North Carolina Transmission Planning Collaborative

Report on the NCTPC 2010-2020 Collaborative Transmission Plan

December 1, 2010
DRAFT

2010 – 2020 NCTPC Study
Table of Contents

I. Executive Summary 1
II. North Carolina Transmission Planning Collaborative Process 7
II.A. Overview of the Process 7
II.B. Reliability Planning Process 8
II.C. Enhanced Transmission Access Planning Process 9
II.D. Collaborative Transmission Plan 12
III. 2010 Reliability Planning Study Scope & Methodology 12
III.A. Assumptions 13
III.B. Study Criteria 19
III.C. Case Development 19
III.D. Transmission Reliability Margin 19
III.E. Technical Analysis and Study Results 20
III.F. Assessment and Problem Identification 22
III.G. Solution Development 22
III.H. Selection of Preferred Reliability Solutions 22
III.I. Contrast NCTPC Report to Other Regional Transfer Assessments 23
IV. Base Reliability Study Results 24
IV.A. Wake 500 kV Sub 24
IV.B. Cape Fear-West End 230 kV West Line 25
IV.C. Rockingham-Lilesville 230 kV Line 25
IV.D. Fisher 230 kV Lines (Central-Shady Grove Tap) 25
V. Climate Change Legislation Scenario Study Results 26
V.A. Coal Generation Retirement Scenario Results 26
V.B. NC Coastal Wind Sensitivity Scenario Results 27
VI. 2015 Enhanced Transmission Access Scenario Results 37
VII. Collaborative Transmission Plan 38
Appendix A 40
Interchange Tables 40
Appendix B Collaborative Transmission Plan Major Project Listing 59
Appendix C Collaborative Transmission Plan Major Project Descriptions 64
Appendix D Projects Investigated for Climate Change Legislation Scenarios 81

Appendix E Projects Investigated for 2015 Enhanced Transmission Access Scenarios...86
Appendix F Collaborative Plan Comparisons 88
Appendix G Acronyms 94

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 2009-2019 Collaborative Transmission Plan (the "2009 Collaborative Transmission Plan" or the "2009 Plan") was published in January 2010.

This report documents the current 2010 – 2020 Collaborative Transmission Plan ("2010 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 2010 reliability planning study scope and methodology. The NCTPC Process document and 2010 NCTPC study scope document are posted in their entirety on the NCTPC website at http://173.201.30.164:8080/nctpc/listDocument.do?catId=REF.

The scope of the Reliability Planning Process Study included a base reliability analysis as well as an analysis of different system conditions under various "climate change" legislation scenarios. The purpose of the base reliability study was to evaluate the transmission system's ability to meet load growth projected for 2010 through 2020 with the Participants' planned Designated Network Resources ("DNRs").

The different system conditions under the "climate change" legislation scenarios evaluated the following hypothetical options to meet load demand forecasts in the study:

- Retire 100% of existing un-scrubbed coal generation plants (approximately 1,500 MW in the PEC control area, 2,000 MW in the Duke control area) by 2015, replace with new generation
- Coastal NC wind sensitivity with wind injections in the following locations, based on information obtained from the **UNC "Coastal Wind: Energy for North Carolina's Future" report[1]:**
  - 2015 case, on peak:
    - Wilmington (30% capacity factor): 125 MW
    - Morehead City (40% capacity factor): 675 MW
    - Bayboro (35% capacity factor): 425 MW
  - 2015 case, off-peak:
    - Wilmington (90% capacity factor): 375 MW
    - Morehead City (90% capacity factor): 1,500 MW
    - Bayboro (90% capacity factor): 1,125 MW

[1] http://www.climate.unc.edu/coastal-wind

The latter sections of the report and the corresponding appendices detail the base reliability analysis and “climate change” legislation scenario results and the specifics of the 2010 Plan resulting from the base reliability analysis. The NCTPC reliability study results affirmed that the planned Duke and Progress transmission projects identified in the 2009 Plan continue to satisfactorily address the reliability concerns identified in the 2010 Study for the near-term (5 year) and the long-term (10 year) planning horizons.

The 2010 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 2010 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 14 projects included in the 2010 Plan is $473 million. This compares to the 2009 Plan estimate of $595 million for 18 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 2009 Plan.

The modified projects for Progress and Duke in the 2010 Collaborative Transmission Plan, relative to the 2009 Plan, include:

- Wake 500 kV Sub, Add 3rd 500/230 kV Transformer Bank (PEC)
- Cape Fear-West End 230 kV West Line,
  Install a 230 kV Series Reactor at West End 230 kV Sub (PEC)
- Rockingham-Lilesville 230 kV Line, Add third line (PEC)
- Reconductor Fisher 230 kV Lines (Central-Shady Grove Tap) (DEC)

All of these projects were deferred beyond the ten-year planning horizon of the 2010 Plan. For the Progress area the project deferrals were generally caused by the lower load forecast and reduced import requests. For Duke the deferral of the Fisher project was a result of changes in south to north transfers from SOCO and the generation dispatch on the 230 kV transmission infrastructure to the north of the line.

Analysis of the retirement of all un-scrubbed coal generation within the Duke and Progress areas did not identify any major projects that would result from the retirements. Retirements of all un-scrubbed coal generation in Progress were already built into the base case along with additions of combined cycle generation at Wayne Co. and Sutton Plant. Therefore, no further transmission enhancements were required in the PEC area. In the Duke area, the localized impacts of the generation retirements and additions were not severe enough to cause overload of facilities in the area of the generators.

A NC coastal wind sensitivity scenario that incorporated hypothetical off-shore wind was studied. The purpose of this scenario was to assess 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 MW output of the units was delivered to Duke and PEC proportional to load ratio shares with Duke receiving 60% and PEC 40%. The geographical locations of wind power injection and the combined wind turbine generators' output capacity factors used in this study, as described in Table 8, are based on the information obtained from the **UNC "Coastal Wind: Energy for North Carolina's Future"** report[2]. Capacity factor is defined in this UNC Study as the average power output by a 3.0 MW turbine divided by its maximum output times 100. Using Figure 10.2 of the UNC Study report, an assumption was made to use a 30% capacity factor potential for the Wilmington area, a 40% capacity factor for Morehead City, and a 35% capacity factor for ties to Bayboro in the on-peak case. The off-peak study case was based on the same build out of generators as the peak study case but assumed a 90% off-peak capacity factor (high wind) and a capacity of 3000 MW. This assumption is consistent with other transmission planning studies that have been performed in the industry. These are generalized study assumptions and actual capacity factors would depend on many factors, including distance to shore. Specifically the study results identify the transmission infrastructure required to support 1,225 MW of offshore wind at peak load and 3,000 MW of offshore wind at 70% of peak load. Further study would be required to determine if the proposed infrastructure results could support 3,000 MW of offshore wind at peak load.

The coastal NC wind sensitivity study indicated the need for significant upgrades to the transmission system in order to accommodate the levels of wind in the study. In an effort to identify a breakpoint in costs versus benefits associated with

[2] http://www.climate.unc.edu/coastal-wind

incorporating various levels of coastal wind, four different wind MW output options were examined for integrating the wind generations into PEC's existing transmission network. A summary of the overall costs associated with each option is shown in Table 1 below. The specific facility additions associated with these cost estimates is summarized in Appendix D.

Table 1
Wind Scenarios Results Summary

Option	Wind Output MW	Comment	Cost Estimate[3] (Billions)
1A	3,000	230 kV wind connection to network	$1.195 B
1B	3,000	500 kV wind connection to network	$1.310 B
2	2,500	500 MW reduction of output doesn't create a breakpoint	$1.155 B
3	2,000	Significant breakpoint in transmission upgrades Removed 500 kV Infrastructure	$0.525 B

[3] 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 off-shore wind farms. Actual costs may be higher or lower than those estimated.

This year's Enhanced Transmission Access Planning Process (ETAP) Study included four scenarios submitted by TAG stakeholders. These scenarios evaluate the means to increase transmission access for Load Serving Entities ("LSEs") in North Carolina to potential network resources inside and outside the control areas of Duke and Progress. The four ETAP scenarios studied are shown in Table 2 below.

Table 2
Enhanced Transmission Access Scenarios Summary

Request	Source[4]	Sink	MW	Service Dates	Cost Estimate (Millions)
1	Cleveland Co. site	CPLE	1,000	1/12 to 1/22	$20 M
2	Cleveland Co. site	DVP	1,000	1/12 to 1/22	$20 M
3	SOCO	DVP	1,000	1/12 to 1/22	$ 0 M
4	SOCO	CPLE	1,000	1/12 to 1/22	$20 M

Analysis of the four ETAP scenarios identified the need for one major project, the construction of a third 230 kV line between Lilesville and Rockingham in PEC's area, for three out of four of the scenarios studied. The estimated cost for this new 230 kV facility is $20 million. This specific facility addition for the ETAP scenarios is summarized in Appendix E.

In this 2010 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.

[4] The Cleveland Co. site is located within Duke's transmission area.

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://173.201.30.164:8080/nctpc/listDocument.do?catId=REF. Figure 1 illustrates the major steps associated with the NCTPC Process.

II.B. Reliability Planning Process

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

The Reliability Planning Process is designed to follow the steps outlined in Figure 1. The OSC approves the scope of the reliability study, oversees the study analysis being performed by the PWG, evaluates the study results, and approves the final reliability study results. The Reliability Planning Process begins with the incumbent transmission owners' most recent reliability planning studies and planned transmission upgrade projects.

In addition, the PWG solicits input from the Participants for different scenarios on where to include alternative supply resources to meet their load demand forecasts in the study. This step provides the opportunity for the Participants to propose the evaluation of other resource supply options to meet future load demand due to load growth, generation retirements, or purchase power agreement expirations. The PWG analyzes the proposed interchange transactions and/or the location of generators to determine if those transactions or generators create any reliability criteria violations. Based on this analysis, the PWG provides feedback to the Participants on the viability of the proposed interchange transactions or generator locations for meeting future load requirements. The PWG coordinates the development of the reliability studies and the resource supply option studies based upon the OSC-approved scope and prepares a report with the recommended transmission reliability solutions.

The results of the Reliability Planning Process include summaries of the estimated costs and schedules to provide any transmission upgrades and/or additions: (i) needed to maintain a sufficient level of reliability necessary to serve the native load of all Participants and (ii) needed to reliably support the resource supply options studied. The reliability study results are reviewed with the TAG, and the TAG participants are given an opportunity to provide comments on the results. All TAG feedback is reviewed by the OSC for consideration for incorporation into the final Collaborative Transmission Plan.

II.C. Enhanced Transmission Access Planning Process

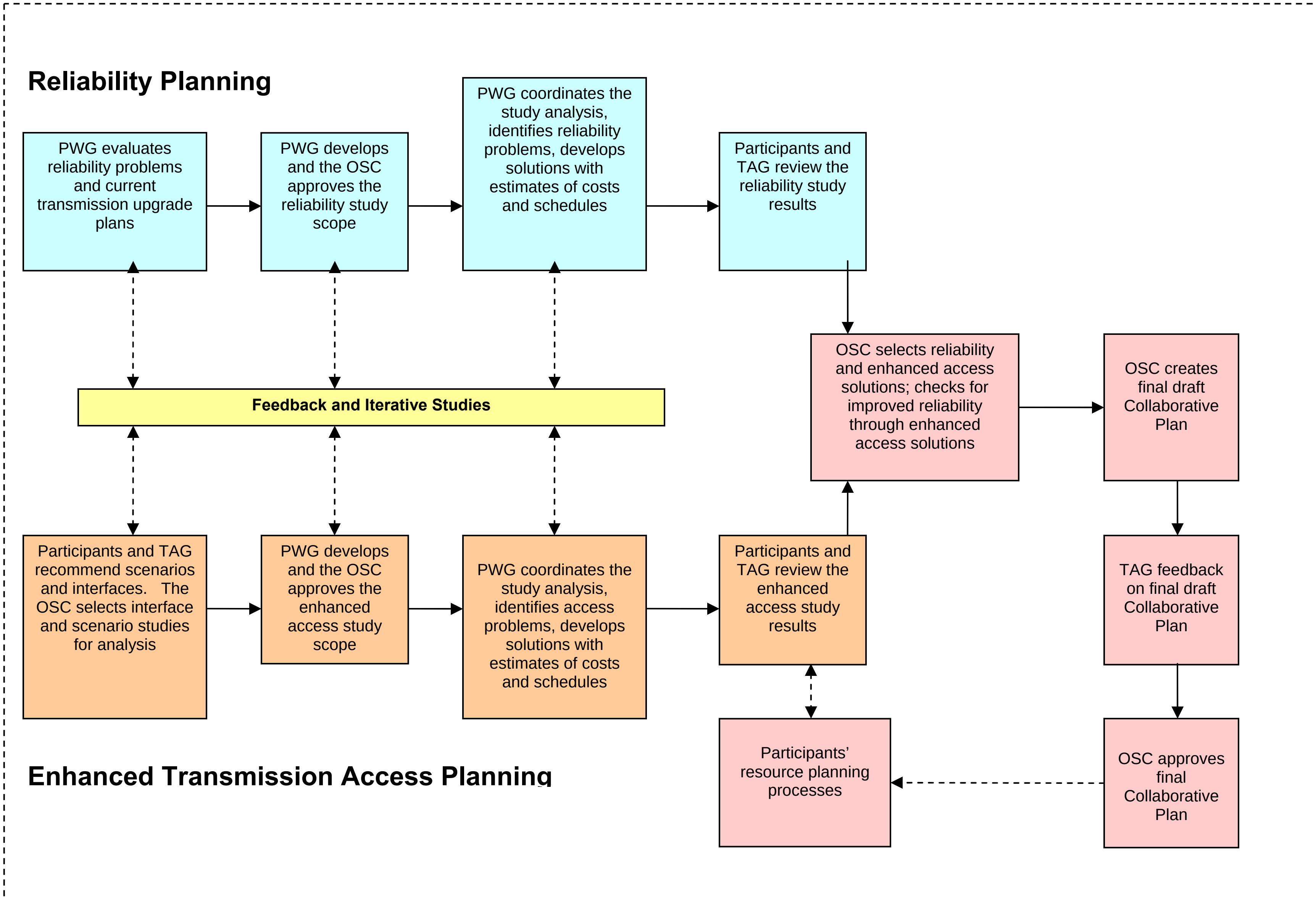
The ETAP Process is the economic planning process that allows the TAG participants to propose economic hypothetical transfers to be studied as part of the transmission planning process. The ETAP Process provides the means to evaluate the impact of potential supply resources inside and outside the Control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

The ETAP Process begins with the Participants and TAG members proposing scenarios and interfaces to be studied. The proposed scenarios and interfaces are compiled by the PWG and then evaluated by the OSC to determine which ones will be included for analysis in the current planning cycle. The PWG coordinates the development of the enhanced transmission access studies based upon the OSC-approved scope and prepares a report which identifies recommended transmission solutions that could increase transmission access.

The results of the ETAP Process include the estimated costs and schedules to provide the increased transmission capabilities. The enhanced transmission access study results are reviewed with the TAG, and the TAG participants are given an opportunity to provide comments on the results. All TAG feedback is reviewed by the OSC for consideration for incorporation into the final Collaborative Transmission Plan.

Figure 1

2010 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. 2010 Reliability Planning Study Scope & Methodology

The 2010 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 purpose of the base reliability study was to evaluate the transmission systems' ability to meet load growth projected for 2015 through 2020 with the Participants' planned Designated Network Resources ("DNRs"). The 2010 Study allowed for identification of any new system impacts not currently addressed by existing transmission plans in which case solutions were developed. The 2010 Study also allowed for adjustments to existing plans where necessary.

The resource supply options for the 2010 NCTPC Study consisted of scenarios to examine the transmission system impacts of potential climate change legislation. The first scenario examined the impact of retiring by 2015 all Duke and Progress un-scrubbed coal-fired generation facilities not already scheduled for retirement in the base reliability study and replacing the power from those facilities with power from new generation facilities. The second resource supply option scenario examined injecting up to 3,000 MW of power onto the transmission system from off-shore wind generators beginning in 2015.

In addition to the scenarios examined under the Reliability Planning Process, the 2010 NCTPC Study also examined four scenarios requested by members of the TAG through the Enhanced Transmission Access Planning Process. They were:

Table 3
Enhanced Transmission Access Scenarios Summary

Request	Source[4]	Sink	MW	Service Dates
1	Cleveland Co. site	CPLE	1,000	1/12 to 1/22
2	Cleveland Co. site	DVP	1,000	1/12 to 1/22
3	SOCO	DVP	1,000	1/12 to 1/22
4	SOCO	CPLE	1,000	1/12 to 1/22

III.A. Assumptions

1. Study Year and Planning Horizon

The 2010 Collaborative Transmission Plan addresses a ten-year planning horizon through 2020. The study years chosen for the 2010 Study are listed in Table 4.

Table 4

Study Years

Study Year / Season	Analysis
2015 Summer	Near-term base reliability, Climate Change Legislation, and Enhanced Transmission Access Planning Scenarios
2015/2016 Winter	Near-term base reliability
2020 Summer	Long-term base reliability

To identify projects required in years other than the base study years of 2015 and 2020, 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	1.4 % per year
Progress	1.8 % per year

2. Network Modeling

The network models developed for the 2010 Study included new transmission facilities and upgrades for the 2015 and 2020 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 2015 and 2020 models. Table 7 lists the generation facility additions and retirements included in the 2015 and 2020 models.

Table 6

Major Transmission Facility Projects Included in Models

Company	Transmission Facility	2015 Base & Sensitivities	2020 Base
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	No	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	2015	2020
Duke	Retired Cliffside Units 1-4 (202 MW)	Yes	Yes
Duke	Retired Buck 3 & 4 (113 MW)	Yes	Yes
Duke	Retired Dan River 1-3 (276 MW)	Yes	Yes
Duke	Retired Riverbend 4 & 5 (188 MW)	Yes	Yes
Duke	Retired Riverbend 6 & 7 (266 MW)	No	Yes
Duke	Retired Dan River CT’s (48 MW)	Yes	Yes
Duke	Retired Riverbend CT’s (64 MW)	Yes	Yes
Duke	Retired Buck CT’s (62 MW)	Yes	Yes
Duke	Retired Buzzard Roost CT’s (196 MW)	Yes	Yes
Duke	Added[5] Cliffside Unit 6 (825 MW)	Yes	Yes
Duke	Added[4] Dan River CC (620 MW)	Yes	Yes
Duke	Added[4] Buck CC (620 MW)	Yes	Yes
Duke	Added Cleveland Co. CT's (716 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[4] 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.

Retirements of all un-scrubbed coal generation in Progress were already built into the base case, so the scenario did not require further retirements in the PEC area. The PEC reserve margin was not impacted since incremental MWs added at Wayne Co. plant will make up the retired MWs from Cape Fear and Weatherspoon plants and the coal generation was fully replaced by combined cycle generation at Sutton plant. All of Duke's retirements were not built into the base case for the un-scrubbed coal scenario. This scenario required turning off the remaining Duke un-scrubbed coal generation and economically dispatching the remaining generation. New generation is planned for both the PEC and Duke systems such that sufficient generation was available for dispatch even with the retirement of the un-scrubbed coal units. Refer to Table 7 for details on retirements and generation additions. No changes were made to the interchange.

The off shore wind energy scenarios required the addition of wind generation to the models as detailed in Section V.B. The MW output of the units was delivered to Duke and PEC control areas proportional

[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.

to load ratio shares with Duke receiving 60% and PEC 40%. In order to study a wind import of 1,225 MW at peak load, 490 MW and 735 MW were allocated to Progress and Duke, 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 735 MW of wind allocated to Duke. The 490 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 off shore wind scenario, each Participant's load was scaled to 70% in order to study an import of 3,000 MW of wind, 1,200 MW to Progress and 1,800 MW to Duke. The 70% load level model is based on participants' load duration curves. This 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 ETAP scenarios either sourcing from SOCO or sinking in DVP, SOCO/DVP generation was scaled up/down by 1,000 MW in order to model the transfer. SOCO/DVP interchange was increased/decreased by 1,000 MW to reflect the export/import. For transfers sourcing from the Cleveland Co. site, the existing generation at the site was not enough to meet the transfer level; an additional 350 MW of generation was placed at Cleveland Co. in order to properly model the transfer. Duke interchange was increased by 1,000 MW to reflect the export. For transfers sinking into CPLE, the interchange was decreased by

1,000 MW along with economically dispatching CPLE generation to model the 1,000 MW import.

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 2009 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	Oconee 1
Oconee 3	Riverbend 6	Riverbend 7
Buck CC	Dan River CC	Rowan CC
Rockingham 1	Thorpe	Nantahala

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 2015 and 2020 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 2010 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 reported 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 2010 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 2009 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 consisted of scenarios to examine the transmission system impacts of potential climate change legislation. The first scenario examined the impact of retiring by 2015 all Duke and Progress un-scrubbed coal-fired generation facilities not already scheduled for retirement in the base reliability study and replacing the power from those facilities with power from new generation facilities. The second resource supply option scenario examined injecting up to 3,000 MW of power onto the transmission system from off-shore wind generators beginning in 2015. 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 time frames. LTSG studies have recently been performed for 2011, 2013, 2015, and 2019 summer time frames. With the exception of the off shore wind scenario, 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.

IV. Base Reliability Study Results

The 2010 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 2020 base case.

The 2010 Collaborative Transmission Plan is detailed in Appendix B which identifies the projects planned with an estimated cost of greater than $10 million. Projects in the 2010 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 modified projects for Progress and Duke in the 2010 Collaborative Transmission Plan, relative to the 2009 Plan, include:

- Wake 500 kV Sub, Add 3rd 500/230 kV Transformer Bank (PEC)
- Cape Fear-West End 230 kV West Line,
  Install a 230 kV Series Reactor at West End 230 kV Sub (PEC)
- Rockingham-Lilesville 230 kV Line, Add third line (PEC)
- Reconductor Fisher 230 kV Lines (Central-Shady Grove Tap) (DEC)

All of these projects were deferred beyond the ten-year planning horizon of the 2010 Plan. In-service dates and cost estimates for some projects that are planned or underway have been revised based on updated information.

Sections IV.A through IV.D describe the specifics of the modified projects in the 2010 Collaborative Transmission Plan.

IV.A. Wake 500 kV Sub

Add 3rd 500/230 kV Transformer Bank

The project at Wake 500 kV Sub to add a third 500/230 kV Transformer Bank was removed from the plan because of changes in load forecasts as well as the Progress Energy decision to install a Combined-Cycle

Power Plant at Lee Plant. The construction of a Combined-Cycle plant at Lee Plant will unload the Wake 500/230 kV Transformers beyond the ten year planning horizon.

IV.B. Cape Fear-West End 230 kV West Line

Install a 230 kV Series Reactor at West End 230 kV Sub

The Cape Fear-West End 230 kV West Line project where Progress was planning to install a 230 kV Series Reactor at West End 230 kV Sub was removed because the current models are no longer showing a need for this project. This is due to load forecast changes and transmission service and generator interconnection request withdrawals.

IV.C. Rockingham-Lilesville 230 kV Line

Add third line

The Rockingham-Lilesville 230 kV Third Line was removed from the plan because of substantial changes in transmission service and generator interconnection requests. This project is very sensitive to transmission service requests as well as area-specific generation requests.

IV.D. Fisher 230 kV Lines (Central-Shady Grove Tap)

Reconductor Lines

The project to reconductor the Fisher 230 kV lines was deferred beyond the planning horizon. Flows on this line are sensitive to south to north transfers from SOCO and generation dispatch on the 230 kV transmission infrastructure to the north of the line. As the project to reconductor the lines continues to move in and out of the plan, the timing of the need for the project will continue to be monitored.

V. Climate Change Legislation Scenario Study Results

Climate change legislation scenarios consisted of a hypothetical coal generation retirement scenario and a hypothetical NC coastal wind sensitivity analysis. These scenarios were reviewed using the 2015 summer base case. Solution alternatives were identified to address any issues that required a solution within the ten-year planning horizon. Where issues were found, solution alternatives were discussed, and a primary set of solutions was determined.

V.A. Coal Generation Retirement Scenario Results

The retirement of all un-scrubbed coal generation in the Duke and PEC control areas was studied. Between the two areas, a total of approximately 3,500 MW (2,000 MW in Duke, 1,500 MW in PEC) of un-scrubbed coal generation was assumed to be retired. The purpose of the study was to assess the impact of carbon legislation on the transmission system.

On the Duke system, the localized impacts of the generation retirements and additions were not severe enough to cause overload of facilities in the area of the generators. At Dan River and Buck the retirement and addition of new combined cycle generation had offsetting impacts. In the Progress area, the incremental combined cycle generation at Wayne Co. covers the retired coal generation from Cape Fear and WSPN plants. The retired coal generation from Sutton is also fully replaced with its combined-cycle generation at Sutton. Therefore the study results do not indicate the need for any new projects beyond the 2010 Collaborative Transmission Plan; and, no new projects are identified in Appendix D for the coal generation retirement scenario.

V.B. *NC Coastal Wind Sensitivity Scenario Results*

A NC coastal wind sensitivity scenario that incorporated hypothetical off-shore wind was studied. The purpose was to assess 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 MW output of the units was delivered to Duke and PEC proportional to load ratio share with Duke receiving 60% and PEC 40%. The geological locations of wind power injection and the combined wind turbine generators' output capacity factors used in this study, as described in Table 8, are based on the information obtained from the **UNC "Coastal Wind: Energy for North Carolina's Future" report**[7]. Capacity factor is defined in this UNC Study as the average power output by a 3.0 MW turbine divided by its maximum output times 100. Using Figure 10.2 of the UNC Study report, an assumption was made to use a 30% capacity factor potential for the Wilmington area, a 40% capacity factor for Morehead City, and a 35% capacity factor for ties to Bayboro in the on-peak case. The off-peak case was based on the same build out of generators as the peak case but assumed a 90% off-peak capacity factor (high wind) and a capacity of 3000 MW. This assumption is consistent with other transmission planning studies that have been performed in the industry. These are generalized assumptions and actual capacity factors would depend on many factors, including distance to shore.

Table 8

Wind Capacity Factor Summary

Injection Point	On-peak MW (30-40% CF)	Off-peak MW (90% CF)
Wilmington	125	375
Morehead City	675	1,500
Bayboro	425	1,125
Total	1,225	3,000

[7] http://www.climate.unc.edu/coastal-wind

Under these study conditions, solving transmission constraints for off-peak loads with wind capacity factor at 90% solves on-peak transmission problems with lower wind capacity factors. Specifically, this year's study results identify the transmission infrastructure required to support 1,225 MW of offshore wind at peak load and 3,000 MW of offshore wind at 70% of peak load. It should be noted that studying only two load levels (on and off-peak) does not mean that the coastal wind can be delivered across all load levels at the MW output levels listed in this report. Further study would be required to determine if the proposed infrastructure could support 3,000 MW of offshore wind at peak load.

Based on power flow results it was deemed desirable to evaluate lower MW output values for the off-peak case in an effort to identify a breakpoint in costs versus benefits associated with incorporating various levels of coastal wind. In all, four different options were examined for integrating the wind generation into PEC's existing transmission network. Tables 9 and 10 summarize the results of the analysis and the costs associated with each of the options. The specific facility results are provided in more detail in Appendix D. These overnight[8] costs represent only the transmission network upgrades necessary to integrate these four options after the power is delivered at an on-shore substation. It should be noted that these costs do not include the wind generator interconnection or capital construction costs associated with off-shore 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 9

Wind Scenarios Results Summary

Option	Wind Output MW	Comment	Cost Estimate (Billions)
1A	**3,000**	**230 kV wind connection to network**	**$1.195**
1B	**3,000**	**500 kV wind connection to network**	**$1.310**
2	**2,500**	**500 MW reduction of output doesn't create a breakpoint**	**$1.155**
3	**2,000**	**Significant breakpoint in transmission upgrades Removed 500 kV Infrastructure**	**$0.525**

Table 10

Transmission Upgrade Cost Assumptions

Transmission Upgrade	Costs
500 kV Line 500 kV Line Common Right of Way	$3M per mile $2.5M per mile
500kV 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 options 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. These are planning cost estimates only for the associated network transmission enhancements and do not include any generator interconnection facilities (those facility costs associated with transmission infrastructure required to move the offshore wind energy onshore) or the capital construction costs associated with the off-shore wind farms.

The four options examined vary based on the total MWs of wind generation injected into the existing transmission system and the corresponding new transmission infrastructure required to accommodate the wind generation at each of the three injection points, Wilmington, Morehead City, and Bayboro. For all four options, the transmission infrastructure is the same for the network integration of the 375 MW's at Southport, the specific interconnection point for the injection location identified as "Wilmington" above. This infrastructure includes the construction of two 230 kV lines from a new 230 kV switching station in Brunswick County to a new 230 kV switching station to be located north of PEC's existing Sutton Power plant. At this new substation the wind output will be connected with several area 230 kV Lines.

While the infrastructure needs are constant across all scenarios for the Southport injection point, it varies across the scenarios for the Bayboro and Morehead City injection points. These variations are described below and illustrated in the figures that follow.

Option 1A will accommodate 3,000 MW's of wind generation into PEC's transmission network. This can be accomplished by connecting the wind generation via 230 kV Lines with network integration with existing transmission infrastructure at Havelock 230 kV and New Bern 230 kV Substations. It would then be necessary to construct a new 500/230 kV substation near PEC's existing New Bern 230 kV Substation. From there the wind generation would be incorporated into the transmission network by construction of two 500 kV Lines from New Bern to a new 500 kV switching station in Lenoir County near PEC's Wommack 230 kV Substation. Additionally, the construction of two 500 kV Lines from Lenoir to PEC's existing Wake and Cumberland 500 kV Stations would be required.

Option 1B will accommodate 3,000 MW's into PEC's transmission network. This can be accomplished by connecting the wind generation via 500 kV lines, instead of 230 kV lines. It would again be necessary to construct a new 500/230 kV substation near PEC's existing New Bern 230 kV Substation. From there the wind generation would be incorporated into the transmission network exactly like Option 1A. This scenario offers the best option if considering a long-term build out of off-shore wind that might exceed the 3,000 MW test level.

Option 2 will accommodate 2,500 MW's into PEC's transmission network. This can be accomplished by connecting the wind via 230 kV Lines with network integration with existing transmission infrastructure at Havelock 230 kV and New Bern 230 kV Substations. This option is almost the same with respect to new transmission infrastructure construction as 1A. The only difference is that it would not be necessary to rebuild two existing 230 kV transmission lines: Aurora-Greenville 230 kV Line (partial rebuild) and the Aurora-New Bern 230 kV Line.

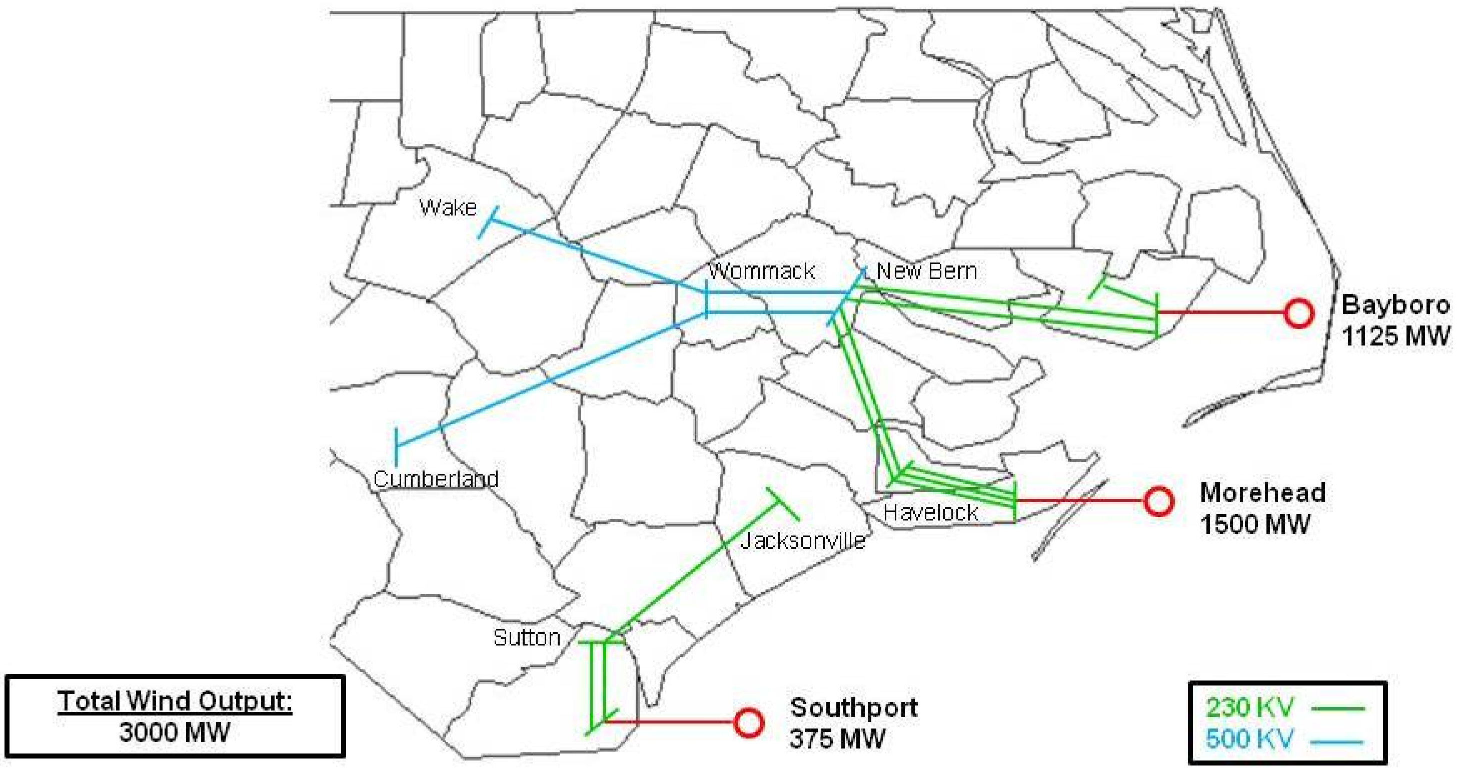
Option 3 will accommodate 2,000 MW's into PEC's transmission network. This option offers a significant breakpoint in transmission upgrades because it does not require any 500 kV infrastructure. This is accomplished by connecting the wind generation via 230 kV Lines with network integration with existing transmission infrastructure at Havelock 230 kV and New Bern 230 kV Substations. It will be necessary to construct an additional 230 kV line from Greenville West 230 kV Substation to New Bern 230 kV Substation.

Based on engineering judgment the inclusion of a static VAr compensator (SVC) in all four of these options is required 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 assumption of 1-SVC is only a high-level starting point that may not cover all system conditions and is not based on any dynamic stability analysis, which would be required for an actual generator interconnection.

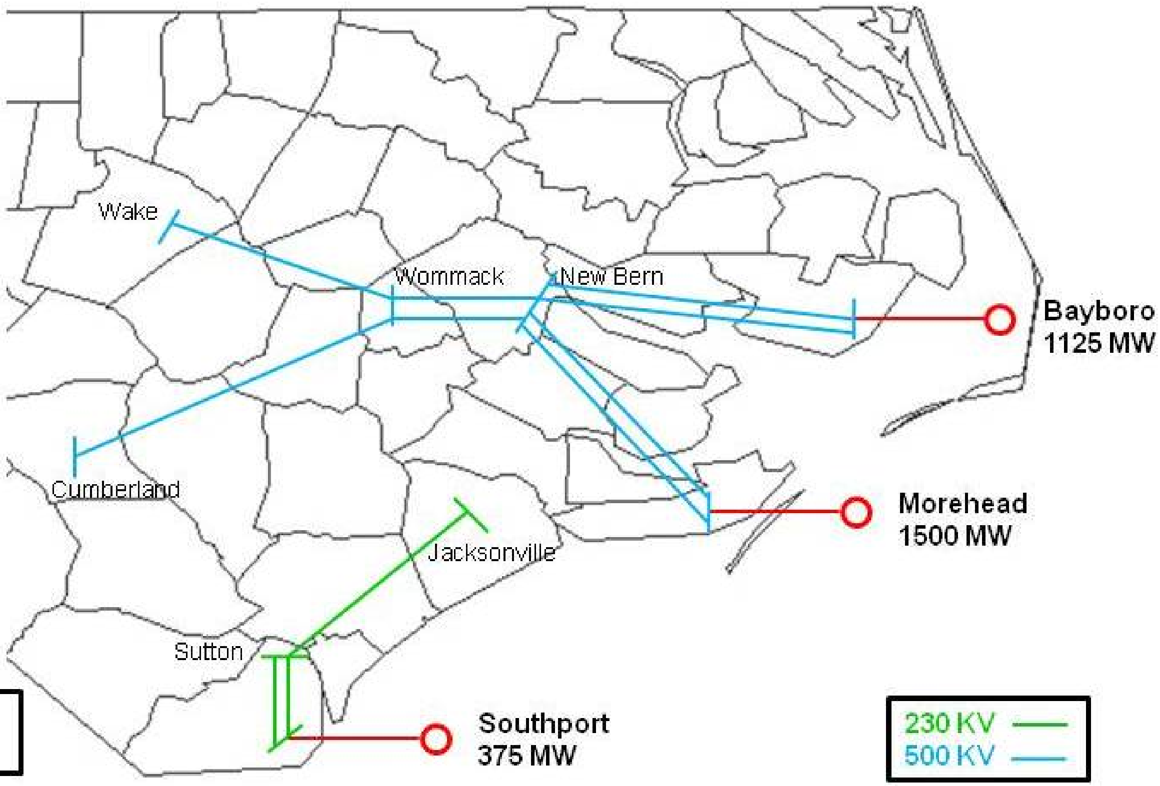
In addition to the new transmission infrastructure described above, the Greenville-Kinston Dupont 230 kV Line which is currently scheduled for 2017 would have to be accelerated to accommodate these coastal wind scenarios.

For Duke, importing its allocation of 60% of the wind output, the analysis showed that no additional transmission upgrades were required to accommodate these wind generation resources.

Offshore Wind: Option 1A

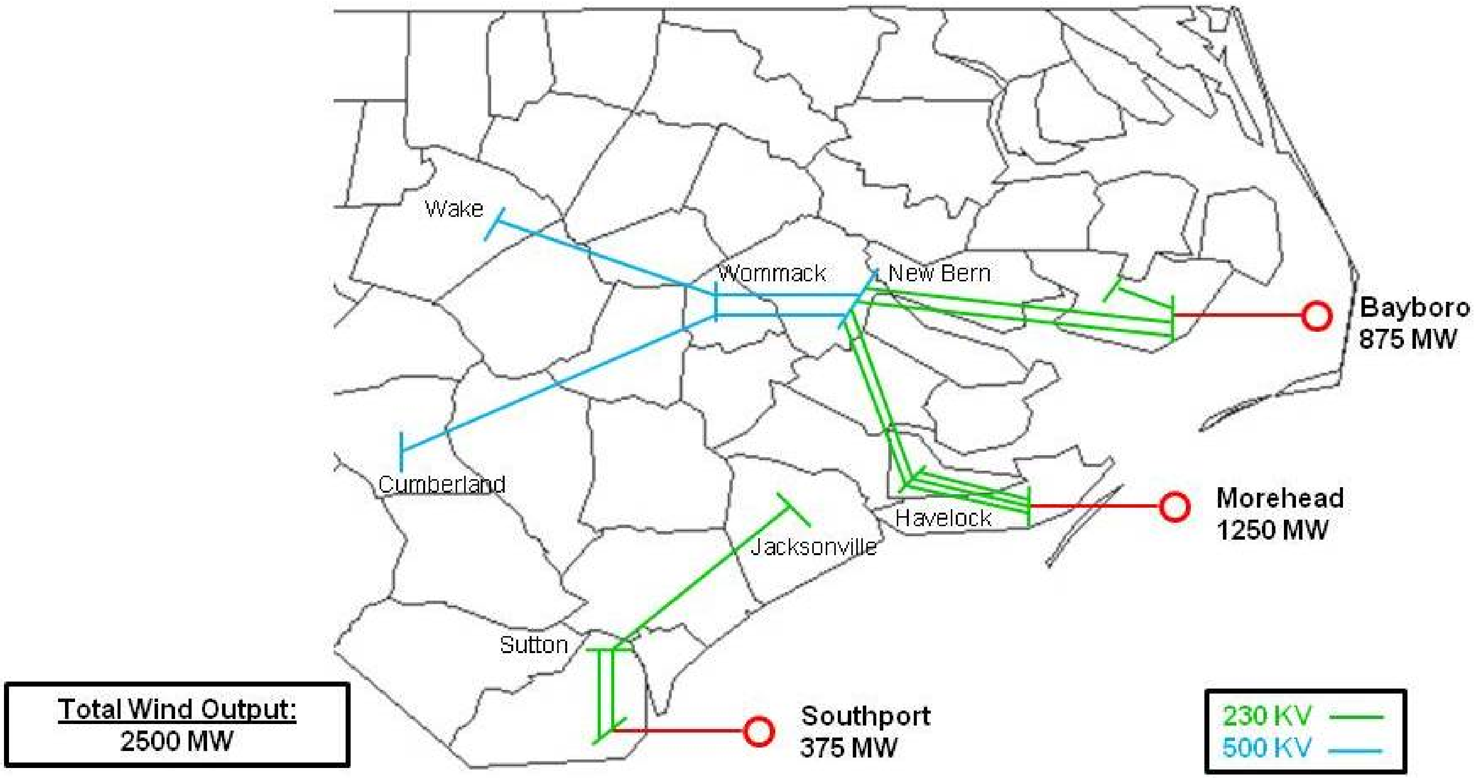


Offshore Wind: Option 1B

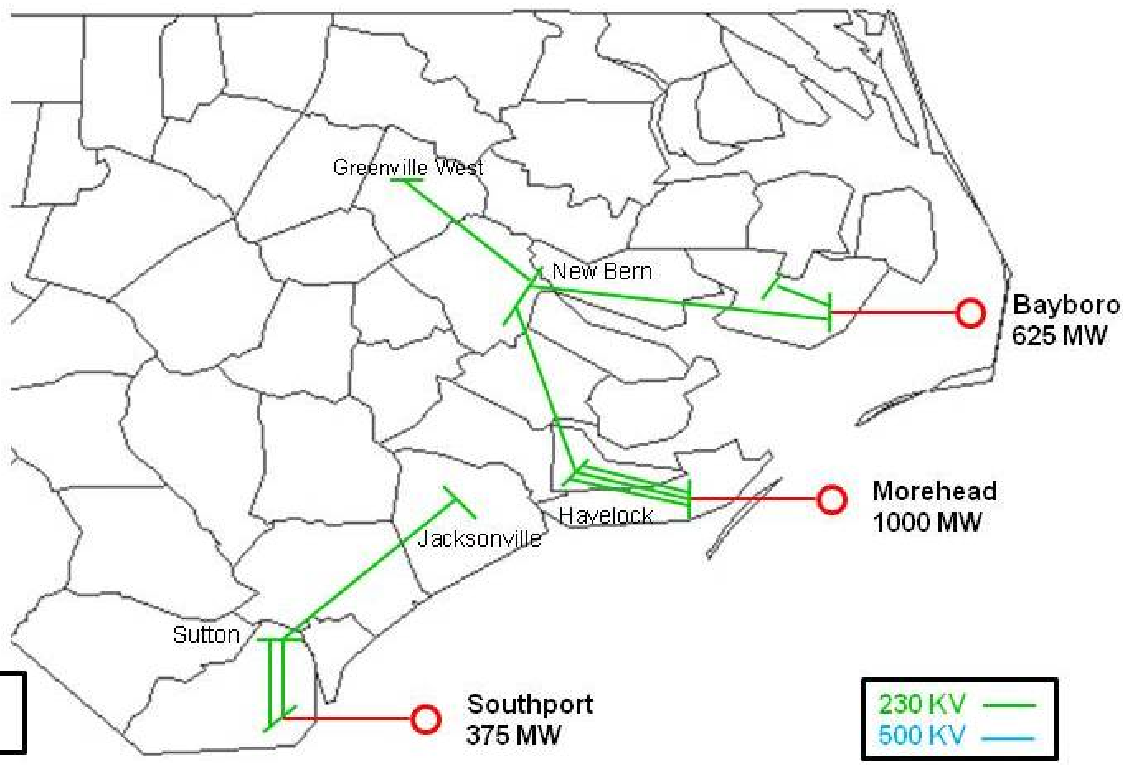


Total Wind Output:
3000 MW

Offshore Wind: Option 2



Offshore Wind: Option 3



Total Wind Output:
2000 MW

VI. 2015 Enhanced Transmission Access Scenario Results

Enhanced Transmission Access Scenarios for 2015 summer consisted of hypothetical 1,000 MW transfers from the Cleveland Co. site or Southern Company to Progress or Dominion. The impacts of these transfers were assessed. Solution alternatives were identified to address any issues that required a solution within the Enhanced Transmission Access Request years. Where issues were found, solution alternatives were discussed, and a primary set of solutions was determined.

Table 11

Enhanced Transmission Access Scenarios Summary

Request	Source[4]	Sink	MW	Service Dates	Cost Estimate (Millions)
1	Cleveland Co. site	CPLE	1,000	1/12 to 1/22	$20 M
2	Cleveland Co. site	DVP	1,000	1/12 to 1/22	$20 M
3	SOCO	DVP	1,000	1/12 to 1/22	$0 M
4	SOCO	CPLE	1,000	1/12 to 1/22	$20 M

Analysis of the four ETAP scenarios identified the need for one major project, the construction of a third 230 kV line between Lilesville and Rockingham in PEC's area, for three out of four of the scenarios studied. The estimated cost for this new 230 kV facility is $20 million. This specific facility addition for the ETAP scenarios is summarized in Appendix E.

VII. Collaborative Transmission Plan

The 2010 Collaborative Transmission Plan includes 14 projects with an estimated cost of $10 million or more each. These projects are listed in Appendix B. . The total estimated cost for these 14 projects included in the 2010 Plan is $473 million. This compares to the 2009 Plan estimate of $595 million for 18 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 2009 Plan. This 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 2010 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 2009 Report and have been deferred beyond the end of the planning horizon based on the 2010 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

2015 SUMMER PEAK
DUKE ENERGY CAROLINAS
DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports/Purchases – MW

	Base Case	PEC TRM	Off-Peak Wind
CPLE (NCEMC)	57	57	57
CPLE (NCEMC/Hamlet)	110	110	110
CPLE (Off-Shore Wind)	0	0	735
SCEG (City of Greenwood)	0	0	0
SCPSA (New Horizons/NHEC)	460	460	460
SEPA (Hartwell)	155	155	155
SEPA (Thurmond)	113	113	113
SOCO (City of Seneca)	30	30	30
SOCO (EU2)	64	64	64
SOCO (NCEMC)	180	180	180
SOCO (PMPA)	170	170	170
Total	**1339**	**1339**	**2074**

Duke Energy Carolinas Modeled Exports/Sales – MW

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

Duke Energy Carolinas Net Interchange – MW

	Base Case	PEC TRM	Off-Peak Wind
	-84	422	-819

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

2015 SUMMER PEAK
PROGRESS ENERGY CAROLINAS (EAST)
DETAILED INTERCHANGE

Progress Energy Carolinas (East) Modeled Imports/Purchases – MW

	Base Case	PEC TRM	Off-Peak Wind
AEP (NCEMC)	100	100	100
AEP (NCEMC#2)	100	100	100
AEP (PEC TRM)	0	97	0
CPLW	150	150	150
DUKE (Rowan)	150	150	150
DUKE (Broad River)	850	850	850
DUKE (NCEMC/Catawba)	205	205	205
DUKE (PEC TRM)	0	506	0
DVP (PEC TRM)	0	835	0
DVP (SEPA-KERR)	95	95	95
SCEG (PEC TRM)	0	200	0
SCPSA (Co-Gen)	0	0	0
SCPSA (PEC TRM)	0	197	0
Total	**1650**	**3485**	**1650**

Progress Energy Carolinas (East) Modeled Exports/Sales – MW

	Base Case	PEC TRM	Off-Peak Wind
DUKE (NCEMC)	57	57	57
DUKE (Off-Shore Wind)	0	0	735
DUKE (NCEMC/Hamlet)	110	110	110
DVP (Littleton)	9	9	9
DVP (NCEMPA)	158	158	158
DVP (PJM-Cravenwood)	47	47	47
DVP (NCEMC)	226	226	226
Total	**607**	**607**	**1342**

Progress Energy Carolinas (East) Net Interchange - MW

	Base Case	PEC TRM	Off-Peak Wind
	-1043	-2878	-308

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

2015 SUMMER PEAK
PROGRESS ENERGY CAROLINAS (WEST)
DETAILED INTERCHANGE

Progress Energy Carolinas (West) Modeled Imports/Purchases – MW

	Base Case	PEC TRM Case	Off-Peak Wind
CPLE (Off-Shore Wind)	0	0	0
TVA (SEPA)	1	1	1
Total	**1**	**1**	**1**

Progress Energy Carolinas (West) Modeled Exports/Sales – MW

	Base Case	PEC TRM Case	Off-Peak Wind
CPLE	150	150	150
Total	**150**	**150**	**150**

Progress Energy Carolinas (West) Net Interchange – MW

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

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

2015 SUMMER / ON-PEAK WIND (OFF-PEAK LOAD) CASE
DUKE ENERGY CAROLINAS
DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports/Purchases – MW

	On - Peak Wind
CPLE (NCEMC)	0
CPLE (NCEMC/Hamlet)	57
CPLE (Off-Shore Wind)	1800
SCEG (City of Greenwood)	0
SCPSA (New Horizons/NHEC)	310
SEPA (Hartwell)	155
SEPA (Thurmond)	113
SOCO (City of Seneca)	23
SOCO (EU2)	0
SOCO (NCEMC)	137
SOCO (PMPA)	17
Total	**2612**

Duke Energy Carolinas Modeled Exports/Sales – MW

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

Duke Energy Carolinas Net Interchange – MW

	On - Peak Wind
	-2357

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

2015 SUMMER / ON-PEAK WIND (OFF-PEAK LOAD) CASE
PROGRESS ENERGY CAROLINAS (EAST)
DETAILED INTERCHANGE

Progress Energy Carolinas (East) Modeled Imports/Purchases – MW

	On - Peak Wind
AEP (NCEMC)	70
AEP (NCEMC#2)	70
AEP (PEC TRM)	0
CPLW	0
DUKE (Rowan)	0
DUKE (Broad River)	0
DUKE (NCEMC/Catawba)	205
DUKE (PEC TRM)	0
DVP (PEC TRM)	0
DVP (SEPA-KERR)	95
SCEG (PEC TRM)	0
SCPSA (Co-Gen)	0
SCPSA (PEC TRM)	0
Total	**440**

Progress Energy Carolinas (East) Modeled Exports/Sales – MW

	On - Peak Wind
DUKE (NCEMC)	0
DUKE (NCEMC/Hamlet)	57
DUKE (Off-Shore Wind)	1800
CPLW	0
DVP (Littleton)	6.3
DVP (NCEMPA)	110.6
DVP (PJM-Cravenwood)	47
DVP (NCEMC)	144
Total	**2164.9**

Progress Energy Carolinas (East) Net Interchange – MW

	On - Peak Wind
	1724.9

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

2015 SUMMER / ON-PEAK WIND (OFF-PEAK LOAD) CASE
PROGRESS ENERGY CAROLINAS (WEST)
DETAILED INTERCHANGE

Progress Energy Carolinas (West) Modeled Imports/Purchases – MW

	On - Peak Wind
CPLE (Off-Shore Wind)	0
TVA (SEPA)	1
Total	**1**

Progress Energy Carolinas (West) Modeled Exports/Sales – MW

	On - Peak Wind
CPLE	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.

2015/2016 WINTER PEAK
DUKE ENERGY CAROLINAS
DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports/Purchases – MW

	Base Case	PEC TRM
CPLE (NCEMC)	0	0
CPLE (NCEMC/Hamlet)	65	65
SCEG (City of Greenwood)	0	0
SCPSA (New Horizons/NHEC)	331	331
SEPA (Hartwell)	155	155
SEPA (Thurmond)	113	113
SOCO (City of Seneca)	24	24
SOCO (EU2)	67	67
SOCO (NCEMC)	180	180
SOCO (PMPA)	80	80
Total	**1015**	**1015**

Duke Energy Carolinas Modeled Exports/Sales – MW

	Base Case	PEC TRM
CPLE (Broad River)	850	850
CPLE (NCEMC/Catawba)	205	205
CPLE (PEC TRM Reserves)	0	0
CPLW (Rowan)	150	150
CPLW (PEC TRM Reserves)	0	206
DVP (NCEMC)	50	50
Total	**1255**	**1461**

Duke Energy Carolinas Net Interchange – MW

	Base Case	PEC TRM
	240	446

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

2015/2016 WINTER PEAK
PROGRESS ENERGY CAROLINAS (EAST)
DETAILED INTERCHANGE

Progress Energy Carolinas (East) Modeled Imports/Purchases – MW

\

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

Progress Energy Carolinas (East) Modeled Exports/Sales – MW

	Base Case	PEC TRM
DUKE (NCEMC)	0	0
DUKE (NCEMC/Hamlet)	65	65
CPLW	400	400
DVP (Littleton)	10	10
DVP (NCEMPA)	137	137
DVP (PJM-Cravenwood)	47	47
DVP (NCEMC)	226	226
Total	**885**	**885**

Progress Energy Carolinas (East) Net Interchange – MW

	Base Case	PEC TRM
	-465	-465

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

2015/2016 WINTER PEAK
PROGRESS ENERGY CAROLINAS (WEST)
DETAILED INTERCHANGE

Progress Energy Carolinas (West) Modeled Imports/Purchases – MW

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

Progress Energy Carolinas (West) Modeled Exports/Sales – MW

	Base Case	PEC TRM Case
CPLE	0	0
Total	**0**	**0**

Progress Energy Carolinas (West) Net Interchange - MW

	Base Case	PEC TRM Case
Total	-551	-757

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

2020 SUMMER PEAK
DUKE ENERGY CAROLINAS
DETAILED INTERCHANGE

Duke Energy Carolinas Modeled Imports/Purchases – MW

	Base Case	PEC TRM Case
CPLE (NCEMC)	0	0
CPLE (NCEMC/Hamlet)	59	59
SCEG (City of Greenwood)	0	0
SCPSA (New Horizons/NHEC)	0	0
SEPA (Hartwell)	155	155
SEPA (Thurmond)	113	113
SOCO (City of Seneca)	31	31
SOCO (EU2)	75	75
SOCO (NCEMC)	180	180
SOCO (PMPA)	214	214
Total	**827**	**827**

Duke Energy Carolinas Modeled Exports/Sales – MW

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

Duke Energy Carolinas Net Interchange

	Base Case	PEC TRM Case
	428	934

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

2020 SUMMER PEAK
PROGRESS ENERGY CAROLINAS (EAST)
DETAILED INTERCHANGE

Progress Energy Carolinas (East) Modeled Imports/Purchases – MW

	Base Case	PEC TRM Case
AEP (NCEMC)	100	100
AEP (NCEMC #2)	100	100
AEP (PEC TRM)	0	97
CPLW	150	150
DUKE (Broad River)	850	850
DUKE (NCEMC/Catawba)	205	205
DUKE (Rowan)	150	150
DUKE (PEC TRM VACAR Reserves)	0	506
DVP (PEC TRM)	0	835
DVP (SEPA-KERR)	95	95
SCEG (PEC TRM)	0	200
SCPSA (Co-Gen)	0	0
SCPSA (PEC TRM)	0	197
Total	**1650**	**3485**

Progress Energy Carolinas (East) Modeled Exports/Sales – MW

	Base Case	PEC TRM Case
DUKE (NCEMC)	0	0
DUKE (NCEMC/Hamlet)	59	59
DVP (Littleton)	10	10
DVP (NCEMPA)	165	165
DVP (PJM-Cravenwood)	47	47
DVP (NCEMC)	226	226
Total	**507**	**507**

Progress Energy Carolinas (East) Net Interchange – MW

	Base Case	PEC TRM Case
	-1143	-2978

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

2020 SUMMER PEAK
PROGRESS ENERGY CAROLINAS (WEST)
DETAILED INTERCHANGE

Progress Energy Carolinas (West) Modeled Imports/Purchases – MW

	Base Case	PEC TRM Case
TVA (SEPA)	1	1
Total	**1**	**1**

Progress Energy Carolinas (West) Modeled Exports/Sales – MW

	Base Case	PEC TRM Case
CPLE	150	150
Total	**150**	**150**

Progress Energy Carolinas (West) Net Interchange – MW

	Base Case	PEC TRM Case
	149	149

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

Appendix B
Collaborative Transmission Plan Major Project Listing

2010 Collaborative Transmission Plan – Major Project Listing (Estimated Cost > $10M)							
Project ID	**Reliability Project**	**Issue Resolved**	**Status[1]**	**Transmission Owner**	**Projected In-Service Date[4]**	**Estimated Cost ($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	Underway	Progress	12/1/2010 12/1/2012	36	- 2
0010	Rockingham-West End 230kV East Line, Construct Line	Address loading on Rockingham-West End 230 kV Line	Underway	Progress	6/1/2011	29	.5
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 l00kV lines, Biscoe-Asheboro 115 kV line, Tillery-Biscoe 115 kV corridor, Newport-Richmond 500 kV line, Wake 500/230 banks	Underway	Progress & Duke	6/1/2011	27	.5
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	Underway	Progress	6/1/2011	83	.5
0004	Clinton-Lee 230kV Line, Construct line	Address loading on Clinton-Vander 115 kV line & Lee Sub-Wallace 115 kV line	Underway	Progress	12/1/2011	22	1

2010 Collaborative Transmission Plan – Major Project Listing (Estimated Cost > $10M)							
Project ID	**Reliability Project**	**Issue Resolved**	**Status**[1]	**Transmission Owner**	**Projected In-Service Date**[4]	**Estimated Cost ($M)**[2]	**Project Lead Time (Years)**[3]
0026	Brunswick 1 - Castle Hayne 230kV Line, Construct New Cape Fear River Crossing	Address loading on Sutton Plant-Castle Hayne 230 kV Line	Underway	Progress	6/1/2012	20	1.5
0022	Jacksonville Static VAR Compensator	Address inadequate dynamic voltage recovery after system faults during periods of high imports	Underway	Progress	6/1/2012	34	1.5
0023	Folkstone 230/115kV Substation	Address voltage on Castle Hayne-Jacksonville City 115kV Line	Underway	Progress	6/1/2013	23	2.5
0010A	Harris Plant-RTP 230 kV Line, Establish a new 230 kV line by utilizing the Amberly 230kV Tap, converting existing Green Level 115kV 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	67	4
0008	Greenville-Kinston Dupont 230 KV Line , Construct line	Address loading on Greenville-Everetts 230 kV Line	Planned	Progress	6/1/2017	22	4

2010 Collaborative Transmission Plan – Major Project Listing (Estimated Cost > $10M)							
Project ID	Reliability Project	Issue Resolved	Status[1]	Transmission Owner	Projected In-Service Date[4]	Estimated Cost ($M)[2]	Project Lead Time (Years)[3]
0024	Durham-RTP 230kV Line, Reconductor	Address loading on the Durham-RTP 230kV Line	Planned	Progress	6/1/2020	19	4
0016	Wake 500 kV Sub, Add 3rd 500/230 kV Transformer Bank	Address loading on existing Wake 500/230 banks	***Removed***	Progress			
0019	Cape Fear-West End 230 kV West Line, Install a 230 kV Series Reactor at West End 230 kV Sub	Address loading on Rockingham-West End 230 kV and Cape Fear-West End 230 kV lines	***Removed***	Progress			
0018	Rockingham-Lilesville 230 kV Line, Add third line	Address loading on Lilesville-Rockingham 230 kV lines	***Removed***	Progress			
0025	Reconductor Elon 100 kV Lines (Sadler Tie-Glen Raven Main #1 & #2)	Following construction of additional generation at Dan River Steam Station, contingency loading of the remaining line on loss of the parallel line	Underway	Duke	6/1/2011	26	.5
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	22	2.5

2010 Collaborative Transmission Plan – Major Project Listing (Estimated Cost > $10M)							
Project ID	**Reliability Project**	**Issue Resolved**	**Status**[1]	**Transmission Owner**	**Projected In-Service Date**[4]	**Estimated Cost ($M)**[2]	**Project Lead Time (Years)**[3]
0014	Reconductor London Creek 230 kV Lines (Peach Valley Tie-Riverview Switching Station #1 & #2)	Contingency loading of the remaining line on loss of the parallel line when a 230 kV connected Oconee unit is off line.	Planned	Duke	6/1/2020	43	4.0
TOTAL						**473**	

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

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

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

[4] Progress Energy in-service date changes are associated with changes in area load forecasts.

Appendix C
Collaborative Transmission Plan Major Project Descriptions

Table of Contents

Project ID	Project Name	Page
0011	Asheville-Enka, Convert 115 kV Line to 230 kV, Construct new 115 kV line	C-1
0010	Rockingham-West End 230 kV East Line	C-2
0010B	Asheboro-Pleasant Garden 230 kV Line, Replace Asheboro 230/115 kV Transformers	C-3
0021	Ft Bragg Woodruff Street- Richmond 230 kV Line	C-4
0004	Clinton-Lee 230 kV Line	C-5
0026	Brunswick 1 - Castle Hayne 230kV Line, Construct New Cape Fear River Crossing	C-6
0022	Jacksonville Static VAR Compensator	C-7
0023	Folkstone 230/115kV Substation	C-8
0010A	Harris-RTP 230 kV Line	C-9
0008	Greenville-Kinston DuPont 230 kV Line	C-10
0024	Durham-RTP 230kV Line	C-11
0025	Sadler Tie–Glen Raven Main 100 kV Lines	C-12
0027	Pisgah Tie-Shiloh Switching Station 230 kV Lines	C-13
0014	Peach Valley Tie-Riverview Switching Station 230 kV Lines	C-14
		C-15

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

Project Description
First phase of project will convert the Asheville-Enka 115 kV West Line to 230 kV operation and establish Enka 230kV Substation by installing 1-300MVA, 230/115kV transformer at the Enka 115kV 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	Underway: Project is on schedule. Conversion of Enka Sw. Station from 115 kV to 230 kV is underway and will be in-service by 12/1/2010. Conceptual Design Complete & Underway for construction of new 115 kV Line.
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, 2 years for new line
Estimated Cost	$35.9 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 construct a new 115kV Line to unload the remaining 115kV 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.

Project ID and Name: 0010 - Rockingham-West End 230 kV East Line

Project Description
This project consists of constructing 38 miles of new 230 kV line between Rockingham and West End 230 kV Substations.

Status	Underway: Project is on schedule, right-of-way acquisition in progress.
Transmission Owner	Progress
Planned In-Service Date	6/1/2011
Estimated Time to Complete	.5 years
Estimated Cost	$29 M

Narrative Description of the Need for this Project
With the Harris unit down an outage of the Richmond-Cumberland 500 kV line will cause the existing Rockingham-West End 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-2

Project ID and Name: 0010B - Asheboro (PEC)-Pleasant Garden (DEC) 230kV Line, Replace Asheboro 230/115 kV Transformers

Project Description
Construct the (PEC) Asheboro-(DE) Pleasant Garden 230 kV tie line between Progress Energy and Duke Energy. Construct 20 miles of new 230 kV line using 6-1590 MCM ACSR. At Asheboro 230 kV Substation replace 2-200MVA 230/115 kV transformers with 2-300 MVA 230/115 kV transformers.

Status	Underway: Construction underway.
Transmission Owner	Progress & Duke
Planned In-Service Date	6/1/2011
Estimated Time to Complete	.5 years
Estimated Cost	$27 M

Narrative Description of the Need for this Project
This project is needed to address contingency voltage issues in the Asheboro area, relieve loadings on the Biscoe/Asheboro and Tillery/Badin corridors and loading in the Raleigh/Durham area.

Other Transmission Solutions Considered
Construct Parkwood-Durham 500 kV line, Harris-Durham 230 kV line, Cape Fear-Siler City 230 kV line, and/or Buck-Asheboro 230 kV line.

Why this Project was Selected as the Preferred Solution
Defers the Cape Fear-Siler City 230 kV line beyond the 10 year planning horizon. Addresses several transmission issues including some that the Cape Fear-Siler City 230 kV line did not address. Cost same as Cape Fear-Siler City 230 kV line.

Project ID and Name: 0021 - Ft. Bragg Woodruff Street - Richmond 230kV Line

Project Description
Construct approximately 65 miles of 6-1590 MCM ACSR between Richmond 500kV Sub and Ft. Bragg Woodruff Street 230kV Sub.

Status	Underway: Construction underway.
Transmission Owner	Progress
Planned In-Service Date	6/1/2011
Estimated Time to Complete	.5 years
Estimated Cost	$83 M

Narrative Description of the Need for this Project
With a large unit down and the installation of Richmond CC, there are several contingencies that will cause 230kV lines around Richmond, Rockingham, and Fayetteville to approach or exceed their thermal ratings.

Other Transmission Solutions Considered
Construct a second Richmond-Cumberland 500kV Line.

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

C-4

Project ID and Name: 0004 - Clinton-Lee 230 kV Line

Project Description
This project consists of construction of 29 miles of new 230 kV line between Lee and Clinton.

Status	Underway: Right of way clearing & construction underway.
Transmission Owner	Progress
Planned In-Service Date	12/1/2011
Estimated Time to Complete	1 years
Estimated Cost	$22 M

Narrative Description of the Need for this Project
With an outage of the Erwin terminal of the Erwin-Clinton 230 kV line or an outage of the Clinton terminal of the Clinton-Wallace 230 kV line will cause several area 115 kV line to exceed their rating.

Other Transmission Solutions Considered
Rebuild, reconductor existing line.

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

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

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

Status	Underway: Underground 230 kV design decision made.
Transmission Owner	Progress
Planned In-Service Date	6/1/2012
Estimated Time to Complete	1.5 years
Estimated Cost	$20 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.

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

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

Status	Planned
Transmission Owner	Progress
Planned In-Service Date	6/1/2012
Estimated Time to Complete	1.5 years
Estimated Cost	$34 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

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

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

Status	Planned
Transmission Owner	Progress
Planned In-Service Date	6/1/2013
Estimated Time to Complete	2.5 years
Estimated Cost	$23 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 115kV 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.

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 & Construction in progress.
Transmission Owner	Progress
Planned In-Service Date	6/1/2014
Estimated Time to Complete	4
Estimated Cost	$67 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.

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	$22 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-10

Project ID and Name: 0024 - Durham-RTP 230kV Line, Reconductor

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

Status	Planned
Transmission Owner	Progress
Planned In-Service Date	6/1/2020
Estimated Time to Complete	4 years
Estimated Cost	$19 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 230kV Lines will cause an overload of the Durham 500kV Sub- RTP 230kV Switching Station Line.

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

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

Project ID and Name: 0025 - Sadler Tie – Glen Raven Main 100 kV Lines

Project Description
The project consists of reconductoring 22 miles of the existing Elon Line (336 and 954 ACSR conductor) with bundled 954 ACSR conductor from Sadler Tie to Glen Raven Main.

Status	Underway: Engineering work being performed at this time. Generation interconnection studies indicate an in-service date of 2011.
Transmission Owner	Duke
Planned In-Service Date	6/1/2011
Estimated Time to Complete	.5 years
Estimated Cost	$26 M

Narrative Description of the Need for this Project
Flow on the 100 kV lines to the south of the Dan River Steam Station is impacted by the amount of generation dispatched at Dan River and Rockingham. Loss of one circuit of the double circuit line causes increased loading on the remaining line. The construction of a 620 MW combined cycle unit at Dan River drives the need to reconductor the line.

Other Transmission Solutions Considered
Conversion of a line to 230 kV to support the planned generation in the area.

Why this Project was Selected as the Preferred Solution
Selected most cost effective solution and needed to support timing of generation projects.

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	Underway: Engineering and procurement activities taking place at this time.
Transmission Owner	Duke
Planned In-Service Date	6/1/2013
Estimated Time to Complete	2.5 years
Estimated Cost	$22 M

Narrative Description of the Need for this Project
The Caesar Lines will achieve 100% of their conductor rating in the 2010 timeframe unless restrictions are 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.

Project ID and Name: 0014 - Peach Valley Tie - Riverview Switching Station #1 & #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 2020. 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	6/1/2020
Estimated Time to Complete	4 years
Estimated Cost	$43 M

Narrative Description of the Need for this Project
Analysis of the 2020 summer base case showed that in the 2020 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.

Appendix D Projects Investigated for Climate Change Legislation Scenarios

Option 1A:
Wind Generation Output 3,000 MW

Line/Equipment Name	Voltage (kV)	Est. Mileage (Miles)	Est. Cost[9] (M)
Brunswick area –Sutton 230 kV lines	230	60 (2 lines)	$90
Sutton area 230 kV Switching Station	230		$15
Jacksonville – Sutton 230 kV line	230	45	$90
Havelock -Morehead City area 230 kV lines	230	60 (3 lines)	$90
Havelock – New Bern 230 kV lines	230	60 (2 lines)	$90
Bayboro – New Bern 230 kV lines	230	50 (2 lines)	$75
Bayboro – Bayboro Tap 230 kV line	230	5	$10
Aurora- Greenville 230 kV line partial rebuild	230	20	$20
Aurora-New Bern 230 230 kV rebuild	230	20	$20
New Bern 500KV Substation w/ 2 Banks	500		$60
Womack 500 kV Switching 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	65	$195
VC at Wommack	500		$40
Totals		**580 Miles**	**$1,195 M**

[9] 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 off-shore wind farms. Actual costs may be higher or lower than those estimated.

Option 1B:
Wind Generation Output 3,000 MW

Line/Equipment Name	Voltage (kV)	Est. Mileage (Miles)	Est. Cost[10] (M)
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
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 500KV Substation w/ 2 Banks	500		$60
Womack 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
Totals		**470 Miles**	**$1,310 M**

[10] 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 off-shore wind farms. Actual costs may be higher or lower than those estimated.

Option 2:
Wind Generation Output 2,500 MW

Cost estimate (Billions): $1.155

Line/Equipment Name	**Voltage (kV)**	**Est. Mileage (Miles)**	**Est. Cost[11] (M)**
Brunswick–Sutton area 230 kV lines	230	60 (2 lines)	$90
Sutton area 230 kV Switching Station	230		$15
Jacksonville – Sutton 230 kV line	230	45	$90
Havelock -Morehead City area 230 kV lines	230	60 (3 lines)	$90
Havelock – New Bern 230 kV lines	230	60 (2 lines)	$90
Bayboro – New Bern 230 kV line	230	50 (2 lines)	$75
Bayboro – Bayboro Tap 230 kV line	230	5	$10
New Bern 500 kV Substation w/ 2 Banks	500		$60
Womack 500 kV Switching 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	65	$195
SVC at Wommack	500		$40
Totals		**480 Miles**	**$1,155 M**

[11] 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 off-shore wind farms. Actual costs may be higher or lower than those estimated.

Option 3:
Wind Generation Output 2,000 MW

Cost estimate (Billions): $0.525

Line/Equipment Name	Voltage (kV)	Est. Mileage (Miles)	Est. Cost[12] (M)
Brunswick area –Sutton 230 kV lines	230	60 (2 lines)	$90
Sutton area 230 kV Switching Station	230		$15
Jacksonville – Sutton 230 kV line	230	45	$90
Havelock -Morehead City area 230 kV lines	230	60 (3 lines)	$90
Havelock – New Bern 230 kV line	230	30	$60
Bayboro – New Bern 230 kV line	230	25	$50
Bayboro – Bayboro Tap 230 kV line	230	5	$10
Greenville West- New Bern 230 kV line	230	40	$80
New Bern SVC	230		$40
Totals		**265 Miles**	**$525 M**

[12] 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 off-shore wind farms. Actual costs may be higher or lower than those estimated.

Appendix E
Projects Investigated for 2015 Enhanced Transmission Access Scenarios

Enhanced Transmission Access Scenarios – 2015 Enhanced Access Scenarios Studied 1000 MW Imports to Progress East or Dominion[1,2]										
Primary Alternative Investigated	Issue Identified	Lead Time (years)	Import into Progress East				Import into Dominion			
			Cleveland County		Southern Company		Cleveland County		Southern Company	
			Date Needed	($M)	Date Needed	($M)	Date Needed	($M)	Date Needed	($M)
Construct Lilesville-Rockingham 230 kV 3rd Line	Overloads of the Lilesville-Rockingham 230 kV Black and White Lines	4	To accept Transmission Service Request	$20	3-4 Years after TSR Start Date	$20	2 Years after TSR Start Date	$20	---	---

[1] The table in Appendix E reflects 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 F
Collaborative Plan Comparisons

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2009 Plan[1]			2010 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($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	30	Underway	12/1/2010 12/1/2012	36
0010	Rockingham-West End 230kV East Line, Construct line	Address loading on Rocking6ham-West End 230 kV Line	Progress	Underway	6/1/2011	32	Underway	6/1/2011	29
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 l00kV lines, Biscoe-Asheboro 115 kV line, Tillery-Biscoe 115 kV corridor, Newport-Richmond 500 kV line, Wake 500/230 banks	Progress & Duke	Underway	6/1/2011	32	Underway	6/1/2011	27
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	85	Underway	6/1/2011	83

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2009 Plan[1]			2010 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
0004	Clinton-Lee 230kV Line, Construct line	Address loading on Clinton-Vander 115 kV line & Lee Sub-Wallace 115 kV line	Progress	Underway	12/1/2011	26	Underway	12/1/2011	22
0026	Brunswick 1 - Castle Hayne 230kV Line, Construct New Cape Fear River Crossing	Address loading on the Sutton Plant-Castle Hayne 230 kV Line.	Progress	Underway	6/1/2012	21	Underway	6/1/2012	20
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	6/1/2012	34
0023	Folkstone 230/115kV Substation	Address voltage on Castle Hayne-Jacksonville City 115kV Line	Progress	Underway	6/1/2013	23	Underway	6/1/2013	23
0010A	Harris Plant-RTP 230 kV Line, Establish a new 230 kV line by utilizing the Amberly 230kV Tap, converting existing Green Level 115kV Feeder to 230 kV operation,	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	63	Underway	6/1/2014	67

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2009 Plan[1]			2010 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
	construction of new 230 kV line, remove 230/115 kV transformation and connection at Apex US1								
0008	Greenville-Kinston Dupont 230 KV Line , Construct line	Address loading on Greenville-Everetts 230 kV Line	Progress	Planned	6/1/2017	25	Planned	6/1/2017	22
0024	Durham-RTP 230kV Line, Reconductor	Address loading on the Durham-RTP 230kV Line	Progress	Planned	6/1/2019	19	Planned	6/1/2020	19
0016	Wake 500 kV Sub, Add 3rd 500/230 kV Transformer Bank	Address loading on existing Wake 500/230 banks	Progress	Planned	6/1/2018	34	Deferred	--	--
0019	Cape Fear-West End 230 kV West Line, Install a 230 kV Series Reactor at West End 230 kV Sub	Address loading on Rockingham-West End 230 kV and Cape Fear-West End 230 kV lines	Progress	Planned	6/1/2019	13	Deferred	--	--
0018	Rockingham-Lilesville 230 kV Line, Add third line	Address loading on Lilesville-Rockingham 230 kV lines	Progress	Underway	6/1/2019	20	Deferred	--	--

NCTPC Update on Major Projects – (Estimated Cost ≥ $10M)									
				2009 Plan[1]			2010 Plan		
Project ID	Reliability Project	Issue Resolved	Transmission Owner	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]	Status[2]	Projected In-Service Date	Estimated Cost ($M)[3]
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	Planned	6/1/2011	26	Underway	6/1/2011	26
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	Planned	6/1/2013	32	Underway	6/1/2013	22
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	6/1/2015	51	Planned	6/1/2020	43
0020	Reconductor Fisher 230 kV Lines (Central-Shady Grove Tap #1 & #2)	Contingency loading of the remaining line on loss of the parallel line when Cliffside 5 is off line	Duke	Planned	6/1/2017	29	Deferred	--	--
TOTAL						595			473

[1] Information reported in Appendix B of the NCTPC 2009 - 2019 Collaborative Transmission Plan" dated January, 19, 2010.

[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 2009 Report and have been deferred beyond the end of the planning horizon based on analysis performed to develop the 2010 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