North Carolina Transmission Planning Collaborative

Report on the NCTPC 2006 Collaborative Transmission Plan

January 25, 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.

This report documents the first 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 2006 Reliability Planning Study Scope and Methodology. While the overall NCTPC Process (Figure 1 in Section II) includes both a Reliability Planning Process and an Enhanced Transmission Access Planning Process, the 2006 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 2006 Study. Enhanced Transmission Access scenarios will again be solicited for the 2007 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 2011 through 2016 with the Participants' planned Designated Network Resources ("DNRs"). The purpose of the resource supply analysis was to evaluate transmission system impacts for various resource supply options to meet future native load requirements. The list of resource supply options studied is shown in Table 2 of Section III. In August 2006, one additional resource supply scenario study was added to evaluate a 1,200 MW import case from Duke to Progress East. The results of this analysis are not yet complete and will be provided in a supplemental report in the first quarter of 2007.

The latter sections of the report and the corresponding appendices detail the study results and specifics of the 2006 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) planning horizon and most of the reliability concerns for the long term (10 year) planning horizon.

The 2006 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 Plan are both those projects identified in the base reliability study as well as selected projects from the resource supply analysis that will have positive financial and power flow benefits on base reliability projects and will also be beneficial toward creating additional import capability. 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 Progress projects in the Plan include:

- 500 kV series reactors at the Richmond 500 kV Substation to mitigate the phase angle issue on the Richmond-Newport 500 kV line.

- A Durham 500 kV project which addresses increased contingency loading on the 500/230 kV transformer banks at the Wake 500 kV Substation and also establishes 500 kV at the Durham 230 kV Substation. To implement the Durham 500 kV project, the Mayo-Wake 500 kV line will be looped into Durham, and one new 500/230 kV transformer bank will be installed at Durham. A third Wake 500/230 kV transformer is being considered in the Raleigh/Durham area in the 10 year planning horizon.

- The Cape Fear-Siler City 230 kV line will provide additional contingency voltage support for the Asheboro area.

- The Rockingham-West End 230 kV line and the new Rockingham-West End 230 kV East line projects address issues with increasing flow on the Progress system to the north from the Richmond County area.

- A Buck-Asheboro 230 kV line and a Harris-Durham 230 kV line are being considered to address loading issues into the Asheboro and Raleigh load pockets in the 10 year planning horizon.

- A new Asheville-Enka 230 kV line and the installation of a new 230/115 kV transformer establishing 230 kV at the Enka 115 kV Substation will address contingency loading on the Asheville 230/115 kV transformers in the 10 year planning horizon.

The Duke projects in the Plan include:

- Increasing the 500/230 kV transformer capacity at the Antioch Substation.

- Bundling of the London Creek (Riverview Switching Station to Peach Valley Tie) 230 kV line.

The timing of both Duke projects is influenced by loop flows across the Duke control area which will continue to be monitored and factored into the in-service date for these facilities.

In addition to the base reliability analysis the 2006 Study analyzed various resource supply options. The potential problems and solutions identified are listed in Section IV.C of the report while the details are included in Appendix D. Table 1 provides a summary of the resource supply analyses. The cost estimates included in Table 1 are the incremental costs above those costs already identified for the facility additions and upgrades identified in the 2006 Collaborative Transmission Plan in Appendix B.[1] This information can assist the Participants and other stakeholders with making decisions on any alternative least cost resources to include with their respective future Integrated Resource Plans.

Table 1
Summary of Independent Resource Supply Option Results

Transfer From	Transfer To	Capacity (MW)	Earliest Resource Supply Option Start Date[2]	Nominal Cost ($M)[3]
PJM (AEP)	Duke	600	2011	3
TVA	Duke	600	2011	2
SOCO	Duke	600	2011	2
SCEG	Duke	600	2011	1
SCPSA	Duke	600	2011	1
CPLE	Duke	600	2011	1
Duke	CPLE	600	2011	130
SCEG	CPLE	600	2011	51
SCPSA	CPLE	600	2011	65
SOCO	CPLE	600	2011	46
TVA	CPLE	600	2011	46
PJM (AEP)	CPLE	600	2011	48

[1] If a project is needed to address a base reliability problem in the planning horizon and the potential need for the project is accelerated based on the resource supply analysis, the estimated cost in Table 1 is the cost to accelerate implementation of the project. If a project is needed beyond the planning horizon and the potential need for the project is accelerated into the planning horizon based on the resource supply analysis, the estimated cost in Table 1 is the total cost to implement the project.

[2] This is the date that the resource supply option could be accommodated if a TSR was submitted and confirmed by a transmission customer in 2007 for delivery of the resource supply option.

[3] The limitations of the use of these cost estimates must be considered. The results of the analysis will change with changing conditions, such as location of future generation, load growth and loop flow. In addition, transmission service is granted through the Transmission Service Request ("TSR") queue on a first come – first serve basis; hence, if other future TSRs are granted service, the results of the analysis may change. Also, the projects required to increase the transfer capability over each of the interfaces were determined independently. Therefore, the projects and cost estimates in Table 1 do not reflect the requirements for simultaneously increasing transfer capability over two or more of the interfaces.

PJM (DVP)	CPLE	600	2011	48
PJM (AEP/AEP)	Duke/CPLE	600/600	2011	79
PJM (AEP/DVP)	Duke/CPLE	600/600	2011	69
PJM (AEP)	CPLW	20	2010/2011	0

From an overall planning perspective, this collaborative effort of North Carolina Load Serving Entities ("LSEs"), both transmission-owning and transmission-dependent, provided valuable information about projected loads and resources used in transmission planning and information about transmission requirements for use by all transmission customers. This joint planning effort produced benefits for all Participants that would not have been realized without this collaborative effort. The benefits include:

1) insight into the neighboring system's modeling approaches, including resource assumptions, contingencies evaluated and system dispatch assumptions;

2) higher confidence in and understanding of data provided by all Participants, including more detailed and timely information shared;

3) improved understanding of the neighboring transmission system, including its strengths and weaknesses and the relationship of impacts between the two transmission systems;

4) shared technical and planning expertise that resulted in improved modeling, more comprehensive evaluation of the impact of generation and transmission contingencies, and consideration of more extensive sets of solutions; and

5) more comprehensive approach to developing solutions to address not only reliability, but also to increase access to alternative resource supply options for LSEs.

Through the course of implementing this NCTPC Process, the Participants, both transmission-owning and transmission-dependent, confirmed these benefits of this collaborative planning process.

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. This transmission planning process is being 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.

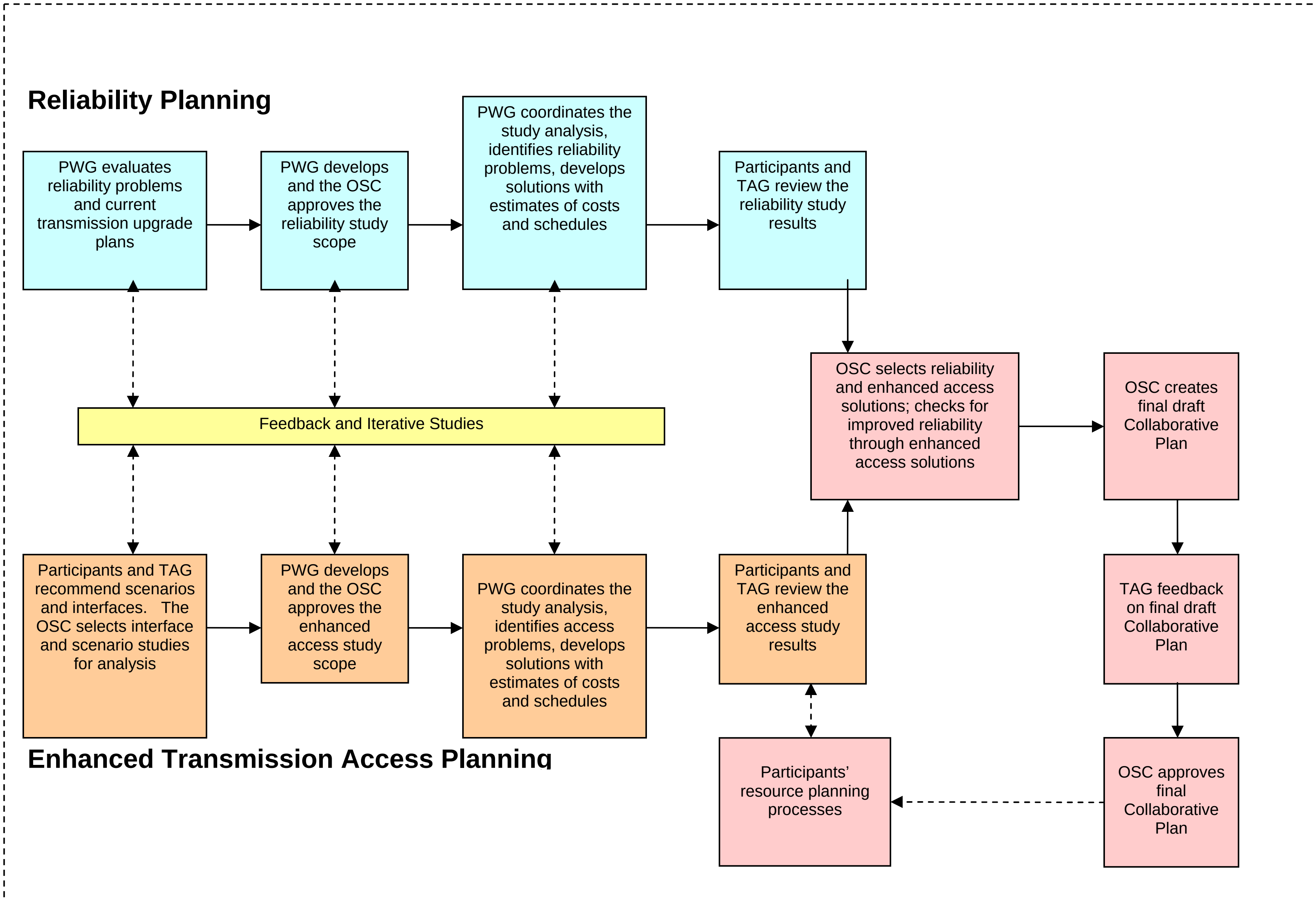
In addition, the PWG solicits input from the Participants for different scenarios on where to include alternative supply resources to meet their load demand forecasts in the study. This step provides the opportunity for the Participants to propose the evaluation of other resource supply options to meet 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 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
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. 2006 Reliability Planning Study Scope & Methodology

The 2006 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”), Duke and Progress requirements. The purpose of the base reliability study was to evaluate the transmission system’s ability to meet load growth projected for 2011 through 2016 with the Participants’ planned DNRs.

The purpose of the resource supply option analysis was to evaluate transmission system impacts for various uncommitted resource supply options to meet future native load requirements. The PWG developed resource supply option scenarios based on Participant input from North Carolina Municipal Power Agency Number 1 (“NCMPA1”), North Carolina Eastern Municipal Power Agency (“NCEMPA”), Fayetteville Public Works Commission, North Carolina Electric Membership Corporation (“NCEMC”), Waynesville, Stantonsburg, Lucama, Black Creek, Forest City/Dallas and Concord. The analysis of these scenarios identified transmission issues and investigated solutions using the proposed alternative supply resources to serve the Participants' load. Table 2 is a list of the resource supply option scenarios studied.

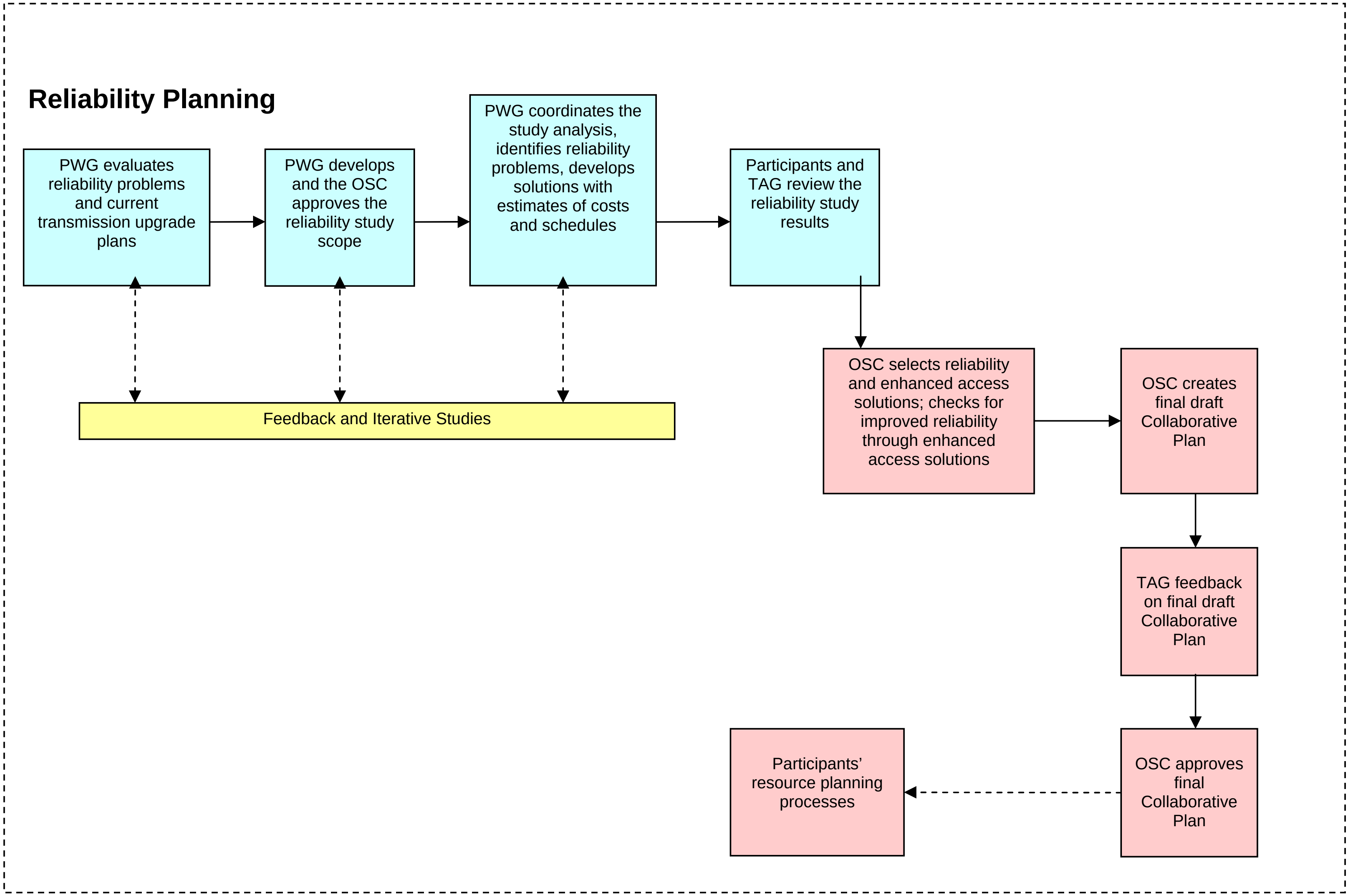
Table 2
List of Resource Supply Options Studied

Resource From	Sink	Sink	Net Requests (MW)	Test Level (MW)
NORTH – PJM (AEP)	Duke		473	600
WEST – TVA	Duke		464	600
SOUTH – SOCO	Duke		564	600
SOUTH – SCEG	Duke		464	600
SOUTH – SCPSA	Duke		464	600
EAST – Progress	Duke		464	600
NORTH – PJM (AEP)		Progress (CPLE)	535	600
NORTH – PJM (DVP)		Progress (CPLE)	535	600
SOUTH – SCEG		Progress (CPLE)	600	600
SOUTH – SCPSA		Progress (CPLE)	500	600
WEST – Duke		Progress (CPLE)	464	600
NORTH – PJM (AEP/AEP)	Duke	Progress (CPLE)	1,008	600 / 600
NORTH – PJM (AEP/DVP)	Duke	Progress (CPLE)	1,008	600 / 600
NORTH – PJM (AEP)		Progress (CPLW)	20	20

As shown in Table 2, optional imports requested by the Participants totaled between 450 MW and 600 MW above base case imports from each neighboring interface with either Duke's control area or Progress' eastern control area ("CPLE"). The last row of Table 2 shows one request to study an additional 20 MW of imports above the base case into Progress' western control area ("CPLW"). Each row in Table 2 represents a single scenario. For simplicity, the net requests were rounded to 600 MW for all scenarios except the scenario importing into Progress West. The PWG decided to study a scenario with simultaneous 600 MW transfers from PJM to both Duke and Progress East because of concern that the possibility of such a large transfer from north to south could potentially stress the transmission system. Two different scenarios were analyzed for imports from PJM since Duke ties directly to PJM via AEP while Progress ties to PJM via both AEP and DVP.

The 2006 NCTPC Process did not include enhanced transmission access studies. At the TAG meeting in February 2006, 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 2006 Collaborative Transmission Plan. The OSC did not receive any input from the TAG. As a result, the OSC decided that for the development of the 2006 Collaborative Transmission Plan it would focus all its resources on the Reliability Planning Process. The ETAP Process will still be included as part of the development of the 2007 Collaborative Transmission Plan; and input will be solicited from the TAG as part of the 2007 NCTPC Process. Figure 2 illustrates the revised steps for the 2006 NCTPC Process.

Figure 2
2006 NCTPC Process Flow Chart - Revised



III.A. Assumptions

1. Study Year and Planning Horizon

The plan addresses a 10 year planning horizon through 2016. The study year chosen for the 2006 NCTPC study was 2011.

Progress operates and plans for two separate control areas: (i) Progress East (summer peaking) and (ii) Progress West (winter peaking). Studies of Duke and Progress East systems were performed on 2011 summer cases. Studies for Progress West were performed on a 2010/2011 winter case.

2. Network Modeling

The network models developed for the 2006 Study included new transmission facilities and upgrades in the current transmission plans of Duke and Progress for the 2011 summer and 2010/2011 winter periods. Duke's generation capacity and transmission facility additions planned for development at Cliffside Steam Station by 2011 were included in the models. Also, the Anson (2007), Richmond (2007) and Wayne County (2008) combustion turbines under development in the Progress control areas were included in the models.

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 and winter base cases were set according to the resources identified outside the Duke and Progress control areas. Interchange tables for the summer and winter base cases and the summer and winter Progress Transmission Reliability Margin ("TRM") cases[4], discussed in Section III.D, are in Appendix A. For resource supply option cases, 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 and/or Progress control area was economically re-dispatched to accept the import of energy.

III.B. Study Criteria

The results of the base reliability study and the resource supply option study were evaluated using established planning criteria, while

[4] Since Progress is an importing system, the worst case for studying imports into Progress is to start with a case that already has all other import commitments modeled, including firm point-to-point transmission service and TRM. Progress calls this maximum import case its TRM case.

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.

In the first year of this collaborative planning endeavor, the PWG spent significant effort reviewing the planning criteria and reliability assumptions used for the individual transmission planning processes of the Participant transmission owners. Both transmission owners' individual company criteria meet the NERC Reliability Standards. This review served to identify whether there were significant differences that needed to be addressed to produce a Collaborative Transmission Plan. Many similarities were identified, along with some key differences. Table 3 lists the key differences identified by the PWG.

Table 3
Key Planning Differences

	Duke	**Progress**
Planning Process Calendar	Performs both near- and long-term (5 and 10 year planning horizons, respectively) screens at same time	Divides screening process into near-term and long-term screens performed during different parts of the year
Case Development	**Duke**	**Progress**
DNR	Includes DNR projections provided by LSEs	Assumes rollover of existing DNRs only, no other changes that have not met Open Access Transmission Tariff requirements
Dispatch Priority	Assumes dispatch priority of LSE resources as provided by LSEs	Includes all LSE import flows and owned generation, backing down Progress resources as needed

	Duke	Progress
Transmission Reliability Margin	As discussed in Section III.D	As discussed in Section III.D
Future "Dummy" Generation[5]	Locates dummy generation at "feasible" locations based on generator interconnection queue information and engineering judgment	Locates dummy generation at a 500 kV bus to minimize system impact
Assessment	**Duke**	**Progress**
Line Loading Growth Rates[6]	2% per year	2.5% per year
Line Ratings for Contingency Analysis	Uses 12-hour and long-term emergency ratings for transformers	Uses continuous ratings for all equipment
Import Assumptions and Generation Contingencies	Assesses loss of one generator with redispatch, keeping imports constant, simulating a generation maintenance scenario with transmission and generation contingencies	Assesses all import obligations, including TRM, simulated by taking one large unit out of service and scaling back additional generation within Progress to simulate capacity reductions with transmission contingencies
Phase Angle	Does not normally monitor phase angle, but would if a problem was indicated	Due to impact on phase angle from significant flow on 500 kV system, monitors the Richmond-Newport 500 kV line phase angle, as discussed in Section IV.A

Of the key differences identified, the PWG determined that for the 2006 Study, only the difference in the annual planning calendars and monitoring of phase angle differences were critical to the PWG's ability to proceed with the joint planning process. As a result, Progress agreed to adjust its annual planning calendar to resolve this difference; and Duke agreed to monitor the phase angle difference on the Richmond-Newport 500 kV line. For some of the remaining differences identified, assessing their impacts on the Collaborative Transmission Plan and resolving those

[5] There are sufficient resources to serve the load in the 2011 case; therefore this is not an issue for the 2006 Collaborative Transmission Plan.
[6] Based on each company's individual load growth projection.

differences, as necessary, would be much more complex. Therefore, the PWG recommended and received OSC support to proceed with the 2006 NCTPC Process using Duke criteria to evaluate the Duke transmission system and Progress criteria to evaluate the Progress transmission system. For the 2007 NCTPC Process, the PWG will again review the differences between the individual planning criteria and reliability assumptions and may recommend changes as the NCTPC Process goes forward.

III.C. Case Development

The base case for the base reliability study was developed using the most current 2005 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, as applicable.

The base case was the starting point for creating resource supply option cases. Resource supply option cases for the scenarios in Table 2 were modeled as an incremental import to the base cases developed. Cases were developed for:

Summer 2011

- With an incremental import of 600 MW to the Duke system;
- With an incremental import of 600 MW to the Progress East system; and
- With both an incremental import of 600 MW to Duke and an incremental import of 600 MW to the Progress East system.

Winter 2010/2011

- With an incremental import of 20 MW to the Progress West system.

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 and utilized in generation down studies as described in Table 3. TRM is composed of contracted VACAR reserve sharing 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 maintenance contingency cases developed were:

Allen 4	Allen 5	Bad Creek 1
Belews Creek 1	Buck 5	Catawba 1
Cliffside 3	Cliffside 5	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. Cases were developed from the base case for each of the following major unit outages:

Anson	Asheville 1	Blewett/Tillery
Brunswick 1	Harris 1	Roxboro 4

Generation down cases were also developed from the resource supply option cases, but were limited to backing down only those units that had the most significant impact on the results of the base case, typically a Harris or Brunswick unit.

To understand regional impacts on each other's systems, Duke and Progress also exchanged their transmission contingency and monitored element files in order for each company to simulate the impact of the other company's contingencies on its own transmission system. Also, each company simulated its own transmission contingencies with the other company generation down scenario to understand the impact of major unit outages.

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 2006 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:

1) Thermal loadings greater than 90% for base reliability, and greater than 80% for resource supply options to allow evaluation of project acceleration.

2) Voltages less than 100% for 500 kV buses and less than 95% for 230 kV buses; pre- to post-contingency voltage drops of 5% or more; voltages outside of requirements at nuclear facilities.

3) Post-contingency phase angle difference of Richmond-Newport 500 kV line.

Line loading results for 2011 were extrapolated into the future assuming the line loading growth rates in Table 3. This allowed assessment of transmission needs throughout the planning horizon.

In order to monitor the post-contingency phase angle difference of the Richmond-Newport 500 kV line in the analysis, the ratings of the line were set to 1350 MVA, the estimated flow that results in post contingency phase angle violations.

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 problems resulting from their assessments of both the base reliability cases and the resource supply option scenarios were documented and shared among the PWG.

III.G. Solution Development

The studies performed by the PWG confirmed base reliability problems already identified by Duke and Progress in company specific planning studies performed individually by the transmission owners. The PWG participated in the development of potential solution alternatives to the identified base reliability problems, if appropriate, 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, alternatives were identified for each interface import scenario. Additional analysis would be required to determine the optimal set of projects that best meet system needs for each scenario. 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 these resource supply options in conjunction with other Participants for the time period being studied. The primary transmission solution alternatives resulting from this process will help complement each LSE's integrated resource planning process and provide valuable system information related to future resource supply needs. Although transmission service for these resources must still be requested and obtained via the OASIS, the LSEs will have a much better idea of what to expect regarding potential transmission upgrades that may be required for resource scenarios before the transmission service request is made and the study results are provided.

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, with the exception of the phase angle issue on the Richmond-Newport 500 kV line which is described in detail in Section IV.A. These limiting facilities have also been identified in the individual transmission owner's internal assessments required by NERC reliability standards.

IV. Reliability Study Results

IV.A. Phase Angle Richmond-Newport 500 kV Line

The base reliability study confirmed the existence of a phase angle problem, previously identified in Progress' internal assessments, during periods of high import into the Progress East system. The phase angle problem develops when trying to close or open the Richmond-Newport 500 kV line, which is approximately an 80 mile interconnection between Duke and Progress. It is imperative that the line be capable of being promptly reclosed after normal and fault operations in order to meet applicable reliability standards. Synch-check relays on the line breakers are currently set to block reclosing when the angular difference across the breaker reaches 30 degrees. Progress has determined through dynamic studies that closing the line with phase angles greater than 30 degrees creates an unacceptable sudden change of power on the generating units in the electrical vicinity of the Richmond 500 kV Substation.

Progress completed a study in April 2004 which described this issue and estimated the scope, schedule and cost of a potential solution to this issue. The study described a traditional solution alternative of building additional 500 kV lines to mitigate the phase angle issue. The study is posted on the Progress OASIS.

After confirming the existence of the phase angle issue, the PWG brainstormed an extensive list of potential solutions. The list was developed for discussion purposes and for further follow-up. Progress informed the OSC at its June 27th meeting that Progress was working with KEMA, Inc. ("KEMA"), a local utility consultant, to gain an understanding of some technologies that were included in the list of potential solutions that were identified by the PWG. Several of the options on the list utilized static series capacitors or reactors at various locations of the transmission system. KEMA provided input on these and other alternatives including the use of Flexible AC Transmission System ("FACTS") devices. KEMA focused on technology with the ability to address the switching issues on the 500 kV system under high power flow. KEMA preliminarily recommended the use of a Thyristor Controlled Series Reactor ("TCSR") due to its ability to quickly impact line flow on closing and opening switching operations. While TCSRs are in use in other parts of the country, none appear to be used for the switching issue Progress is seeking to address.

Progress engaged KEMA in a Phase II effort to focus on the TCSR with regard to feasibility of solution, size, schedule, operation, capital and installation costs and operation and maintenance costs. The Phase II study report was released by KEMA on November 21, 2006. After detailed study under normal and various fault operations, the recommendation was made to pursue 500 kV series reactors at the Richmond 500 kV Substation to mitigate the phase angle issue. Progress is pursuing this project and currently plans to have the reactors in service by June 2010. The reactors are included in the 2006 Collaborative Transmission Plan to address reliability concerns.

IV.B. Base Reliability Study

The 2006 NCTPC Study verified that Duke and Progress have projects planned to address reliability concerns for the near term (5 year) planning horizon and most of the reliability concerns for the long term (10 year) planning horizon. The 2006 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 Plan are both those projects identified in the base reliability study as well as selected projects from the resource supply analysis that will have positive financial and power flow benefits on base reliability projects and will also be beneficial toward creating additional import capability. 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 Progress projects in the Plan include:

- 500 kV series reactors at the Richmond 500 kV Substation to mitigate the phase angle issue on the Richmond-Newport 500 kV line as discussed in Section IV.A.

- A Durham 500 kV project which addresses increased contingency loading on the 500/230 kV transformer banks at the Wake 500 kV Substation and also establishes 500 kV at the Durham 230 kV Substation. To implement the Durham 500 kV project, the Mayo-Wake 500 kV line will be looped into Durham, and one 500/230 kV bank will be installed at Durham. A third Wake 500/230 kV transformer is being considered in the Raleigh/Durham area in the 10 year planning horizon.

- The Cape Fear-Siler City 230 kV line will provide additional contingency voltage support for the Asheboro area.

- The Rockingham-West End 230 kV line and the new Rockingham-West End 230 kV East line projects address issues with increasing flow on the Progress system to the north from the Richmond County area.

- A Buck-Asheboro 230 kV line and a Harris-Durham 230 kV line are being considered to address loading issues into the Asheboro and Raleigh load pockets in the 10 year planning horizon.

- A new Asheville-Enka 230 kV line and the installation of a new 230/115 kV transformer establishing 230 kV at the Enka 115 kV Substation will address contingency loading on the Asheville 230/115 kV transformers in the 10 year planning horizon.

The Duke projects in the Plan include:

- Increasing of 500/230 kV transformer capacity at the Antioch Substation.

- Bundling of the London Creek (Riverview Switching Station to Peach Valley Tie) 230 kV line.

The timing of both Duke projects is influenced by loop flows across the Duke control area which will continue to be monitored and factored into the in-service date for these facilities.

IV.C. 600 MW Resource Supply Option Studies – Increased Imports to Progress East and to Duke

Prior to additional imports into Progress East, the 500 kV phase angle issue described in Section IV.A has to be resolved. Once the phase angle is resolved, additional thermal issues will need to be addressed. The PWG reviewed the thermal results for the 600 MW resource supply option studies listed in Table 2 of Section III. The results show that it may be difficult to meet a 2011 in-service date for the 600 MW resource supply option projects given the lead time to complete these projects. Appendix D provides detailed information on the estimated cost and schedule for transmission infrastructure needed to support these imports.

Highlights of the results of the 600 MW resource supply option studies show the following:

Progress East Imports from North (PJM-AEP and PJM-DVP):

- Problem: Overload of the Wake 500/230 kV banks.
  Solution: Install 3rd Wake 500/230 kV transformer bank by 2011.

- Problem: Overload 230 kV lines in Durham/Cary area.
  Solution: Construct new Harris-Durham 230 kV line by 2014.

- Problem: Overload 230 kV lines in the Rockingham/Cape Fear and Asheboro/Biscoe areas.
  Solution: Construct new Buck-Asheboro 230 kV tie to Duke Energy by 2011.

- Problem: Overload of Duke's Antioch 500/230 kV transformers.
  Solution: Accelerate capacity upgrade.

- Problem: Overload of Duke's Harrisburg-Oakboro 230 kV line.
  Solution: Bundle conductor by 2015.

Progress East Imports from South (SCPSA and SCEG):

- Problem: Overload of the Wake 500/230 kV banks.
  Solution: Install 3rd Wake 500/230 kV transformer bank by 2012.

- Problem: Overload 230 kV lines in Durham/Cary area.
  Solution: Construct new Harris-Durham 230 kV line by 2014.

- Problem: Overload 230 kV lines in the Rockingham/Cape Fear and Asheboro/Biscoe areas.
  Solution: Construct new Buck-Asheboro 230 kV tie to Duke Energy by 2011.

Progress East Imports from West (Duke):

- Problem: Overload of the Wake 500/230 kV banks.
  Solution: Install 3rd Wake 500/230 kV transformer bank by 2012.

- Problem: Overload 230 kV lines in Durham/Cary area.
  Solution: Construct new Harris-Durham 230 kV line by 2014.

- Problem: Overload 230 kV lines in the Rockingham/Cape Fear and Asheboro/Biscoe areas.
  Solution: Construct new Buck-Asheboro 230 kV tie to Duke Energy by 2011.

- Problem: Overload of Duke's Harrisburg-Oakboro 230 kV line.
  Solution: Bundle conductor by 2013.

- Problem: Overload of Duke's Eno-Pleasant Garden 230 kV line.
  Solution: Bundle conductor by 2014.

Duke Imports from All Interfaces

- Duke will continue to monitor the timing of the future transformer upgrades at the Antioch substation. Transformer replacement schedule would be advanced from 2014 if higher imports occur.

Duke Imports from West (TVA)

- Planning model included an upgrade to the Nantahala-Robbinsville-Santeetlah 161 kV tie line and increased capacity to 596 MVA.

- No thermal limits were identified at the levels tested.

Duke Imports from South (SCPSA, SCEG, SOCO)

- No thermal limits were identified at the levels tested.

IV.D. 20 MW Resource Supply Option Study – Increased Imports to Progress West

Progress West Imports from North (PJM-AEP)

- Problem: Overload of the Asheville 230/115 kV banks.
  Solution: Construct new Asheville-Enka 230 kV line and install new 230/115 kV transformer establishing 230 kV at the Enka 115 kV Substation by the winter of 2011/2012.

IV.E. 1,200 MW Resource Supply Option Studies – Increased Imports to Progress East

In August 2006, in response to new OASIS transmission service requests received by Progress and Duke, the PWG recommended and the OSC approved incorporation of the new requests as additional resource supply option studies. The PWG scoped out the following approach to study the impact of the requests. Using the previously created 2011 case with a 600 MW import from Duke to Progress East, the PWG created a 1,200 MW import case from Duke to Progress East. The 1,200 MW import represents the following resource supply options from Duke into Progress East:

- 500 MW for Fayetteville;
- 400 MW for Progress; and
- 200 MW for NCEMC.

A 100 MW redirect OASIS request by NCEMC for changing the source from AEP to Duke was also added to the models thus creating a 1,200 MW Duke to Progress East import case.

The PWG has commenced the 1,200 MW Duke to Progress East import studies but was not able to complete the analysis in time for this report. The PWG plans to provide a supplement to this report in the first quarter of 2007.

V. Reliability Study

The scope of the 2006 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 systems' ability to meet load growth projected for 2011 through 2016 with Participants' planned DNRs. The purpose of the resource supply analysis was to evaluate transmission system impacts for various resource supply options to meet future native load requirements. The list of resource supply options studied is shown in Table 2 of Section III. In August 2006, one additional resource supply scenario study was added to evaluate a 1,200 MW import case from Duke to Progress East. The results of this analysis are not yet completed and will be provided in a supplemental report in the first quarter of 2007.

V.A. Base Reliability Study

The 2006 Study verified that Duke and Progress have projects in place to address reliability concerns for the planning horizon particularly in the 1 to 5 year period. Some issues were identified on the Progress system that may need to be addressed in the 6 to 10 year period. It should be noted that there is a significant amount of uncertainty in this time period as to the location of new generation sources.

V.B. *Resource Supply Options Summary*

The issues identified and solutions investigated for the 600 MW resource supply option scenarios studied are listed in Appendix D. The tables in Appendix D are intended to give an estimate of the cost and schedule impact in order to accommodate a new request to increase imports into either Progress or Duke by 600 MW in 2011. The cost estimates provided reflect either the total cost of new projects needed solely for the import or the acceleration of an existing project already identified. The need date and lead time determine the estimated year the request could be accommodated.

VI. Collaborative Transmission Plan

Once the reliability and 600 MW resource supply options studies were completed, the PWG evaluated the results to determine if any proposed resource supply option projects should be incorporated into the 2006 Collaborative Transmission Plan. The PWG recommended and the OSC approved three projects, identified from the resource supply option studies, to include in the Plan. These three projects were not identified in the base reliability studies; however, based on additional analysis performed by the PWG, the projects will have positive financial and power flow benefits on base reliability projects and will address issues that had not been addressed in the 6 to 10 year time horizon of the reliability studies. The projects will also be beneficial toward creating additional import capability as identified in the resource supply option studies. The three projects are listed below:

1) Buck-Asheboro 230 kV Interconnection;
2) Harris-Durham 230 kV Line; and
3) Add #3 500/230 kV transformer at Wake 500 kV Substation.

The Buck-Asheboro 230 kV interconnection would be a new tie line between Progress and Duke A detailed joint study is planned for the first quarter of 2007 to further investigate this potential new interconnection as well as alternatives.

The 2006 Collaborative Transmission Plan is currently comprised of the 16 projects with an estimated cost of $10 million or more each. These projects are listed in Appendix B. The list 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. *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.

   b. *Planned* – Projects with this status do not have money in the Transmission Owner's current year budget; and the project is subject to change.

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

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

6) Estimated Cost: Best estimate of the cost available. The estimate accuracy may vary dependent on the maturity of the project.

7) Estimated Time to Complete: Number of years needed to complete project.

A detailed description of each of the 16 projects is provided in Appendix C.

VII. Conclusions

The benefits to be gained from a collaborative transmission planning process stem from the interdependent nature of adjoining network systems in terms of performance impacts. For a transmission owner, a collaborative effort that provides information about a neighboring system is directly relevant to issues and potential issues in one's own system. From a planning perspective, a collaborative effort that includes all LSEs, both transmission-owning and transmission-dependent, provides valuable information about projected loads and resources for transmission planning and information about transmission requirements for resource planning. Through the course of implementing this collaborative planning process, the Participants' PWG representatives confirmed the benefits of such joint planning.

First, the collaborative process was an educational process for PWG representatives. Transmission planning practices, including similarities and differences in reliability planning assumptions, along with reliability results were shared and discussed within the group. The PWG became a forum for sharing technical and planning expertise to achieve a common goal. For example, as reliability problems were documented and shared with the group, the PWG held brainstorming sessions to propose solutions to the problems identified. Through this collaboration, potentially promising solutions that had not been considered previously by a transmission owner were identified and explored in greater detail.

Bringing all Participants together to address North Carolina's transmission issues resulted in more comprehensive modeling and analysis of the Duke and Progress transmission networks. The PWG built a combined detailed model that incorporated improved generation dispatch assumptions relative to the assumptions that either transmission owner had available to them when they planned individually. Duke and Progress exchanged contingency and monitored elements files such that each could test the impact of the neighboring system's transmission and generation outages on their own systems. Each owner's generation down cases included modeling outages of key generators on the neighboring system. A specific example of this showed how an outage of the largest Roxboro unit on Progress' system could advance the need for a previously identified transmission project on Duke's system. This type of information is a direct result of the collaborative process, because it had not and would not have been identified in the separate transmission planning studies typically conducted.

A primary objective for the PWG in this planning process was to compare transmission solution alternatives and select the preferred alternatives, while appropriately balancing associated costs, benefits, and risks. As a joint effort, this process took into consideration the costs, benefits, and risks to *all* Participants, and therefore, delivered solution alternatives that benefited a larger mix of stakeholders than individual planning processes would have otherwise. For example, solutions were evaluated not only in terms of whether they corrected the identified problem on one system, but also on whether they negatively impacted the adjoining system. Scenarios were studied that not only addressed reliability for the Participants' planned DNRs, but also for alternative resource supply options that could benefit LSEs otherwise limited in their choices of resource suppliers. PWG representatives looked for comprehensive solutions that would best benefit multiple stakeholders, rather than piecemeal fixes that only satisfy the reliability requirements of the separate transmission systems. The work of the PWG in this planning process provided concrete examples for Participants, both transmission-owning and transmission-dependent, of the benefits of collaboration.