North Carolina Transmission Planning Collaborative

Report on the NCTPC 2007 Collaborative Transmission Plan

DRAFT – December 6, 2007

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I. Executive Summary

The North Carolina Transmission Planning Collaborative ("NCTPC") was established to:

1) provide the Participants (Duke Energy Carolinas, Progress Energy Carolinas, Inc., North Carolina Electric Membership Corporation and ElectriCities of North Carolina) and other stakeholders an opportunity to participate in the electric transmission planning process for the Participants in the State of North Carolina;

2) preserve the integrity of the current reliability and least-cost planning processes;

3) expand the transmission planning process to include analysis of increasing transmission access to supply resources inside and outside the control areas of Duke Energy Carolinas ("Duke") and Progress Energy Carolinas, Inc. ("Progress"); and

4) develop a single coordinated transmission plan for the Participants in North Carolina that includes reliability and enhanced transmission access considerations while appropriately balancing costs, benefits and risks associated with the use of transmission and generation resources.

The first report documenting the 2006 Collaborative Transmission Plan was published in January 2007. In addition to reliability study results and potential solutions, that report included study results and potential solutions for 600 MW transfers into Duke and/or Progress from various source control areas. In April 2007, the NCTPC published the Supplemental Report on the NCTPC 2006 Collaborative Transmission Plan (the "2006 Supplemental Report"). The purpose of the 2006 Supplemental Report was two-fold:

1) to report on results of additional analyses performed to study a transfer of 1,200 MW from Duke to Progress East; and

2) to update the preferred solutions presented in the 2006 Collaborative Transmission Plan based on additional analysis performed over the first quarter of 2007.

In June 2007, the NCTPC published an update on the major projects in the 2006 Collaborative Transmission Plan. The June 2007 update is posted with the reference documents on the NCTPC website at:

http://www.nctpc.org/nctpc/listDocument.do?catId=REF.

At the Transmission Advisory Group ("TAG") meeting held in September 2007, the NCTPC presented a second update on the major projects in the 2006 Plan. The September 2007 update is posted with the TAG meeting materials on the NCTPC website at:

http://www.nctpc.org/nctpc/document/TAG/2007-09-17/M_Mat/PWG-TAG%20Meeting%20Presentation%2009-17-07%20Final.pdf .

This report documents the second single Collaborative Transmission 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 2007 reliability planning study scope and methodology. The NCTPC Process document and 2007 NCTPC study scope document are posted in their entirety on the NCTPC website at http://www.nctpc.org/nctpc/listDocument.do?catId=REF.

While the overall NCTPC Process (Figure 1 in Section II) includes both a Reliability Planning Process and an Enhanced Transmission Access Planning Process, the 2007 NCTPC Process (Figure 2 in Section III) focused exclusively on the Reliability Planning Process because stakeholders did not request any Enhanced Transmission Access scenarios for the 2007 Study. Enhanced Transmission Access scenarios will again be solicited for the 2008 Study and included if appropriate.

The scope of the Reliability Planning Study included a base reliability analysis as well as analysis of potential resource supply options. The purpose of the base reliability study was to evaluate the transmission system's ability to meet load growth projected for 2012 through 2017 with the Participants' planned Designated Network Resources ("DNRs"). The purpose of the resource supply options analysis was to evaluate transmission system impacts for various resource supply options to meet future native load requirements. All resource supply options were proposed and analyzed for a start date of 2016.

The latter sections of the report and the corresponding appendices detail the study results and specifics of the 2007 Collaborative Transmission Plan. The NCTPC reliability study results verified that Duke and Progress have projects planned to address reliability concerns for the near-term (5 year) and the long-term (10 year) planning horizons.

The 2007 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 2007 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.

Relative to the 2006 Collaborative Transmission Plan, the new or modified projects for Progress in the 2007 Collaborative Transmission Plan include:

- Construct a new Durham-Falls 230 kV line. This existing project was identified in the base reliability studies performed for the 2006 Collaborative Transmission Plan but not described in the 2006 Plan because the estimated cost at that time was less than $10 million. Now, the estimated cost of this project is above $10 million; and the project is described in the 2007 Plan.

- Modify the Asheville-Enka 230 kV line project contained in the 2006 Collaborative Transmission Plan. The 2006 Plan included construction of a new Asheville-Enka 230 kV line. The modified project in the 2007 Plan provides for first converting an existing Asheville-Enka 115 kV line to 230 kV operation and later constructing a new Asheville-Enka 115 kV line.

- Construct a third Rockingham-Lilesville 230 kV line, add a third 500/230 kV transformer bank at the Wake 500 kV substation, and install a 230 kV series reactor on the Cape Fear-West End 230 kV line at the West End 230 kV substation. These projects were identified in the Duke to Progress import resource supply option studies performed for the 2006 Collaborative Transmission Plan and for the 2006 Supplemental Report. After the 2006 Supplemental Report was issued in April 2007, 600 MW of firm transmission service requests from Duke to Progress East were confirmed. The studies performed for the 2007 Plan verified the need for these projects in order to accommodate the 600 MW of confirmed transmission service.

The new projects for Duke in the 2007 Plan include:

- Reconductor Fisher 230 kV lines. This project was identified outside the planning horizon in the studies performed for the 2006 Collaborative Transmission Plan. The studies performed for the 2007 Plan identified the need for this project had moved into the planning horizon as flow on the 230 kV backbone through the south and central region of the Duke system increased due to load growth and loop flow impacts from the south. Increased import from SOCO can accelerate the need for this project.

For the 2007 Study, ten import scenarios for varying quantities of imported MW from neighboring systems into Duke or Progress East were studied. In addition, the PWG also evaluated ten scenarios where hypothetical generation was proposed at sites on either the Duke or Progress East system. The resulting analysis of the resource supply options showed that for all import scenarios analyzed, the Duke and Progress East transmission systems can accommodate the imports without additional projects beyond those planned as a result of the base reliability study. For the ten generation resource supply options, only two of the proposed sites, both on the Progress East system, indicated a need for additional projects within the planning horizon related to the hypothetical generation. Tables 1 and 2 provide a summary of the resource supply analyses, including the incremental costs for upgrades needed to accommodate the resource supply options above the costs for facility additions and upgrades identified in the 2007 Collaborative Transmission Plan in Appendix B.

Table 1[1]
Resource Supply Option Results – 2016 Hypothetical Import Scenarios Studied

Resource From	Sink	Test Level (MW)	Estimated Cost ($M)
Duke	Progress East	600	0
Duke	Progress East	1,200	0
PJM	Progress East	200	0
SCPSA	Progress East	400	0
SCEG	Progress East	600	0
CPLE	Duke	100	0
PJM	Duke	600	0
SCEG	Duke	600	0
SOCO	Duke	600	0
TVA	Duke	600	0

Table 2
Resource Supply Option Results – 2016 Hypothetical Generation Scenarios Studied

Resource In (County)	Sink	Test Level (MW)	Estimated Cost ($M)
Scotland	Progress East	450	2
Cumberland	Progress East	450	0
Wilson	Progress East	450	0
Johnston	Progress East	450	0
Robeson	Progress East	600	70
Guilford	Duke	150	0
Davidson	Duke	150	0
Union	Duke	150	0
Gaston	Duke	150	0
Rockingham	Duke	800	0

In this second year of the NCTPC Process, the Participants validated and continued to build on the information learned from last year's efforts. The resource supply option analysis was expanded to include not only import scenarios, but also hypothetical generation scenarios. Each year the Participants will look for ways to improve and enhance the planning process. The study process confirmed again this

[1] In Tables 1 and 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. Also, the projects required to accommodate each resource supply option were determined independently. Therefore, the projects and cost estimates do not reflect the requirements for simultaneously accommodating two or more resource supply options.

year that the joint planning approach produces benefits for all Participants that would not have been realized without a collaborative effort.

II. North Carolina Transmission Planning Collaborative Process

II.A. Overview of the Process

The NCTPC Process was established by the Participants to:

1) provide the Participants 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 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 Participation Agreement which is posted at http://www.nctpc.org/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.

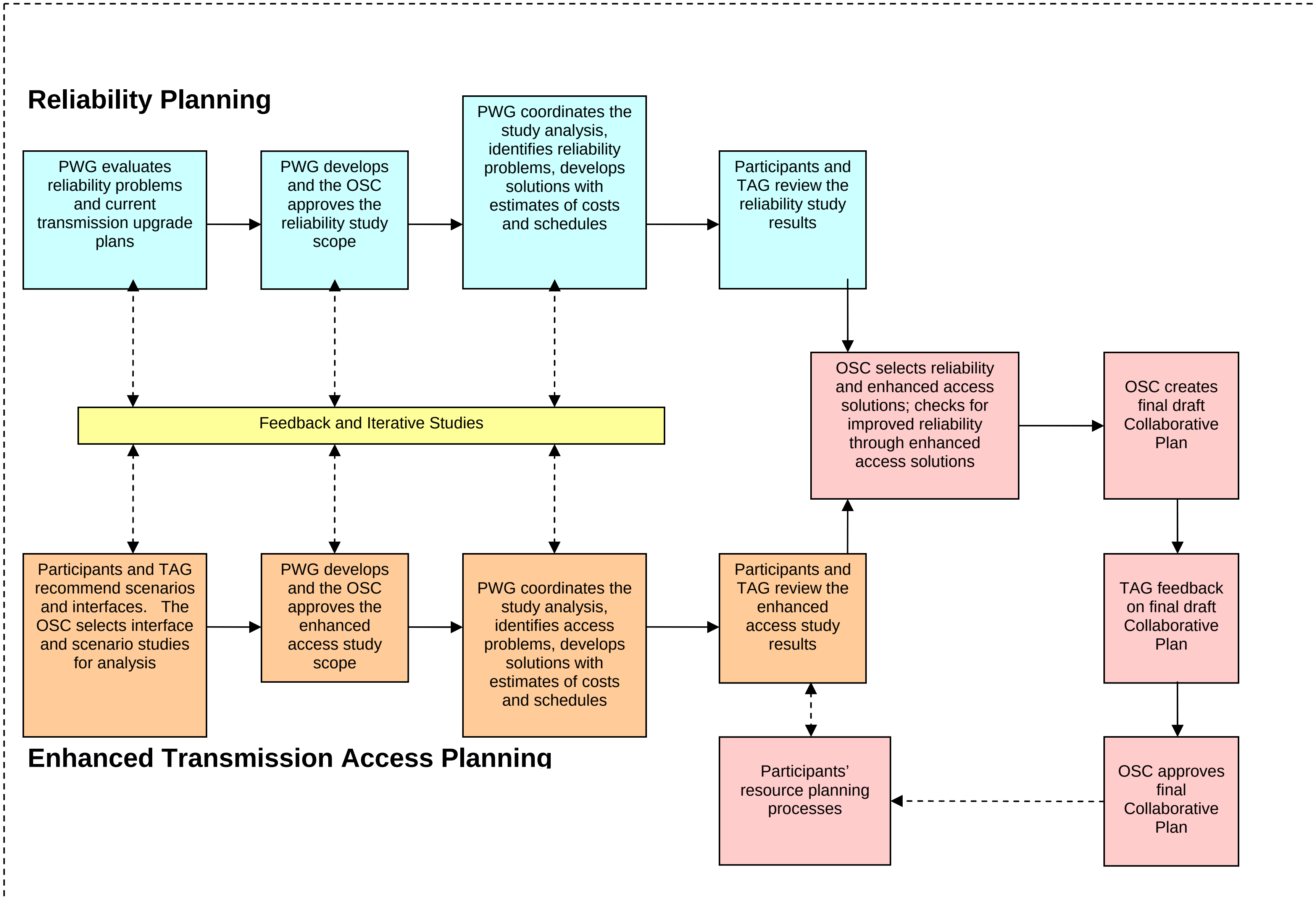
In addition, the PWG solicits input from the Participants for different scenarios on where to include alternative supply resources to meet their load demand forecasts in the study. This step provides the opportunity for the Participants to propose the evaluation of other resource supply options to meet 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 final results of the Reliability Planning Process includes 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.

II.C. Enhanced Transmission Access Planning Process

The ETAP Process evaluates 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 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.

Figure 1
2007 NCTPC Process Flow Chart



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 final 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.

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. The final plan is reviewed with the TAG.

The Collaborative Transmission Plan information is available for Participants to identify any alternative least cost resources to include with their respective Integrated Resource Plans. Other stakeholders can similarly use this information for their resource planning purposes.

III. 2007 Reliability Planning Study Scope & Methodology

The 2007 Reliability Planning Process included a base reliability study and 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 Council ("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 2012 through 2017 with the Participants' planned DNRs. The 2007 Study allowed for identification of any new system impacts not currently addressed by existing transmission plans in which case solutions were developed. The 2007 Study also allowed for adjustments to existing plans where necessary.

The purpose of the resource supply option analysis was to evaluate transmission system impacts for various hypothetical/uncommitted resource supply options to meet future native load requirements. For the 2007 Study, North Carolina Municipal Power Agency Number 1 ("NCMPA1"), North Carolina Eastern Municipal Power Agency ("NCEMPA"), North Carolina Electric Membership Corporation ("NCEMC"), EnergyUnited, the City of Concord, Duke and Progress provided input regarding resource supply options to be studied. The PWG developed resource supply option scenarios based on this Participant input. For each resource supply option studied, system impacts were identified that could require new projects or adjustments to existing plans. Tables 3 and 4 list of the resource supply option scenarios studied.

Table 3
Resource Supply Options – 2016 Hypothetical Import Scenarios Studied

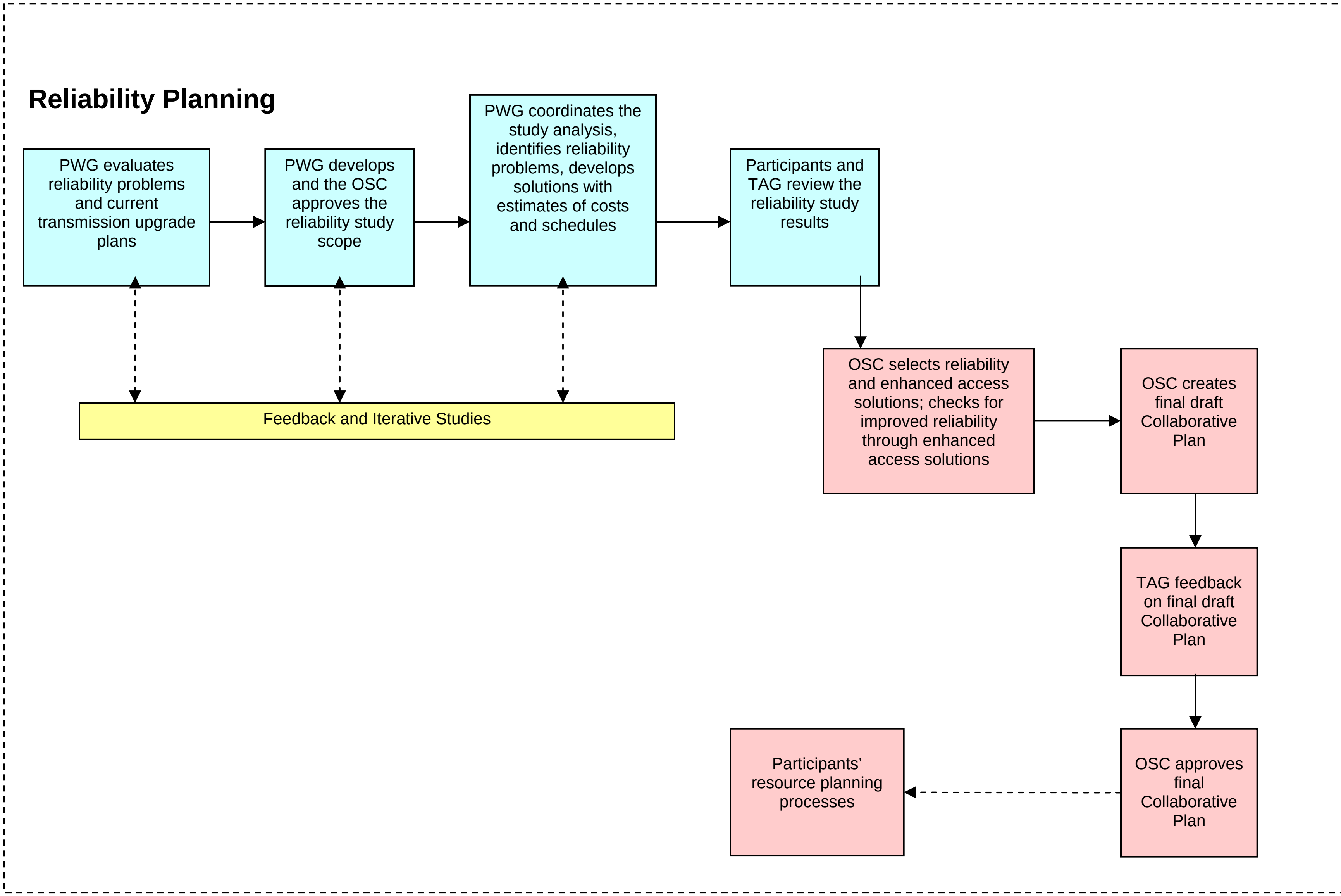
Resource From	Sink	Test Level (MW)
Duke	Progress East	600
Duke	Progress East	1,200
PJM	Progress East	200
SCPSA	Progress East	400
SCEG	Progress East	600
CPLE	Duke	100
PJM	Duke	600
SCEG	Duke	600
SOCO	Duke	600
TVA	Duke	600

Table 4
Resource Supply Options – 2016 Hypothetical Generation Scenarios Studied

Resource In (County)	Sink	Test Level (MW)
Scotland	Progress East	450
Cumberland	Progress East	450
Wilson	Progress East	450
Johnston	Progress East	450
Robeson	Progress East	600
Guilford	Duke	150
Davidson	Duke	150
Union	Duke	150
Gaston	Duke	150
Rockingham	Duke	800

The 2007 NCTPC Process did not include enhanced transmission access studies. At the TAG meeting in January 2007, the OSC presented the TAG with an overview of the ETAP Process, as described in Section II.C, and solicited input from the TAG on scenarios and interfaces to be studied as part of the development of the 2007 Collaborative Transmission Plan. The OSC did not receive any requests for ETAP studies from the TAG. As a result, the OSC decided that for the development of the 2007 Collaborative Transmission Plan, the NCTPC would focus all its resources on the Reliability Planning Process. The ETAP Process will be included as part of the development of the 2008 Collaborative Transmission Plan and input will be solicited from the TAG as part of the 2008 NCTPC Process. Figure 2 illustrates the revised steps for the 2007 NCTPC Process.

Figure 2
2007 NCTPC Process Flow Chart - Revised



III.A. Assumptions

1. Study Year and Planning Horizon

The 2007 Collaborative Transmission Plan addresses a 10 year planning horizon through 2017. The study years chosen for the 2007 Study are listed in Table 5.

Table 5
Study Years

Study Year / Season	Analysis
2012 summer	Near-term base reliability
2016 summer	Long-term base reliability
2016 summer	Resource supply options

Line loading results for 2012 and 2016 were extrapolated into the future assuming the line loading growth rates in Table 6. This allowed assessment of transmission needs throughout the planning horizon. The line loading growth rates are based on each company's individual load growth projection.

Table 6
Line Loading Growth Rates

Company	Line Loading Growth Rate
Duke	2 % per year
Progress	2.5 % per year

2. Network Modeling

The network models developed for the 2007 Study included new transmission facilities and upgrades for the 2012 and 2016 summer periods, as appropriate, from the current transmission plans of Duke and Progress and from the 2006 Collaborative Transmission Plan as modified by the 2006 Supplemental Report. Table 7 lists the planned major transmission facility projects (with an estimated cost of $10 million or more each) included in the 2012 and 2016 models. Table 8 lists the generation facility additions and retirements included in the 2012 and 2016 models. These generation additions were needed to fulfill the modeled load obligations of Duke and Progress in the development of the base cases and/or Duke's generator maintenance cases. The generator additions were located to minimize any transmission impacts on the study results.

Table 7
Major Transmission Facility Projects Included in Models

Company	Transmission Facility	2012 Base	2016 Base	2016 Resource Supply Option
Progress	Upgraded Lee Sub-Wommack 230 kV South Line	Yes	Yes	Yes
Progress	Durham 500 kV Sub	Yes	Yes	Yes
Progress	New Durham-Falls 230 kV Line	Yes	Yes	Yes
Progress	Upgraded Rockingham-West End 230 kV Line	Yes	Yes	Yes
Progress	New Clinton-Lee 230 kV Line	Yes	Yes	Yes
Progress	Installed Series Reactor at Richmond 500 kV Sub	Yes	Yes	Yes
Progress	Converted Asheville-Enka 115 kV Line to 230 kV	Yes	Yes	Yes
Progress	New Asheville-Enka 115 kV Line	No	Yes	Yes
Progress	New Greenville-Kinston Dupont 230 kV Line	Yes	Yes	Yes
Progress	New Rockingham-West End 230 kV East Line	Yes	Yes	Yes
Progress	New Harris Plant-RTP 230 kV Line	Yes	Yes	Yes
Progress/ Duke	New Asheboro-Pleasant Garden 230 kV Line	Yes	Yes	Yes
Progress	New Rockingham-Lilesville 230 kV Line	No	Yes	Yes
Progress	Added 3rd 500/230 kV Wake Bank	No	Yes	Yes
Progress	Installed Series Reactor at Cape Fear-West End 230 kV West Line	No	Yes	Yes
Duke	Upgraded Antioch 500/230 kV Transformers	No	Yes	Yes

Table 8
Major Generation Facility Additions and Retirements in Models

Company	Generation Facility	2012 Base	2016 Base	2016 Resource Supply Option
Duke	Retired Cliffside Units 1-4 (202 MW)	Yes	Yes	Yes
Duke	Added Cliffside Unit 6 (800 MW)	Yes	Yes	Yes
Duke	Added Buck CC	620MW	620MW	800 MW
Duke	Added Cliffside Unit 7 (800 MW)	No	Yes	Yes
Duke	Added Lee CC (800 MW)	No	Yes	Yes
Duke	Added Anderson CC (800 -1,200 MW)	No	No	Yes[2]
Progress	Added Wayne County (300 MW)	No	Yes	Yes

3. Interchange and Generation Dispatch

Each Participant provided a resource dispatch order for each of its DNRs for the Duke and Progress control areas. Generation was dispatched for each Participant to meet that Participant's peak load in accordance with the designated dispatch order.

Interchange in the summer base cases were set according to the DNRs identified outside the Duke and Progress control areas. Interchange tables for the summer base cases and the summer Progress Transmission Reliability Margin ("TRM") cases[3], discussed in Section III.D, are in Appendix A.

For the 2016 hypothetical import scenarios studied, which are listed in Table 3 of Section III, the sink and source control area interchange was modified to accommodate the import from the prescribed control area. The source control area's generation was scaled to allow the export; and the Duke or Progress control area, as appropriate, was economically re-dispatched to accept the import of energy.

For the 2016 hypothetical generation scenarios studied, which are listed in Table 4 of Section III, the hypothetical generation facility and the generation local to the hypothetical generation facility were at full output and the remainder of the generation in the Duke or Progress control area, as appropriate, was economically re-dispatched to accept the full output of the hypothetical generation facility.

[2] The Anderson CC was modeled only in the hypothetical import scenario cases studied at import levels of 600 MW or more.

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

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 2006 VACAR-Southern-TVA-Entergy ("VSTE") model for the systems external to Duke and Progress. The VSTE 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.

Changes that took place on the Progress OASIS during the 2007 Study resulted in a modification of the initial Duke to Progress East resource supply options studied. After the 2012 and 2016 base cases were developed for the 2007 Study and the screening of the base cases had been performed, two Open Access Transmission Tariff ("OATT") firm transmission service requests with a Point of Receipt of Duke and a Point of Delivery in Progress East were confirmed on the Progress system totaling 600 MW. The initial 2016 resource supply options studied included an import scenario of 600 MW from Duke to Progress East, similar to the newly confirmed requests. Upon the confirmation of the 600 MW OATT requests described above, the NCTPC modified the Duke to Progress East resource supply option scenarios to include a 1,200 MW Duke to Progress East import scenario in order to reflect the 600 MW of confirmed transmission service and a resource supply option of an additional 600 MW.

The 2016 base cases were the starting point for creating resource supply option cases. Resource supply option cases for the hypothetical import scenarios in Table 3 of Section III were modeled as an incremental import to the 2016 base cases developed. For the hypothetical generation scenarios in Table 4 of Section III, the hypothetical generation facility and the generation local to the hypothetical generation facility were modeled at full output and the remainder of the generation was economically redispatched within the control area in which the hypothetical generation was located.

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 on the resource supply option cases 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.

The generator maintenance cases developed were:

Allen 4	Allen 5	Bad Creek 1
Belews Creek 1	Buck 5	Catawba 1
Cliffside 5	Cliffside 6	Cliffside 7[4]

[4] Cliffside 7 was a generator maintenance case only in the screenings performed on the 2016 cases.

Dan River 3	Jocassee 1	Lee 3
Marshall 3	McGuire 1	McGuire 2
Oconee 1	Oconee 3	Riverbend 6
Riverbend 7		

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 2012 and 2016 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 systems, 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 2007 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.

The post-contingency phase angle difference of the Richmond-Newport 500 kV line was not monitored in the 2007 Study, because the solution to the phase angle problem identified in the 2006 Collaborative Transmission Plan is scheduled to be in-service in December 2009.

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 load 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 2007 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 2006 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, criteria and cases 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 hypothetical imports into Duke or Progress from external control areas and hypothetical generators located internal to Duke or Progress. Solution alternatives were identified to address issues found for each scenario studied. The results provide a good measure of the network impacts that each scenario may have on the Duke and Progress transmission systems. Additional analysis would be required to determine the optimal set of projects that would best meet system needs to fully integrate each resource supply option.

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 VSTE studies performed for similar time frames. VSTE studies have recently been performed for 2008, 2011 and 2013 summer time frames. The limiting facilities identified in the PWG study have been previously identified in the VSTE 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 2007 Study verified that Duke and Progress have projects planned to address reliability concerns for the near-term (5 year) and long-term (10 year) planning horizons. The 2007 Study results from the reliability studies performed on the 2012 base cases were consistent with the 2006 Study results from the reliability studies performed on the 2011 base cases. Also, there were no unforeseen problems identified in the reliability studies performed on the 2016 base cases.

The 2007 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 2007 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 new or modified projects for Progress in the 2007 Collaborative Transmission Plan include:

- Construct a new Durham-Falls 230 kV line.
- Modify the Asheville-Enka project included in the 2006 Collaborative Transmission Plan.
- Construct a third Rockingham-Lilesville 230 kV line.
- Install third 500/230 kV transformer bank at the Wake 500 kV substation.
- Install a 230 kV series reactor on the Cape Fear-West End 230 kV line at the West End 230 kV substation.

The new projects for Duke in the 2007 Plan include:

- Reconductor Fisher 230 kV lines.

Sections IV.A through IV.E describe the new or modified projects in the 2007 Collaborative Transmission Plan. Section IV.F describes the Wateree 100 kV operating solutions. Section IV.G describes the London Creek 230 kV reconductoring project that was in the 2006 Collaborative Transmission Plan and the 2006 Supplemental Report, but was deferred based on the 2007 Study results.

IV.A. Durham-Falls 230 kV

This existing project was identified in the base reliability studies performed for the 2006 Collaborative Transmission Plan but not described in the 2006 Plan because the estimated cost at that time was less than $10 million. Now, the estimated cost of this project is above $10 million; and the project is described in the 2007 Plan.

IV.B. Asheville-Enka

Modify the Asheville-Enka 230 kV line project contained in the 2006 Collaborative Transmission Plan. The 2006 Plan included construction of a new Asheville-Enka 230 kV line. The modified project in the 2007 Plan provides for first converting one of the existing common tower Asheville-Enka 115 kV lines to 230 kV operation (these 115 kV circuits were designed for 230 kV operation). In a second phase a new Asheville-Enka 115 kV line will be constructed. The phase two construction is needed to address 115 kV overloads for the common tower outage of the Asheville-Enka 230 kV and 115 kV circuits.

IV.C. 3rd Rockingham-Lilesville 230 kV Line, 3rd Wake 500/230 kV Bank and Series Reactor at West End 230 kV Sub

After the 2006 Supplemental Report was issued in April 2007, 600 MW of firm transmission service requests from Duke to Progress East were confirmed. The Duke to Progress East import resource supply option studies performed for the 2007 Study verified the need for new transmission projects on the Progress system to accommodate the 600 MW of transmission service from Duke to Progress East. As a result of the confirmation of the requests, three projects were added to the 2007 Collaborative Transmission Plan. The projects are: install a third Rockingham-Lilesville 230 kV line, install a third 500/230 kV transformer bank at the Wake 500 kV substation, and install a 230 kV series reactor on the Cape Fear-West End 230 kV line at the West End 230 kV substation. These same projects were identified in the Duke to Progress East import resource supply option studies performed for the 2006 Study and were listed in Appendix 3 of the 2006 Supplemental Report.

In addition to these three major projects, other projects on the Progress system identified in Appendix 3 of the 2006 Supplemental Report are also being constructed, but their costs are less than $10 million, and they are therefore not listed in the 2007 Plan.

IV.D. Fisher 230 kV Lines

Flow on the 230 kV backbone through the south and central region of the Duke system continues to increase due to load growth and loop flow impacts from the south. Around 2016, loss of one circuit of the Fisher 230 kV double circuit line causes the remaining line to overload. The project consists of reconductoring 18 miles of the existing 954 ACSR conductor with bundled 954 ACSR conductor. The line is sensitive to south to north transfers. Increased import from SOCO increases loading on the Fisher lines and can accelerate the need for an upgrade. Duke will continue to monitor the timing of this upgrade.

IV.E. Wateree Operating Solutions

In the 2012 analysis, loss of one circuit of the double circuit Wateree 100 kV lines (Wateree-Great Falls) causes the remaining line to overload. This overload would require reconductoring 20 miles of the existing 2/0 Cu conductor. An approved operating guide has been used with increasing frequency to mitigate this problem in the current operating horizon. The operating guide calls for either (1) a decrease in local area generation, if possible, at Wateree (Duke), Great Falls/Dearborn (Duke), or Darlington County/Robinson (Progress) or (2) opening both circuits of the Wateree 100 kV lines. Testing the use of the operating guide in the 2012 and 2016 analyses showed opening the Wateree 100 kV lines remains an effective operating solution with no reliability impacts. With the recent increase in use of the operating guide expected to continue, there is a strong possibility that the system will need to operate in the future with the tie open almost all the time. Since opening the Wateree

100 kV lines removes the Wateree generation's connection to the Duke system, the preferred operating solution would be to open the Wateree 115/100 kV tie between Duke and Progress. This operating solution would leave the Wateree generation radially connected to Duke at the end of the Wateree 100 kV lines. Since the total Wateree generation (83 MW) exceeds Duke's summer 1 hour rating (71.2 MVA) for one circuit of the Wateree 100 kV lines, the loss of one circuit of the Wateree 100 kV lines would cause the remaining line to overload if the Wateree generation were operating at close to full output. If this contingency were to occur, Duke would be required to quickly reduce Wateree generation to protect the remaining Wateree line. This preferred operating solution is currently being used in the operating horizon.

IV.F. Deferred Projects

On the Duke system, the London Creek 230 kV reconductoring project was deferred from the 2015 timeframe indicated by the 2006 Collaborative Transmission Plan and the 2006 Supplemental Report. The 2007 Study indicates that the upgrade will not be required until 2020 which is beyond the 10 year planning horizon. The line is sensitive to south to north transfers. Increased import from SOCO lowers loading on the London Creek lines and can delay the need for an upgrade. Siting of new generation can also impact the timing of this project. Duke will continue to monitor the timing of this upgrade.

V. Resource Supply Option Study Results

Resource supply options for 2016 summer consisted of hypothetical imports into Duke or Progress from external control areas and hypothetical generators located internal to Duke or Progress. Solution alternatives were identified to address any issues that required a solution within the 10 year planning horizon. Where issues were found, solution alternatives were discussed, and a primary set of solutions was determined.

V.A. Import Resource Supply Options

For the import resource supply options listed in Table 3 of Section III, the study results show that the Duke and Progress East transmission systems can each accommodate the scenarios studied without additional projects beyond those in the 2007 Collaborative Transmission Plan.

V.B. Generation Resource Supply Options

For the generation resource supply options in the Duke control area listed in Table 4 of Section III, study results show that the Duke system can accommodate the scenarios studied without additional projects beyond those in the 2007 Collaborative Transmission Plan.

For the generation resource supply options in the Progress East control area listed in Table 4 of Section III, study results identified issues for two scenarios, Robeson County and Scotland County. The solution alternatives were discussed in the PWG and the final set of projects was selected. A 2016 in-service date for the solution alternatives is feasible. Highlights of the results of the generation resource supply options studied in the Progress control area show the following:

Robeson County Hypothetical Generation (600 MW):

- Problem: Thermal loadings on Fayetteville-Fayetteville East 230 kV line and Weatherspoon Plant-Fayetteville DuPont 115 kV line.
- Solution: Construct Weatherspoon-Cumberland 230 kV line and Cumberland-Fayetteville East 230 kV line

- Problem: Thermal loading on Weatherspoon-Raeford 115 kV line
- Solution: Install 115kV series reactors on Weatherspoon Plant-Fayetteville DuPont 115 kV line and on Weatherspoon-Raeford 115 kV line

Scotland County Hypothetical Generation (450 MW):

- Problem: Thermal loading on Raeford-Wagram 115 kV line
- Solution: Install a 115kV series reactor at Weatherspoon on the Wagram 115 kV terminal

Appendix D lists the projects, identified in this Section, which were investigated for the resource supply options studied. For each of these projects, Appendix D provides the estimated cost, the lead time, and the date the project would be needed in order to implement the resource supply option studied.

While it is still up to all of the Participants to develop their own resource supply plans, the NCTPC Process offers a valuable way to assess the transmission impacts of the resource supply options for the time period being studied. The primary transmission solution alternatives resulting from this process will help complement integrated resource planning processes and provide valuable transmission system information related to future resource supply needs. The 2007 Study targeted resource supply options in 2016 summer which is near the end of the current 10 year planning horizon. For the hypothetical generation resource supply options, the solutions identified in the 2007 Study may not fully address all of the issues that may occur beyond the planning horizon. Although transmission service for these resources must still be requested and obtained via the OASIS, the 2007 Study results provide the Participants and other stakeholders information regarding potential transmission upgrades that may be required for various resource supply options before the transmission service request is made and the transmission service study results are provided.

VI. Collaborative Transmission Plan

The 2007 Collaborative Transmission Plan includes 17 projects with an estimated cost of $10 million or more each. These projects are listed in Appendix B. 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. The list provides the following information for each project:

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 2006 Supplemental Report and have been deferred beyond the end of the planning horizon based on the 2007 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 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.

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.

A detailed description of each of the 17 projects is provided in Appendix C.