North Carolina Transmission Planning Collaborative

Report on the NCTPC 2011-2021 Collaborative Transmission Plan

January 18, 2012

2011 – 2021 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") and Progress Energy Carolinas, Inc. ("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 2010-2020 Collaborative Transmission Plan (the "2010 Collaborative Transmission Plan" or the "2010 Plan") was published in January 2011.

This report documents the current 2011 – 2021 Collaborative Transmission Plan

(“2011 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 2011 reliability planning study scope and methodology. The NCTPC Process document and 2011 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 2011 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 and the impact of the pending merger was not evaluated. The purpose of the base reliability study was to evaluate the transmission systems’ ability to meet load growth projected for 2016 through 2021 with the Participants’ planned Designated Network Resources (“DNRs”). The 2011 Study allowed for identification of any new system impacts not currently addressed by existing transmission plans in which case solutions were developed. The 2011 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 2011 NCTPC Process focused exclusively on the Reliability Planning Process because stakeholders did not request any Enhanced Transmission Access scenarios for the 2011 Study. Enhanced Transmission Access scenarios will again be solicited for the 2012 Study and included if appropriate.

The NCTPC reliability study results affirmed that the planned Duke and Progress transmission projects identified in the 2010 Plan continue to satisfactorily address the reliability concerns identified in the 2011 Study for the near-term (5 year) and the long-term (10 year) planning horizons. The 2011 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 2011 Plan are those projects identified in the base reliability study. For each of these projects, Appendix B provides the project status, the estimated cost, the planned in-service date, and the estimated time to complete the project. The total estimated cost for these 11 projects included in the 2011 Plan is $296 million. This compares to the 2010 Plan estimate of $473 million for 14 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 2010 Plan.

The modified projects for Progress and Duke in the 2011 Collaborative Transmission Plan, relative to the 2010 Plan, include four Progress projects, one Duke project and one joint Progress / Duke project that were placed in-service. The projects placed in-service are:

- Asheville – Enka 230 kV Line, Convert 115 kV Line (Progress)
- Rockingham – West End 230 kV East Line (Progress)
- Ft. Bragg Woodruff Street – Richmond 230 kV Line (Progress)
- Clinton – Lee 230 kV Line, Construct line (Progress)
- Pleasant Garden (Duke) – Asheboro (Progress) 230 kV Line along with the replacement of the Asheboro 230 kV transformer
- Sadler Tie – Glen Raven Main Circuit 1 & 2 (Elon 100 kV Lines), Reconductor (Duke)

As a result of changes in load forecasts, there were revised in-service dates for the following previously identified projects:

- Brunswick 1 – Castle Hayne 230 kV Line, Construct New Cape Fear River Crossing (Progress)
- Durham – RTP 230 kV Line, Reconductor (Progress)
- Jacksonville Static VAR Compensator (Progress)
- Folkstone 230/115 kV Substation (Progress)
- Reconductor London Creek 230 kV Lines (Peach Valley Tie – Riverview Switching Station #1 & #2) (Duke)

In addition, two new Progress projects were added to the 2011 Collaborative Transmission Plan. These new projects are:

- Brunswick #1 – Jacksonville 230 kV Line Loop-In to Folkstone 230 kV substation
- Arabia 230 kV substation

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 2011 NCTPC Study consisted of three different types of scenarios to examine the transmission system impacts of hypothetical transfers and a hypothetical generation resource. The first resource supply option, the NC Coastal Wind Sensitivity, examined injecting 5,000 MW of renewable wind generation off of the North Carolina coast. The second option examined the impact of fourteen different hypothetical transfers (600 to 1,200 MW) in 2021 across the Duke and Progress interfaces with neighboring utilities. The third resource supply option examined injecting 1,000 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.

For the 2011 NCTPC resource supply option 1, Year 2021 cases were developed for offshore wind scenarios to complement the 2010 offshore wind study analysis. In 2010, studies were done on the impacts of receiving up to 3,000 MW of wind generation off the coast of NC into PEC’s and Duke’s transmission service territories. The 2010 results showed how the transmission system could accommodate up to 3,000 MW’s of wind generation via new transmission infrastructure upgrades. In an effort to understand and quantify how the transmission system could accommodate higher levels of wind generation, additional 2021 cases were developed to study up to 5,000 MW of offshore wind. The analysis examined the impacts of the wind injection on the transmission system requirements to meet the load demand forecasts in the study, and also examined any potential beneficial impacts of the offshore wind scenarios on reliability projects identified in the PWG base reliability plan. The wind scenarios included the following on- and off-peak cases:

Coastal NC wind sensitivity with wind injections in the following locations,

- 2021 case, on-peak:
  - Morehead City (~40% capacity factor): 1,175 MW
  - Bayboro (~35% capacity factor): 875 MW
- 2021 case, off-peak:
  - Morehead City (90% capacity factor): 2,700 MW
  - Bayboro (90% capacity factor): 2,300 MW

Table 1 identifies how these offshore wind energy scenarios were modeled to reflect the following sink allocations:

Table 1

Wind Generation Injection in PEC to Duke and SOCO – Sink Allocation

Participating Transmission Owners	Participation Factor (%)	MW Allocation On Peak	MW Allocation Off Peak
Progress Energy Carolinas	24%	**492**	**1,200 MW**
Duke Energy	36%	**738**	**1,800 MW**
Southern Company[1]	40%	**820**	**2,000 MW**
Total	**100.00%**	**2,050 MW**	**5,000 MW**

For the original 2011 analysis, it was deemed desirable to evaluate possible alternate solutions to accommodate 5,000 MW of offshore wind generation into PEC's existing transmission network. After examining several possible solutions, the 2011 study scope was modified based on the interim study results. This resulted in moving away from integrating the wind generation at the PEC New Bern 230 kV substation and, instead, integrating it at PEC's existing Jacksonville 230 kV substation. PEC's Jacksonville

[1] Southern Company was modeled as a potential sink for this wind energy but was not a direct participant in this study.

substation was identified as the optimum location to accommodate 5,000 MW of wind generation.

Table 2 summarizes the results of the analysis and the costs associated with integrating several levels of the wind generation into the Jacksonville 230 kV Substation. The specific facility results are provided in more detail in Section V.A.3 and Appendix E.

Table 2

Wind Scenario Results at Jacksonville vs. New Bern 230 kV Substations

Wind Output MW	Cost Estimate at Jacksonville Substation (Billions)	Cost Estimate at New Bern Substation (Billions)	Comment
Up to 5,000	$1.239	Not evaluated	Additional infrastructure upgrades required at Jacksonville substation compared to New Bern substation
Up to 3500	Not evaluated	$1.115	Option 1B capacity
Up to 3,000	$1.029	$1.115	Do not need to build the 500 kV line between Jacksonville and Cumberland 500 kV substations
Up to 2,000	$0.430	$0.525	Significant breakpoint in transmission upgrades. Removed 500 kV infrastructure

For the 2011 NCTPC resource supply option 2, Year 2021 cases were developed to re-evaluate fourteen separate hypothetical transfers, last evaluated in the 2009 Study, to meet load demand forecasts projected in the current study. Table 3 provides a summary of the hypothetical transfers that were evaluated.

Table 3

Resource Supply Options – Hypothetical Transfer Scenarios

Source[2]	**Sink**[2]	**MW**	**Estimated Cost ($M)**
Duke	CPLE	600	32
PJM (AEP)	CPLE	600	32
PJM (DVP)	CPLE	600	32
SCEG	CPLE	600	12
SCPSA	CPLE	600	12
CPLE	Duke	600	0
PJM (AEP)	Duke	600	0
SCEG	Duke	600	0
SCPSA	Duke	600	0
SOCO	Duke	600	0
TVA	Duke	600	0
PJM (AEP)	CPLE/Duke[3]	1,200	32
PJM (AEP/DVP)[4]	CPLE/Duke[3]	1,200	12
CPLE/Duke[3]	PJM (DVP)	1,200	0

[2] The various sources and the PJM (DVP) sink were only utilized for modeling the hypothetical transfer scenarios in this analysis and did not directly participate in this study.

[3] 1,200 MW shared 600/600 between CPLE and DUKE

[4] 1,200 MW shared 600/600 between AEP and DVP

Analysis of the fourteen hypothetical transfer scenarios did not identify any projects in Duke beyond those in the 2011 Collaborative Plan. For Progress, however, two major projects were identified beyond those in the 2011 Collaborative Plan. These consisted of, for certain scenarios, the construction of a third 230 kV line between Lilesville and Rockingham and the reconductoring of the existing Sumter – (SCEG) Eastover 115 kV line. The estimated costs for the two upgrades are $20 M and $12 M, respectively.

For the 2011 NCTPC resource supply option 3, Year 2021 cases were developed to evaluate a hypothetical 1,000 MW generator located in Davidson County sinking on the Duke system.

Analysis of a hypothetical 1,000 MW generation resource supply option scenario located in Davidson County and sinking on the Duke system identified four additional projects in Duke beyond those in the 2011 Collaborative Plan. The scenario required upgrading the 230 kV line between the Davidson County hypothetical resource and Beckerdite Tie, to the north, as well as the 230 kV line between the Davidson County hypothetical resource and Buck Tie, to the south. As a result of the generation, the studies showed the need for additional 230/100 kV transformer capacity at Beckerdite Tie and Buck Tie. The Beckerdite - High Point City 4 section of the Linden Street 100 kV lines also needed to be upgraded. The total estimated cost of all these upgrades was $55 M. The specific facility additions for the hypothetical transfer and hypothetical generation scenarios are summarized in Appendix D.

In this 2011 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 First Revised Participation Agreement dated February 11, 2008 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 prepare 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.

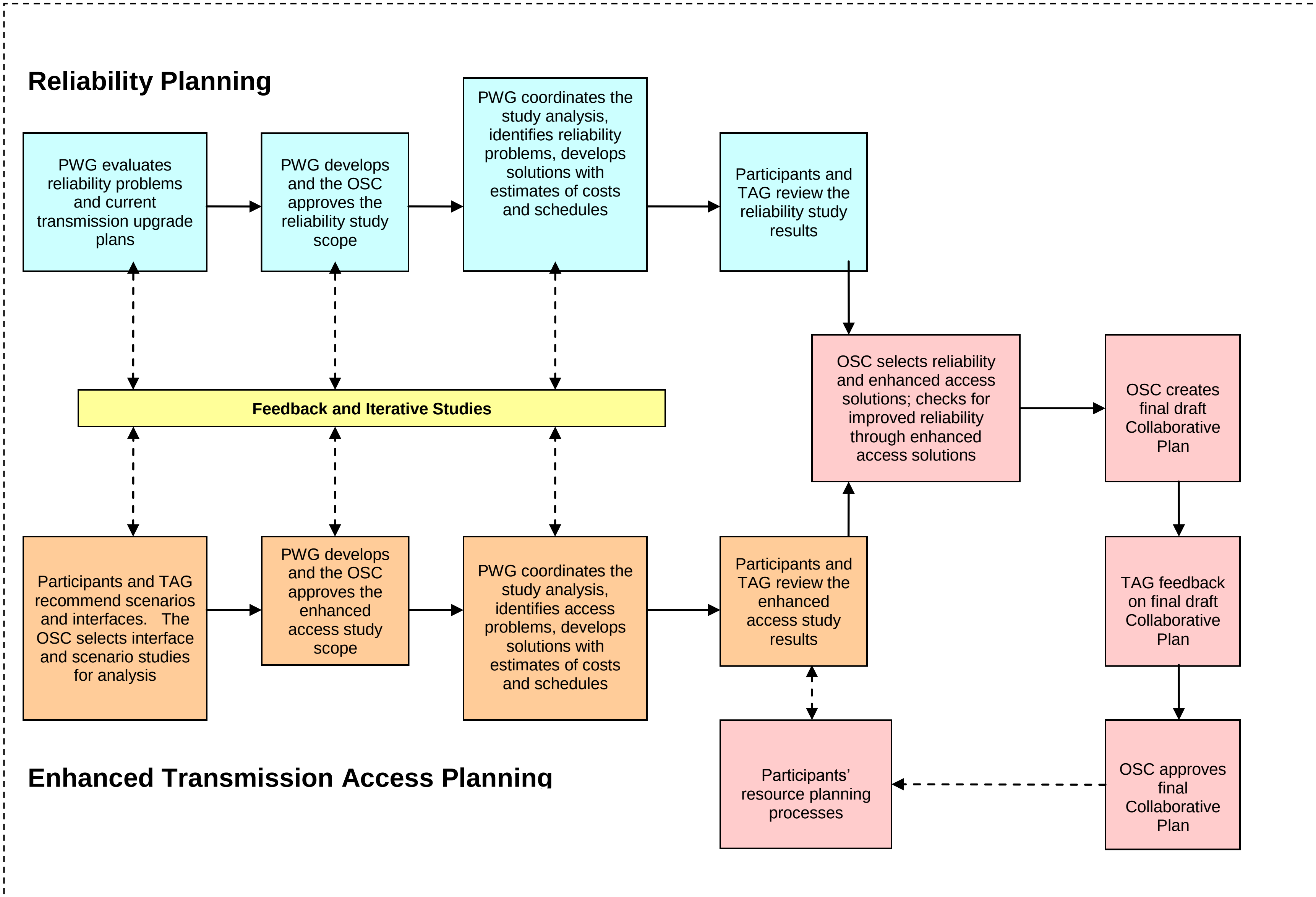
The ETAP Process begins with the Participants and TAG members proposing scenarios and interfaces to be studied. The proposed scenarios and interfaces are compiled by the PWG and then evaluated by the OSC to determine which ones will be included for analysis in the current planning cycle. The PWG coordinates 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 2011 NCTPC Process focused exclusively on the Reliability Planning Process because stakeholders did not request any Enhanced Transmission Access scenarios for the 2011 Study. Enhanced Transmission Access scenarios will again be solicited for the 2012 Study and included if appropriate.

Figure 1

2011 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. 2011 Reliability Planning Study Scope and Methodology

The 2011 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 and the impact of the pending merger was not evaluated. The purpose of the base reliability study was to evaluate the transmission systems' ability to meet load growth projected for 2016 through 2021 with the Participants' planned Designated Network Resources ("DNRs"). The 2011 Study allowed for identification of any new system impacts not currently addressed by existing transmission plans in which case solutions were developed. The 2011 Study also allowed for adjustments to existing plans where necessary.

The resource supply options for the 2011 NCTPC Study consisted of scenarios to examine the transmission system impacts of hypothetical transfers and a hypothetical generation resource. The first scenario examined the impact of fourteen different hypothetical transfers (600 to 1,200 MW) in 2021 across the Duke and Progress interfaces with neighboring utilities. The second resource supply option scenario examined injecting 1,000 MW of power into the transmission system from a hypothetical resource in Davidson County, NC, located within the Duke footprint near the Duke Energy Buck Plant. The third resource supply option scenario examined injecting 5,000 MW of renewable wind generation off of the North Carolina coast.

III.A. Assumptions

1. Study Year and Planning Horizon

The 2011 Collaborative Transmission Plan addresses a ten-year planning horizon through 2021. The study years chosen for the 2011 Study are listed in Table 4.

Table 4
Study Years

Study Year / Season	Analysis
2016 Summer	Near-term base reliability
2016/2017 Winter	Near-term base reliability
2021 Summer	Long-term base reliability, Offshore wind, Resource supply options

To identify projects required in years other than the base study years of 2016 and 2021, 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	1.8 % per year

2. Network Modeling

The network models developed for the 2011 Study included new transmission facilities and upgrades for the 2016 and 2021 models, as appropriate, from the current transmission plans of Duke and Progress and from the 2010 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 2016 and 2021 models. Table 7 lists the generation facility additions and retirements included in the 2016 and 2021 models.

Table 6

Major Transmission Facility Projects Included in Models

Company	Transmission Facility	2016 Base	2021 Base & Sensitivities
Progress	Converted Asheville - Enka 115 kV Line to 230 kV	Yes	Yes
Progress	Asheville - Enka 115 kV Line	Yes	Yes
Progress	Rockingham - West End 230 kV East Line	Yes	Yes
Progress/ Duke	Asheboro - Pleasant Garden 230 kV Line	Yes	Yes
Progress	Fort Bragg Woodruff Street - Richmond 230 kV Line	Yes	Yes
Progress	Clinton - Lee 230 kV Line	Yes	Yes
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	Greenville - Kinston DuPont 230 kV Line	Yes	Yes
Progress	Durham - RTP 230 kV Line	No	No
Duke	Reconductored Elon 100 kV Line from Sadler Tie to Glen Raven Main	Yes	Yes
Duke	Reconductored Caesar 230 kV Line from Pisgah Tie to Shiloh Switching Station	Yes	Yes

Table 7

Major Generation Facility Additions and Retirements in Models

Company	Generation Facility	2016	2021
Duke	Retired Buck 3-6 (369 MW)	Yes	Yes
Duke	Retired Cliffside Units 1-4 (202 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 CT’s (62 MW)	Yes	Yes
Duke	Retired Buzzard Roost CT’s (196 MW)	Yes	Yes
Duke	Retired Dan River CT’s (48 MW)	Yes	Yes
Duke	Retired Riverbend CT’s (64 MW)	Yes	Yes
Duke	Added[3] Buck CC (650 MW)	Yes	Yes
Duke	Added Cleveland Co. CT's (716 MW)	Yes	Yes
Duke	Added[5] Cliffside Unit 6 (825 MW)	Yes	Yes
Duke	Added[3] 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[3] 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

[5] A Certificate of Public Convenience and Necessity has been granted for Duke Energy’s Cliffside Unit 6, Dan River CC, Buck CC, and Progress Energy’s Richmond Co. CC.

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, NC coastal wind sensitivity cases, and the Progress Transmission Reliability Margin ("TRM") cases[6], 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. 1,230 MW of the 2,050 MW output of the units was delivered to DEC and PEC control areas proportional to load ratio shares, with Duke receiving 60% and PEC 40%. In order to study a wind import of 2,050 MW at peak load, 492 MW, 738 MW and 820 MW were allocated to Progress, Duke and SOCO, respectively. Under the assumption that wind was a first-priority resource for Progress and Duke, all remaining load was met by following each Participant's resource dispatch order. Interchange was adjusted in order to reflect the 738 MW of wind allocated to Duke and the 820 MW of wind allocated to SOCO. The 492 MW of wind allocated to Progress was not designated in the interchange because the wind turbines were assumed to be internal to CPLE.

In the off-peak load case of the offshore wind scenario, each Participant's load was scaled to 70% in order to study an import of 5,000 MW of wind, 1,200 MW to Progress, 1,800 MW to Duke and 2,000 MW to SOCO. The 70% load level model is based on Participants' load duration curves. This

[6] 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.

load level simulates highly probable off-peak load conditions creating the most stressed operating conditions for the transmission system at a time when offshore wind would be at its peak capacity. Under the assumption that wind was a first-priority resource for Progress and Duke, all remaining load was met by following each Participant's resource dispatch order. Interchange was adjusted according to each Participant's resource needs following load scaling and wind allocation. The 1,200 MW of wind allocated to Progress was not designated in the interchange, because the wind turbines were assumed to be internal to CPLE.

For hypothetical transfer scenarios, generation outside of the Participants' area was scaled up/down for exports/imports, and the interchange was increased / decreased by the transfer value. For transfers sourcing/sinking from/in Duke, Duke load/generation was scaled down along with economically dispatching Duke generation, and the interchange was increased/decreased by 600 MW in order to model the 600 MW export/import. For transfers sourcing/sinking from/into CPLE, the interchange was increased / decreased by 600 MW along with economically dispatching CPLE generation in order to model the 600 MW export/import.

There was no change in interchange in the hypothetical generation scenario, because the 1,000 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.

III.C. Case Development

The base case for the base reliability study was developed using the most current 2010 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").

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	Buck 5	Catawba 1
Cliffside 5	Cliffside 6	Broad River 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		

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 2016 and 2021 base cases with either a Brunswick 1 unit outage or a Harris 1 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 2011 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 in Section III 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 2011 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 2010 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 impact of transferring 600-1,200 MW across the northern, eastern, southern, and western interfaces of Duke and Progress in 2021. The second resource supply option examined the hypothetical installation of 1,000 MW of new base load generation in the Duke footprint in 2021. 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 2011, 2013, 2015, 2016, and 2019 summer timeframes. For the hypothetical transfers and generation options examined, the limiting facilities identified in the PWG study 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 2011 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 2021 base case.

The 2011 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 2011 Plan are those projects identified in the base reliability study. For each of these projects, Appendix B provides the project status, the estimated cost, the planned in-service date, and the estimated time to complete the project. The total estimated cost for the 11 projects included in the 2011 Plan is $296 million. This compares to the 2010 Plan estimate of $473 million for 14 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 2010 Plan.

V. Resource Supply Option Results

V.A. Option 1 - NC Coastal Wind Sensitivity

1. Follow-up to 2010 Wind Study

In 2010, a NC Coastal Wind Sensitivity scenario that incorporated 3,000 MWs of hypothetical offshore wind into PEC's and Duke's transmission service territories was studied. Of all the options that were examined in the 2010 Study, Option 1B, as described in Table 8, was determined to best accommodate the required 3,000 MW test level. This was accomplished by connecting the wind generation via 500 kV lines into PEC's existing New Bern 230 kV substation. From there, the wind generation was incorporated into the transmission network by connecting to a new switching station near PEC's Wommack 230 kV substation. Additionally, it was also necessary to construct two 500 kV Lines from Wommack to PEC's existing Wake and Cumberland 500 kV Stations. This solution provided the best option to potentially accommodate a long-term build out of offshore wind that might exceed the 3,000 MW test level.

Table 8

2010 Option 1B: 3000 MW of Wind Generation into New Bern 230 kV Substation

Line/Equipment Name	Voltage (kV)	Estimated Mileage (Miles)	Estimated Cost[7] (M)
Morehead City area – New Bern 500 kV lines	500	100 (2 lines)	$250
Bayboro – New Bern 500 kV lines	500	50 (2 lines)	$125
New Bern 500 kV Substation w/ 2 Banks	500		$60

[7] 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.

Wommack 500 kV Switch Station	500		$30
New Bern – Wommack 500 kV lines	500	70 (2 Lines)	$175
Wake – Wommack 500 kV line	500	65	$195
Cumberland – Wommack 500 kV line	500	80	$240
SVC at Wommack	500		$40
Brunswick – Sutton area 230 kV lines	230	60 (2 lines)	$90
230 kV Switch Station at Sutton	230		$15
Sutton – Jacksonville 230 kV line	230	45	$90
Totals		**470 Miles**	**$1,310 M**

2. 2011 Original Wind Scenario Scope

As a follow-up to last year's NCTPC study, the original 2011 study scope was to understand and quantify exactly how much more wind generation Option 1B could accommodate. The initial wind generation injection test level was set at 5,000 MW for the off-peak case and 2,050 MW for the on-peak case. The MW output of the units was delivered to Duke, PEC and Southern Company proportional to load ratio share, with Duke receiving 36%, PEC 24% and SOCO 40%. The geographical locations of wind power injection were only focused at Morehead City and Bayboro in this study, as described below in Table 9. The "Wilmington" location, from the 2010 Study, was not included in this year's study because of its practical lack of expandability.

Table 9

Wind Capacity Factor Summary

Injection Point	***Wind Nameplate Capacity MW***	***On-peak MW (30-40% CF)***	***Off-peak MW (90% CF)***
Morehead City	*3,000*	*1,175*	*2,700*
Bayboro	*2,556*	*875*	*2,300*
Total	*5,556*	*2,050*	*5,000*

Under these study conditions, the off-peak case with wind capacity factor at 90%

presents a greater stress on the transmission system than the on-peak case with lower wind capacity factors. Therefore, solving the transmission constraints for the off-peak case also solves any transmission problems associated with the lower capacity factor on-peak case. Specifically, this year's study results identify that the upper range of total wind capacity for Option 1B is 3,500 MW without any additional infrastructure upgrades. It should be noted that considering only two load levels (on and off-peak) does not mean that the coastal wind can be delivered across all load levels at the output levels listed in this report. Further study would be required to determine if the proposed infrastructure could support 3,500 MW of offshore wind across all load levels.

3. 2011 New Wind Scenario Scope

For the 2011 analysis, the original scope included evaluating possible alternate solutions to accommodate 5,000 MW of offshore wind generation into PEC's existing transmission network. After examining several possible solutions, the 2011 study scope was modified based on the interim study results. This resulted in moving away from integrating the wind generation at the PEC New Bern 230 kV substation, and, instead, integrating it at PEC's existing Jacksonville 230 kV substation. PEC's Jacksonville substation was identified as the optimum location to accommodate 5,000 MW of wind generation. Tables 10 and 11 summarize the results of the analysis and the costs associated with integrating several levels of the wind generation into the Jacksonville 230 kV substation. The specific facility results are provided in more detail in Appendix E. The overnight[8] costs presented in that appendix represent only the transmission network upgrades necessary to integrate this option after the power is delivered to onshore substations. It should be noted that these costs do not include the wind generator interconnection or capital construction costs associated with offshore wind farms.

[8] A project's cost estimate can be reported as "overnight cost" or current year dollars. This would be the cost of the project if all expenditures were spent today (current year cost estimate).

Table 10

Wind Scenario Results at Jacksonville vs. New Bern 230 kV Substations

Wind Output MW	Cost Estimate at Jacksonville Substation (Billions)	Cost Estimate at New Bern Substation (Billions)	Comment
Up to 5,000	$1.239	Not evaluated	Additional infrastructure upgrades required at Jacksonville substation compared to New Bern substation
Up to 3500	Not evaluated	$1.115	Option 1B capacity
Up to 3,000	$1.029	$1.115	Do not need to build the 500 kV line between Jacksonville and Cumberland 500 kV substations
Up to 2,000	$0.430	$0.525	Significant breakpoint in transmission upgrades. Removed 500 kV infrastructure

Table 11

Transmission Upgrade Cost Assumptions for Offshore Wind Study

Transmission Upgrade	Costs
500 kV Line 500 kV Line Common Right of Way	$3M per mile $2.5M per mile
500 kV Station w/ 2-500/230 kV Transformers	$60M

500 kV Switching Station	$30M
230 kV Line 230 kV Line Common Right of Way	$2M per mile $1.5M per mile
Static VAR Compensator (SVC)	$40M

The costs for these output levels represent fully redundant transmission network integration. This means that the analysis was performed in a manner similar to a conventional generator interconnection request in that an outage of a single transmission element would not result in an outage or curtailment of the wind generators.

For the 5,000 MW level, it can be accomplished by connecting the wind generation via 500 kV lines into the Jacksonville 230 kV substation by developing a 500 kV station bus along with two new 500/230 kV transformers. From there, the wind generation would be incorporated into the transmission network by construction of two 500 kV lines from Jacksonville to the Wommack substation and one 500 kV line from Jacksonville to PEC's existing Cumberland 500 kV Substation. Two new 500/230 kV transformers are also needed to upgrade Wommack 230 kV substation to a 500 kV substation. Additionally, the construction of one 500 kV line from Wommack to PEC's existing Wake 500 kV station would be required.

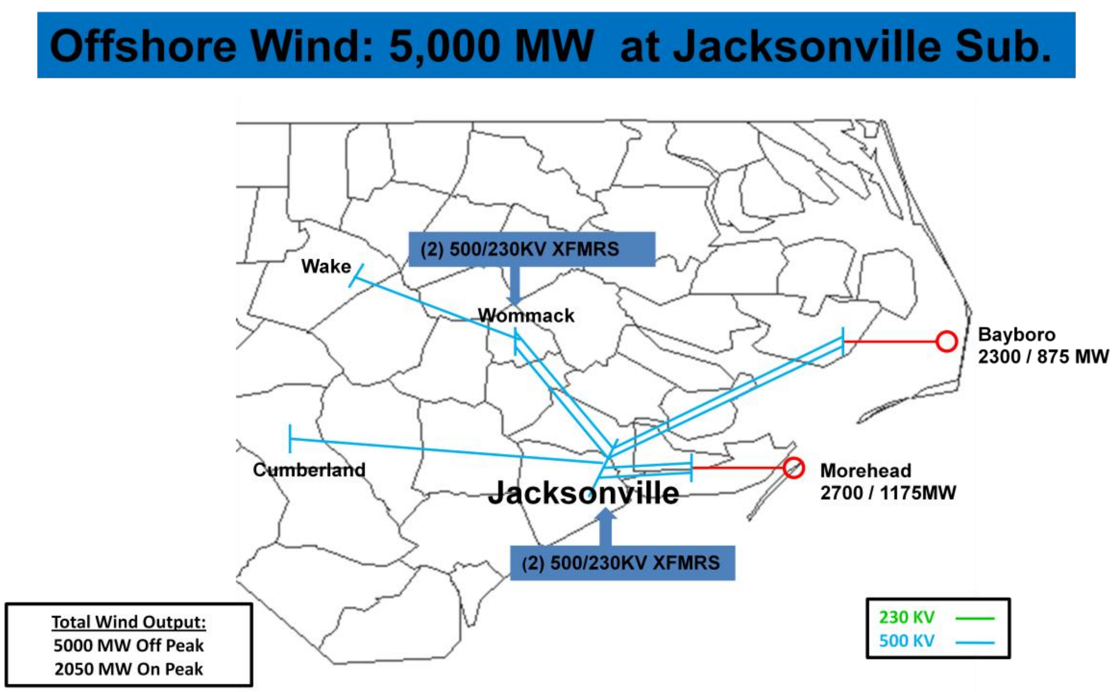
Using this Jacksonville path for the 3,000 MW level is almost the same, with respect to new transmission infrastructure construction, as the 5,000 MW level. The only difference is that the need for a new 500 kV line between the Jacksonville and Cumberland substations is eliminated.

Using this Jacksonville path for the 2,000 MW level offers a significant breakpoint in transmission upgrades, because it does not require any 500 kV infrastructure. Rather, the wind generation is connected via 230 kV lines, with two additional 230 kV lines from the Jacksonville 230 kV substation to the Wommack 230 kV substation.

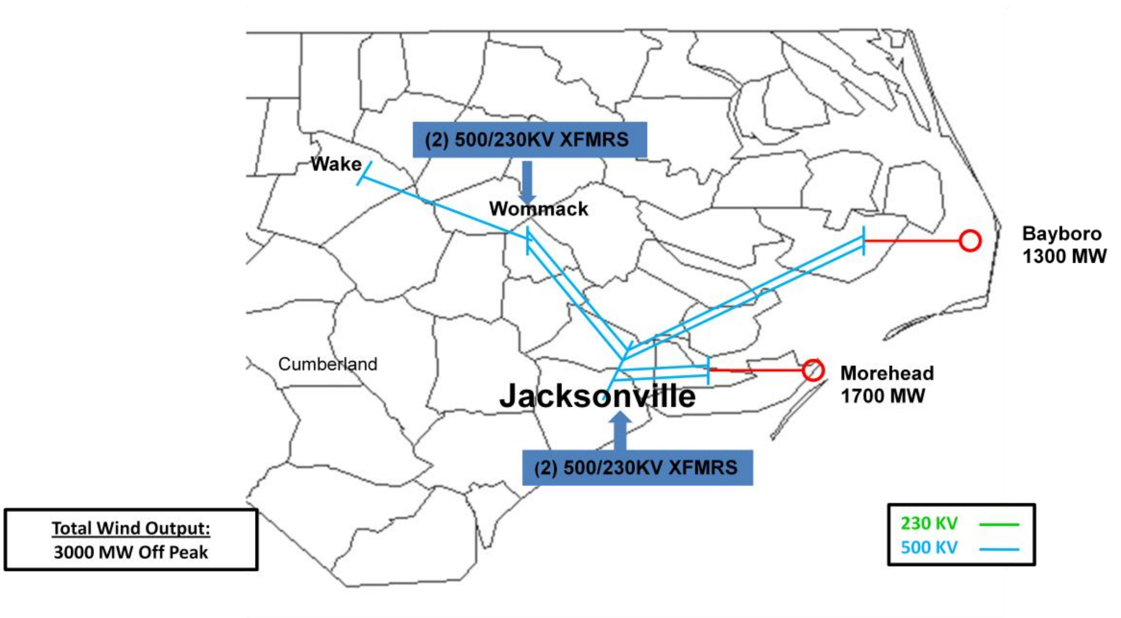
Based on engineering judgment, a static VAR compensator (SVC) is included in all four of these options to mitigate voltage swings associated with the variability of wind generation output as well as the potential area transmission network voltage instability associated with the opening and closing of transmission lines. The inclusion of a SVC provides a starting point for mitigating voltage instability, but a dynamic stability analysis, required for an actual generator interconnection, would be necessary to determine whether the SVC is sufficient for all system conditions.

In addition to the new transmission infrastructure described above, the Greenville - Kinston DuPont 230 kV Line, which is currently scheduled for 2017, would have to be accelerated to accommodate these coastal wind scenarios.

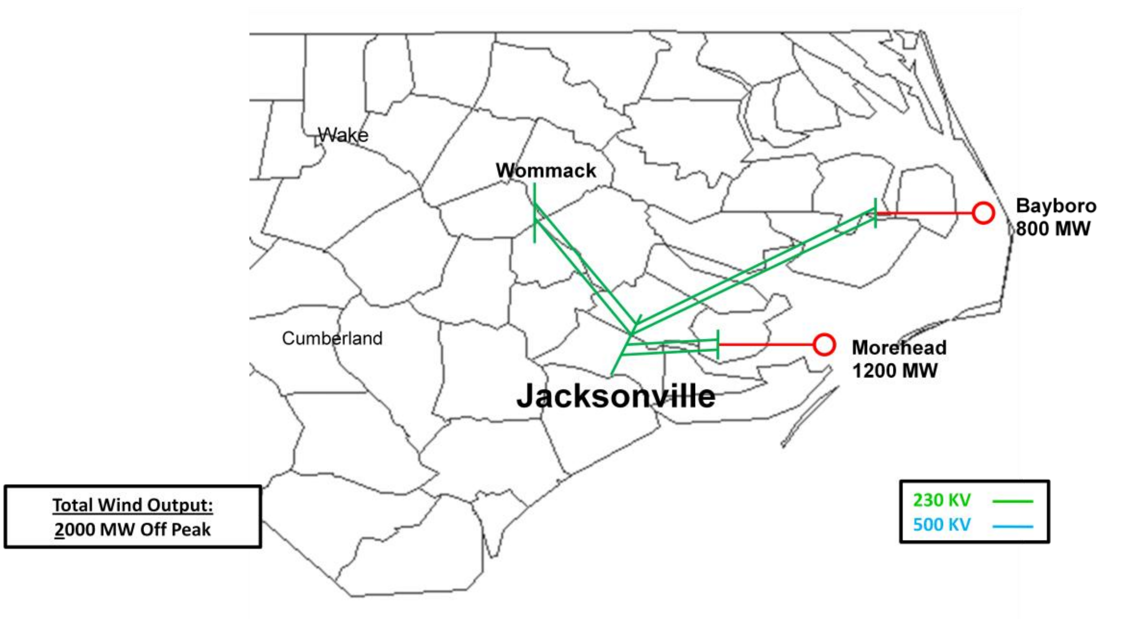
For Duke, the analysis showed that no additional transmission upgrades were required on its system to accommodate the studied wind generation resources.



Offshore Wind: 3,000 MW at Jacksonville Sub.



Offshore Wind: 2,000 MW at Jacksonville Sub.



V.B. Option 2 - Fourteen Hypothetical Transfers

Resource Supply Option 2 consisted of fourteen hypothetical transfer scenarios consisting of 600 MW across the Duke and Progress interfaces with their neighbors, as well as 1,200 MW transfers between the Participants and PJM. Each of these transfers, identified in Table 12, were examined individually, and not in combination with other transfers. Where issues requiring solutions within the applicable planning window were identified, alternative solutions were discussed, and a primary set of solutions was determined.

Table 12

Hypothetical Transfer Scenarios

Source[9]	Sink[9]	MW
Duke	CPLE	600
PJM (AEP)	CPLE	600
PJM (DVP)	CPLE	600
SCEG	CPLE	600
SCPSA	CPLE	600
CPLE	Duke	600
PJM (AEP)	Duke	600
SCEG	Duke	600
SCPSA	Duke	600
SOCO	Duke	600
TVA	Duke	600
PJM (AEP)	CPLE/Duke[10]	1,200
PJM (AEP/DVP)[11]	CPLE/Duke[10]	1,200
CPLE/Duke[10]	PJM (DVP)	1,200

[9] The various sources and the PJM (DVP) sink were only utilized for modeling the hypothetical transfer scenarios in this analysis and did not directly participate in this study.

[10] 1,200 MW shared 600/600 between CPLE and DUKE

[11] 1,200 MW shared 600/600 between AEP and DVP

Analysis of the fourteen hypothetical transfer scenarios did not require any additional transmission projects for Duke beyond those in the 2011 Collaborative Plan. However, two major projects were identified for Progress beyond those in the 2011 Collaborative Plan. These consisted of, for certain scenarios, the construction of a third 230 kV line between Lilesville and Rockingham and the reconductoring of the existing Sumter – (SCEG) Eastover 115 kV line. The estimated costs for the two upgrades are $20 M and $12 M, respectively. The specific facility additions for the hypothetical transfer scenarios are summarized in Appendix D.

V.C. Option 3 - Generation Resource in Davidson County, NC

Analysis of a hypothetical 1,000 MW generator located in Davidson County and sinking on the Duke system identified four additional projects in Duke beyond those in the 2011 Collaborative Plan. The scenario required upgrading the 230 kV line between the Davidson County hypothetical resource and Beckerdite Tie, to the north, as well as the 230 kV line between the Davidson County hypothetical resource and Buck Tie, to the south. As a result of the hypothetical generation, the studies also showed the need for additional 230/100 kV transformer capacity at Beckerdite Tie and Buck Tie. Finally, the Beckerdite - High Point City 4 section of the Linden Street 100 kV lines required upgrading. The total estimated cost of all these upgrades was $55 M. The specific facility additions for this hypothetical generation scenario are summarized in Appendix D.

VI. Collaborative Transmission Plan

The 2011 Collaborative Transmission Plan includes 11 projects with an estimated cost of $10 million or more each. These projects are listed in Appendix B. The total estimated cost for these 11 projects in the 2011 Plan is $296 million. This compares to the 2010 Plan estimate of $473 million for 14 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 2010 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 detailed description of each project in the 2011 Plan, and includes the following information:

1) Reliability Project: 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 2010 Report and have been deferred beyond the end of the planning horizon based on the 2011 Study results.

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

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

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

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

Appendix A
Interchange Tables

2016 SUMMER PEAK

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports – MW

	Base	PEC TRM
CPLE (NCEMC)	37	37
CPLE (NCEMC/Hamlet)	110	110
SCEG (Chappells)	2	2
SCPSA (New Horizons/NHEC)	319	319
SCPSA (PMPA)	179	179
SEPA (Hartwell)	155	155
SEPA (Thurmond)	113	113
SOCO (City of Seneca)	25	25
SOCO (EU2)	0	0
SOCO (NCEMC)	180	180
Total	**1120**	**1120**

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
	135	641

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

2016 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
CPLW (Transfer)	150	150
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	**1650**	**3485**

Progress Energy Carolinas (East) Modeled Exports – MW

	Base	**PEC TRM**
CPLW (Transfer)	0	0
DUKE (NCEMC)	37	37
DUKE (NCEMC/Hamlet)	110	110
DVP (NCEMC)	220	220
DVP (NCEMPA)	150	150
PJM (Cravenwood)	47	47
Total	**564**	**564**

Progress Energy Carolinas (East) Net Interchange - MW

	Base	**PEC TRM**
	-1086	-2921

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

2016 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)	150	150
Total	**150**	**150**

Progress Energy Carolinas (West) Net Interchange – MW

	Base	PEC TRM
Total	149	149

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

2016/2017 WINTER PEAK

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports – MW

	Base	PEC TRM
CPLE (NCEMC)	0	0
CPLE (NCEMC/Hamlet)	110	110
SCEG (Chappells)	2	2
SCPSA (New Horizons/NHEC)	208	208
SCPSA (PMPA)	36	36
SEPA (Hartwell)	155	155
SEPA (Thurmond)	113	113
SOCO (City of Seneca)	20	20
SOCO (EU2)	40	40
SOCO (NCEMC)	144	144
Total	**828**	**828**

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	**1255**	**1461**

Duke Energy Carolinas Net Interchange – MW

	Base	PEC TRM
	427	633

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

2016/2017 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
CPLW (Transfer)	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)	400	400
DUKE (NCEMC)	0	0
DUKE (NCEMC/Hamlet)	110	220
DVP (NCEMC)	220	220
DVP (NCEMPA)	140	140
PJM (Cravenwood)	47	47
Total	**917**	**917**

Progress Energy Carolinas (East) Net Interchange – MW

	Base	**PEC TRM**
Total	-433	-433

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

2016/2017 WINTER PEAK

PROGRESS ENERGY CAROLINAS (WEST)

DETAILED INTERCHANGE

Progress Energy Carolinas (West) Modeled Imports – MW

	Base	**PEC TRM**
CPLE (Transfer)	400	400
DUKE (Rowan)	150	150
DUKE (PEC TRM)	0	206
TVA (SEPA)	1	1
Total	**551**	**757**

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**
Total	-551	-757

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

2021 SUMMER PEAK

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports – MW

	Base	PEC TRM	Off-Peak Wind
CPLE (NCEMC)	56	56	56
CPLE (NCEMC/Hamlet)	110	110	110
CPLE (Offshore Wind)	0	0	738
SCEG (Chappells)	2	2	2
SCPSA (New Horizons/NHEC)	0	0	0
SCPSA (PMPA)	213	213	213
SEPA (Hartwell)	155	155	155
SEPA (Thurmond)	113	113	113
SOCO (City of Seneca)	25	25	25
SOCO (EU2)	0	0	0
SOCO (NCEMC)	180	180	180
Total	**854**	**854**	**1592**

Duke Energy Carolinas Modeled Exports – MW

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

Duke Energy Carolinas Net Interchange

	Base	PEC TRM	Off-Peak Wind
Total	401	907	-337

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

2021 SUMMER PEAK
PROGRESS ENERGY CAROLINAS (EAST)
DETAILED INTERCHANGE

Progress Energy Carolinas (East) Modeled Imports – MW

	Base	PEC TRM	Off-Peak Wind
AEP (NCEMC)	100	100	100
AEP (NCEMC #2)	100	100	100
AEP (PEC TRM)	0	97	0
CPLW (Transfer)	150	150	150
DUKE (Broad River)	850	850	850
DUKE (NCEMC/Catawba)	205	205	205
DUKE (Rowan)	150	150	150
DUKE (PEC TRM)	0	506	0
DVP (SEPA-KERR)	95	95	95
DVP (PEC TRM)	0	835	0
SCEG (PEC TRM)	0	200	0
SCPSA (PEC TRM)	0	197	0
Total	**1650**	**2979**	**1650**

Progress Energy Carolinas (East) Modeled Exports – MW

	Base	PEC TRM	Off-Peak Wind
CPLW (Transfer)	0	0	0
DUKE (NCEMC)	56	56	56
DUKE (NCEMC/Hamlet)	110	110	110
DUKE (Offshore Wind)	0	0	738
DVP (NCEMC)	220	220	220
DVP (NCEMPA)	156	156	156
PJM (Cravenwood)	47	47	47
SOCO (Offshore Wind)	0	0	820
Total	**589**	**589**	**2147**

Progress Energy Carolinas (East) Net Interchange – MW

	Base	PEC TRM	Off-Peak Wind
Total	-1061	-2390	497

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

2021 SUMMER PEAK

PROGRESS ENERGY CAROLINAS (WEST)

DETAILED INTERCHANGE

Progress Energy Carolinas (West) Modeled Imports – MW

	Base	**PEC TRM**	**Off-Peak Wind**
CPLE (Transfer)	0	0	0
DUKE (Rowan)	0	0	0
DUKE (PEC TRM)	0	0	0
TVA (SEPA)	1	1	0
Total	**1**	**1**	**1**

Progress Energy Carolinas (West) Modeled Exports – MW

	Base	**PEC TRM**	**Off-Peak Wind**
CPLE (Transfer)	150	150	150
Total	**150**	**150**	**150**

Progress Energy Carolinas (West) Net Interchange – MW

	Base	**PEC TRM**	**Off-Peak Wind**
Total	149	149	149

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

2021 SUMMER / ON-PEAK WIND (OFF-PEAK LOAD) CASE

DUKE ENERGY CAROLINAS

DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports – MW

	On-Peak Wind
CPLE (NCEMC)	0
CPLE (NCEMC/Hamlet)	110
CPLE (Offshore Wind)	1800
SCEG (Chappells)	2
SCPSA (New Horizons/NHEC)	0
SCPSA (PMPA)	47
SEPA (Hartwell)	155
SEPA (Thurmond)	113
SOCO (City of Seneca)	17
SOCO (EU2)	0
SOCO (NCEMC)	22
Total	**2266**

Duke Energy Carolinas Modeled Exports – MW

	On-Peak Wind
CPLE (Broad River)	0
CPLE (NCEMC/Catawba)	205
CPLE (Rowan)	0
CPLW (Rowan)	0
DVP (NCEMC)	50
Total	**255**

Duke Energy Carolinas Net Interchange – MW

	On-Peak Wind
Total	-2011

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

2021 SUMMER / ON-PEAK WIND (OFF-PEAK LOAD) CASE

PROGRESS ENERGY CAROLINAS (EAST)

DETAILED INTERCHANGE

Progress Energy Carolinas (East) Modeled Imports – MW

	On-Peak Wind
AEP (NCEMC)	70
AEP (NCEMC#2)	70
CPLW (Transfer)	0
DUKE (Broad River)	0
DUKE (NCEMC/Catawba)	205
DUKE (Rowan)	0
DVP (SEPA-KERR)	95
Total	**440**

Progress Energy Carolinas (East) Modeled Exports – MW

	On-Peak Wind
CPLW (Transfer)	0
DUKE (NCEMC)	0
DUKE (NCEMC/Hamlet)	110
DUKE (Offshore Wind)	1800
DVP (NCEMC)	154
DVP (NCEMPA)	109
PJM (Cravenwood)	47
SOCO (Offshore Wind)	2000
Total	**4220**

Progress Energy Carolinas (East) Net Interchange – MW

	On-Peak Wind
Total	3780

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

2021 SUMMER / ON-PEAK WIND (OFF-PEAK LOAD) CASE

PROGRESS ENERGY CAROLINAS (WEST)

DETAILED INTERCHANGE

Progress Energy Carolinas (West) Modeled Imports – MW

	On-Peak Wind
CPLE (Transfer)	0
CPLE (Rowan)	0
TVA (SEPA)	1
Total	**1**

Progress Energy Carolinas (West) Modeled Exports – MW

	On-Peak Wind
CPLE (Transfer)	0
Total	**0**

Progress Energy Carolinas (West) Net Interchange – MW

	On-Peak Wind
Total	-1

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

Appendix B
Collaborative Transmission Plan Major Project Listing

2011 Collaborative Transmission Plan – Major Project Listing (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	Partial In-Service	Progress	12/1/2010 12/1/2012	34	- 1
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	25	1
0022	Jacksonville Static VAR Compensator	Address inadequate dynamic voltage recovery after system faults during periods of high imports	Underway	Progress	6/1/2013	30	1.5
0023	Folkstone 230/115 kV Substation	Address voltage on Castle Hayne - Jacksonville City 115 kV Line	Underway	Progress	12/1/2012	21	1
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	57	2.5

2011 Collaborative Transmission Plan – Major Project Listing (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	6/1/2016	11	4
0008	Greenville - Kinston DuPont 230 KV Line Construct line	Address loading on Greenville - Everetts 230 kV Line	Planned	Progress	6/1/2017	20	4
0029	Arabia 230 kV substation	Address loading on Raeford 230/115 kV transformer	Planned	Progress	6/1/2020	20	4
0024	Durham - RTP 230 kV Line, Reconductor	Address loading on the Durham - RTP 230 kV Line	Planned	Progress	6/1/2021	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	6/1/2013	20	1.5
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	6/1/2021	43	4
TOTAL						**296**	

[1] Status: *Underway:* Projects with this status range from the Transmission Owner having some money in its current year budget for the project to the Transmission Owner having completed some construction activities for the project. *Planned:* Projects with this status do not have money in the Transmission Owner's current year budget; and the project is subject to change.

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

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

Appendix C
Collaborative Transmission Plan Major Project Descriptions

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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	Partial Complete: Project is on schedule. Conversion of Enka Switching Station from 115 kV to 230 kV is completed and is in-service. Conceptual Design of second phase is complete and construction of new 115 kV Line is underway.
Transmission Owner	Progress
Planned In-Service Date	12/1/2010, conversion of existing line 12/1/2012, construction of new line
Estimated Time to Complete	0 year for conversion, 1 year for new line
Estimated Cost	$34 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 is 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.

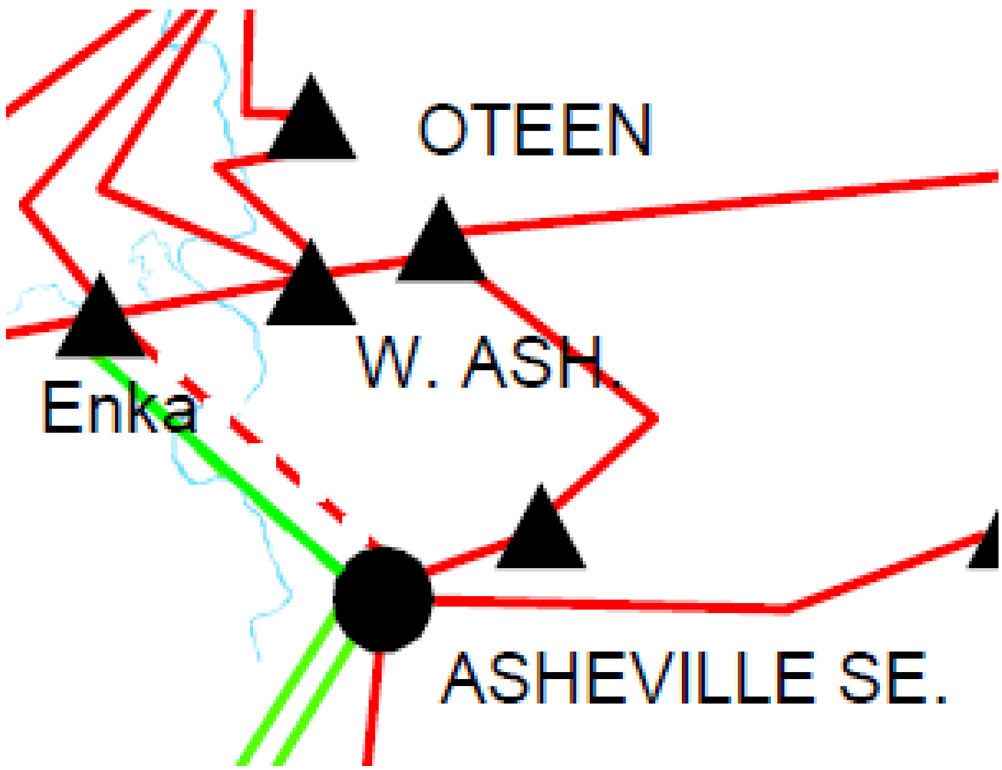
Other Transmission Solutions Considered
Replace Asheville 230/115 kV transformers with higher rated transformers.

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: Underground 230 kV design decision made.
Transmission Owner	Progress
Planned In-Service Date	12/31/2012
Estimated Time to Complete	1 year
Estimated Cost	$25 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.

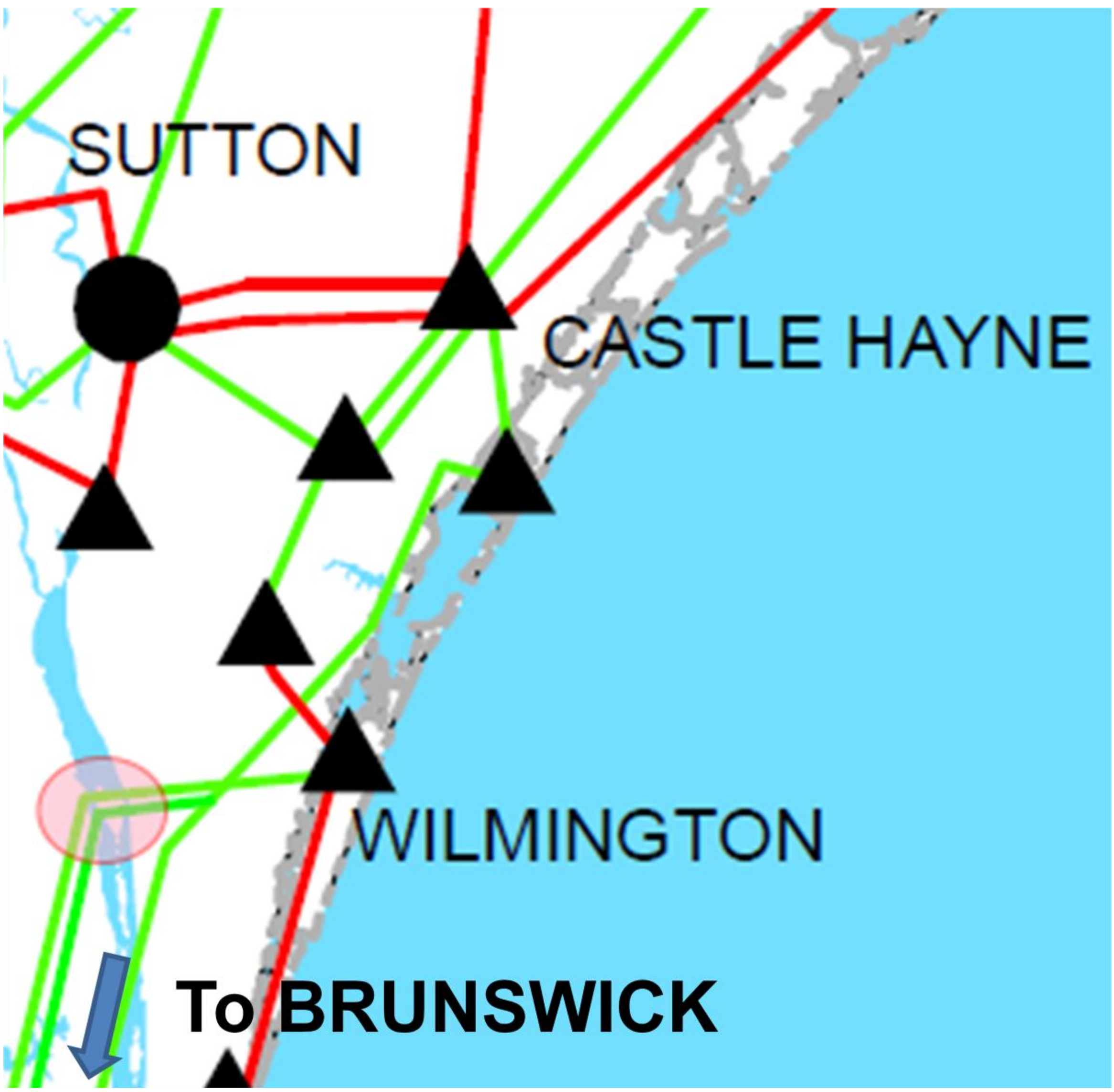
Other Transmission Solutions Considered
Rebuild, reconductor existing line.

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	1.5 years
Estimated Cost	$30 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.

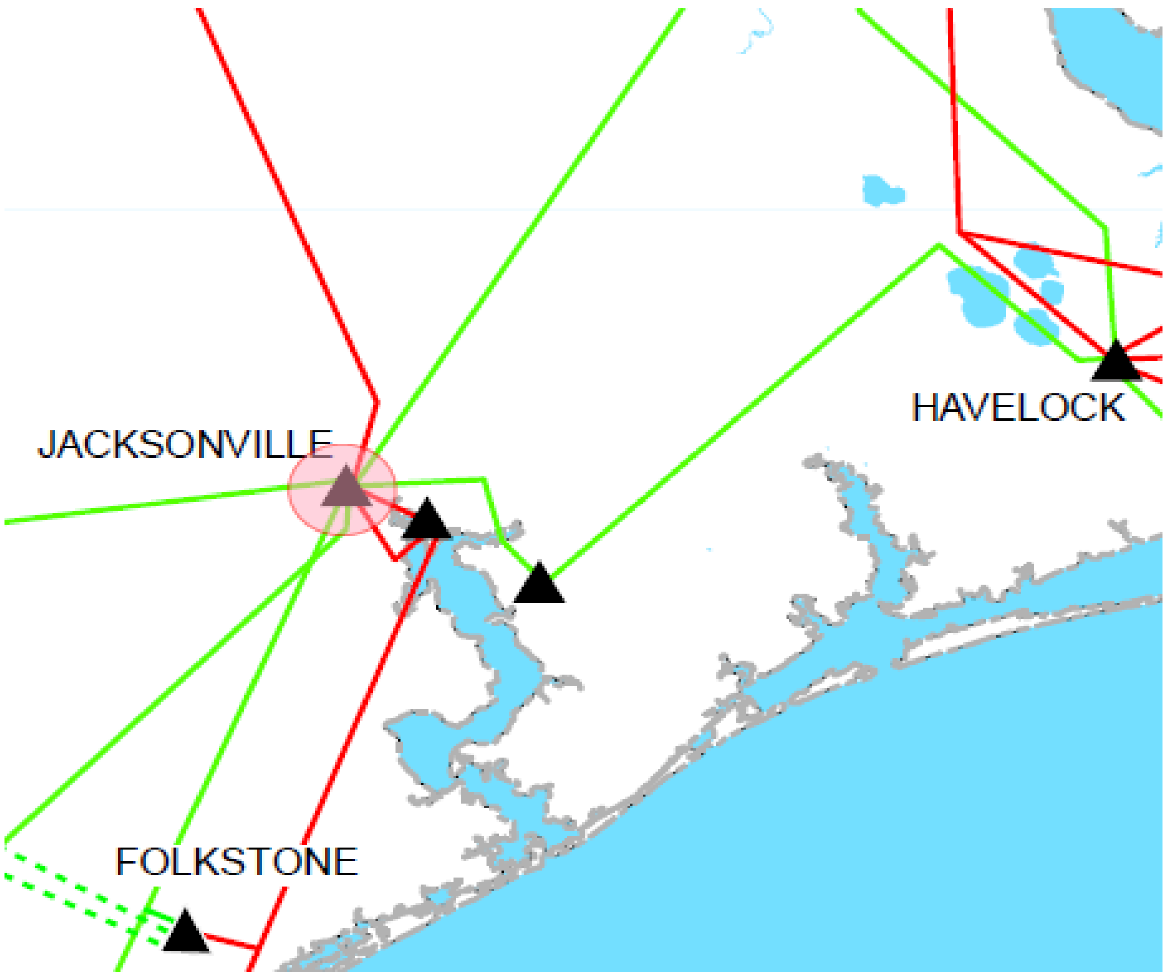
Other Transmission Solutions Considered
N/A

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	Planned
Transmission Owner	Progress
Planned In-Service Date	12/1/2012
Estimated Time to Complete	1 year
Estimated Cost	$21 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.

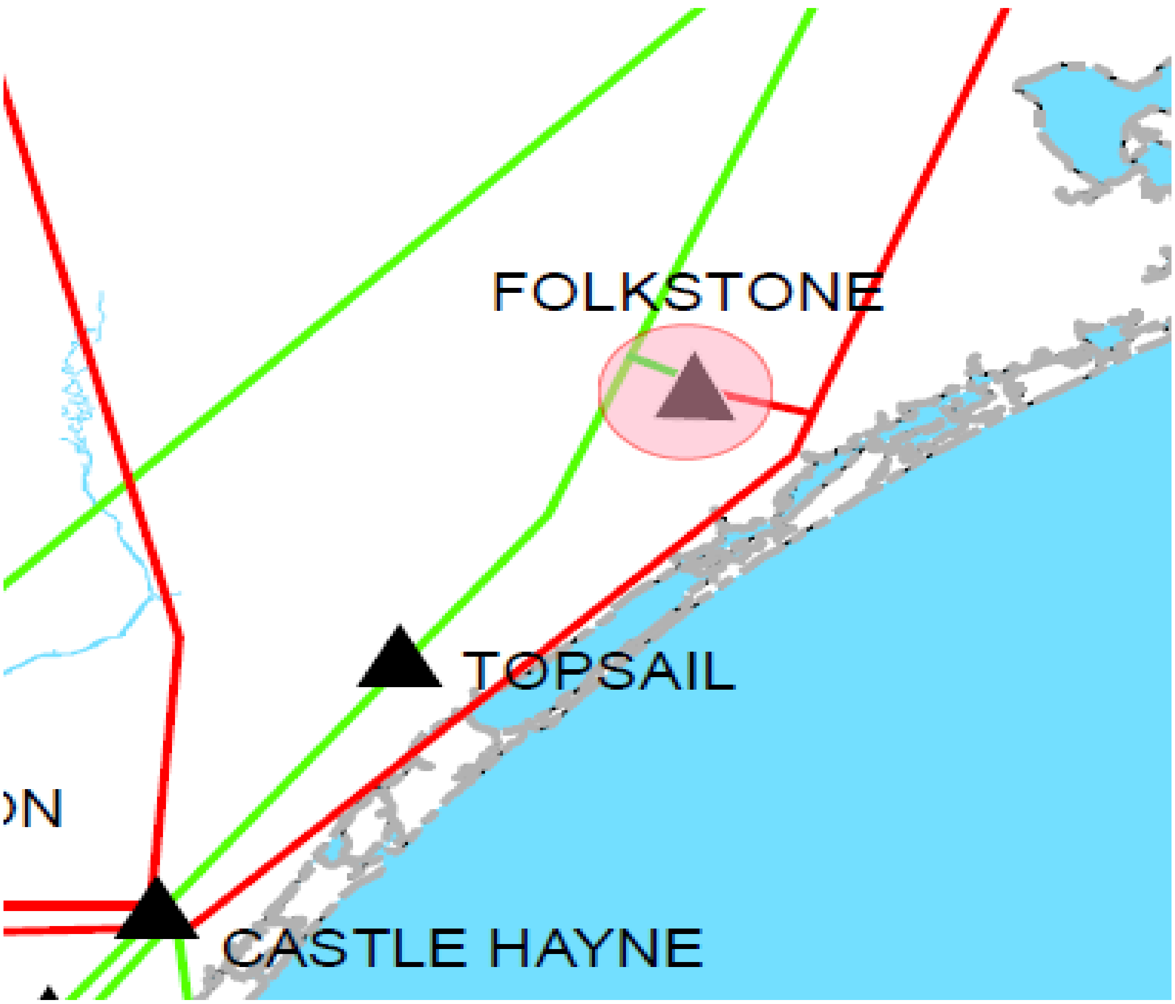
Other Transmission Solutions Considered
Reconductor existing line.

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	2.5 years
Estimated Cost	$57 M

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

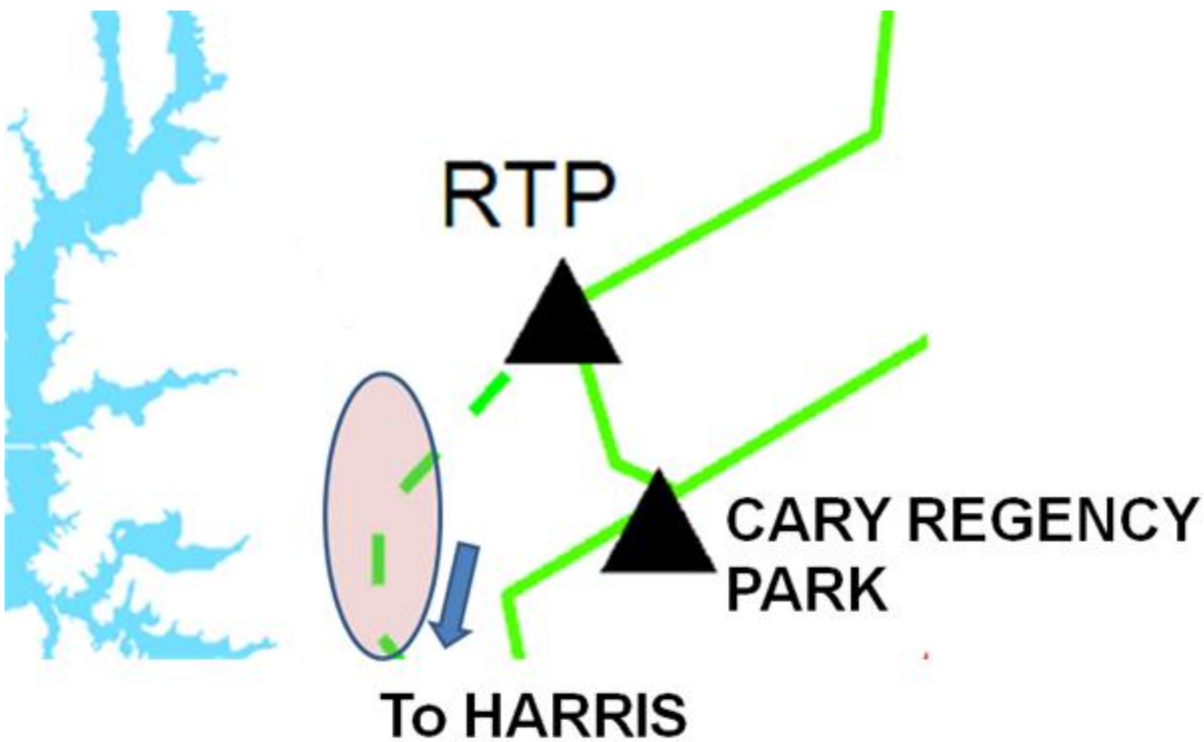
Other Transmission Solutions Considered
Construct Harris - Durham 230 kV line.

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	6/1/2016
Estimated Time to Complete	4 years
Estimated Cost	$11 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.

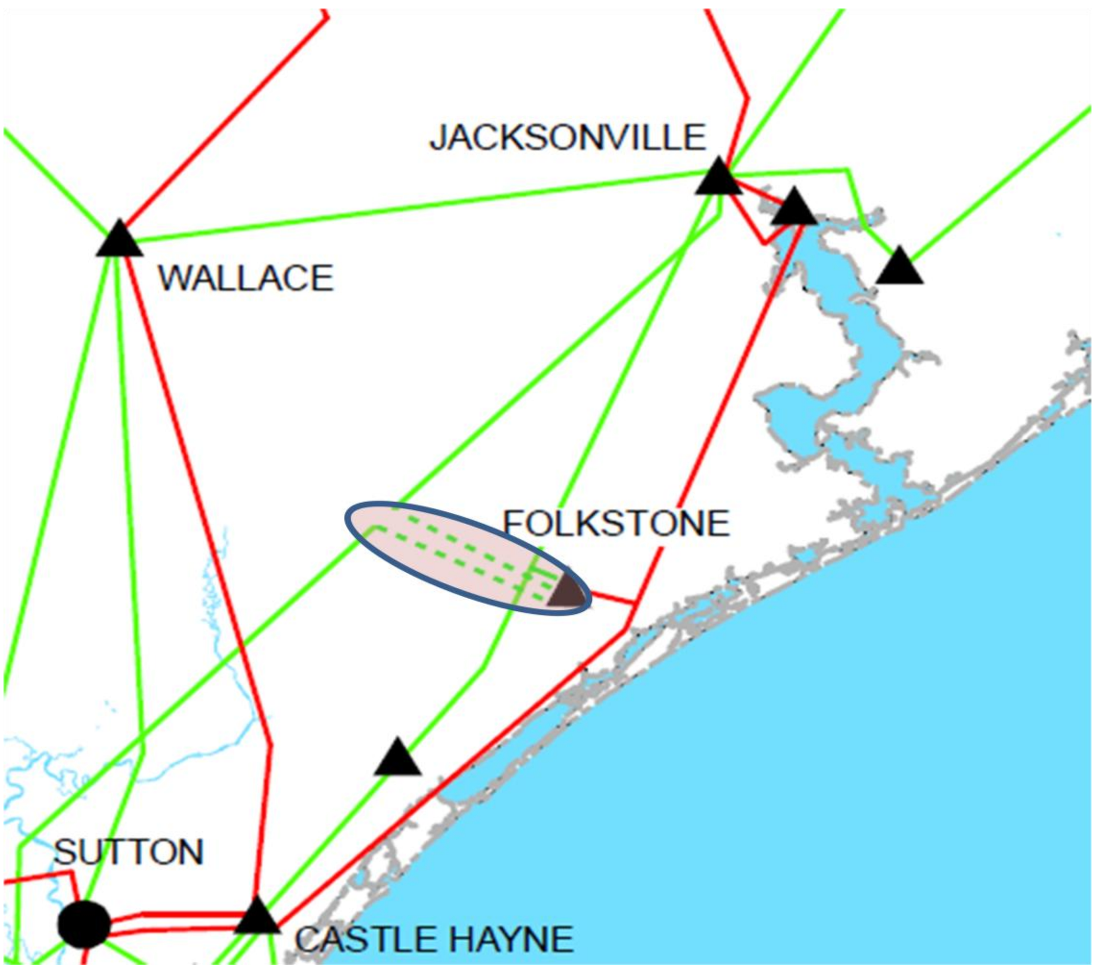
Other Transmission Solutions Considered
Rebuild, reconductor existing line.

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

C-6

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	6/1/2017
Estimated Time to Complete	4 years
Estimated Cost	$20 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.

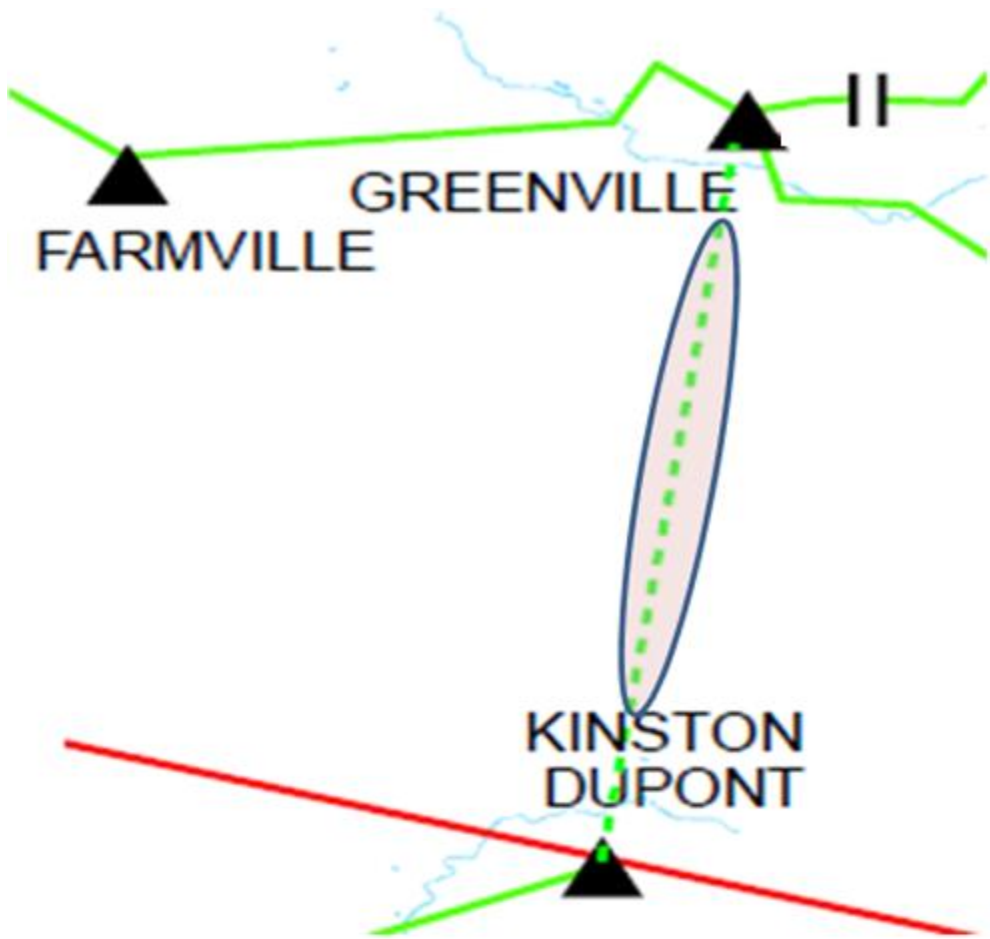
Other Transmission Solutions Considered
Rebuild, reconductor existing line.

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.



Project ID and Name: 0029 – Arabia 230 kV Substation

Project Description
Construct the new Arabia 230 kV Substation, loop-in the Richmond – Ft. Bragg Woodruff St. 230 kV line and connect to the Lumbee River EMC's Arabia POD and Rockfish POD 115 kV line on the low voltage side. This project will require the construction of approximately 4 miles of 3-1590 at 115 kV and the installation of a 200 MVA 230/115 kV transformer. This project will utilize a 200 MVA transformer bank from another project if feasible.

Status	Planned: All right-of-way has been acquired.
Transmission Owner	Progress
Planned In-Service Date	6/1/2020
Estimated Time to Complete	4 years
Estimated Cost	$20 M

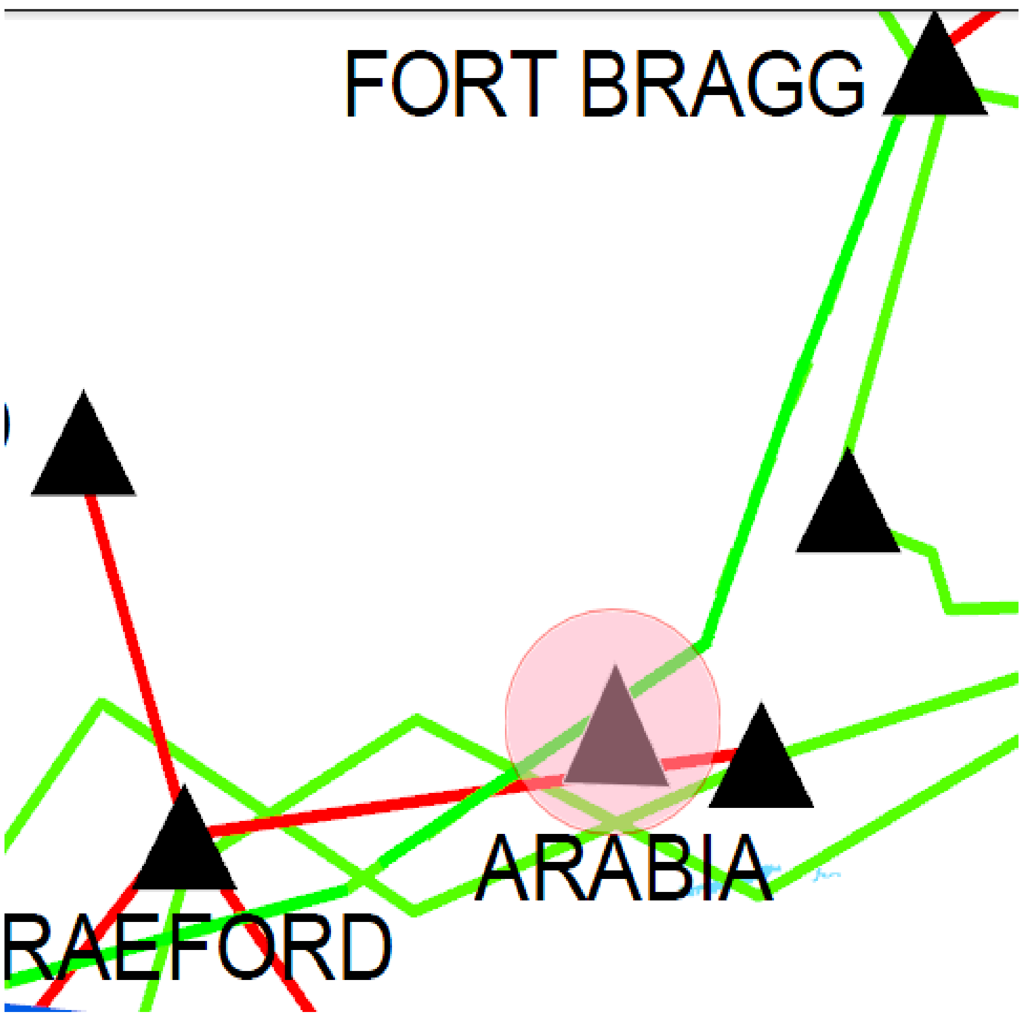
Narrative Description of the Need for this Project
By 2020, with a Brunswick Unit down, either of the Raeford 230/115 kV, 200 MVA transformers at the Raeford 230 kV Substation will overload during an outage of the other 230/115 kV transformer. Similar scenario also applies to the Laurinburg transformers. This project will mitigate each of these contingencies.

Other Transmission Solutions Considered
Replace Raeford Transformers.

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

Arabia 230 kV Substation

- **NERC Category C Violations**
- **Problem:** With a Brunswick Unit down 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:** Construct the new Arabia 230 kV Substation, loop-in the Richmond – Ft. Bragg Woodruff St. 230 kV line and connect to the Lumbee River EMC's Arabia POD and Rockfish POD 115 kV line on the low voltage side.



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	6/1/2021
Estimated Time to Complete	4 years
Estimated Cost	$15 M

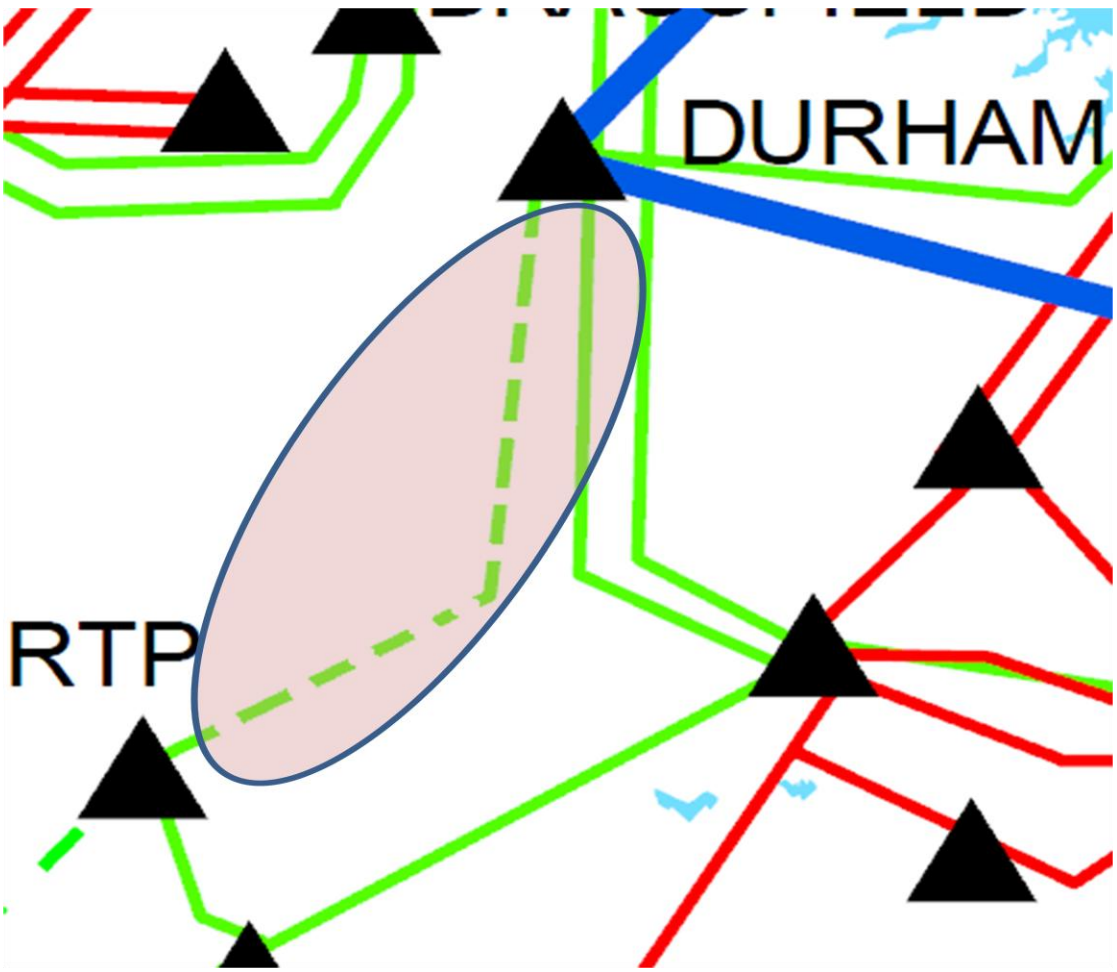
Narrative Description of the Need for this Project
With Harris Plant down, a common tower outage of the Method - (DPC) East Durham and the Durham - Method 230 kV Lines will cause an overload of the Durham 500 kV Sub - RTP 230 kV Switching Station Line.

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	6/1/2013
Estimated Time to Complete	1.5 years
Estimated Cost	$20 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.

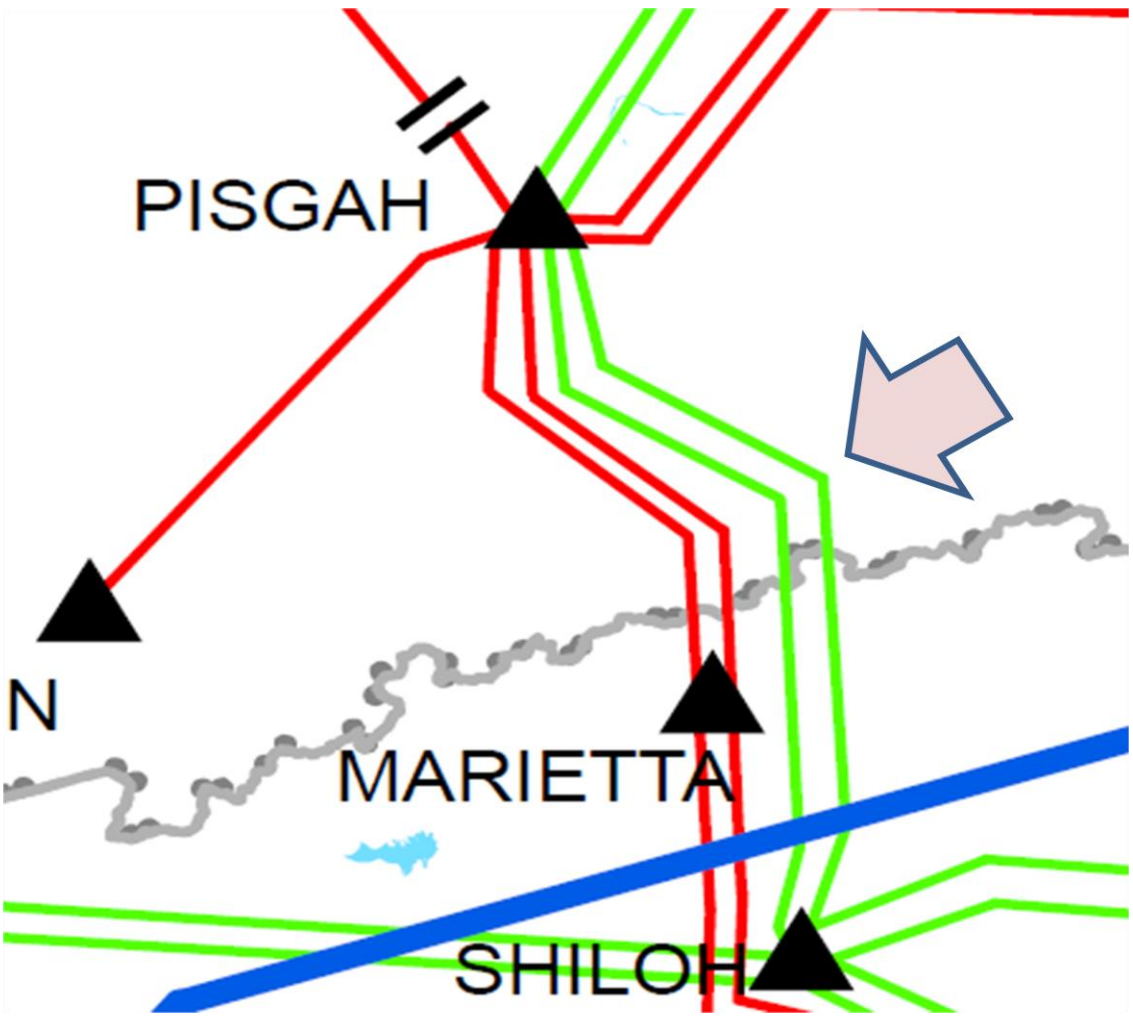
Other Transmission Solutions Considered
Bundle the line. An additional tie line from Duke to CPLW

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

C-10

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 2021. 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	6/1/2021
Estimated Time to Complete	4 years
Estimated Cost	$43 M

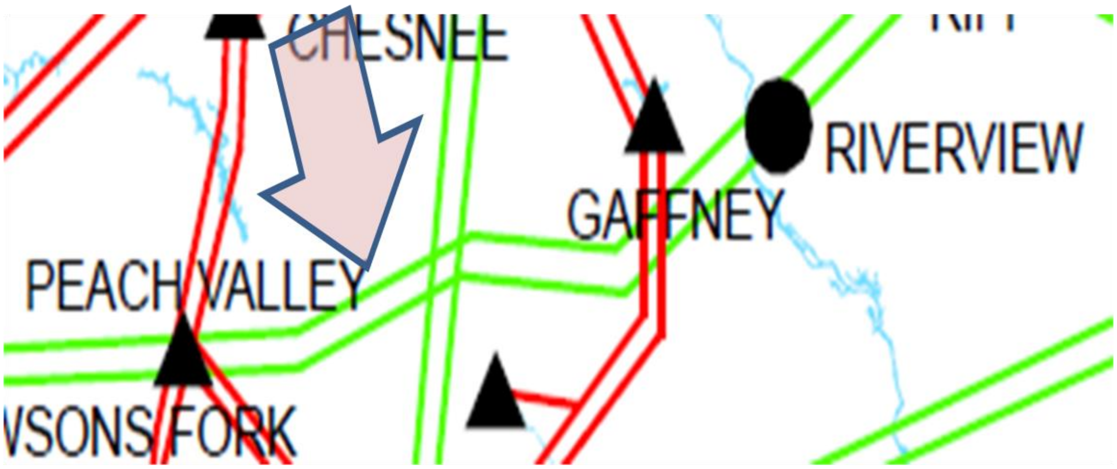
Narrative Description of the Need for this Project
Analysis of the 2021 summer base case showed that in the 2021 timeframe, loss of one circuit of the London Creek 230 kV double circuit line with the outage of a 230 kV connected Oconee unit causes the remaining line to overload. The import level into 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 D
Projects Investigated for 2021 Resource Supply Options

Resource Supply Options – 2021 Hypothetical Transfer Scenarios Studied Exports to DEC															
Primary Alternative Investigated	**Issue Identified**	**TO**	**Lead Time (years)**	**CPLE 600 MW**		**PJM (AEP) 600 MW**		**SCEG 600 MW**		**SCPSA 600 MW**		**SOCO 600 MW**		**TVA 600 MW**	
				Date Needed[1]	**($M)[2]**	**Date Needed[1]**	**($M)[2]**	**Date Needed[1]**	**($M)[2]**	**Date Needed[1]**	**($M)[2]**	**Date Needed[1]**	**($M)[2]**	**Date Needed[1]**	**($M)[2]**
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[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.

Resource Supply Options – 2021 Hypothetical Transfer Scenarios Studied Exports to CPLE													
Primary Alternative Investigated	**Issue Identified**	**TO**	**Lead Time (years)**	**DEC 600 MW**		**PJM (AEP) 600 MW**		**PJM (DVP) 600 MW**		**SCEG 600 MW**		**SCPSA 600 MW**	
				Date Needed[1]	**($M)[2]**	**Date Needed[1]**	**($M)[2]**	**Date Needed[1]**	**($M)[2]**	**Date Needed[1]**	**($M)[2]**	**Date Needed[1]**	**($M)[2]**
Rockingham – Lilesville 230 kV line, construct 3rd line	Line overloads for loss of parallel line	CPLE	4	2021	20	2022	20	-	-	-	-	-	-
Sumter - Eastover (SCEG) 115 kV line, reconductor	Line overloads for common tower outage of Sumter – (SCEG) Wateree and Sumter – (SCEG) Santee	CPLE	3	2023	12	2022	12	2022	12	2021	12	2021	12

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[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.

Resource Supply Options – 2021 Hypothetical Transfer Scenarios Studied PJM (AEP), PJM (AEP/DVP) Exports to CPLE/Duke and CPLE/Duke Export to PJM(DVP)									
Primary Alternative Investigated	**Issue Identified**	**TO**	**Lead Time (years)**	**PJM (AEP) Export of 1,200 MW to CPLE/Duke[2]**		**PJM (AEP/DVP)[1] Export of 1,200 MW to CPLE/Duke[2]**		**CPLE/Duke[2] Export of 1,200 MW To PJM (DVP)**	
				Date Needed[3]	**($M)[4]**	**Date Needed[3]**	**($M)[4]**	**Date Needed[3]**	**($M)[4]**
Rockingham - Lilesville 230 kV line, construct 3rd line	Line overloads for loss of parallel line	CPLE	4	2024	20	-	-	-	-
Sumter - Eastover (SCEG) 115 kV line, reconductor	Line overloads for common tower outage of Sumter – (SCEG) Wateree and Sumter – (SCEG) Santee	CPLE	3	2023	12	2022	12	-	-

[1] 1,200 MW shared 600/600 between AEP and DVP

[2] 1,200 MW shared 600/600 between CPLE and DUKE

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

[4] 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.

Resource Supply Options – 2021 Hypothetical Generation Scenario Studied in DEC					
Primary Alternative Investigated	**Issue Identified**	**TO**	**Lead Time (years)**	**Davidson County 1,000 MW**	
				Date Needed[1]	**($M)[2]**
Beckerdite 230/100 kV transformer, replacement	Transformer overloads for loss of parallel transformer	DEC	2	2021	4.3
Beckerdite - Davidson County 230 kV line, bundle conductor	Line overloads for loss of parallel line	DEC	4	2021	20.6
Beckerdite - High Point City 4 100 kV line, bundle conductor	Line overloads for loss of parallel line	DEC	2	2021	11.7
Buck 230/100 kV transformer, addition 2 banks	Transformer overloads under N-0 conditions as a result of the new generation	DEC	2	2021	12.2
Buck - Davidson County 230 kV line, bundle conductor	Line overloads for loss of parallel line	DEC	4	2021	6.2

[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
Projects Investigated for NC Coastal Wind Sensitivity

New Bern vs. Jacksonville Side by Side Comparison #1

New Bern (3,000[1] MW)			Jacksonville (5,000 MW)		
Line/Equipment Name	Est. Mileage (Miles)	Est. Cost [2] (M)	Line/Equipment Name	Est. Mileage (Miles)	Est. Cost [2] (M)
Morehead City area – New Bern 500 kV Lines (2)	100	$250	Morehead City Area – Jacksonville 500 kV lines (2)	80	$200
Bayboro – New Bern 500 kV Lines (2)	50	$125	Bayboro – Jacksonville 500 kV Lines (2)	100	$250
New Bern 500 kV substation w/ 2 banks	-	$60	Jacksonville 500 kV substation w/ 2 banks	-	$60
New Bern – Wommack 500 kV Lines (2)	70	$175	Jacksonville – Wommack 500 kV Lines (2)	80	$200
Wake – Wommack 500 kV Line	65	$195	Wake – Wommack 500 kV	65	$195
Cumberland – Wommack 500 kV Line	80	$240	Cumberland – Jacksonville 500 kV Line	70	$210
SVC at Wommack	-	$40	SVC at Wommack	-	$40
Wommack 500 kV Switching Station	-	$30	Wommack 500 kV substation w/ 2 Banks	-	$60
			Reconductor Wommack – Kinston DuPont 230 kV Line	17	$17
			Reconductor Rocky Mt – (DVP) Battleboro 115 kV Line	9	$7
Total	**365**	**$1,115**	**Total**	**421**	**$1,239**

[1] The 2010 NCTPC study included evaluation of 3000 MW of offshore wind and identified the facilities in Option 1B as being required to accommodate this level of offshore wind. The 2011 NCTPC study determined that those same facilities proposed in Option 1B can accommodate up to 3,500 MW.

[2] 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.

New Bern vs. Jacksonville Side by Side Comparison #2

New Bern (3,000 MW[1])			Jacksonville (3,000 MW)		
Line/Equipment Name	Est. Mileage (Miles)	Est. Cost [2] (M)	Line/Equipment Name	Est. Mileage (Miles)	Est. Cost [1] (M)
Morehead City area – New Bern 500 kV Lines (2)	100	$250	Morehead City Area – Jacksonville 500 kV lines (2)	80	$200
Bayboro – New Bern 500 kV Lines (2)	50	$125	Bayboro – Jacksonville 500 kV Lines (2)	100	$250
New Bern 500 kV substation w/ 2 banks	-	$60	Jacksonville 500 kV substation w/ 2 banks	-	$60
New Bern – Wommack 500 kV Lines (2)	70	$175	Jacksonville – Wommack 500 kV Lines (2)	80	$200
Wake – Wommack 500 kV Line	65	$195	Wake – Wommack 500 kV	65	$195
Cumberland – Wommack 500 kV Line	80	$240	~~Cumberland – Jacksonville 500 kV Line~~	~~70~~	~~$210~~
SVC at Wommack	-	$40	SVC at Wommack	-	$40
Wommack 500 kV Switching Station	-	$30	Wommack 500 kV substation w/ 2 Banks		$60
			Reconductor Wommack – Kinston DuPont 230 kV Line	17	$17
			Reconductor Rocky Mt – (DVP) Battleboro 115 kV Line	9	$7
Total	**365**	**$1,115**	**Total**	**351**	**$1,029**

[1] The 2010 NCTPC study included evaluation of 3000 MW of offshore wind and identified the facilities in Option 1B as being required to accommodate this level of offshore wind. The 2011 NCTPC study determined that those same facilities proposed in Option 1B can accommodate up to 3,500 MW.

[2] 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.

New Bern vs. Jacksonville Side by Side Comparison #3

New Bern (2,000 MW)			Jacksonville (2,000 MW)		
Line/Equipment Name	Est. Mileage (Miles)	Est. Cost [1] (M)	Line/Equipment Name	Est. Mileage (Miles)	Est. Cost [1] (M)
Havelock - Morehead City area 230 kV Lines (3)	60	$90	Morehead City Area – Jacksonville 230 kV lines (2)	80	$120
Havelock – New Bern 230 kV Line	30	$60	Bayboro – Jacksonville 230 kV Lines (2)	100	$150
Bayboro – New Bern 230 kV Line	25	$50	Jacksonville – Wommack 230 kV Lines (2)	80	$120
Bayboro-Bayboro Tap 230 kV Line	5	$10	SVC at Wommack	-	$40
Greenville West – New Bern 230 kV line	40	$80			
New Bern SVC	-	$40			
Brunswick area – Sutton 230 kV lines	60	$90			
Sutton area 230 kV Switching Station	-	$15			
Jacksonville – Sutton 230 kV line	-	$90			
Total	**265**	**$525**	**Total**	**260**	**$430**

[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 ≥ $10M)									
				2010 Plan[1]			2011 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($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	Underway	12/1/2010 12/1/2012	36	Partial In-Service	12/1/2010 12/1/2012	34
0010	Rockingham - West End 230 kV East Line, Construct line	Address loading on Rockingham-West End 230 kV Line	Progress	Underway	6/1/2011	29	In-Service	-	-
0010B	Asheboro - Pleasant Garden 230 kV Line, Construct new line, at Asheboro replace 2-200 MVA 230/115 kV Banks with 2-300 MVA Banks	Address loading on Badin - Tillery 100 kV lines, Biscoe - Asheboro 115 kV line, Tillery - Biscoe 115 kV corridor, Newport -Richmond 500 kV line, Wake 500/230 kV banks	Progress & Duke	Underway	6/1/2011	27	In-Service	-	-
0021	Ft Bragg Woodruff Street - Richmond 230 kV Line	Address loading of several transmission lines out of the Richmond/Rockingham area due to Richmond Co. Combined Cycle generator	Progress	Underway	6/1/2011	83	In-Service	-	-

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2010 Plan[1]			2011 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0004	Clinton-Lee 230 kV Line, Construct line	Address loading on Clinton - Vander 115 kV line & Lee Sub - Wallace 115 kV line	Progress	Underway	12/1/2011	22	In-Service	-	-
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	20	Underway	12/31/2012	25
0022	Jacksonville Static VAR Compensator	Address inadequate dynamic voltage recovery after system faults during periods of high transfers	Progress	Underway	6/1/2012	34	Underway	6/1/2013	30
0023	Folkstone 230/115 kV Substation	Address voltage on Castle Hayne - Jacksonville City 115 kV Line	Progress	Underway	6/1/2013	23	Underway	12/1/2012	21

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2010 Plan[1]			2011 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($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	67	Underway	6/1/2014	57
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
0008	Greenville - Kinston DuPont 230 kV Line, Construct line	Address loading on Greenville - Everetts 230 kV Line	Progress	Planned	6/1/2017	22	Planned	6/1/2017	20

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2010 Plan[1]			2011 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0029	Arabia 230 kV Substation	Address loading on Raeford 230/115 kV transformer.	Progress	-	-	-	Planned	6/1/2020	20
0024	Durham - RTP 230 kV Line, Reconductor	Address loading on the Durham-RTP 230 kV Line	Progress	Planned	6/1/2020	19	Planned	6/1/2021	15
0025	Sadler Tie - Glen Raven Main Circuit 1 & 2 (Elon 100 kV Lines), Reconductor	Following construction of additional generation at Dan River Steam Station, contingency loading of the remaining line on loss of the parallel line	Duke	Underway	6/1/2011	26	In-Service	-	-
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	22	Underway	6/1/2013	20

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2010 Plan[1]			2011 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
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	6/1/2020	43	Planned	6/1/2021	43
TOTAL						**473**			**296**

[1] Information reported in Appendix B of the NCTPC 2010 - 2020 Collaborative Transmission Plan" dated January, 18, 2011.

[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 2010 Report and have been deferred beyond the end of the planning horizon based on analysis performed to develop the 2011 Collaborative Transmission Plan.

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

Appendix 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
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