North Carolina Transmission Planning Collaborative

Report on the NCTPC 2012-2022 Collaborative Transmission Plan

January 17, 2013
FINAL

2012 – 2022 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, Progress Energy Carolinas, Inc., 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 Participants in the State of North Carolina;

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 control areas of Duke Energy Carolinas ("Duke or DEC") and Progress Energy Carolinas, Inc. ("Progress or PEC"); and

4) develop a single coordinated transmission plan for the Participants in North Carolina that includes reliability and enhanced transmission access 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 Enhanced Transmission Access Planning ("ETAP") 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 2011-2021 Collaborative Transmission Plan (the "2011 Collaborative Transmission Plan" or the "2011 Plan") was published in January 2012.

This report documents the current 2012 – 2022 Collaborative Transmission Plan ("2012 Plan") for the Participants in North Carolina. The initial sections of this report provide an overview of the NCTPC Process as well as the specifics of the 2012 reliability planning study scope and methodology. The NCTPC Process document and 2012 NCTPC study scope document are posted in their entirety on the NCTPC website at http://www.nctpc.net/nctpc/home.jsp.

The scope of the 2012 Reliability Planning Process included a base reliability study and an analysis of resource supply options. The base reliability study assessed the reliability of the transmission systems of both Duke and Progress in order to ensure reliability of service in accordance with North American Electric Reliability Corporation ("NERC"), SERC Reliability Corporation ("SERC"), and Duke and Progress requirements. The study was done with the assumption of business as usual except that DEC-PEC 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 2017 through 2022 with the Participants' planned Designated Network Resources ("DNRs"). The 2012 Study allowed for identification of any new system impacts not currently addressed by existing transmission plans, in which case solutions were developed. The 2012 Study also allowed for adjustments to existing plans where necessary.

While the overall NCTPC Process (Figure 1 in Section II) includes both a Reliability Planning Process and an Enhanced Transmission Access Planning Process, the 2012 NCTPC Process focused exclusively on the Reliability Planning Process, because stakeholders did not request any Enhanced Transmission Access scenarios for the 2012 Study.

The NCTPC reliability study results affirmed that the planned Duke and Progress transmission projects identified in the 2011 Plan continue to satisfactorily address the reliability concerns identified in the 2012 Study for the near-term (5 year) and the long-term (10 year) planning horizons. The 2012 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 2012 Report, projects in Appendix B have been divided into Reliability Projects (B-1) and Merger Projects (B-2). Projects in the 2012 Plan are those projects identified in the base reliability study (B-1) and those projects that DEC and PEC have committed to construct as a result of the DEC-PEC Merger (B-2). 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. Appendix C provides a more detailed description of each project in the 2012 Plan. Appendix C has also been divided into Reliability Projects (C-1) and Merger Projects (C-2).

The total estimated cost for the 11 projects included in the 2012 Plan for reliability is $318 million as documented in Appendix B-1. This compares to the 2011 Plan estimate of $296 million for 11 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 F for a detailed comparison of this year's Plan to the 2011 Plan.

As a Merger commitment, DEC and PEC agreed to construct a total of 9 projects with a cost of approximately $116 million. Of these 9 projects, four have cost estimates greater than $10 million and are documented in Appendix B. One of these four 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-PEC 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 three merger projects are listed in Appendix B-2.

The modified projects for Progress and Duke in the 2012 Collaborative Transmission Plan, relative to the 2011 Plan, include one Progress project that was placed in service. The project placed in service is:

- Asheville – Enka 115 kV Line – Construct new line

There are revised in-service dates and scope changes for the following previously identified projects:

- Greenville-Kinston Dupont 230 kV Line - Project required for the DEC-PEC Merger. In-service date moved up to June 2014.
- Brunswick #1 – Jacksonville 230 kV Line Loop-in to Folkstone Substation – In-service date delayed to June 2020 due to updated Folkstone substation

location and line impedance information.

- Raeford 230 kV Substation – Replaced Arabia project and moved up in-service date to June 2018. This alternative solves multiple loading issues.
- Reconductor Caesar 230 kV Line – The in-service date has been delayed 6 months to 12/1/2012 due to resources being required for higher priority work. Reconductor project was required to meet winter period load requirements, therefore delay has no reliability impact.

In addition, two new Progress projects and one new Duke project were added to the 2012 Plan as Merger commitments. These new projects are:

- Lilesville-Rockingham 230KV Line #3 – Construct new line
- Person-(DVP) Halifax 230kV Line – Reconductor DVP Section (DVP work)
- Antioch 500/230kV Substation – Replace Two Transformer Banks

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.

The Resource Supply Options for the 2012 NCTPC Study consisted of two different types of scenarios to examine the transmission system impacts of hypothetical transfers and a hypothetical generation resource. The first resource supply option examined injecting 500 MW of power into the transmission system from a hypothetical generation resource in Davidson County, NC, located within the Duke footprint near the Duke Energy Buck Plant. The second option examined the impact of three different Wind Generation Scenarios as part of the joint NCTPC – PJM inter-regional study.

For the 2012 NCTPC resource supply option 1, Year 2022 summer cases were developed to evaluate a hypothetical 500 MW generator located in Davidson County sinking on the Duke system. This analysis identified two additional projects in Duke beyond those in the 2012 Plan. The scenario required upgrading the 100 kV buslines between Buck Steam Station and Buck Tie. The studies also showed the need for additional 230/100 kV transformer capacity at Buck Tie. The total estimated cost of all these upgrades was $18.2 M. The specific facility additions for this hypothetical generation scenario are summarized in Appendix D.

For the 2012 NCTPC resource supply option 2, Year 2027 summer cases were developed for the Wind Generation Scenarios located off the North Carolina / Virginia coast as part of the joint NCTPC – PJM inter-regional study analysis. The joint study consisted of a reliability analysis of the PJM Interconnection and North Carolina Transmission Planning Collaborative (NCTPC) footprint to assess the interaction of hypothetical off-shore wind injections into the transmission systems of PJM and PEC. The goals of the analysis were to identify potential thermal constraints to wind penetration and to propose network reinforcements to mitigate identified constraints. The study evaluated wind penetration at three off-shore injection points: Dominion's Landstown 230 kV Substation, PEC's Morehead City area and PEC's Southport area. In the PEC areas, wind generation was connected to the system via 500 kV lines. Three different scenarios were evaluated with varying levels of wind penetration and varying levels of power transfer between the PJM, DEC and PEC systems.

Off-peak load study conditions were chosen to coincide with the ideal conditions for wind resource output. Wind resources typically experience higher production during off-peak or overnight hours when weather conditions are typically windier than during on-peak periods. The load level of each study area was set to 60% of 2027 summer forecasted peak levels, and generation, other than the new wind generation, was economically dispatched to satisfy the load and interchange requirements. The new wind generation was modeled according to each scenario's assumed level of wind injection. Other than the interchange associated with sinking offshore wind resources, the interchange between study participants was established in accordance with long-term firm transmission service requests.

The following tables summarize the wind injection amounts and respective sink area amounts for the three scenarios.

Table 1
Summary of Scenario 1 Wind Injection and Area Transfers

Scenario 1 – Wind Generation	PJM – Load Sink	DEC – Load Sink	PEC – Load Sink
PJM – 1,000 MW injection at Landstown	0 MW 0%	600 MW 60%	400 MW 40%
NCTPC – 1,000 MW injection at Morehead City	0 MW 0%	600 MW 60%	400 MW 40%
NCTPC –1,000 MW injection at Southport	0 MW 0%	600 MW 60%	400 MW 40%
Total	0 MW	1,800 MW	1,200 MW

Table 2
Summary of Scenario 2 Wind Injection and Area Transfers

Scenario 2 – Wind Generation	PJM – Load Sink	DEC – Load Sink	PEC – Load Sink
PJM – 2,000 MW injection at Landstown	2,000 MW 100%	0 MW 0%	0 MW 0%
NCTPC – 1,500 MW injection at Morehead City	0 MW 0%	900 MW 60%	600 MW 40%
NCTPC –1,500 MW injection at Southport	0 MW 0%	900 MW 60%	600 MW 40%
Total	2,000 MW	1,800 MW	1,200 MW

Table 3
Summary of Scenario 3 Wind Injection and Area Transfers

Scenario 3 – Wind Generation	PJM – Load Sink	DEC – Load Sink	PEC – Load Sink
PJM – 4,500 MW injection at Landstown	4,500 MW 100%	0 MW 0%	0 MW 0%
NCTPC – 3,500 MW injection at Morehead City	955 MW 27.3%	1,527 MW 43.6%	1,018 MW 29.1%
NCTPC – 2,000 MW injection at Southport	545 MW 27.3%	873 MW 43.6%	582 MW 29.1%
Total	6,000 MW	2,400 MW	1,600 MW

At the point in time of this NCTPC report, the Joint NCTPC-PJM Inter-Regional Study is still in progress. The required upgrades and cost estimates for the PEC transmission system are provided in Appendix E. The total PEC transmission system cost estimate for Scenario #1 is $932 million, for Scenario #2 is $1,214 million, and for Scenario #3 is $1,736 million. The DEC transmission system does not have any projects with an estimated cost greater than $10 million under any of the three Wind Generation Scenarios. Upgrades and cost estimates for the PJM system are still being evaluated and will be provided in the final Joint NCTPC-PJM Inter-Regional Study report.

In this 2012 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, Progress Energy Carolinas, Inc., 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 Participants in the State of North Carolina;

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 control areas of Duke and Progress; and

4) develop a single coordinated transmission plan for the Participants in North Carolina that includes reliability and enhanced transmission access 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 Enhanced Transmission Access Planning ("ETAP") 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 Second Revised Participation Agreement dated January 12, 2010 which is posted at http://www.nctpc.net/nctpc/home.jsp. Figure 1 illustrates the major steps associated with the NCTPC Process.

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 in Figure 1. 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 studies and the resource supply option studies 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. Enhanced Transmission Access Planning Process

The ETAP Process is the economic planning process that allows the TAG participants to propose economic hypothetical transfers to be studied as part of the transmission planning process. The ETAP Process provides the means to evaluate the impact of potential supply resources inside and outside the Control Areas of the Transmission Providers. This economic analysis provides the opportunity to study what transmission upgrades would be required to reliably integrate new resources. In addition, this economic analysis would include, if requested, the evaluation of Regional Economic Transmission Paths (RETPs) that would facilitate potential regional point-to-point economic transactions. The ETAP Process follows the steps outlined in Figure 1. The OSC approves the scope of the ETAP study (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 ETAP study results.

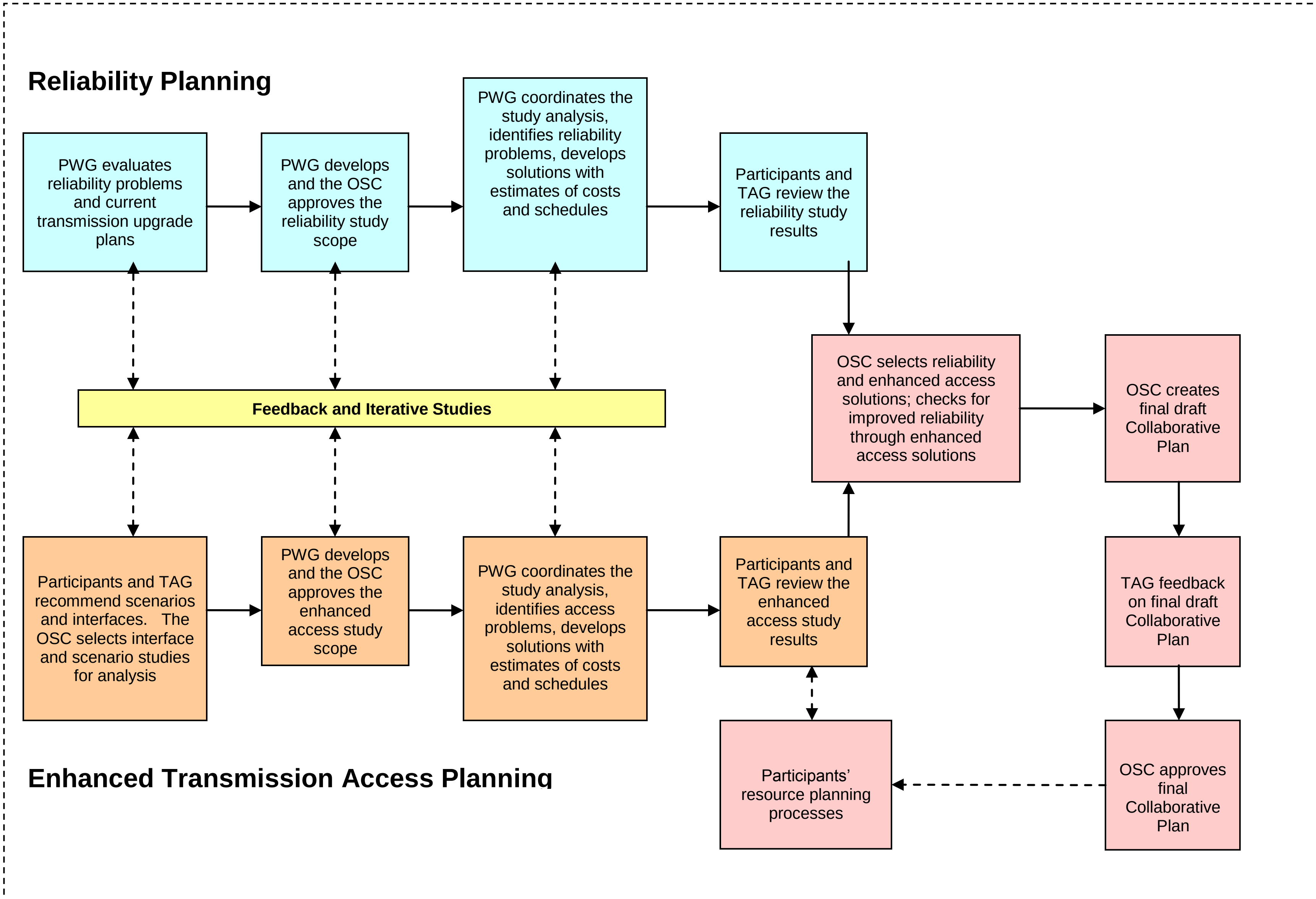
The ETAP Process begins with the Participants and TAG members proposing scenarios and interfaces to be studied. The proposed scenarios and interfaces are compiled by the PWG and then evaluated by the OSC to determine which ones will be included for analysis in the current planning cycle. The PWG coordinates the development of the enhanced transmission access 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 ETAP Process include the estimated costs and schedules to provide the increased transmission capabilities. The enhanced transmission access 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 (Figure 1 below) includes both a Reliability Planning Process and an Enhanced Transmission Access Planning Process, the 2012 NCTPC Process focused exclusively on the Reliability Planning Process because stakeholders did not request any Enhanced Transmission Access scenarios for the 2012 Study. Enhanced Transmission Access scenarios will again be solicited for the 2013 Study and included if appropriate.

Figure 1

2012 NCTPC Process Flow Chart



II.D. *Collaborative Transmission Plan*

Once the reliability and ETAP studies are completed, the OSC evaluates the results and the PWG recommendations to determine if any proposed enhanced transmission access 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. 2012 Reliability Planning Study Scope and Methodology

The 2012 Reliability Planning Process included a base reliability study and an analysis of resource supply options. The base reliability study assessed the reliability of the transmission systems of both Duke and Progress in order to ensure reliability of service in accordance with North American Electric Reliability Corporation ("NERC"), SERC Reliability Corporation ("SERC"), and Duke and Progress requirements. The study was done with the DEC – PEC 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 2017 through 2022 with the Participants' planned Designated Network Resources ("DNRs"). The 2012 Study allowed for identification of any new system impacts not currently addressed by existing transmission plans in which case solutions were developed. The 2012 Study also allowed for adjustments to existing plans where necessary.

The resource supply options for the 2012 NCTPC Study consisted of two scenarios to examine the transmission system impacts of hypothetical transfers and a hypothetical generation resource. The first scenario examined injecting 500 MW of power into the transmission system from a hypothetical 500 MW generation resource in Davidson County, NC, located within the Duke footprint near the Duke Energy Buck Plant. The second resource supply option consisted of three different Wind Generation Scenarios that examined injecting 3,000 – 10,000 MW of renewable wind generation off of the North Carolina and Virginia coasts into the NCTPC and PJM transmission systems as part of a joint study.

III.A. Assumptions

1. Study Year and Planning Horizon

The 2012 Collaborative Transmission Plan addressed a ten-year planning horizon through 2022. The study year for the joint NCTPC – PJM Wind Scenarios was 2027 summer. The study years chosen for the 2012 Study are listed in Table 4.

Table 4
Study Years

Study Year / Season	Analysis
2017 Summer	Near-term base reliability
2017/2018 Winter	Near-term base reliability
2022 Summer	Long-term base reliability, and resource supply options
2027 Summer	NCTPC – PJM Wind Scenarios

To identify projects required in years other than the base study years of 2017 and 2022, line loading results for those base study years were extrapolated into future years assuming the line loading growth rates in Table 5. 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 5
Line Loading Growth Rates

Company	Line Loading Growth Rate
Duke	1.7 % per year
Progress	1.6 % per year

2. Network Modeling

The network models developed for the 2012 Study included new transmission facilities and upgrades for the 2017 and 2022 models, as appropriate, from the current transmission plans of Duke and Progress and from the 2011 Collaborative Transmission Plan. Table 6 lists the planned major transmission facility projects (with an estimated cost of $10 million or more each) included in the 2017 and 2022 models. Table 7 lists the generation facility additions and retirements included in the 2017 and 2022 models.

Table 6

Major Transmission Facility Projects Included in Models

Company	Transmission Facility	2017 Base	2022 Base & Sensitivities
Progress	Converted Asheville - Enka 115 kV Line to 230 kV	Yes	Yes
Progress	Asheville - Enka 115 kV Line new line in-service 12/01/2012	Yes	Yes
Progress	Raeford 230 kV Substation, Loop-in Richmond-Ft Bragg WS 230 kV Line	No	No
Progress	Brunswick - Castle Hayne 230 kV River Crossing	Yes	Yes
Progress	Jacksonville 230 kV SVC	Yes	Yes
Progress	Folkstone 230/115 kV	Yes	Yes
Progress	Harris Plant - RTP 230 kV Line	Yes	Yes
Progress	Brunswick#1-Jacksonvl 230 kV Line, Loop-in to Folkstone	No	No
Progress	Greenville - Kinston DuPont 230 kV Line	Yes	Yes
Progress	Durham - RTP 230 kV Line	No	No
Duke	Reconductored Caesar 230 kV Line from Pisgah Tie to Shiloh Switching Station	Yes	Yes
Duke	Reconductored London Creek 230 kV Line from Peach Valley Tie to Riverview Switching Station	Yes	Yes

Table 7

Major Generation Facility Additions and Retirements in Models

Company	Generation Facility	2017	2022
Duke	Retired Buck 5, 6 (256 MW)	Yes	Yes
Duke	Retired Dan River 1-3 (276 MW)	Yes	Yes
Duke	Retired Riverbend 4-7 (454 MW)	Yes	Yes
Duke	Retired Buck CTs (62 MW)	Yes	Yes
Duke	Retired Buzzard Roost CTs (196 MW)	Yes	Yes
Duke	Retired Dan River CTs (48 MW)	Yes	Yes
Duke	Retired Riverbend CTs (64 MW)	Yes	Yes
Duke	Added Cleveland Co. CTs (716 MW)	Yes	Yes
Duke	Added Cliffside Unit 6 (825 MW)	Yes	Yes
Duke	Added Dan River CC (650 MW)	Yes	Yes
Progress	Retired Lee Units 1-3 (417 MW)	Yes	Yes
Progress	Retired Sutton Units 1-3 (616 MW)	Yes	Yes
Progress	Retired Cape Fear Units 5&6 (323 MW)	Yes	Yes
Progress	Retired Weatherspoon Units 1-3 (177 MW)	Yes	Yes
Progress	Added Richmond Co. CC (650 MW)	Yes	Yes
Progress	Added Wayne Co. CC (920 MW)	Yes	Yes
Progress	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 Duke and Progress control 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 Duke and Progress control areas. Interchange tables for the summer and winter base cases, the Progress Transmission Reliability Margin ("TRM") cases[1], and the cases for the renewable wind generation as part of the joint NCTPC – PJM inter-regional study analysis, discussed in Section III.D, are in Appendix A.

The offshore wind scenarios required the addition of wind generation to the models as detailed in Section V.B. In the offshore wind scenarios, each Participant's load was scaled to 60% of their 2027 projected summer peak load in order to study imports of 3,000 - 10,000 MW of wind, with power sinking in the NCTPC footprint being allocated 60/40 between Duke and Progress. Interchange was adjusted according to each Participant's resource needs following load scaling and wind allocation.

There was no change in interchange in the hypothetical generation scenario, because the 500 MW Davidson County resource was assumed to be internal to Duke. After forcing on the hypothetical generation at Davidson County, the remaining generation in Duke was economically dispatched in order to meet its load.

III.B. Study Criteria

The results of the base reliability study and the resource supply option study were evaluated using established planning criteria, while recognizing differences between the systems of Duke and Progress. The planning criteria used to evaluate the results include:

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

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

III.C. Case Development

The base case for the base reliability study was developed using the most current 2011 series NERC Multiregional Modeling Working Group (MMWG) model for the systems external to Duke and Progress. The MMWG model of the external systems, in accordance with NERC Multiregional Modeling Working Group ("MMWG") criteria, included modeling known long-term firm transmission reservations. Detailed internal models of the Duke and Progress East/West systems were merged into the base case, including Duke and Progress transmission additions planned to be in service by the period under study. In the base cases, all confirmed long-term firm transmission reservations with roll-over rights were modeled.

III.D. Transmission Reliability Margin

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

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

Progress' reliability planning studies model all confirmed transmission obligations for its control 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. Progress models TRM by scheduling the reserved amount on actual reserved interfaces as posted on the Progress Open Access Same-time Information System ("OASIS").

In the planning horizon, Duke 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 Duke-VACAR interfaces to allow both export and import of the required VACAR reserves. Duke posts the TRM value for each interface on the Duke OASIS.

Both Progress and Duke ensure that TRM is maintained consistent with NERC requirements. The major difference between the methodologies used by the two companies to calculate TRM is that Progress uses a flow-based methodology, while Duke 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. Each transmission owner simulated its own transmission and generation down contingencies on its own transmission system.

Duke 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	

Progress created generation down cases which included the use of TRM, as discussed in Section III.D. Progress 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 2017 and 2022 base cases with either a Brunswick 1 unit outage, a Harris 1 unit outage, or a Robinson 2 unit outage with the remainder of TRM addressed by miscellaneous unit de-rates.

To understand regional impacts on each other's system, Duke and Progress 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 Duke and Progress systems were shared with all Participants. Solutions of known issues within Duke and Progress were discussed. New or emerging issues identified in the 2012 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

The PWG performed an assessment in accordance with the methodology and criteria discussed earlier in this section of this report, with the analysis work shared by Duke and Progress. The reliability issues identified from the assessments of both the base reliability cases and the resource supply option scenarios were documented and shared within the PWG.

III.G. Solution Development

The 2012 Study performed by the PWG confirmed base reliability problems already identified (i) by Duke and Progress in company-specific planning studies performed individually by the transmission owners and (ii) by the 2011 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. Duke and Progress developed rough, 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.

For the resource supply options, the scenarios included examining the system impacts of hypothetical transfers and hypothetical generation. The first resource supply option examined the hypothetical installation of 500 MW of new base load generation in the Duke footprint in 2022. The second resource supply option examined three different Wind Generation Scenarios that located renewable wind generation off the North Carolina / Virginia coast as part of the joint NCTPC – PJM inter-regional study analysis in 2027. Analysis of the results identified potential issues that each option may create on the Duke and Progress transmission systems. Solutions to address these issues were identified and evaluated based on cost, benefit, and risk. From the evaluation, 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 Duke and Progress control 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 2013, 2015, 2016, 2017, and 2019 summer timeframes. The limiting facilities identified in the PWG study of base reliability and of the resource supply 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. No similar LTSG offshore wind scenario exists to compare to the PWG's offshore wind scenario results.

IV. Base Reliability Study Results

The 2012 Study verified that Duke and Progress 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 2022 base case.

The 2012 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 2012 Plan are those projects identified in the base reliability study and DEC-PEC 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 11 reliability projects included in the 2012 Plan is $318 million as documented in Appendix B-1. This compares to the 2011 Plan estimate of $296 million for 11 projects. In-service dates and cost estimates for some projects that are planned or underway have been revised based on updated information. See Appendix F for a detailed comparison of this year's Plan to the 2011 Plan.

As a Merger commitment, DEC and PEC agreed to construct a total of 9 projects with a cost of approximately $116 million. Of these 9 projects, four have cost estimates greater than $10 million and are documented in Appendix B. One of these four 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-PEC 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 three merger projects are listed in Appendix B-2. The 2012 study analysis determined that the DEC – PEC Merger projects did not negatively impact any existing projects in the Plan.

Appendix C provides a more detailed description of each project in the 2012 Plan. Appendix C has also been divided into Reliability Projects (C-1) and Merger Projects (C-2).

V. Resource Supply Option Results

V.A. Option 1 - Generation Resource in Davidson County, NC

Analysis of a hypothetical 500 MW generator located in Davidson County and sinking on the Duke system identified two additional projects in Duke beyond those in the 2012 Collaborative Plan. The scenario required upgrading the 100 kV buslines between Buck Steam Station and Buck Tie. The studies also showed the need for additional 230/100 kV transformer capacity at Buck Tie. The total estimated cost of all these upgrades was $18.2 M. The specific facility additions for this hypothetical generation scenario are summarized in Appendix D.

V.B. Option 2 - Wind Generation Scenarios as part of the Joint NCTPC – PJM inter-regional study

In 2012, a Joint NCTPC-PJM Inter-Regional Study was performed. The joint study consisted of a reliability analysis of the PJM Interconnection and North Carolina Transmission Planning Collaborative (NCTPC) footprint to assess the interaction of hypothetical off-shore wind injections into the transmission systems of PJM and Progress Energy Carolinas (PEC). The goals of the analysis were to identify potential thermal constraints to wind penetration and to propose network reinforcements to mitigate identified constraints. The study evaluated wind penetration at three off-shore injection points: Dominion's Landstown 230 kV substation, PEC's Morehead City area and PEC's Southport area. In the PEC areas, wind generation was connected to the system via 500 kV lines. Three different scenarios were evaluated with varying levels of wind penetration and varying levels of power transfer between the PJM, DEC and PEC systems.

A 2027 off-peak base case was developed as the starting point model and was used to develop three scenario cases for the reliability analysis. Off-peak load study conditions were chosen to coincide with the ideal conditions for wind resource output. Wind resources typically experience higher production during off-peak or overnight hours when weather conditions are typically windier than during on-peak periods. The load level of each study area was set to 60% of 2027 summer forecasted peak levels, and generation, other than the new wind, was economically dispatched to satisfy the load and interchange requirements. The new wind generation was modeled according to each scenario's assumed level of wind injection. Other than the interchange associated with sinking offshore wind resources, the interchange between study participants was established in accordance with long-term firm transmission service requests.

The most recent available internal planning models of study participants were incorporated into the 2027 off-peak base case. PJM's system topology was representative of the 2017 Regional Transmission Expansion Plan (RTEP) Summer Peak Model which included all 2012 RTEP approved upgrades at the time the model was created. DEC and PEC system topologies reflected internal 2022 summer peak cases. DEC - PEC merger projects were included in the base case. The surrounding system topologies were based on the 2011 MMWG Series.

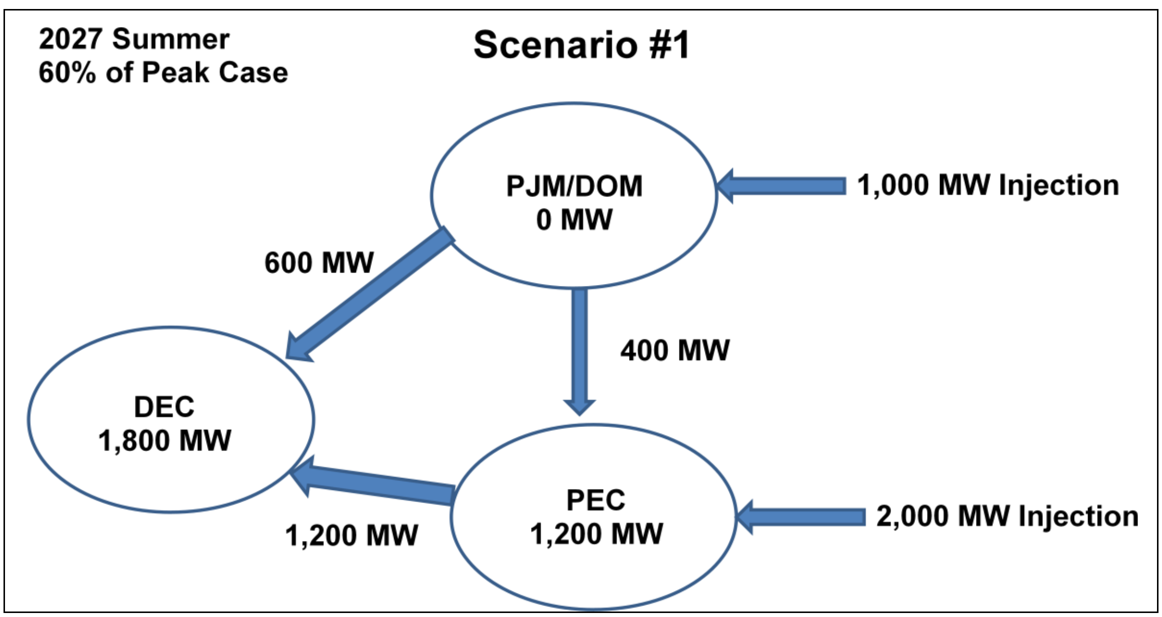
PJM generation reflected existing units, queue project units which have a signed ISA or FSA, and all deactivation requests made by the end of April 2012. No generation expected after the 2017 study year was added to the base case. For the PJM system, the 2027 off-peak case was screened for base thermal overloads and voltage violations. Base case issues were identified and mitigated with non-topology changes such as generation re-dispatch, the adjustment of capacitor banks or conductor rating corrections. The PEC system was screened with transmission upgrades from prior NCTPC wind studies already incorporated. Bulk electric system elements, 100 kV and above, for facilities in PJM, DEC and PEC, as well as areas surrounding the common interfaces between the systems, were monitored for contingencies at or above 100 kV.

A thermal N-1 analysis was conducted to test the post-contingency reliability of the network. The results were reported as monitored element and contingency pairs, while indicating the loading on the respective monitored element. Results were reported and reviewed to determine which overloads would require additional reinforcements to the network. Violations in each scenario case were addressed independently from the next scenario. Solutions were determined, modeled in the scenario case, and then verified to ensure the solutions were effective.

The following sections provide a more detailed description of each of the three scenarios.

Scenario 1

Scenario 1 modeled a total of 3,000 MW of wind injected into the PJM and PEC systems. A total of 1,800 MW (60%) was sunk in the DEC system and 1,200 MW (40%) was sunk in the PEC system. A 600 MW transfer from PJM to DEC and a 400 MW transfer from PJM to PEC were modeled to simulate the power sinking in the DEC and PEC systems. A 1,200 MW transfer from PEC to DEC was modeled to satisfy the remaining power sinking in the DEC system. These transactions are illustrated in the following bubble diagram.



The following table summarizes the wind injection amounts and respective sink area amounts for Scenario 1.

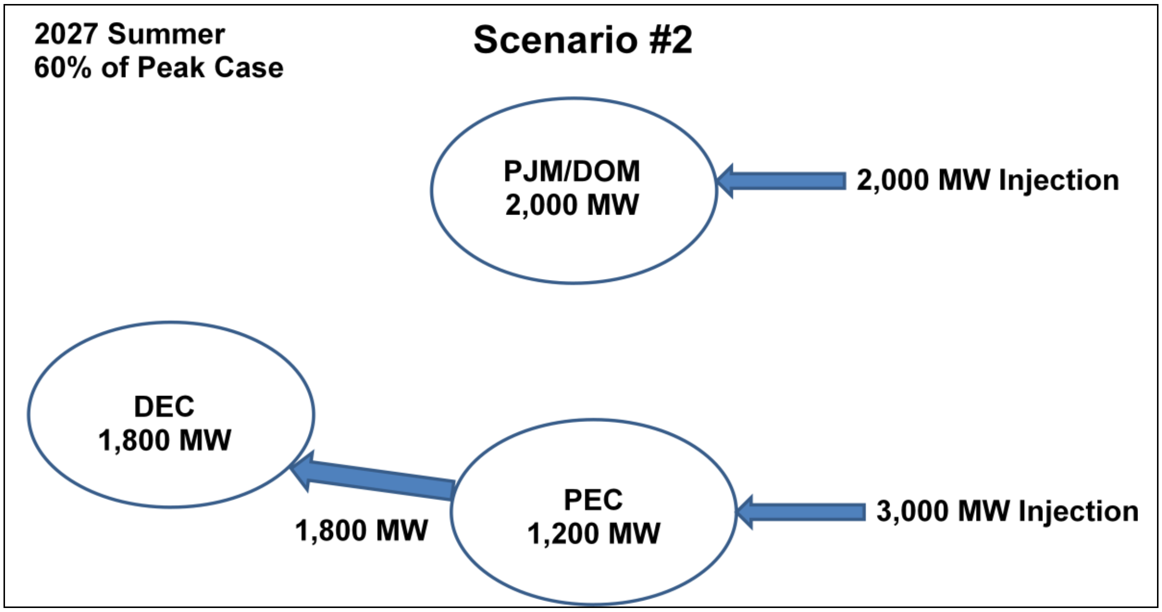
Table 8

Summary of Scenario 1 Wind Injection and Area Transfers

Scenario 1 – Wind Generation	PJM – Load Sink	DEC – Load Sink	PEC – Load Sink
PJM – 1,000 MW injection at Landstown	0 MW 0%	600 MW 60%	400 MW 40%
NCTPC – 1,000 MW injection at Morehead City	0 MW 0%	600 MW 60%	400 MW 40%
NCTPC –1,000 MW injection at Southport	0 MW 0%	600 MW 60%	400 MW 40%
Total	0 MW	1,800 MW	1,200 MW

Scenario 2

Scenario 2 modeled a total of 5,000 MW of wind injection into the PJM and PEC systems. A total of 2,000 MW (40%) was sunk in the PJM system and was satisfied by the wind injection at Landstown. A total of 1,800 MW (36%) was sunk in the DEC system and 1,200 MW (24%) was sunk in the PEC system. A 1,800 MW transfer from PEC to DEC was modeled to simulate the power sinking in the DEC system. These transactions are illustrated in the following bubble diagram.



The following table summarizes the wind injection amounts and respective sink area amounts for Scenario 2.

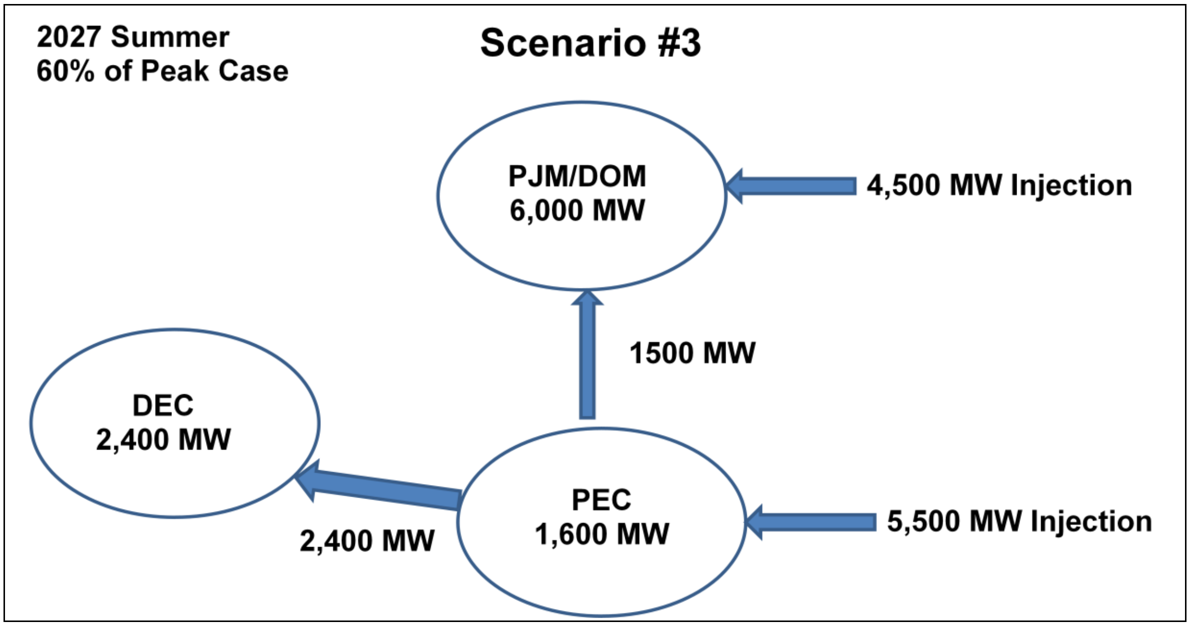
Table 9

Summary of Scenario 2 Wind Injection and Area Transfers

Scenario 2 – Wind Generation	PJM – Load Sink	DEC – Load Sink	PEC – Load Sink
PJM – 2,000 MW injection at Landstown	2,000 MW 100%	0 MW 0%	0 MW 0%
NCTPC – 1,500 MW injection at Morehead City	0 MW 0%	900 MW 60%	600 MW 40%
NCTPC –1,500 MW injection at Southport	0 MW 0%	900 MW 60%	600 MW 40%
Total	2,000 MW	1,800 MW	1,200 MW

Scenario 3

Scenario 3 modeled a total of 10,000 MW of wind injection into the PJM and PEC systems. A total of 6,000 MW (60%) was sunk in the PJM system and was satisfied by the wind injection at Landstown with an additional transfer of 1,500 MW from PEC to PJM. A total of 2,400 MW (24%) was sunk in the DEC system and 1,600 MW (16%) was sunk in the PEC system. A 2,400 MW transfer from PEC to DEC was modeled to simulate the power sinking in the DEC system. These transactions are illustrated in the following bubble diagram.



The following table summarizes the wind injection amounts and respective sink area amounts for Scenario 3.

Table 10

Summary of Scenario 3 Wind Injection and Area Transfers

Scenario 3 – Wind Generation	PJM – Load Sink	DEC – Load Sink	PEC – Load Sink
PJM –4,500 MW injection at Landstown	4,500 MW 100%	0 MW 0%	0 MW 0%
NCTPC –3,500 MW injection at Morehead City	955 MW 27.3%	1,527 MW 43.6%	1,018 MW 29.1%
NCTPC –2,000 MW injection at Southport	545 MW 27.3%	873 MW 43.6%	582 MW 29.1%
Total	6,000 MW	2,400 MW	1,600 MW

Status of Joint Study

At the point in time of this NCTPC report, the Joint NCTPC-PJM Inter-Regional Study is still in progress. The required upgrades and cost estimates for the PEC transmission system are provided in Appendix E. The DEC transmission system does not have any projects with an estimated cost greater than $10 million under any of the three Wind Generation Scenarios. Upgrades and cost estimates for the PJM system are still being evaluated and will be provided in the final joint report.

VI. Collaborative Transmission Plan

The 2012 Collaborative Transmission Plan includes 11 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 11 reliability projects in the 2012 Plan is $318 million. This compares to the 2011 Plan estimate of $296 million for 11 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 F for a detailed comparison of this year's reliability Plan to the 2011 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 2012 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 2011 Report and have been deferred beyond the end of the planning horizon based on the 2012 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

2017 SUMMER PEAK

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports – MW

	Base	PEC TRM
CPLE (NCEMC)	33	33
CPLE (NCEMC/Hamlet)	55	55
DVP (PJM)	2	2
SCEG (Chappells)	2	2
SCPSA (New Horizons/NHEC)	159	159
SCPSA (PMPA)	201	201
SEPA (Hartwell)	155	155
SEPA (Thurmond)	113	113
SOCO (City of Seneca)	29	29
SOCO (NCEMC)	180	180
Total	**929**	**929**

Duke Energy Carolinas Modeled Exports – MW

	Base	PEC TRM
CPLE (Broad River)	850	850
CPLE (NCEMC/Catawba)	205	205
CPLE (Rowan)	150	150
CPLE (PEC TRM)	0	506
CPLW (Rowan)	0	0
CPLW (PEC TRM)	0	0
DVP (NCEMC)	50	50
Total	**1255**	**1761**

Duke Energy Carolinas Net Interchange – MW

	Base	PEC TRM
	326	832

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

2017 SUMMER PEAK

PROGRESS ENERGY CAROLINAS (EAST)

DETAILED INTERCHANGE

Progress Energy Carolinas (East) Modeled Imports – MW

	Base	**PEC TRM**
AEP (NCEMC)	100	100
AEP (NCEMC#2)	100	100
AEP (PEC TRM)	0	97
DUKE (Broad River)	850	850
DUKE (NCEMC/Catawba)	205	205
DUKE (Rowan)	150	150
DUKE (PEC TRM)	0	506
DVP (SEPA-KERR)	95	95
DVP (PEC TRM)	0	835
SCEG (PEC TRM)	0	200
SCPSA (PEC TRM)	0	197
Total	**1500**	**3335**

Progress Energy Carolinas (East) Modeled Exports – MW

	Base	**PEC TRM**
CPLW (Transfer)	0	0
DUKE (NCEMC)	33	33
DUKE (NCEMC/Hamlet)	55	55
DVP (NCEMC)	275	275
Total	**363**	**363**

Progress Energy Carolinas (East) Net Interchange - MW

	Base	**PEC TRM**
	-1137	-2972

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

2017 SUMMER PEAK

PROGRESS ENERGY CAROLINAS (WEST)

DETAILED INTERCHANGE

Progress Energy Carolinas (West) Modeled Imports – MW

	Base	PEC TRM
CPLE (Transfer)	0	0
DUKE (Rowan)	0	0
DUKE(PEC TRM)	0	0
TVA (SEPA)	1	1
Total	**1**	**1**

Progress Energy Carolinas (West) Modeled Exports – MW

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

Progress Energy Carolinas (West) Net Interchange – MW

	Base	PEC TRM
	-1	-1

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

2017/2018 WINTER PEAK

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports – MW

	Base	PEC TRM
CPLE (NCEMC)	0	0
CPLE (NCEMC/Hamlet)	35	35
DVP (PJM)	2	2
SCEG (Chappells)	2	2
SCPSA (New Horizons/NHEC)	24	24
SCPSA (PMPA)	49	49
SEPA (Hartwell)	155	155
SEPA (Thurmond)	113	113
SOCO (City of Seneca)	23	23
SOCO (NCEMC)	180	180
Total	**583**	**583**

Duke Energy Carolinas Modeled Exports – MW

	Base	PEC TRM
CPLE (Broad River)	850	850
CPLE (NCEMC/Catawba)	205	205
CPLE (Rowan)	0	0
CPLE (PEC TRM)	0	0
CPLW (Rowan)	150	150
CPLW (PEC TRM)	0	206
DVP (NCEMC)	50	50
Total	**1355**	**1461**

Duke Energy Carolinas Net Interchange – MW

	Base	PEC TRM
	672	878

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

2017/2018 WINTER PEAK
PROGRESS ENERGY CAROLINAS (EAST)
DETAILED INTERCHANGE

Progress Energy Carolinas (East) Modeled Imports – MW

	Base	PEC TRM
AEP (NCEMC)	100	100
AEP (NCEMC#2)	100	100
AEP (PEC TRM)	0	0
DUKE (Broad River)	850	850
DUKE (NCEMC/Catawba)	205	205
DUKE (Rowan)	0	0
DUKE (PEC TRM)	0	0
DVP (SEPA-KERR)	95	95
DVP (PEC TRM)	0	0
SCEG (PEC TRM)	0	0
SCPSA (PEC TRM)	0	0
Total	**1350**	**1350**

Progress Energy Carolinas (East) Modeled Exports – MW

	Base	PEC TRM
CPLW (Transfer)	250	250
DUKE (NCEMC)	0	0
DUKE (NCEMC/Hamlet)	35	35
DVP (NCEMC)	275	275
Total	**560**	**560**

Progress Energy Carolinas (East) Net Interchange – MW

	Base	PEC TRM
	-790	-790

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

2017/2018 WINTER PEAK

PROGRESS ENERGY CAROLINAS (WEST)

DETAILED INTERCHANGE

Progress Energy Carolinas (West) Modeled Imports – MW

	Base	**PEC TRM**
CPLE (Transfer)	250	250
DUKE (Rowan)	150	150
DUKE (PEC TRM)	0	206
TVA (SEPA)	1	1
Total	**401**	**607**

Progress Energy Carolinas (West) Modeled Exports – MW

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

Progress Energy Carolinas (West) Net Interchange - MW

	Base	**PEC TRM**
	-401	-607

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

2022 SUMMER PEAK

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports – MW

	Base	PEC TRM
CPLE (NCEMC)	0	0
CPLE (NCEMC/Hamlet)	0	0
DVP (PJM)	2	2
SCEG (Chappells)	2	2
SCPSA (New Horizons/NHEC)	0	0
SCPSA (PMPA)	237	237
SEPA (Hartwell)	155	155
SEPA (Thurmond)	113	113
SOCO (City of Seneca)	31	31
SOCO (NCEMC)	180	180
Total	**720**	**720**

Duke Energy Carolinas Modeled Exports – MW

	Base	PEC TRM
CPLE (Broad River)	850	850
CPLE (NCEMC/Catawba)	205	205
CPLE (Rowan)	150	150
CPLE (PEC TRM)	0	506
CPLW (Rowan)	0	0
CPLW (PEC TRM)	0	0
DVP (NCEMC)	50	50
Total	**1255**	**1761**

Duke Energy Carolinas Net Interchange

	Base	PEC TRM
	535	1041

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

2022 SUMMER PEAK

PROGRESS ENERGY CAROLINAS (EAST)

DETAILED INTERCHANGE

Progress Energy Carolinas (East) Modeled Imports – MW

	Base	PEC TRM
AEP (NCEMC)	100	100
AEP (NCEMC #2)	100	100
AEP (PEC TRM)	0	97
DUKE (Broad River)	850	850
DUKE (NCEMC/Catawba)	205	205
DUKE (Rowan)	150	150
DUKE (PEC TRM)	0	506
DVP (SEPA-KERR)	95	95
DVP (PEC TRM)	0	835
SCEG (PEC TRM)	0	200
SCPSA (PEC TRM)	0	197
Total	**1500**	**3335**

Progress Energy Carolinas (East) Modeled Exports – MW

	Base	PEC TRM
CPLW (Transfer)	0	0
DUKE (NCEMC)	0	0
DUKE (NCEMC/Hamlet)	0	0
DVP (NCEMC)	275	275
Total	**275**	**275**

Progress Energy Carolinas (East) Net Interchange – MW

	Base	PEC TRM
	-1225	-3060

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

2022 SUMMER PEAK

PROGRESS ENERGY CAROLINAS (WEST)

DETAILED INTERCHANGE

Progress Energy Carolinas (West) Modeled Imports – MW

	Base	**PEC TRM**
CPLE (Transfer)	0	0
DUKE (Rowan)	0	0
DUKE (PEC TRM)	0	0
TVA (SEPA)	1	1
Total	**1**	**1**

Progress Energy Carolinas (West) Modeled Exports – MW

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

Progress Energy Carolinas (West) Net Interchange – MW

	Base	**PEC TRM**
	-1	-1

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

2027 SUMMER / ON-PEAK WIND (OFF-PEAK LOAD) CASE

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports – MW

	Base	Scenario 1	Scenario 2	Scenario 3
CPLE (NCEMC)	0	0	0	0
CPLE (NCEMC/Hamlet)	0	0	0	0
CPLE (Offshore Wind)	0	1200	1800	2400
DVP (PJM)	2	2	2	2
DVP (Offshore Wind)	0	600	0	0
SCEG (Chappells)	2	2	2	2
SCPSA (New Horizons/NHEC)	0	0	0	0
SCPSA (PMPA)	28	28	28	28
SEPA (Hartwell)	155	155	155	155
SEPA (Thurmond)	113	113	113	113
SOCO (City of Seneca)	19	19	19	19
SOCO (NCEMC)	83	83	83	83
Total	**400**	**2202**	**2202**	**2802**

Duke Energy Carolinas Modeled Exports – MW

	Base	Scenario 1	Scenario 2	Scenario 3
CPLE (Broad River)	0	0	0	0
CPLE (NCEMC/Catawba)	205	205	205	205
CPLE (Rowan)	150	150	150	150
CPLW (Rowan)	0	0	0	0
DVP (NCEMC)	50	50	50	50
Total	**405**	**405**	**405**	**405**

Duke Energy Carolinas Net Interchange – MW

	Base	Scenario 1	Scenario 2	Scenario 3
	3	-1797	-1797	-2397

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

2027 SUMMER / ON-PEAK WIND (OFF-PEAK LOAD) CASE

PROGRESS ENERGY CAROLINAS (EAST)

DETAILED INTERCHANGE

Progress Energy Carolinas (East) Modeled Imports – MW

	Base	Scenario 1	Scenario 2	Scenario 3
AEP (NCEMC)	100	100	100	100
AEP (NCEMC#2)	100	100	100	100
CPLW (Transfer)	0	0	0	0
DUKE (Broad River)	0	0	0	0
DUKE (NCEMC/Catawba)	205	205	205	205
DUKE (Rowan)	150	150	150	150
DVP (SEPA-KERR)	95	95	95	95
DVP (Offshore Wind)	0	400	0	0
Total	**650**	**1050**	**650**	**650**

Progress Energy Carolinas (East) Modeled Exports – MW

	Base	Scenario 1	Scenario 2	Scenario 3
CPLW (Transfer)	0	0	0	0
DUKE (NCEMC)	0	0	0	0
DUKE (NCEMC/Hamlet)	0	0	0	0
DUKE (Offshore Wind)	0	1200	1800	2400
DVP (NCEMC)	0	0	0	0
DVP (Offshore Wind)	0	0	0	1500
Total	**0**	**1200**	**1800**	**3900**

Progress Energy Carolinas (East) Net Interchange – MW

	Base	Scenario 1	Scenario 2	Scenario 3
	-650	150	1150	3250

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

2027 SUMMER / ON-PEAK WIND (OFF-PEAK LOAD) CASE

PROGRESS ENERGY CAROLINAS (WEST)

DETAILED INTERCHANGE

Progress Energy Carolinas (West) Modeled Imports – MW

	Base	Scenario 1	Scenario 2	Scenario 3
CPLE (Transfer)	0	0	0	0
DUKE (Rowan)	0	0	0	0
TVA (SEPA)	1	1	1	1
Total	**1**	**1**	**1**	**1**

Progress Energy Carolinas (West) Modeled Exports – MW

	Base	Scenario 1	Scenario 2	Scenario 3
CPLE (Transfer)	0	0	0	0
Total	**0**	**0**	**0**	**0**

Progress Energy Carolinas (West) Net Interchange – MW

	Base	Scenario 1	Scenario 2	Scenario 3
	-1	-1	-1	-1

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

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

2012 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]**
0011	Asheville - Enka, Convert 115 kV Line to 230 kV, Construct new 115 kV line	Address Asheville 230/115 kV transformer loading	In-Service	Progress	12/1/2010 12/1/2012	30	-
0026	Brunswick 1 - Castle Hayne 230 kV Line, Construct New Cape Fear River Crossing	Address loading on Sutton Plant - Castle Hayne 230 kV Line	Underway	Progress	12/31/2012	27	0
0022	Jacksonville Static VAR Compensator	Address inadequate dynamic voltage recovery after system faults during periods of high imports	Underway	Progress	6/1/2013	32	0.5
0023	Folkstone 230/115 kV Substation	Address voltage on Castle Hayne - Jacksonville City 115 kV Line	Underway	Progress	12/1/2012	19	0
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	Underway	Progress	6/1/2014	59	2

2012 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	Progress	6/1/2020	14	4
0008	Greenville - Kinston DuPont 230 KV Line Construct line[4]	Address loading on Greenville - Everetts 230 kV Line	Underway	Progress	6/1/2014	34	2
0029	Arabia 230 kV substation	Address loading on Raeford 230/115 kV transformer	***Removed***	Progress			
0030	Raeford 230 kV substation, loop-in Richmond-Ft Bragg Woodruff St 230 kV Line and replace banks	Address loading on Raeford 230/115 kV transformer	Planned *(Replaced 0029)*	Progress	6/1/2018	14	4
0024	Durham - RTP 230 kV Line, Reconductor	Address loading on the Durham - RTP 230 kV Line	Planned	Progress	6/1/2022	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 Progress West	Underway	Duke	12/1/2013	26	1.0

2012 Collaborative Transmission Plan – Reliability 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]**
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	Planned	Duke	6/1/2017	48	4
TOTAL						**318**	

[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 Duke/Progress merger mitigation projects.

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

2012 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 Duke/Progress merger mitigation projects.	Underway	Progress	6/1/2014	15	2
M-0002	Person-(DVP) Halifax 230kV Line - Reconductor DVP Section (DVP work)	This project is part of the Duke/Progress merger mitigation projects.	Underway	Progress/ Dominion	6/1/2014	16	2
M-0003	Antioch 500/230kV Substation: Replace Two Transformer Banks	This project is part of the Duke/Progress merger mitigation projects.	Underway	Duke	6/1/2014	28	2
TOTAL						**59**	

[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: 0011 – Asheville – Enka, Convert 115 kV Line to 230 kV, Construct new 115 kV line

Project Description
First phase of project will convert the Asheville - Enka 115 kV West Line to 230 kV operation and establish Enka 230 kV Substation by installing 1-300 MVA, 230/115 kV transformer at the Enka 115 kV Switching Station site. The second phase of the project consists of constructing approximately 10 miles of 3-1590 MCM ACSR for 115 kV operation between Asheville Plant and Enka 230 kV Substations.

Status	Project is complete.
Transmission Owner	Progress
Planned In-Service Date	Project is complete.
Estimated Time to Complete	Project is complete.
Estimated Cost	$30 M

Narrative Description of the Need for this Project
With an Asheville unit down an outage of one 230/115 kV transformer at Asheville 230 kV will cause the remaining transformer to exceed its rating. After the line was converted in 2010 there is a need to construct a new 115 kV Line to unload the remaining 115 kV lines out of Asheville S.E. Plant as well as maintain Asheville Plant stability.

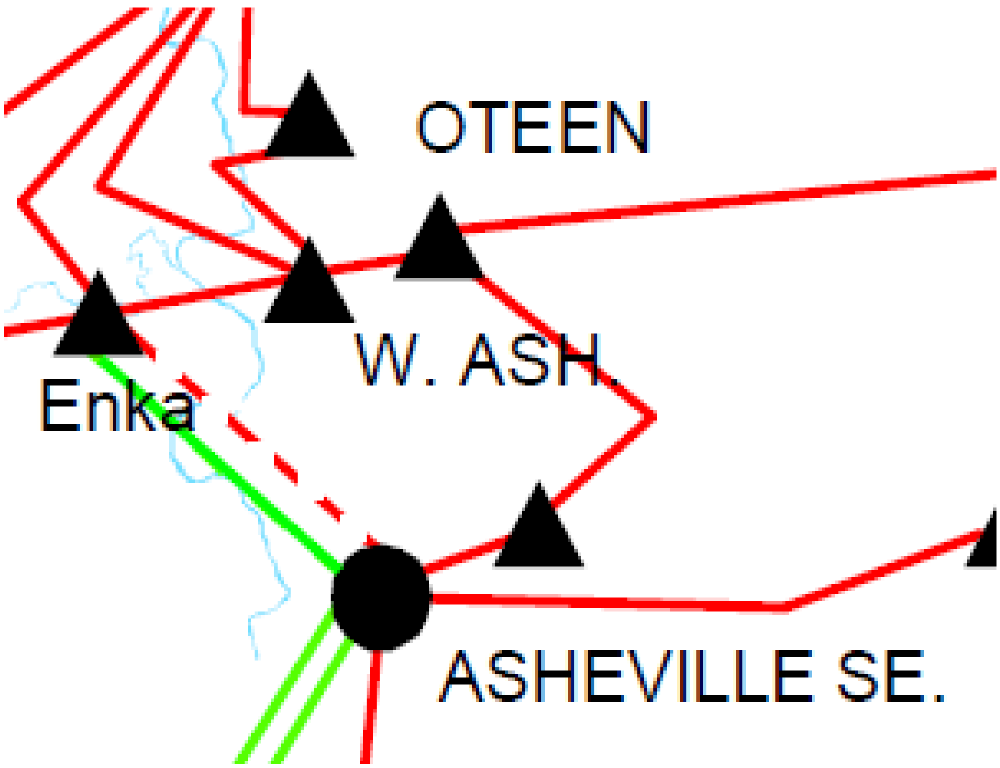
Other Transmission Solutions Considered
Replace Asheville 230/115 kV transformers with higher rated transformers.

Why this Project was Selected as the Preferred Solution
Effective solution.

C-1

Asheville – Enka 115 kV West Line

- **NERC Category B Violations**
- **Problem:** Asheville Plant might become unstable under certain contingencies.
- **Solution:** Constructing approximately 10 miles 115 kV line between Asheville Plant and Enka 230 kV Substations.



Project ID and Name: 0026 - Brunswick 1 - Castle Hayne 230 kV Line, Construct New Cape Fear River Crossing

Project Description
This project consists of constructing a new 230 kV line under the Cape Fear River.

Status	Underway
Transmission Owner	Progress
Planned In-Service Date	12/31/2012
Estimated Time to Complete	0.1 years
Estimated Cost	$27 M

Narrative Description of the Need for this Project
The common tower outage of the two lines (at river crossing) that run from Brunswick Plant to Castle Hayne can cause the thermal rating of the Sutton Plant - Castle Hayne 230 kV Line to be exceeded. This event will also require significant reduction in Brunswick units output for several days to several months, depending upon the damage caused to the lines and towers. Studies show that separating these lines at their common river crossing will eliminate overloading issues for the 10 year planning horizon, will reduce any impact on Brunswick Plant operation, and will increase reliability to the Wilmington load area.

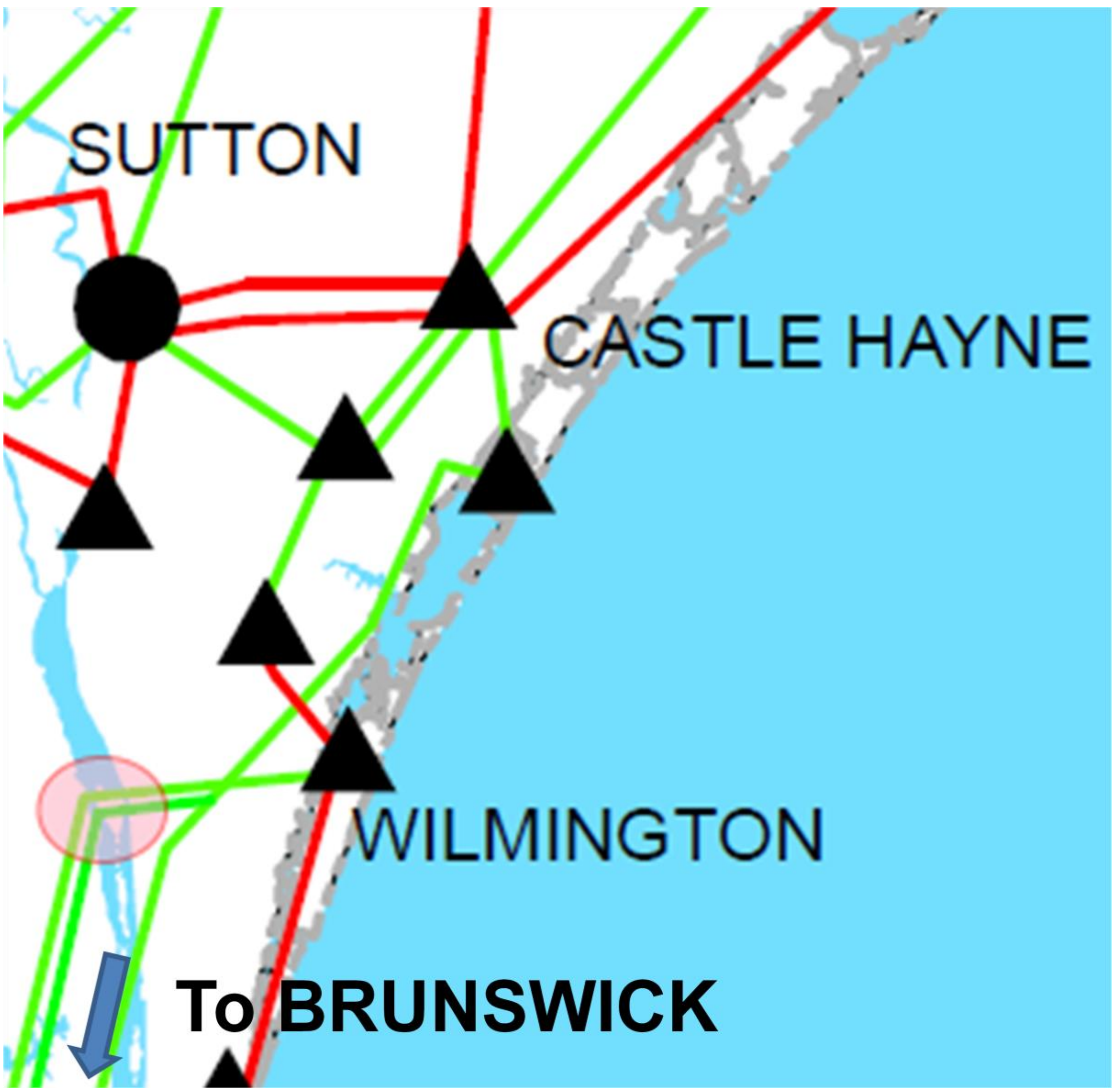
Other Transmission Solutions Considered
Rebuild, reconductor existing line.

Why this Project was Selected as the Preferred Solution
Cost, feasibility and improved area reliability.

C-2

Brunswick 1 - Castle Hayne 230 kV Line

- **NERC Category B Violations**
- **Problem:** The common tower outage of the two lines (at river crossing) that run from Brunswick Plant to Castle Hayne can cause the thermal rating of the Sutton Plant - Castle Hayne 230 kV Line to be exceeded.
- **Solution:** Constructing a new 230 kV line under the Cape Fear River.



Project ID and Name: 0022 - Jacksonville Static VAR Compensator (SVC)

Project Description
Install a 300 MVAR 230 kV Static VAR Compensator (SVC) at the Jacksonville 230 kV Substation.

Status	Planned
Transmission Owner	Progress
Planned In-Service Date	6/1/2013
Estimated Time to Complete	0.5 years
Estimated Cost	$32 M

Narrative Description of the Need for this Project
This project was identified during a dynamic evaluation of PEC's East System during periods of increased imports. The analysis indicated that under certain faulted conditions that PEC East's transmission network along the coast of NC would be unable to maintain adequate voltage support. The lack of voltage support in the coastal area means that voltage recovery following certain faults is inadequate to maintain proper voltage.

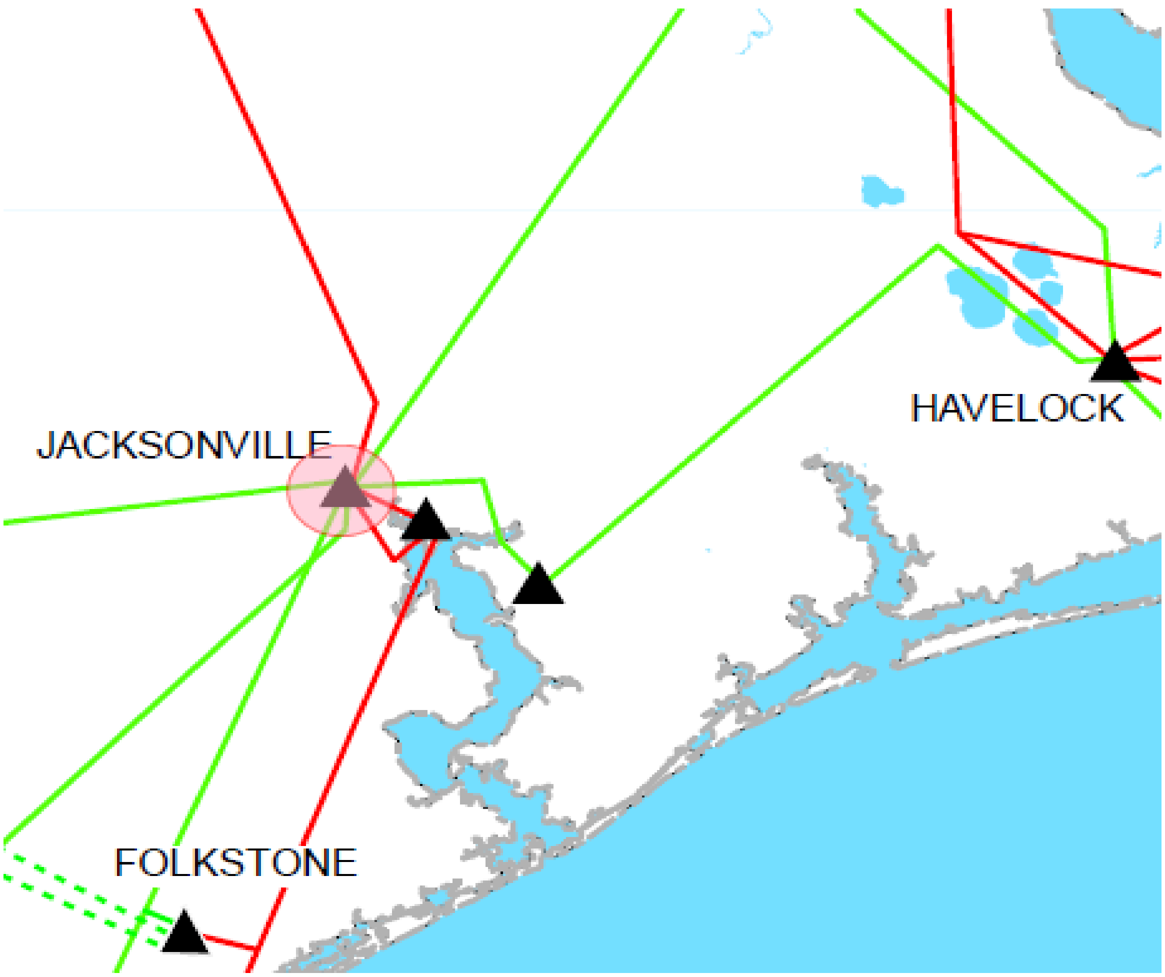
Other Transmission Solutions Considered
N/A

Why this Project was Selected as the Preferred Solution
Only viable solution

C-3

Jacksonville Static VAR Compensator (SVC)

- **NERC Category B Violations**
- **Problem:** Under certain faulted conditions PEC East's transmission network along the coast of NC would be unable to maintain adequate voltage support.
- **Solution:** Install a 300 MVAR 230 kV Static VAR Compensator (SVC) at the Jacksonville 230 kV Substation.



Project ID and Name: 0023 - Folkstone 230/115 kV Substation

Project Description
Construct the new Folkstone 230 kV Substation, loop-in the Castle Hayne - Jacksonville 230 kV line and connect to the Castle Hayne - Jacksonville City 115 kV line. This project will require the construction of approximately 16 miles of 115 kV and the installation of a 200 MVA 230/115 transformer.

Status	Underway
Transmission Owner	Progress
Planned In-Service Date	12/1/2012
Estimated Time to Complete	0.1 years
Estimated Cost	$19 M

Narrative Description of the Need for this Project
An outage of either of the Castle Hayne or Jacksonville terminals of the Castle Hayne-Jacksonville 115 kV line will cause voltage along the line to drop below planning criteria.

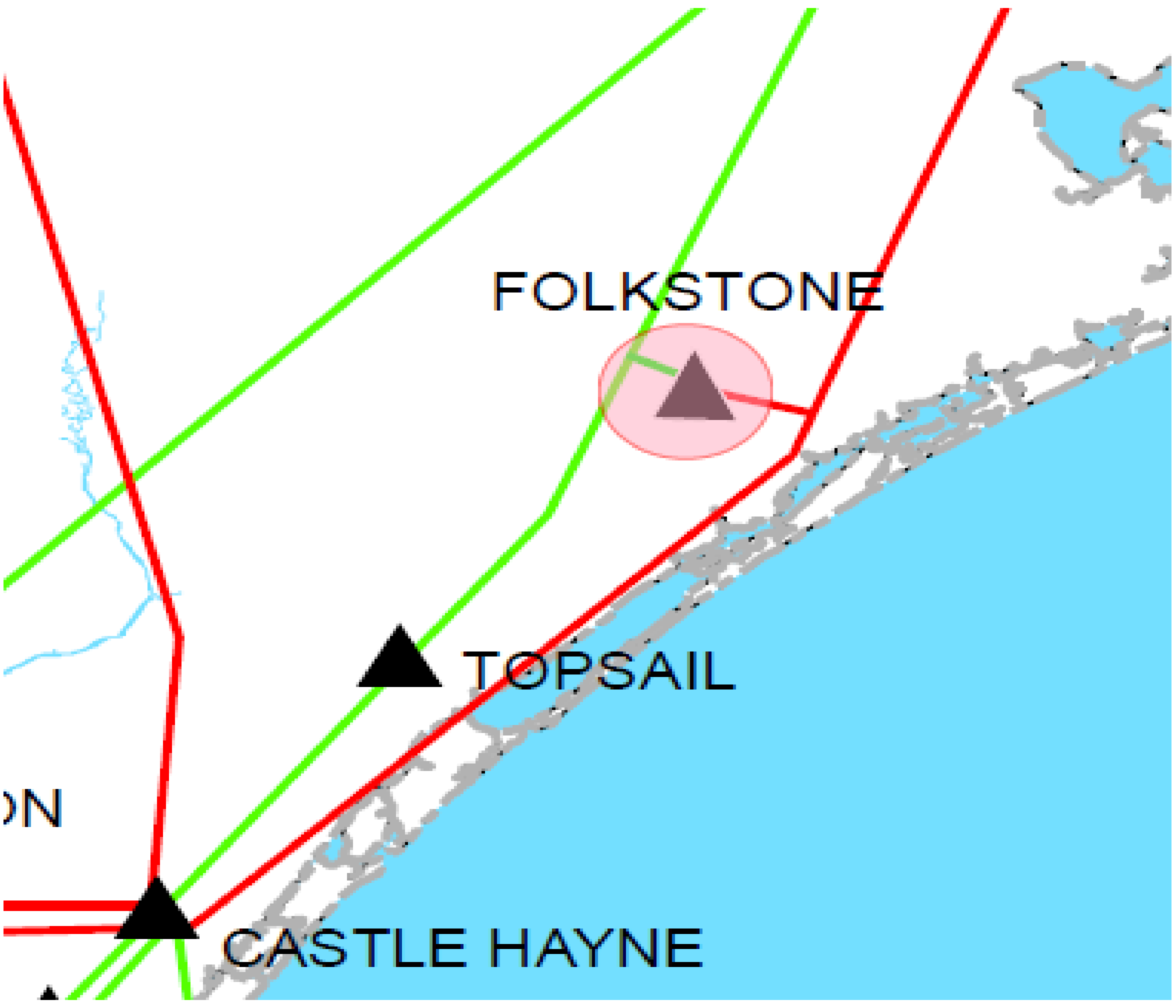
Other Transmission Solutions Considered
Reconductor existing line.

Why this Project was Selected as the Preferred Solution
Cost, feasibility, and long term effectiveness.

C-4

Folkstone 230/115 kV Substation

- **NERC Category B Violations**
- **Problem:** An outage of either of the Castle Hayne or Jacksonville terminals of the Castle Hayne-Jacksonville 115 kV line will cause voltage along the line to drop below planning criteria.
- **Solution:** Construct the new Folkstone 230 kV Substation, loop-in the Castle Hayne - Jacksonville 230 kV line and connect to the Castle Hayne - Jacksonville City 115 kV line.



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	Underway: Engineering and Construction in progress.
Transmission Owner	Progress
Planned In-Service Date	6/1/2014
Estimated Time to Complete	2 years
Estimated Cost	$59 M

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

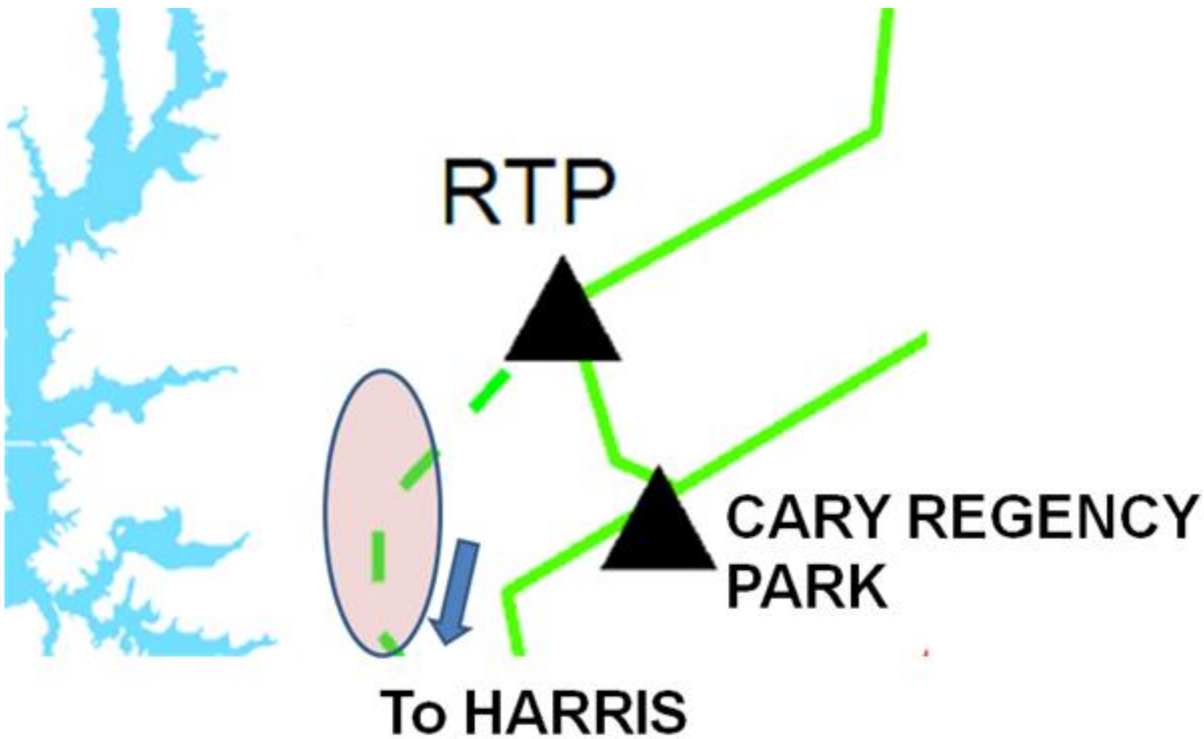
Other Transmission Solutions Considered
Construct Harris - Durham 230 kV line.

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

C-5

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	Planned
Transmission Owner	Progress
Planned In-Service Date	6/1/2020
Estimated Time to Complete	4 years
Estimated Cost	$14 M

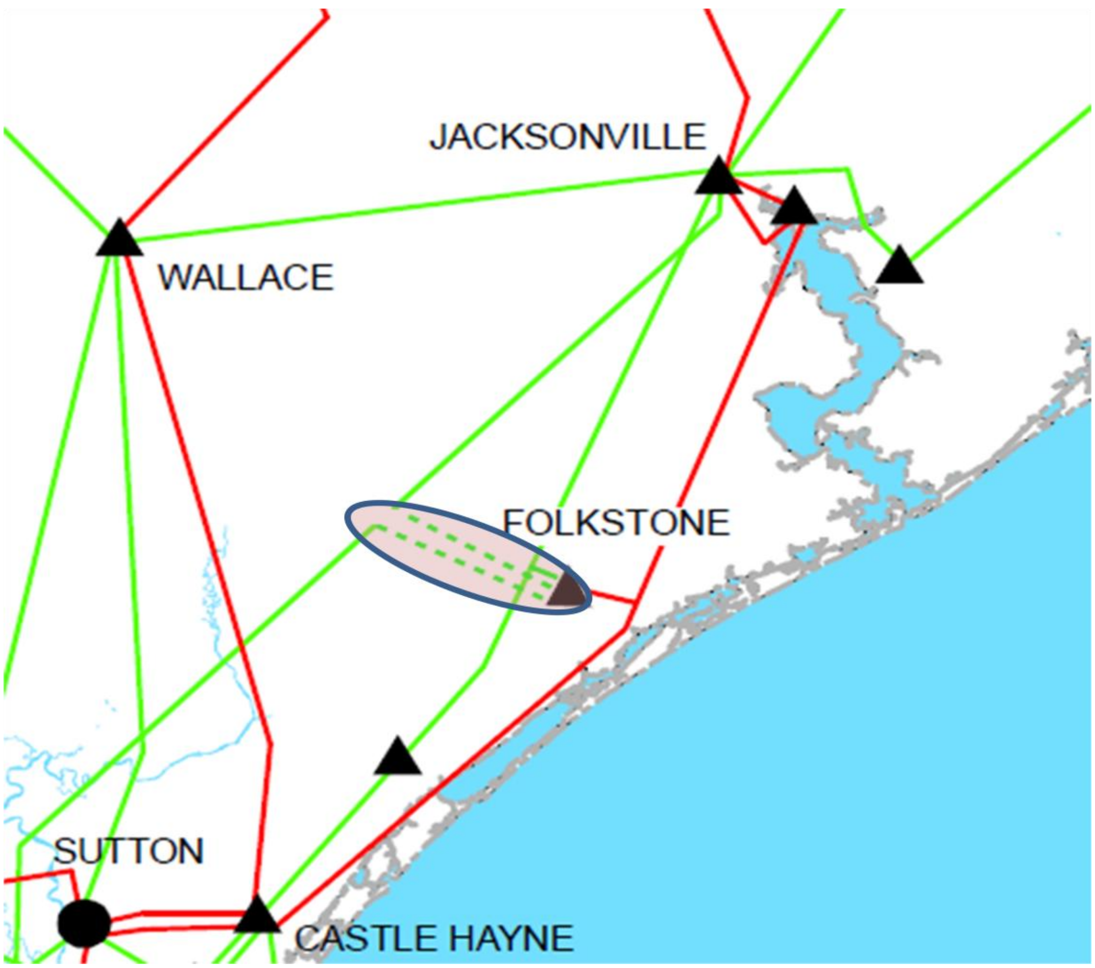
Narrative Description of the Need for this Project
This project is needed to alleviate loading on the Folkstone – Jacksonville City 115 kV Line under the contingency of losing Folkstone – Jacksonville 230 kV Line. This project will mitigate each of these contingencies.

Other Transmission Solutions Considered
Rebuild, reconductor existing line.

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

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: 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	Planned: All right-of-way has been acquired.
Transmission Owner	Progress
Planned In-Service Date	6/1/2014
Estimated Time to Complete	2 years
Estimated Cost	$34 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.

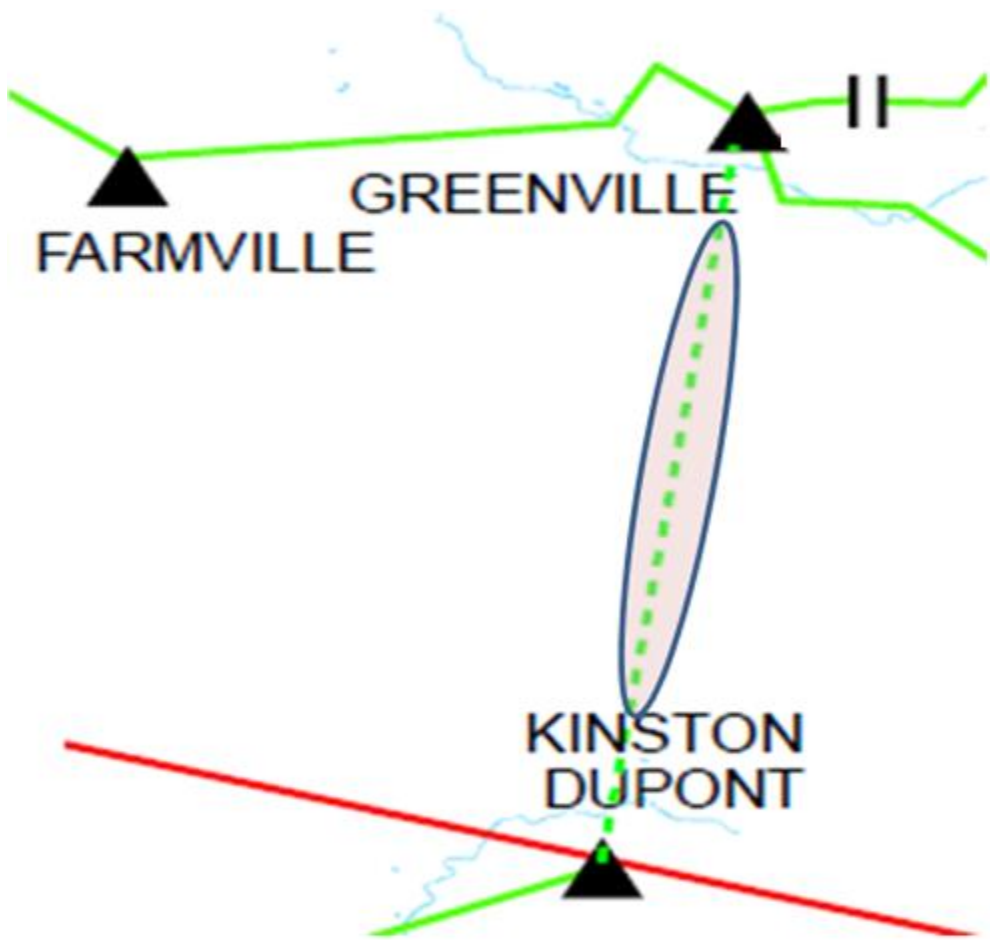
Other Transmission Solutions Considered
Rebuild, reconductor existing line.

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

C-7

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 Duke/Progress merger mitigation projects.



Project ID and Name: 0030 – Raeford 230 kV Substation, Loop-in Richmond-Ft Bragg Woodruff St 230 kV Line and Replace Banks

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 replacement of the existing 2-200 MVA 230/115kV transformers with 2-300MVA 230/115kV transformers.

Status	Planned: All right-of-way has been acquired.
Transmission Owner	Progress
Planned In-Service Date	6/1/2018
Estimated Time to Complete	4 years
Estimated Cost	$14 M

Narrative Description of the Need for this Project
With a Brunswick Unit down, loss of the Richmond – Raeford 230 kV Line will cause unacceptably low voltages at Rockfish feeder. In addition, either of the Raeford 230/115 kV, 200 MVA transformers at the Raeford 230 kV Substation will overload during an outage of the other 230/115 kV transformer. Similar scenario also applies to the Laurinburg transformers. This project will mitigate each of these contingencies.

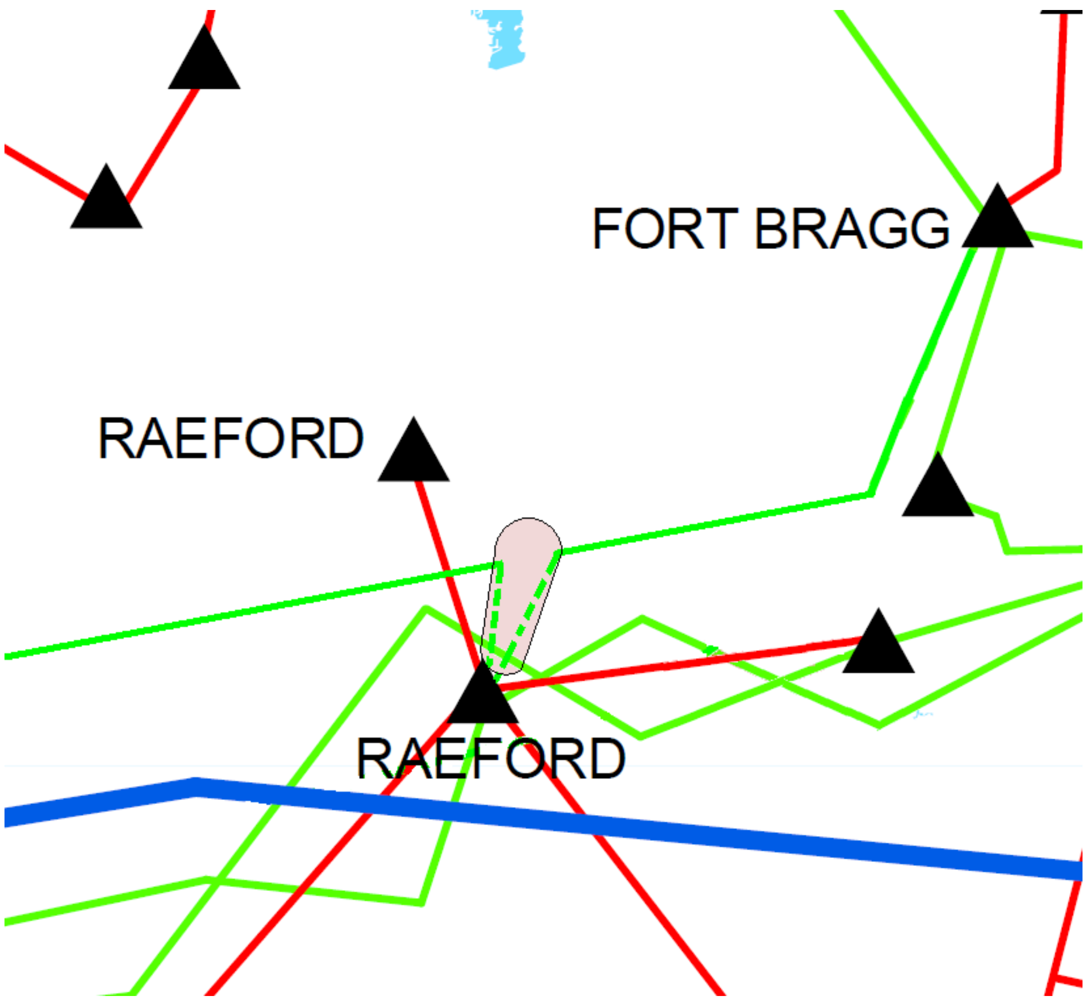
Other Transmission Solutions Considered
Construct Arabia 230kV Substation.

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

C-8

Raeford 230 kV Substation, Loop-in Richmond-Ft Bragg Woodruff St 230 kV Line and Replace Banks

- **NERC Category C Violations**
- **Problem:** With a Brunswick Unit down, loss of the Richmond – Raeford 230 kV Line will cause unacceptably low voltages at Rockfish feeder. In addition, either of the Raeford 230/115 kV, 200 MVA transformers at the Raeford 230 kV Substation will overload during an outage of the other transformer.
- **Solution:** At the Raeford 230kV Substation, loop-in the Richmond – Ft. Bragg Woodruff St. 230 kV line and replace the 200 MVA transformers with 300 MVA transformers**.**



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	Progress
Planned In-Service Date	6/1/2022
Estimated Time to Complete	4 years
Estimated Cost	$15 M

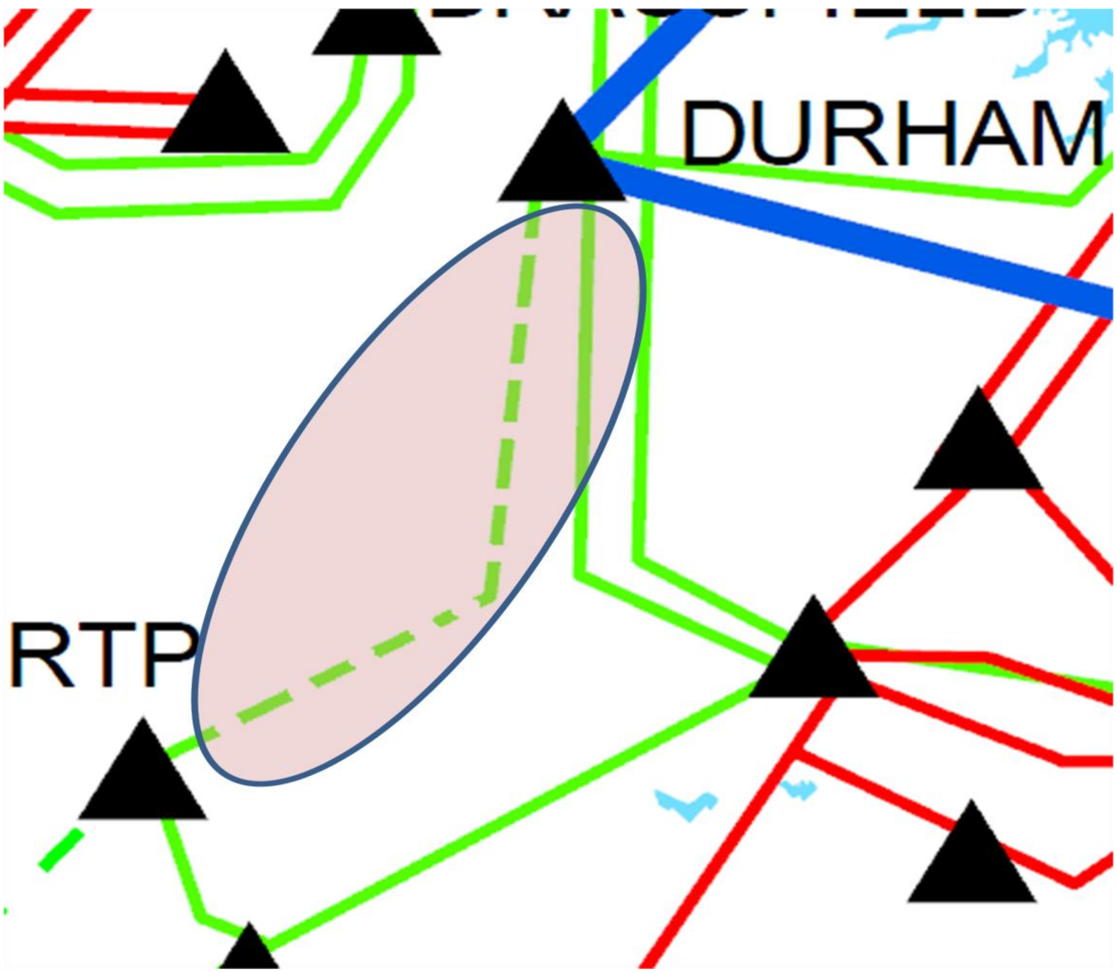
Narrative Description of the Need for this Project
With Harris Plant down, a common tower outage of the Method - (DPC) East Durham and the Durham - Method 230 kV Lines will cause an overload of the Durham 500 kV Sub - RTP 230 kV Switching Station Line.

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.

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	Construction underway
Transmission Owner	Duke
Planned In-Service Date	12/1/2013
Estimated Time to Complete	1.0 years
Estimated Cost	$26 M

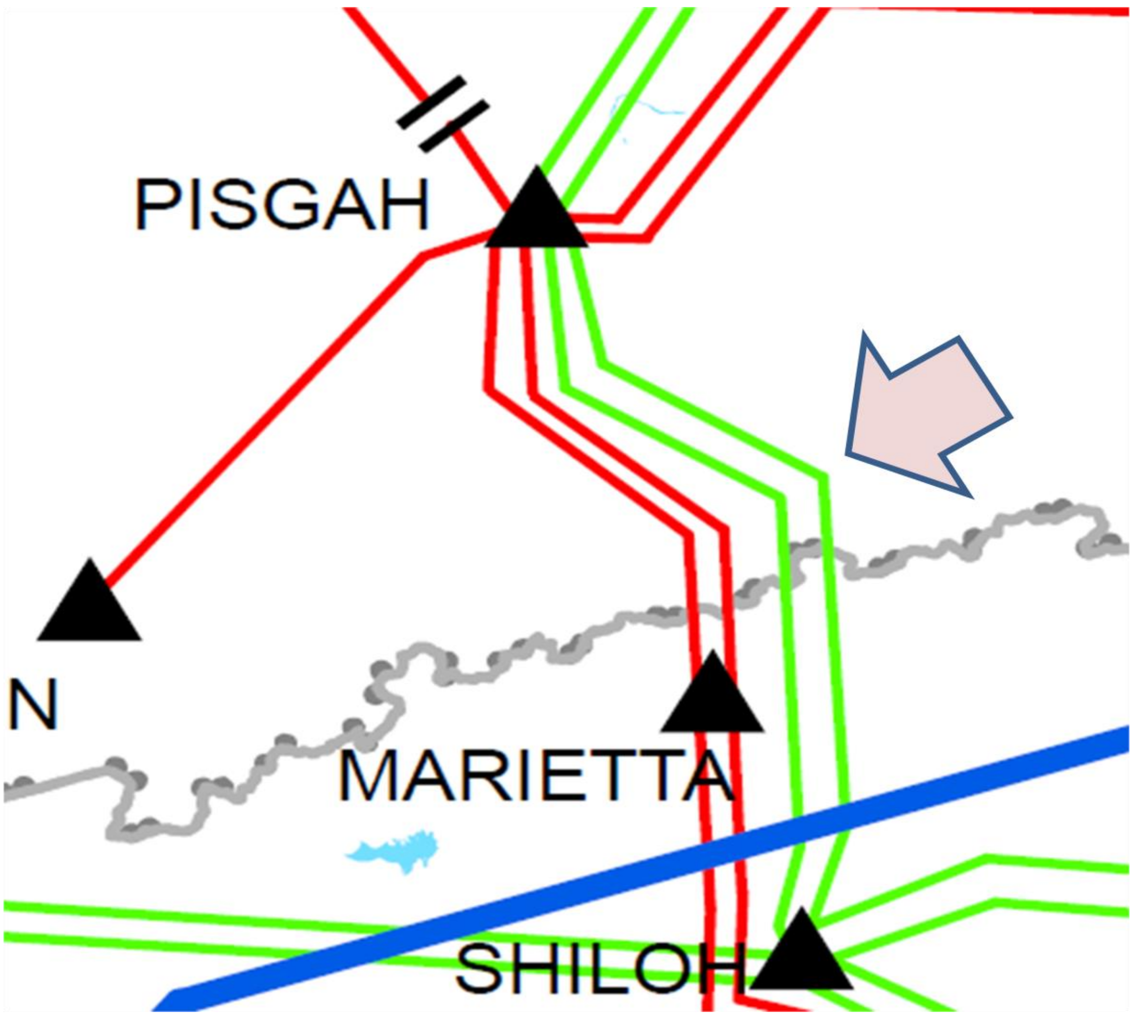
Narrative Description of the Need for this Project
The Caesar Lines would have achieved 100% of their conductor rating in the 2010 timeframe unless restrictions were made on transmission service to Progress West. The lines are most heavily loaded when there is high import into the Progress West area.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

Other Transmission Solutions Considered
Bundle the line. An additional tie line from Duke to 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: 0014 - Peach Valley Tie - Riverview Switching Station #1 and #2 230 kV Lines

Project Description
The project consists of reconductoring 20 miles of the existing 795 ACSR conductor with bundled 795 ACSR conductor.

Status	Planned: No activities taking place at this time. Recent internal studies indicate an in-service date of 2017. Timing of the need for the upgrade will continue to be monitored and action taken considering appropriate lead time required.
Transmission Owner	Duke
Planned In-Service Date	6/1/2017
Estimated Time to Complete	4 years
Estimated Cost	$48 M

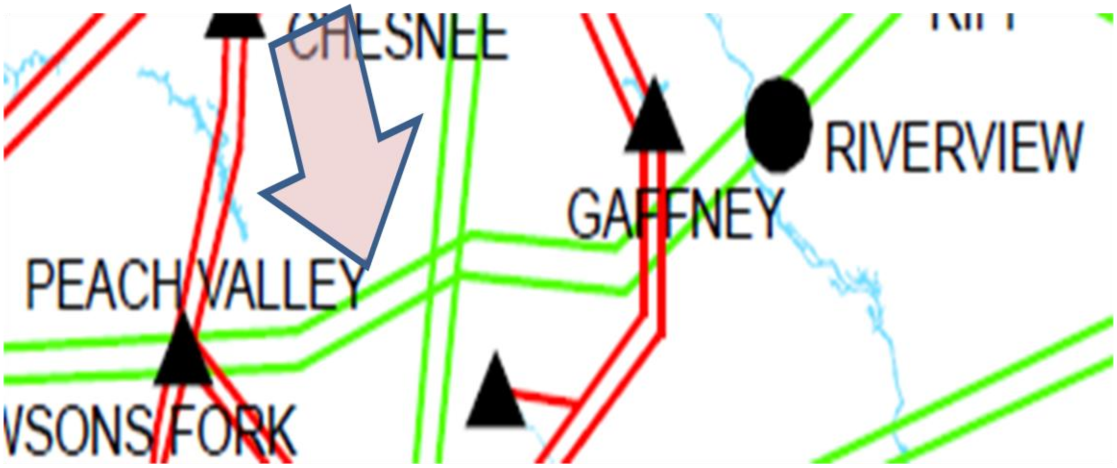
Narrative Description of the Need for this Project
Analysis of the 2017 summer base case showed that in the 2017 timeframe, loss of one circuit of the London Creek 230 kV double circuit line with the outage of a 230 kV connected Oconee unit causes the remaining line to overload. The import level into Progress West, the planned bundling of the Pisgah Tie-Shiloh Switching Station (Caesar) 230 kV Line, and new generation on the 230 kV backbone through the south and central region of the Duke system influence flow on this line. The line is sensitive to south to north transfers, so increased import from SOCO decreases loading on the London Creek Lines and can postpone the need for an upgrade.

Other Transmission Solutions Considered
Reactors

Why this Project was Selected as the Preferred Solution
Duke does not routinely use reactors to redistribute flows on the system. Reactors would increase losses and cause increased flow on the underlying 100 kV system. Bundling of the line will alleviate the loading concern and reduce system losses.

Peach Valley Tie - Riverview Switching Station #1 and #2 230 kV Lines

- **NERC Category B violation**
- **Problem:** The loss of one of the parallel 230 kV lines (London Creek) between Riverview and Peach Valley stations in SC causes the thermal rating of the parallel line to be exceeded.
- **Solution:** Reconductor the 230 kV lines with bundled 795 ACSR.



Appendix C-2
Collaborative Transmission Plan Major Project Descriptions - **Merger 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 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: 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	Underway: Engineering and Construction in progress.
Transmission Owner	Progress
Planned In-Service Date	6/1/2014
Estimated Time to Complete	2 years
Estimated Cost	$15 M

Narrative Description of the Need for this Project
This project is part of the Duke/Progress merger mitigation projects.

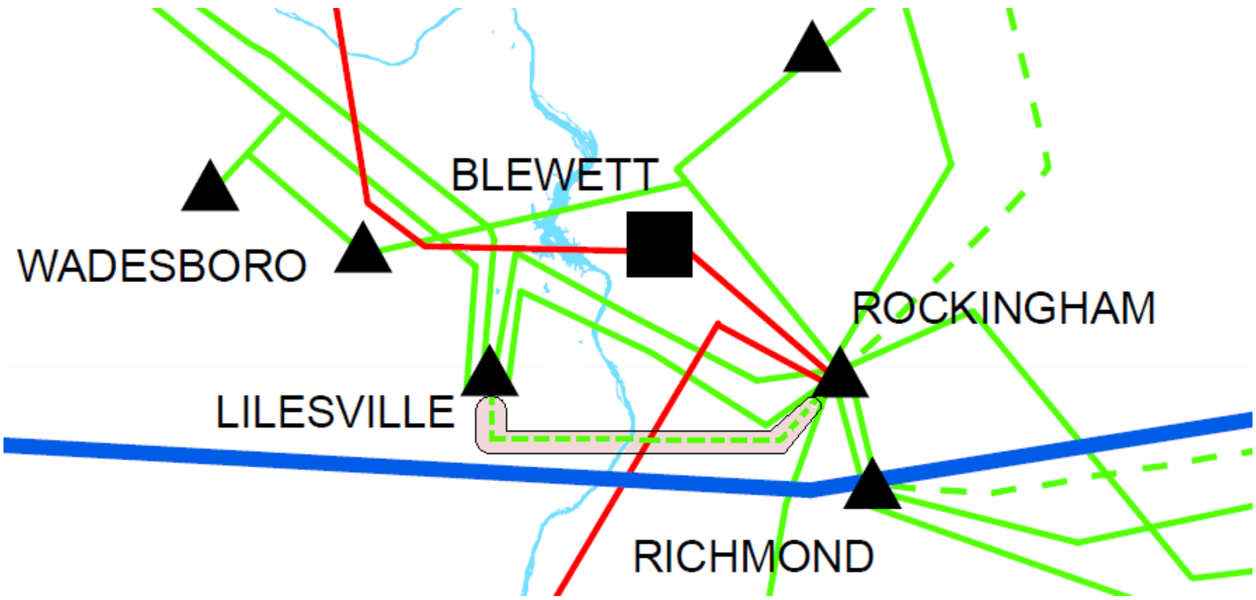
Other Transmission Solutions Considered

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

C-12

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

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

Status	Underway: Engineering and Construction in progress.
Transmission Owner	Dominion
Planned In-Service Date	6/1/2014
Estimated Time to Complete	2 years
Estimated Cost	$16 M

Narrative Description of the Need for this Project
This project is part of the Duke/Progress merger mitigation projects.

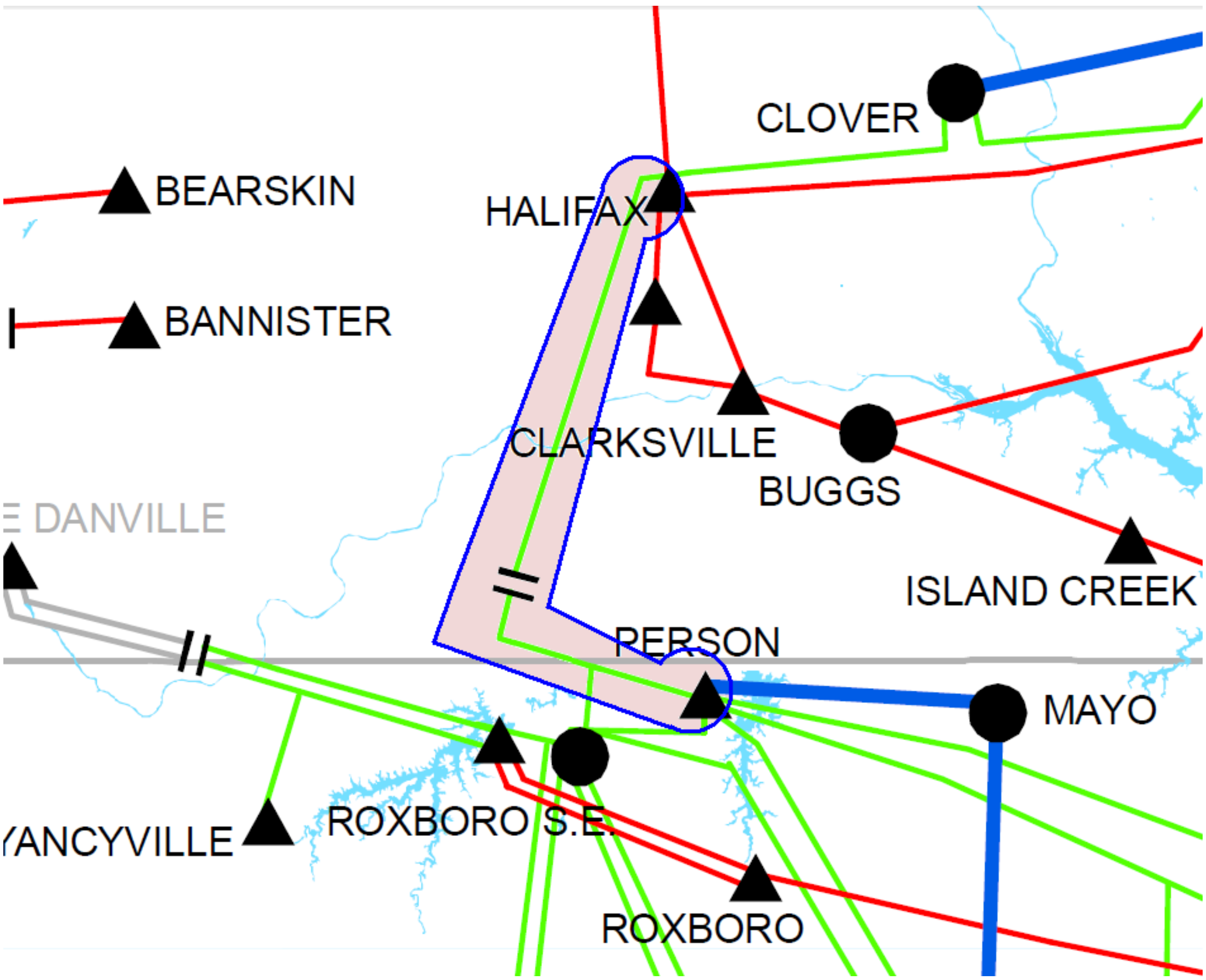
Other Transmission Solutions Considered

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

C-13

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: Antioch 500/230 kV Substation: Replace Two Transformer Banks

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

Status	Underway: Engineering and Construction in progress.
Transmission Owner	Duke
Planned In-Service Date	6/1/2014
Estimated Time to Complete	2 years
Estimated Cost	$28 M

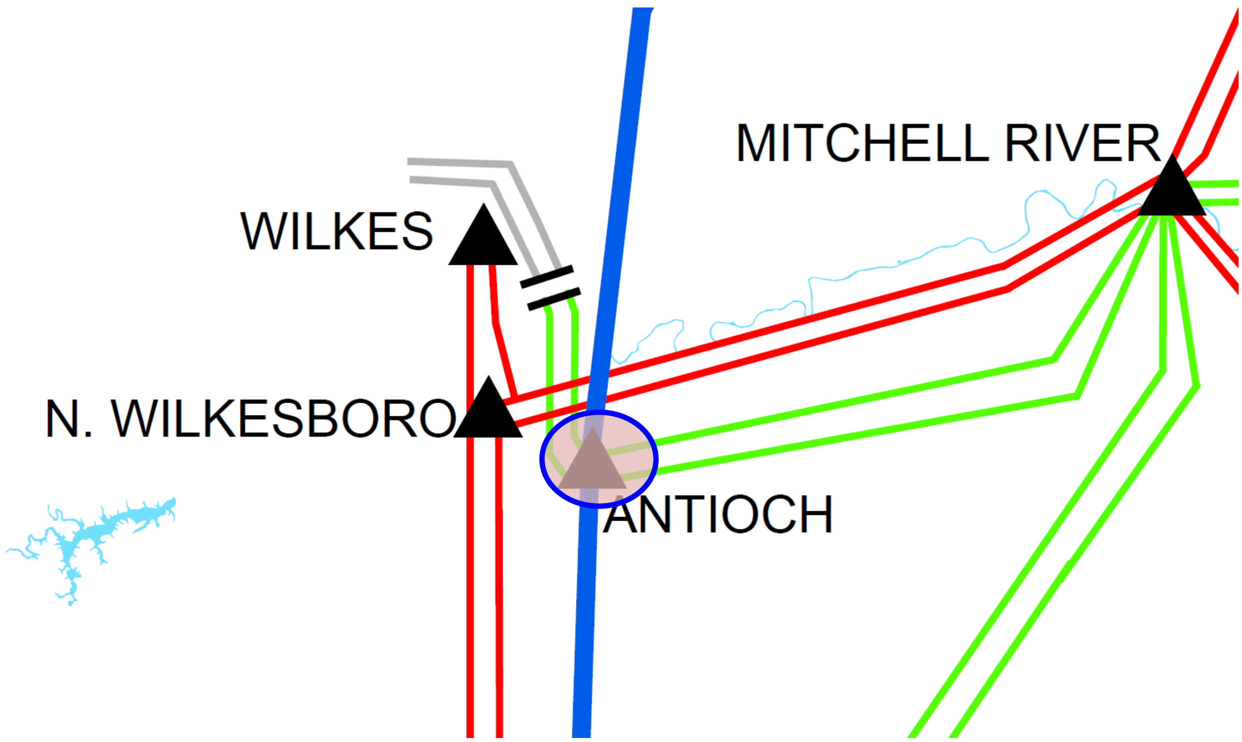
Narrative Description of the Need for this Project
This project is part of the Duke/Progress merger mitigation projects

Other Transmission Solutions Considered

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

Antioch 500/230 kV Substation: Replace Two Transformer Banks

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



Appendix D

Projects Investigated for 2022 Resource Supply Options

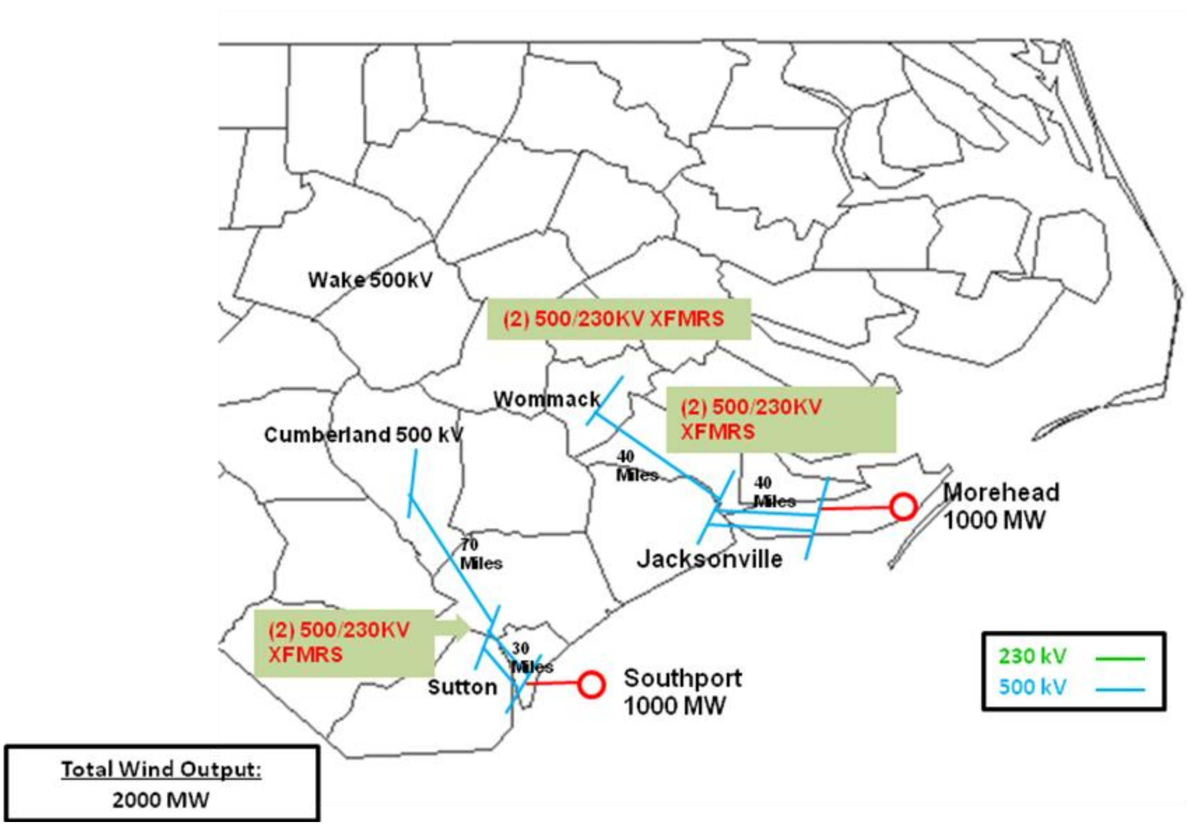
Resource Supply Option – 2022 Hypothetical Generation Scenario Studied in DEC					
Primary Alternative Investigated	**Issue Identified**	**TO**	**Lead Time (years)**	**Davidson County 500 MW**	
				Date Needed[1]	**($M)[2]**
Buck Steam – Buck Tie 100 kV buslines, upgrade conductor	Busline overloads for loss of parallel busline	DEC	1	2022	1.4
Buck Tie 230/100 kV transformers, additional 2 banks	Existing transformer overloads under N-0 conditions as a result of the new generation	DEC	3	2022	16.8

[1] The tables in Appendix D reflect the date the project is needed in order to implement the resource supply option studied.

[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.

Appendix E
PEC Projects Investigated for Wind Scenarios as part of the Joint NCTPC – PJM inter-regional study

NCTPC/PJM Wind Scenario #1 (PEC Upgrades)

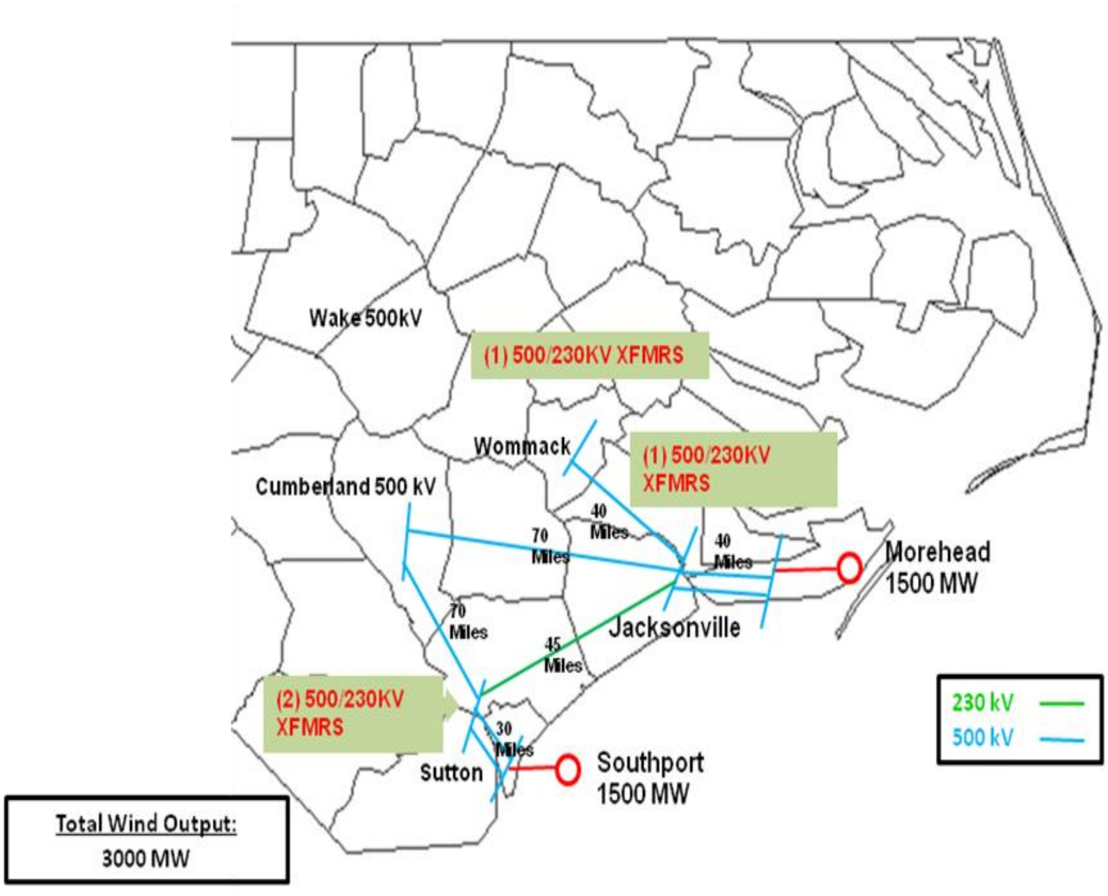


Scenario 1 Summary

Line/Equipment Name	Voltage (kV)	Estimated Mileage (Miles)	Estimated Cost[1] (M)
Morehead 500 kV Switching Station	500		$30
Jacksonville 500 kV Substation	500		$60
Jacksonville - Morehead Switching Station 500 kV Lines	500	80	$200
Wommack 500 kV Substation	500		$60
Jacksonville - Wommack 500 kV Line	500	40	$120
Southport 500 kV Switching Station	500		$30
Sutton North 500 kV Substation (including 230 kV work)	500		$70
Southport - Sutton North 500 kV Lines	500	60	$150
Cumberland - Sutton North 500 kV Line	500	70	$210
Cumberland 500 kV Substation - Add terminals	500		$2
Totals		**250 Miles**	**$932 M**

[1] These are planning cost estimates only for the associated network transmission enhancements and do not include any generator interconnection facilities or capital construction costs associated with the offshore wind farms. Actual costs may be higher or lower than those estimated.

NCTPC/PJM Wind Scenario #2 (PEC Upgrades)

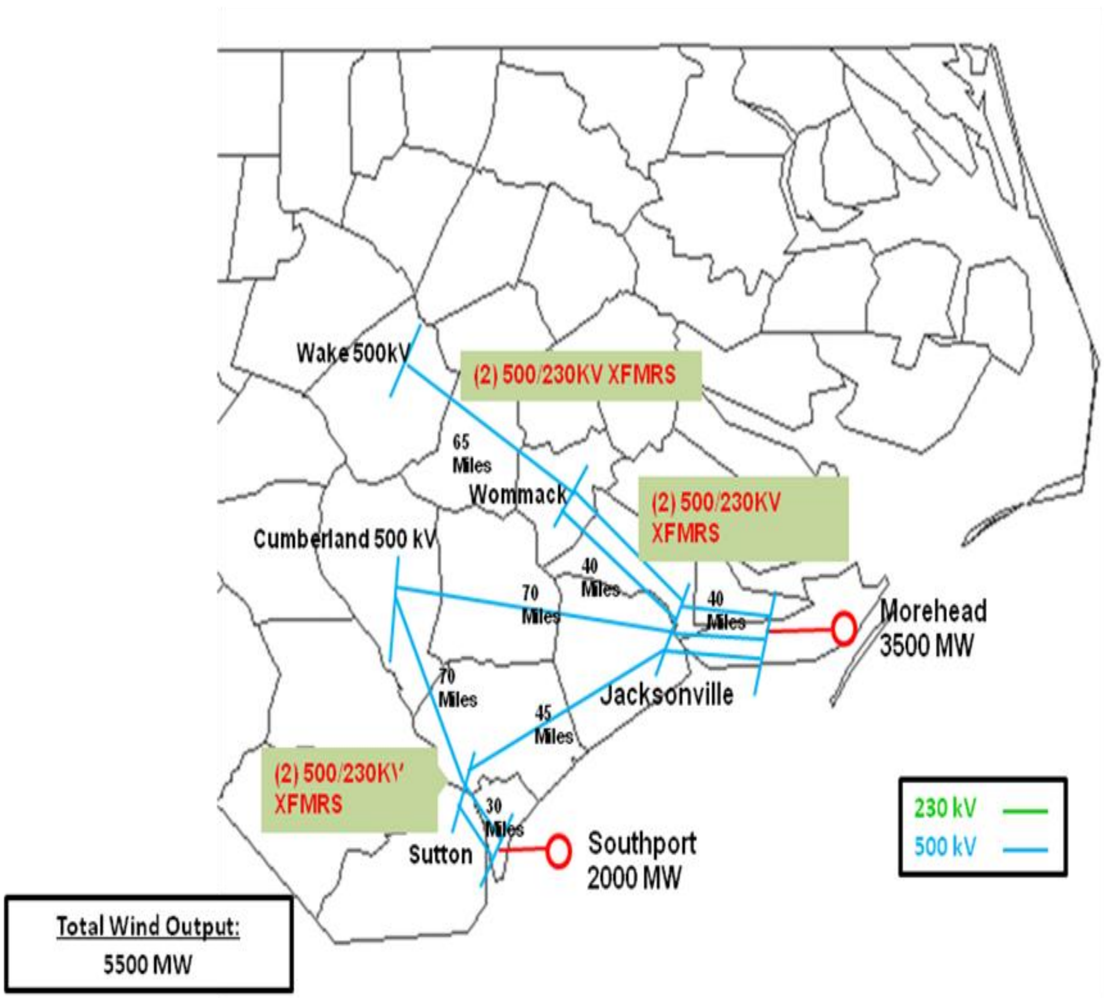


Scenario 2 Summary

Line/Equipment Name	Voltage (kV)	Estimated Mileage (Miles)	Estimated Cost[1] (M)
Morehead 500 kV Switching Station	500		$30
Jacksonville 500 kV Substation	500		$30
Jacksonville - Morehead Switching Station 500 kV Lines	500	80	$200
Wommack 500 kV Substation	500		$30
Jacksonville - Wommack 500 kV Line	500	40	$120
Cumberland - Jacksonville 500 kV Line	500	70	$210
Jacksonville - Sutton North 230 kV Line	500	45	$90
Southport 500 kV Switching Station	500		$30
Sutton North 500 kV Substation (including 230 kV work)	500		$70
Southport - Sutton North 500 kV Lines	500	60	$150
Cumberland - Sutton North 500 kV Line	500	70	$210
Cumberland 500 kV Substation - Add terminals	500		$4
SVC at Sutton North	500		$40
Totals		**365 Miles**	**$1,214 M**

[1] These are planning cost estimates only for the associated network transmission enhancements and do not include any generator interconnection facilities or capital construction costs associated with the offshore wind farms. Actual costs may be higher or lower than those estimated.

NCTPC/PJM Wind Scenario #3 (PEC Upgrades)



Scenario 3 Summary

Line/Equipment Name	Voltage (kV)	Estimated Mileage (Miles)	Estimated Cost[1] (M)
Morehead 500 kV Switching Station	500		$30
Jacksonville 500 kV Substation	500		$60
Jacksonville - Morehead Switching Station 500 kV Lines	500	120	$300
Wommack 500 kV Substation	500		$60
Jacksonville - Wommack 500 kV Lines	500	80	$200
Cumberland - Jacksonville 500 kV Line	500	70	$210
Jacksonville - Sutton North 500 kV Line	500	45	$135
Wake - Wommack 500 kV Line	500	65	$195
Wake 500 kV Sub - Add terminals	500		$2
Southport 500 kV Switching Station	500		$30
Sutton North 500 kV Substation (including 230 kV work)	500		$70
Southport - Sutton North 500 kV Lines	500	60	$150
Cumberland - Sutton North 500 kV Line	500	70	$210
Cumberland 500 kV Substation- Add terminals	500		$4
SVC at Sutton North	500		$40
SVC at Wommack	500		$40
Totals		**510 Miles**	**$1,736 M**

[1] These are planning cost estimates only for the associated network transmission enhancements and do not include any generator interconnection facilities or capital construction costs associated with the offshore wind farms. Actual costs may be higher or lower than those estimated.

Appendix F
Collaborative Plan Comparisons

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2011 Plan[1]			2012 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0011	Asheville - Enka, Convert 115 kV Line to 230 kV, Construct new 115 kV line	Address Asheville 230/115 kV transformer loading	Progress	Partial In-Service	12/1/2010 12/1/2012	34	In-Service	12/1/2010 12/1/2012	30
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.	Progress	Underway	6/1/2012	25	Underway	12/31/2012	27
0022	Jacksonville Static VAR Compensator	Address inadequate dynamic voltage recovery after system faults during periods of high transfers	Progress	Underway	6/1/2012	30	Underway	6/1/2013	32
0023	Folkstone 230/115 kV Substation	Address voltage on Castle Hayne - Jacksonville City 115 kV Line	Progress	Underway	6/1/2013	21	Underway	12/1/2012	19

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)										
				2011 Plan[1]			2012 Plan			
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($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	Progress	Underway	6/1/2014	57	Underway	6/1/2014	59
0028	Brunswick #1 – Jacksonville 230 kV Line Loop-In to Folkstone 230 kV Substation	Address loading on Folkstone – Jacksonville City 115 kV Line.	Progress	Planned	6/1/2016	11	Planned	6/1/2020	14

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2011 Plan[1]			2012 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0008	Greenville - Kinston DuPont 230 kV Line, Construct line	Address loading on Greenville - Everetts 230 kV Line and meet Merger commitment	Progress	Planned	6/1/2017	20	Underway	6/1/2014	34
0029	Arabia 230 kV Substation	Address loading on Raeford 230/115 kV transformer.	Progress	Planned	6/1/2020	20	Replaced with Project 0030		
0030	Raeford 230 kV substation, loop-in Richmond-Ft Bragg Woodruff St 230 kV Line and replace banks	Address loading on Raeford 230/115 kV transformer.	Progress	-	-	-	Planned	6/1/2018	14
0024	Durham - RTP 230 kV Line, Reconductor	Address loading on the Durham-RTP 230 kV Line	Progress	Planned	6/1/2021	15	Planned	6/1/2022	15

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2011 Plan[1]			2012 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($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 Progress West.	Duke	Underway	6/1/2013	20	Underway	12/1/2013	26
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.	Duke	Planned	6/1/2021	43	Planned	6/1/2017	48
TOTAL						**296**			**318**

[1] Information reported in Appendix B of the NCTPC 2011 - 2021 Collaborative Transmission Plan" dated January, 19, 2012.

[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 2011 Report and have been deferred beyond the end of the planning horizon based on analysis performed to develop the 2012 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 Duke/Progress merger mitigation projects.

Appendix G
Acronyms

ACRONYMS

AEP	American Electric Power
AFUDC	Allowance for Funds Used During Construction
CC	Combined Cycle
CPLE	Carolina Power & Light East, or Progress East
CPLW	Carolina Power & Light West, or Progress West
DEC	Duke Energy Carolinas
DNR	Designated Network Resource
DVP	Dominion Virginia Power
ERAG	Eastern Interconnection Reliability Assessment Group
ETAP	Enhanced Transmission Access Planning
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
MMWG	Multiregional Modeling Working Group
MVA	megavolt-ampere
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
PEC	Progress Energy Carolinas, Inc.
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
SEPA	South Eastern Power Administration
SERC	SERC Reliability Corporation
SOCO	Southern Company
TAG	Transmission Advisory Group
TRM	Transmission Reliability Margin
TTC	Total Transfer Capability
TVA	Tennessee Valley Authority
VACAR	Virginia-Carolinas Reliability Agreement