North Carolina Transmission Planning Collaborative

Report on the NCTPC 2015-2025 Collaborative Transmission Plan

December 1, 2015
DRAFT Report

2015 – 2025 NCTPC Study
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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) 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 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, whose studies 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 2014-2024 Collaborative Transmission Plan (the "2014 Collaborative Transmission Plan" or the "2014 Plan") was published in January 2015.

This report documents the current 2015 – 2025 Collaborative Transmission Plan ("2015 Collaborative Transmission Plan" or the "2015 Plan") for the Participants. The initial sections of this report provide an overview of the NCTPC Process as well as the specifics of the 2015 reliability planning study scope and methodology. The NCTPC Process document and 2015 NCTPC study scope document are posted in their entirety on the NCTPC website at http://www.nctpc.org/nctpc/.

The scope of the 2015 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 2015 through 2025 with the Participants' planned Designated Network Resources ("DNRs"). The 2015 Study[1] model included the transmission portion of the Western Carolinas Modernization Project ("WCMP") announced in early 2015 that had planned in-service dates prior to 2020, resulting from an associated 600 MW Transmission Service Request (TSR)[2]. Based on the study's input assumptions, the 2015 Study allowed for identification of any new system impacts not currently addressed by existing transmission plans, in which case solutions were developed. The 2015 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 2015 Plan continue to satisfactorily address the reliability concerns identified in the 2015 Study for the near-term (5 year) and the long-term (10 year) planning horizons. The 2015 Plan is detailed in Appendix B which identifies the new and updated projects planned with an estimated cost of greater than $10 million.

The 2015 Plan includes eight reliability projects with an estimated cost of $10 million or more each. These projects are listed in Appendix B. The total estimated cost for

[1] The term "2015 Study" is a generic term referring to all the study work that was done in 2015 which includes the reliability analysis as well the resource supply option analysis and the local economic analysis.

[2] The WCMP was significantly changed and reduced in scope in November of 2015 after this study was completed. The revised plan for Western Carolinas will be reflected in next year's study process.

these eight reliability projects in the 2015 Plan is $156 million. This compares to the original 2014 Plan estimate of $209 million for seven 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 E for a detailed comparison of this year's Plan to the 2014 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 2015 Plan.

The modified projects for DEP and DEC in the 2015 Plan, relative to the 2014 Plan, include two DEP projects and one DEC project that were placed in service. The projects placed in service were:

- Harris Plant-RTP 230 kV Line (DEP)
- Greenville-Kinston DuPont 230 kV Line (DEP)
- Caesar 230 kV Lines Reconductor (Pisgah Tie - Shiloh SS) (DEC)

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

- Brunswick #1 - Jacksonville 230 kV Line Loop-in to Folkstone 230 kV Substation was re-instated.
- Raeford 230 kV substation, project to loop-in Richmond-Ft Bragg Woodruff St 230 kV Line and add 3rd 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 the new substation name changed from Piney Green to Grants Creek.
- Fort Bragg Woodruff St 230 kV Sub, project to replace 150 MVA 230/115 kV transformer with two 300 MVA banks & reconductor Manchester 115 kV feeder was added since its cost changed to greater than $10M.
- Sutton-Castle Hayne 115 kV North line Rebuild was added since its cost changed to $10M.
- Reconductor Norman 230 kV Lines (McGuire-Riverbend) was added since its cost became greater than $10M.

Two local economic study requests were received during this planning cycle. The purpose of the first study request was to determine the capacity available for a Tennessee Valley Authority ("TVA") to Duke Energy (DEC and DEP) transfer and the marginal system upgrades necessary to increase this capacity, if needed. More specifically, the request was to study the import of 661 MW into the CPLE and DUK Balancing Authority Areas from the TVA Balancing Authority Area in the year 2020. Of the 661 MW, 397 MW were allocated to DUK and 264 MW were allocated to CPLE. These allocations were based on an assumed load-share ratio of 60/40. In the modeling of the 661 MW transfer from TVA into CPLE and DUK, no limits were identified. These results indicate that the scenario can be accommodated without transmission upgrades.

The stated purpose of the second study request was as follows: "Simulate the hypothetical scenario of NRC regulation impacting nuclear units of similar technology (all nuclear units of Westinghouse 1980s Vintage) in NCTPC footprint and assess reliability impact (N-1 contingencies) assuming redispatch internally first to the extent possible and replace remaining capacity equally from Southern Company and PJM Market." The forced outages affected 5 nuclear units and roughly 5,600 MW of DEC/DEP generation in the year 2020. Imports to replace the lost generation were 3,400 MW for DEC and 1,000 MW for DEP. The 4,400 MW of DEC/DEP import was made up of 2,200 MW from PJM and 2,200 MW from SOCO. The 2,200 MW of PJM export was made up of 1,700 MW from AEP and 500 MW from DVP. AEP and DVP were used to simulate the PJM export because they are the only PJM areas that share an interface with DEC/DEP. This approach provides the most severe flows across that interface. A summary of the thermal results are provided in Appendix D. These results indicate that the scenario cannot be accommodated without significant transmission upgrades to mitigate the indicated thermal overloads.

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 2015, the Planning Working Group ("PWG") analyzed, among its resource supply options, cases that examine the impacts of sixteen different hypothetical transfers into and out of the DEC and DEP systems. 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.

Analysis of the sixteen hypothetical transfer scenarios did not require any additional transmission projects for DEC or DEP beyond those in the 2015 Collaborative Plan.

In this 2015 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 (Duke Energy Carolinas, Duke Energy Progress, 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 overall NCTPC Process is performed annually and includes the Reliability Planning and Local Economic Study Processes, whose studies 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 Oversight Steering Committee ("OSC") manages the NCTPC Process. The PWG supports 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 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

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 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 purchase power agreement expirations. 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 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.

II.C. Resource Supply Options Process

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 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 purchase power agreement expirations. 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 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.

II.D. Local Economic Study Process

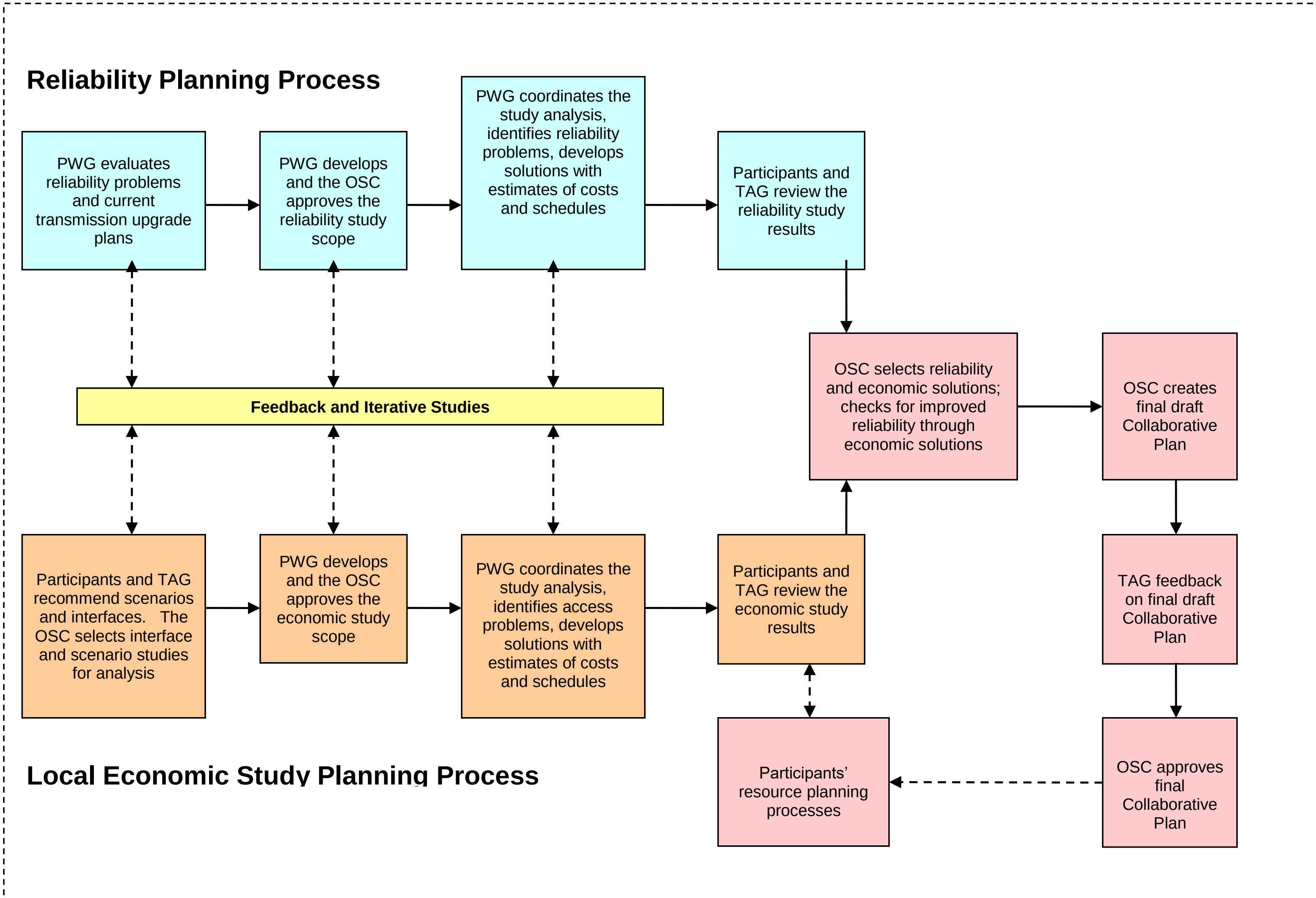
The Local Economic Study Process allows the TAG participants to propose economic hypothetical transfers to be studied as part of the transmission planning process. The Local Economic Study Process provides the means to evaluate the impact of potential supply resources inside and outside the Balancing Authority Areas 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 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 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 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 Collaborative Transmission Plan.

The overall 2015 NCTPC Process includes both a reliability planning process and the Local Economic Study Process as during 2015, stakeholders' submitted two requests for Local Economic Studies to be evaluated. These scenarios are described in detail in Section III. Local Economic Study Process scenarios will be solicited again for the 2016 Study and included if appropriate.

2015 NCTPC Process Flow Chart



II.E. *Collaborative Transmission Plan*

Once the reliability and local economic studies are completed, 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 final plan. If so, the initial plan developed based on the results of the reliability studies is modified accordingly. This process results in a single Collaborative 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 Collaborative Transmission Plan.

The Collaborative 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. 2015 Reliability Planning Study Scope and Methodology

The scope of the 2015 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. In May of 2015, DEC and DEP announced their Western Carolinas Modernization Project (WCMP). The overall project was a forward-looking solution to meet electricity demands in the western Carolinas, while lowering emissions and reducing the company's environmental footprint by retiring the Asheville coal plant and replacing it with a natural gas plant that would be larger, cleaner and more efficient. The 2015 Study models included the Western Carolinas Modernization transmission projects (see Table 9), and DEP's Asheville 1 and 2 coal units were not dispatched. At the time of this study, a Large

Generator Interconnection Agreement (LGIA) had not been executed for the addition of one or more combined cycle units in place of the coal units that were assumed to be not dispatched. The exclusion of the proposed generation is consistent with transmission planning practices regarding generators that have not executed a LGIA. The purpose of the base reliability study was to evaluate the transmission systems' ability to meet load growth projected for 2020 summer through 2025 summer with the Participants' planned Designated Network Resources ("DNRs"). The 2015 Study allowed for identification of any new system impacts not currently addressed by existing transmission plans in which case solutions were developed. The 2015 Study also allowed for adjustments to existing plans where necessary.

The Local Economic Study Process allows the TAG participants to propose economic hypothetical transfers to be studied as part of the transmission planning process. The Local Economic Study Process provides the means to evaluate the impact of potential supply resources inside and outside the Balancing Authority Areas of the Transmission Providers. In 2015 as part of the Local Economic Study Process, two local economic study requests were received during this planning cycle and were analyzed by the PWG.

The purpose of the first study request was to determine the capacity available for a TVA to Duke Energy (DEC and DEP) transfer and the marginal system upgrades necessary to increase this capacity, if needed. More specifically, the request was to study the import of 661 MW into the CPLE and DUK Balancing Authority Areas from the TVA Balancing Authority Area in the year 2020. Of the 661 MW, 397 MW were allocated to DUK and 264 MW were allocated to CPLE. These allocations were based on an assumed load-share ratio of 60/40. In the modeling of the 661 MW transfer from TVA into CPLE and DUK, no limits were identified.

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For a variety of reasons (such as load growth, generation retirements, or power purchase agreements expiring), some Load Serving Entities (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.

Where issues requiring solutions within the applicable planning window were identified, alternative solutions were discussed, and a primary set of solutions was determined. The power flow analysis assumed an N-1 evaluation and was performed based on the assumption that thermal limits would be the controlling limit.

III.A. Assumptions

1. Study Year and Planning Horizon

The 2015 Plan addressed a ten-year planning horizon through 2025. The study years chosen for the 2015 Study are listed in Table 5.

Table 5

Study Years

Study Year / Season	Analysis
2020 Summer	Near-term base reliability
2020/2021 Winter	Near-term base reliability, local economic study
2025 Summer	Long-term base reliability, resource supply options

To identify projects required in years other than the base study years of 2020 and 2025, line loading results for those base study years were extrapolated into future years assuming the line loading growth rates in Table 6. This allowed assessment of transmission needs throughout the planning horizon. The line loading growth rates are based on each Balancing Authority Area's individual load growth projection.

Table 6
Line Loading Growth Rates

Company	Line Loading Growth Rate
DEC	1.4 % per year
DEP	1.4 % per year

2. Network Modeling

The network models developed for the 2015 Study included new transmission facilities and upgrades for the 2020 and 2025 models, as appropriate, from the current transmission plans of DEC and DEP and from the 2014 Plan. Table 7 lists the planned major transmission facility projects (with an estimated cost of $10 million or more each) included in the 2020 and 2025 models. Table 8 lists the generation facility changes included in the 2020 and 2025 models. The projects in Table 9 are included in all 2020 and 2025 models. Table 9 lists the major transmission facility projects (with an estimated cost of $10 million or more each) that are associated with the WCMP announcement on May 19, 2015[3].

[3] A revised plan was announced on November 4, 2015. The revised plan removed the projects to construct Foothills 500/230 kV station and a double circuit 230 kV line between Foothills Tie and Asheville Plant. It is yet to be determined whether or not the remaining projects in Table 9 will be needed in order to ensure a reliable transmission system.

Table 7

Major Transmission Facility Projects Included in Models

Company	Transmission Facility	2020	2025
DEP	Raeford 230 kV Substation, Loop-in Richmond-Ft Bragg WS 230 kV Line	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	Durham - RTP 230 kV Line	No	Yes
DEC	Reconductored Norman 230 kV Line from McGuire to Riverbend	Yes	Yes

Table 8

Major Generation Facility Changes in Models

Company	Generation Facility	2020	2025
DEC	Retired Lee 1-2 (200 MW)	Yes	Yes
DEC	Added Lee CC (776 MW)	Yes	Yes
DEC	Added Kings Mountain Energy CC (452 MW)	Yes	Yes
DEP	Asheville 1-2 not dispatched	Yes	Yes

Table 9

WCMP Major Transmission Facility Projects in Models

Company	Transmission Facility	Project Description
DEC	Reconductor Davidson River 100 kV Lines from North Greenville to Marietta	This project consists of rebuilding 11.5 miles of conductor with 477 ACSS/TW.
DEC	Foothills 500/230 kV Substation	This project consists of constructing a new 500/230 kV substation on the existing Jocassee-Cliffside 500 kV line. The new substation includes two 500/230 kV banks and shunt reactors on each 500 kV circuit that terminates at the substation.
DEC/DEP	Asheville-Foothills 230 kV Lines	This project consists of constructing an approximately 45-mile double circuit 230 kV line between DEC's Foothills Tie and DEP's Asheville Plant. Each circuit uses 1533 ACSS/TW conductor, which is smaller than ACSR conductor of comparable capacity.
DEP	Asheville Plant, Replace 2-300 MVA 230/115 kV banks with 2-400 MVA banks and reconductor 115 kV ties to switchyard	At Asheville Plant, replace 2-300 MVA 230/115 kV banks with 2-400 MVA banks, reconductor 115 kV ties to switchyard, install new and replace existing 230 kV and 115 kV circuit breakers.
DEP	Craggy-Enka 230 kV Line	This project consists of constructing a new 230 kV Line from the Craggy 230 kV Substation to the Enka 230 kV Substation. The 230 kV line uses 3-1590 MCM ACSR or equivalent. 3-230kV circuit breakers are needed at the Craggy 230 kV Substation and 3-230kV circuit breakers at the Enka 230 kV Substation.

3. Interchange and Generation Dispatch

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

Interchange in the base cases was set according to the DNRs identified outside the DEC and DEP Balancing Authority Areas. Interchange tables for the summer and winter base cases, and the DEP Transmission Reliability Margin ("TRM") cases[4], discussed in Section III.D, are in Appendix A.

The study assumed the availability of the existing 400 MW TSR from CPLE to CPLW as well as the proposed 600 MW TSR[5] from CPLE to CPLW from the May 2015 WCMP. Of this 1000 MW in available transfer capability from CPLE to CPLW, the summer models assumed a total transfer of 600 MW from CPLE to CPLW, and the winter models assumed a total transfer of 700 MW from CPLE to CPLW.

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.

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[4] Since DEP is an importing system, the worst case for studying transfers into DEP is to start with a case that models all firm transfer commitments, including designated network resources and TRM. DEP calls this maximum transfer case its TRM case.

[5] The 600 MW OASIS reservation was annulled on 11/5/15.

III.C. Case Development

The base case for the base reliability study was developed using the most current 2014 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 Balancing Authority Area in its base case. Included in this is TRM for use by all LSEs. TRM is composed of contracted VACAR reserve sharing, inrush impacts and parallel path flow 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 2020 and 2025 summer peak base cases with a Brunswick 1 unit outage, a Harris 1 unit outage, or a Robinson 2 unit outage, and from the 2020/2021 winter peak case with an Asheville CT1 unit outage, with the remainder of TRM addressed by miscellaneous unit de-rates.

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 2015 Study were also discussed with all Participants so that all are aware of potential issues. Appropriate solutions were jointly 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 2015 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 2014 Study. The PWG participated in the development 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 Balancing Authority Areas, 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 2016, 2017 and 2020 summer timeframes. The limiting facilities identified in the PWG study of base reliability and of the local economic study options 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 2015 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 2015 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 2015 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 eight reliability projects included in the 2015 Plan is $156 million as documented in Appendix B. This compares to the 2014 Plan estimate of $209 million for seven 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 E for a detailed comparison of this year's Plan to the 2014 Plan.

Appendix C provides a more detailed description of each project in the 2015 Plan.

V. Resource Supply Options Results

For a variety of reasons (such as load growth, generation retirements, or power purchase agreements expiring), some 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 2015, the PWG analyzed, among its resource supply options, cases that examine the impacts of sixteen different hypothetical transfers into, out of and through the DEC and DEP systems – Table 10. Each of these transfers, identified in Table 10, 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.

Table 10

Resource Supply Options

2025 Hypothetical Transfer Scenarios

Resource From	Sink	Test Level (MW)
PJM	DUK[6]	1,000
SOCO	DUK	1,000
SCEG	DUK	1,000
SCPSA	DUK	1,000
CPLE	DUK	1,000
TVA	DUK	1,000
PJM	CPLE[7]	1,000
SCEG	CPLE	1,000
SCPSA	CPLE	1,000
DUK	CPLE	1,000
DUK	SOCO	1,000
PJM	DUK/CPLE	1,000 / 1,000
DUK/CPLE	PJM	1,000 / 1,000
CPLE	PJM	1,000
DUK	PJM	1,000
SOCO[8]	PJM	1,000

Analysis of the sixteen hypothetical transfer scenarios did not identify any additional transmission projects for DEC or DEP beyond those in the 2015 Collaborative Plan.

[6] DUK is the Balancing Authority Area for DEC

[7] CPLE is the eastern Balancing Authority Area for DEP

[8] This hypothetical transfer is intended to evaluate the impact of a 1000 MW Southern Company transaction through the DEC/DEP transmission system into PJM Market

VI. Local Economic Study Results

Two local economic study requests were received during this planning cycle. The purpose of the first study request was to determine the capacity available for a TVA to Duke Energy (DEC and DEP) transfer and the marginal system upgrades necessary to increase this capacity, if needed. More specifically, the request was to study the import of 661 MW into the CPLE and DUK Balancing Authority Areas from the TVA Balancing Authority Area in the year 2020. Of the 661 MW, 397 MW were allocated to DUK and 264 MW were allocated to CPLE. These allocations were based on an assumed load-share ratio of 60/40. Analysis of the 661 MW transfer from TVA to CPLE and DUK did not identify any additional transmission projects for DEC or DEP beyond those in the 2015 Collaborative Plan.

The stated purpose of the second study request was as follows: “Simulate hypothetical scenario of NRC regulation impacting nuclear units of similar technology (all nuclear units of Westinghouse 1980s Vintage) in NCTPC footprint and assess reliability impact (N-1 contingencies) assuming redispatch internally first to extent possible and replace remaining capacity equally from Southern Company and PJM Market.” The forced outages affected 5 nuclear units and roughly 5,600 MW of DEC/DEP generation in the year 2020. Imports to replace the lost generation were 3,400 MW for DEC and 1,000 MW for DEP. The 4,400 MW of DEC/DEP import was made up of 2,200 MW from PJM and 2,200 MW from SOCO. The 2,200 MW of PJM export was made up of 1,700 MW from AEP and 500 MW from DVP. AEP and DVP were used to simulate the PJM export because they are the only PJM areas that share an interface with DEC/DEP. This approach provides the most severe flows across that interface.

A summary of the thermal results are provided in Appendix D. These results indicate that the scenario cannot be accommodated without significant transmission upgrades to mitigate the indicated thermal overloads.

VII. Collaborative Transmission Plan

The 2015 Plan includes eight 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 eight reliability projects in the 2015 Plan is $156 million. This compares to the original 2014 Plan estimate of $209 million for seven 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 E for a detailed comparison of this year's Plan to the 2014 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 2015 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. *Deferred* – Projects with this status were identified in the 2014 Report and have been deferred beyond the end of the planning horizon based on the 2015 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

2020 SUMMER PEAK

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports – MW

	Base	DEP TRM
CPLE (NCEMC)	147	147
DVP (PJM)	2	2
SCEG (Chappells)	2	2
SCPSA (PMPA)	189	189
SCPSA (Seneca)	38	38
SEPA (Hartwell)	155	155
SEPA (Thurmond)	113	113
SOCO (EU)	218	218
SOCO (NCEMC)	0	0
Total	**864**	**864**

Duke Energy Carolinas Modeled Exports – MW

	Base	DEP TRM
CPLE (Broad River)	850	850
CPLE (NCEMC/Catawba)	205	205
CPLE (DEP TRM)	0	773
CPLW (DEP TRM)	0	0
DVP (NCEMC)	100	100
Total	**1155**	**1928**

Duke Energy Carolinas Net Interchange – MW

	Base	DEP TRM
	291	**1064**

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

2020 SUMMER PEAK

DUKE ENERGY PROGRESS (EAST)

DETAILED INTERCHANGE

Duke Energy Progress (East) Modeled Imports – MW

	Base	DEP TRM
AEP (NCEMC)	100	100
AEP (DEP TRM)	0	100
DEC (Broad River)	850	850
DEC (NCEMC/Catawba)	205	205
DEC (DEP TRM)	0	773
DVP (SEPA-KERR)	95	95
DVP (DEP TRM)	0	427
SCEG (DEP TRM)	0	200
SCPSA (DEP TRM)	0	326
Total	**1250**	**3076**

Duke Energy Progress (East) Modeled Exports – MW

	Base	DEP TRM
CPLW (Transfer)	600	600
DEC (NCEMC)	147	147
PJM (Ingenco)	6	6
PJM (NCEMC)	330	330
Total	**1083**	**1083**

Duke Energy Progress (East) Net Interchange - MW

	Base	DEP TRM
	-167	**-1993**

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

2020 SUMMER PEAK
DUKE ENERGY PROGRESS (WEST)
DETAILED INTERCHANGE

Duke Energy Progress (West) Modeled Imports – MW

	Base	DEP TRM
CPLE (Transfer)	600	600
DEC (DEP TRM)	0	0
TVA (SEPA)	1	1
Total	**601**	**601**

Duke Energy Progress (West) Modeled Exports – MW

	Base	DEP TRM
CPLE (Transfer)	0	0
Total	**0**	**0**

Duke Energy Progress (West) Net Interchange – MW

	Base	DEP TRM
	-601	**-601**

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

2020/2021 WINTER PEAK

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports – MW

	Base	DEP TRM
CPLE (NCEMC)	147	147
DVP (PJM)	2	2
SCEG (Chappells)	2	2
SCPSA (PMPA)	88	88
SCPSA (Seneca)	26	26
SEPA (Hartwell)	155	155
SEPA (Thurmond)	113	113
SOCO (EU)	230	230
SOCO (NCEMC)	0	0
Total	**763**	**763**

Duke Energy Carolinas Modeled Exports – MW

	Base	DEP TRM
CPLE (Broad River)	850	850
CPLE (NCEMC/Catawba)	205	205
CPLE (DEP TRM)	0	0
CPLW (DEP TRM)	0	135
DVP (NCEMC)	100	100
Total	**1155**	**1290**

Duke Energy Carolinas Net Interchange – MW

	Base	DEP TRM
	392	**527**

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

2020/2021 WINTER PEAK

DUKE ENERGY PROGRESS (EAST)

DETAILED INTERCHANGE

Duke Energy Progress (East) Modeled Imports – MW

	Base	**DEP TRM**
AEP (NCEMC)	100	100
AEP (DEP TRM)	0	0
DEC (Broad River)	850	850
DEC (NCEMC/Catawba)	205	205
DEC (DEP TRM)	0	0
DVP (SEPA-KERR)	95	95
DVP (DEP TRM)	0	0
SCEG (DEP TRM)	0	0
SCPSA (DEP TRM)	0	0
Total	**1250**	**1250**

Duke Energy Progress (East) Modeled Exports – MW

	Base	**DEP TRM**
CPLW (Transfer)	700	700
DEC (NCEMC)	147	147
PJM (Ingenco)	6	6
PJM (NCEMC)	330	330
Total	**1183**	**1183**

Duke Energy Progress (East) Net Interchange – MW

	Base	**DEP TRM**
	-67	**-67**

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

2020/2021 WINTER PEAK

DUKE ENERGY PROGRESS (WEST)

DETAILED INTERCHANGE

Duke Energy Progress (West) Modeled Imports – MW

	Base	**DEP TRM**
AEP (TRM)	0	49
CPLE (Transfer)	700	700
DEC (DEP TRM)	0	135
TVA (SEPA)	1	1
TVA (TRM)	0	14
Total	**701**	**899**

Duke Energy Progress (West) Modeled Exports – MW

	Base	**DEP TRM**
CPLE (Transfer)	0	0
Total	**0**	**0**

Duke Energy Progress (West) Net Interchange - MW

	Base	**DEP TRM**
	-701	**-899**

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

2025 SUMMER PEAK

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports – MW

	Base	**DEP TRM**
CPLE (NCEMC)	45	45
DVP (PJM)	2	2
SCEG (Chappells)	2	2
SCPSA (PMPA)	226	226
SCPSA (Seneca)	40	40
SEPA (Hartwell)	155	155
SEPA (Thurmond)	113	113
SOCO (EU)	70	70
SOCO (NCEMC)	0	0
Total	**653**	**653**

Duke Energy Carolinas Modeled Exports – MW

	Base	**DEP TRM**
CPLE (Broad River)	850	850
CPLE (NCEMC/Catawba)	205	205
CPLE (DEP TRM)	0	773
CPLW (DEP TRM)	0	0
DVP (NCEMC)	100	100
Total	**1155**	**1928**

Duke Energy Carolinas Net Interchange

	Base	**DEP TRM**
	502	**1275**

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

2025 SUMMER PEAK

DUKE ENERGY PROGRESS (EAST)

DETAILED INTERCHANGE

Duke Energy Progress (East) Modeled Imports – MW

	Base	**DEP TRM**
AEP (NCEMC)	100	100
AEP (DEP TRM)	0	100
DEC (Broad River)	850	850
DEC (NCEMC/Catawba)	205	205
DEC (DEP TRM)	0	773
DVP (SEPA-KERR)	95	95
DVP (DEP TRM)	0	427
SCEG (DEP TRM)	0	200
SCPSA (DEP TRM)	0	326
Total	**1250**	**3076**

Duke Energy Progress (East) Modeled Exports – MW

	Base	**DEP TRM**
CPLW (Transfer)	600	600
DEC (NCEMC)	45	45
PJM (Ingenco)	6	6
PJM (NCEMC)	330	330
Total	**981**	**981**

Duke Energy Progress (East) Net Interchange – MW

	Base	**DEP TRM**
	-269	**-2095**

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

2025 SUMMER PEAK

DUKE ENERGY PROGRESS (WEST)

DETAILED INTERCHANGE

Duke Energy Progress (West) Modeled Imports – MW

	Base	DEP TRM
CPLE (Transfer)	600	600
DEC (DEP TRM)	0	0
TVA (SEPA)	1	1
Total	**601**	**601**

Duke Energy Progress (West) Modeled Exports – MW

	Base	DEP TRM
CPLE (Transfer)	0	0
Total	**0**	**0**

Duke Energy Progress (West) Net Interchange – MW

	Base	DEP TRM
	-601	**-601**

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

Appendix B
Collaborative Transmission Plan Major Project Listings -

Reliability Projects

2015 Collaborative Transmission Plan – Reliability Projects (Estimated Cost > $10M)							
Project ID	**Reliability Project**	**Issue Resolved**	**Status[1]**	**Transmission Owner**	**Projected In-Service Date**	**Estimated Cost ($M)[2]**	**Project Lead Time (Years)[3]**
0028	Brunswick #1 – Jacksonville 230 kV Line Loop-In to Folkstone 230 kV substation	Address loading on Folkstone – Jacksonville City 115 kV Line	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	Address loading on Raeford 230/115 kV transformer	Planned	DEP	6/1/2018	20	2.5
0024	Durham - RTP 230 kV Line, Reconductor	Address loading on the Durham - RTP 230 kV Line	Planned	DEP	6/1/2024	15	4
0031	Jacksonville-Grants Creek 230 kV Line and Grants Creek 230/115 kV Substation	Mitigate loading and voltage issues on existing Havelock-Jacksonville 230 kV Line	Planned	DEP	6/1/2020	37	4.5
0032	Newport-Harlowe 230 kV Line, Newport SS and Harlowe 230/115 kV Substation	Mitigate loading and voltage issues on existing Havelock-Morehead Wildwood 115 kV Line	Planned	DEP	6/1/2020	32	4.5
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	Mitigate transformer bank and 115 kV feeder loading	Planned	DEP	12/1/2016	13	1.5
0034	Sutton-Castle Hayne 115 kV North line Rebuild	Mitigate contingency loading	Planned	DEP	6/1/2018	10	2.5

2015 Collaborative Transmission Plan – Reliability Projects (Estimated Cost > $10M)							
Project ID	Reliability Project	Issue Resolved	Status[1]	Transmission Owner	Projected In-Service Date	Estimated Cost ($M)[2]	Project Lead Time (Years)[3]
0035	Reconductor Norman 230 kV Lines (McGuire-Riverbend)	Mitigate loading issues that were aggravated by retirement of Riverbend generation	Underway	DEC	12/1/15	15	0.5
TOTAL						**156**	

[1] Status: *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.

[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
Collaborative Transmission Plan Major Project Descriptions - **Reliability Projects**

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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: 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 Folkstone – Jacksonville City 115 kV Line under the contingency of losing Folkstone – Jacksonville 230 kV Line.

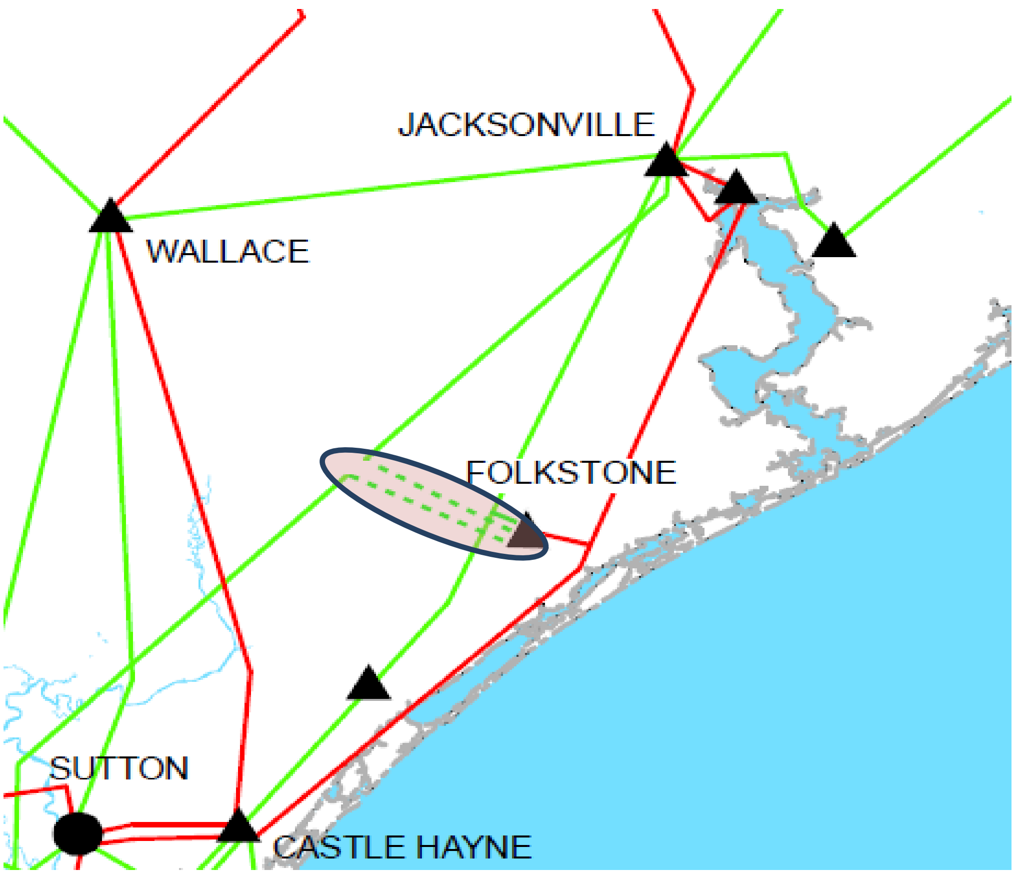
Other Transmission Solutions Considered
Rebuild, reconductor existing line.

Why this Project was Selected as the Preferred Solution
Transmission system versus local fixes.

C-1

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

- **NERC Category B Violations**
- **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	Planned:
Transmission Owner	DEP
Planned In-Service Date	6/1/2018
Estimated Time to Complete	2,5 years
Estimated Cost	$20 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.

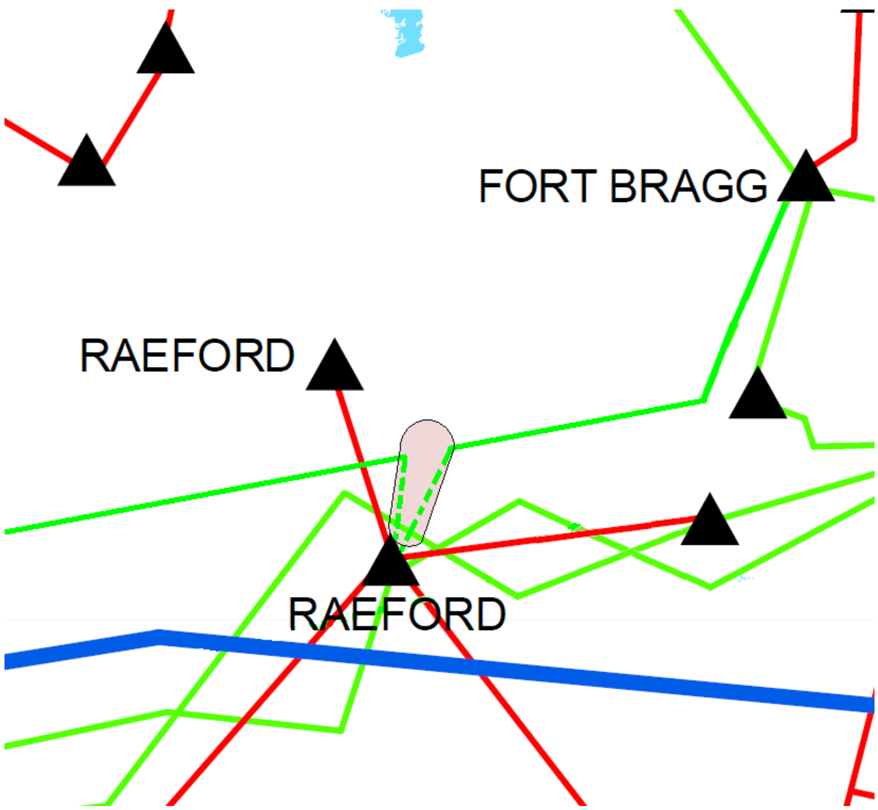
Other Transmission Solutions Considered
Construct Arabia 230kV Substation.

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

C-2

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

- **NERC Category C Violations**
- **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: 0024 – Durham - RTP 230 kV Line, Reconductor

Project Description
Reconductor approximately 10 miles of 230 kV Line with 6-1590 ACSR conductor.

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	6/1/2024
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 - (DPC) 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.

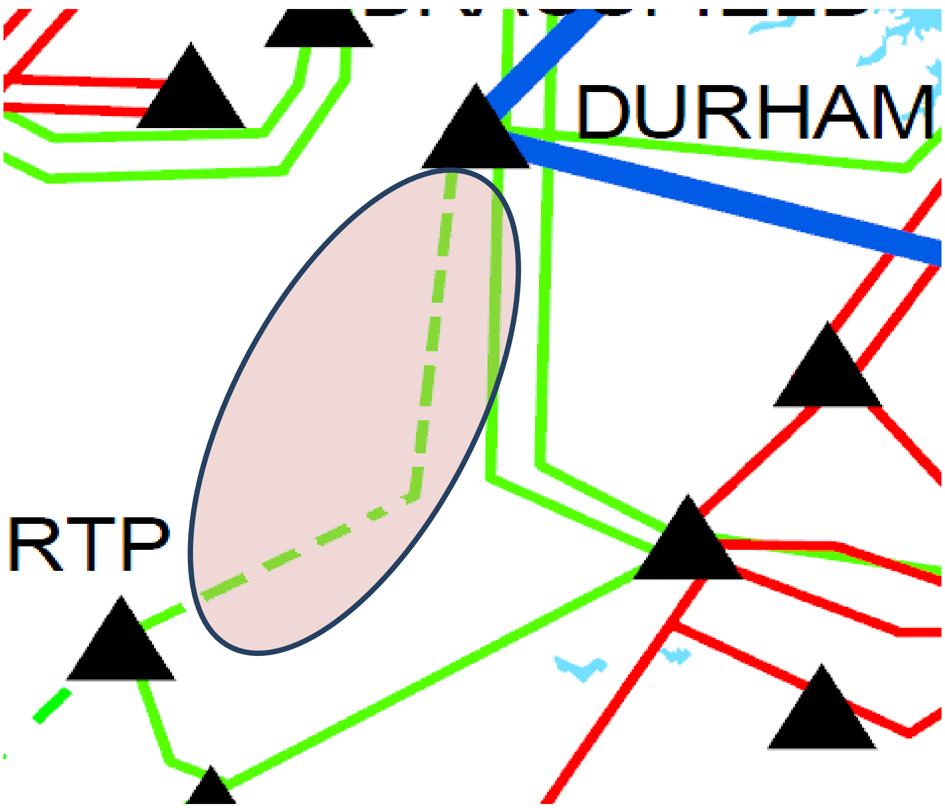
Other Transmission Solutions Considered
Construct a new line between Durham and RTP 230 kV Subs.

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

C-3

Durham-RTP 230 kV Line

- **NERC Category C Violations**
- **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: 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	Planned
Transmission Owner	DEP
Planned In-Service Date	6/1/2020
Estimated Time to Complete	4.5 years
Estimated Cost	$37 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.

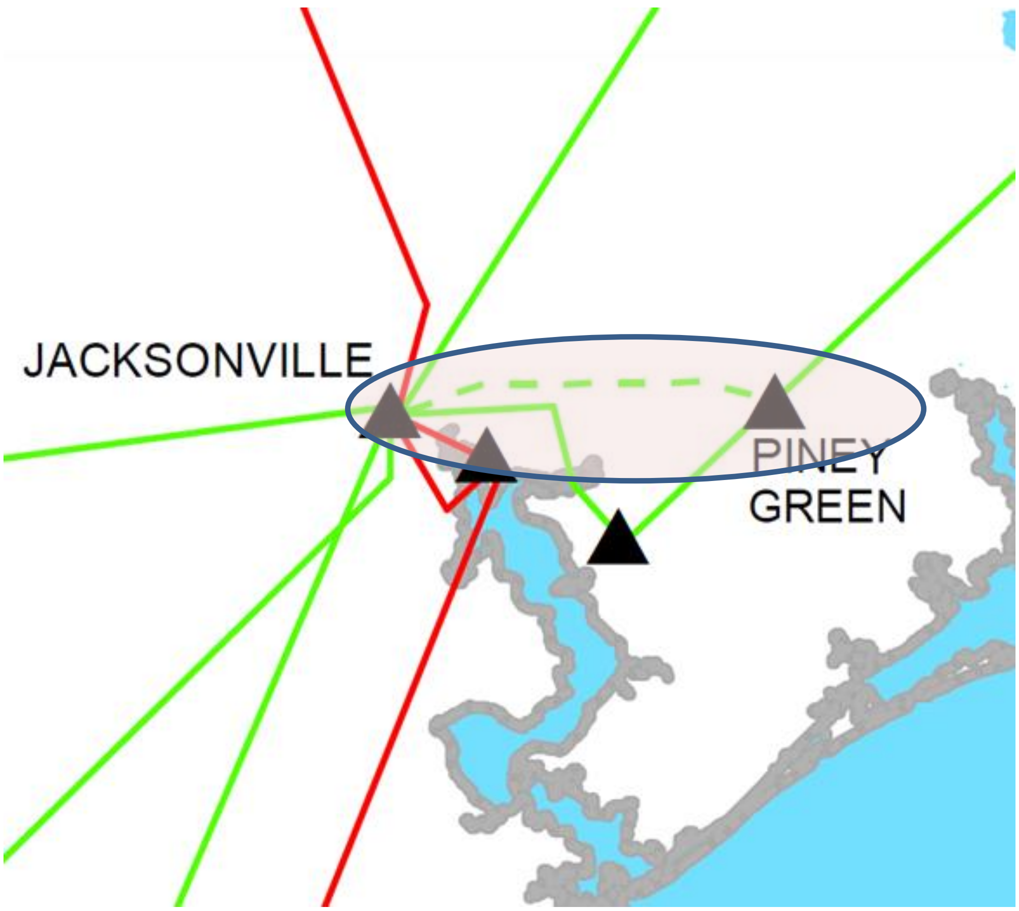
Other Transmission Solutions Considered
Construct alternate 230 kV lines.

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

C-4

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

- **NERC Category B 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 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	Planned
Transmission Owner	DEP
Planned In-Service Date	6/1/2020
Estimated Time to Complete	4.5 years
Estimated Cost	$32 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.

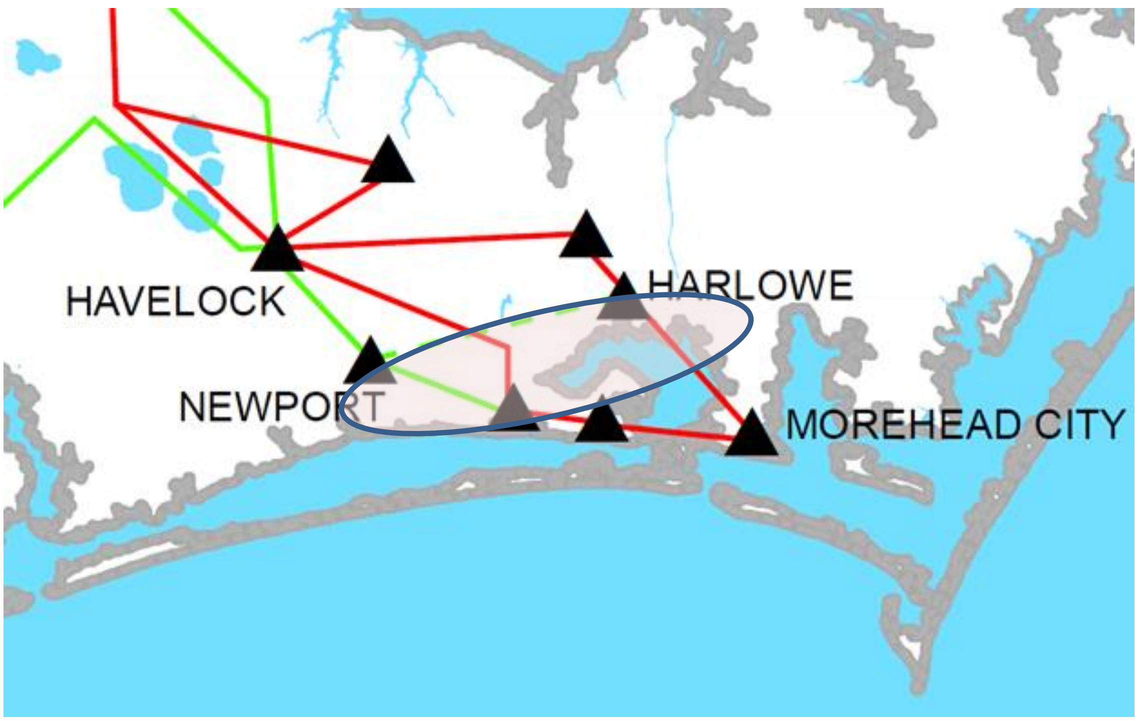
Other Transmission Solutions Considered
Convert 115 kV line to 230 kV.

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

C-5

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

- **NERC Category B 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: 0033 – Fort Bragg Woodruff St 230 kV Sub, Replace 150 MVA 230/115 kV transformer with two 300 MVA banks and reconductor Manchester 115 kV feeder

Project Description
Replace the existing 150 MVA, 230/115 kV transformer bank (three 1-phase & spare 50 MVA) at the Ft. Bragg Woodruff Street 230kV Substation with two 3-phase 300 MVA, 230/115 kV transformers from Apex US#1 230kV Substation per Equipment Engineering. Two 115 kV circuit breakers with associated disconnect switches will be installed. Also reconductor the Ft. Bragg Woodruff Street-Manchester 115kV Feeder (4.42 miles) with 3-1590 MCM ACSR or equivalent.

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	12/1/2016
Estimated Time to Complete	1.5 years
Estimated Cost	$13 M

Narrative Description of the Need for this Project
In 2016/17 winter, during peak load conditions, load on the Ft. Bragg Woodruff Street-Manchester 115kV Feeder will exceed the feeder capacity and the transformer bank rating at the Ft. Bragg Woodruff Street 230kV Substation. DEP has been working with South River EMC and Central EMC to manage the loading on this feeder for several years and we have jointly agreed that this is the best alternative to alleviate these issues.

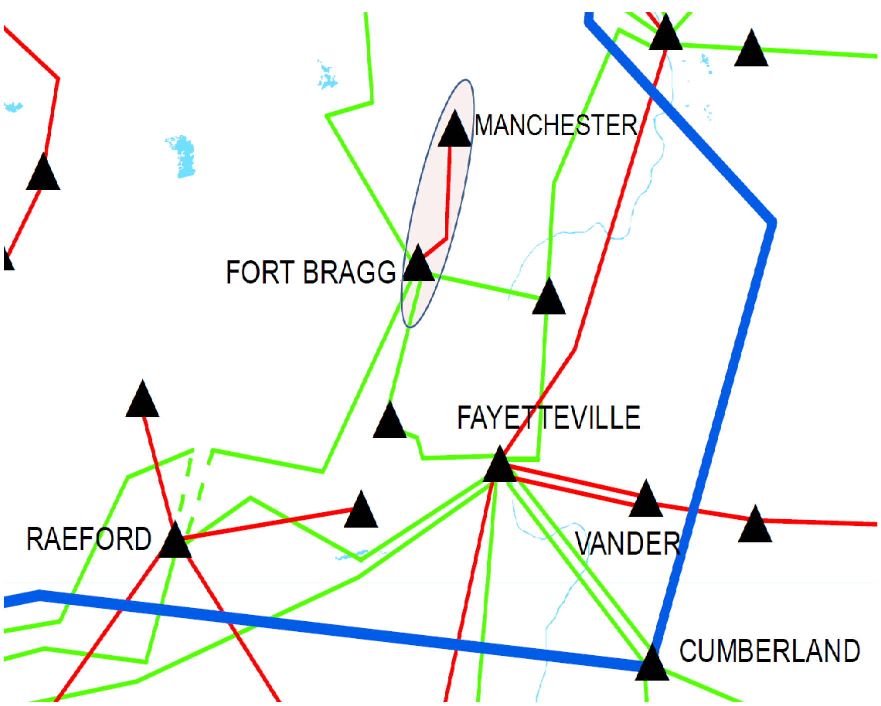
Other Transmission Solutions Considered
Convert 115 kV feeder to 230 kV.

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

C-6

Fort Bragg Woodruff St 230 kV Sub, Replace 150 MVA 230/115 kV transformer with two 300 MVA banks & reconductor Manchester 115 kV feeder

- **NERC Category B violation**
- **Problem:** In 2016/17 winter, during peak load conditions, load on the Ft. Bragg Woodruff Street-Manchester 115kV Feeder will exceed the feeder capacity and the transformer bank rating at the Ft. Bragg Woodruff Street 230kV Substation. DEP has been working with South River EMC and Central EMC to manage the loading on this feeder for several years and we have jointly agreed that this is the best alternative to alleviate these issues.
- **Solution:** Replace transformers, reconductor 115 kV feeder.



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 CT's at both line terminals will have to be uprated as part of this project. The thermal rating of this line will then be limited to 239 MVA due to the 1200 A disconnects at both terminals.

Status	Planned
Transmission Owner	DEP
Planned In-Service Date	6/1/2018
Estimated Time to Complete	2.5 years
Estimated Cost	$10 M

Narrative Description of the Need for this Project
By 2018, 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.

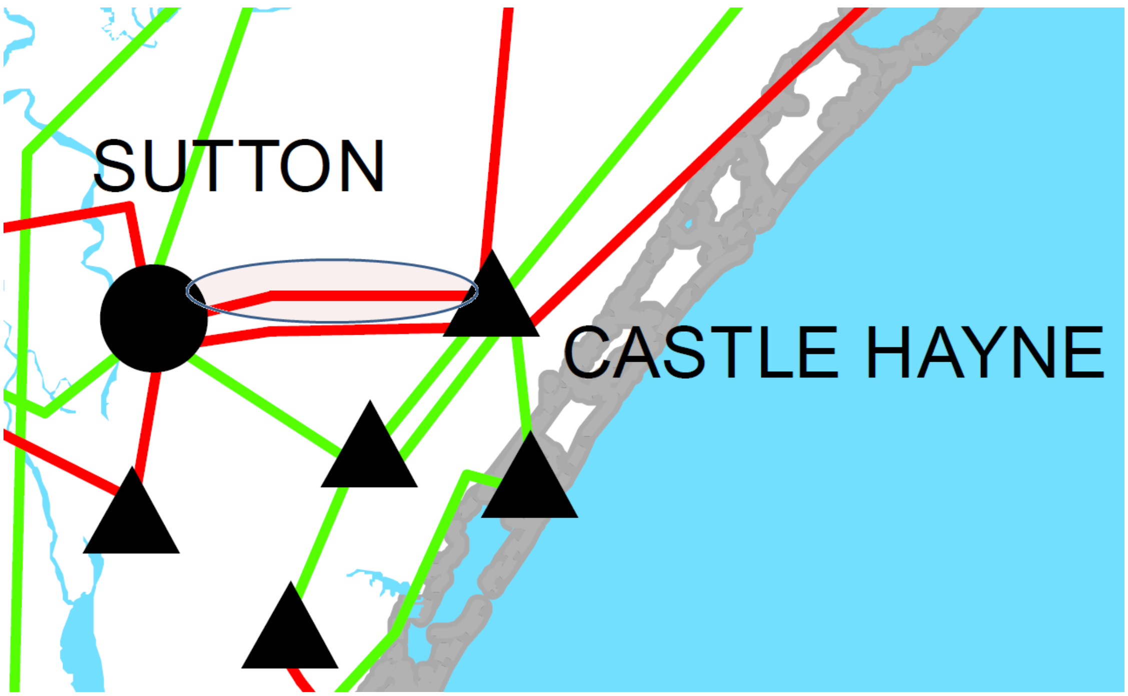
Other Transmission Solutions Considered
Convert 115 kV line to 230 kV.

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

C-7

Sutton-Castle Hayne 115 kV North Line - Rebuild

- **NERC Category B violation**
- **Problem:** By 2018, 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: 0035 – Reconductor Norman 230 kV Lines (McGuire-Riverbend)

Project Description
This project consists of rebuilding 6 miles of the existing 1272 ACSR conductor with 1533 ACSS/TW.

Status	Underway
Transmission Owner	DEC
Planned In-Service Date	12/1/2015
Estimated Time to Complete	.5 years
Estimated Cost	$15 M

Narrative Description of the Need for this Project
The retirement of generation at Riverbend in 2013 has caused increased loading on these lines. For the loss of the parallel line, the remaining line may overload. The short-term solution has been to redispatch generation in order to operate around this issue; however, construction of this new line will mitigate this thermal problem and will be more economical long-term.

Other Transmission Solutions Considered
Redispatching generation as an operating solution

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

C-8

Reconductor Norman 230 kV Lines (McGuire-Riverbend)

- **NERC Category B violation**
- **Problem:** The retirement of generation at Riverbend in 2013 has caused increased loading on these lines. For the loss of the parallel line, the remaining line may overload. The short-term solution has been to redispatch generation in order to operate around this issue; however, the rebuilding of this existing line will mitigate this thermal problem and will be more economical long-term.
- **Solution:** Rebuild 230 kV lines with higher capacity conductors.

PROJECT MAP REMOVED

Contains Critical Energy Infrastructure Information (CEII)

Appendix D
Local Economic Studies

Local Economic Study #1 – 2020 661 MW TVA-DEC/DEP Transfer					
Primary Alternative Investigated	**Issue Identified**	**TO**	**Lead Time (years)**	**Date Needed**[1]	**($M)**[2]
-	No new issues identified	DEC/DEP	-	-	-

[1] The tables in Appendix D reflect the date the project is needed in order to implement the local economic study.

[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.

Local Economic Study #2 – 2020 Forced Outage(s) of Multiple Nuclear Units					
Primary Alternative Investigated	**Issue Identified**	**TO**	**Lead Time (years)**	**Date Needed**Error! Bookmark not defined.	**($M)**Error! Bookmark not defined.
Reconductor Fisher 230 kV Lines (Central-Shady Grove Tap)	Line overloads for loss of parallel line	DEC	2	2020	35
Reconductor Parr 230 kV Line (VC Summer-Newport)	Line overloads for loss of Newport 500/230 kV transformer	DEC	5	2020	85
Replace Newport 500/230 kV Transformer	Line overloads for loss of McGuire 500/230 kV transformer	DEC	4	2020	20
Upgrade DEP/SCPSA 230 kV Tie (Darlington-S. Bethune)	Line overloads for loss of Sumter-Wateree(SCE&G) 230 kV line	DEP	5	2020	10
Convert Camden Junction to a 230kV station and construct new DEP/SCPSA 230 kV Tie (Camden Junction-Camden(SCPSA))	Camden-Camden Junction 115 kV line overloads for loss of Camden-Wateree(DEC) 115 kV line	DEP	5	2020	18

Appendix E
Collaborative Plan Comparisons

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2014 Plan[1]			2015 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0010A	Harris Plant - RTP 230 kV Line, Establish a new 230 kV line by utilizing the Amberly 230 kV Tap, converting existing Green Level 115 kV Feeder to 230 kV operation, Construction of new 230 kV line, remove 230/115 kV transformation and connection at Apex US1	Address the need for new transmission source to serve rapidly growing load in the western Wake County area; helps address loading on Cary Regency Park - Durham 230 kV line	DEP	In-Service	5/23/2014	54	-	-	-
0028	Brunswick #1 – Jacksonville 230 kV Line Loop-In to Folkstone 230 kV Substation	Address loading on Folkstone – Jacksonville City 115 kV Line.	DEP	Removed	-	-	Planned	6/1/2024	14
0008	Greenville - Kinston DuPont 230 kV Line, Construct line (See Note 4)	Address loading on Greenville - Everetts 230 kV Line and meet merger commitment	DEP	In-Service	5/12/2014	31	-	-	-

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2014 Plan[1]			2015 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0030	Raeford 230 kV substation, loop-in Richmond-Ft Bragg Woodruff St 230 kV Line and add 3rd bank	Address loading on Raeford 230/115 kV transformer.	DEP	Planned	6/1/2018	13	Planned	6/1/2018	20
0024	Durham - RTP 230 kV Line, Reconductor	Address loading on the Durham-RTP 230 kV Line	DEP	Planned	6/1/2023	15	Planned	6/1/2024	15
0027	Reconductor Caesar 230 kV Lines (Pisgah Tie - Shiloh Switching Station #1 & #2)	Contingency loading of the remaining line on loss of the parallel line during high imports to DEP West	DEC	In-Service	12/3/2013	27	-	-	-
0031	Jacksonville-Grants Creek 230 kV Line and Grants Creek 230/115 kV Substation	Mitigate loading and voltage issues on existing Havelock-Jacksonville 230 kV Line	DEP	Planned	6/1/2020	37	Planned	6/1/2020	37
0032	Newport-Harlowe 230 kV Line, Newport SS and Harlowe 230/115 kV Substation	Mitigate loading and voltage issues on existing Havelock-Morehead Wildwood 115 kV Line	DEP	Planned	6/1/2020	32	Planned	6/1/2020	32

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2014 Plan[1]			2015 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
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	Mitigate transformer bank and 115 kV feeder loading	DEP	-	-	-	Underway	6/1/2016	13
0034	Sutton-Castle Hayne 115 kV North line Rebuild	Mitigate contingency loading	DEP	-	-	-	Planned	6/1/2018	10
0035	Reconductor Norman 230 kV Lines (McGuire-Riverbend)	Mitigate loading issues that were aggravated by retirement of Riverbend generation	DEC	-	-	-	Underway	12/1/2015	15
TOTAL						**209**			**156**

[1] Information reported in Appendix B-1 of the NCTPC 2014 - 2024 Collaborative Transmission Plan" dated January 15, 2015.

[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.

Deferred: Projects with this status were identified in the 2014 Report and have been deferred beyond the end of the planning horizon based on analysis performed to develop the 2015 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.

[4] This project was originally scheduled to be completed 6/1/2017, but was accelerated to 6/1/2014 as part of the DEC - DEP merger mitigation projects.

Appendix F
Acronyms

ACRONYMS

ACSR	Aluminum Conductor Steel Reinforced
ACSS	Aluminum Conductor, Steel Supported
AEP	American Electric Power
AFUDC	Allowance for Funds Used During Construction
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
EU2	Energy United
FSA	Facilities Study Agreement
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
NC	North Carolina
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
NHEC	New Horizons Electric Cooperative
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
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
WCMP	Western Carolinas Modernization Project