North Carolina Transmission Planning Collaborative

Report on the NCTPC 2014-2024 Collaborative Transmission Plan

December 8, 2014
Final Draft

2014 – 2024 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, 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 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 2013-2023 Collaborative Transmission Plan (the "2013 Collaborative Transmission Plan" or the "2013 Plan") was published in January 2014.

This report documents the current 2014 – 2024 Collaborative Transmission Plan ("2014 Collaborative Transmission Plan" or the "2014 Plan") for the Participants. The initial sections of this report provide an overview of the NCTPC Process as well as the specifics of the 2014 reliability planning study scope and methodology. The NCTPC Process document and 2014 NCTPC study scope document are posted in their entirety on the NCTPC website at http://www.nctpc.org/nctpc/.

The scope of the 2014 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 study was done with the assumption of business as usual except that DEC - DEP merger related upgrades were included in the base models. The purpose of the base reliability study was to evaluate the transmission systems' ability to meet load growth projected for 2019 through 2024 with the Participants' planned Designated Network Resources ("DNRs"). The 2014 Study[1] allowed for identification of any new system impacts not currently addressed by existing transmission plans, in which case solutions were developed. The 2014 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 2014 Plan continue to satisfactorily address the reliability concerns identified in the 2014 Study for the near-term (5 year) and the long-term (10 year) planning horizons. The 2014 Plan is detailed in Appendix B which identifies the new and updated projects planned with an estimated cost of greater than $10 million.

For the 2014 Report, projects in Appendix B have been divided into Reliability Projects (B-1) and Merger Projects (B-2). Projects in the 2014 Plan are those projects identified in the base reliability study (B-1) and those projects that DEC and DEP have committed to construct as a result of the DEC - DEP Merger (B-2). For each of these

[1] The term "2014 Study" is a generic term referring to all the study work that was done in 2014 which includes the reliability analysis as well the local economic analysis.

projects, Appendix B provides the project status, the estimated cost, the planned in-service date, and the estimated time to complete the project. Appendix C provides a more detailed description of each project in the 2014 Plan. Appendix C has also been divided into Reliability Projects (C-1) and Merger Projects (C-2).

The total estimated cost for the eight reliability projects included in the 2014 Plan is $209 million as documented in Appendix B-1. This compares to the 2013 Plan estimate of $223 million for nine 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 2013 Plan.

As a merger commitment, DEC and DEP agreed to construct a total of nine projects with a cost of approximately $118 million. Of these nine projects, five have cost estimates greater than $10 million and are documented in Appendix B. One of these five projects, the Greenville-Kinston Dupont 230 kV Line, was already a reliability project in the 2011 Plan with a target date of June 1, 2017. As part of the DEC - DEP merger, a commitment was made to accelerate this project to June 1, 2014 and increase the line capacity. This project is grouped with the reliability projects in Appendix B-1 because it was already in the 2011 Plan. The remaining four merger projects are listed in Appendix B-2. The total estimated cost for the four merger projects in the 2014 Plan is $73 million. This compares to the 2013 Plan estimate of $67 million for three of the four merger projects; the Kinston Dupont-Wommack 230 kV Line was not included in the 2013 Plan because it previously did not meet the $10 million threshold for reporting. The 2014 study analysis determined that the DEC – DEP merger projects did not negatively impact any existing projects in the Plan.

The modified projects for DEP and DEC in the 2014 Plan, relative to the 2013 Plan, include five DEP projects and two DEC projects that were placed in service. The projects placed in service were:

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- Harris Plant-RTP 230 kV Line (DEP)
- Greenville-Kinston Dupont 230 kV Line (DEP)
- Lilesville-Rockingham 230 kV South Line (DEP)
- Person-(DVP)Halifax 230 kV Line Uprate (DEP)

- Kinston Dupont-Wommack 230 kV Line Uprate (DEP)
- Pisgah Tie-Shiloh Switching Station 230 kV Lines Reconductor (DEC)
- Antioch 500/230 kV Transformers Uprate (DEC)

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

- Brunswick #1-Jacksonville 230 kV Line Loop-in to Folkstone 230 kV Substation was replaced by another project.
- The Jacksonville-Piney Green 230 kV Line and Piney Green 230/115 kV Substation was added
- The Newport-Harlowe 230 kV Line, Newport SS, and Harlowe 230/115 kV Substation was added

The NCTPC planning process allows the TAG participants to propose economic hypothetical transfers to be studied as part of the annual transmission planning process. The Local Economic Study Process provides the means to evaluate the impact of potential supply resources inside and outside the Balancing Areas of the Transmission Providers. A local economic study request was received this planning cycle on February 18, 2014. The request was to study the import of 250 MW into the CPLW Balancing Area from the Tennessee Valley Authority (TVA) Balancing Area. After review of the request by both the Oversight Steering Committee (OSC) and the Planning Working Group (PWG), it was decided that the PWG would perform thermal MUST transfer analysis on the 2019-2020 winter peak load NCTPC power flow case.

In the modeling of the 250 MW transfer from TVA into CPLW, several limits have been identified for the contingency outage of the Asheville Plant (DEP) – Pisgah (DEC) 230 kV Lines indicating that the transfer could not take place without significant transmission upgrades to mitigate the indicated thermal overloads. There are also known voltage issues in this region that would have to be mitigated for increased imports but reviewing those was beyond the scope of this study.

In addition to the reliability analysis and the local economic study request, the NCTPC participated in a joint interregional study with the participants of Midcontinent ISO

(MISO) and PJM Interconnection (PJM) at the request of the North Carolina Utilities Commission (NCUC). This joint study was to determine whether or not the generation resources which cleared in the PJM 2016/2017 base residual capacity auction (BRA) could reasonably be expected to exacerbate loop flows on the transmission grid of North Carolina due to an unprecedented amount of those generation resources being located outside the PJM transmission system. Specifically, the NCUC requested the study to determine whether the planned imports would be likely to cause Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) to alter their joint generation dispatch in a manner that increases costs and whether the planned imports would reduce the reliability of the North Carolina transmission grid. The joint interregional study details, assumptions, results and conclusions are to be provided in a separate report.

In this 2014 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 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 Planning Working Group ("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 NCPTC, 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. 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 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.

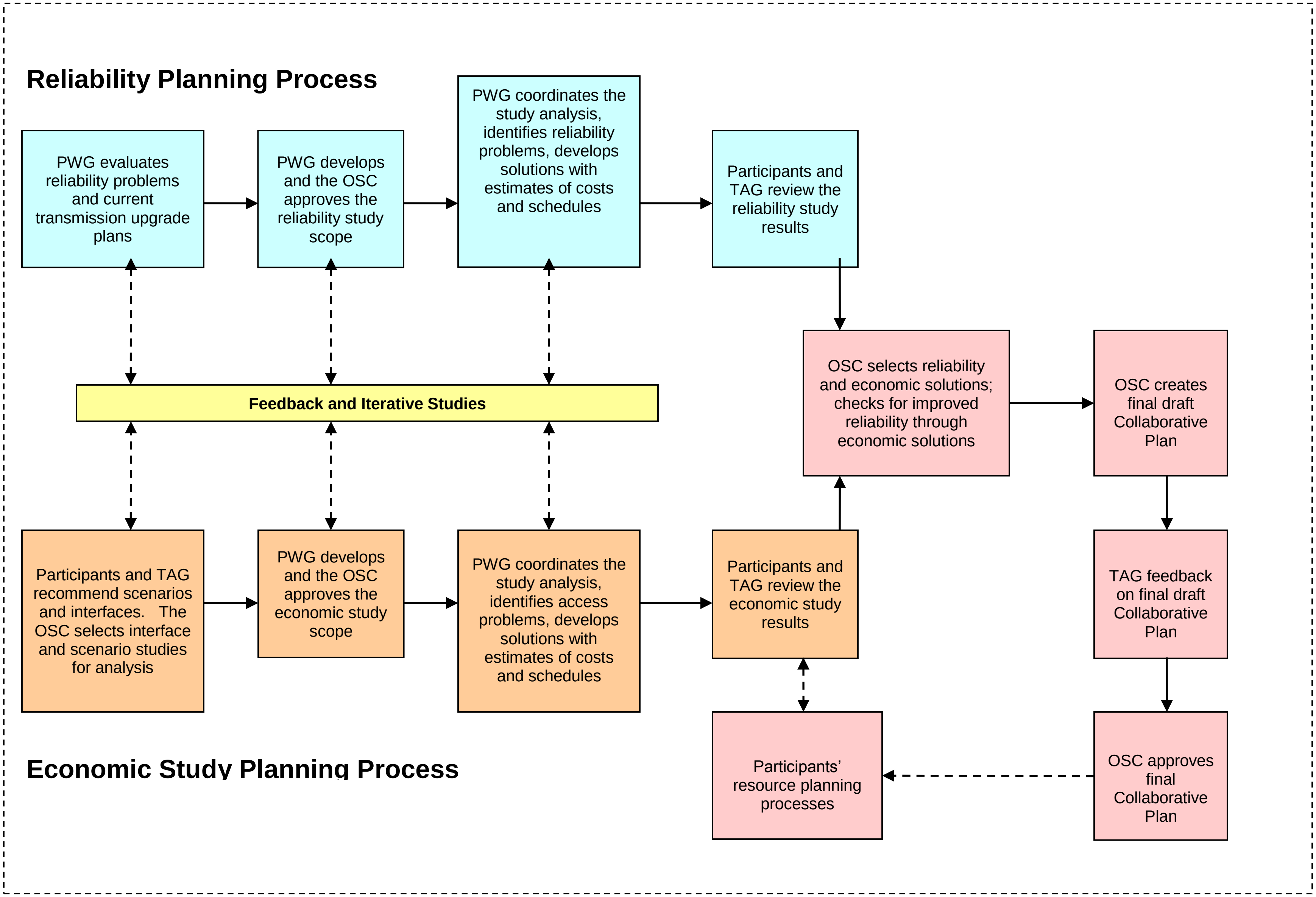
While the overall NCTPC Process includes both a reliability planning process and the Local Economic Study Process, some planning cycles may only focus on the reliability planning process if stakeholders do not request any local economic study scenarios for a particular planning cycle.

II.D. MISO-NCTPC-PJM Joint Study of NC Impact of PJM 2016/2017 BRA

In December 2013, the North Carolina Utilities Commission (NCUC) requested a joint interregional study to be performed by the participants of Midcontinent ISO (MISO), the North Carolina Transmission Planning Collaborative (NCTPC) and PJM Interconnection (PJM), to determine whether or not the generation resources which cleared in the PJM 2016/2017 base residual capacity auction (BRA) could reasonably be expected to exacerbate loop flows on the transmission grid of North Carolina due to an unprecedented amount of those generation resources being located outside the PJM transmission system. Specifically, the NCUC requested the study to determine whether the planned imports would be likely to cause DEC and DEP to alter their joint generation dispatch in a manner that increases costs and whether the planned imports would reduce the reliability of the North Carolina transmission grid.

The joint interregional study details, assumptions, results and conclusions are to be provided in a separate report.

2014 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. 2014 Reliability Planning Study Scope and Methodology

The scope of the 2014 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 study was done with the DEC and DEP merger projects included in the cases. The purpose of the base reliability study was to evaluate the transmission systems' ability to meet load growth projected for 2019 summer through 2024 summer with the Participants' planned Designated Network Resources ("DNRs"). The 2014 Study allowed for identification of any new system impacts not currently addressed by existing transmission plans in which case solutions were developed. The 2014 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 Areas of the Transmission Providers. 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. In 2014 as part of the Local Economic Study Process, the PWG analyzed a case that examined the impacts of a 250 MW transfer from TVA into the CPLW Balancing Area for 2019/2020 winter. 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 2014 Plan addressed a ten-year planning horizon through 2024. The study year for the local economic study was 2019/2020 winter. The study years chosen for the 2014 Study are listed in Table 5.

Table 5
Study Years

Study Year / Season	**Analysis**
2019 Summer	Near-term base reliability
2019/2020 Winter	Near-term base reliability, local economic study
2024 Summer	Long-term base reliability

To identify projects required in years other than the base study years of 2019 and 2024, 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's individual load growth projection.

Table 6
Line Loading Growth Rates

Company	Line Loading Growth Rate
DEC	1.5 % per year
DEP	1.4 % per year

2. Network Modeling

The network models developed for the 2014 Study included new transmission facilities and upgrades for the 2019 and 2024 models, as appropriate, from the current transmission plans of DEC and DEP and from the 2013 Plan. Table 7 lists the planned major transmission facility projects (with an estimated cost of $10 million or more each) included in the 2019 and 2024 models. Table 8 lists the generation facility additions and retirements included in the 2019 and 2024 models.

Table 7
Major Transmission Facility Projects Included in Models

Company	Transmission Facility	2019 Base & Sensitivities	2024 Base
DEP	Raeford 230 kV Substation, Loop-in Richmond-Ft Bragg WS 230 kV Line	Yes	Yes
DEP	Brunswick - Castle Hayne 230 kV River Crossing	Yes	Yes
DEP	Jacksonville 230 kV SVC	Yes	Yes

Company	Transmission Facility	2019 Base & Sensitivities	2024 Base
DEP	Harris Plant - RTP 230 kV Line	Yes	Yes
DEP	Greenville - Kinston DuPont 230 kV Line	Yes	Yes
DEP	Jacksonville-Piney Green 230 kV Line, Piney Green 230/115 kV Substation	No	Yes
DEP	Newport-Harlowe 230 kV Line, Newport Switching Station, Harlowe 230/115 kV Substation	No	Yes
DEP	Durham - RTP 230 kV Line	No	Yes
DEC	Reconductored Caesar 230 kV Line from Pisgah Tie to Shiloh Switching Station	Yes	Yes

Table 8

Major Generation Facility Additions and Retirements in Models

Company	Generation Facility	2019 Base & Sensitivities	2024 Base
DEC	Retired Buck 5-6 (256 MW)	Yes	Yes
DEC	Retired Riverbend 4-7 (454 MW)	Yes	Yes
DEC	Retired Lee 1-2 (200 MW)	Yes	Yes
DEP	Retired Sutton Units 1-3 (616 MW)	Yes	Yes
DEP	Added Sutton Plant CC (628 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 Balancing 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 Areas. Interchange tables for the summer and winter base cases, and the DEP Transmission Reliability Margin ("TRM") cases[2], discussed in Section III.D, are in Appendix A.

III.B. Study Criteria

The results of the base reliability study and the resource supply option 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 2013 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.

[2] 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.

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 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 re-dispatched 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	

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 2019 and 2024 summer peak base cases with a Brunswick 1 unit outage, a Harris 1 unit outage, or a Robinson 2 unit outage, and from the 2019/2020 winter peak case with an Asheville 1 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 2014 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 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 2014 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 2013 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 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 2015, 2016, 2017, and 2019 summer timeframes. The limiting facilities identified in the PWG study of base reliability and of the local economic study option examining hypothetical new generation 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 2014 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 2014 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 2014 Plan are those projects identified in the base reliability study and DEC-DEP merger projects. 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 2014 Plan is $209 million as documented in Appendix B-1. This compares to the 2013 Plan estimate of $223 million for nine 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 2013 Plan.

As a merger commitment, DEC and DEP agreed to construct a total of nine projects with a cost of approximately $118 million. Of these nine projects, five have cost estimates greater than $10 million and are documented in Appendix B. One of these five projects, the Greenville-Kinston Dupont 230 kV Line, was already a reliability project in the 2011 Plan with a target date of June 1, 2017. As part of the DEC - DEP merger, a commitment was made to accelerate this project to June 1, 2014 and increase the line capacity. This project is grouped with the reliability projects in Appendix B-1 because it was already in the 2012 Plan. The remaining four merger projects are listed in Appendix B-2. The total estimated cost for the four merger projects in the 2014 Plan is $73 million. This compares to the 2013 Plan estimate of $67 million for only three of the four merger projects; the Kinston Dupont-Wommack 230 kV Line reconductor project was not included in the 2013 Plan because it previously did not meet the $10 million threshold for reporting. The 2014 study analysis determined that the DEC – DEP merger projects did not negatively impact any existing projects in the Plan.

Appendix C provides a more detailed description of each project in the 2014 Plan. Appendix C has also been divided into Reliability Projects (C-1) and Merger Projects (C-2).

V. Local Economic Study Results

A local economic study request was received this planning cycle on February 18, 2014. The stated purpose of the study request was as follows: "Study and establish the additional transmission required by Asheville, NC in the event of a catastrophic loss of one or more existing generation resources in the region." More specifically, the request was to study the import of 250 MW into the CPLW Balancing Area from the TVA Balancing Area in the year 2017. After review of the request by both the OSC and the PWG, it was decided that the PWG would perform thermal MUST transfer analysis on the 2019-2020 winter peak load NCTPC power flow case that was already being developed for the Reliability Analysis portion of the 2014 NCTPC Study. The NCTPC did not commit to determining the additional transmission that would be required to complete this proposed transfer but instead agreed to the transfer analysis to determine the most obvious limits, if any, that were encountered when modeling the requested transfer. It must be noted that the power flow case was not set up for worst case import conditions as would normally be done for an analysis to determine if Firm Transmission Capability was available for a Transmission Service Request (TSR) and only a thermal analysis was performed which did not consider voltage issues. Because of these limiting assumptions, the results provided should not be construed to be a complete set of issues that would have to be mitigated to complete an actual request for this transfer.

A summary of the thermal results are provided in Appendix D which is an output of the MUST thermal transfer analysis. In the modeling of the 250 MW transfer from TVA into CPLW several limits are indicated for the contingency outage of the Asheville Plant (DEP) – Pisgah (DEC) 230 kV Lines. The first limit is reached when 58 MW is imported from TVA. There are other limits reached at 127 MW, 174 MW, 197 MW, and at 216 MW. These limits represent five (5) different transmission facilities that indicated contingency overloads before the proposed 250 MW import from TVA was reached.

Generally, these results indicate that the proposed 250 MW transfer could not take place without significant transmission upgrades to mitigate the indicated thermal overloads. There are also known voltage issues in this region that would have to be mitigated for increased imports but reviewing those was beyond the scope of this study.

VI. Collaborative Transmission Plan

The 2014 Plan includes eight reliability projects with an estimated cost of $10 million or more each. These projects are listed in Appendix B-1. The total estimated cost for these eight reliability projects in the 2014 Plan is $209 million. This compares to the original 2013 Plan estimate of $223 million for nine reliability projects. The total estimated cost for the four merger projects in the 2014 Plan is $73 million. This compares to the 2013 Plan estimate of $67 million for three merger projects. The Kinston Dupont-Wommack 230 kV Line Reconductor project had originally been estimated below $10 million. More recent estimates show the cost at $10 million resulting in this project now being included in Appendix B-2. 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 2013 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 2014 Plan, and includes the following information:

1) Reliability (or Merger) 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 2012 Report and have been deferred beyond the end of the planning horizon based on the 2014 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 C has also been divided into Reliability Projects (C-1) and Merger Projects (C-2).

Appendix A
Interchange Tables

2019 SUMMER PEAK

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports – MW

	Base	DEP TRM
CPLE (NCEMC)	131	131
DVP (PJM)	2	2
SCEG (Chappells)	2	2
SCPSA (New Horizons/NHEC)	0	0
SCPSA (PMPA)	190	190
SEPA (Hartwell)	155	155
SEPA (Thurmond)	113	113
SOCO (City of Seneca)	40	40
SOCO (EU)	120	120
SOCO (NCEMC)	176	176
Total	**929**	**929**

Duke Energy Carolinas Modeled Exports – MW

	Base	DEP TRM
CPLE (Broad River)	850	850
CPLE (NCEMC/Catawba)	205	205
CPLE (Rowan)	150	150
CPLE (DEP TRM)	0	773
CPLW (Rowan)	0	0
CPLW (DEP TRM)	0	0
DVP (NCEMC)	50	50
Total	**1255**	**2028**

Duke Energy Carolinas Net Interchange – MW

	Base	DEP TRM
	326	**1099**

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

2019 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 (Rowan)	150	150
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	**1400**	**3226**

Duke Energy Progress (East) Modeled Exports – MW

	Base	DEP TRM
CPLW (Transfer)	150	150
DEC (NCEMC)	131	131
PJM (NCEMC)	330	330
Total	**611**	**611**

Duke Energy Progress (East) Net Interchange - MW

	Base	DEP TRM
	-939	**-2615**

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

2019 SUMMER PEAK

DUKE ENERGY PROGRESS (WEST)

DETAILED INTERCHANGE

Duke Energy Progress (West) Modeled Imports – MW

	Base	DEP TRM
CPLE (Transfer)	150	150
DEC (Rowan)	0	0
DEC(DEP TRM)	0	0
TVA (SEPA)	151	151
Total	**1**	**1**

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
	-151	**-151**

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

2019/2020 WINTER PEAK

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports – MW

	Base	DEP TRM
CPLE (NCEMC)	0	0
DVP (PJM)	2	2
SCEG (Chappells)	2	2
SCPSA (New Horizons/NHEC)	0	0
SCPSA (PMPA)	93	93
SEPA (Hartwell)	155	155
SEPA (Thurmond)	113	113
SOCO (City of Seneca)	29	29
SOCO (EU)	120	120
SOCO (NCEMC)	176	176
Total	**690**	**690**

Duke Energy Carolinas Modeled Exports – MW

	Base	DEP TRM
CPLE (Broad River)	850	850
CPLE (NCEMC/Catawba)	205	205
CPLE (Rowan)	0	0
CPLE (DEP TRM)	0	0
CPLW (Rowan)	150	150
CPLW (DEP TRM)	0	135
DVP (NCEMC)	50	50
Total	**1255**	**1390**

Duke Energy Carolinas Net Interchange – MW

	Base	DEP TRM
	565	**700**

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

2019/2020 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 (Rowan)	0	0
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)	250	250
DEC (NCEMC)	0	0
PJM (NCEMC)	330	330
Total	**580**	**580**

Duke Energy Progress (East) Net Interchange – MW

	Base	**DEP TRM**
	-670	**-670**

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

2019/2020 WINTER PEAK

DUKE ENERGY PROGRESS (WEST)

DETAILED INTERCHANGE

Duke Energy Progress (West) Modeled Imports – MW

	Base	DEP TRM
AEP (TRM)	0	49
CPLE (Transfer)	250	250
DEC (Rowan)	150	150
DEC (DEP TRM)	0	135
TVA (SEPA)	1	1
TVA (TRM)	0	14
Total	**401**	**599**

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
	-401	**-599**

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

2024 SUMMER PEAK

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports – MW

	Base	**DEP TRM**
CPLE (NCEMC)	127	127
DVP (PJM)	2	2
SCEG (Chappells)	2	2
SCPSA (New Horizons/NHEC)	0	0
SCPSA (PMPA)	229	229
SEPA (Hartwell)	155	155
SEPA (Thurmond)	113	113
SOCO (City of Seneca)	42	42
SOCO (EU)	43	43
SOCO (NCEMC)	176	176
Total	**889**	**889**

Duke Energy Carolinas Modeled Exports – MW

	Base	**DEP TRM**
CPLE (Broad River)	850	850
CPLE (NCEMC/Catawba)	205	205
CPLE (Rowan)	150	150
CPLE (DEP TRM)	0	773
CPLW (Rowan)	0	0
CPLW (DEP TRM)	0	0
DVP (NCEMC)	50	50
Total	**1255**	**2028**

Duke Energy Carolinas Net Interchange

	Base	**DEP TRM**
	366	**1139**

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

2024 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 (Rowan)	150	150
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	**1400**	**3226**

Duke Energy Progress (East) Modeled Exports – MW

	Base	DEP TRM
CPLW (Transfer)	150	150
DEC (NCEMC)	127	127
PJM (NCEMC)	330	330
Total	**607**	**607**

Duke Energy Progress (East) Net Interchange – MW

	Base	DEP TRM
	-793	**-2619**

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

2024 SUMMER PEAK

DUKE ENERGY PROGRESS (WEST)

DETAILED INTERCHANGE

Duke Energy Progress (West) Modeled Imports – MW

	Base	DEP TRM
CPLE (Transfer)	150	150
DEC (Rowan)	0	0
DEC (DEP TRM)	0	0
TVA (SEPA)	1	1
Total	**151**	**151**

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
	-151	**-151**

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

Appendix B-1
Collaborative Transmission Plan Major Project Listings - **Reliability Projects**

2014 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]**
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	In-service	DEP	5/23/2014	54	0
0028	Brunswick #1 – Jacksonville 230 kV Line Loop-In to Folkstone 230 kV substation	Address loading on Folkstone – Jacksonville City 115 kV Line	Removed	DEP			
0008	Greenville - Kinston DuPont 230 KV Line Construct line (see note 4)	Address loading on Greenville - Everetts 230 kV Line	In-service	DEP	5/12/2014	31	0
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	13	4
0024	Durham - RTP 230 kV Line, Reconductor	Address loading on the Durham - RTP 230 kV Line	Planned	DEP	6/1/2023	15	4
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	In-service	DEC	12/3/2013	27	0

2014 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]**
		DEP West					
0014	Reconductor London Creek 230 kV Lines (Peach Valley Tie - Riverview Switching Station #1 & #2)	Contingency loading of the remaining line on loss of the parallel line when a 230 kV connected Oconee unit is off line	Removed	DEC			
0031	Jacksonville-Piney Green 230 kV Line and Piney Green 230/115 kV Substation	Mitigate loading and voltage issues on existing Havelock-Jacksonville 230 kV Line	Planned	DEP	6/1/2020	37	6
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	6
TOTAL						**209**	

[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.

[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 B-2
Collaborative Transmission Plan Major Project Listings –
Merger Projects

2014 Collaborative Transmission Plan – Merger Projects (Estimated Cost > $10M)							
Project ID	**Merger Project**	**Issue Resolved**	**Status[1]**	**Transmission Owner**	**Projected In-Service Date**	**Estimated Cost ($M)[2]**	**Project Lead Time (Years)[3]**
M-0001	Lilesville-Rockingham 230KV Line #3 – Construct new line	This project is part of the DEC - DEP merger mitigation projects.	In-Service	DEP	12/22/13	14	0
M-0002	Person-(DVP) Halifax 230kV Line - Reconductor DVP Section (DVP work)	This project is part of the DEC - DEP merger mitigation projects.	In-Service	DEP/ Dominion	4/30/2014	19	0
M-0003	Antioch 500/230kV Substation: Replace Two Transformer Banks	This project is part of the DEC - DEP merger mitigation projects.	In-Service	DEC	5/1/2014	30	0
M-0004	Kinston Dupont-Wommack 230 kV Line - Reconductor	This project is part of the Duke/Progress merger mitigation projects.	In-Service	DEP	5/12/2014	10	0
TOTAL						**73**	

[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-1 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: **0010A – Harris - RTP 230 kV Line**

Project Description
Construct the Harris-RTP 230 kV Line. Develop RTP 230 kV Switching Substation at or near the existing Amberly 230 kV tap on the Cary Regency Park - Durham 230 kV line. Construct 7 miles of new 230 kV line between Amberly 230/23 kV and Green Level 115/23 kV using 6-1590 MCM ACSR and convert Green Level 115 kV Substation to 230/23 kV. Convert the existing Apex US 1 – Green Level 115 kV Feeder (approximately 7 miles) to 230 kV using 6-1590 MCM ACSR and remove the termination at Apex US #1. From the termination point removed at Apex US #1, continue with 4 miles of new 230 kV construction to the Harris 230 kV Switchyard using 6-1590 MCM ACSR.

Status	In-service
Transmission Owner	DEP
Planned In-Service Date	5/23/2014
Estimated Time to Complete	0 year
Estimated Cost	$54 M

Narrative Description of the Need for this Project
This project is needed to serve rapidly growing load in the western Wake County area.

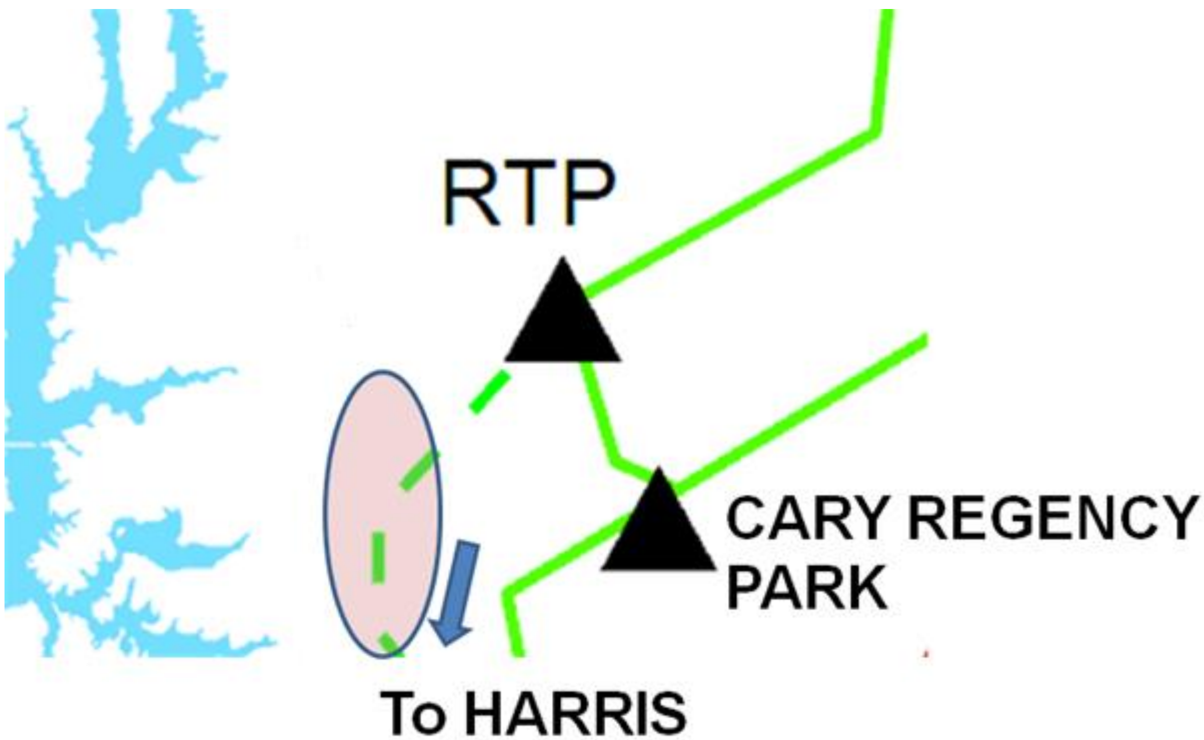
Other Transmission Solutions Considered
Construct Harris - Durham 230 kV line.

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

C-1

Harris - RTP 230 kV Line

- **Load Serving**
- **Problem:** This project is needed to serve rapidly growing load in the western Wake County area.
- **Solution:** Construct the Harris-RTP 230 kV Line.



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	Removed
Transmission Owner	DEP
Planned In-Service Date	
Estimated Time to Complete	
Estimated Cost	

Narrative Description of the Need for this Project
This project was needed to alleviate loading on the Folkstone – Jacksonville City 115 kV Line under the contingency of losing Folkstone – Jacksonville 230 kV Line. New Jacksonville-Piney Green 230 kV Line Project mitigates the loading issue.

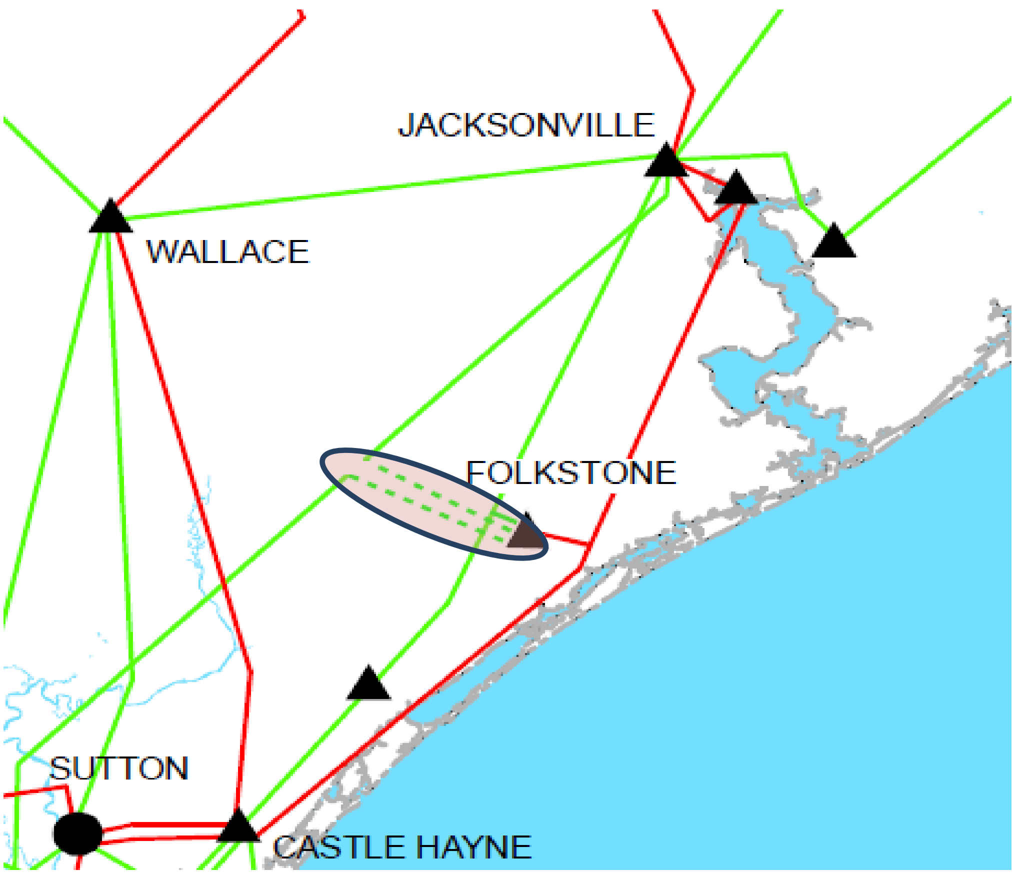
Other Transmission Solutions Considered
Rebuild, reconductor existing line.

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

C-2

Brunswick #1 – Jacksonville 230 kV Line Loop Into Folkstone 230 kV substation - Cancelled

- **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. New Jacksonville-Piney Green 230 kV Line Project mitigates the loading issue.



Project ID and Name: 0008 – Greenville - Kinston DuPont 230 kV Line

Project Description
This project consists of constructing 30 miles of 230 kV line between Greenville and Kinston DuPont 230 kV Substations.

Status	In-service
Transmission Owner	DEP
Planned In-Service Date	5/12/2014
Estimated Time to Complete	0 year
Estimated Cost	$31 M

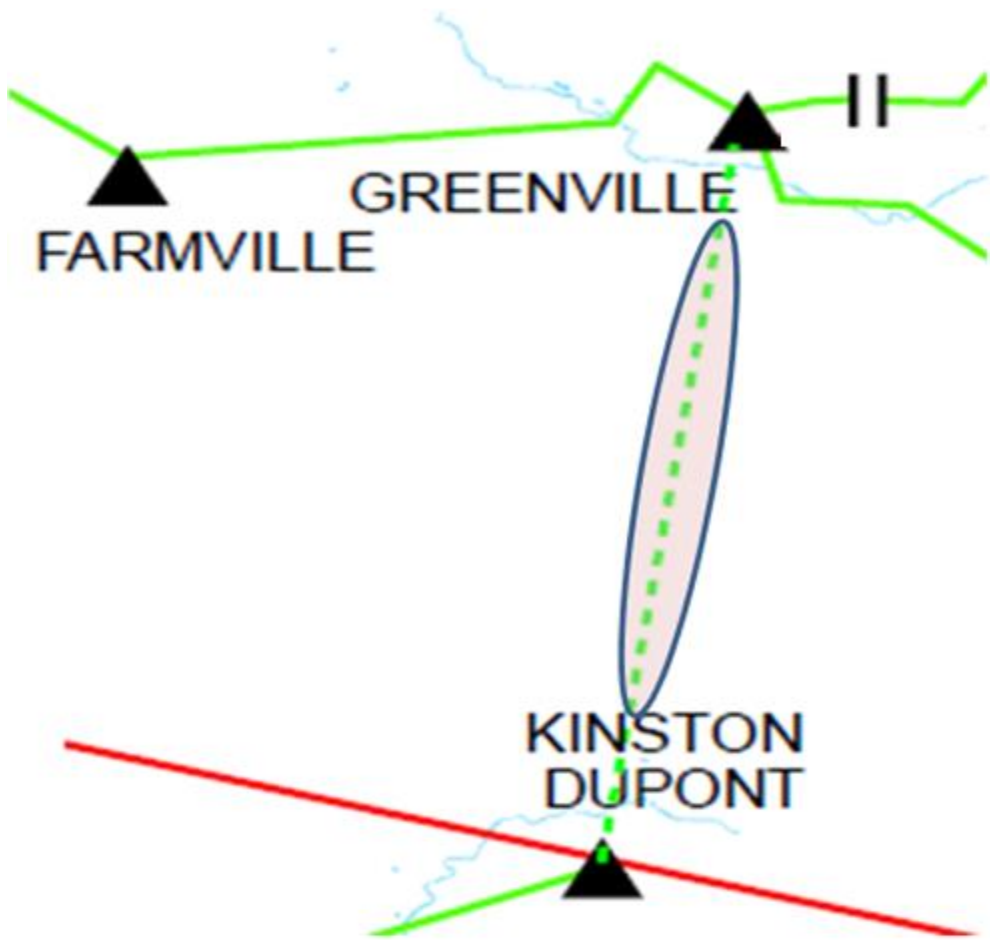
Narrative Description of the Need for this Project
With a Brunswick unit down an outage of the Wilson - Greenville 230 kV line will cause the Greenville - (DVP) Everetts 230 kV line to exceed its rating.

Other Transmission Solutions Considered
Rebuild, reconductor existing line.

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

Greenville - Kinston DuPont 230 kV Line

- **NERC Category C Violations**
- **Problem:** With a Brunswick unit down an outage of the Wilson - Greenville 230 kV line will cause the Greenville - (DVP) Everetts 230 kV line to exceed its rating.
- **Solution:** Construct a 30 mile 230 kV line between Greenville and Kinston DuPont 230 kV Substations.
- **Note:** 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.



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	4 years
Estimated Cost	$13 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.

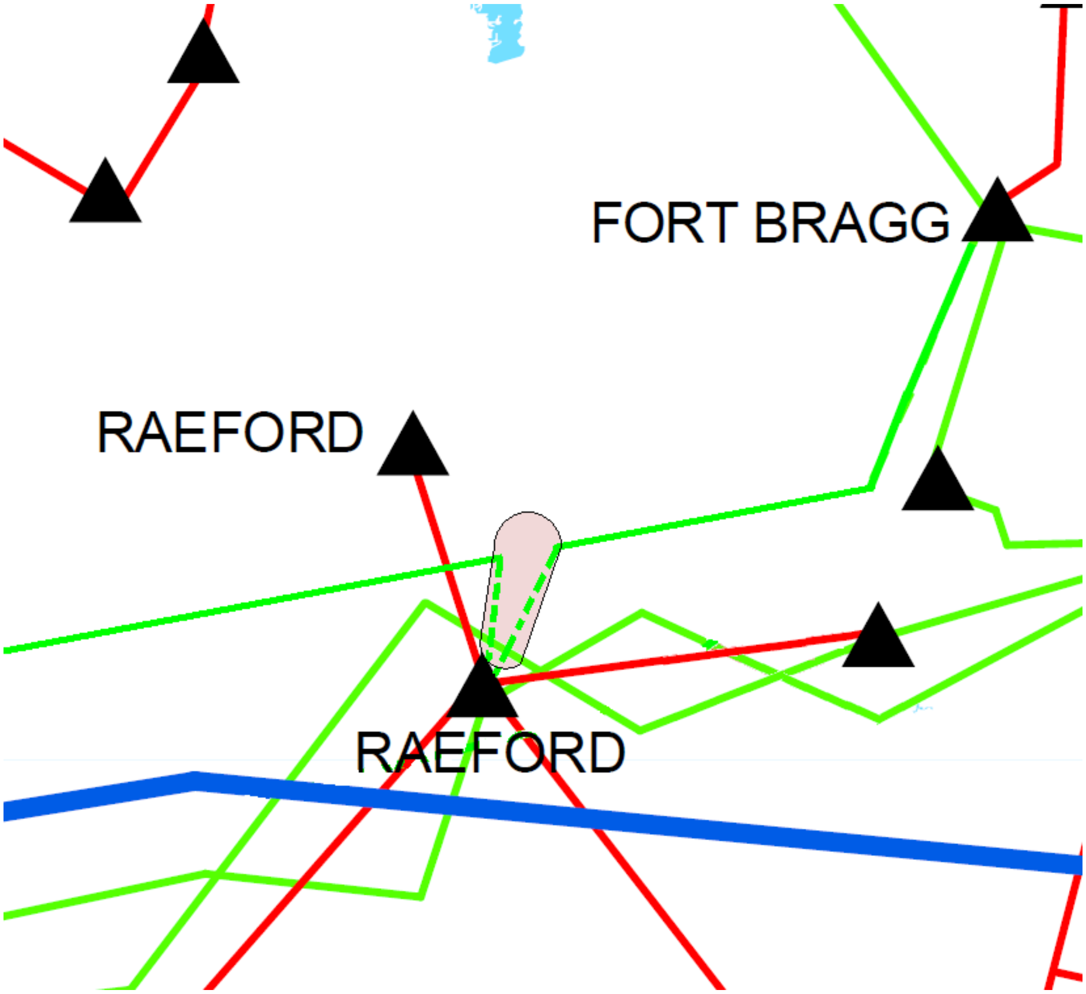
Other Transmission Solutions Considered
Construct Arabia 230kV Substation.

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

C-4

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**.**


FORT BRAGG
RAEFORD
RAEFORD

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	6/1/2023
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.

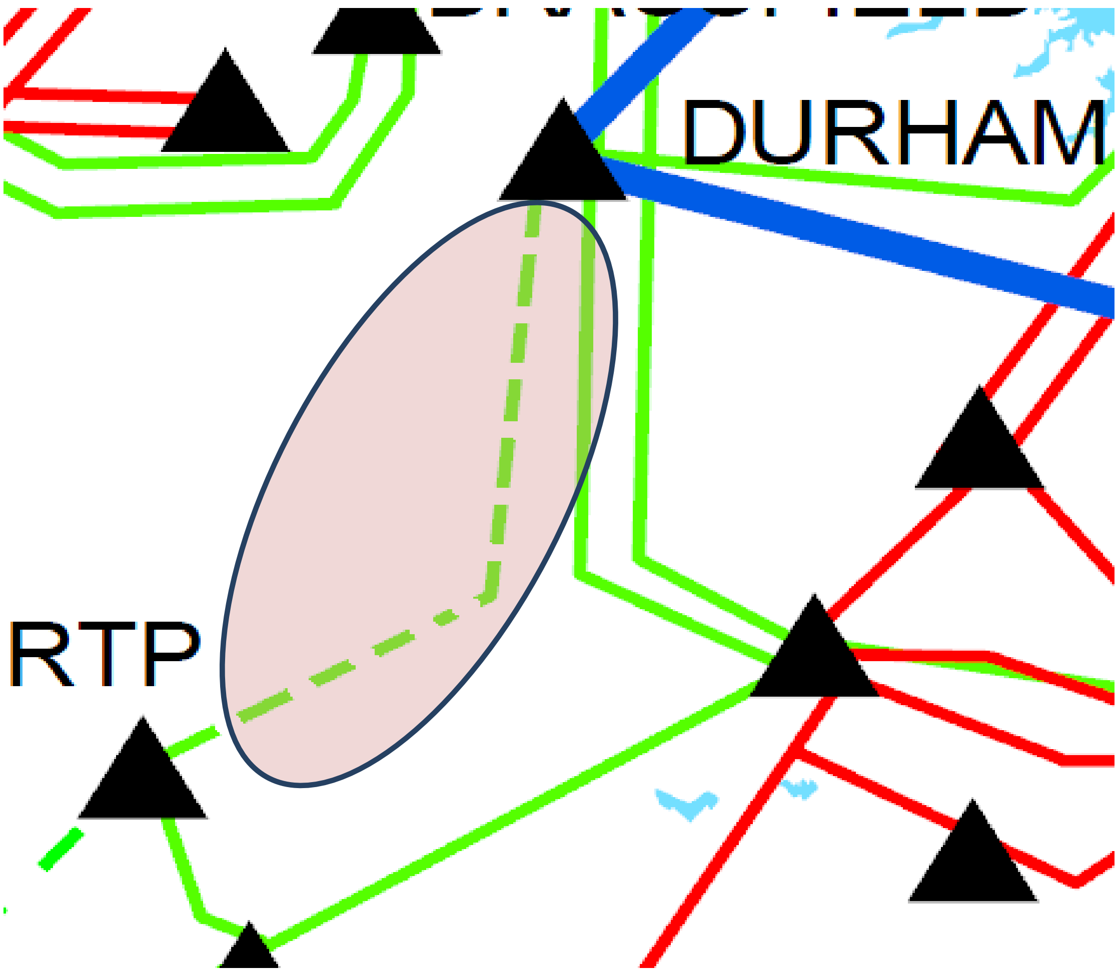
Other Transmission Solutions Considered
Construct a new line between Durham and RTP 230 kV Subs.

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

C-5

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: 0027 – Pisgah Tie - Shiloh Switching Station #1 & #2 230 kV Lines

Project Description
The project consists of reconductoring 22 miles of the existing 954 ACSR conductor with 1158 ACSS conductor.

Status	In-service
Transmission Owner	DEC
Planned In-Service Date	12/3/2013
Estimated Time to Complete	0 years
Estimated Cost	$27 M

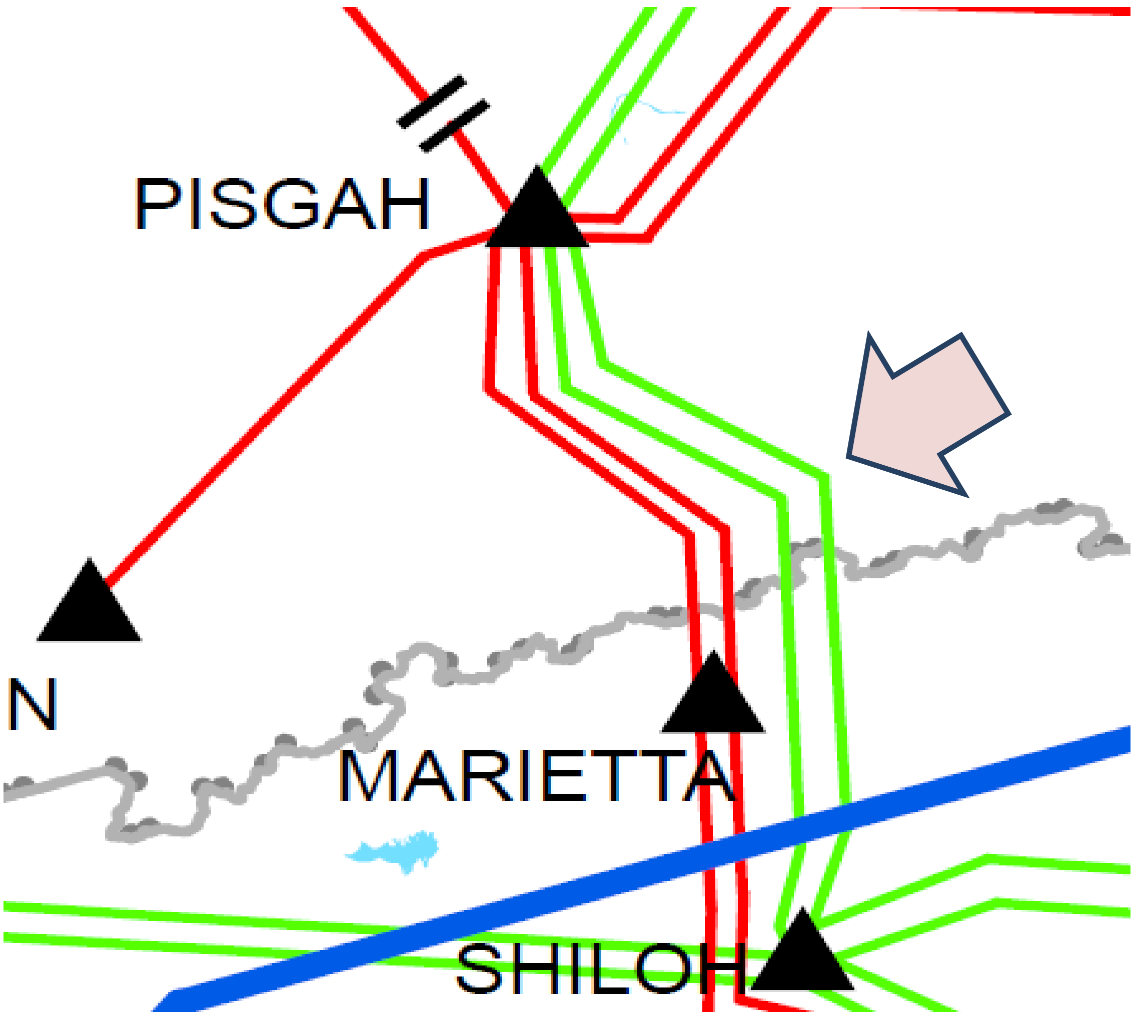
Narrative Description of the Need for this Project
The Caesar Lines would have achieved 100% of their conductor rating in the 2010 timeframe unless restrictions were made on transmission service to DEP West. The lines are most heavily loaded when there is high import into the DEP West area. For that reason, some transmission service on the DEC - DEP(CPLW) interface will have conditional firm status until the upgrades are completed.

Other Transmission Solutions Considered
Bundle the line. An additional tie line from DEC to DEP(CPLW)

Why this Project was Selected as the Preferred Solution
The high temperature conductor option has the lowest overall cost while meeting reliability requirements.

Pisgah Tie - Shiloh Switching Station #1 & #2 230 kV Lines

- **NERC Category B violation**
- **Problem:** The loss of one of the parallel 230 kV lines (Caesar) between Pisgah and Shiloh stations in NC/SC causes the thermal rating of the parallel line to be exceeded.
- **Solution:** Reconductor the 230 kV lines with 1158 ACSS.



Project ID and Name: 0031 – Jacksonville-Piney Green 230 kV Line and Piney Green 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 Harmon 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-Harmon 230 kV Line and Harmon-Havelock 230 kV Line. The new 230 kV Harmon 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	6 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.

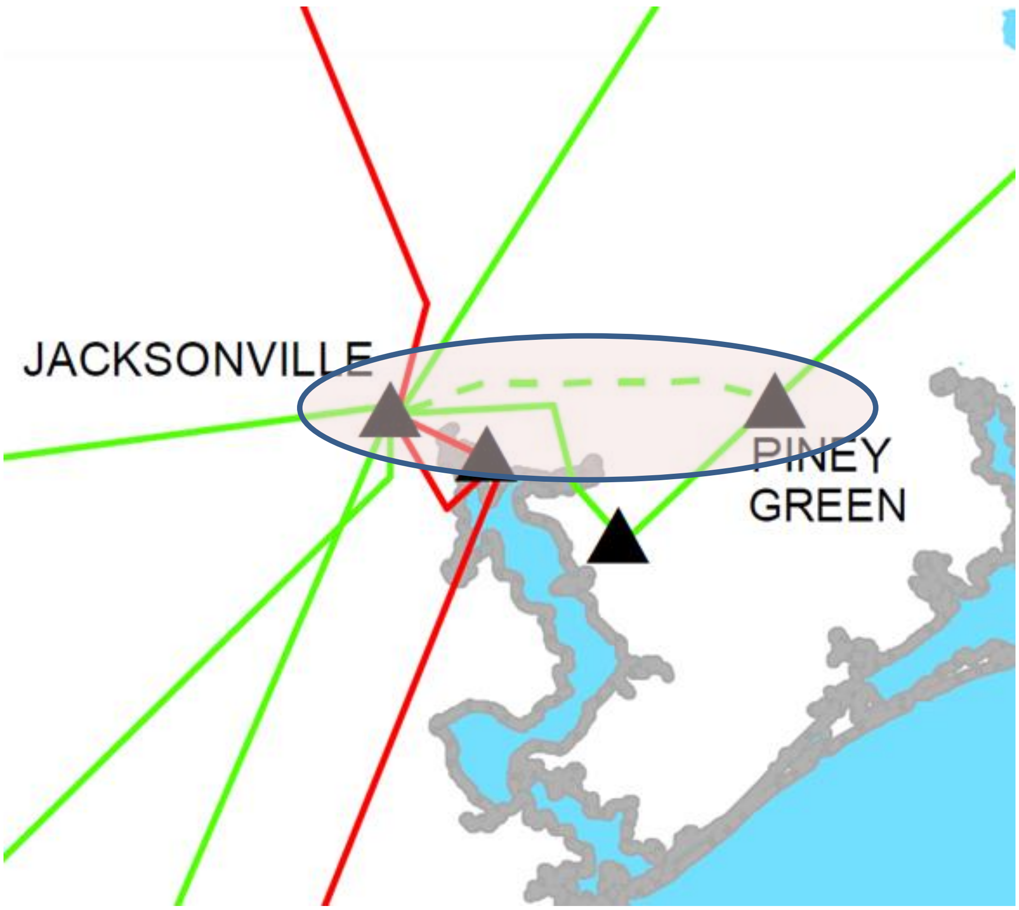
Other Transmission Solutions Considered
Construct alternate 230 kV lines.

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

C-7

Jacksonville-Piney Green 230 kV Line and Piney Green 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	6 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.

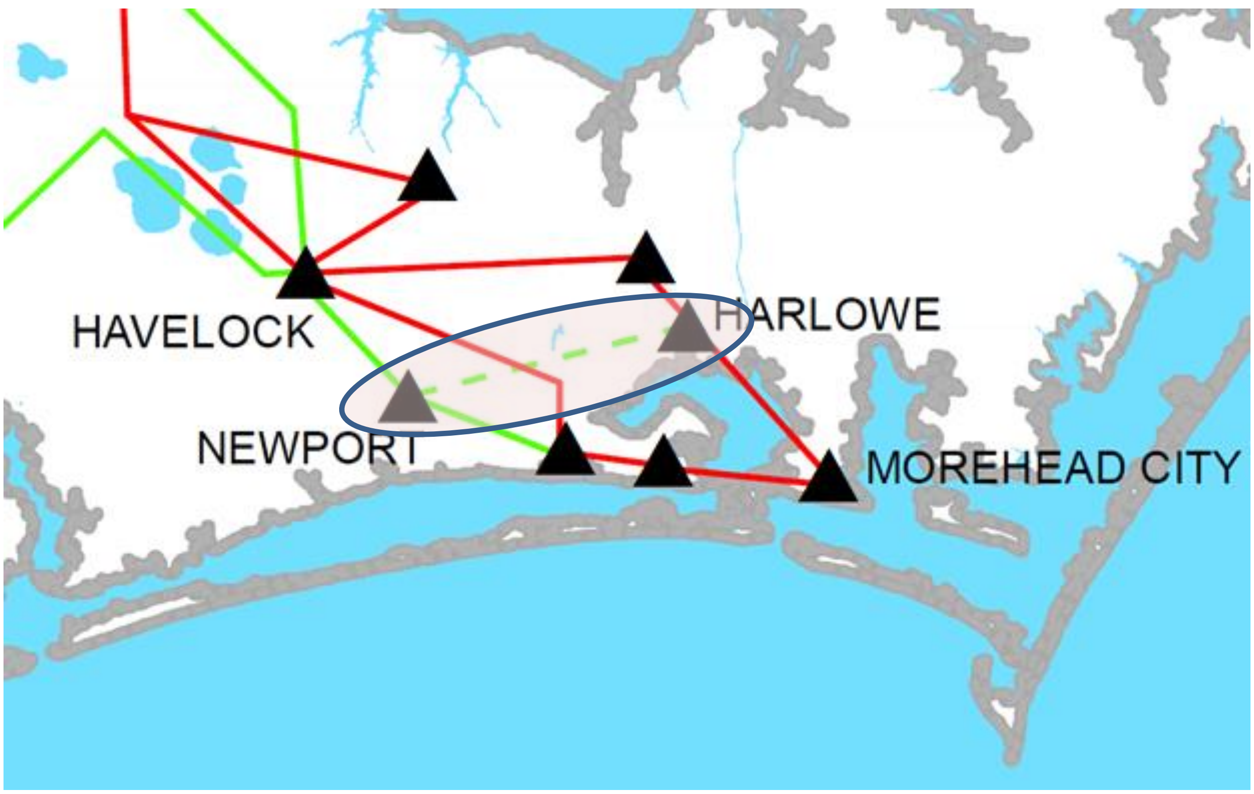
Other Transmission Solutions Considered
Convert 115 kV line to 230 kV.

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

C-8

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.



Appendix C-2
Collaborative Transmission Plan Major Project Descriptions - **Merger Projects**

Table of Contents

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 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: M-0001 - Lilesville-Rockingham 230 kV Line #3 Construct

Project Description
Construct approximately 14 miles of 1-2515 between Rockingham 230 kV Substation and Lilesville 230 kV Substation.

Status	In-Service
Transmission Owner	DEP
Planned In-Service Date	12/22/2013
Estimated Time to Complete	0 years
Estimated Cost	$14 M

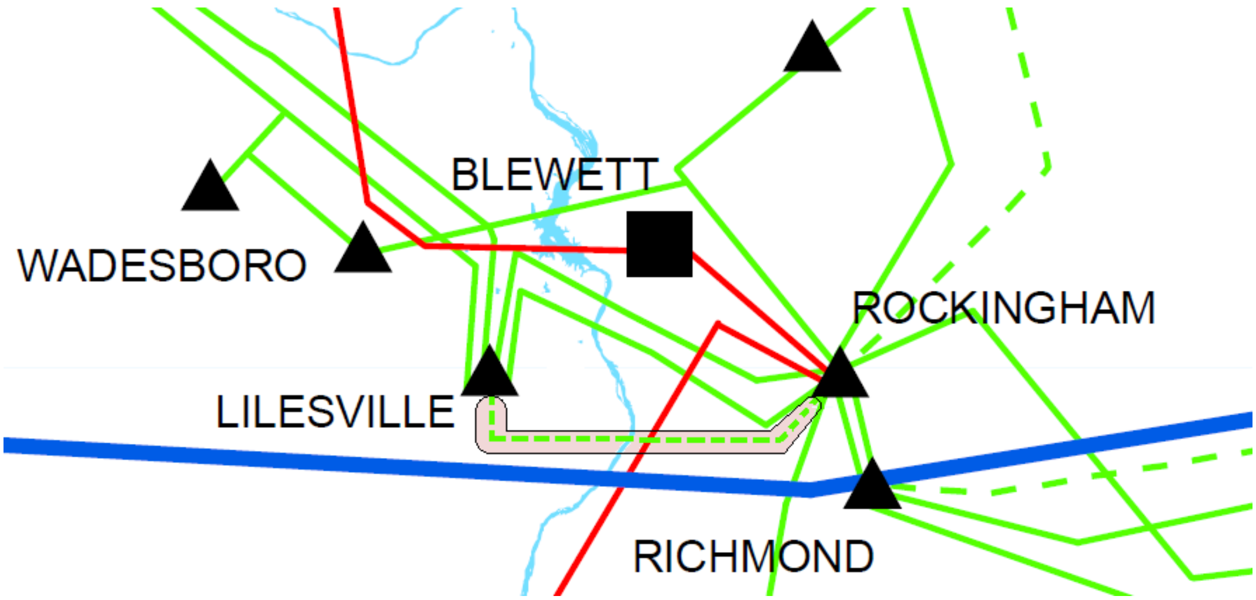
Narrative Description of the Need for this Project
This project is part of the DEC - DEP merger mitigation projects.

Other Transmission Solutions Considered

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

Lilesville-Rockingham 230 kV Line #3 Construct

- **Project Description:** Construct approximately 14 miles of 1-2515 between Rockingham 230 kV Substation and Lilesville 230 kV Substation.



Project ID and Name: M-0002 - Person-(DVP) Halifax 230 kV Line Reconductor DVP Section (DVP work)

Project Description
Reconductor approximately 20 miles of 230 kV Line – Dominion portion.

Status	In-Service
Transmission Owner	Dominion
Planned In-Service Date	4/30/2014
Estimated Time to Complete	0 year
Estimated Cost	$19 M

Narrative Description of the Need for this Project
This project is part of the DEC - DEP merger mitigation projects.

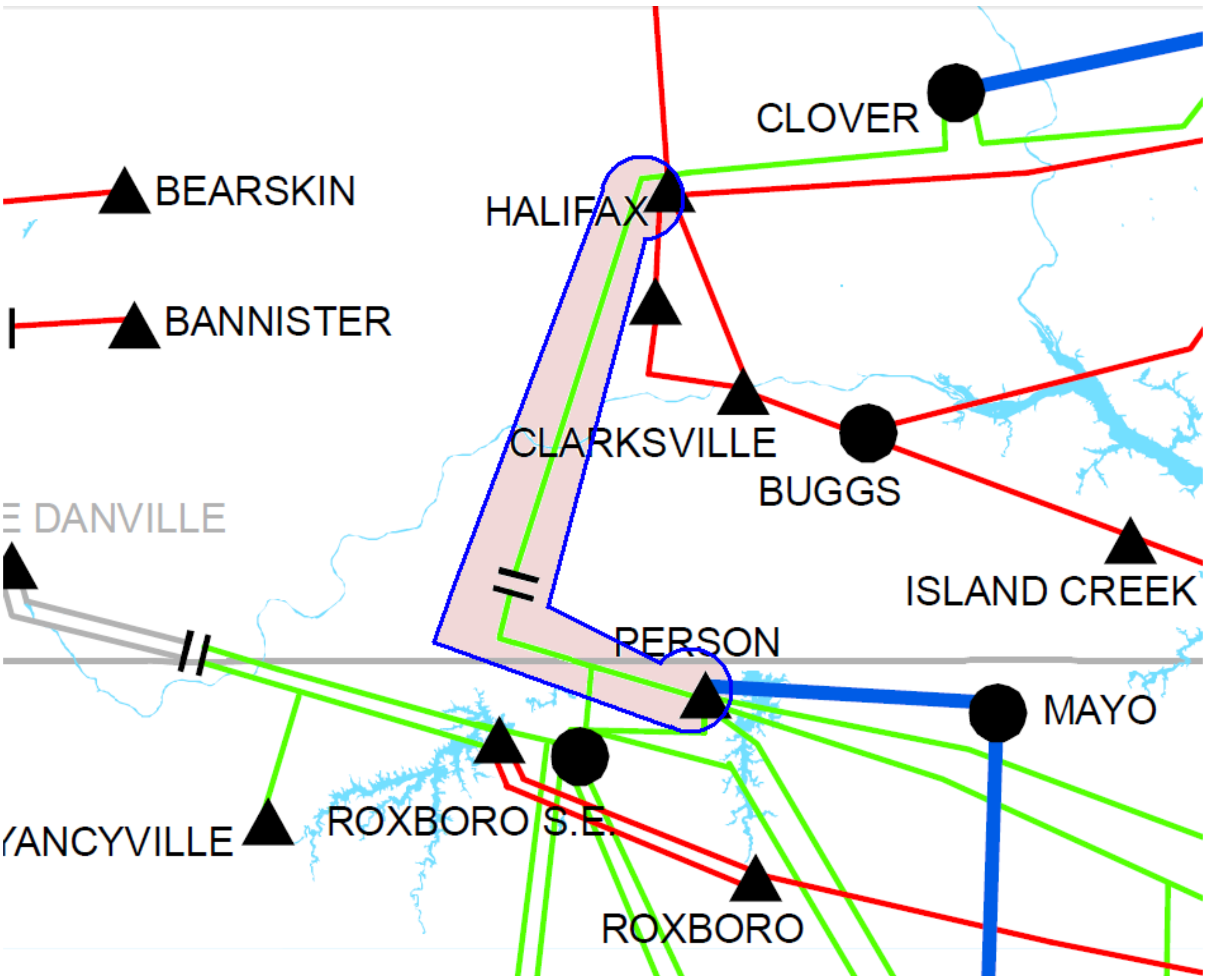
Other Transmission Solutions Considered

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

C-10

Person-(DVP) Halifax 230 kV Line Reconductor DVP Section (DVP work)

- **Project Description:** Reconductor approximately 20 miles of 230 kV Line – Dominion portion.



Project ID and Name: M-0003 - Antioch 500/230 kV Substation: Replace Two Transformer Banks

Project Description
Replace two transformer banks at the Antioch 500/230 kV Substation

Status	In-Service
Transmission Owner	DEC
Planned In-Service Date	5/1/2014
Estimated Time to Complete	0 year
Estimated Cost	$30 M

Narrative Description of the Need for this Project
This project is part of the DEC - DEP merger mitigation projects

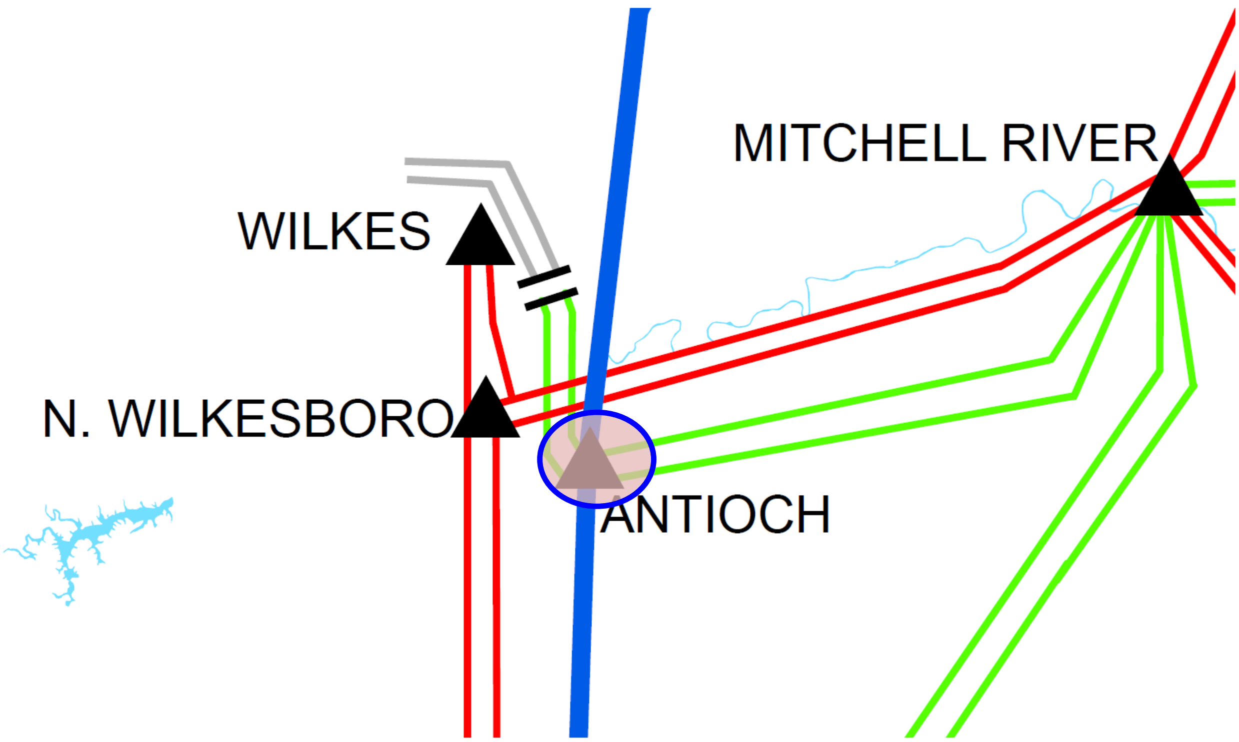
Other Transmission Solutions Considered

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

C-11

Antioch 500/230 kV Substation: Replace Two Transformer Banks

- **Project Description:** Replace two transformer banks at the Antioch 500/230 kV Substation.



Project ID and Name: M-0004 - Kinston Dupont-Wommack 230 kV Line - Reconductor

Project Description
At Kinston Dupont 230 kV substation, reconfigure the existing bus to a three-breaker ring scheme by adding three new 230 kV breakers. Reconductor approximately 20 miles of 230 kV transmission line with bundled 795 ACSS between the Wommack and Kinston DuPont 230 kV substations.

Status	In-Service
Transmission Owner	DEP
Planned In-Service Date	5/12/2014
Estimated Time to Complete	0 years
Estimated Cost	$10 M

Narrative Description of the Need for this Project
This project is part of the DEC - DEP merger mitigation projects.

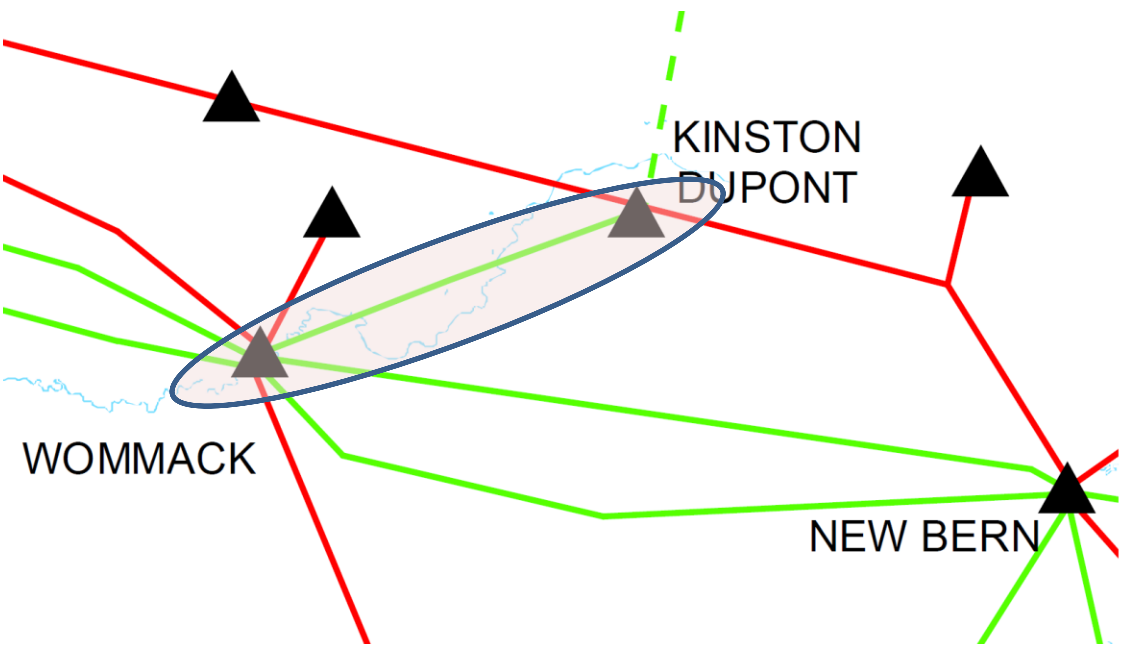
Other Transmission Solutions Considered

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

C-12

Kinston Dupont-Wommack 230 kV Line - Reconductor

- **Project Description:** Reconductor approximately 20 miles of 230 kV transmission line with bundled 795 ACSS between the Wommack and Kinston DuPont 230 kV substations.



Appendix D
Local Economic Study

From	To	Transfer Level
TVA_ EXPORT	DEP_WEST_IMPORT	250.0

AC FCITC	Limiting Constraint	Contingency	PreShift	Rating	AC TDF
58.0	L:306190 PISGAH 100 308711 BLANTYRERET 100 2		131.0	138.0	0.12088
	Rugby 100 kV - White	C:ASHVL-PISGAH230_CKTS_1& 2			
		Open 304803 6ASHVLE230 T 230 306108 6PISGAH 230 1			
		Open 304803 6ASHVLE230 T 230 306108 6PISGAH 230 2			
127.3	L:304750 3PISGAH 115 305196 3E8-CRADLE 115 1		181.4	200.0	0.14609
	Canton - Pisgah - 115	C:ASHVL-PISGAH230_CKTS_1& 2			
		Open 304803 6ASHVLE230 T 230 306108 6PISGAH 230 1			
		Open 304803 6ASHVLE230 T 230 306108 6PISGAH 230 2			
174.5	L:304750 3PISGAH 115 306190 PISGAH 100 2		91.6	104.0	0.06867
	Pisgah 115/100 Transformer 2	C:ASHVL-PISGAH230_CKTS_1& 2			
		Open 304803 6ASHVLE230 T 230 306108 6PISGAH 230 1			
		Open 304803 6ASHVLE230 T 230 306108 6PISGAH 230 2			
197.7	L:304750 3PISGAH 115 306190 PISGAH 100 1		113.5	138.0	0.12308
	Pisgah 115/100 Transformer 1	C:ASHVL-PISGAH230_CKTS_1& 2			
		Open 304803 6ASHVLE230 T 230 306108 6PISGAH 230 1			
		Open 304803 6ASHVLE230 T 230 306108 6PISGAH 230 2			
216.6	L:306164 HORSESHO 100 306190 PISGAH 100 1		89.1	104.0	0.06635
	Rugby 100 kV - Black	C:ASHVL-PISGAH230_CKTS_1& 2			
		Open 304803 6ASHVLE230 T 230 306108 6PISGAH 230 1			
		Open 304803 6ASHVLE230 T 230 306108 6PISGAH 230 2			

Appendix E
Collaborative Plan Comparisons

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2013 Plan[1]			2014 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0026	Brunswick 1 - Castle Hayne 230 kV Line, Construct New Cape Fear River Crossing	Address loading on the Sutton Plant - Castle Hayne 230 kV Line.	DEP	In-Service	3/3/2013	27	-	-	-
0022	Jacksonville Static VAR Compensator	Address inadequate dynamic voltage recovery after system faults during periods of high transfers	DEP	In-Service	5/14/2013	31	-	-	-
0023	Folkstone 230/115 kV Substation	Address voltage on Castle Hayne - Jacksonville City 115 kV Line	DEP	In-Service	12/1/2012	19	-	-	-
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	Underway	6/1/2014	49	In-Service	5/23/2014	54

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2013 Plan[1]			2014 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0028	Brunswick #1 – Jacksonville 230 kV Line Loop-In to Folkstone 230 kV Substation	Address loading on Folkstone – Jacksonville City 115 kV Line.	DEP	Planned	6/1/2020	11	Removed	-	-
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	Underway	6/1/2014	32	In-Service	5/12/2014	31
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	13
0024	Durham - RTP 230 kV Line, Reconductor	Address loading on the Durham-RTP 230 kV Line	DEP	Planned	6/1/2023	15	Planned	6/1/2023	15

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2013 Plan[1]			2014 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
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	Underway	12/31/2013	26	In-Service	12/3/2013	27
0031	Jacksonville-Piney Green 230 kV Line and Piney Green 230/115 kV Substation	Mitigate loading and voltage issues on existing Havelock-Jacksonville 230 kV Line	DEP	-	-	-	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
TOTAL						**223**			**209**

NCTPC Update on Merger Projects – (Estimated Cost ≥ $10M)									
				2013 Plan[1]			2014 Plan		
Project ID	**Merger Project**	**Issue Resolved**	**Transmission Owner**	**Status[1]**	**Projected In-Service Date**	**Estimated Cost ($M)[2]**	**Status[2]**	**Projected In-Service Date**	**Estimated Cost ($M)[3]**
M-0001	Lilesville-Rockingham 230KV Line #3 – Construct new line	This project is part of the DEC - DEP merger mitigation projects.	DEP	Underway	12/31/2013	14	In-Service	12221/2013	14
M-0002	Person-(DVP) Halifax 230kV Line - Reconductor DVP Section (DVP work)	This project is part of the DEC - DEP merger mitigation projects.	DEP/ Dominion	Underway	6/1/2014	21	In-Service	4/30/2014	19
M-0003	Antioch 500/230kV Substation: Replace Two Transformer Banks	This project is part of the DEC - DEP merger mitigation projects.	DEC	Underway	6/1/2014	32	In-Service	5/1/2014	30
M-0004	Kinston Dupont-Wommack 230 kV Line - Reconductor	This project is part of the Duke/Progress merger mitigation projects.	DEP	-	-	-	In-Service	5/12/2014	10
TOTAL						**67**			**73**

[1] Information reported in Appendix B-1 and B-2 of the NCTPC 2013 - 2023 Collaborative Transmission Plan" dated December 31, 2013.

[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 2012 Report and have been deferred beyond the end of the planning horizon based on analysis performed to develop the 2014 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
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
TTC	Total Transfer Capability
TVA	Tennessee Valley Authority
VACAR	Virginia-Carolinas Reliability Agreement
VAR	Volt Ampere Reactive