North Carolina Transmission Planning Collaborative

Report on the NCTPC 2018-2028 Collaborative Transmission Plan

December 7, 2018
DRAFT REPORT

2018 – 2028 NCTPC Transmission Plan
Table of Contents

I. Executive Summary 1
II. North Carolina Transmission Planning Collaborative Process 7
II.A. Overview of the Process 7
II.B. Reliability Planning Process and Resource Supply Options Processes 9
II.C. Local Economic Study Process 11
II.D. Local Public Policy Process 12
II.E. Local Transmission Plan 14
III. 2018 Reliability Planning Study Scope and Methodology 15
III.A. Assumptions 15
1. Study Year and Planning Horizon 15
2. Network Modeling 16
3. Interchange and Generation Dispatch 18
III.B. Study Criteria 19
III.C. Case Development 20
III.D. Transmission Reliability Margin 20
III.E. Technical Analysis and Study Results 21
III.F. Assessment and Problem Identification 22
III.G. Solution Development 22
III.H. Selection of Preferred Reliability Solutions 23
III.I. Contrast NCTPC Report to Other Regional Transfer Assessments 23
IV. Base Reliability Study Results 24
V. Local Economic Study Development Sites Study 25
VI. Collaborative Transmission Plan 27
Appendix A Interchange Tables 29
Appendix B Transmission Plan Major Project Listings - Reliability Projects 34
Appendix C Transmission Plan Major Project Descriptions - Reliability Projects 39
Appendix D Collaborative Plan Comparisons 79
Appendix E Acronyms 86

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 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 and Local Economic Study Transmission Planning while appropriately balancing costs, benefits and risks associated with the use of transmission and generation resources.

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

The 2017-2027 Collaborative Transmission Plan (the "2017 Collaborative Transmission Plan" or the "2017 Plan") was published in January 2018.

This report documents the current 2018 – 2028 Collaborative Transmission Plan ("2018 Collaborative Transmission Plan" or the "2018 Plan") for the Participants. The initial sections of this report provide an overview of the NCTPC Process as well as the specifics of the 2018 reliability planning study scope and methodology. The NCTPC Process document and 2018 Study scope document are posted in their entirety on the NCTPC website at http://www.nctpc.org/nctpc/.

The scope of the 2018 reliability planning process was focused on the annual base reliability study. The base reliability study assessed 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 was to evaluate the transmission systems' ability to meet load growth projected for 2018 through 2028 with the Participants' planned Designated Network Resources ("DNRs").

The 2018 Study[1] model included the following modelling assumptions related to CPLW upgrades:

- DEP assumed that Asheville 1 and 2 coal units will be shut down in all three study cases, and the two planned Asheville combined cycle ("CC") units (260/280 MW Summer/Winter each, 520/560 MW Summer/Winter total) were added to all three study cases.

- One of the planned Asheville CC units was connected to the Asheville 230 kV switchyard and the other was connected to the Asheville 115 kV switchyard. The 2023 summer case includes a CPLW import of 37 MW (23 MW from SCPSA, and 14 MW from TVA).

- The 2023/2024 winter case includes a CPLW import of 287 MW (100 MW from CPLE, 150 MW from DEC-Rowan, 23 MW from SCPSA, and 14 MW from TVA). The 2028/2029 winter case includes a CPLW import of 364 MW (200 MW from

[1] The term "2018 Study" is a generic term referring to all the study work that was done in 2018 which includes the reliability analysis as well the additional stress tests to the transmission systems of DEC and DEP as a part of the Reliability Planning Process.

CPLE, 150 MW from DEC-Rowan, 0 MW from SCPSA, and 14 MW from TVA).

- To meet the remaining CPLW load, CPLW generation was dispatched in the following order: Walters, Marshall, planned Asheville CC units, and finally the existing Asheville CTs. The projects needed for the installation of these units were modeled in the cases.

Based on the study's input assumptions, the 2018 Study allowed for identification of any new system impacts not currently addressed by existing transmission plans, in which case solutions were developed. The 2018 Study also allowed for adjustments to existing plans where necessary.

The NCTPC reliability study results affirmed that the planned DEC and DEP transmission projects identified in the 2017 Plan continue to satisfactorily address the reliability concerns identified in the 2018 Study for the near-term (5 year) and the long-term (10 year) planning horizons. The 2018 Plan is detailed in Appendix B which identifies the new and updated projects planned with an estimated cost of greater than $10 million.

The total estimated cost for the 19 reliability projects included in the 2018 Plan is $657 million as documented in Appendix B. This compares to the 2017 Plan estimate of $426 million for 17 reliability projects. In-service dates and cost estimates for some projects that are planned or underway have been revised based on updated information. See Appendix D for a detailed comparison of this year's Plan to the 2017 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 completed or eliminated from the list. Appendix C provides a more detailed description of each project in the 2018 Plan.

The 2018 Plan, relative to the 2017 Plan, includes 4 new DEC projects and 1 new DEP project.

The 4 new DEC projects in the 2018 Plan are:

- Windmere 100 kV Line (Dan River-Sadler), Construct
- NTE II, Generator Interconnection
- Wilkes 230/100 kV Tie Station, Construct
- Ballantyne Switching Station, Construct

The 1 new DEP project in the 2018 Plan is:

- Craggy-Enka 230kV Line, Construct

There are revised in-service dates, estimated cost changes, and scope changes for the following DEC and DEP projects:

- Raeford 230 kV substation, project to loop-in Richmond - Ft Bragg Woodruff St 230 kV Line and the added third bank had an increase in estimated cost.
- Durham - RTP 230 kV Line Reconductor had its in-service date pushed out.
- Jacksonville - Grants Creek 230 kV Line and Grants Creek 230/115 kV Substation project had an increase in estimated cost.
- Newport - Harlowe 230 kV Line, Newport SS and Harlowe 230/115 kV Substation had an increase in estimated cost.
- Fort Bragg Woodruff St. 230 kV Sub, project to replace 150 MVA 230/115 kV transformer with two 300 MVA banks and reconductor Manchester 115 kV feeder was placed in service 2/24/2017 and was removed.
- Sutton - Castle Hayne 115 kV North line Rebuild had an increase in estimated cost and its in-service date was pushed out.
- Harley 100 kV Lines (Tiger - Campobello) Reconductor had a decrease in estimated cost, and its in-service date was pushed out.
- Asheboro-Asheboro East 115kV North Line Reconductor had an increase in estimated cost.

- Delco 230kV Substation, Convert to Double Breaker had an increase in estimated cost.

- Castle Hayne 230kV Substation, Convert to Double Breaker was placed in service 6/1/2018.

- Asheville Plant, Replace 2-300 MVA 230/115 kV Banks with 2-400 MVA Banks, Reconductor 115 kV Ties to Switchyard, Upgrade Breakers, and Add 230 kV Capacitor Bank was placed in service 11/1/2018.

No Public Policy Study requests were received from TAG stakeholders by the February 7th deadline for the 2018 Study year. Therefore there were no evaluations of Public Policy impacts as a part of the 2018 Study.

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. 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 2017, the Planning Working Group ("PWG") analyzed resource supply options that examined the impacts of sixteen different hypothetical transfers into and out of the DEC and DEP systems.

In 2018, the Oversight Steering Committee ("OSC") decided to evaluate six potential economic development sites in North Carolina[2] as part of the Local Economic Study Process. The potential economic development sites were selected to evaluate the transmission system impact of 300 MW of new load at each site where the customer can choose their electric service provider. The six economic development sites selected are listed in Table 1 below:

[2] https://edpnc.com/relocate-or-expand/available-sites-location-data/

Table 1

Local Economic Studies

2028/2029 Hypothetical Loads (300 MW)

Name	Latitude (°)	Longitude (°)	BAA
Chatham-Siler City Advanced Manufacturing Site	35.74167067	-79.5412302	DEP
GTP Parcel 1	35.32759074	-77.61823654	DEP
Highway 70 East	35.751578	-80.761313	DEC
Peppercorn Plantation	35.82102763	-80.84566802	DEC
SouthPark Phase II – Duplin County Business & Industry	34.760981	-77.969416	DEP
US 401 North Site	35.169472	-78.846784	DEP

In this 2018 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, North Carolina Electric Membership Corporation, and ElectriCities of North Carolina) 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 and economic 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 entire, iterative process ultimately results in a single Local Transmission Plan that appropriately balances the costs, benefits and risks associated with the use of transmission, generation, and demand-side resources. 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

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 the DEC and DEP. This economic analysis provides the opportunity to study the transmission upgrades that would be required to reliably integrate new resources.

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 local transmission.

The Oversight Steering Committee (“OSC”) manages the NCTPC Process. The PWG implements the development of the NCTPC Process and coordinates the study development. The Transmission Advisory Group (“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 representing 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 Processes

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

The Reliability Planning Process is designed to follow the steps outlined below. 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. 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 any transmission upgrades and/or additions: (i) needed to maintain a sufficient level of reliability necessary to serve the native load of all Participants and (ii) needed to 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 for consideration for incorporation into the final Collaborative Transmission Plan.

For the 2018 Study, the NCTPC evaluated no resource supply scenarios.

II.C. Local Economic Study Process

The Local Economic Study Process allows the TAG participants to propose economic hypothetical 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. The proposed scenarios and interfaces are compiled by the PWG and then 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.

While the overall NCTPC Process includes both a Reliability Planning

Process and the Local Economic Study Process, 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 2018 Study, the NCTPC evaluated six potential economic development sites in North Carolina.

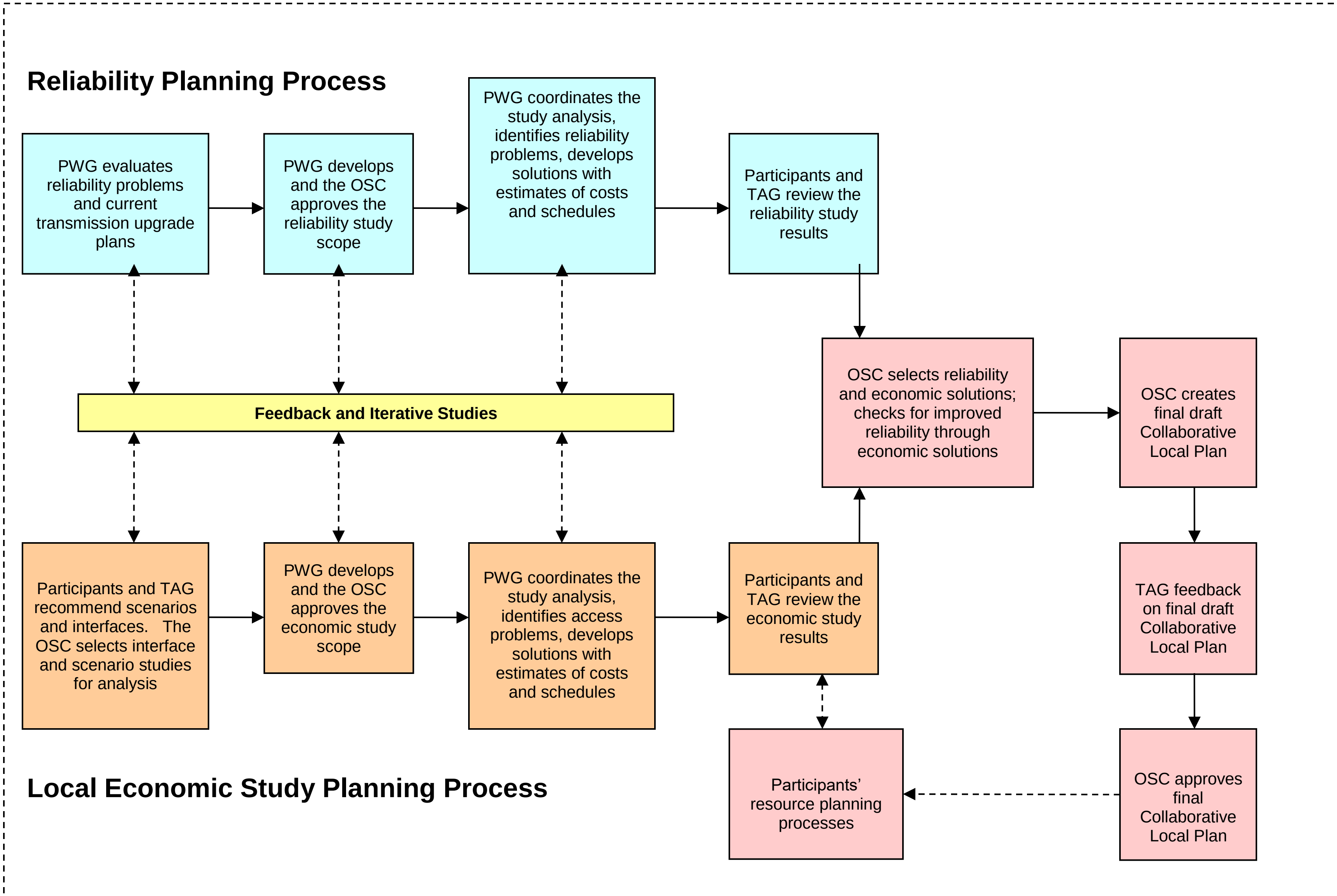
II.D. Local Public Policy Process

Each year, the OSC will determine if there are any public policies driving the need for local transmission upgrades. Through this process the OSC will seek input from TAG participants to identify any public policy impacts 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 to determine if there are any public policies driving the need for local transmission as follows:

- 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 2018 Study, the NCTPC evaluated no local public policy impacts as no public policy requests were received from TAG stakeholders by the deadline of February 7, 2018. Local public policy requests will be solicited again for the 2019 Study and included if appropriate.

2018 NCTPC Process Flow Chart



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 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 being developed 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 feedback is reviewed by the OSC for consideration for incorporation 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. 2018 Reliability Planning Study Scope and Methodology

The scope of the 2018 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 2018 Study models assume that DEP’s Asheville 1 and 2 coal units were shut down in all three study cases, and the two planned Asheville combined cycle (CC) units (260/280 MW Summer/Winter each, 520/560 MW total Summer/Winter total) were added to all three study cases. One of the planned Asheville CC units was connected to the Asheville 230 kV switchyard and the other was connected to the Asheville 115 kV switchyard. The purpose of the base reliability study was to evaluate the transmission systems’ ability to meet load growth projected for 2023 summer through 2028/2029 winter with the Participants’ planned Designated Network Resources (“DNRs”). The 2018 Study allowed for identification of any new system impacts not currently addressed by existing transmission plans in which case solutions were developed. The 2018 Study also allowed for adjustments to existing plans where necessary.

III.A. Assumptions

1. Study Year and Planning Horizon

The 2018 Plan addressed a ten-year planning horizon through 2028. The study years chosen for the 2018 Study are listed in Table 2.

Table 2

Study Years

Study Year / Season	Analysis
2023 Summer	Near-term base reliability
2023/2024 Winter	Near-term base reliability
2028/2029 Winter	Long-term base reliability

To identify projects required in years other than the base study years of 2023, 2023/2024 and 2028/2029, line loading results for those base study years were extrapolated into future years assuming the line loading growth rates in Table 3. This allowed assessment of transmission needs throughout the planning horizon. The line loading growth rates are based on each BAAs individual load growth projection at the time the study process was initiated.

Table 3
Line Loading Growth Rates

Company	Line Loading Growth Rate
DEC[3]	1.2 % per year (summer) 1.2% per year (winter)
DEP	0.8% per year (summer) 0.7% per year (winter)

2. Network Modeling

The network models developed for the 2018 Study included new transmission facilities and upgrades for the 2023, 2023/2024 and 2028/2029 models, as appropriate, from the current transmission plans of DEC and DEP and from the 2017 Plan. Table 4 lists the planned major transmission facility projects (with an estimated cost of $10 million or more each) included in the 2023, 2023/2024 and 2028/2029 models. Table 5 lists the generation facility changes included in the 2023, 2023/2024 and 2028/2029 models.

[3] For the purpose of planning a transmission system with appropriate robustness, DEC line loading growth rates shown in Table 3 exceed the growth rates provided in DEC's IRP.

Table 4

Major Transmission Facility Projects Included in Models

Company	Transmission Facility	2023	2028/2029
DEP	Raeford 230 kV Substation, Loop-in Richmond - Ft Bragg Woodruff St 230 kV Line and add 3rd bank	Yes	Yes
DEP	Jacksonville - Grants Creek 230 kV Line, Grants Creek 230/115 kV Substation	Yes	Yes
DEP	Newport - Harlowe 230 kV Line, Newport Switching Station, Harlowe 230/115 kV Substation	Yes	Yes
DEP	Sutton - Castle Hayne 115 kV North line rebuild	Yes	Yes
DEP	Asheville Plant, Replace 2-300 MVA 230/115 kV banks with 2-400 MVA banks, reconductor 115 kV ties to switchyard, upgrade breakers, and add 230 kV capacitor bank	Yes	Yes
DEP	Cane River 230 kV Substation, Construct 150 MVAR SVC	Yes	Yes
DEP	Asheboro-Asheboro East 115kV North Line, Reconductor	Yes	Yes
DEC	Orchard Tie 230/100 kV Tie Station, Construct	Yes	Yes

Table 5

Major Generation[4] Facility Changes in Models

Company	Generation Facility	2023	2028/2029
DEC	Added Lee CC (776 MW)	Yes	Yes
DEC	Added Kings Mountain Energy CC (452 MW)	Yes	Yes
DEC	Added Lincoln County CT (402 MW)	No	Yes
DEC	Added Reidsville Energy Center (477 MW)	Yes	Yes
DEC	Retired Allen 1-3 (617 MW)	No	Yes
DEC	Retired Allen 4-5 (564 MW)	No	Yes
DEP	Asheville 1-2 not dispatched	Yes	Yes
DEP	Added Asheville CC (2 x 280 MW)	Yes	Yes
DEP	Frazier Solar (50.2 MW)	Yes	Yes
DEP	Buckleberry Canal Solar (52.1 MW)	Yes	Yes
DEP	Willard Solar (34.2 MW)	Yes	Yes
DEP	Louisburg Fox Creek Solar (49.3 MW)	Yes	Yes
DEP	Sandy Bottom Solar (48.9 MW)	Yes	Yes

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

[4] Major Generation Threshold is considered to be 20 MW or greater and connected to the transmission system

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. This level of 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. These dispatch assumptions reflect the expected solar generation output coincident with the DEC peak load. DEC models 201 MW of transmission-connected solar generation available for dispatch, dispatched consistent with the aforementioned 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 2023 summer power flow case has approximately 735 MW of transmission-connected and 1446 MW of distribution-connected solar generation for a total of 2181 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 that can be reflective of various factors such as geography and plant design. For winter peak studies, DEP makes the assumption 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 2017 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 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 case and scenarios were performed using Power System Simulator for Engineering ("PSS/E") power flow or equivalent. Each transmission planner simulated its own transmission and generation down contingencies on its own transmission system.

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

Generator maintenance cases were developed for the following units:

Allen 4	Allen 5	Bad Creek 1
Belews Creek 1	Catawba 1	Cliffside 5
Cliffside 6	Broad River 1	Mill Creek 1
Jocassee 1	Lee 3	Marshall 3
McGuire 1	McGuire 2	Nantahala
Oconee 1	Oconee 3	Buck CC
Dan River CC	Rowan CC	Rockingham 1
Thorpe	Lincoln 1	Lee CC

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. To model this worst case import scenario for TRM, cases were developed from the 2023 summer, 2023/2024 winter and 2028/2029 winter peak base cases. 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 exchanged 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 2018 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 2018 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 2017 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 Study Group ("LTSG") studies performed for similar timeframes. LTSG studies have recently been performed for 2022 winter and 2023 summer timeframes. The limiting facilities identified in the PWG study of base reliability have been previously identified in the LTSG 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 2018 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 2018 Plan is detailed in Appendix B which identifies the new and updated projects planned with an estimated cost of greater than $10 million. Projects in the 2018 Plan are those projects identified in the base reliability study. For each of these projects, Appendix B 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 19 reliability projects included in the 2018 Plan is $657 million as documented in Appendix B. This compares to the 2017 Plan estimate of $426 million for 17 reliability projects. In-service dates and cost estimates for some projects that are planned or underway have been revised based on updated information. See Appendix D for a detailed comparison of this year's Plan to the 2017 Plan.

V. Local Economic Study Development Sites Study

In 2018, the PWG analyzed as part of the local economic studies, cases that examine the impacts of 6 hypothetical loads in the DEC and DEP footprints — see Figure 1. Each of these hypothetical loads were analyzed, some in a single case. Where issues requiring solutions within the applicable planning window were identified, alternative solutions were discussed, and a primary set of solutions was determined.

Figure 1
Local Economic Studies
2028/2029 Hypothetical Loads (300 MW)

The six economic development sites selected are listed in Table 6 below:

Table 6

Local Economic Studies

2028/2029 Hypothetical Loads (300 MW) Sites

Name	**Latitude (°)**	**Longitude (°)**	**BAA**
Chatham-Siler City Advanced Manufacturing Site	35.74167067	-79.5412302	DEP
GTP Parcel 1	35.32759074	-77.61823654	DEP
Highway 70 East	35.751578	-80.761313	DEC
Peppercorn Plantation	35.82102763	-80.84566802	DEC
SouthPark Phase II – Duplin County Business & Industry	34.760981	-77.969416	DEP
US 401 North Site	35.169472	-78.846784	DEP

For the purpose of this study, interconnection costs describe costs to make the interconnection to the transmission system (i.e. fold-in, station), and network upgrades costs describe additional costs to mitigate thermal loading issues. The estimated Interconnection and Network Upgrade costs for the 6 hypothetical loads are listed in Table 7 below:

Table 7

Local Economic Studies

Hypothetical Loads Transmission Costs

Name	**Estimated Interconnection Costs, $**	**Estimated Network Upgrade Costs, $**	**BAA**
Chatham-Siler City Advanced Manufacturing Site	$ 11,800,000	$ 15,920,000	DEP
GTP Parcel 1	$ 23,250,000	$ 500,000	DEP
Highway 70 East	$ 17,500,000	$ -	DEC
Peppercorn Plantation (Option 1)	$ 28,500,000	$ -	DEC
Peppercorn Plantation (Option 2)	$ 27,000,000	$ -	DEC
SouthPark Phase II – Duplin County Business & Industry	$ 10,300,000	$ -	DEP
US 401 North Site	$ 17,860,000	$ 24,100,000	DEP

VI. Collaborative Transmission Plan

The 2018 Plan includes 18 reliability projects with an estimated cost of $10 million or more each. These projects are listed in Appendix B. The total estimated cost for these 19 reliability projects in the 2018 Plan is $657 million. This compares to the 2017 Plan estimate of $426 million for 17 reliability projects. In-service dates and cost estimates for some projects that are planned or underway have been revised based on updated information. See Appendix D for a detailed comparison of this year's Plan to the 2017 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 completed or eliminated from the list. Appendix C provides a more detailed description of each project in the 2018 Plan, and includes the following information:

1) Reliability Projects: 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 2017 Report and have been deferred beyond the end of the planning horizon based on the 2018 Study results.

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.

Appendix A
Interchange Tables

2023 SUMMER PEAK, 2023/20242 WINTER PEAK, 2028/2029 WINTER PEAK

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE (BASE)

Duke Energy Carolinas Modeled Imports – MW

	23S	23/24W	28/29W
CPLE (NCEMC-Hamlet)	4	0	0
PJM (DVP)	2	2	2
SCEG (Chappells)	2	2	2
SCPSA (PMPA)	173	57	61
SCPSA (Seneca)	48	29	31
SEPA (Hartwell)	155	155	155
SEPA (Thurmond)	113	113	113
SOCO (EU)	0	0	670
Total	**497**	**358**	**1034**

Duke Energy Carolinas Modeled Exports – MW

	23S	23/24W	28/29W
CPLE (Broad River)	850	850	850
CPLE (NCEMC-Catawba)	281	281	281
CPLE (CPLC)	150	0	0
CPLW (Rowan)	0	150	150
PJM (NCEMC-Catawba)	100	100	100
SCPSA (Haile)	10	10	10
Total	**1391**	**1391**	**1391**

Duke Energy Carolinas Net Interchange – MW

	23S	23/24W	28/29W
	894	**1033**	**357**

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

2023 SUMMER PEAK, 2023/2024 WINTER PEAK, 2028/2029 DUKE ENERGY PROGRESS (EAST)

DETAILED INTERCHANGE (BASE)

Duke Energy Progress (East) Modeled Imports – MW

	23S	23/24W	28/29W
PJM (NCEMC-AEP)	100	100	100
DUK (Broad River)	850	850	850
DUK (NCEMC-Catawba)	281	281	281
DUK (CPLC)	150	0	0
PJM (SEPA-KERR)	95	95	95
Total	**1476**	**1326**	**1326**

Duke Energy Progress (East) Modeled Exports – MW

	23S	23/24W	28/29W
CPLW (Transfer)	0	100	200
PJM (Ingenco)	6	6	6
PJM (NCEMC-Hamlet)	165	165	165
DUK (NCEMC-Hamlet)	4	0	0
Total	**175**	**271**	**371**

Duke Energy Progress (East) Net Interchange - MW

	23S	23/24W	28/29W
	-1301	**-1055**	**-955**

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

2023 SUMMER PEAK, 2023/2024 WINTER PEAK, 2028/2029 DUKE ENERGY PROGRESS (WEST)

DETAILED INTERCHANGE (BASE)

Duke Energy Progress (West) Modeled Imports – MW

	23S	23/24W	28/29W
CPLE (Transfer)	0	100	200
DUK (Rowan)	0	150	150
SCPSA (Waynesville)	23	23	0
TVA (SEPA)	14	14	14
Total	**37**	**287**	**364**

Duke Energy Progress (West) Modeled Exports – MW

	23S	23/24W	28/29W
---	---	---	---
Total	**---**	**---**	**---**

Duke Energy Progress (West) Net Interchange – MW

	23S	23/24W	28/29W
	-37	**-287**	**-364**

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

2023 SUMMER PEAK, 2023/2024 WINTER PEAK, 2028/2029 WINTER PEAK

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

DETAILED INTERCHANGE (TRM)

Duke Energy Progress (West) Modeled Imports – MW

	23S, 23/24W, 28/29W
AEP (TRM)	70
DUK (TRM)	191
TVA (TRM)	19
Total	**280**

Duke Energy Progress (East) Modeled Imports – MW

	23S, 23/24W, 28/29W
AEP (TRM)	100
DUK (TRM)	773
DVP (TRM)	427
SCEG (TRM)	200
SCPSA (TRM)	326
Total	**1826**

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

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

Appendix B
Transmission Plan Major Project Listings - **Reliability Projects**

2018 Collaborative Transmission Plan – Reliability Projects (Estimated Cost > $10M)						
Project ID	Reliability Project	Status[1]	Transmission Owner	Projected In-Service Date	Estimated Cost ($M)[2]	Project Lead Time (Years)[3]
0024	Durham - RTP 230 kV Line, Reconductor	Conceptual	DEP	TBD	15	4
0028	Brunswick #1 – Jacksonville 230 kV Line, Loop into Folkstone 230 kV Substation	Planned	DEP	6/1/2024	14	4
0030	Raeford 230 kV Substation, Loop-in Richmond - Ft Bragg Woodruff St 230 kV Line and Add 3rd Bank	Underway	DEP	12/1/2018	29	0.1
0031	Jacksonville - Grants Creek 230 kV Line and Grants Creek 230/115 kV Substation	Underway	DEP	6/1/2020	73	2
0032	Newport - Harlowe 230 kV Line, Newport SS and Harlowe 230/115 kV Substation	Underway	DEP	6/1/2020	64	2
0034	Sutton - Castle Hayne 115 kV North Line, Rebuild	Underway	DEP	12/31/2019	25	1

2018 Collaborative Transmission Plan – Reliability Projects (Estimated Cost > $10M)							
Project ID	Reliability Project	Status[1]	Transmission Owner	Projected In-Service Date	Estimated Cost ($M)[2]	Project Lead Time (Years)[3]
0036	Asheville Plant, Replace 2-300 MVA 230/115 kV Banks with 2-400 MVA Banks, Reconductor 115 kV Ties to Switchyard, Upgrade Breakers, and Add 230 kV Capacitor Bank	In-Service	DEP	11/1/2018	40	-
0037	Cane River 230 kV Substation, Construct 150 MVAR SVC	Underway	DEP	6/1/2019	42	0.5
0038	Harley 100 kV Lines (Tiger -Campobello), Reconductor	Conceptual	DEC	TBD	18	3
0039	Asheboro-Asheboro East 115kV North Line, Reconductor	Underway	DEP	6/1/2019	15	0.5
0040	Delco 230kV Substation, Convert to Double Breaker	Underway	DEP	6/1/2019	15	0.5
0041	Castle Hayne 230kV Substation, Convert to Double Breaker	In-Service	DEP	6/1/2018	11	-
0042	Rural Hall 100 kV, Install SVC	Underway	DEC	12/1/2019	50	1

2018 Collaborative Transmission Plan – Reliability Projects (Estimated Cost > $10M)						
Project ID	Reliability Project	Status[1]	Transmission Owner	Projected In-Service Date	Estimated Cost ($M)[2]	Project Lead Time (Years)[3]
0043	Orchard Tie 230/100 kV Tie Station, Construct	Planned	DEC	12/1/2020	80	2
0044	Reidsville 100 kV Lines (Dan River-Sadler), Reconductor	Removed	DEC	-	-	-
0045	Wolf Creek 100 kV Lines (Dan River-Sadler), Reconductor	Removed	DEC	-	-	-
0046	Windmere 100 kV Line (Dan River-Sadler), Construct	Planned	DEC	12/1/2021	26	3
0047	NTE II, Generator Interconnection	Underway	DEC	12/1/2021	53	3
0048	Wilkes 230/100 kV Tie Station, Construct	Planned	DEC	12/1/2023	22	3

2018 Collaborative Transmission Plan – Reliability Projects (Estimated Cost > $10M)						
Project ID	Reliability Project	Status[1]	Transmission Owner	Projected In-Service Date	Estimated Cost ($M)[2]	Project Lead Time (Years)[3]
0049	Ballantyne Switching Station, Construct	Underway	DEC	12/1/2019	15	1
0050	Craggy-Enka 230 kV Line, Construct	Conceptual	DEP	12/1/2025	50	4
TOTAL					**657**	

[1] Status: ***In-service****:* Projects with this status are in-service.

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 2017 Report and have been deferred beyond the end of the planning horizon based on analysis performed to develop the 2018 Collaborative Transmission 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 C
Transmission Plan Major Project Descriptions - **Reliability Projects**

Table of Contents

Project ID	Project Name	Page
0024	Durham - RTP 230 kV Line, Reconductor	C-1
0028	Brunswick #1 – Jacksonville 230 kV Loop into Folkstone 230kV Substation	C-2
0030	Raeford 230 kV Substation, Loop-in Richmond-Ft Bragg Woodruff St 230 kV Line and Add a 3rd Bank	C-3
0031	Jacksonville - Grants Creek 230 kV Line and Grants Creek 230/115 kV Substation	C-4
0032	Newport - Harlowe 230 kV Line, Newport SS and Harlowe 230/115 kV Substation	C-5
0034	Sutton - Castle Hayne 115 kV North Line , Rebuild	C-6
0036	Asheville Plant, Replace 2-300 MVA 230/115 kV Banks with 2-400 MVA Banks, Reconductor 115 kV Ties to Switchyard, Upgrade Breakers, and Add 230 kV Capacitor Bank	C-7
0037	Cane River 230 kV Substation, Construct 150 MVAR SVC	C-8
0038	Harley 100 kV Lines (Tiger - Campobello), Reconductor	C-9
0039	Asheboro-Asheboro East 115kV North Line, Reconductor	C-10
0040	Delco 230kV Substation, Convert to Double Breaker	C-11
0041	Castle Hayne 230kV Substation, Convert to Double Breaker	C-12
0042	Rural Hall 100 kV, Install SVC	C-13
0043	Orchard Tie 230/100 kV Tie Station, Construct	C-14
0046	Windmere 100 kV Line (Dan River-Sadler), Construct	C-15
0047	NTE II, Generator Interconnection	C-16
0048	Wilkes 230/100 kV Tie Station, Construct	C-17
0049	Ballantyne Switching Station, Construct	C-18
0050	Craggy-Enka 230 kV Line, Construct	C-19

Note: The estimated cost for each of the projects described in Appendix C 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	$15 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.

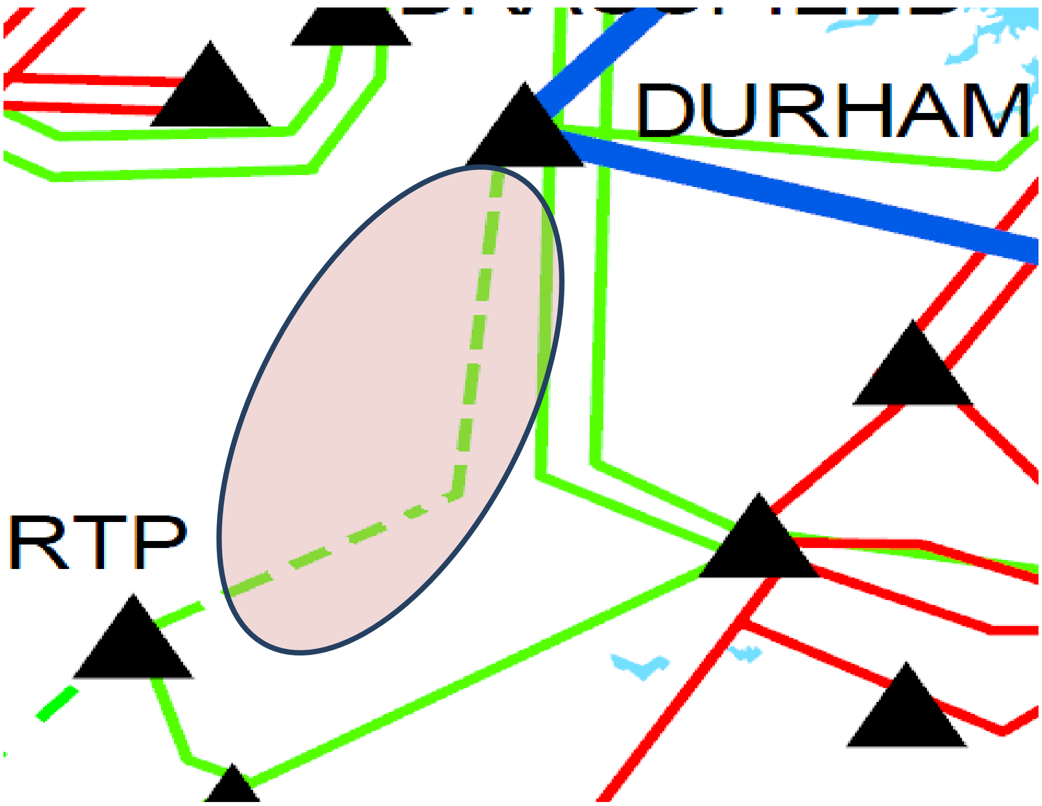
Other Transmission Solutions Considered
Construct a new line between Durham and RTP 230 kV subs.

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

C-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: 0028 – Brunswick #1 – Jacksonville 230 kV Line, Loop into Folkstone 230 kV Substation

Project Description
Loop existing Brunswick Plant Unit 1 – Jacksonville 230 kV Line into the Folkstone 230 kV Substation. Also convert the Folkstone 230 kV bus configuration to breaker-and-one-half by installing three (3) new 230 kV breakers.

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	6/1/2024
Estimated Time to Complete	4 years
Estimated Cost	$14 M

Narrative Description of the Need for this Project
This project is needed to alleviate loading on the Castle Hayne-Folkstone 115 kV Line under the contingency of losing Castle Hayne-Folkstone 230 kV Line.

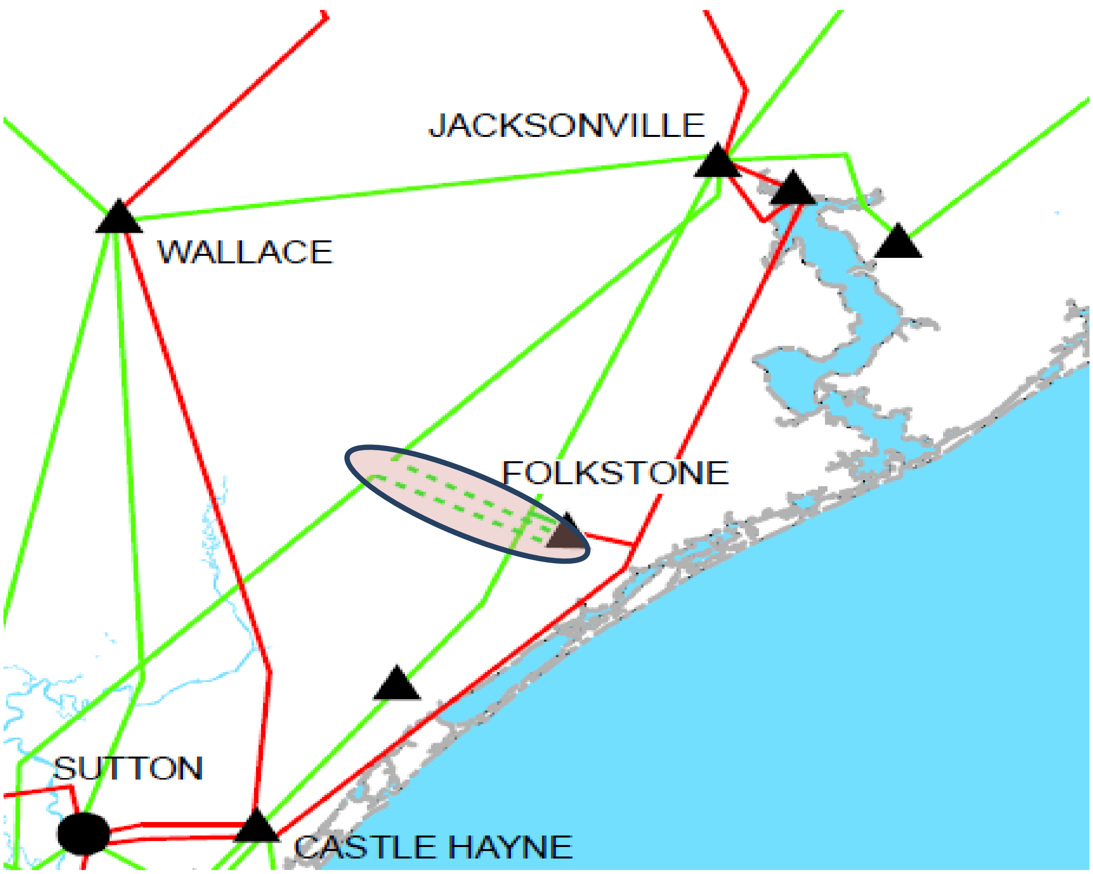
Other Transmission Solutions Considered
Rebuild, reconductor existing Castle Hayne-Folkstone 115 kV line.

Why this Project was Selected as the Preferred Solution
The selected project fixes additional transmission contingencies that the alternate solution does not.

C-2

Brunswick #1 – Jacksonville 230 kV Line Loop Into Folkstone 230 kV Substation

- **NERC Category P1 Violation**
- **Problem:** Outage of the Folkstone – Jacksonville 230 kV Line can cause the thermal rating of the Folkstone – Jacksonville City 115 kV Line to be exceeded.
- **Solution:** Loop existing Brunswick Plant Unit 1 – Jacksonville 230 kV Line into the Folkstone 230 kV Substation.



Project ID and Name: 0030 – Raeford 230 kV Substation, Loop-in Richmond - Ft Bragg Woodruff St 230 kV Line and Add 3rd Bank

Project Description
This project will require the loop-in of the Richmond – Ft. Bragg Woodruff St. 230 kV Line into the Raeford 230kV Substation and add a 300 MVA 230/115kV transformer.

Status	Underway
Transmission Owner	DEP
Planned In-Service Date	12/1/2018
Estimated Time to Complete	0.1 year
Estimated Cost	$29 M

Narrative Description of the Need for this Project
By 2018, with a Brunswick Unit down, loss of the common tower Fayetteville – Rockingham 230 kV and Fayetteville – Raeford 230 kV Lines may cause the Weatherspoon – Raeford 115 kV Line to overload. In addition, by 2018, the N-1-1 contingency of losing both of the Raeford 230/115 kV, 200 MVA transformers at the Raeford 230 kV Substation may overload the Laurinburg - Raeford 115 kV Line. This project will mitigate each of these contingencies.

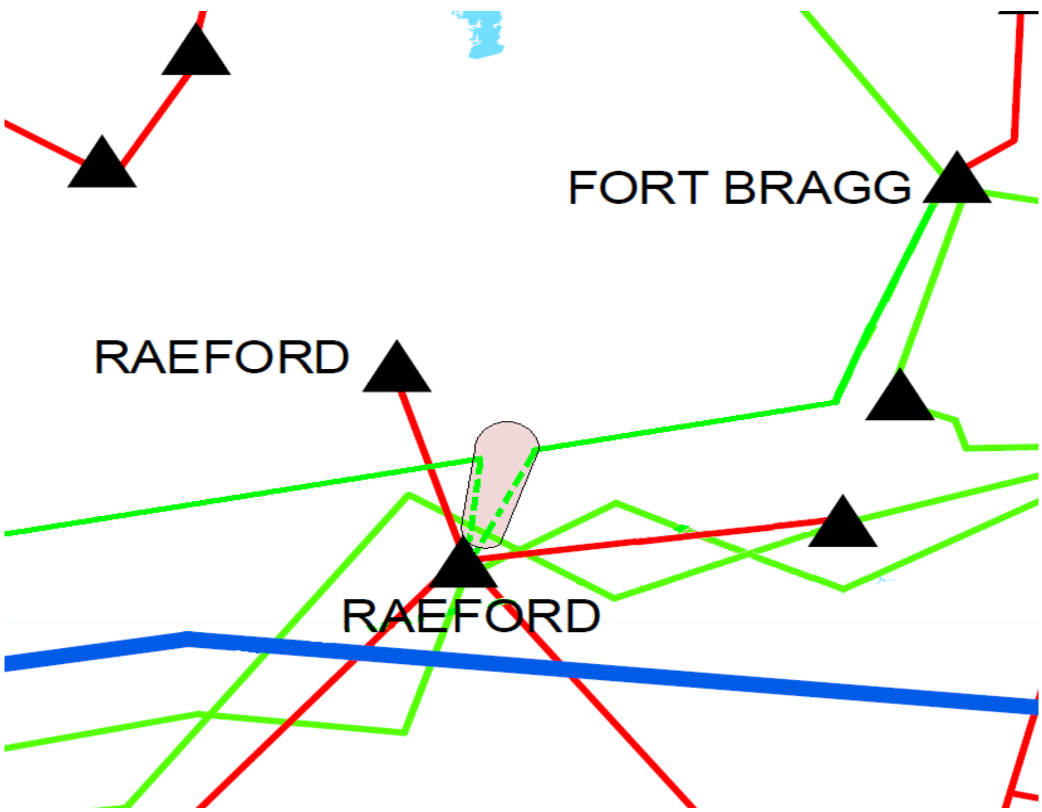
Other Transmission Solutions Considered
Construct Arabia 230kV Substation.

Why this Project was Selected as the Preferred Solution
Arabia had a higher cost and did not mitigate other contingencies of concern.

C-3

Raeford 230 kV Substation, Loop-in Richmond - Ft Bragg Woodruff St 230 kV Line and Add 3rd Bank

- **NERC Category P5 Violation**
- **Problem:** By 2018, with a Brunswick Unit down, loss of the common tower Fayetteville – Rockingham 230 kV and Fayetteville – Raeford 230 kV Lines may cause the Weatherspoon – Raeford 115 kV Line to overload. In addition, by 2018, the N-1-1 contingency of losing both of the Raeford 230/115 kV, 200 MVA transformers at the Raeford 230 kV Substation may overload the Laurinburg - Raeford 115 kV Line.
- **Solution:** At the Raeford 230kV Substation, loop-in the Richmond – Ft. Bragg Woodruff St. 230 kV Line and add a 300 MVA transformer**.**



Project ID and Name: 0031 – Jacksonville - Grants Creek 230 kV Line and Grants Creek 230/115 kV Substation

Project Description
The project scope consists of constructing a new 230 kV Line from Jacksonville 230 kV to a new 230 kV substation in the Grants Creek area. The 230 kV line shall be constructed with 6-1590 MCM ACSR or equivalent and will convert the existing Jacksonville - Havelock 230 kV Line into Jacksonville - Grants Creek 230 kV Line and Grants Creek - Havelock 230 kV Line. The new 230 kV Grants Creek Substation will be built with 4-230 kV breakers, a new 230/115 kV transformer, and tap into the Jacksonville City - Harmon POD 115 kV Feeder with 1-115 kV breaker.

Status	Underway
Transmission Owner	DEP
Planned In-Service Date	6/1/2020
Estimated Time to Complete	1.5 years
Estimated Cost	$73 M

Narrative Description of the Need for this Project
The common tower outage of Jacksonville – Havelock 230 kV Line and Jacksonville – Jacksonville City 115 kV Line may cause the voltages in the Camp Lejeune area to fall below the planning criteria. Also, outage of the Jacksonville - New Bern 230 kV Line may cause the Havelock- Jacksonville 230 kV to overload.

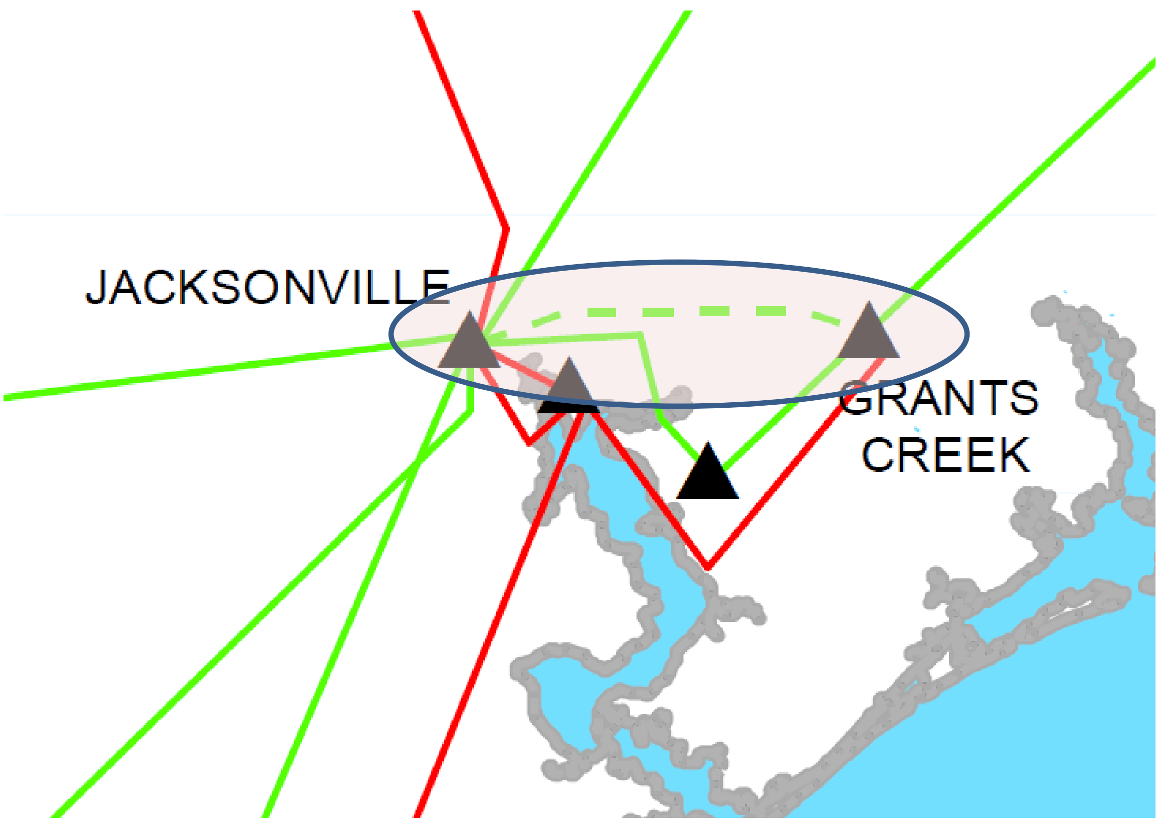
Other Transmission Solutions Considered
Construct 230 kV feeder from Jacksonville to Camp Lejeune Tap.

Why this Project was Selected as the Preferred Solution
The alternate solution was determined to be infeasible due to routing challenges.

C-4

Jacksonville - Grants Creek 230 kV Line and Grants Creek 230/115 kV Substation

- **NERC Category P7 violation**
- **Problem:** The common tower outage of Jacksonville – Havelock 230 kV Line and Jacksonville – Jacksonville City 115 kV Line may cause the voltages in the Camp Lejeune area to fall below the planning criteria. Also, outage of the Jacksonville - New Bern 230 kV Line may cause the Havelock - Jacksonville 230 kV Line to overload.
- **Solution:** Construct new 230 kV line and substation.



Project ID and Name: 0032 – Newport - Harlowe 230 kV Line, Newport SS and Harlowe 230/115 kV Substation

Project Description
Construct new 230kV Switching Station in the Newport Area, construct new 230kV Substation in the Harlowe Area, and construct the Newport Area - Harlowe Area 230kV line comprised of 3-1590 MCM ACSR or equivalent. The Newport Area 230kV Switching Station will initially consist of a 3-breaker ring bus but should be laid out for future development as a standard 230/115 kV substation with breaker-and-a-half configuration in the 230kV yard. The Harlowe Area 230kV Substation will initially consist of one 200 MVA (or 300MVA), 230/115kV transformer and 3-115kV breakers, and should be laid out for future development as a standard 230/115 kV substation with breaker-and-a-half configuration in the 230kV yard.

Status	Underway
Transmission Owner	DEP
Planned In-Service Date	6/1/2020
Estimated Time to Complete	1.5 years
Estimated Cost	$64 M

Narrative Description of the Need for this Project
By summer 2020, an outage of the Havelock terminal of the Havelock - Morehead Wildwood 115 kV North Line will cause the voltages in the Havelock area to fall below planning criteria. The construction of this new line will mitigate this voltage problem.

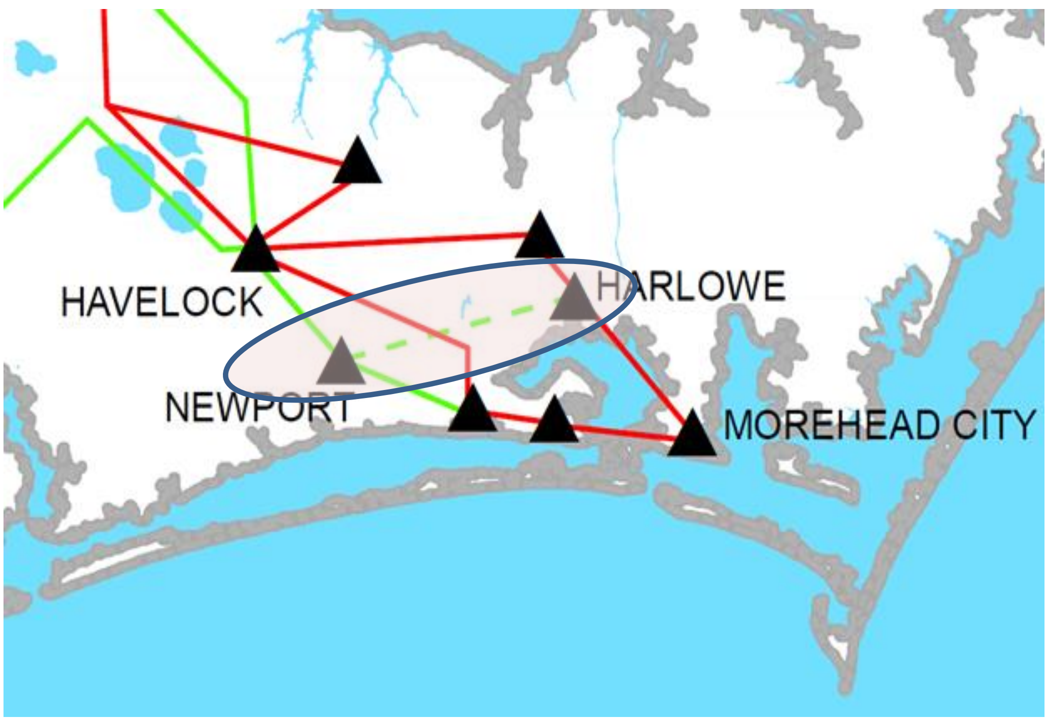
Other Transmission Solutions Considered
Convert Havelock-Morehead Wildwood115 kV North Line to 230 kV.

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

C-5

Newport - Harlowe 230 kV Line, Newport SS and Harlowe 230/115 kV Substation

- **NERC Category P1 violation**
- **Problem:** By summer 2020, an outage of the Havelock terminal of the Havelock - Morehead Wildwood 115 kV North Line will cause the voltages in the Havelock area to fall below planning criteria. The construction of this new line will mitigate this voltage problem.
- **Solution:** Construct new 230 kV line, switching station and substation.



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 800A current transformers at both line terminals will have to be uprated as part of this project.

Status	Underway
Transmission Owner	DEP
Planned In-Service Date	12/31/2019
Estimated Time to Complete	1 year
Estimated Cost	$25 M

Narrative Description of the Need for this Project
By 2019, 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.

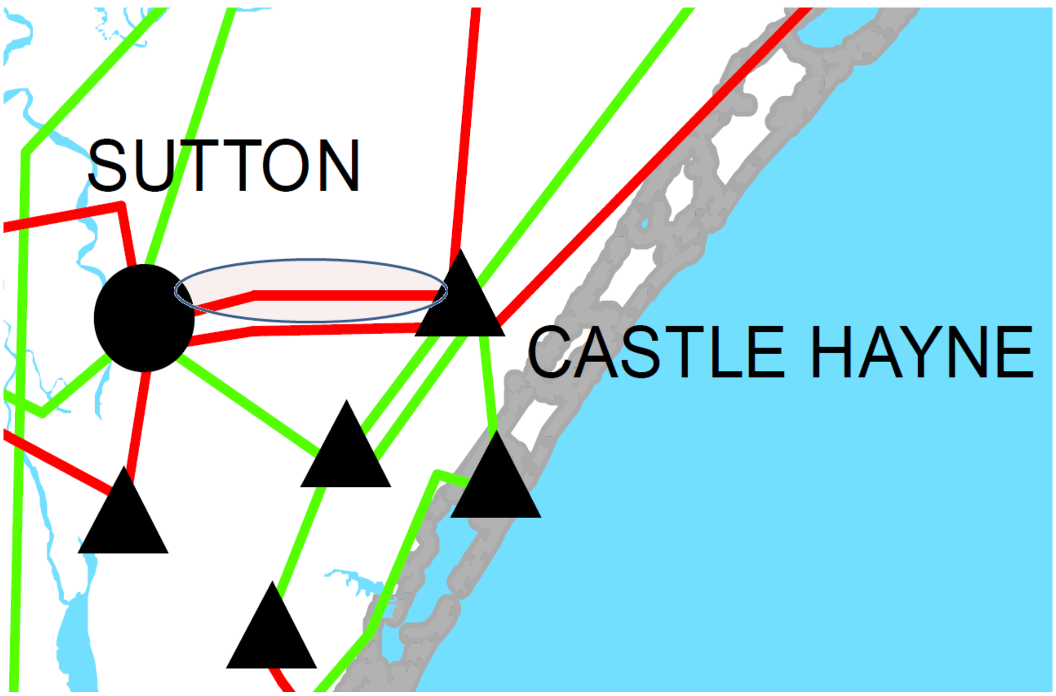
Other Transmission Solutions Considered
Convert 115 kV line to 230 kV.

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

C-6

Sutton - Castle Hayne 115 kV North Line, Rebuild

- **NERC Category P1 violation**
- **Problem:** By 2019, 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: 0036 – Asheville Plant, Replace 2-300 MVA 230/115 kV Banks with 2-400 MVA Banks, Reconductor 115 kV Ties to Switchyard, Upgrade Breakers, and Add 230 kV Capacitor Bank

Project Description
This project consists of upgrading Asheville Plant to interconnect two combined cycle units. The project includes upgrading the existing 230/115 kV transformers to 400 MVA each, reconductoring the 115 kV north and south transformer tie lines, replacing breakers, and adding a 230 kV capacitor bank.

Status	In-Service
Transmission Owner	DEP
Planned In-Service Date	11/1/2018
Estimated Time to Complete	-
Estimated Cost	$40 M

Narrative Description of the Need for this Project
Interconnect two combined cycle units.

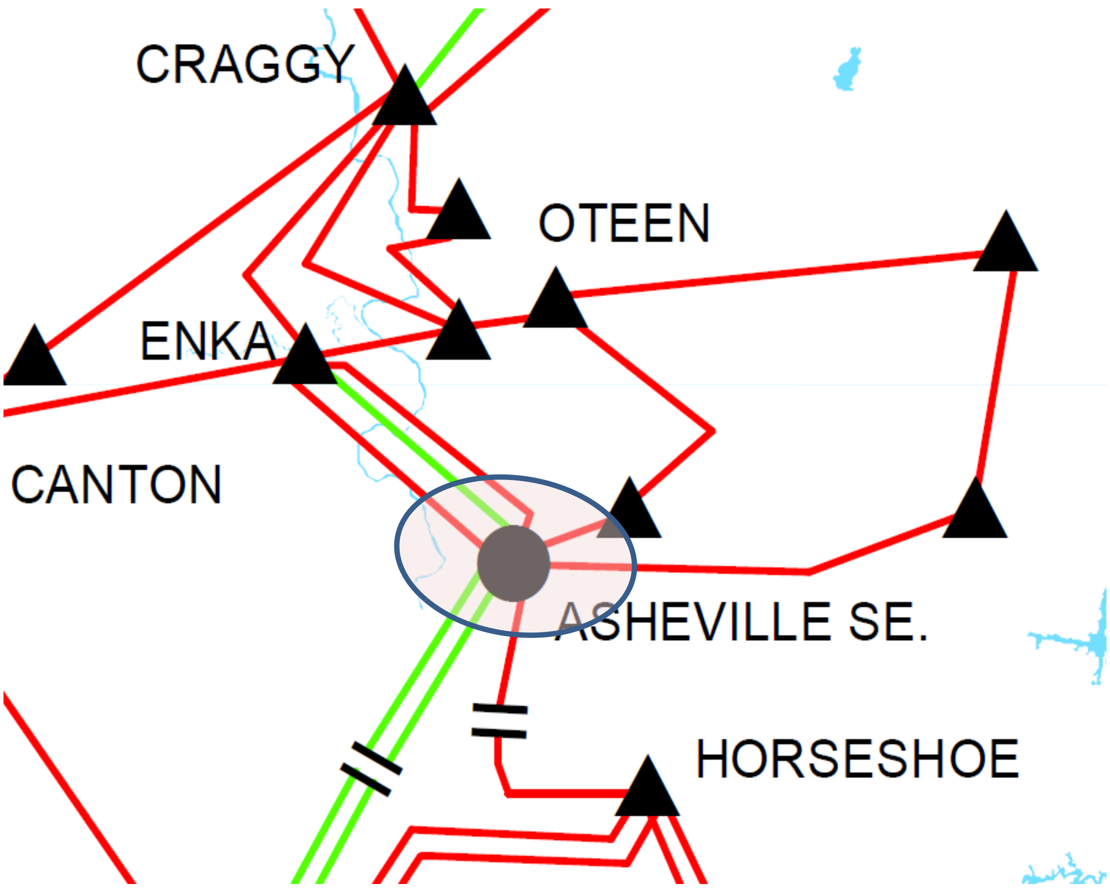
Other Transmission Solutions Considered
These are generation interconnection network upgrade facilities without a feasible alternative.

Why this Project was Selected as the Preferred Solution
There is not a feasible alternative.

C-7

Asheville Plant, Replace 2-300 MVA 230/115 kV Banks with 2-400 MVA Banks, Reconductor 115 kV Ties to Switchyard, Upgrade Breakers, and Add 230 kV Capacitor Bank

- **NERC Category P3 violation**
- **Problem:** Interconnect two combined cycle units at Asheville Plant in 2019.
- **Solution:** Upgrade the existing 230/115 kV transformers to 400 MVA each, reconductor the 115 kV north and south transformer tie lines, replace breakers, and add a 230 kV capacitor bank.



Project ID and Name: 0037 – Cane River 230 kV Substation, Construct 150 MVAR SVC

Project Description
This project consists of upgrading Cane River 230 kV Substation by adding a +150/-50 MVAR 230 kV static VAR compensator (SVC).

Status	Underway
Transmission Owner	DEP
Planned In-Service Date	6/1/2019
Estimated Time to Complete	0.5 years
Estimated Cost	$42 M

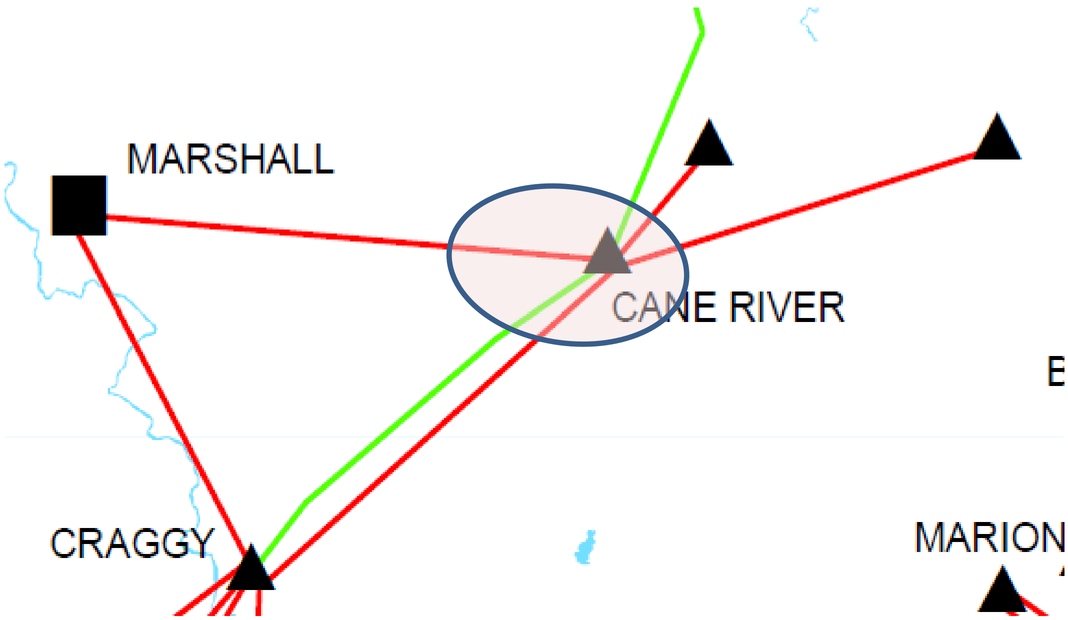
Narrative Description of the Need for this Project
Interconnect two combined cycle units.

Other Transmission Solutions Considered
Considered constructing new interconnections between AEP and DEP.

Why this Project was Selected as the Preferred Solution
It was determined that constructing new interconnections was not feasible due to difficulty obtaining ROW.

Cane River 230 kV Substation, Construct 150 MVAR SVC

- **NERC Category B violation**
- **Problem:** Interconnect two combined cycle units at Asheville Plant in 2019.
- **Solution:** Upgrade the Cane River 230 kV Substation by adding a 150 MVAR 230 kV static VAR compensator (SVC).



Project ID and Name: 0038 –Harley 100 kV Lines (Tiger - Campobello), Reconductor

Project Description
This project consists of rebuilding 11.8 miles of the existing 336 ACSR conductor with 1158 ACSS/TW.

Status	Conceptual
Transmission Owner	DEC
Planned In-Service Date	TBD
Estimated Time to Complete	3 years
Estimated Cost	$18 M

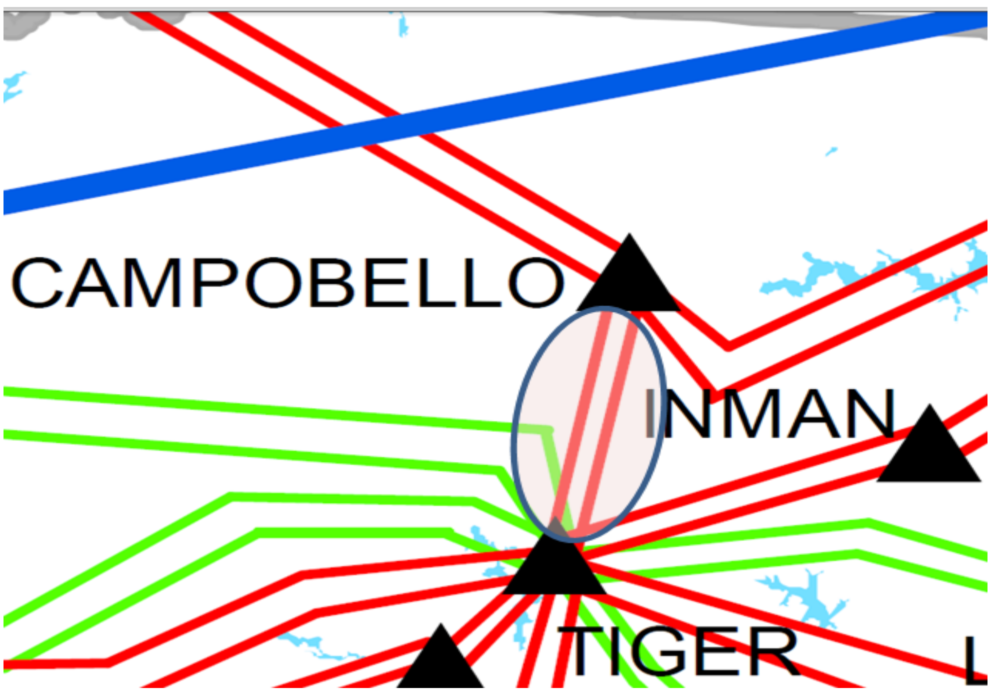
Narrative Description of the Need for this Project
Under high levels of transfer to CPLW, these lines may become overloaded because they are on one of the two 100 kV paths that connect DEC to CPLW.

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.

Harley 100 kV Lines (Tiger - Campobello), Reconductor

- **NERC Category P7 violation**
- **Problem:** The outage of both Pisgah - Shiloh 230 kV lines may overload these lines.
- **Solution:** Rebuild 100 kV lines with higher capacity conductors.



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

Project Description
This project consists of rebuilding/reconductoring approximately 6.5 miles of the existing 115kV line using 3-1590 or equivalent conductor. This project requires the replacement of disconnect switches at Asheboro 230kV and the replacement of the breaker, the disconnect switches, and the 115 kV east bus at Asheboro East 115kV 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	6/1/2019
Estimated Time to Complete	0.5 years
Estimated Cost	$15 M

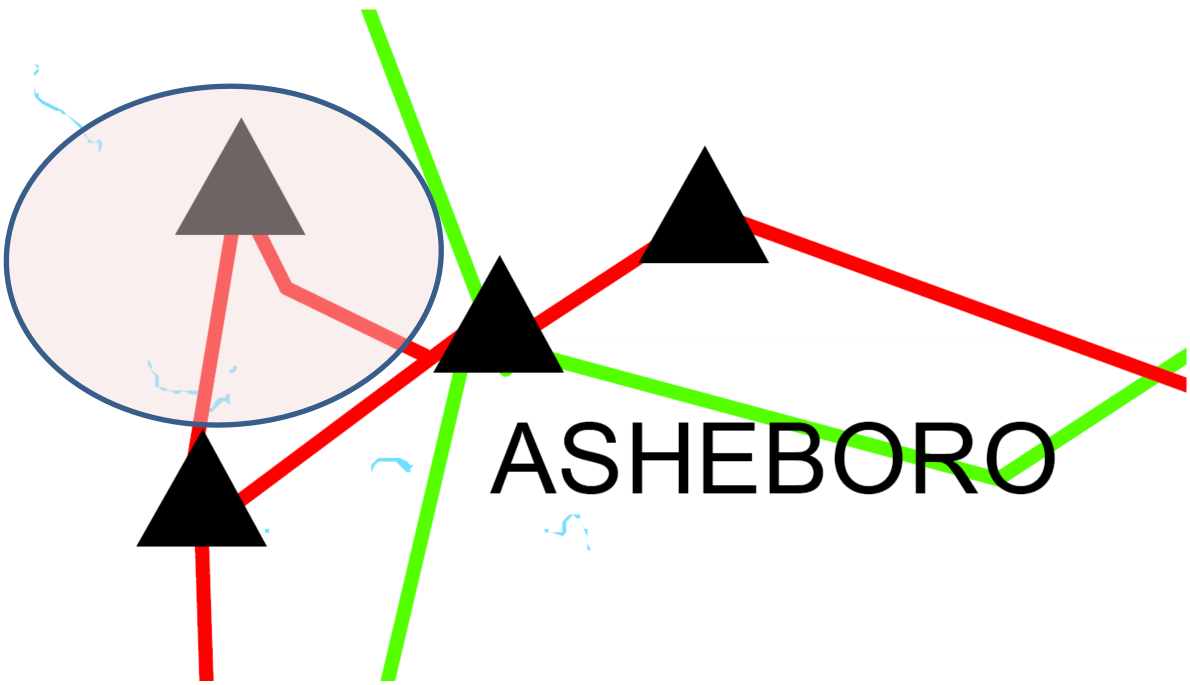
Narrative Description of the Need for this Project
This project is needed to alleviate loading on the Asheboro-Asheboro East 115kV North line under the contingency of losing the Asheboro-Asheboro-East 115kV South line with Harris Plant down.

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

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

Asheboro-Asheboro East 115kV North Line, Reconductor

- **NERC Category P3 violation**
- **Problem:** By the summer of 2019, with Harris down, the loss of the Asheboro-Asheboro East 115kV South line will cause the Asheboro-Asheboro East 115kV North line to overload.
- **Solution:** Rebuild/reconductor the Asheboro-Asheboro East 115kV North Line and upgrade equipment.



Project ID and Name: 0040 – Delco 230kV Substation, Convert to Double Breaker

Project Description
This project consists of relocating the Cumberland and Brunswick Plant East 230kV Line Terminals, converting the Sutton Plant 230kV Terminal and Brunswick Plant 230kV West Terminal to a double breaker scheme, and converting the Cumberland 230kV Terminal and Brunswick Plant 230kV East Terminal to a double breaker scheme.

Status	Underway
Transmission Owner	DEP
Planned In-Service Date	6/1/2019
Estimated Time to Complete	1.5 years
Estimated Cost	$15 M

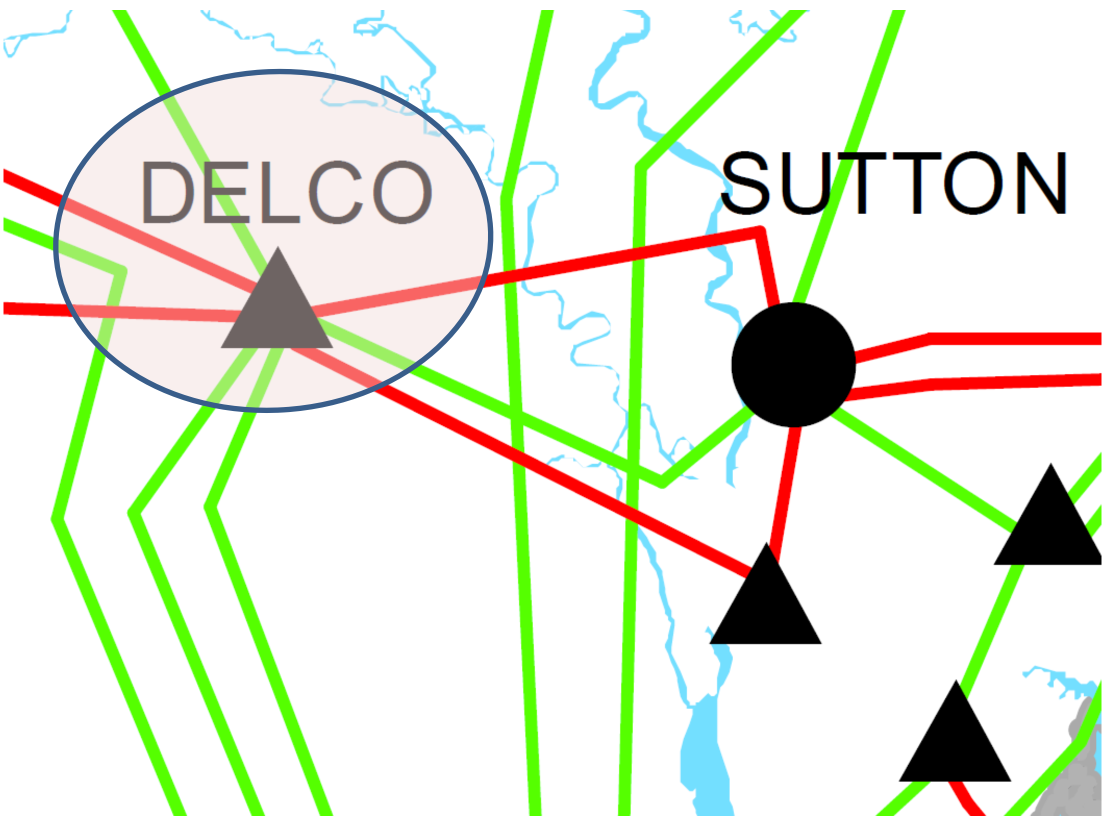
Narrative Description of the Need for this Project
The conversion of the Delco 230kV bus scheme will improve system reliability and thereby reduce interruption exposure to the customers in the area in case of an event; while maintaining compliance with NERC Transmission Planning Standards.

Other Transmission Solutions Considered
There is not a feasible alternative.

Why this Project was Selected as the Preferred Solution
There is not a feasible alternative.

Delco 230kV Substation, Convert to Double Breaker

- **NERC Category P4 violation**
- **Problem:** The conversion of the Delco 230kV bus scheme will improve system reliability and thereby reduce interruption exposure to the customers in the area in case of an event; while maintaining compliance with NERC Transmission Planning Standards.
- **Solution:** At Delco 230kV Substation, relocate the Cumberland and Brunswick Plant East 230kV Line Terminals. Convert the Sutton Plant 230kV Terminal and Brunswick Plant 230kV West Terminal to a double breaker scheme. Convert the Cumberland 230kV Terminal and Brunswick Plant 230kV East Terminal to a double breaker scheme.



Project ID and Name: 0041 – Castle Hayne 230kV Substation, Convert to Double Breaker

Project Description
This project consists of relocating the Sutton Plant 230kV and Folkstone 230kV Line Terminals, converting the new Folkstone 230kV Terminal and Wilmington Corning 230kV Terminal to a double breaker scheme, and converting the new Sutton Plant 230kV Terminal and Brunswick Plant Unit 1 230kV Terminal to a double breaker scheme.

Status	In-Service
Transmission Owner	DEP
Planned In-Service Date	6/1/2018
Estimated Time to Complete	**-**
Estimated Cost	$11 M

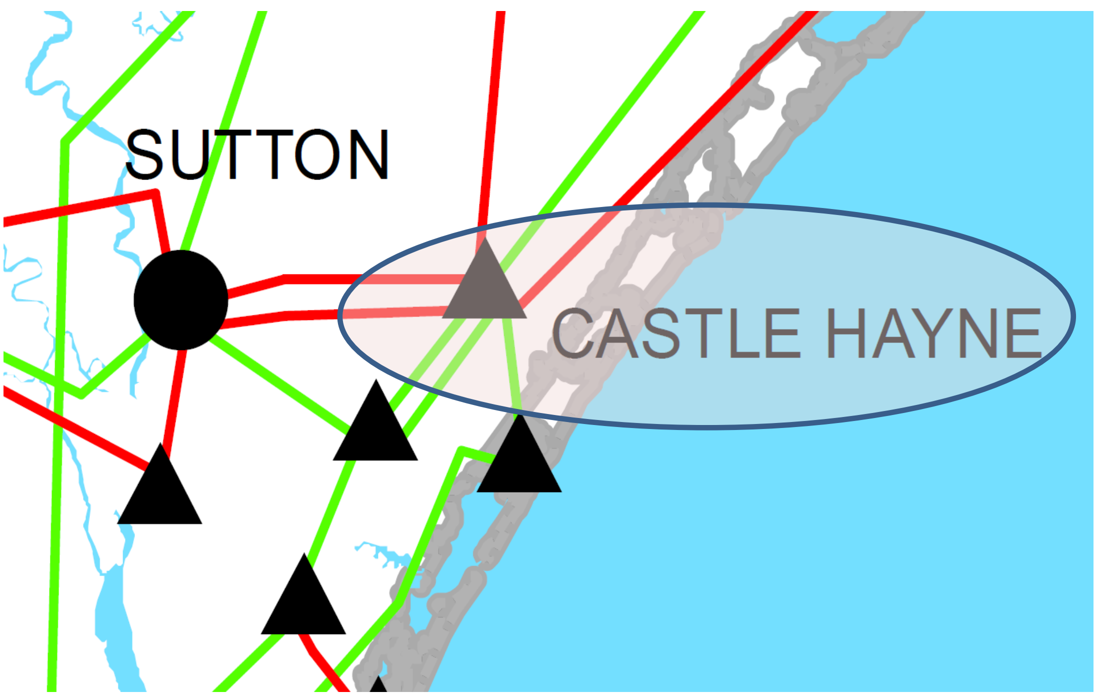
Narrative Description of the Need for this Project
The conversion of the Castle Hayne 230kV bus scheme will improve system reliability and thereby reduce interruption exposure to the customers in the area in case of an event, while maintaining compliance with NERC Transmission Planning Standards.

Other Transmission Solutions Considered
There is not a feasible alternative.

Why this Project was Selected as the Preferred Solution
There is not a feasible alternative.

Castle Hayne 230kV Substation, Convert to Double Breaker

- **NERC Category P4 violation**
- **Problem:** The conversion of the Castle Hayne 230kV bus scheme will improve system reliability and thereby reduce interruption exposure to the customers in the area in case of an event, while maintaining compliance with NERC Transmission Planning Standards.
- **Solution:** At Castle Hayne 230kV Substation, relocate the Sutton Plant 230kV and Folkstone 230kV Line Terminals. Convert the new Folkstone 230kV Terminal and Wilmington Corning 230kV Terminal to a double breaker scheme. Convert the new Sutton Plant 230kV Terminal and Brunswick Plant Unit 1 230kV Terminal to a double breaker scheme.



Project ID and Name: 0042 – Rural Hall 100 kV, Install SVC

Project Description
This project consists of installing a -100/+300 MVAR SVC at Rural Hall 100 kV.

Status	Underway
Transmission Owner	DEC
Planned In-Service Date	12/1/2019
Estimated Time to Complete	1 year
Estimated Cost	$50 M

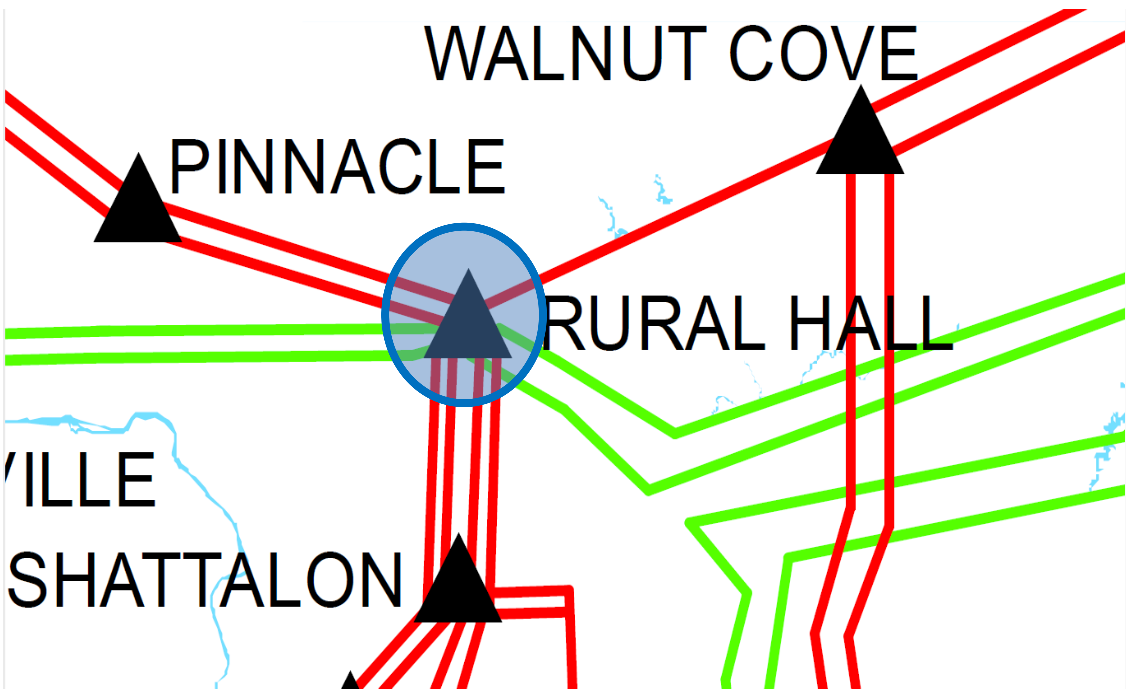
Narrative Description of the Need for this Project
Installation of a SVC at Rural Hall will mitigate dynamic voltage concerns driven by certain contingency conditions in DEC.

Other Transmission Solutions Considered
New generation.

Why this Project was Selected as the Preferred Solution
Solution can be implemented quicker than new generation and at a lower cost.

Rural Hall 100 kV, Install SVC

- **Problem:** Under certain conditions, additional voltage support is required in order to maintain system reliability.
- **Solution:** The installation of a SVC at Rural Hall 100 kV will provide voltage support to the region and increase system reliability under certain conditions. As part of the project there will be a reconfiguration of the 100 kV capacitors at Rural Hall.



Project ID and Name: 0043 – Orchard Tie 230/100 kV Tie Station, Construct

Project Description
This project consists of constructing the Orchard Tie 230/100 kV Tie Station

Status	Planned
Transmission Owner	DEC
Planned In-Service Date	12/1/2020
Estimated Time to Complete	2 years
Estimated Cost	$80 M

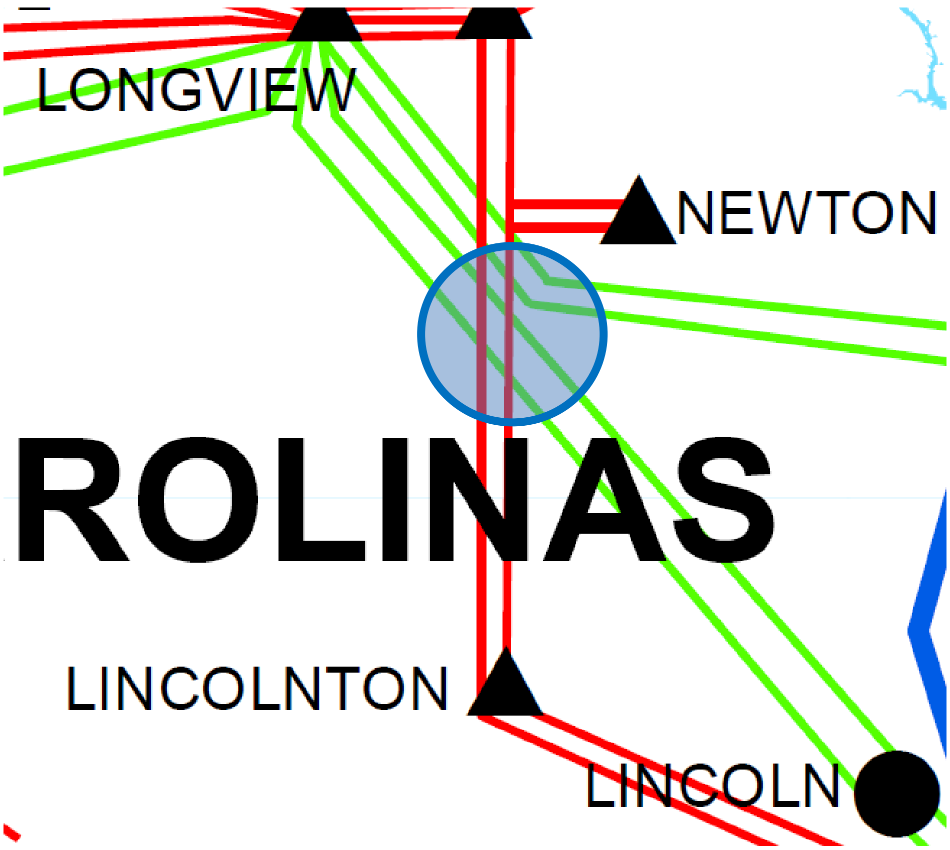
Narrative Description of the Need for this Project
The installation of this new 230/100 kV tie station will provide greater ability to meet local load growth and maintain compliance with NERC Transmission Planning Standards.

Other Transmission Solutions Considered
Upgrade ≈30 miles of 100 kV.

Why this Project was Selected as the Preferred Solution
Ability to meet local load growth and cost of rebuilding 100kV line.

Orchard Tie 230/100 kV Tie Station, Construct

- **Problem:** Existing transmission lines are not sufficient to meet local load growth.
- **Solution:** Fold-in existing 230 kV and 100 kV lines to new station. Add sufficient transformation between 230 kV and 100 kV.



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 AAC) along an existing ROW.

Status	Planned
Transmission Owner	DEC
Planned In-Service Date	TBD
Estimated Time to Complete	3 years
Estimated Cost	$26 M

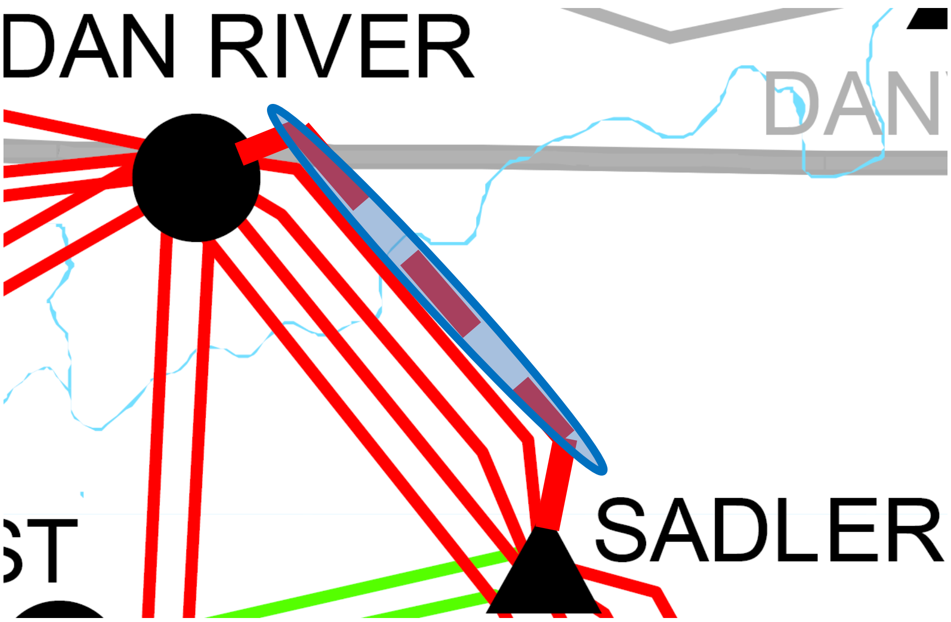
Narrative Description of the Need for this Project
The Reidsville and Wolf Creek 100 kV lines (Dan River-Sadler) can become overloaded for the loss of any of the circuits between Dan River and Sadler.

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.

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: 0047 – NTE II, Generator Interconnection

Project Description
This project consists of the network upgrades driven by the interconnection of a 1x1 combined cycle unit at Ernest Switching Station The project includes upgrading 13.71 miles of 230 kV lines (Ernest-Belews Creek) to B-1272 ACSR, adding a 230/100 kV transformer at Sadler, and installing switchable 2% series reactors on 230 kV lines (Ernest-Sadler).

Status	Planned
Transmission Owner	DEC
Planned In-Service Date	12/1/21
Estimated Time to Complete	3 years
Estimated Cost	$53 M

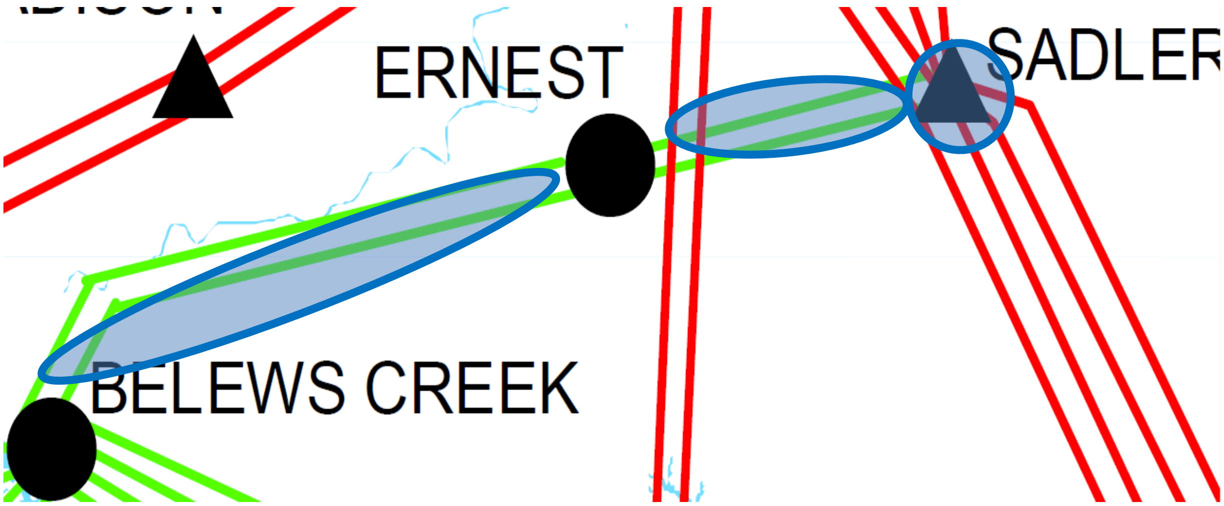
Narrative Description of the Need for this Project
Interconnect a 1x1 combined cycle unit.

Other Transmission Solutions Considered
These are generation interconnection network upgrade facilities without a feasible alternative.

Why this Project was Selected as the Preferred Solution
There is not a feasible alternative.

NTE II, Generator Interconnection

- **NERC Category P3 violation**
- **Problem:** Thermal and stability issues driven by installation of new generation at Ernest Switching Station.
- **Solution:** Upgrading 13.71 miles of 230 kV lines (Ernest-Belews Creek) to B-1272 ACSR, add a 230/100 kV transformer at Sadler, and install switchable 2% series reactors on 230 kV lines (Ernest-Sadler).



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	Planned
Transmission Owner	DEC
Planned In-Service Date	12/1/23
Estimated Time to Complete	3 years
Estimated Cost	$22 M

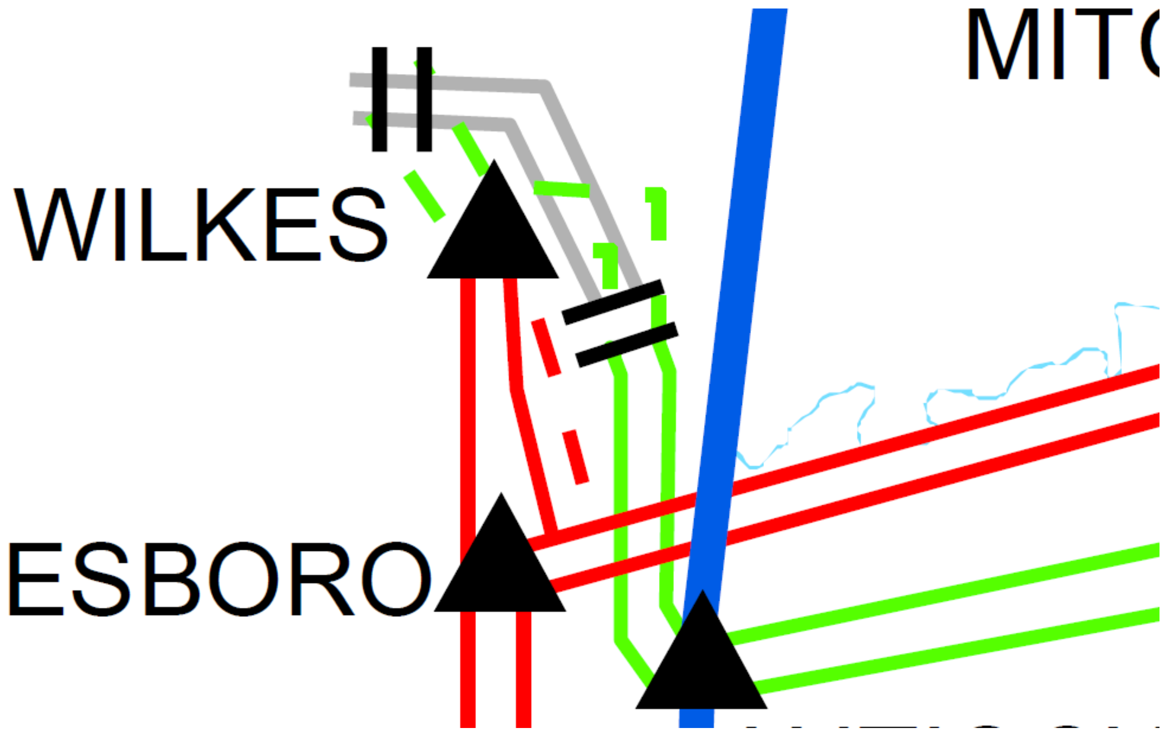
Narrative Description of the Need for this Project
The primary driver for this project is to increase support in the area around Wilkesboro NC. Contingencies, especially in the winter, have the tendency to drop voltage in the area as well as some thermal loading concerns with the loss of the Oxford 100kV 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.

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: 0049 – Ballantyne Switching Station, Construct

Project Description
Construction of new switching station on 100 kV lines between Wylie Switching Station and Morning Star Tie.

Status	Planned
Transmission Owner	DEC
Planned In-Service Date	12/1/19
Estimated Time to Complete	1 years
Estimated Cost	$15 M[5]

Narrative Description of the Need for this Project
Construction of new switching station mitigates loading issues under contingency and provides greater operational flexibility.

Other Transmission Solutions Considered
Rebuilding existing 100 kV lines between Wylie Switching Station and Morning Star Tie (up to 21 miles).

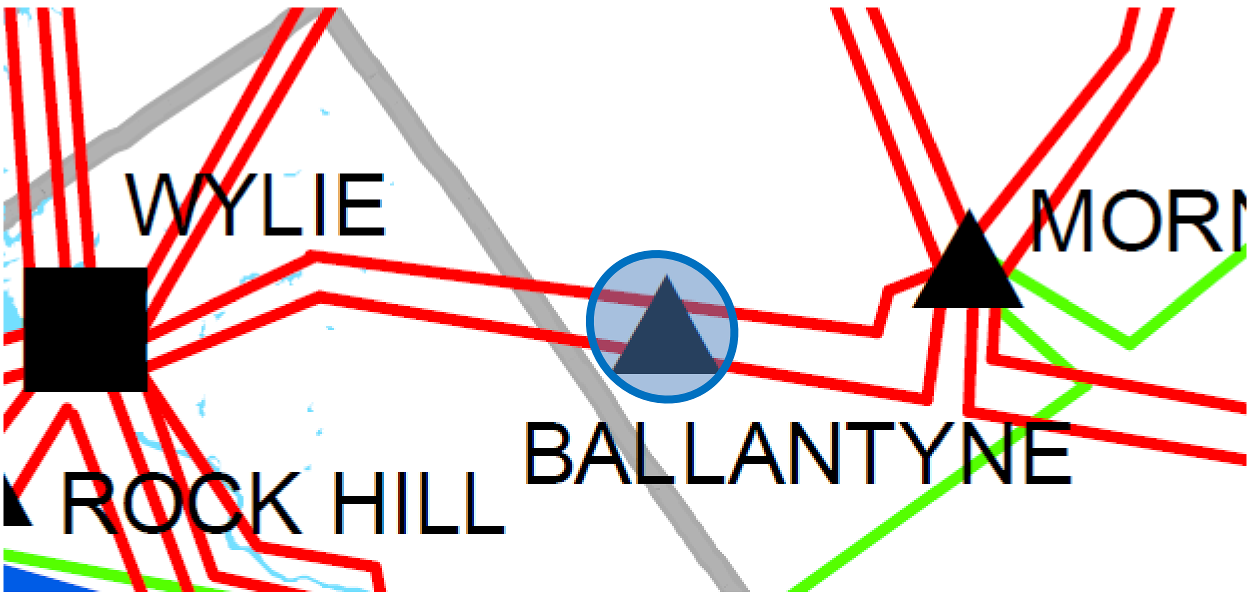
Why this Project was Selected as the Preferred Solution
Greater operational flexibility in the area.

C-18

[5] Initial project estimates didn't exceed $10 M, but factors such as station siting increased the cost of the project.

Ballantyne Switching Station, Construct

- **NERC Category P3 violation**
- **Problem:** Thermal issues driven by loss of either circuit between Wylie and Morning Star.
- **Solution:** Rebuild 100 kV line.



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

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

Status	Conceptual
Transmission Owner	DEP
Planned In-Service Date	12/1/2025
Estimated Time to Complete	4 years
Estimated Cost	$50 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 12/1/2026. Outage of the West Asheville 115 kV bus overloads the Craggy-Enka 115 kV line.

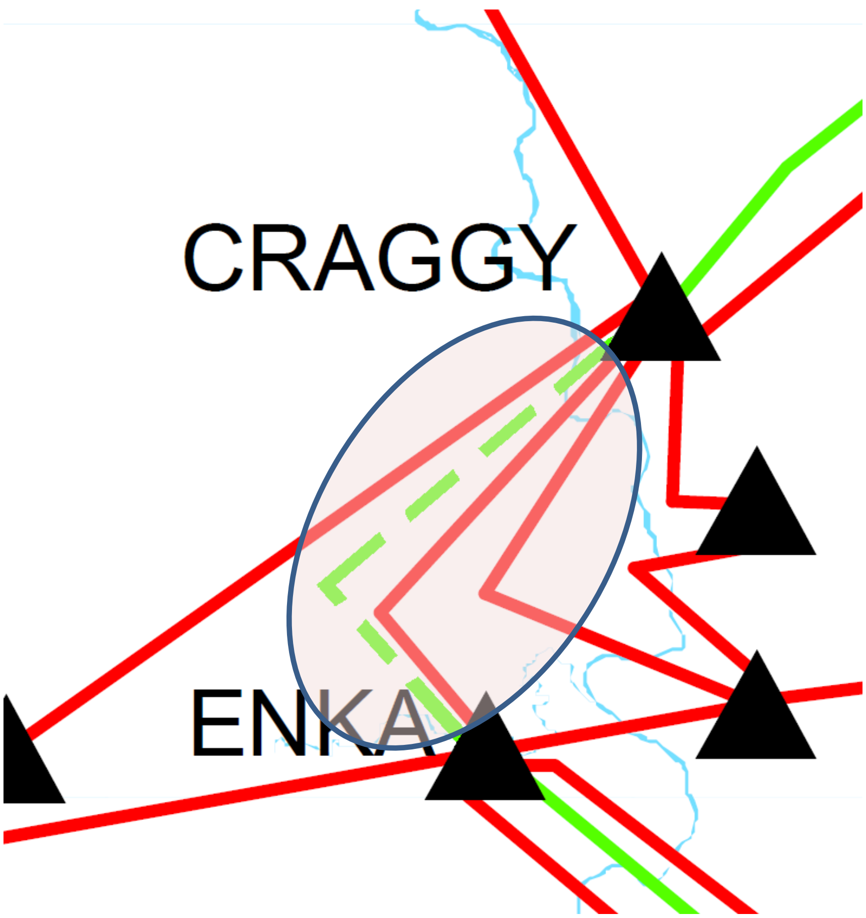
Other Transmission Solutions Considered
Reconductoring multiple transmission lines. These include the Enka-West Asheville 115 kV Line, the Craggy-Enka 115 kV line, the Canton-Craggy 115 kV Line, and the Asheville-Oteen 115 kV East Line.

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

C-19

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 and Asheville-Oteen 115 West lines has no viable operating procedure beginning 12-2026. Outage of the West Asheville 115 kV bus overloads the Craggy-Enka 115 kV line.
- **Solution:** Construct the Craggy-Enka 230 kV Line.



Appendix D
Collaborative Plan Comparisons

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
			2017 Plan[1]			2018 Plan			
Project ID	Reliability Project	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0024	Durham - RTP 230 kV Line, Reconductor	DEP	Planned	6/1/2024	15	Conceptual	TBD	15
0028	Brunswick #1 – Jacksonville 230 kV Line Loop into Folkstone 230 kV Substation	DEP	Planned	6/1/2024	14	Planned	6/1/2024	14
0030	Raeford 230 kV Substation, Loop-in Richmond - Ft Bragg Woodruff St 230 kV Line and Add 3rd Bank	DEP	Planned	6/1/2018	20	Underway	12/1/2018	29
0031	Jacksonville - Grants Creek 230 kV Line and Grants Creek 230/115 kV Substation	DEP	Planned	6/1/2020	51	Underway	6/1/2020	73

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)								
			2017 Plan[1]			2018 Plan		
Project ID	Reliability Project	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0032	Newport - Harlowe 230 kV Line, Newport SS and Harlowe 230/115 kV Substation	DEP	Planned	6/1/2020	40	Underway	6/1/2020	64
0033	Fort Bragg Woodruff St 230 kV Sub, Replace 150 MVA 230/115 kV Transformer with Two 300 MVA Banks & Reconductor Manchester 115 kV Feeder	DEP	In-Service	2/24/2017	19	Removed	---	---
0034	Sutton - Castle Hayne 115 kV North Line, Rebuild	DEP	Underway	6/1/2019	11	Underway	12/31/2019	25

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)								
			2017 Plan[1]			2018 Plan		
Project ID	**Reliability Project**	**Transmission Owner**	**Status[2]**	**Projected In-Service Date**	**Estimated Cost ($M)[3]**	**Status[2]**	**Projected In-Service Date**	**Estimated Cost ($M)[3]**
0036	Asheville Plant, Replace 2-300 MVA 230/115 kV Banks with 2-400 MVA Banks, Reconductor 115 kV Ties to Switchyard, Upgrade Breakers, and Add 230 kV Capacitor Bank	DEP	Planned	12/1/2019	40	In-Service	11/1/2018	40
0037	Cane River 230 kV Substation, Construct 150 MVAR SVC	DEP	Planned	12/1/2019	42	Underway	6/1/2019	42
0038	Harley 100 kV Lines (Tiger - Campobello), Reconductor	DEC	Planned	6/1/2020	18	Conceptual	TBD	18
0039	Asheboro-Asheboro East 115kV North Line, Reconductor	DEP	Underway	6/1/2019	12	Underway	6/1/2019	15
0040	Delco 230kV Substation, Convert to Double Breaker	DEP	Underway	6/1/2019	13	Underway	6/1/2019	15

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)								
			2017 Plan[1]			2018 Plan		
Project ID	Reliability Project	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0041	Castle Hayne 230kV Substation, Convert to Double Breaker	DEP	Underway	6/1/2019	10	In-Service	6/1/2018	11
0042	Rural Hall 100 kV, Install SVC	DEC	Planned	6/1/2020	50	Underway	12/1/2019	50
0043	Orchard 230/100 kV Tie Station, Construct	DEC	Planned	12/1/2021	45	Planned	12/1/2020	80
0044	Reidsville 100 kV Lines (Dan River-Sadler), Reconductor	DEC	Conceptual	TBD	13	Removed	-	-
0045	Wolf Creek 100 kV Lines (Dan River-Sadler), Reconductor	DEC	Conceptual	TBD	13	Removed	-	-

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
			2017 Plan[1]			2018 Plan			
Project ID	Reliability Project	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0046	Windmere 100 kV Line (Dan River-Sadler), Construct	DEC	-	-	-	Planned	12/1/2021	26
0047	NTE II, Generator Interconnection	DEC	-	-	-	Underway	12/1/2021	53
0048	Wilkes 230/100 kV Tie Station, Construct	DEC	-	-	-	Planned	12/1/2023	22
0049	Ballantyne Switching Station, Construct	DEC	-	-	-	Underway	12/1/2019	15
0050	Craggy-Enka 230 kV Line, Construct	DEP	-	-	-	Conceptual	12/1/2025	50

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)								
			2017 Plan[1]			2018 Plan		
Project ID	Reliability Project	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
TOTAL					**426**			**657**

[1] Information reported in Appendix B of the NCTPC 2017 - 2027 Collaborative Transmission Plan" dated January 16, 2018.

[2] Status: ***In-service****:* Projects with this status are in-service.

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 2017 Report and have been deferred beyond the end of the planning horizon based on analysis performed to develop the 2018 Collaborative Transmission 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 E

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
FSA	Facilities Study Agreement
GTP	North Carolina Global TransPark
ISA	Interconnection Service Agreement
kV	Kilovolt
LGIA	Large Generator Interconnection Agreement
LSE	Load Serving Entity
LTSG	SERC Long-Term Study 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
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
PSS/E	Power System Simulator for Engineering
PWG	Planning Working Group
RTP	Research Triangle Park
SCEG	South Carolina Electric & Gas Company
SCPSA	South Carolina Public Service Authority
SE	Steam Electric (Plant)
SEPA	South Eastern 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