4
TOTAL					**554**	

[1] Status: ***In-service****:* Projects with this status are in-service. This status was updated as of 12/1/2022.

Underway*:* Projects with this status range from the Transmission Owner having some money in its current year budget for the project to the Transmission Owner having completed some construction activities for the project.

Planned*:* Projects with this status do not have money in the Transmission Owner's current year budget; and the project is subject to change.

Conceptual*:* Projects with this status are not p*lanned* at this time but will continue to be evaluated as a potential project in the future.

Deferred*:* Projects with this status were identified in the 2021 Report and have been deferred beyond the end of the planning horizon based on analysis performed to develop the 2022 Collaborative Transmission Plan.

Removed: Project is cancelled and no longer in the plan

[2] The estimated cost is in nominal dollars which reflects the sum of the estimated annual cash flows over the expected development period for the specific project (typically 2 – 5 years), including direct costs, loadings and overheads; but not including AFUDC. Each year's cash flow is escalated to the year of the expenditures. The sum of the expected cash flows is the estimated cost.

[3] For projects with a status of Underway, the project lead time is the time remaining to complete construction and place in-service.

Appendix F Transmission Plan Major Project Descriptions – Public Policy Projects

Table of Contents

Note: The estimated cost for each of the projects described in Appendix F is in nominal dollars which reflects the sum of the estimated annual cash flows over the expected development period for the specific project (typically 2 – 5 years), including direct costs, loadings and overheads; but not including AFUDC. Each year's cash flow is escalated to the year of the expenditures. The sum of the expected cash flows is the estimated cost.

Project ID and Name: 0070 – Cape Fear Plant – West End 230 kV Line, Rebuild

Project Description
This project consists of rebuilding portions of the Cape Fear – West End 230 kV Line using 6-1590 MCM ACSR conductor (approximately 26.6 miles).

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	6/5/2026
Estimated Time to Complete	2.5
Estimated Cost	$70 M

Narrative Description of the Need for this Project
Various solar studies performed have shown the need to upgrade this line. This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals. With additional solar generation in southern DEP, outage of the Cumberland-Wake 500 kV line can overload the Cape Fear – West End 230 kV line.

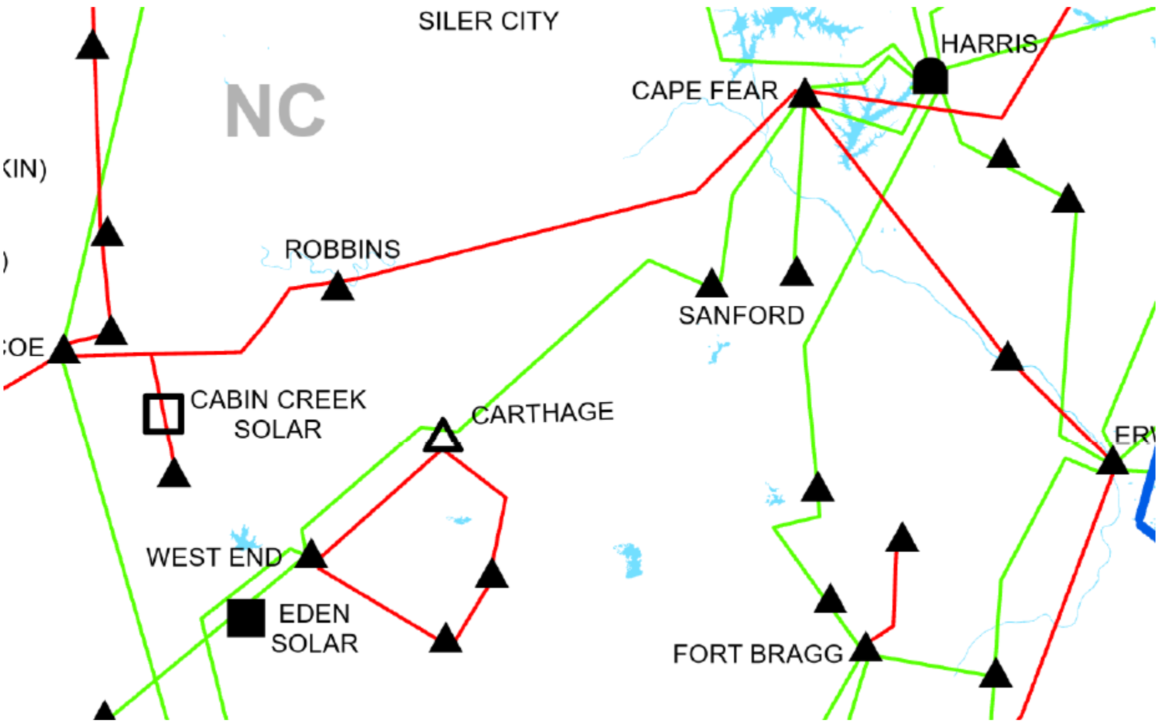
Other Transmission Solutions Considered
Construct a new 230 kV line between Cape Fear and West End.

Why this Project was Selected as the Preferred Solution
Cost and feasibility are much improved with selected alternative.

F–1

Cape Fear–West End 230 kV Line, Rebuild

- **Proactive Solar Upgrade**
- **Problem:** This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals.
- **Solution:** Rebuild 230 kV line.



Project ID and Name: 0071 – Erwin – Fayetteville East 230 kV Line, Rebuild

Project Description
This project consists of rebuilding the Erwin – Fayetteville East 230 kV Line using 6-1590 MCM ACSR conductor (approximately 23 miles).

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	6/5/2026
Estimated Time to Complete	2.5
Estimated Cost	$84 M

Narrative Description of the Need for this Project
Various solar studies performed have shown the need to upgrade this line. This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals. With additional solar generation in southern DEP, outage of the Cumberland-Wake 500 kV line can overload the Erwin – Fayetteville East 230 kV line.

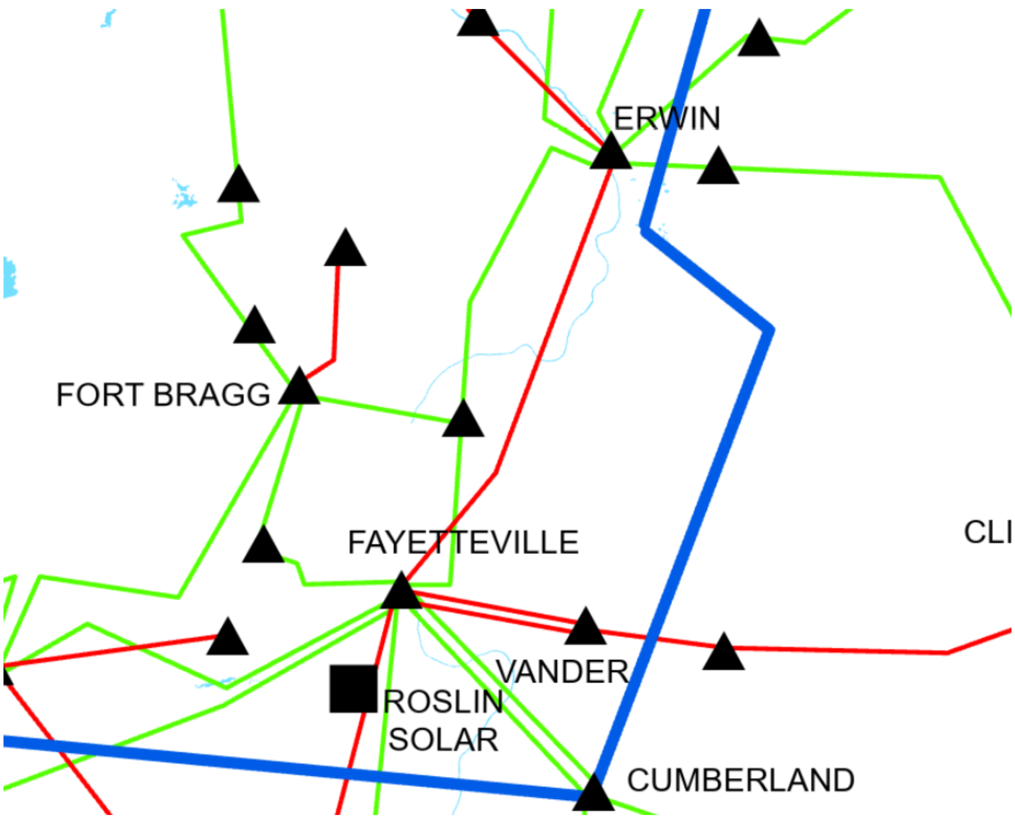
Other Transmission Solutions Considered
Construct a new 230 kV line between Erwin and Fayetteville East.

Why this Project was Selected as the Preferred Solution
Cost and feasibility are much improved with selected alternative.

F–2

Erwin–Fayetteville East 230 kV Line, Rebuild

- **Proactive Solar Upgrade**
- **Problem:** This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals.
- **Solution:** Rebuild 230 kV line.



Project ID and Name: 0072 – Erwin – Fayetteville 115 kV Line, Rebuild

Project Description
This project consists of rebuilding portions the Erwin – Fayetteville 115 kV Line using 795 ACSS conductor or equivalent (approximately 9 miles).

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	6/5/2025
Estimated Time to Complete	2.5
Estimated Cost	$21 M

Narrative Description of the Need for this Project
Various solar studies performed have shown the need to upgrade this line. This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals. With additional solar generation in southern DEP, outage of the Cumberland-Wake 500 kV line can overload the Erwin – Fayetteville 115 kV line.

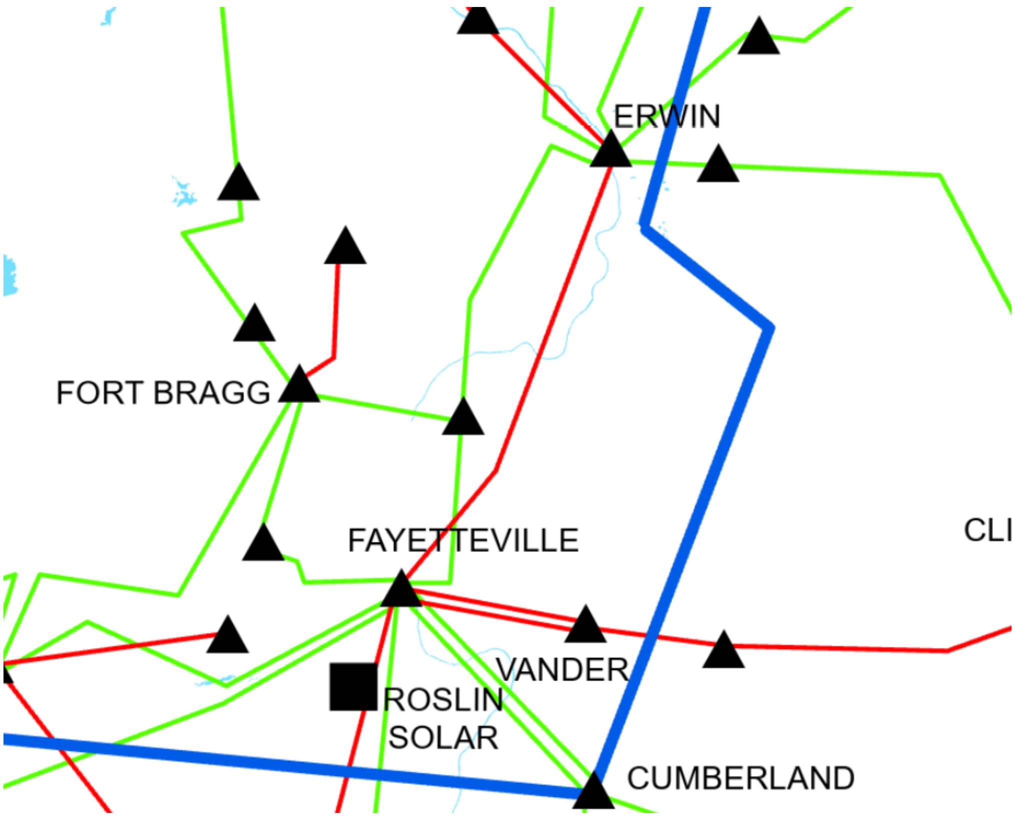
Other Transmission Solutions Considered
Construct a new 115 kV line between Erwin and Fayetteville.

Why this Project was Selected as the Preferred Solution
Cost and feasibility are much improved with selected alternative.

F–3

Erwin – Fayetteville 115 kV Line, Rebuild

- **Proactive Solar Upgrade**
- **Problem:** This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals.
- **Solution:** Rebuild 115 kV line.



Project ID and Name: 0073 – Fayetteville – Fayetteville Dupont 115 kV Line, Rebuild 3.2 miles

Project Description
This project consists of rebuilding the Hope Mills Church St – Roslin section of the Fayetteville – Fayetteville Dupont 115 kV Line using 1590 MCM ACSR conductor (approximately 3.2 miles).

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	12/26/2024
Estimated Time to Complete	2.5
Estimated Cost	$14 M

Narrative Description of the Need for this Project
Various solar studies performed have shown the need to upgrade this line. This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals. With additional solar generation in southern DEP, outage of a section of the Weatherspoon – Fayetteville 230 kV line can overload this section of the Fayetteville – Fayetteville Dupont 115 kV line.

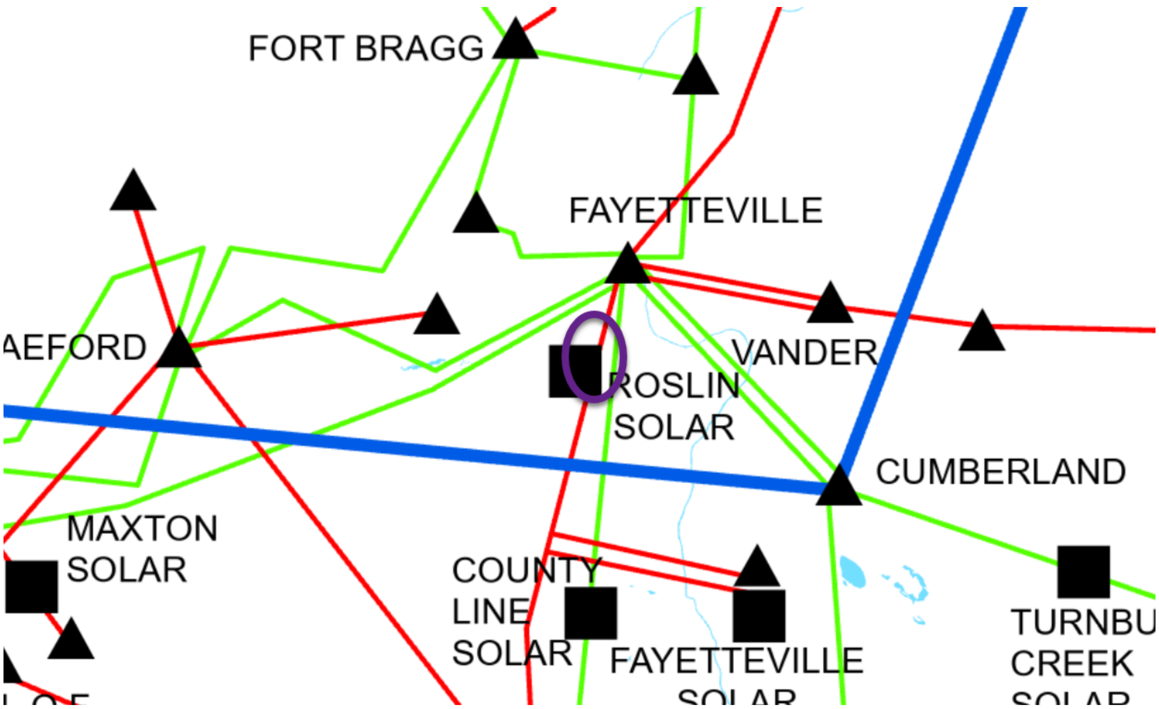
Other Transmission Solutions Considered
Construct a new 115 kV line between Fayetteville and Fayetteville Dupont.

Why this Project was Selected as the Preferred Solution
Cost and feasibility are much improved with selected alternative.

F–4

Fayetteville – Fayetteville Dupont 115 kV Line, Rebuild 3.2 miles

- **Proactive Solar Upgrade**
- **Problem:** This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals.
- **Solution:** Rebuild 115 kV line.



Project ID and Name: 0074 – Milburnie 230 kV Substation, Upgrade

Project Description
This project consists of adding redundant bus protection at Milburnie 230 kV Substation.

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	4/2/2026
Estimated Time to Complete	2.5
Estimated Cost	$4 M

Narrative Description of the Need for this Project
Various solar studies have shown the need for this upgrade. This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals. With additional solar generation in eastern DEP, a Milburnie 230 kV bus fault with relay failure can overload a section of the Clayton Industrial – Selma 115 kV line.

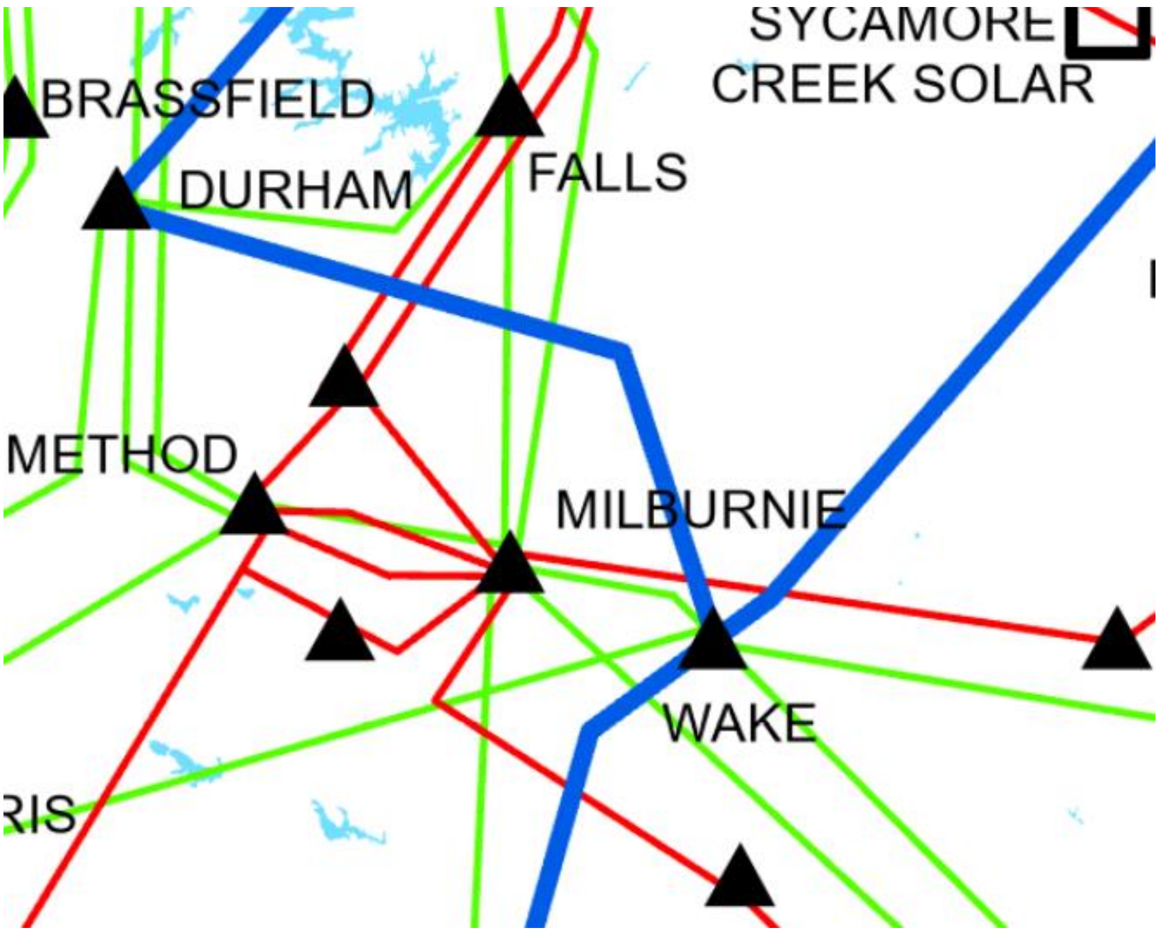
Other Transmission Solutions Considered
Reconductor the 115 kV line between Clayton Industrial and Selma.

Why this Project was Selected as the Preferred Solution
Cost and feasibility are much improved with selected alternative.

F–5

Milburnie 230 kV Substation, Upgrade

- **Proactive Solar Upgrade**
- **Problem:** This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals.
- **Solution:** Add redundant bus protection.



Project ID and Name: 0075 – Weatherspoon – Marion 115 kV Line, Upgrade

Project Description
This project consists of raising portions of the Weatherspoon-Marion 115 kV Line to achieve the 212 degree F rating of the line 119 MVA (approximately 14.6 miles).

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	12/12/2025
Estimated Time to Complete	2.5
Estimated Cost	$13 M

Narrative Description of the Need for this Project
Various solar studies performed have shown the need to upgrade this line. This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals. With additional solar generation in DEP, outage of a section of the Weatherspoon – Latta 230 kV line can overload this section of the Weatherspoon – Marion 115 kV line.

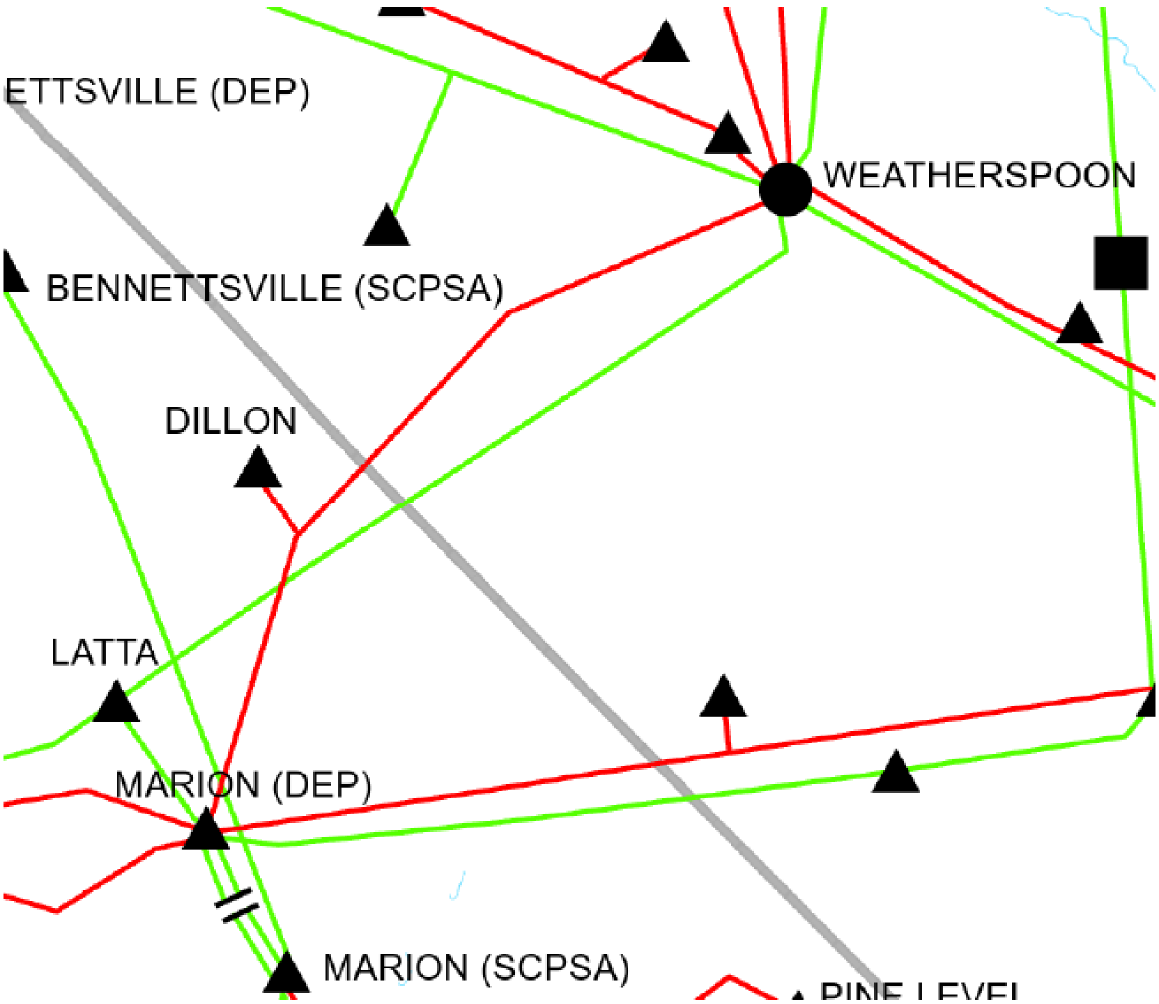
Other Transmission Solutions Considered
Construct a new 115 kV line between Weatherspoon and Marion.

Why this Project was Selected as the Preferred Solution
Cost and feasibility are much improved with selected alternative.

F–6

Weatherspoon – Marion 115 kV Line, Upgrade

- **Proactive Solar Upgrade**
- **Problem:** This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals.
- **Solution:** Raise 115 kV line.



Project ID and Name: 0076 – Camden Junction – Wateree 115 kV Line, Rebuild

Project Description
This project consists of rebuilding the Camden Junction – Wateree 115 kV Line using 1590 MCM ACSR conductor or equivalent (approximately 17 miles).

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	12/11/2026
Estimated Time to Complete	2.5
Estimated Cost	$10 M

Narrative Description of the Need for this Project
Various solar studies performed have shown the need to upgrade this line. This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals. With additional solar generation in DEP, outage of a section of the Camden – Camden Junction 115 kV line can overload this section of the Camden Junction – Wateree 115 kV Line.

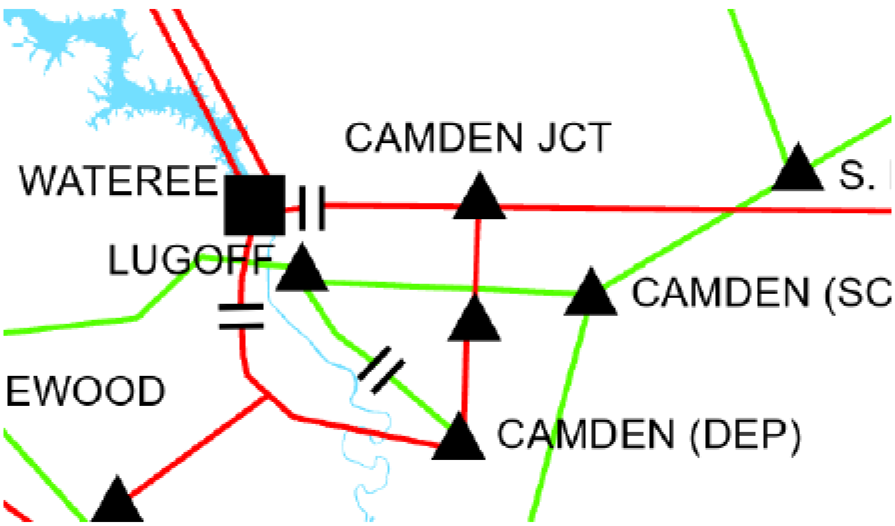
Other Transmission Solutions Considered
Construct a new 115 kV line between Camden Junction and Wateree.

Why this Project was Selected as the Preferred Solution
Cost and feasibility are much improved with selected alternative.

F–7

Camden Junction – Wateree 115 kV Line, Rebuild

- **Proactive Solar Upgrade**
- **Problem:** This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals.
- **Solution:** Rebuild 115 kV line.



Project ID and Name: 0077 – Robinson – Rockingham 115 kV Line, Rebuild

Project Description
This project consists of rebuilding portions of the Robinson – Rockingham 115 kV Line using 1590 MCM ACSR conductor or equivalent (approximately 17 miles).

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	11/18/2027
Estimated Time to Complete	2.5
Estimated Cost	$38 M

Narrative Description of the Need for this Project
Various solar studies performed have shown the need to upgrade this line. This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals. With additional solar generation in DEP, double circuit outage of sections of the Richmond – Rockingham West 230 kV line and Robinson – Rockingham 230 kV line can overload this section of the Robinson - Rockingham 115 kV Line.

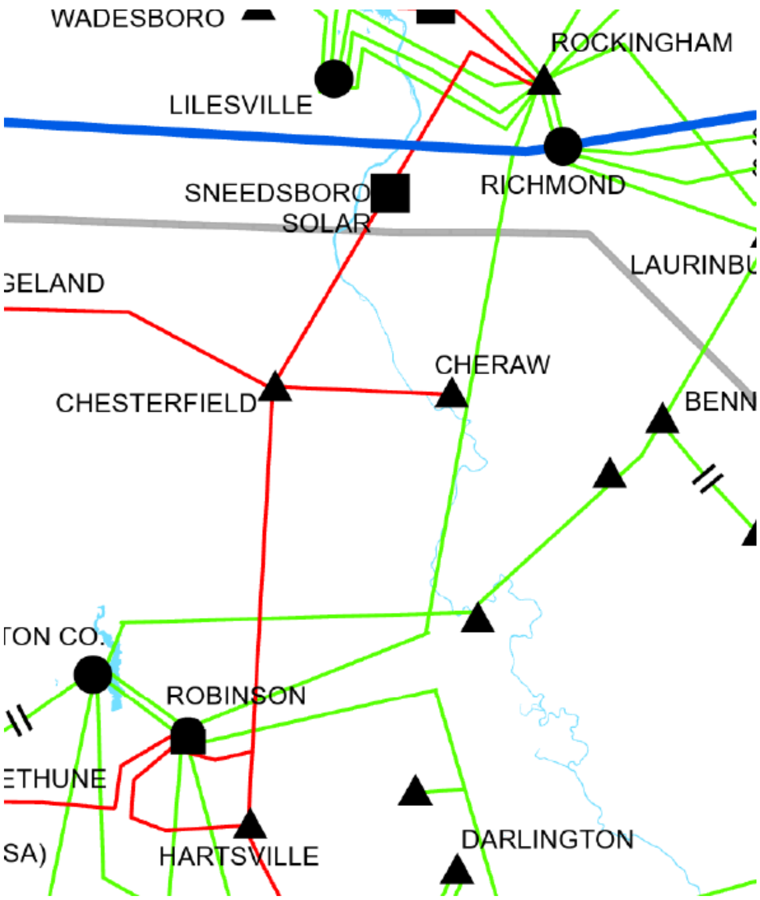
Other Transmission Solutions Considered
Construct a new 115 kV line between Robinson and Rockingham.

Why this Project was Selected as the Preferred Solution
Cost and feasibility are much improved with selected alternative.

F–8

Robinson – Rockingham 115 kV, Rebuild

- **Proactive Solar Upgrade**
- **Problem:** This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals.
- **Solution:** Rebuild 115 kV line.



Project ID and Name: 0078 – Robinson – Rockingham 230 kV Line, Rebuild

Project Description
This project consists of rebuilding portions of the Robinson – Rockingham 230 kV Line using 6-1590 MCM ACSR conductor or equivalent (approximately 20.5 miles).

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	6/5/2026
Estimated Time to Complete	2.5
Estimated Cost	$43 M

Narrative Description of the Need for this Project
Various solar studies performed have shown the need to upgrade this line. This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals. With additional solar generation in DEP, outage of section of the Bennettsville – Laurinburg 230 kV line can overload these sections of the Robinson - Rockingham 230 kV Line.

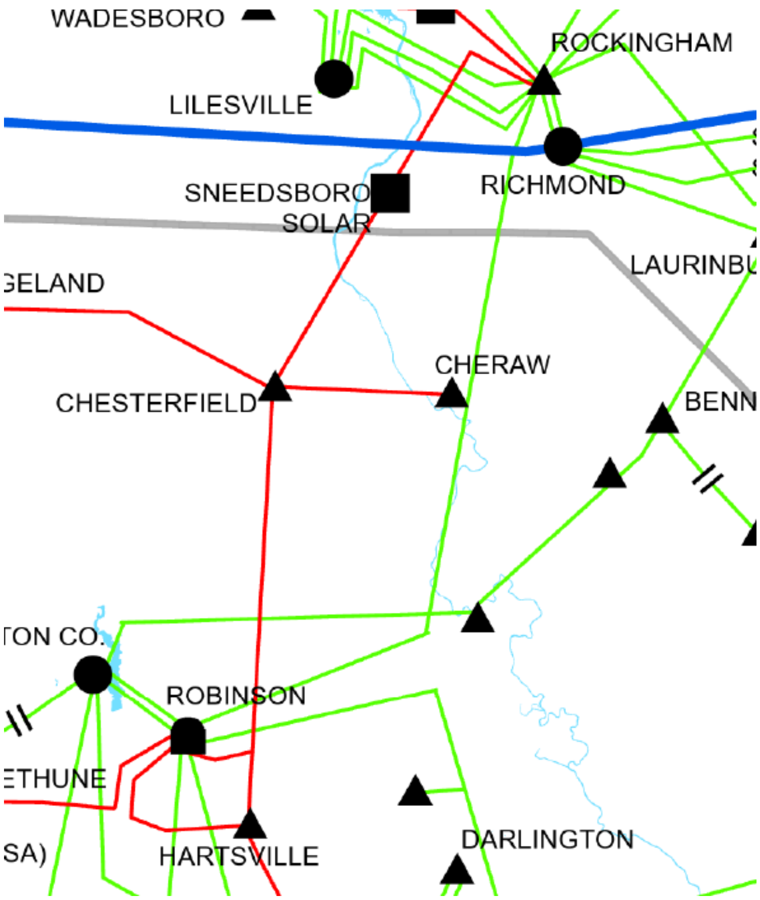
Other Transmission Solutions Considered
Construct a new 230 kV line between Robinson and Rockingham.

Why this Project was Selected as the Preferred Solution
Cost and feasibility are much improved with selected alternative.

F–9

Robinson – Rockingham 230 kV, Rebuild

- **Proactive Solar Upgrade**
- **Problem:** This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals.
- **Solution:** Rebuild 230 kV line.



Project ID and Name: 0079 – Fayetteville – Fayetteville Dupont 115 kV Line, Rebuild 4.9 miles

Project Description
This project consists of rebuilding the Fayetteville - Hope Mills Church St section of the Fayetteville – Fayetteville Dupont 115 kV Line using 1590 MCM ACSR conductor (approximately 4.9 miles).

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	4/16/2026
Estimated Time to Complete	2.5
Estimated Cost	$11.6 M

Narrative Description of the Need for this Project
Various solar studies performed have shown the need to upgrade this line. This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals. With additional solar generation in southern DEP, outage of a section of the Weatherspoon – Fayetteville 230 kV line can overload this section of the Fayetteville – Fayetteville Dupont 115 kV line.

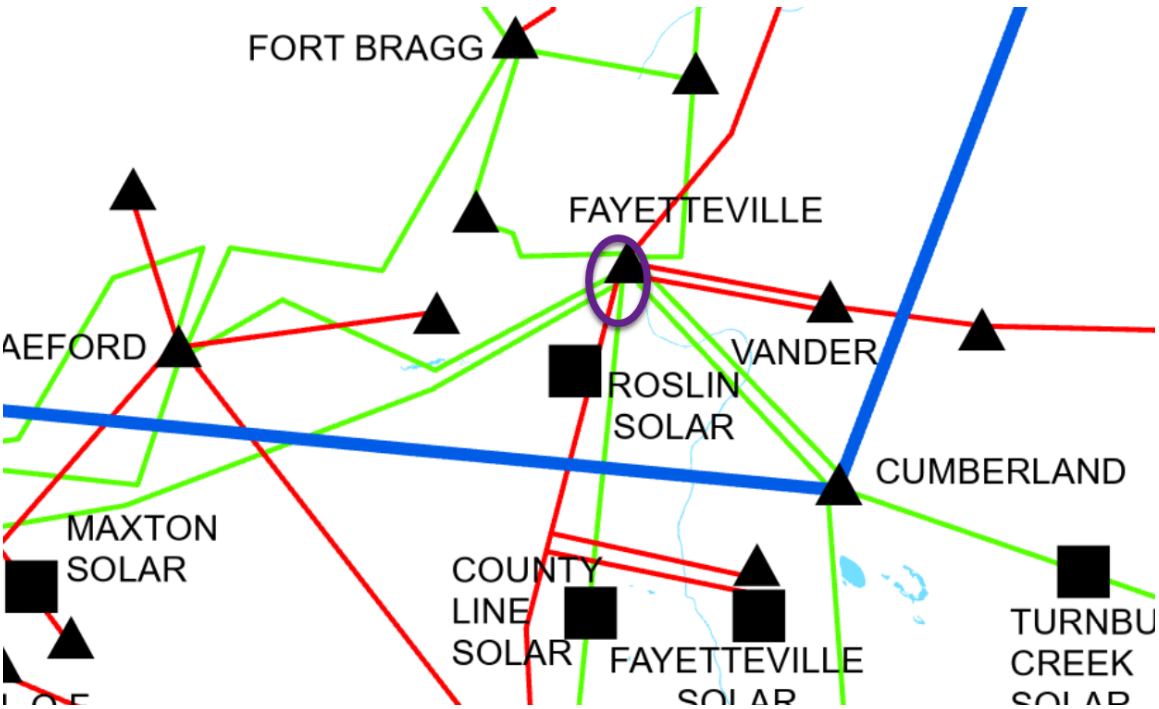
Other Transmission Solutions Considered
Construct a new 115 kV line between Fayetteville and Fayetteville Dupont.

Why this Project was Selected as the Preferred Solution
Cost and feasibility are much improved with selected alternative.

F–10

Fayetteville – Fayetteville Dupont 115 kV Line, Rebuild 4.9 miles

- **Proactive Solar Upgrade**
- **Problem:** This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals.
- **Solution:** Rebuild 115 kV line.



Project ID and Name: 0080 – Lee 100 kV Line (Lee-Shady Grove), Upgrade

Project Description
This project consists of rebuilding 11.9 miles of the existing 477 ACSR conductor with 1158 ACSS/TW.

Status	Planned
Transmission Owner	DEC
Planned In-Service Date	12/1/2026
Estimated Time to Complete	4.5
Estimated Cost	$45 M

Narrative Description of the Need for this Project
Various solar studies performed have shown the need to upgrade this line. This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals. With high solar penetration in the southwestern area of the DEC system, this line can overload for various contingencies.

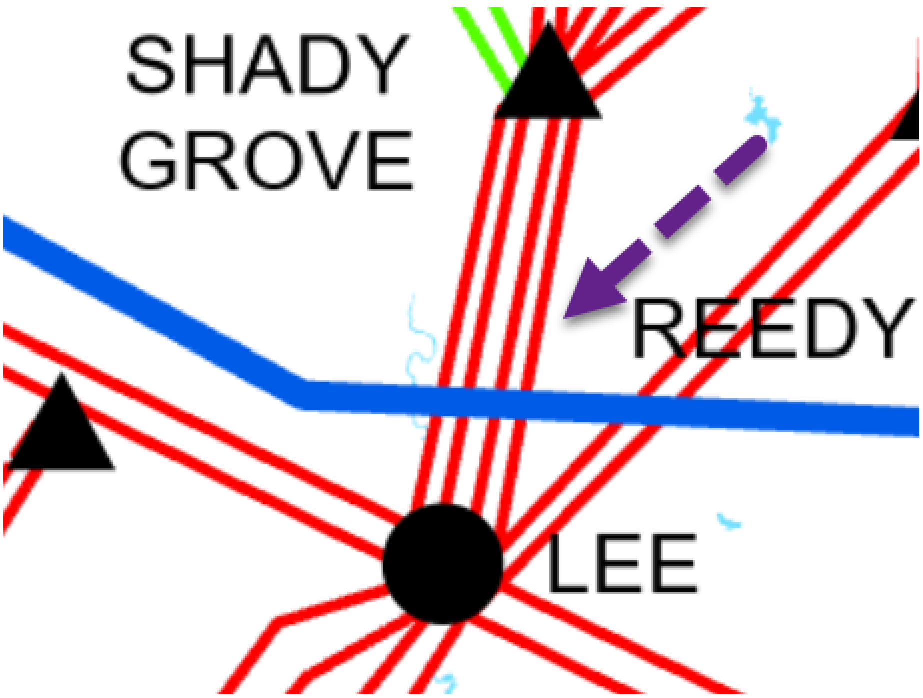
Other Transmission Solutions Considered
New transmission line. Curtailment of solar.

Why this Project was Selected as the Preferred Solution
Reliability. Facilitates integration of higher levels of renewables.

F–11

Lee 100 kV Line (Lee-Shady Grove), Upgrade

- **Proactive Solar Upgrade**
- **Problem:** This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals.
- **Solution:** Rebuild 100 kV line with higher capacity conductors.



Project ID and Name: 0081 – Piedmont 100 kV Line (Lee-Shady Grove), Upgrade

Project Description
This project consists of rebuilding 12.7 miles of the existing 477 ACSR conductor with 1158 ACSS/TW.

Status	Planned
Transmission Owner	DEC
Planned In-Service Date	12/1/2026
Estimated Time to Complete	4.5
Estimated Cost	$45 M

Narrative Description of the Need for this Project
Various solar studies performed have shown the need to upgrade this line. This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals. With high solar penetration in the southwestern area of the DEC system, this line can overload for various contingencies.

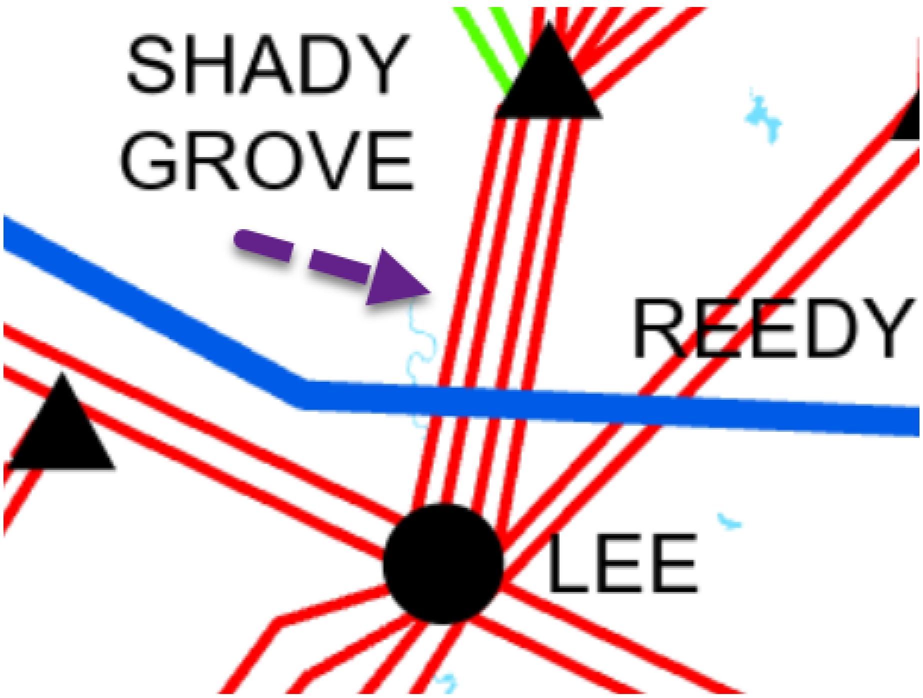
Other Transmission Solutions Considered
New transmission line. Curtailment of solar.

Why this Project was Selected as the Preferred Solution
Reliability. Facilitates integration of higher levels of renewables.

F–12

Piedmont 100 kV Line (Lee-Shady Grove), Upgrade

- **Proactive Solar Upgrade**
- **Problem:** This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals.
- **Solution:** Rebuild 100 kV line with higher capacity conductors.



Project ID and Name: 0082 – Newberry 115 kV Line (Bush River-DESC), Upgrade

Project Description
This project consists of rebuilding 11.3 miles of the existing 266 ACSR conductor with 1272 ACSR.

Status	Planned
Transmission Owner	DEC
Planned In-Service Date	12/1/2026
Estimated Time to Complete	4.5
Estimated Cost	$42 M

Narrative Description of the Need for this Project
Various solar studies performed have shown the need to upgrade this line. This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals. With high solar penetration in the southwestern area of the DEC system, this line can overload for various contingencies.

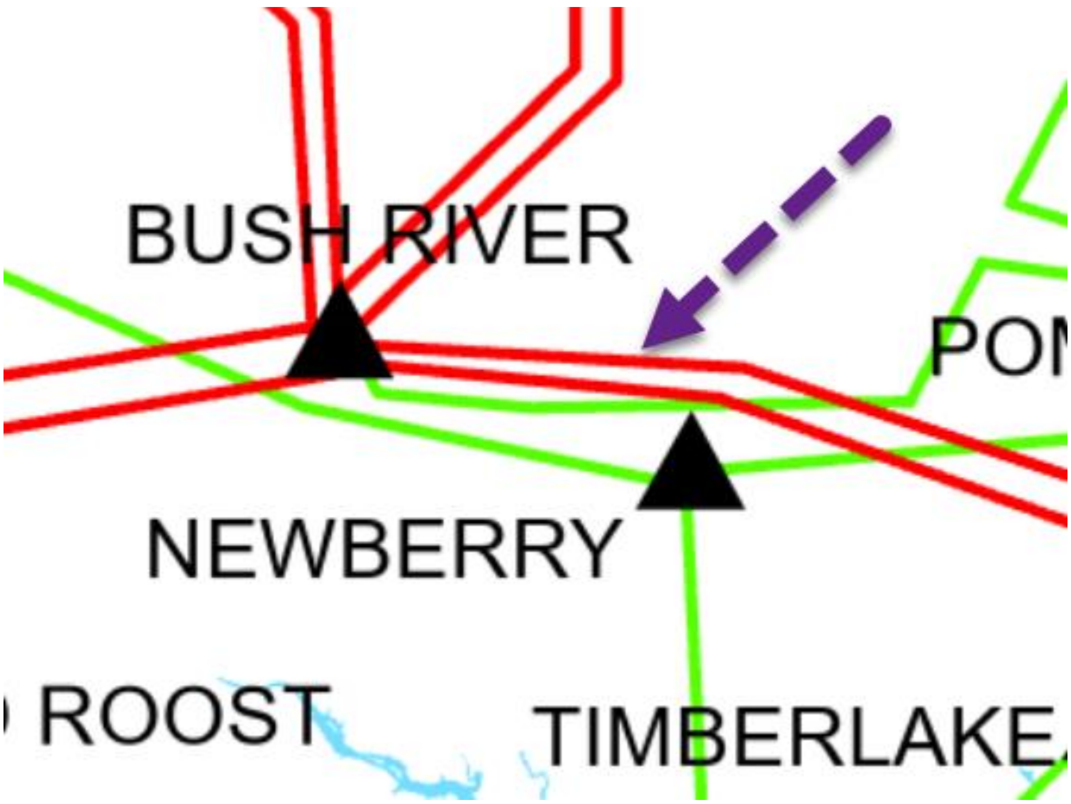
Other Transmission Solutions Considered
Curtailment of solar.

Why this Project was Selected as the Preferred Solution
Reliability. Facilitates integration of higher levels of renewables.

F–13

Newberry 115 kV Line (Bush River-DESC), Upgrade

- **Proactive Solar Upgrade**
- **Problem:** This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals.
- **Solution:** Rebuild 115 kV line with higher capacity conductors.



Project ID and Name: 0083 – Clinton 100 kV Line (Bush River-Laurens), Upgrade

Project Description
This project consists of rebuilding 29.3 miles of the existing 2/0 Cu, 336 ACSR / 477 ACSR conductor with 1158 ACSS/TW.

Status	Planned
Transmission Owner	DEC
Planned In-Service Date	12/1/2026
Estimated Time to Complete	4.5
Estimated Cost	$109 M

Narrative Description of the Need for this Project
Various solar studies performed have shown the need to upgrade this line. This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals. With high solar penetration in the southwestern area of the DEC system, this line can overload for various contingencies.

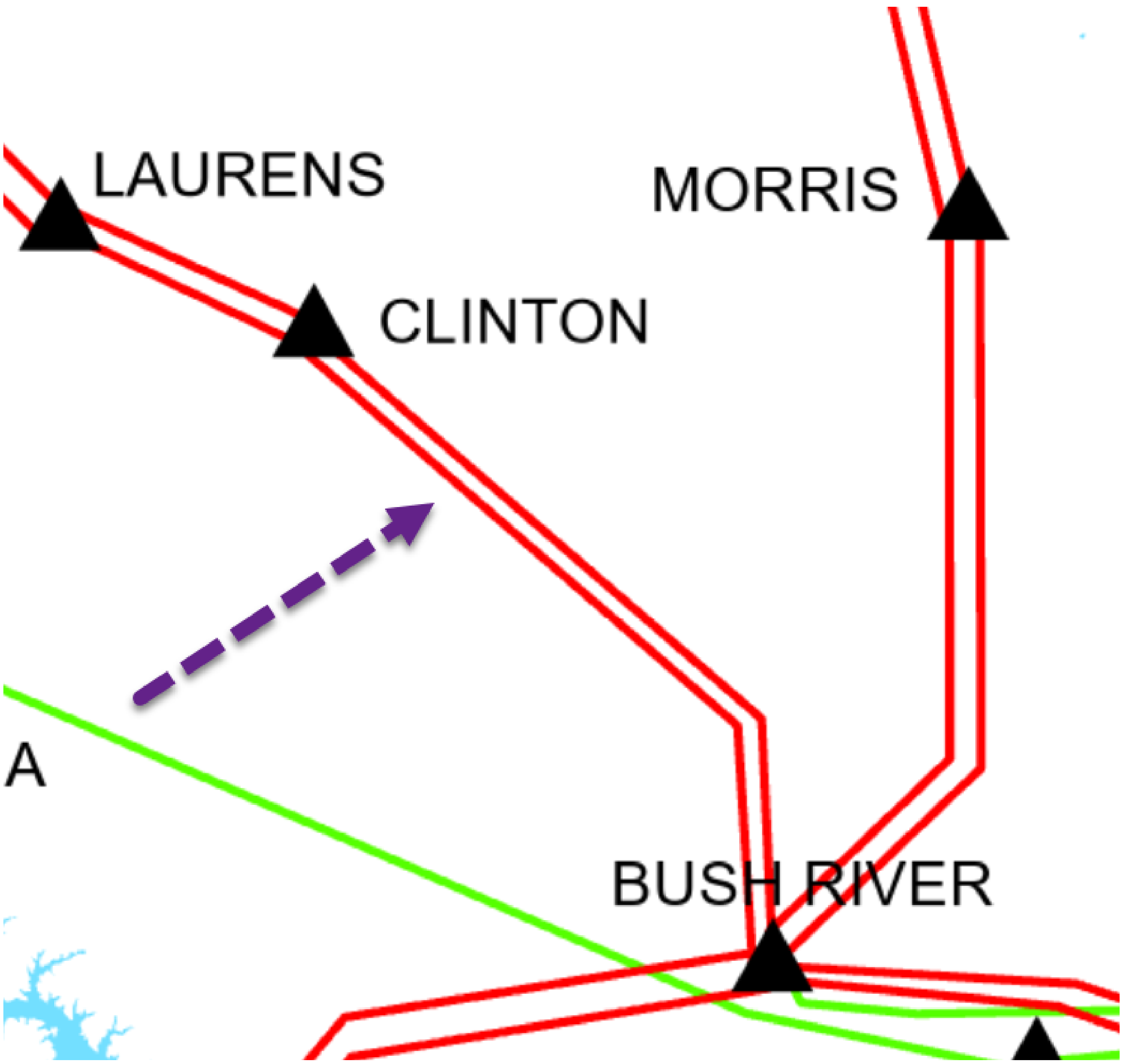
Other Transmission Solutions Considered
Curtailment of solar. New transmission lines.

Why this Project was Selected as the Preferred Solution
Reliability. Facilitates integration of higher levels of renewables.

F–14

Clinton 100 kV Line (Bush River-Laurens), Upgrade

- **Proactive Solar Upgrade**
- **Problem:** This upgrade is needed for future solar generation proposed for compliance with the Carbon Plan goals.
- **Solution:** Rebuild 100 kV line with higher capacity conductors.



Appendix G Collaborative Plan Comparisons

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M) Items identified in red are changes from the previous report.								
			2021 Plan[1]			2022 Plan		
Project ID	Reliability Project	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0024	Durham–RTP 230 kV Line, Reconductor	DEP	Conceptual	TBD	20	Conceptual	TBD	20
0039	Asheboro–Asheboro East 115 kV North Line, Reconductor	DEP	Underway	6/1/2022	12	In-service	12/1/2022	28
0046	Windmere 100 kV Line (Dan River–Sadler), Construct	DEC	Underway	12/1/2023	28	Underway	6/1/2024	26
0048	Wilkes 230/100 kV Tie Station, Construct	DEC	Underway	6/1/2024	69	Underway	12/1/2024	53
0050	Craggy–Enka 230 kV Line, Construct	DEP	Planned	12/1/2025	74	Underway	12/1/2024	104

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M) Items identified in red are changes from the previous report.								
			2021 Plan[1]			2022 Plan		
Project ID	Reliability Project	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0051	Cokesbury 100 kV Line (Coronaca–Hodges), Upgrade	DEC	Planned	12/1/2024	20	Planned	6/1/2025	22
0052	South Point 100 kV Switching Station, Construct	DEC	Underway	12/1/2024	111	Underway	12/1/2025	96
0053	Wateree Hydro Plant, Upgrade	DEP	Underway	12/1/2023	10	Underway	6/1/2023	15
0054	Carthage 230/115 kV Substation, Construct	DEP	Conceptual	12/1/2027	27	Underway	12/1/2025	28.5
0055	Falls 230 kV Sub, Upgrade	DEP	Conceptual	12/1/2028	45	Conceptual	12/1/2028	45

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M) Items identified in red are changes from the previous report.								
			2021 Plan[1]			2022 Plan		
Project ID	Reliability Project	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0056	Castle Hayne–Folkstone115 kV Line, Rebuild	DEP	Planned	12/1/2026	85	Underway	12/1/2025	95.5
0057	Holly Ridge North 115 kV Switching Station, Construct	DEP	Planned	12/1/2026	20	Underway	12/1/2026	12
0058	Coronaca 100 kV Line (Coronaca-Creto), Upgrade and Construct	DEC	Planned	12/1/2025	15	Planned	6/1/2026	18
0059	Monroe 100 kV Line (Lancaster-Monroe), Upgrade	DEC	Planned	6/1/2027	88	Underway	12/1/2027	53
0060	Westport 230 kV Line (McGuire-Marshall), Upgrade	DEC	Conceptual	TBD	40	Conceptual	TBD	65

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M) Items identified in red are changes from the previous report.								
			2021 Plan[1]			2022 Plan		
Project ID	Reliability Project	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0061	Wateree 100 kV Line (Great Falls-Wateree), Upgrade	DEC	-	-	-	Underway	12/1/2023	10
0062	Silas 100 kV Line (Mocksville-Idols Tap), Upgrade	DEC	-	-	-	Underway	6/1/2025	22
0063	North Greenville 230 kV Tie Station, Upgrade	DEC	-	-	-	Underway	12/1/2026	20
0064	Wylie 100 kV Line (Wylie-Arrowood Retail), Upgrade	DEC	-	-	-	Underway	12/1/2026	15
0065	Morning Star 230kV Tie Station, Upgrade	DEC	-	-	-	Planned	6/1/2028	36

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M) Items identified in red are changes from the previous report.								
			2021 Plan[1]			2022 Plan		
Project ID	Reliability Project	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0066	Davidson River 100 kV Line (North Greenville-Marietta), Upgrade	DEC	-	-	-	Conceptual	TBD	30
0067	Harley 100 kV Line (Tiger-Campobello), Upgrade	DEC	-	-	-	Conceptual	TBD	45
0068	Sandy Ridge 230 kV Line (Newport-Morning Star), Upgrade	DEC	-	-	-	Conceptual	TBD	60
0069	Skybrook 100 kV Line (Winecoff-Eastfield Retail), Upgrade	DEC				Conceptual	TBD	17
0070	Cape Fear – West End 230 kV Line, Rebuild	DEP				Planned	6/5/2026	70

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M) Items identified in red are changes from the previous report.								
			2021 Plan[1]			2022 Plan		
Project ID	Reliability Project	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0071	Erwin – Fayetteville East 230 kV Line, Rebuild	DEP				Planned	6/5/2026	84
0072	Erwin – Fayetteville 115 kV Line, Rebuild	DEP				Planned	6/5/2025	21
0073	Fayetteville-Fayetteville Dupont 115 kV Line, Rebuild 3.2-mile section	DEP				Planned	12/26/2024	16
0074	Milburnie 230 kV Substation, Upgrade	DEP				Planned	4/2/2026	4
0075	Weatherspoon-Marion 115 kV Line, Upgrade	DEP				Planned	12/12/2025	13
0076	Camden Junction-Wateree 115 kV Line, Rebuild	DEP				Planned	12/11/2026	10

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M) Items identified in red are changes from the previous report.									
			2021 Plan[1]			2022 Plan			
Project ID	Reliability Project	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0077	Robinson Plant-Rockingham 115 kV Line, Rebuild	DEP				Planned	11/18/2027	38
0078	Robinson Plant-Rockingham 230 kV Line, Upgrade	DEP				Planned	6/5/2026	43
0079	Fayetteville-Fayetteville Dupont 115 kV Line, Rebuild 4.9-mile section	DEP				Planned	4/16/2026	14
0080	Lee 100 kV Line (Lee-Shady Grove), Upgrade	DEC				Planned	12/1/2026	45
0081	Piedmont 100 kV Line (Lee-Shady Grove), Upgrade	DEC				Planned	12/1/2026	45
0082	Newberry 115 kV Line (Bush River-DESC), Upgrade	DEC				Planned	12/1/2026	42
0083	Clinton 100 kV Line (Bush River-Laurens), Upgrade	DEC				Planned	12/1/2026	109
TOTAL								1,490

[1] Information reported in Appendix B of the NCTPC 2021–2031 Collaborative Transmission Plan" dated January 24, 2022 and updated to reflect the mid-year plan report dated August 22, 2022.

[2] Status: ***In-service**:* Projects with this status are in-service. This status was updated as of 12/1/2022.

***Underway**:* Projects with this status range from the Transmission Owner having some money in its current year budget for the project to the Transmission Owner having completed some construction activities for the project.

***Planned**:* Projects with this status do not have money in the Transmission Owner's current year budget; and the project is subject to change.

***Conceptual**:* Projects with this status are not p*lanned* at this time but will continue to be evaluated as a potential project in the future.

***Deferred**:* Projects with this status were identified in the 2021 Report and have been deferred beyond the end of the planning horizon based on analysis performed to develop the 2022 Collaborative Transmission Plan.

Removed: Project is cancelled and no longer in the plan

[3] The estimated cost is in nominal dollars which reflects the sum of the estimated annual cash flows over the expected development period for the specific project (typically 2 – 5 years), including direct costs, loadings and overheads; but not including AFUDC. Each year's cash flow is escalated to the year of the expenditures. The sum of the expected cash flows is the estimated cost.

Appendix H
Acronyms

ACRONYMS

ACSR	Aluminum Conductor Steel Reinforced
ACSS/TW	Aluminum Conductor Steel Supported/Trapezoidal Wire
AEP	American Electric Power
AFUDC	Allowance for Funds Used During Construction
BAA	Balancing Authority Area
CC	Combined Cycle
CPLE	Carolina Power & Light East, or DEP East
CPLW	Carolina Power & Light West, or DEP West
CT	Combustion Turbine
DEC	Duke Energy Carolinas
DEP	Duke Energy Progress
DNR	Designated Network Resource
DVP	Dominion Virginia Power
ERAG	Eastern Interconnection Reliability Assessment Group
EU	Energy United
FERC	Federal Energy Regulatory Commission
FSA	Facilities Study Agreement
ISA	Interconnection Service Agreement
KMEC	Kings Mountain Energy Center
kV	Kilovolt
LGIA	Large Generator Interconnection Agreement
LSE	Load Serving Entity
LTWG	SERC Long-Term Working Group
M	Million
MCM	Thousand Circular Mils
MMWG	Multiregional Modeling Working Group
MVA	Megavolt-Ampere
MVAR	Megavolt-Ampere Reactive
MW	Megawatt
NCEMC	North Carolina Electric Membership Corporation
NCEMPA	North Carolina Eastern Municipal Power Agency

NCMPA1	North Carolina Municipal Power Agency Number 1
NCTPC	North Carolina Transmission Planning Collaborative
NCUC	North Carolina Utilities Commission
NERC	North American Electric Reliability Corporation
NTE	NTE Energy
OASIS	Open Access Same-time Information System
OATT	Open Access Transmission Tariff
OSC	Oversight Steering Committee
OTDF	Outage Transfer Distribution Factor
PJM	PJM Interconnection, LLC
PMPA	Piedmont Municipal Power Agency
POD	Point of Delivery
PSS/E	Power System Simulator for Engineering
PV	Photovoltaic (Solar)
PWG	Planning Working Group
RZEP	Red Zone Expansion Plan
ROW	Right of Way
RTP	Research Triangle Park
SCEG	South Carolina Electric & Gas Company / Dominion Energy South Carolina
SCPSA	South Carolina Public Service Authority
SE	Steam Electric (Plant)
SEPA	Southeastern Power Administration
SERC	SERC Reliability Corporation
SOCO	Southern Company
SS	Switching Station
SVC	Static VAR Compensator
TAG	Transmission Advisory Group
TRM	Transmission Reliability Margin
TSR	Transmission Service Request
TTC	Total Transfer Capability
TVA	Tennessee Valley Authority

VACAR	Virginia-Carolinas Reliability Agreement
VAR	Volt Ampere Reactive