STEPTOE & JOHNSON LLP
ATTORNEYS AT LAW

Jennifer L. Key
202.429.6746
jkey@steptoe.com

1330 Connecticut Avenue, NW
Washington, DC 20036-1795
Tel 202.429.3000
Fax 202.429.3902
steptoe.com

December 7, 2007

Via Hand Delivery

Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: **Duke Energy Carolinas, LLC, Docket No. OA08-_____-000**
Progress Energy Carolinas, Inc., Docket No. OA08-_____-000

Dear Secretary Bose:

In compliance with the Commission's Order No. 890[1] and Section 206 of the Federal Power Act ("FPA"), Duke Energy Carolinas, LLC ("Duke") and Progress Energy Carolinas, Inc., also known as Carolina Power and Light Company ("Progress") (collectively, the "Filing Parties") tender for filing their joint compliance filing regarding Attachment K.[2] The Filing Parties are serving an electronic copy of this filing on all of their respective open access transmission tariff ("OATT") customers by email as well as on their state commissions. Hard copies will be made available upon request and the revised OATTs will be posted on the Filing Parties' websites. Because the entire Attachment K is new, the Filing Parties are seeking a waiver of the redline requirements. The Filing Parties seek consolidation of the dockets containing their filings, as they would like the tariff language in the relevant Attachment to each of their OATTs to remain identical to each other. Each Attachment K contains an Appendix 1, which describes the Southeast Inter-Regional Participation Process ("SIRPP") -- process through which stakeholders could request economic planning studies for hypothetical

[1] *Preventing Undue Discrimination and Preference in Transmission Service*, 118 FERC ¶ 61,119 (2007), *reh'g pending*.

[2] For Duke, "Attachment K" will actually be Attachment N to its OATT. To prevent confusion, the Filing Parties refer to the attachment as Attachment K.

service that would transverse multiple regional transmission planning efforts. This appendix is sponsored by thirteen transmission owners in the Southeast: Duke, Progress, Alabama Electric Cooperative, Santee Cooper, Dalton Utilities, South Carolina Electric & Gas, South Mississippi Electric Power Association, Entergy, Georgia Transmission Corporation, Southern Companies, Municipal Electric Authority of Georgia, Tennessee Valley Authority, and E.ON U.S. All of the FERC-jurisdictional SIRPP sponsors intend that the SIRPP portion of their OATTs remain identical.

This compliance filing contains the parts listed immediately below. As evident from the headers and footers, only Attachments A and B hereto are part of the OATTs (of Duke and Progress respectively). The other Attachments hereto are documents that are provided for informational purposes as they elaborate on the planning processes described in Attachment K, but they are not part of the relevant tariffs. The attachments are as follows:

- Attachment A, a clean copy of the Duke tariff sheets;
- Attachment B, a clean copy of the Progress tariff sheets;

The following documents are not part of the OATT:

- Attachment C, the NCTPC Participation Agreement, with proposed revisions[3];
- Attachment D, North Carolina Transmission Planning Collaborative Process;
- Attachment E, Scope - Oversight/Steering Committee;
- Attachment F, Scope - Planning Working Group;

[3] The NCTPC Participation Agreement is being revised in conjunction with this filing, as are several other documents of the NCTPC which are attached. Although the NCTPC Participants have indicated that they expect to execute this version of the NCTPC Participation Agreement (which version the Filing Parties expect to have an effective date of December 7, 2007), the revised version has not yet been executed. The revisions to this document are designed to ensure that it is fully consistent with Attachment K. References to the NCTPC Participation Agreement in Attachment K are thus intended to refer to that agreement as it exists at the relevant point in time, recognizing that it may change from time to time. If a change to the NCTPC Participation Agreement triggers a need to change Attachment K, the Filing Parties will attempt to make sure the changes are made concurrently.

- Attachment G, Transmission Advisory Group - Scope;
- Attachment H, NCTPC Transmission Cost Allocation;
- Attachment I, Reliability Planning in the Southeast and the Relationship between Reliability and Economic Planning; and
- Attachment J, map of region covered by the NCTPC.

I. COMMUNICATIONS

The Filing Parties request that questions or other communications with them regarding this filing be addressed to:

Jeffrey M. Trepel
Associate General Counsel
Duke Energy Corporation
526 South Church Street
Mail Code: EC03T
Charlotte, NC 28201
(704) 382-8131
jtrepel@duke-energy.com

James B. Gainer
Vice President, Fed. Reg. Policy
Duke Energy Corporation
526 South Church Street
P.O. Box 1006
Charlotte, NC 28202
(704) 382-5618
james.gainer@duke-energy.com

Kendal Bowman
Associate General Counsel
Progress Energy
P.O. Box 1551, PEB 17B2
Raleigh, NC 27602
(919) 546-6794
kendal.bowman@pgnmail.com

Jennifer L. Key
Steptoe & Johnson LLP
1330 Connecticut Ave., N.W.
Washington, D.C. 20036
(202) 429-6746
jkey@steptoe.com

II. BACKGROUND

In Order No. 890, the Commission directed all Transmission Providers to develop a transmission planning process that satisfies nine principles and to clearly describe that process in a new attachment (Attachment K) to their OATT.

Since 2005, the Filing Parties have been participants in a regional planning process called the North Carolina Transmission Planning Collaborative Process ("NCTPC Process"). The NCTPC was formed by the following load serving entities ("LSEs") in the State of North Carolina: Duke, Progress, ElectriCities of North Carolina

("ElectriCities"), and the North Carolina Electric Membership Corporation ("NCEMC") (collectively, "NCTPC Participants"). The NCTPC Process includes a stakeholder group -- the Transmission Advisory Group ("TAG"). When FERC instructed Transmission Providers to draft a strawman planning process and post it on their websites, the Filing Parties thus decided to issue a joint strawman and consulted with the other NCTPC Participants in performing that task. The existing NCTPC Process served as the backbone for the strawman and the NCTPC Participants provided valuable feedback throughout this drafting process. The Filing Parties next participated in a FERC technical conference with stakeholders to obtain further feedback on the strawman proposal. Also, the TAG was invited to provide comments on the strawman outside of the FERC technical conference process.

In a July 27 order, the Commission explained that there was much work left to be done in many regions to develop tariff language that satisfies Order No. 890.[4] The Commission extended the compliance date for submitting an Attachment K to December 7, 2007 and directed Staff to convene additional technical conferences to allow stakeholders and Staff to provide feedback on draft Attachment Ks, which had to be posted September 14, 2007.

After the posting of the September 14, 2007 draft Attachment K, the Filing Parties continued to collaborate with the other NCTPC Participants, as well as other stakeholders, to finalize Attachment K. On September 17, 2007, the TAG met to discuss and comment on the draft Attachment K. On October 1, 2007, the Filing Parties, other NCTPC Participants, and stakeholders participated in a FERC technical conference on their draft Attachment K. FERC Staff and stakeholder input were considered over the next several months. Both a new draft of Attachment K and proposed changes to certain NCTPC documents were posted for comment and were the subject of a November 15, 2007 TAG meeting.

In addition to these regional implementation activities, the Filing Parties are participating in the development of a new, inter-regional planning process. The SIRPP was initiated by a group of transmission providers in the southeast. Stakeholders were invited to provide comments on the SIRPP whitepaper that was attached to, but not part of, the Filing Parties' draft Attachment K. Since that time, a revised SIRPP whitepaper was provided to stakeholders, including the TAG, for comment. The latest version of this SIRPP document is being incorporated into the OATTs and is Appendix 1 to each of the Filing Parties' Attachment K. It is the Filing Parties' understanding that other SIRPP

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[4] *Preventing Undue Discrimination and Preference in Transmission Service*, 120 FERC ¶ 61,103 (2007).

transmission providers will include this same document in their Attachment K submissions.

III. THE NCTPC IS A REGIONAL PLANNING PROCESS AND THE VEHICLE FOR SATISFYING ORDER NO. 890'S REQUIREMENTS

The region addressed by the Filing Parties' Attachment K are the portions of North Carolina and South Carolina where the Filing Parties' transmission systems are located and is shown on the map attached as Attachment J. The NCTPC Process meets the Filing Parties' obligations under Order No. 890 with regard to transmission planning. The Filing Parties have selected a region of a size that will permit effective, efficient coordination at a reasonable cost. In recognition of the fact that this region does not encompass *every* transmission owner interconnected to both Duke and Progress, the Filing Parties have ensured that inter-regional coordination, i.e., coordination with other interconnected neighbors, will occur through various other means, as described in Attachment K. Two very important inter-regional planning efforts are the reliability assessments that are performed within SERC and the newly-formed SIRPP.

IV. STRUCTURE OF ATTACHMENT K

The substance of Attachment K is described in detail through the Filing Parties' explanation of how the nine planning principles adopted in Order No. 890 are met. This section provides a brief overview of the structure of Attachment K. Section 1 of Attachment K provides a brief introduction to the NCTPC and its structure. Section 2 overviews the NCTPC Process, explaining the role of stakeholders and others in that Process. It explains the committee/component structures, as well as the roles of various committees/components. Section 3 describes the procedures used by the NCTPC to ensure there is effective communication among the NCTPC Participants and the TAG.

Section 4 explains how the NCTPC transmission plan is developed each year. Such process involves both reliability and economic planning. Section 5 describes how transmission studies are performed and the sources of data underlying those studies. It explains the step-by-step process that eventually leads to the issuance of the transmission plan and how stakeholders may participate in that effort through the TAG. Section 6 describes the methodologies for resolving disputes about the plan or planning process.

Typically, the Filing Parties' OATTs govern transmission facility cost allocation to wholesale customers. The states of North Carolina and South Carolina have jurisdiction over the allocation of transmission costs to retail customers. Section 7 describes two cost allocation methodologies -- one approach for Regional Reliability Projects and one approach for Regional Economic Transmission Paths -- that are in

addition to the policies currently included in the OATT. Section 8 discusses cost allocation policies relating to the costs of transmission planning itself.

Section 9 describes how confidentiality concerns will be addressed. Section 10 focuses on inter-regional coordination, which efforts will feed into the NCTPC transmission plan. Section 11 explains the inter-relationship of integrated resource planning with the transmission planning process. Section 12 addresses local planning.

Appendix 1 to Attachment K is the Southeast Inter-Regional Participation Process, which describes the SIRPP in some detail.

V. ATTACHMENT K MEETS THE NINE PLANNING PRINCIPLES

In order to understand how the NCTPC Process meets the nine planning principles, it must be understood that prior to Order No. 890, the Filing Parties helped create a planning structure that is unusual among vertically-integrated utilities and their load-serving network customers. The NCTPC itself is a collaboration of *both* the Transmission Providers and LSEs that serve load in the relevant region. It was formed with backing from the state of North Carolina, but it plans for the Duke and Progress transmission systems, both of which span the Carolinas. The NCTPC is a collaboration of transmission/power delivery personnel, not those engaged in the merchant function. Indeed, those persons who serve on the NCTPC's Oversight Steering Committee ("OSC") and Planning Working Group ("PWG") are expected to have high levels of technical knowledge regarding planning. That is, although certain of the LSEs that are NCTPC Participants own no integrated transmission facilities, they nonetheless participate in the NCTPC in a manner that treats them as if they were subject to the FERC Standards of Conduct and they are not permitted to relay information obtained through the NCTPC Process to their merchant personnel.

In effect, the *NCTPC Participants* are *jointly* acting in a Transmission Provider-like role for planning purposes, with transmission customers (e.g., merchant functions) and potential customers acting as stakeholders. Thus, as evident from Attachment K, certain committees are limited to NCTPC Participants. Such an approach is not discriminatory because all similarly-situated *transmission customers* are treated alike, whether such customers are investor-owned merchant functions, municipal or cooperative-owned merchant functions, independent power producers, or others. Similarly, such an approach is not contrary to the openness principle.

Under this approach, LSEs serving retail load in the region are ensured complete and full comparability vis-à-vis one another and the Filing Parties. And, the NCTPC Participants have created a process, reflected in Attachment K, which ensures comparability in the treatment of stakeholders (i.e., the non-NCTPC Participants, which

include the merchant functions of the NCTPC Participants). The non-NCTPC Participants participate in the planning process through the TAG.

A. The Coordination Principle

The coordination principle requires Transmission Providers to meet with all of their transmission customers and interconnected neighbors to develop local and/or regional transmission plans on a nondiscriminatory basis. The Filing Parties meet the coordination principle for the region through the NCTPC, which has a committee, stakeholder, and meeting structures for conducting planning activities. The public is welcome to participate in the NCTPC Process through attendance at TAG meetings, which are open, and commenting when requests for comments are issued. Although TAG membership is open to the public,[5] only "valid stakeholders" may request to be TAG Voting Members who have certain voting rights and whose representatives may access confidential or CEII information ("Confidential Information"). Valid stakeholders are organizations that have a direct interest in transmission planning due to their status as Eligible Customers under the OATT or certain other characteristics.[6] TAG Voting Members also have the right to avail themselves of the dispute resolution process overseen by the NCUC Public Staff.

The reason for having a two-tiered TAG membership (participants and Voting Members) is to ensure a smooth planning process that cannot be gamed by individuals whose interests do not lie in having a reliable, efficient electric system, but whose interests lie elsewhere (e.g., ensuring no new transmission projects are constructed in a particular region). Also, restricting voting to TAG Voting Members ensures that those voting have some experience and knowledge relating to the electric industry. Limiting TAG Voting Members to one vote each prevents gaming (i.e., one Voting Member simply bringing as many bodies as it can muster to vote at a TAG meeting). Also, restricting access to Confidential Information to TAG Voting Members, ensures that such information does not fall into the hands of persons who would be difficult to monitor and limits the number of persons that will have to turn to FERC for clearance as eligible to receive CEII.

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[5] There may be TAG meetings at which Confidential Information will be discussed or presented, in which case the meetings will be open to representatives of TAG Voting Members that are eligible to obtain such information.

[6] Valid stakeholders are: any Eligible Customer, generation owner/generation development company, any organization capable of providing Ancillary Services under the Duke or Progress OATTs, as well as any Transmission Owner, Transmission Operator, or Transmission Planner, other than an NCTPC Participant, as those terms or their successors are used under the NERC Functional Model.

All TAG participants may request to be placed on the TAG e-mail distribution list to receive meeting notice and other announcements. TAG meetings normally are conducted in person, but participation by telephone is permitted. The NCTPC has a website with the e-mail addresses for points of contact and questions. A calendar of noticed meetings and other significant events also is provided on the NCTPC website. If votes will be taken at a TAG meeting, the intent to hold a vote will be noticed.

The processes for becoming a TAG participant and a TAG Voting Member, as well as a member of the OSC and PWG, are described in Section 2 of Attachment K, as are the decisionmaking processes for each of the three groups. The NCTPC Participants, not only the Filing Parties, govern these processes. The roles of each of the committees are fully described in Section 2 of Attachment K, and more detail is provided in various NCTPC documents. *See* Attachments C, E, F, and G. The TAG is not governed or controlled by the Filing Parties, but rather "organized" by an independent third-party, the Independent Third Party ("ITP"). The TAG can bring any matters it wants to the attention of the OSC and PWG, as appropriate.

In sum, the TAG provides an opportunity for its members to participate in the planning process from start to finish. *See generally* Att. K, § 5.

B. The Openness Principle

The openness principle requires that transmission planning meetings be open to all affected parties, including but not limited to all transmission and interconnection customers, state authorities, and other stakeholders. The NCTPC Process meets the openness principle through the TAG, which is open to the public. As discussed above, TAG Voting Member status is open to a wide variety of entities with an interest in transmission system planning. Authorized agents of TAG Voting Members will be permitted to represent them in the NCTPC Process and vote on their behalf. As noted, representatives of TAG Voting Members, but not TAG participants generally, are permitted to access Confidential Information.

Attachment K has a process for dealing with Confidential Information. Both FERC rules[7] and state policies require that certain customer information be treated confidentially and such rules and policies will be enforced. In the case of customer

[7] For example, the OATT does not generally permit the release of the actual identity of entities in the interconnection queue until the interconnection agreement is filed. Such information would not be made available to those TAG Voting Members who can otherwise obtain (non-customer) confidential information until it becomes public.

information, such information may not be made available at all to third-parties and thus such customer information may have to be redacted or masked when released to the TAG Voting Members. A representative of a TAG Voting Member requesting Confidential Information must first seek access to the CEII information contained in the Filing Parties' Form 715s from FERC, which will ensure that the individual does not pose a security threat. TAG Voting Members seeking such data also must enter into both a SERC and TAG Voting Member Confidentiality Agreement. The SERC and TAG Voting Member Confidentiality Agreements are posted on their websites and address issues such as breach of the agreement.

C. The Transparency Principle

The transparency principle requires Transmission Providers to reduce to writing and make available the basic methodology, criteria, and processes used to develop transmission plans, including how they treat retail native loads, in order to ensure that standards are consistently applied. As discussed below, the Filing Parties will disclose the criteria, assumptions, and data that underlie their transmission system plan by posting such information on their websites, and/or the NCTPC website.

The entire planning cycle, dates for data exchange, studies, and the like are all developed with TAG input and reviewed by the TAG annually. The NCTPC transmission plan is prepared annually and Attachment K includes a flow chart showing that process. All resources (*e.g.*, generation, demand response, transmission) are considered in all planning steps, thus there is no special timelines for specific entities to participate.

The Study Scope for each year is described in an NCTPC document that is posted annually. TAG meetings and presentation distributed to the TAG are the "procedure" for communicating with stakeholders regarding the basic criteria, assumptions, and data that underlie the NCTPC plan and planning process. Stakeholders may question and discuss the assumptions used in planning at such meetings or through written communications.

As to planning criteria used, such criteria are quite extensive and thus the documentation concerning such criteria is not included in Attachment K. For example, facility connection requirements of Duke alone are nearly 80 pages long and it would be unwieldy to include this document, which changes with some regularity, and is only one of well more than a dozen Duke planning-related documents, in the OATT. Attachment K does direct readers to the appropriate websites of Duke and Progress to locate planning criteria.

The software and analytical tools used in the planning process are described in the Study Scope. In addition, a TAG Voting Member will be able to obtain access to

the underlying data used for transmission planning, such as load flow base cases and associated files needed for transmission planning, contingency files, by contacting the ITP.

Stakeholders can discuss, question, or propose alternatives for any solutions identified before the draft transmission plan is written. After the draft plan is written, a TAG meeting will be held to brief the participants and describe the draft plan in a manner that is understandable to stakeholders. TAG meetings also routinely provide information on the status of upgrades identified in the transmission plan.

The procedures described will ensure that the transmission planning process is fully transparent.

D. The Information Exchange Principle

The information exchange principle requires network customers to submit information on a comparable basis (*e.g.*, planning horizon and format) as used by Transmission Providers in planning for their native load and requires point-to-point customers to submit any projections they have of a need for service over the planning horizon and at what receipt and delivery points. Attachment K reflects the fact that the OATTs of the Filing Parties set forth the obligations of network customers to submit data to them.[8] Point-to-point customers and others that are not seeking any particular service, have no comparable tariff obligations, but are free under Attachment K to submit any data they desire to the NCTPC Participants for consideration as to whether such information is relevant to the transmission planning process. Eligible Customers seeking new transmission and interconnection service of course also submit data with their service requests that is relevant to the planning process.

At this time, there is no formal schedule and procedures for submission of information by transmission customers, just as there are no such formal procedures for native load, although a general transmission planning schedule will be developed each year and will indicate when data should be provided. Transmission customers are expected to provide timely written notice of material changes in any information previously provided relating to their load, resources, or other aspects of their facilities or operations affecting the Filing Parties' ability to provide service.

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[8] Network customers presumably would take demand response into consideration in their forecast information for load.

E. Comparability

The comparability principle requires Transmission Providers, after considering the data and comments supplied by customers and other stakeholders, to develop a transmission system plan that meets the specific service requests of their transmission customers and otherwise treats similarly-situated customers (*e.g.*, network and retail native load) comparably in transmission system planning. By having a single transmission planning process for native load and OATT customers (i.e., the NCTPC Process), comparability is largely inevitable. That is, the Attachment K process is not just comparable to a similar planning process that applies to native load; rather, there is only one process. Also, the non-jurisdictional NCTPC Participants that take service under the OATT subject to FERC jurisdiction play a valuable and important role in ensuring that the NCTPC Process meets the comparability principle, as it is in their interest that OATT customers, like themselves, to be treated comparably to the native load of the Filing Parties.

F. Dispute Resolution

The dispute resolution principle requires Transmission Providers to identify a process to manage disputes that arise from the planning process. The Filing Parties have proposed to resolve disputes based on the nature of the dispute and jurisdiction over the dispute, although they expect that the need to resort to dispute resolution will be rare based on the experience of the NCTPC to date.

Disputes that arise within the NCTPC context can be resolved in a number of manners. The OSC voting structure allows the ITP to cast a tie-breaking vote if necessary to decide on a particular issue for the OSC, although a Transmission Provider has the right to reject an OSC decision if it believes that it would harm reliability. TAG Voting Members may use votes to resolve disputes amongst themselves. Any NCTPC Participant or TAG Voting Member has the right to seek assistance from the NCUC Public Staff to mediate an issue and render a non-binding opinion on any disputed decision made by the NCTPC Participants.

Transmission siting disputes are the jurisdiction of the respective states as are Integrated Resource Planning disputes. The procedures for state commission proceedings are available at their respective websites.

The existing dispute resolution provisions included in the OATTs apply to disputes involving compliance with the Commission's transmission planning obligations set forth in Order No. 890. Matters over which the Commission does not have jurisdiction, including planning to meet retail native load of the Filing Parties are not within the scope of the dispute resolution process of the OATT.

The Commission's Dispute Resolution Service would be used to settle any issues arising from the cost allocation related to Regional Reliability Projects, discussed *infra,* that involve Transmission Providers outside the NCTPC.

G. The Regional Participation Principle

The regional participation principle provides that, in addition to preparing a system plan for its own control area on an open and nondiscriminatory basis, each Transmission Provider is required to coordinate with interconnected systems to (i) share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data and (ii) identify system enhancements that could relieve congestion or integrate new resources. The NCTPC Participants meet this requirement in several manners. First, through the NCTPC Process, Duke and Progress, which are in separate control areas, fully coordinate their planning efforts. Second, through SERC, all SERC transmission owners share transmission system plans to ensure simultaneously feasibility. Third, through the SIRPP, a large number of transmission owners in the southeast engage in a process designed to identify system enhancements that could relieve congestion or integrate new resources. Finally, there are numerous other inter-regional efforts that address planning and reliability issues, through a variety of bilateral and multi-party agreements. Additional detail is provided below.

1. Regional Planning

As already noted, Duke and Progress are fully coordinating transmission planning in the region in which they are located with one another through the NCTPC Process. The other NCTPC Participants play a vital role in such coordination, effectively as their partners. The Filing Parties share duties equally. The NCTPC Participants have made the NCTPC Participation Agreement fully available and keep it posted on the NCTPC website, so all stakeholders may understand the relationship between and the roles of the NCTPC Participants. The relevant region was selected based on the existing NCTPC Process, discussions with other potential members, and historical practices. While VACAR could be viewed as a natural region, one of the VACAR Transmission Providers is a member of PJM, and it would have been unwieldy for such entity to have to participate in two comprehensive planning processes. Other neighboring transmission providers are non-jurisdictional (Santee Cooper and the Tennessee Valley Authority) and are thus not under the same level of coordination obligations. Other jurisdictional neighbors are so large geographically, such as Southern Company, that it was not viewed as feasible to engage in a process such as the NCTPC, where quite frequent face-to-face meetings are the norm. Moreover, given that inter-regional reliability-related activities already existed (primarily through SERC and VACAR), there was no need to expand the relevant region to ensure reliability.

2. Local Planning

The Filing Parties consider local planning to be planning that focuses on service over low-voltage transmission facilities and typically is customer-specific in nature. For example, the need of a growing wholesale customer to obtain additional load delivery points typically would involve local planning issues. In contrast, the desire of that customer to obtain new wholesale power supplies would be addressed by regional planning (i.e., through the NCTPC). The same data and information is used for local and regional planning, so stakeholder participation in data input in the NCTPC process will be used in local planning. Any local area plans developed by a Transmission Provider are rolled into the power system models of the Filing Parties and these models subsequently roll up to the NCTPC transmission models.

3. Inter-Regional Planning

The Filing Parties coordinate with other transmission systems primarily through participation in SERC, other inter-regional study groups, and bilateral agreements between Duke and/or Progress and transmission systems to which they are interconnected. Due to historic planning and reliability activities, SERC is a natural area over which to engage in inter-regional planning for reliability purposes. Too broad an area for this process could render this group unwieldy.

Inter-Regional Reliability Assessments. SERC assists the transmission owners within its region through the creation of a SERC-wide transmission model. The construction of the SERC transmission model is a "bottoms-up" process. Each transmission owner in SERC, incorporating input from their regional planning process, develops and submits their transmission models to a model development databank. The databank then joins the models to create a SERC-wide model for use in a reliability assessment. If the SERC-wide model projects additional planning criteria concerns that were not identified in the regional reliability studies, then the impacted transmission owners will initiate one or more inter-regional joint studies to better identify the planning criteria concerns and determine the optimal inter-regional reliability transmission enhancements to resolve the limitations. Accordingly, planning criteria concerns identified at the SERC-wide level are "pushed down" to the transmission owner level for detailed resolution.

Importantly, given that the construction of the SERC-wide model is a bottoms-up process, stakeholders provide input into this process in accordance with Order No. 890 by participating in the development of the regional reliability models

discussed above.[9] In addition, as part of the SIRPP, the participating transmission owners in that process will review with stakeholders at the inter-regional level the data, assumptions, and assessments that are being conducted on a SERC-wide basis.

Also, as described in Section 10 of Attachment K, there are subgroups within SERC that engage in planning activities as well as bilateral planning activities. Such activities feed directly into the NCTPC Process.

Economic Planning. Duke and Progress have joined with a group of southeast transmission owners to develop the SIRPP, which will address economic planning on an inter-regional basis. This process provides the Southeast Inter-Regional Participation Process Stakeholder Group ("SIRPPSG") the ability to request economic studies that need to be evaluated on an inter-regional basis. The framework for this process is provided in Appendix 1 to Attachment K, entitled "Southeast Inter-Regional Participation Process." The SIRPPSG may request up to five inter-regional "Economic Planning Studies" to identify potential economic transmission projects above and beyond the base reliability transmission expansion plan. A study coordination team will coordinate with the SIRPPSG regarding the study assumptions underlying the identified stakeholder requested Economic Planning Studies. Results of the analyses will be reviewed by stakeholders who will be provided an opportunity to comment and provide input regarding that initial analysis. The study coordination team will then finalize its analysis and draft reports, which will be open to stakeholder comment.

H. Economic Planning Studies

The economic planning studies principle requires Transmission Providers to account for economic, as well as reliability, considerations in the transmission planning process. All transmission planning, whether nominally delineated as reliability planning or economic planning, takes into account both economic and reliability considerations. For example, a generator seeking to export power may make a point-to-point transmission service request that requires upgrades to certain facilities. While one would consider that upgrade project to be needed for economic reasons in the view of the generator, the Transmission Provider has an obligation to ensure that the request to export power can be met while maintaining the reliability of its system. At the same time, the Transmission Provider must take into account economics and build an upgrade that is prudent in scope. A Transmission Provider's retail function building a new generator to

[9] Again, at the SERC-wide level, the model development essentially consists of ensuring that the different regional reliability models are compatible at the SERC-wide level, meaning that substantive transmission planning is performed at the regional level where stakeholders may provide input.

serve native load has likely engaged in integrated resource planning and carefully considered the economics of various resource options in such decision, including the potential rate impacts of the costs of related transmission upgrades on retail transmission rates. It is up to the transmission planners to decide what upgrades might be needed to maintain reliability as a result of such new generator and balance the reliability need with prudence. Again, economics and reliability considerations intermingle. Attachment I, Reliability Planning in the Southeast and the Relationship between Reliability and Economic Planning, further elaborates on the relationship of reliability and economic planning on an inter-regional basis.

Despite the fact that virtually all planning has both an economic and reliability component, in order to abide by Order No. 890's requirement that a certain number of "economic" studies be performed, the two types of planning are distinguished. Economic studies focus on potential upgrades that are not associated with any actual transmission requests submitted under the OATT. The NCTPC Process provides for economic studies through the Enhanced Transmission Access Planning (ETAP) Process, as discussed below and set forth in Section 4.2 of Attachment K.

Up to five economic studies a year may be selected by the TAG Voting Members. The method for selecting the studies is described in Attachment K. In addition, the SIRPP also provides for five inter-regional economic studies to be performed annually. The costs of the five NCTPC economic studies are borne by the NCTPC Participants pursuant to the Participation Agreement. Additionally, economic studies will be performed, if the requesting TAG participant is willing to pay for the study if the study can be reasonably accommodated (i.e., if it will not overburden the transmission planning staffs). A study agreement will be entered into for such studies. The form for requesting such studies is posted on the NCTPC website and may be submitted at any time, although each year a deadline will be determined as to the date on which the request must be submitted to be considered in a particular planning year. There are no restrictions on the type or scope of the economic planning studies that will be undertaken on behalf of stakeholders, be they native load or OATT customers. ETAP study results will be published, as are all study results.

I. The Cost Allocation Principle

The cost allocation principle requires that Transmission Providers address in their Attachment K the allocation of costs of new facilities that do not fit under existing rate structures set forth in the OATT. The NCTPC has identified two types of projects -- Regional Reliability Projects and Regional Economic Transmission Paths ("RETPs") -- that are not covered under existing cost allocation rules. Since both of these cost allocation approaches are described in great detail in the paper (Attachment H)

entitled "NCTPC Transmission Cost Allocation," which is posted on the NCTPC website, the approaches will be discussed only briefly below.

Through the Regional Reliability Project concept, the NCTPC recognizes an exception to the general rule that the costs of projects needed for reliability on a Transmission Provider's system should be allocated to that particular Transmission Provider (and then to its ratepayers). Specifically, the exceptions are Regional Reliability Projects, which will be identified through the NCTPC's regional planning process and will have their costs allocated on an avoided-cost basis. A Regional Reliability Project can be defined as any reliability project that requires an upgrade to Duke's or Progress' system that would not have otherwise been made at that time based upon the reliability needs of the Transmission Provider. Under the avoided cost approach, each Transmission Provider looks at the next-best approach to maintaining reliable service and shares the savings on a pro-rata basis. These cost responsibility determinations will then be reflected in transmission rates. Each Transmission Provider will be reimbursed for its investment for the Regional Reliability Project based on a transmission levelized fixed charge rate filed with FERC.

The NCTPC has set forth a "requestor pays" cost allocation methodology for RETPs -- economic projects required to permit Transmission Providers to ensure that point-to-point ("PTP") transmission service can be provided over the systems of two or more Transmission Providers. Transmission customers that are subscribing to the RETP would provide the up-front funding of any transmission construction that was required to ensure that the path was available for the relevant time period. These "requestors" would be the transmission customers that were awarded the transmission capacity as a result of the successful subscription during the Open Season process. Subscribers would pay for firm PTP transmission service on each transmission system along the path of the RETP at the embedded cost rate. The transmission customer would receive a levelized repayment of this initial funding amount from Duke and/or Progress in the form of monthly transmission credits over a maximum 20-year period. As credits are paid, Duke and Progress could have the opportunity to include the costs of upgrades that were needed for the RETP in transmission rates, similar to the Generator Interconnection pricing/rate approach. A network customer may subscribe to an RETP, using the path to import power from designated or secondary network resources into the control area where its load is located.

The NCTPC Transmission Cost Allocation document explains the details as to how project costs will be allocated, how project costs will be allocated when the requested project accelerates or expands an upgrade that was already planned for native load customers, as well as numerous other details.

The Filing Parties have presented their two cost allocation methodologies to the North Carolina Utilities Commission ("NCUC") and the South Carolina Office of Regulatory Staff[10] ("ORS") in South Carolina and discussed them with these agencies' staffs. Based on these discussions, the Filing Parties believe that they support these approaches, but expect that the commissions will provide FERC with their opinions, and thus the Filing Parties are not making any representations on their behalf.

J. The Recovery of Planning Costs Principle

The methodology used to recover costs associated with planning will depend on the role of the entity seeking to recover such costs. Although the NCTPC Participation Agreement addresses who initially is allocated certain NCTPC-related costs, that assignment does not dictate cost recovery, which is left to each individual entity that incurs costs. Those entities providing transmission service can recover planning costs in their transmission rates and/or bundled retail rates in accordance with FERC and state policies. Those entities that do not provide transmission service can recover their costs, if any, through any means at their disposal, *i.e.*, wholesale power rates, bundled retail rates, etc.

VI. EFFECTIVE DATE

The Attachment Ks should be given an effective date of December 7, 2007, in accordance with Order No. 890 and subsequent orders.

If you have any questions regarding this filing please do not hesitate to call.

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[10] The South Carolina Office of Regulatory Staff ("ORS") was created by the South Carolina General Assembly by Act 175 (2004) which was signed into law on February 18, 2004. Under Act 175, effective January 1, 2005, the ORS is a party of record in all filings, applications, and proceedings before the South Carolina Public Service Commission and is charged with balancing the concerns of the using and consuming public with the preservation of the financial integrity of the state's public utilities and economic development and job retention in the State of South Carolina. S.C. Code Ann. § 58-4-10 (Supp. 2006). Additionally, the ORS is charged under S.C. Code Ann. § 58-4-50(A)(8) with "provide[ing] legal representation of the public interest before state courts, federal regulatory agencies, and federal courts in proceedings that could affect the rates or service of any public utility."

Respectfully submitted on behalf of the Filing Parties,

/Jennifer L. Key/

Jennifer L. Key
Attorney for Duke Energy Carolinas, LLC

Attachments

ATTACHMENT A

DUKE ENERGY CAROLINAS, LLC
CLEAN TARIFF SHEETS

ATTACHMENT N -- TRANSMISSION PLANNING PROCESS

1. INTRODUCTION

Duke Energy Carolinas, LLC (Duke) and Progress Energy Carolinas, Inc. (Progress), Transmission Providers with transmission facilities located in the states of North Carolina and South Carolina, ensure that their entire Transmission Systems (i.e., both the portions located in North Carolina and the portions located in South Carolina) are planned in accordance with the requirements imposed by Order No. 890 through the process developed by the North Carolina Transmission Planning Collaborative Process (NCTPC Process). The NCTPC was formed by the following load serving entities (LSEs) in the State of North Carolina: Duke, Progress, ElectriCities of North Carolina (ElectriCities), and the North Carolina Electric Membership Corporation (NCEMC) (collectively, NCTPC Participants or Participants).

In addition to engaging in regional planning through the NCTPC Process, as discussed in Section 10, the Transmission Providers engage in "inter-regional" study and planning activities with transmission providers located outside their Control Areas. Such activities include participation in SERC and the Southeast Inter-Regional Participation Process (Appendix 1), which focus on reliability assessments and economic planning respectively.

2. NCTPC PROCESS OVERVIEW INCLUDING THE PROCESS FOR CONSULTING WITH CUSTOMERS

The NCTPC will annually develop a single, coordinated transmission plan (Collaborative Transmission Plan) that appropriately balances costs, benefits, and risks associated with the use of transmission, generation, and demand-side resources to meet the needs of LSEs as well as Transmission Customers under this Tariff.

2.1 The *North Carolina Transmission Planning Collaborative Participation Agreement* (*Participation Agreement*) governs the NCTPC and the NCTPC Process. The *Participation Agreement* is located on the NCTPC Website (http://www.nctpc.org/nctpc/).

2.2 The NCTPC Process is summarized in a document entitled *North Carolina Transmission Planning Collaborative Process* that is located on the NCTPC Website.

2.3 Participation in the NCTPC

2.3.1 Pursuant to the *Participation Agreement*, the NCTPC has four components: the Oversight/Steering Committee (OSC), the

Planning Working Group (PWG), the Transmission Advisory Group (TAG), and the Independent Third Party (ITP). 2.3.2 Eligibility for participation in the four NCTPC components is as follows:

2.3.2.1 The appointment of OSC members by the NCTPC Participants is governed by the *Participation Agreement*. The ITP is an *ex officio* member of the committee. The qualifications required to serve on the OSC are set forth in a document entitled *Scope - Oversight/Steering Committee* that is located on the NCTPC Website.

2.3.2.2 The appointment of PWG members by the NCTPC Participants is governed by the *Participation Agreement*. The ITP also has a representative on the PWG. The qualifications required to serve on the PWG are set forth in a document entitled *Scope - Planning Working Group* that is located on the NCTPC Website.

2.3.2.3 Anyone may participate in the TAG (TAG participants) and sign-up to receive TAG communications. Entities that are valid stakeholders may apply to become TAG Voting Members. A valid stakeholder includes any Eligible Customer, generation owner/generation development company, and any organization capable of providing Ancillary Services under the Duke Energy Carolinas or Progress Energy Carolinas OATTs. In addition, any Transmission Owner, Transmission Operator, or Transmission Planner as those terms or their successors are used under the NERC Functional Model, as may be amended from time to time, will be considered valid stakeholders and may become a TAG Voting Member. Persons who are not employed by, but are authorized agents of, one or more TAG Voting Members also will be permitted to represent TAG Voting Members in the NCTPC Process. The transmission function of a NCTPC Participant may not be a TAG Voting Member, but the merchant function of an NCTPC Participant may be a TAG Voting Member.

2.3.2.4 The Independent Third Party (ITP) is selected by the OSC. The ITP must have qualifications similar to OSC and PWG members.

2.4 Responsibilities and Decision-Making of NCTPC Components

The responsibilities of the components within the NCTPC are determined by the *Participation Agreement* and/or the OSC. Decision-making likewise is established in the *Participation Agreement*, or by policies established by the OSC.

2.4.1 Oversight/Steering Committee

2.4.1.1 The OSC is responsible for overseeing and directing all the activities associated with this NCTPC Process. A list of the OSC's responsibilities is found in *Scope - Oversight/Steering Committee.*

2.4.1.2 OSC decision-making is governed by the *Participation Agreement.*

2.4.1.3 Officers of the OSC are selected in the manner set forth in the *Participation Agreement.*

2.4.2 Planning Working Group

2.4.2.1 The PWG is responsible for developing and performing the appropriate simulation studies to evaluate the transmission conditions in the Participants' service territories and recommend a coordinated solution for the various transmission limitations identified in the studies. A list of the PWG's responsibilities is found in *Scope - Planning Working Group.*

2.4.2.2 PWG decision-making is governed by the *Participation Agreement.*

2.4.2.3 Officers of the PWG are selected in the manner set forth in the *Participation Agreement.*

2.4.3 Transmission Advisory Group

2.4.3.1 The purpose of the TAG is to provide advice and recommendations to the NCTPC Participants to aid in the development of an annual Collaborative Transmission Plan. The TAG participants may propose enhanced transmission access projects for evaluation as described in Section 4.2.2 hereof. The TAG Voting Members select which of those

projects should be evaluated. The TAG participants also provide input on the annual study scope elements of both the Reliability Planning Process as well as the Enhanced Transmission Access Planning Process, including input on the following: Study Assumptions; Study Criteria; Study Methodology; Case Development and Technical Analysis; Problem Identification; Assessment and Development of Solutions (including proposing alternative solutions for evaluation); Comparison and Selection of the Preferred Transmission Plan; and the Transmission Plan Study Results Report. A full list of the TAG's responsibilities is found in *Scope - Transmission Advisory Group,* which is located on the NCTPC Website.

2.4.3.2 The ITP will chair the TAG meetings and serve as a facilitator for the group. TAG decision-making is by consensus among the TAG participants. However, in the event consensus cannot be reached, voting will be conducted with each TAG Voting Member represented at the meeting (either physically present or participating via phone) receiving one vote. As to matters that must be resolved by vote, rather than by consensus, majority and minority positions will be forwarded to the OSC for their consideration on the issue. The independent third-party will provide notices to the TAG participants in advance of the TAG meeting that specific votes will be taken during the TAG meeting. Only TAG Voting Members participating in the meeting will be allowed to participate in the voting. A single person may represent more than one TAG Voting Member.

2.4.4. Independent Third Party

2.4.4.1 The ITP facilitates the overall NCTPC Process.

2.4.4.2 A list of the ITP's primary responsibilities is found in *Scope - Planning Working Group* and *Scope - Oversight/Steering Committee.*

2.4.4.3 The ITP also provides the leadership role in developing the Enhanced Transmission Access Planning (ETAP) Process, subject to the oversight of the OSC.

2.4.4.4The ITP maintains the NCTPC Website.

2.4.4.5The ITP's role in decision-making varies based on which group s/he is participating as documented in the NCTPC documents posted on the NCTPC Website.

2.5 Participation of State Regulators

State regulators, including state-sanctioned entities representing the public, like other members of the public, may choose to be TAG participants. State public utility regulatory commissions also may seek to receive periodic status updates and the progress reports on the NCTPC Process.

3. NOTICE PROCEDURES, MEETINGS, AND PLANNING-RELATED COMMUNICATIONS

All information regarding transmission planning meetings and communications are located on the NCTPC Website.

3.1 Notice

3.1.1 Notice of all meetings of a component (TAG, PWG, OSC) will be by email to such component.

All TAG meeting notices and agendas will be posted on the NCTPC Website.

3.1.2 Information about signing up to be a TAG participant and to receive email communications is posted on the NCTPC Website. Information about applying to be a TAG Voting Member also is available.

3.1.3 The OSC will publish highlights of its meetings on the NCTPC Website.

3.2 Location

3.2.1 The location of an OSC or PWG meeting will be determined by the component.

3.2.2 The location of a TAG meeting will be determined by the OSC.

3.2.3 Conference call dial-in technology will be available for meetings upon request.

3.3 Meeting Protocols

3.3.1 OSC

3.3.1.1 The OSC chair schedules meetings, provides notice, ensures that meeting minutes are taken, develops the agenda, chairs the meetings.

3.3.1.2 The OSC generally will meet at least monthly, and more frequently as necessary.

3.3.1.3 OSC meetings are open to the OSC members (including the ITP), their alternates, PWG members, and, if approved, guests.

3.3.2 PWG

3.3.2.1 The PWG chair schedules meetings, provides notice, ensures that meeting minutes are taken, develops the agenda, and chairs the meetings.

3.3.2.2 The PWG generally meets at least monthly, and more frequently as necessary.

3.3.2.3 PWG meetings are open to the PWG members, the ITP, the OSC (and their alternates), and, if approved, guests.

3.3.3 TAG

3.3.3.1 TAG meetings are chaired and facilitated by the ITP.

3.3.3.2 The TAG generally meets four times a year.

3.3.3.3 Meetings of the TAG generally are open to the public, i.e., TAG participants. When necessary, TAG meetings may be restricted by the ITP to representatives of TAG Voting Members that are qualified to receive Confidential Information.

3.3.3.4 A yearly meeting and activity schedule is proposed, discussed with, and provided to TAG participants annually.

4. DESCRIPTION OF THE METHODOLOGY, CRITERIA, AND PROCESSES USED TO DEVELOP TRANSMISSION PLANS

The NCTPC Process is a coordinated regional planning process that includes both a "Reliability Planning" and an "Enhanced Transmission Access Planning" (ETAP) process, both of which ultimately result in the development of a Collaborative Transmission Plan. The entire, iterative process ultimately results in a single Collaborative Transmission Plan that appropriately balances the costs, benefits and risks associated with the use of transmission, generation, and demand-side resources.

4.1 Overview of Reliability Planning Process

The Reliability Planning Process addresses transmission upgrades needed to maintain reliability and to integrate new generation resources and/or loads. The Reliability Planning Process includes a base reliability study (base case) that evaluates each Transmission System's ability to meet projected load with a defined set of resources as well as the needs of firm point-to-point customers, whose needs are reflected in their transmission contracts and reservations. A resource supply analysis also is conducted to evaluate transmission system impacts for other potential resource supply options to meet future load requirements. The final results of the Reliability Planning Process include summaries of the estimated costs and schedules to provide any transmission upgrades and/or additions needed to maintain a sufficient level of reliability necessary to serve customers.

4.2 Overview of Enhanced Transmission Access Planning Process

4.2.1 The ETAP Process is the economic planning process that allows the TAG participants to propose economic upgrades to be studied as part of the transmission planning process. The ETAP Process evaluates the means to increase transmission access to potential supply resources inside and outside the Control Areas of the Transmission Providers. This economic analysis provides the opportunity to study what transmission upgrades would be required to reliably integrate new resources. In addition, this economic analysis would include, if requested, the evaluation of Regional Economic Transmission Paths (RETPs) that would facilitate potential regional point-to-point economic transactions. RETPs are described in more detail below and in the document entitled *NCTPC Transmission Cost Allocation* on the NCTPC Website.

4.2.2 The ETAP Process begins with the TAG participants proposing scenarios and interfaces to be studied. The information required and

the form necessary to submit a request as well as the submittal deadline is reviewed and discussed with the TAG participants early in the annual planning cycle. The form is posted on the NCTPC Website. The PWG will determine if it would be efficient to combine and/or cluster any of the proposed scenarios and will also determine if any of the proposed scenarios are of an Inter-Regional nature. The OSC will direct the TAG participants to submit the Inter-Regional study requests to the Southeast Inter-Regional Participation Process since those studies would have to be evaluated within that forum.

4.2.3 The OSC will review the PWG analysis, approve the compiled study list, and provide the study list to the TAG. For the study scenarios that impact the NCTPC region, but are not Inter-Regional in nature, the TAG Voting Members will select a maximum of five scenarios that will be studied within the current NCTPC planning cycle. TAG Voting Members will be permitted to cast one vote in support of any particular scenario and may vote for up to a maximum of five study scenarios. There may be multiple representatives of TAG Voting Members within the TAG; however, for voting purposes, each TAG Voting Member can only submit one vote. The five study scenarios that receive the largest number of votes will be the study scenarios that are selected to be studied within the current NCPTC planning cycle. To be able to vote, the TAG Voting Member must participate in the meeting, either by having a representative physically present at the meeting or through participation by phone. No representative of a TAG Voting Member shall be permitted to cast a vote of another TAG Voting Member that has no participating representative.

4.2.4 There will be no charge to the TAG participants for the five studies selected by the TAG Voting Members. However, if a particular TAG participant wants the NCTPC to evaluate a scenario that was not chosen by the TAG Voting Members, then the TAG participant can request to have the NCTPC conduct the study. The NCTPC will evaluate this request and will conduct the study if the study can be reasonably accommodated, however the cost of conducting this additional study will be allocated to that specific TAG participant.

4.2.5 RETPs

4.2.5.1 As part of the ETAP, TAG Voting Members may propose that a particular RETP be studied. The creation of an RETP

would permit energy to be transferred on a Point-to Point basis from an interface or a Point of Receipt on one Transmission Provider's system to an interface or a Point of Delivery on another Transmission Provider's system for a specific period of time. A subscriber to an RETP is under no obligation to use the complete RETP, it may resell its rights to portions of the RETP. An RETP ensures that Point-to-Point Transmission Service can be provided over the Duke and/or Progress systems. The costs of the projects necessary to create an RETP will be subject to the "requestor pays" cost allocation methodology described *infra*. A network customer may seek to use an RETP as the firm Point-to-Point Transmission Service necessary to support a designated network resource external to the Control Area in which its load is located.

4.2.5.2 The TAG Voting Members will identify RETPs that they would like studied. There would be a need for an initial study of an RETP ("Initial RETP Study"). If a proposed RETP would be solely contained within the NCTPC, then the NCTPC Process would be used to address the RETP. However, if a proposed RETP would impact transmission providers outside the NCTPC, there will be a need to coordinate such an initial study with other transmission providers.

4.2.5.3 If an Initial RETP Study is performed, it would identify any transmission system problems/limitations related to the Transmission Providers impacted by the RETP and would identify the transmission solutions/upgrades that would be needed to accommodate the RETP. An RETP would be evaluated in the Initial RETP Study as if it was a request for Point-to Point Transmission Service from a source control area (Point of Receipt) to a sink control area (Point of Delivery) over a specific period of time (the TAG Voting Members requesting the study would determine the time period), but it will not be considered to be a request that is in the transmission queue. The Point of Receipt and Point of Delivery can be interfaces.

4.2.5.4 The Initial RETP Study would only provide preliminary information on the projected cost and scope of the facilities

that would be needed to create the RETP, and the time it would take to complete the RETP. In the Initial RETP Study, each Transmission Provider along the RETP would identify the estimated costs for any upgrades necessary to provide service over the RETP.

4.2.5.5 If the RETP was totally contained within the NCTPC, then the following process would be used to move the RETP through the study to potential project commitment phases. Once the Initial RETP Study is complete, a determination would be made as to whether there is sufficient interest in the project to move the RETP from the "initial study" mode to the establishment of an "Open Season" for the RETP. The Open Season will provide the structure whereby Duke and Progress will be able to process these RETP Point-to Point Transmission Service requests for the entire proposed MW of the RETP from the source control area to the sink control area for the relevant time period. During this Open Season all potential transmission customers would have a 60-day window to put in their request to subscribe to all or a portion of the MW of service being made available along the RETP.

4.2.5.6 When the Open Season process is initiated by Duke and Progress, the transmission queue positions for these RETP requests will be established.

4.2.5.7 Through the Open Season process, which will be iterative, if the RETP is fully subscribed, it would move forward to a Facilities Study stage. After such stage, if it remained fully subscribed, the RETP would be included in the Collaborative Transmission Plan (and/or a supplement to such Plan) and Service Agreements will be executed (or filed on an unexecuted basis).

4.2.5.8 If an RETP encompasses Transmission Providers outside the NCTPC, the impacted Transmission Providers will work individually and through applicable stakeholder forums to perform the necessary studies and develop the processes that would be used to move from a study of a RETP to actual transmission reservations that would be needed to support the RETP. The above study and Open Season concepts could be

used by these larger inter-regional transmission provider groups.

4.2.6 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 and discussed with the TAG participants.

4.3 Overview of the Steps in the Planning Processes

4.3.1 Each year, the OSC will initiate the process to develop the annual Collaborative Transmission Plan.

4.3.2 The OSC will provide notice of the commencement of the process to develop the annual Collaborative Transmission Plan via e-mail to the TAG and posts a notice on the NCTPC Website.

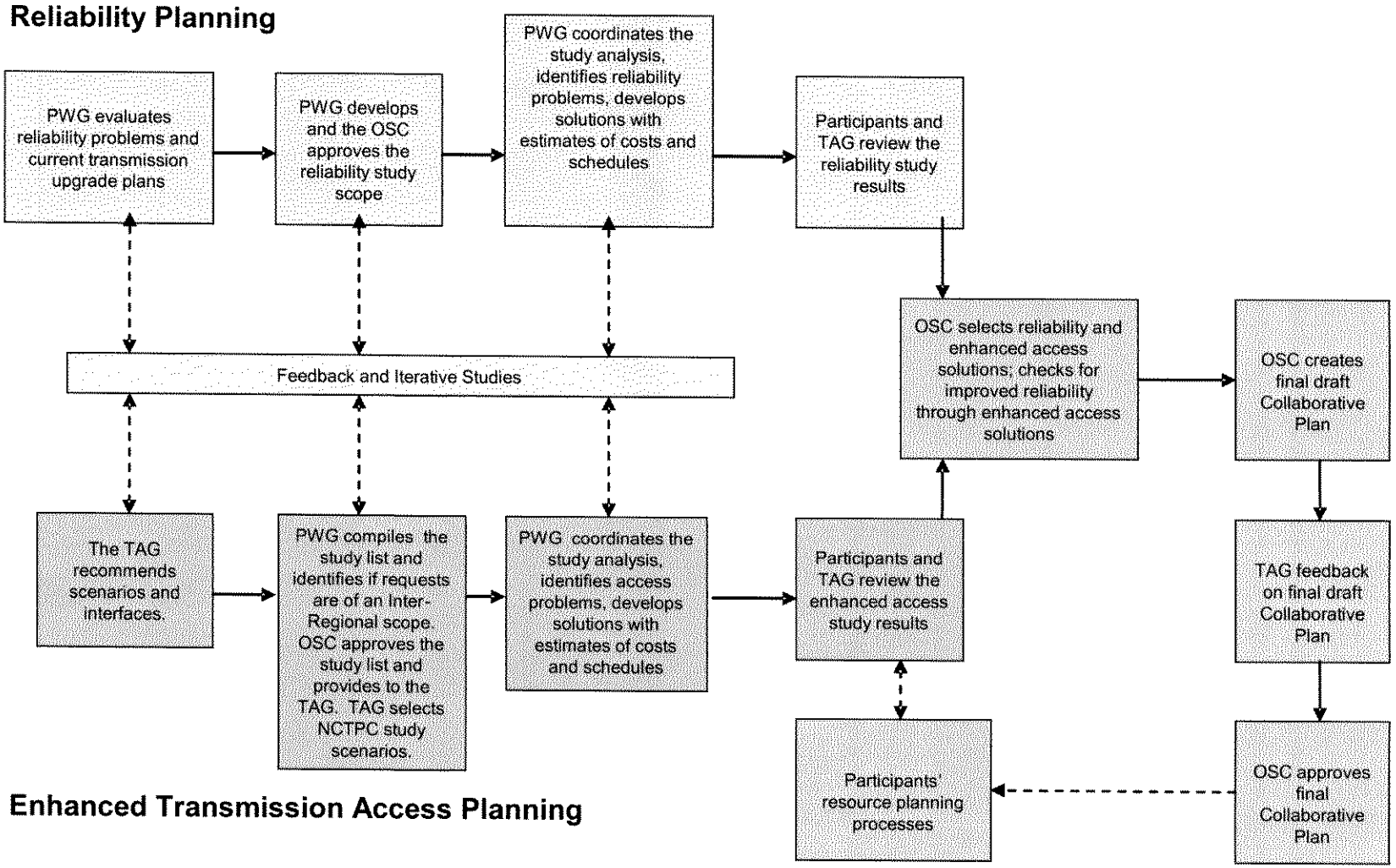
4.3.3 The process will allow for flexibility to make modifications to the development of the plan throughout the year as needs change, new needs arise, or new solutions to problems are identified.

4.3.4 The schedule for all of the activities will be set by the PWG and OSC, but will vary from year to year. The basic order of events is as set forth in Section 5, although the planning process is an iterative one. A list of relevant dates established for planning cycle will be posted on the NCTPC website.

4.4 Summary Flow Chart of Process

The following page contains a flow chart of the NCTPC Process.

Figure 1
North Carolina Transmission Planning Collaborative Process Flowchart



5. CRITERIA, ASSUMPTIONS, AND DATA UNDERLYING THE PLAN AND METHOD OF DISCLOSURE OF TRANSMISSION PLANS AND STUDIES

5.1 Study Assumptions

5.1.1 The PWG will select the study assumptions for the analysis based on direction provided by the OSC.

5.1.2 Once the PWG identifies the study assumptions, they will be reviewed with the TAG participants before the set of final assumptions are approved by the OSC. The process for this dialogue is in-person meetings, written submissions, and/or other forms of communication selected by TAG participants. Input should be provided in the timeframes agreed upon.

5.1.3 The study assumptions shall be set forth in an annual *Study Scope Document.*

5.1.4 The Transmission Providers will prepare the base case models. These models will be reviewed with the PWG to ensure that they represent the study assumptions approved by the OSC.

5.1.5 The Transmission Providers will also develop the necessary change case models as required to evaluate different resource supply scenarios and enhanced transmission access scenarios as directed by the OSC. Such change case models will also be reviewed with the PWG to ensure that they represent the study assumptions approved by the OSC.

5.2 Study Criteria

5.2.1 The PWG establishes the planning criteria by which the study results will be measured, in accordance with NERC and SERC Reliability Standards and individual Transmission Provider criteria. TAG participants may review and comment on the planning criteria.

5.2.2 Transmission System planning documents of Duke and Progress will be posted on their respective OASIS sites. Some planning documents may not be posted due to CEII and confidentiality concerns, but will be identified such that they can be requested via the methodology posted on the relevant OASIS.

5.3 Data Collection and Case Development

5.3.1 The most current Multi-Regional Modeling Working Group (MMWG) or SERC Long-Term Study Group model will be used for the systems external to Duke and Progress as a starting point for the base case to be used by both Progress and Duke. The base case will include the detailed internal models for Progress and Duke and will include current transmission additions planned to be in-service for given years.

5.3.2 The following data are relevant to the development of internal models for Progress and Duke:

Load and resource projections provided by network customers (including the native load of the NCTPC Participants);

Confirmed, firm point-to-point transmission service reservations (including rollover rights);

Generation real and reactive capacity data;

Generation dispatch priority data;

Transmission facility impedance and rating data; and

Interchange data adjusted to correctly model transfers associated with designated network resources from outside the Transmission Providers' Control Areas.

5.3.3 The Transmission Providers collect the necessary planning data and information that are not already in their possession. One element of this data collection process will be the annual collection of data from Network Customers required by this Tariff. Any guidelines, data formats, and schedules for any data and information exchanges will be established by the PWG. Aside from the annual submission of data by Network Customers, the timing of this data collection process is established as part of the development of the annual study work plan that is prepared by the PWG, reviewed with the TAG participants, and approved by the OSC.

5.3.4 TAG participants may provide additional input into the data collection process (i.e., the provision of data not required to be submitted under this Tariff), such as providing information on future point-to-point transmission service scenarios. Such non-required information may be used in the appropriate study process.

5.3.5 Transmission customers should provide the Transmission Providers with timely written notice of material changes in any information previously provided relating to load, resources, or other aspects of its facilities or operations affecting the Transmission Provider's ability to provide service. Network customers may provide revised versions of previously submitted annual data reporting forms.

5.3.6 Additional cases will be developed as required for different scenarios to evaluate other options to meet load demand forecasts in the study, including where fictitious or as yet undesignated network resources are deemed to be designated. Other cases may be developed and approved by the OSC to evaluate enhanced access scenarios, such as predicted future point-to-point transmission uses, as submitted by the TAG participants.

5.3.7 The Case Development details will be identified in the annual *Study Scope Document.*

5.3.8 Sufficient information will be made available, subject to CEII and confidentiality restrictions, to enable TAG Voting Members to replicate the results of planning studies. A TAG Voting Member seeking data and information that would allow it to replicate the NCTPC planning studies should provide such request to the ITP, who will verify that confidentiality requirements described in Section 9 have been met before providing such information.

5.4 Methodology

5.4.1 The PWG determines the methodologies that will be used to carry out the technical analysis required for the approved studies. The PWG also determines the specific software and models that will be utilized to perform the technical analysis. The study methodology will be identified in the annual *Study Scope Document.* TAG participants may review and comment on the study methodology.

5.5 Technical Analysis and Study Results

5.5.1 The PWG performs the technical study analysis in accordance with the OSC approved study methodology and produces the study results.

5.5.2 Results from the technical analysis are reported to identify transmission elements approaching their limits such that all NCTPC

Participants are made aware of potential issues and appropriate steps can be identified to correct these issues, including the potential of identifying previously undetected problems.

5.5.3 Study results are made available to the TAG participants for review and comment.

5.6 Assessment and Problem Identification

5.6.1 The Transmission Providers provide the summary data identifying the reliability problems and causes resulting from their assessments and comprehensively review the information with the PWG. The PWG evaluates the technical results provided by the Transmission Providers to identify problems and issues and reports to the OSC.

5.6.2 TAG participants are provided information relating to technical assessments and problem identification.

5.7 Solution Development

5.7.1 The PWG identifies potential solutions to the transmission problems identified and will test the effectiveness of the potential solutions through additional analysis as required and ensure that the solutions meet the study criteria previously developed.

5.7.2 TAG participants will have the opportunity to suggest alternative solutions.

5.7.3 All options that satisfactorily resolve an identified reliability problem would be given consideration.

5.7.4 The Transmission Providers estimate the costs for each of the proposed transmission solutions (e.g., cost, cash flow, present value) and develop a rough schedule estimate to complete the construction of the proposed facility. This information is reviewed and discussed by the PWG.

5.8 Selection of Preferred Transmission Plan

5.8.1 The PWG compares all of the alternatives and select the preferred solution by balancing the project cost, benefit, and associated risks.

5.8.2 The PWG selects a preferred set of transmission improvements that provides the most reliable and cost effective transmission solution while prudently managing the associated risks.

5.8.3 The PWG provides the OSC and the TAG participants with their recommendations based on this selection process in order to obtain their input.

5.9 Collaborative Transmission Plan Report

5.9.1 The PWG prepares a draft "Collaborative Transmission Plan Report" based on the study results and the recommended transmission solutions and provides to the OSC for review. The draft Report describes the plan in a manner that is understandable to the TAG participants (*e.g.*, describing any needs, the underlying assumptions, applicable planning criteria, and methodology used to determine the need), rather than simply reporting engineering results. The report includes a comprehensive summary of all the study activities as well as the recommended transmission improvements including estimates of costs and construction schedules.

5.9.2 The OSC forwards the draft report to the TAG participants for their review and discussion. The PWG members are the technical points of contact that can respond to questions regarding modeling criteria, assumptions, and data underlying the Report. The TAG participants may discuss, question, or propose alternatives for any upgrades identified by the draft Report.

5.9.3 The OSC evaluates the results and the PWG recommendations and the TAG participants' input. The OSC approves the final Collaborative Transmission Plan for posting on the NCTPC Website. The Plan also is posted on the Transmission Providers' OASIS and distributed to the TAG participants.

5.9.4 The Collaborative Transmission Plan Report allows the NCTPC Participants to identify alternative, least-cost resources to include with their respective Integrated Resource Plans. Others can similarly use this information for their own resource planning purposes.

5.10 Status Reports

5.10.1 As part of the NCTPC Process, the Transmission Providers periodically provide the TAG participants a report on the status of

the transmission upgrades presented in the previous Collaborative Transmission Plans. The update is posted on the NCPTC Website and includes the following information: the name of the project, the issue it resolves, the name of the relevant Transmission Provider(s), the original planned in-service date and the current expected in-service date.

6. DISPUTE RESOLUTION MECHANISM

6.1 NCTPC Process Disputes

6.1.1 The OSC voting structure allows the ITP to cast a tie breaking vote if necessary to decide on a particular issue.

6.1.2 A Transmission Provider has the right to reject an OSC decision if it believes that it would harm reliability.

6.1.3 Any NCTPC Participant or TAG Voting Member has the right to seek assistance from the NCUC Public Staff to mediate an issue and render a non-binding opinion on any disputed decision.

6.1.4 If the Participants cannot resolve a disputed decision by NCUC Public Staff facilitation, they may seek review from a judicial or regulatory body that has jurisdiction.

6.2 Transmission Siting Disputes

6.2.1 The South Carolina Code of Laws Section 58, Chapter 33 addresses disputes involving utilities' transmission projects that require South Carolina authorization through the certificates of public convenience and necessity process.

6.2.2 NCUC Rule R8-62 addresses disputes involving utilities' transmission projects that require North Carolina authorization through the certificates of public convenience and necessity process.

6.3 Integrated Resource Planning Disputes

6.3.1 The NCUC allows public participation in and may hold hearings regarding matters related to integrated resource planning.

6.3.2 The SC PSC allows public participation in and may hold hearings regarding matters related to integrated resource planning.

6.4 Tariff Disputes

6.4.1 The dispute resolution process provisions included in this Tariff apply to disputes involving compliance with the Commission's transmission planning obligations set forth in Order No. 890. Matters over which the Commission does not have jurisdiction, including planning to meet retail native load of the Transmission Providers shall not be within the scope of the dispute resolution process of this Tariff.

6.5 Regional Reliability Project Planning Disputes

6.5.1 The Commission's Dispute Resolution Service would be used to settle any issues arising from the cost allocation related to Regional Reliability Projects, discussed *infra,* that involve transmission providers outside the NCTPC.

7. TRANSMISSION COST ALLOCATION

7.1 OATT Cost Allocation

7.1.1 The costs of Reliability Projects included in the Collaborative Transmission Plan are allocated in accordance with this Tariff. "Regional Reliability Projects," as discussed below, are an exception to this rule.

7.1.2 While the Transmission Providers study economic upgrades through ETAP, they do not have an obligation to build or fund such projects and thus the projects studied are not included in the Collaborative Transmission Plan, unless and until either: 1) a transmission service request is submitted to the appropriate Transmission Provider(s) or 2) an RETP is fully subscribed.

7.1.3 If a transmission service request is submitted under this Tariff for an economic project, its costs will be allocated in accordance with this Tariff.

7.2 Regional Reliability Project Cost Allocation

7.2.1 An "avoided cost" cost allocation methodology will apply to reliability projects where there is a demonstration that a regional transmission solution and regional approach to cost allocation results in cost savings.

7.2.2 The NCTPC Planning Process results in a set of projects that satisfy the reliability criteria of the Transmission Providers who are a party to the Participation Agreement (i.e., Reliability Projects). Through this process, a project may be identified that meets a reliability need in a more cost-effective manner than if each Transmission Provider were only considering projects on its system to meet its reliability criteria. A Regional Reliability Project can be defined as any reliability project that requires an upgrade to a Transmission Provider's system that would not have otherwise been made based upon the reliability needs of the Transmission Provider. A Regional Reliability Project must have a cost of at least $1 million to be subject to the avoided-cost cost allocation methodology. The costs of a Regional Reliability Project with a cost of less than $1 million would be borne by each Transmission Provider based on the costs incurred on its system.

7.2.3 Unless a Regional Reliability Project is determined by the NCTPC to be the most cost-effective solution to a reliability need, it will not be selected to be included in the Collaborative Transmission Plan. But, if a Regional Reliability Project is cost effective, it will have its costs allocated based on an avoided cost approach, whereby each Transmission Provider looks at the stand-alone approach to maintaining reliable service and shares the savings of not implementing the stand-alone approach on a pro-rata basis. The avoided cost approach formula can be expressed as follow:

(Transmission Provider$_x$'s Avoided Cost/Total Avoided Cost) * cost of Regional Reliability Project = Transmission Provider$_x$'s Cost Allocation

(Transmission Provider$_y$'s Avoided Cost/Total Avoided Cost) * cost of Regional Reliability Project = Transmission Provider$_y$'s Cost Allocation

These cost responsibility determinations will then be reflected in transmission rates. The avoided cost approach also will take into account in determining avoided costs, the acceleration or delay of Reliability Projects. Examples of the application of the avoided-cost approach may be found in *NCTPC Transmission Cost Allocation*.

7.2.4 If a Regional Reliability Project that is suitable for this alternate cost allocation approach involves a Transmission System(s) outside the NCTPC, the costs should be fairly allocated among the affected Transmission Providers based on good-faith negotiation among the parties involved using the "avoided cost" approach outlined above used as a starting point in the negotiations. The resulting transmission costs and the associated revenue requirements of each Transmission Provider will be recovered through their respective existing rate structures at the time.

7.3 RETP Cost Allocation

7.3.1 The costs of upgrades or facilities that result from RETPs are allocated on a "requestor pays" basis.

7.3.2 Transmission customer(s) that are subscribing to the RETP would provide the up-front funding of any transmission construction that was required to ensure that the path was available for the relevant time period. These "requestor(s)" would be the transmission customers that were awarded the MW as a result of the successful subscription during the Open Season process. On the Duke and/or Progress systems, the transmission customer would receive a levelized repayment of this initial funding amount from Duke and/or Progress in the form of monthly transmission credits over a maximum 20-year period. The Transmission Providers will be permitted to work with the transmission customers to provide shorter or different crediting. As credits are paid, Duke and Progress would have the opportunity to include the costs of upgrades that were needed for the RETP in transmission rates, similar to the Generator Interconnection pricing/rate approach.

7.3.3 As part of the RETP process, a network customer may ensure that power can be delivered from an interface on an RETP to network load. Such network transmission service would not be subject to the requestor pays approach. This transmission cost allocation would be in accordance with OATT provisions for network service.

7.3.4 No compensation is provided to the "requestors" of the RETPs for any "head-room" that would be created on the Transmission Systems. The total project cost for the transmission expansion required due to an RETP will be adjusted to provide compensation

for the positive transmission impacts that the RETP would provide, given the existing Collaborative Transmission Plan.

7.3.5 This RETP concept and cost allocation methodology applies to the NCTPC footprint, which consists of the Duke and Progress Control Areas. Pursuant to Order No. 890, other regions will adopt cost methodologies that apply to the costs of facilities located in their region.

8. COST ALLOCATION FOR PLANNING COSTS

8.1 NCTPC-Related Planning Costs

8.1.1 Each NCTPC Participant bears its own expenses.

8.1.2 TAG participants and TAG Voting Members bear their own expenses.

8.1.3 The costs of the NCTPC base reliability studies are born by Duke and Progress.

8.1.4 Costs associated with incremental reliability studies, the ITP's costs, and the costs of the ETAP are all allocated to NCTPC Participants in the manner set forth in the *Participation Agreement*.

8.1.5 Pursuant to Section 4, costs associated with economic studies that are outside the scope of the ETAP, will be borne by the study requestor.

8.1.6 NCTPC Participants may challenge the correctness of NCTPC cost allocations.

8.1.7 For the Transmission Providers, transmission planning costs are a routine cost-of-service item that would be reflected in both wholesale and retail transmission rates. There is no plan to allocate planning costs to customers, other than as described above, or as contemplated by this Tariff when a customer makes a specific request that must be studied.

8.2 Non-NCTPC-Related Planning Costs

Each Transmission Provider will bear its own costs of planning-related activities that are not occurring through the rubric of the NCTPC Process, which costs may be recovered in rates, pursuant to the then-applicable ratemaking policies.

9. CONFIDENTIALITY

9.1 The Transmission Providers will take appropriate steps to protect CEII information, which is one form of Confidential Information.

9.2 Identification of Confidential Information

The confidentiality of information is determined in the first instance by a NCTPC Participant, TAG Voting Member, or TAG participant providing the information. Examples of Confidential Information, other than CEII, include commercially sensitive information and customer-related information that is proprietary to a particular wholesale or retail customer. The NCTPC Participant, TAG Voting Member, or TAG participant providing Confidential Information must indicate whether the Confidential Information is permitted to be released to the representatives of TAG Voting Members that have abided by the procedures in Section 9.4.3.

9.3 Availability of Confidential Information

9.3.1 The NCTPC Participants will mask all Confidential Information in documents that are released to the public.

9.3.2 Confidential Information will be made available, to the extent not prohibited by law or government policy, to the NCTPC Participants, as limited by the *Participation Agreement*. Each NCTPC Participant is restricted from sharing or giving access to Confidential Information with any employee, representative, and/or organization directly involved in the sale and/or resale of electricity in the wholesale electricity such that they do not receive preferential treatment or a competitive advantage.

9.3.3 Representatives of the TAG Voting Members may be provided Confidential Information if the providing NCTPC Participant, TAG Voting Member, or TAG participant has consented to its release.

9.4 Obtaining CEII or non-CEII Confidential Information

9.4.1 The ITP is tasked with ensuring that no marketing/brokering organizations receive preferential treatment or achieve competitive advantage through the distribution of any transmission-related information in the TAG. Only persons representing TAG Voting Members may have access to Confidential Information.

9.4.2 The ITP ensures that the confidentiality of information and Standards/Code of Conduct requirements are being adhered to within the TAG process, to the extent necessary.

9.4.3 If a representative of a TAG Voting Member seeks Confidential Information, s/he must formally request the data from the ITP and demonstrate that s/he has:

9.4.3.1 Been authorized by FERC to receive the CEII-protected version of Form 715 for both Duke and Progress.

9.4.3.2 Is a representative of a TAG Voting Member that has signed the SERC Confidentiality Agreement.

9.4.3.3 Signed Attachment A to the TAG Voting Member Confidentiality Agreement.

9.4.4 The NCTPC ITP will process the above requests, approve/deny the request, and if approved, provide the data to the representative of the TAG Voting Member.

10. INTER-REGIONAL COORDINATION

The Transmission Providers will coordinate with other transmission systems primarily through participation in SERC, other inter-regional study groups, and bilateral agreements between Duke and/or Progress and transmission systems to which they are interconnected.

10.1 Description of SERC Coordination Activities

10.1.1 All transmission providers within SERC coordinate with other interconnected systems in SERC by sharing their modeling data, assumptions, and transmission expansion plans that results from their own regional planning processes. The results of such coordinated efforts will be addressed with the TAG participants.

10.1.2 The Transmission Providers will participate in SERC studies conducted to assess the performance of the interconnected system under both normal and contingency conditions and to assess the ability of the interconnected system to support large power transfers across subregions.

10.1.3 Duke and Progress must abide by SERC's own confidentiality requirements.

10.2 Description of ERAG & SERC-RFC East Coordination Activities

10.2.1 SERC is a Member of the Eastern Interconnection Reliability Assessment Group (ERAG) along with the Florida Reliability Coordinating Council, Inc., the Midwest Reliability Organization, the Northeast Power Coordinating Council, Inc., ReliabilityFirst Corporation, and the Southwest Power Pool. ERAG augments the reliability of the bulk-power system through periodic reviews of generation and transmission expansion programs and forecasted system conditions within the regions served by ERAG members.

10.2.2 The Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group (MMWG) administers the development of a library of power-flow base case models for the benefit of members.

10.2.3 The SERC-RFC East study group was established in 2006 and is a sub-group within the ERAG structure. Through the SERC-RFC East study group, coordination of plans, data and assumptions is achieved between Tennessee Valley Authority, VACAR, and the transmission systems of the eastern portion of PJM.

10.3 Description of VACAR Coordination Activities

10.3.1 The Transmission Providers both participate with Fayetteville, NCEMC, North Carolina Municipal Power Agency #1, North Carolina Eastern Municipal Power Agency, South Carolina Electric & Gas Company, South Carolina Public Service Authority, Southeastern Power Administration, Dominion Virginia Power, and Alcoa Power Generating, Inc. in the VACAR Planning Task Force.

10.3.2 A VACAR contract agreement provides for coordination between the various entities within the VACAR region.

10.3.3 As members of the VACAR Planning Task Force, the Transmission Providers will engage in studies of the bulk power supply system. VACAR typically analyzes the performance of their proposed future transmission systems based on five- or ten-year projections. VACAR studies are similar to those conducted for SERC, but are

focused on the VACAR subregion, although VACAR coordinates with Southern and TVA under existing agreements.

10.4 Bilateral Coordination Activities

Through bilateral interconnection agreements or joint operating agreements with the interconnected transmission systems of American Electric Power, TVA, Southern Companies, PJM, Dominion, SCE&G, Santee Cooper, and Yadkin, Duke and Progress perform coordinated studies on an as-needed basis.

10.5 Description of Southeast Inter-Regional Participation Process Activities

10.5.1 Duke and Progress have joined with a group of southeast utilities to develop the Southeast Inter-Regional Participation Process. This process provides valid stakeholders the ability to request economic studies that would be evaluated on an inter-regional basis. The framework for this process is provided in a document entitled "Southeast Inter-Regional Participation Process" which is attached as Appendix 1. The purpose of the Southeast Inter-Regional Participation Process is to facilitate the development of inter-regional economic planning studies.

11. INTEGRATED RESOURCE PLANNING

In addition to the NCTPC Process, the Transmission Providers must abide by state laws regarding Integrated Resource Planning (IRP). The information provided below is intended to assist persons who may want to participate in state IRP and siting proceedings.

11.1 North Carolina

North Carolina Utilities Commission (NCUC) analyzes the probable growth in the use of electricity and the long-range need for future generating capacity in North Carolina. Duke and Progress annually furnish the NCUC a report of their respective resource plans, which contain a ten-year forecast of loads and generating capacity. The report describes all generating facilities and known transmission facilities with operating voltage of 161 kV or more which, in the judgment of the utility, will be required to supply system demands during the 10-year forecast period. Such filings must include a section containing a comprehensive analysis of their Demand-Side Management (DSM) plans and activities.

11.2 South Carolina

Section 58-37-40 of the South Carolina Code of Laws requires that all electrical utilities prepare integrated resource plans and submit them to the State Energy Office. The plans must be submitted every three years and must be updated on an annual basis. For electrical utilities subject to the jurisdiction of the SC PSC, submission of the IRP plans required by the SC PSC (which similarly are submitted triennially and updated at least annually) constitutes compliance with the state law. The SC PSC requires that the plans submitted cover 15 years and evaluate the cost effectiveness of supply-side and demand-side options in an economic and reliable manner that considers relevant costs and benefits.

12. LOCAL PLANNING

The Transmission Providers coordinate with their network and native load customers to ensure adequate and reliable electric service to all points of delivery within their control areas. The focus of the NCTPC is planning higher-voltage facilities and transfers of bulk power and thus "local planning" focuses on lower-voltage facilities and the delivery of energy to customer locations. Customer meetings may be held, when necessary, to discuss the respective plans of the customer and the provider and how such plans impact local areas. Any local area plans developed by a Transmission Provider are rolled into the power system models of the transmission providers and these models subsequently roll up to the NCTPC transmission models. The same data and assumptions would be used in local planning as are used in the NCTPC Process.

Appendix 1
Southeast Inter-Regional Participation Process

November 30, 2007

Introduction:

In an effort to more fully address the regional participation principle outlined in the Order 890 Attachment K Tariff requirements and the related guidance contained in the FERC Transmission Planning Process Staff White Paper (dated August 2, 2007), this Southeast Inter-Regional Participation Process expands upon the existing processes for regional planning in the Southeast. This document outlines an inter-regional process among various Southeastern interconnected transmission owners. The inter-regional process described herein is incorporated into each Participating Transmission Owner's[3] planning process and OATT Attachment K (for those transmission owners that have a regulatory requirement to file an Attachment K).

Purpose:

This inter-regional process complements the regional planning processes developed by the Participating Transmission Owners in the Southeast. For the purpose of this document, the term "Southeast Inter-Regional Participation Process" ("SIRPP") is defined as a new process to more fully address the regional participation principle of Order 890 for multiple transmission systems in the Southeast. The term "Regional Planning Processes" refers to the regional transmission planning processes a Transmission Owner has established within its particular region for Attachment K purposes. Importantly, the Economic Planning Studies discussed herein are hypothetical studies that do not affect the transmission queue for purposes of System Impact Studies, Facilities Studies, or interconnection studies performed under other portions of the OATT.

Current Inter-Regional Planning Process:

Each Southeastern transmission owner currently develops a transmission plan to account for service to its native load and other firm transmission service commitments on its transmission system. This plan development is the responsibility of each transmission planner individually and does not directly involve the Regional Reliability Organization

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3 The sponsors of the Southeast Inter-Regional Participation Process are referred to as transmission owners, rather than transmission providers, because not all of the sponsors are "Transmission Providers" for purposes of the *pro forma* OATT.

(e.g. SERC). Once developed, the Participating Transmission Owners collectively conduct inter-regional reliability transmission assessments, which include the sharing of the individual transmission system plans, providing information on the assumptions and data inputs used in the development of those plans and assessing whether the plans are simultaneously feasible.

Participating Transmission Owners:

Due to the additional regional planning coordination principals that have been announced in Order 890 and the associated Transmission Planning White Paper, several transmission owners have agreed to provide additional transmission planning coordination, as further described in this document. The "Participating Transmission Owners" are listed on the SIRPP website (http://www.southeastirpp.com):

Southeast Inter-Regional Participation Process:

The Southeast Inter-Regional Participation Process is outlined in the attached diagram. As shown in that diagram, this process will provide a means for conducting stakeholder requested Economic Planning Studies across multiple interconnected systems. In addition, this process will build on the current inter-regional, reliability planning processes required by existing multi-party reliability agreements to allow for additional participation by stakeholders.

The established Regional Planning Processes outlined in the Participating Transmission Owners' Attachment Ks will be utilized for collecting data, coordinating planning assumptions, and addressing stakeholder requested Economic Planning Studies internal to their respective regions. The data and assumptions developed at the regional level will then be consolidated and used in the development of models for use in the Inter-Regional Participation Process. This will ensure consistency in the planning data and assumptions used in local, regional, and inter-regional planning processes.

These established Attachment K processes may also serve as a mechanism to collect requests for inter-regional Economic Planning Studies by a participant's stakeholders group. The Economic Planning Studies requested through each participant's Attachment K process that involve impacts on multiple systems between Regional Planning Processes will be consolidated and evaluated as part of the Southeast Inter-Regional Participation Process. Stakeholders will also be provided the opportunity to submit their requests for inter-regional Economic Planning Studies directly to the Inter-Regional process.

The Participating Transmission Owners recognize the importance of coordination with neighboring (external) planning processes. Therefore, seams coordination will take place

at the regional level where external regional planning processes adjoin the Southeast Inter-Regional Participation Process (e.g. Southeastern Regional Planning Process coordinating with FRCC Regional Planning Process, Entergy coordinating with SPP, TVA coordinating with MISO and PJM, and the North Carolina Transmission Planning Collaborative coordinating with PJM). External coordination is intended to include planning assumptions from neighboring processes and the coordination of transmission enhancements and stakeholder requested Economic Planning Studies to support the development of simultaneously feasible transmission plans both internal and external to the Southeast Inter-Regional Participation Process.

With regard to the development of the stakeholder requested inter-regional Economic Planning Studies, the Participating Transmission Owners will each provide staff (transmission planners) to serve on the study coordination team. The study coordination team will lead the development of study assumptions (and coordinate with stakeholders, as discussed further below), perform model development, and perform any other coordination efforts with stakeholders and impacted external planning processes. During the study process, the study coordination team will also be responsible for performing analysis, developing solution options, evaluating stakeholder suggested solution options, and developing a report(s) once the study(ies) is completed. Once the study(ies) is completed, the study coordination team will distribute the report(s) to all Participating Transmission Owners and the stakeholders.

With regard to coordinating with stakeholders in the development of the inter-regional Economic Planning Study(ies), in each cycle of the Southeast Inter-Regional Participation Process, the Participating Transmission Owners will conduct the "1st Inter-Regional Stakeholder Meeting", as shown in the attached diagram. At this meeting, a review of all of the Economic Planning Study(ies) submitted through the participants' Regional Planning Processes or directly to the Inter-Regional process, along with any additional Economic Planning Study requests that are submitted at this 1st meeting, will be conducted. During this meeting, the stakeholders will select up to five studies that will be evaluated within the planning cycle. The study coordination team will coordinate with the stakeholders regarding the study assumptions underlying the identified stakeholder requested inter-regional Economic Planning Study(ies). Through this process, stakeholders will be provided an opportunity to comment and provide input regarding those assumptions. Following that meeting, and once the study coordination team has an opportunity to perform its initial analyses of the inter-regional Economic Planning Study(ies), the Participating Transmission Owners will then conduct the "2nd Inter-Regional Stakeholder Meeting." At this meeting, the study coordination team will review the results of such initial analysis, and stakeholders will be provided an opportunity to comment and provide input regarding that initial analysis. The study coordination team will then finalize its analysis of the inter-regional study(ies) and draft the Economic

Planning Study(ies) report(s), which will be presented to the stakeholders at the "3rd Inter-Regional Stakeholder Meeting." Stakeholders will be provided an opportunity to comment and provide input regarding the draft report(s). Subsequent to that meeting, the study coordination team will then finalize the report(s), which will be issued to the Participating Transmission Owners and stakeholders.

In addition to performing inter-regional Economic Planning Studies, the Southeast Inter-Regional Participation Process will also provide a means for the Participating Transmission Owners to review, at the Southeast Inter-Regional Participation Process stakeholder meetings, the regional data, assumptions, and assessments that are then being performed on an inter-regional basis.

Southeast Inter-Regional Participation Process Cycle:

The Southeast Inter-Regional Participation Process will be performed annually. Due to the expected scope of the requested studies and size of the geographical region encompassed, the Participating Transmission Owners will perform up to five (5) inter-regional Economic Planning Studies annually, which could encompass both Step 1 and Step 2 evaluations. A Step 1 evaluation will consist of a high level screen of the requested transfer and will be performed during a single year's planning cycle. The high level screen will identify transfer constraints and likely transmission enhancements to resolve the identified constraints. The Participating Transmission Owners will also provide approximate costs and timelines associated with the identified transmission enhancements to facilitate the stakeholders' determination of whether they have sufficient interest to pursue a Step 2 evaluation. Once a Step 1 evaluation has been completed for a particular transfer, the stakeholders have the option to request a Step 2 evaluation for that transfer to be performed during the subsequent year's Inter-Regional Participation Process Cycle. If the stakeholders opt to not pursue Step 2 evaluation for the requested transfer during the subsequent year's Inter-Regional Participation Process Cycle, an Economic Planning Study of that request may be re-evaluated in the future by being submitted for a new Step 1 evaluation. In the event that the stakeholders request a Step 2 evaluation, the Participating Transmission Owners will then perform additional analysis, which may include additional coordination with external processes. The Participating Transmission Owners will then develop detailed cost estimates and timelines associated with the final transmission enhancements. The Step 2 evaluation will ensure that sufficient coordination can occur with stakeholders and among the impacted Participating Transmission Owners. In addition, the Step 2 evaluation will provide sufficient time to ensure that the inter-regional study results are meaningful and meet the needs of the stakeholders.

It is important to note that the Participating Transmission Owners expect that a Step 2 evaluation will be completed prior to interested parties requesting to sponsor transmission enhancements identified in an Economic Planning Study. However, the Participating Transmission Owners will work with stakeholders if a situation develops where interested parties attempt to sponsor projects identified in a Step 1 evaluation and there is a compelling reason (*e.g.* where time is of the essence).

Inter-Regional Cost Allocation:

The cost allocation for Inter-Regional Economic Upgrade projects will be determined by each region in which the construction of such upgrades (in whole or in part) would occur.

Inter-Regional Coordination of Economic Transmission Project Development:

Once an Economic Planning Study report has been finalized, multiple stakeholders may be interested in jointly participating in the project development. An Inter-Regional process addressing each such economic upgrade request will be developed that will formalize the process of determining if there is sufficient stakeholder interest to pursue economic project development and the coordination that will be required of the impacted Transmission Owners to support this process. The Participating Transmission Owners and the stakeholders will support this process development activity beginning in 2008.

Stakeholder Participation in the Southeast Inter-Regional Participation Process:

Purpose

The purpose of the Southeast Inter-Regional Participation Process Stakeholder Group (SIRPPSG) is to provide a structure to facilitate the stakeholders' participation in the Southeast Inter-Regional Participation Process. Importantly, the SIRPPSG shall have the flexibility to change the "Meeting Procedures" section discussed below but cannot change the Purpose, Responsibilities, Membership, or Data and Information Release Protocol sections absent an appropriate filing with (and order by) FERC to amend the OATT.

Responsibilities

In general, the SIRPPSG is responsible for working with the Participating Transmission Owners on Inter-Regional Economic Planning Study requests so as to facilitate the development of such studies that meet the goals of the stakeholders. The specific responsibilities of this group include:

1. Adherence to the intent of the FERC Standards of Conduct requirements in all discussions.
2. Develop the SIRPPSG annual work plan and activity schedule.

3. Propose and select the Economic Planning Study(ies) to be evaluated (five annually).
    a. Step 1 evaluations
    b. Step 2 evaluations
4. Provide timely input on the annual Economic Planning Study(ies) scope elements, including the following:
    a. Study Assumptions, Criteria and Methodology
    b. Case Development and Technical Analysis
    c. Problem Identification, Assessment and Development of Solutions (including proposing alternative solutions for evaluation)
    d. Comparison and Selection of the Preferred Solution Options
    e. Economic Planning Study Results Report.
5. Providing advice and recommendations to the Participating Transmission Owners on the Southeast Inter-Regional Participation Process.

Membership

The SIRPPSG membership is open to any valid stakeholder in the SIRPP. For the SIRPP a valid stakeholder is defined as any Eligible Customer, generation owner/development company, state or federal agency, and any organization capable of providing Ancillary Services under one of the Participating Transmission Owners' OATTs. In addition, any Transmission Owner, Transmission Operator, or Transmission Planner as those terms or their successors are used under the NERC Functional Model, as may be amended from time to time, are eligible to be stakeholders under this SIRPP. Authorized agents of the above identified stakeholder organizations will also be permitted to represent those organizations in the SIRPP. Any individual wishing to become an SIRPPSG member can make an application for membership on the SIRPP website (http://www.southeastirpp.com). On the application for SIRPPSG membership, the applicant must provide their name, their organization affiliation, and an explanation of how they meet at least one of the categories listed in the above valid stakeholder definition.

Meeting Procedures

The SIRPPSG may change the Meeting Procedures criteria provided below pursuant to the voting structure in place for the SIRPPSG at that time. The currently effective Meeting Procedures for the SIRPPSG shall be provided to the Participating Transmission Owners to be posted on the SIRPP website and shall become effective once posted on that website (http://www.southeastirpp.com), which postings shall be made within a reasonable amount of time upon receipt by the Transmission Owners. Accordingly, the following provisions contained under this Meeting Procedures heading provide a starting-point structure for the SIRPPSG, which the SIRPPSG shall be allowed to change.

Meeting Chair

A stakeholder elected member of the SIRPPSG will chair the SIRPPSG meetings and serve as a facilitator for the group by working to bring consensus within the group. In addition, the duties of the SIRPPSG chair will include:

1. Developing mechanisms to solicit and obtain the input of all interested stakeholders related to inter-regional Economic Planning Studies.
2. Ensuring that SIRPPSG meeting notes are taken and meeting highlights are posted on the SIRPP website (http://www.southeastirpp.com) for the information of the participants after all SIRPPSG meetings.

Meetings

Meetings of the SIRPPSG shall be open to all SIRPPSG members interested in inter-regional Economic Planning Studies across the respective service territories of the Participating Transmission Owners. There are no restrictions on the number of people attending SIRPPSG meetings from any organization.

Quorum

Since SIRPPSG membership is open to all valid stakeholders, there are no quorum requirements for SIRPPSG meetings.

Voting

In attempting to resolve any issue, the goal is for the SIRPPSG to develop consensus solutions. However, in the event consensus cannot be reached, voting will be conducted with each SIRPPSG member's organization represented at the meeting (either physically present or participating via phone) receiving one vote. The SIRPPSG chair will provide notices to the SIRPPSG members in advance of the SIRPPSG meeting that specific votes will be taken during the SIRPPSG meeting. Only SIRPPSG members participating in the meeting will be allowed to participate in the voting. No proxy votes will be allowed. During each SIRPP cycle, the SIRPPSG members will propose and select the inter-regional Economic Planning Studies that will be performed during that particular SIRPP cycle. The SIRPPSG will annually select up to five (5) inter-regional Economic Planning Studies, including both Step 1 evaluation(s) and any Step 2 evaluations, with any such Step 2 evaluations being performed for the previous years Step 1 studies for the pertinent transfers. Each organization represented by their SIRPPSG members will be able to cast a single vote for up to five Economic Planning Studies that their organization would like to be studied within the SIRPP cycle. If needed, repeat voting will be conducted until there are clear selections for the five Economic Planning Studies to be conducted.

Meeting Protocol

In the absence of specific provisions in this document, the SIRPPSG shall conduct its meetings guided by the most recent edition of *Robert's Rules of Order, Newly Revised.*

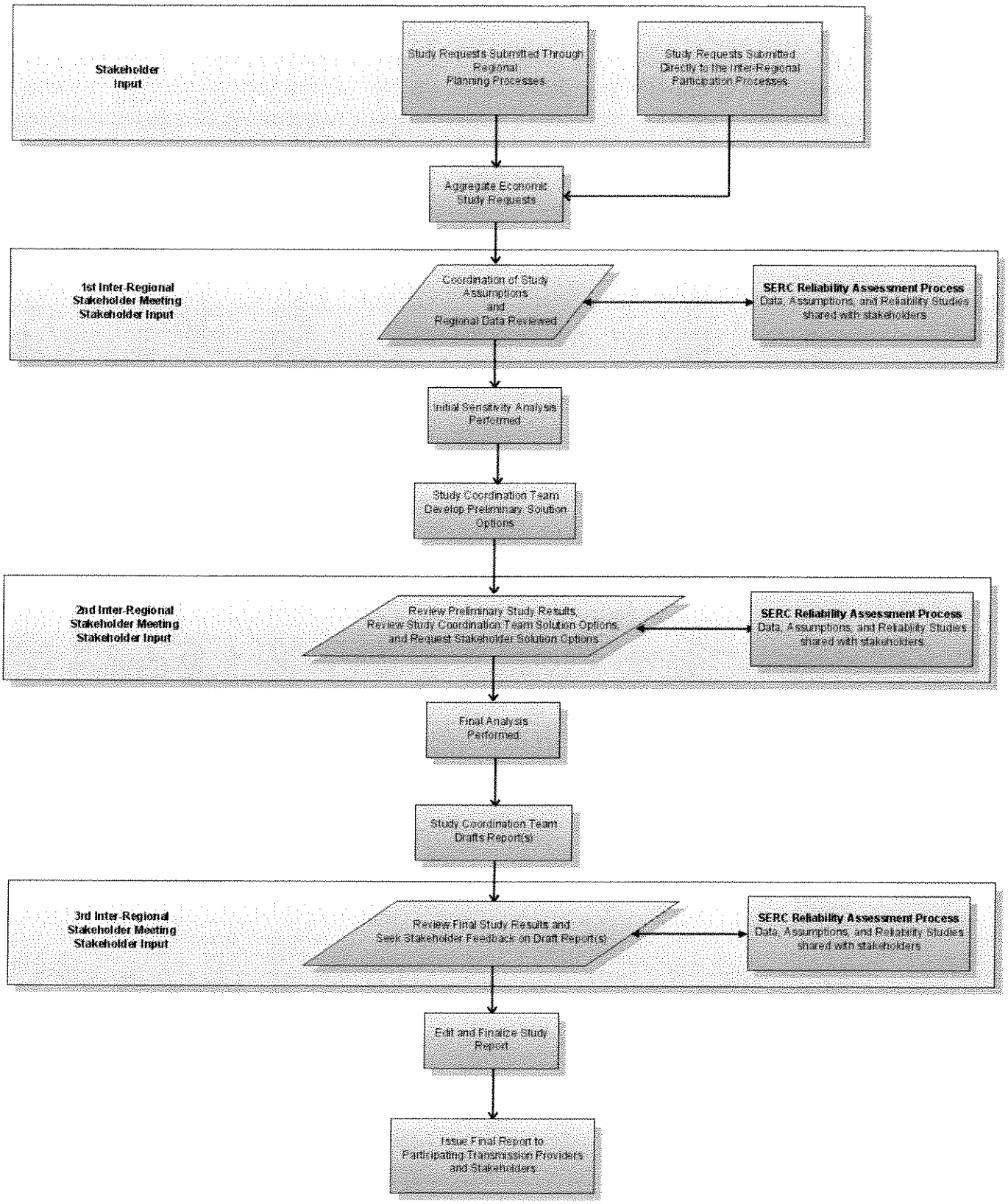
Data and Information Release Protocol

SIRPPSG members can request data and information that would facilitate their ability to replicate the SIRPP inter-regional Economic Planning studies while ensuring that CEII and other confidential data is protected. The following outlines the process the SIRPPSG members would use to obtain the data and information.

1. Request and obtain from FERC the FERC Form No. 715 data (that includes CEII data) for the Participating Transmission Owners, where applicable.
2. Have a current SERC Confidentiality Agreement in place.
3. Have a current SIRPP Confidentiality Agreement in place.
4. Formally request the data on the SIRPP website (http://www.southeastirpp.com) with attestations that they have fulfilled the above 3 steps.

The SIRPP Participating Transmission Owners will process the above requests, approve/deny the request, and if approved, provide the data to the SIRPPSG member.

Southeast Inter-Regional Participation Process Diagram:



ATTACHMENT B

PROGRESS ENERGY CAROLINAS, INC.
CLEAN TARIFF SHEETS

ATTACHMENT K

Transmission Planning Process

1. INTRODUCTION

Duke Energy Carolinas, LLC (Duke) and Progress Energy Carolinas, Inc. (Progress), Transmission Providers with transmission facilities located in the states of North Carolina and South Carolina, ensure that their entire Transmission Systems (i.e., both the portions located in North Carolina and the portions located in South Carolina) are planned in accordance with the requirements imposed by Order No. 890 through the process developed by the North Carolina Transmission Planning Collaborative Process (NCTPC Process). The NCTPC was formed by the following load serving entities (LSEs) in the State of North Carolina: Duke, Progress, ElectriCities of North Carolina (ElectriCities), and the North Carolina Electric Membership Corporation (NCEMC) (collectively, NCTPC Participants or Participants).

In addition to engaging in regional planning through the NCTPC Process, as discussed in Section 10, the Transmission Providers engage in "inter-regional" study and planning activities with transmission providers located outside their Control Areas. Such activities include participation in SERC and the Southeast Inter-Regional Participation Process (Appendix 1), which focus on reliability assessments and economic planning respectively.

2. NCTPC PROCESS OVERVIEW INCLUDING THE PROCESS FOR CONSULTING WITH CUSTOMERS

The NCTPC will annually develop a single, coordinated transmission plan (Collaborative Transmission Plan) that appropriately balances costs, benefits, and risks associated with the use of transmission, generation, and demand-side resources to meet the needs of LSEs as well as Transmission Customers under this Tariff.

2.1 The *North Carolina Transmission Planning Collaborative Participation Agreement* (*Participation Agreement*) governs the NCTPC and the NCTPC Process. The *Participation Agreement* is located on the NCTPC Website (http://www.nctpc.org/nctpc/).

2.2 The NCTPC Process is summarized in a document entitled *North Carolina Transmission Planning Collaborative Process* that is located on the NCTPC Website.

2.3 Participation in the NCTPC

2.3.1 Pursuant to the *Participation Agreement*, the NCTPC has four components: the Oversight/Steering Committee (OSC), the

Planning Working Group (PWG), the Transmission Advisory Group (TAG), and the Independent Third Party (ITP). 2.3.2 Eligibility for participation in the four NCTPC components is as follows:

2.3.2.1 The appointment of OSC members by the NCTPC Participants is governed by the *Participation Agreement*. The ITP is an *ex officio* member of the committee. The qualifications required to serve on the OSC are set forth in a document entitled *Scope - Oversight/Steering Committee* that is located on the NCTPC Website.

2.3.2.2 The appointment of PWG members by the NCTPC Participants is governed by the *Participation Agreement.* The ITP also has a representative on the PWG. The qualifications required to serve on the PWG are set forth in a document entitled *Scope - Planning Working Group* that is located on the NCTPC Website.

2.3.2.3 Anyone may participate in the TAG (TAG participants) and sign-up to receive TAG communications. Entities that are valid stakeholders may apply to become TAG Voting Members. A valid stakeholder includes any Eligible Customer, generation owner/generation development company, and any organization capable of providing Ancillary Services under the Duke Energy Carolinas or Progress Energy Carolinas OATTs. In addition, any Transmission Owner, Transmission Operator, or Transmission Planner as those terms or their successors are used under the NERC Functional Model, as may be amended from time to time, will be considered valid stakeholders and may become a TAG Voting Member. Persons who are not employed by, but are authorized agents of, one or more TAG Voting Members also will be permitted to represent TAG Voting Members in the NCTPC Process. The transmission function of a NCTPC Participant may not be a TAG Voting Member, but the merchant function of an NCTPC Participant may be a TAG Voting Member.

2.3.2.4 The Independent Third Party (ITP) is selected by the OSC. The ITP must have qualifications similar to OSC and PWG members.

2.4 Responsibilities and Decision-Making of NCTPC Components

The responsibilities of the components within the NCTPC are determined by the *Participation Agreement* and/or the OSC. Decision-making likewise is established in the *Participation Agreement*, or by policies established by the OSC.

2.4.1 Oversight/Steering Committee

2.4.1.1 The OSC is responsible for overseeing and directing all the activities associated with this NCTPC Process. A list of the OSC's responsibilities is found in *Scope - Oversight/Steering Committee.*

2.4.1.2 OSC decision-making is governed by the *Participation Agreement.*

2.4.1.3 Officers of the OSC are selected in the manner set forth in the *Participation Agreement.*

2.4.2 Planning Working Group

2.4.2.1 The PWG is responsible for developing and performing the appropriate simulation studies to evaluate the transmission conditions in the Participants' service territories and recommend a coordinated solution for the various transmission limitations identified in the studies. A list of the PWG's responsibilities is found in *Scope - Planning Working Group.*

2.4.2.2 PWG decision-making is governed by the *Participation Agreement.*

2.4.2.3 Officers of the PWG are selected in the manner set forth in the *Participation Agreement.*

2.4.3 Transmission Advisory Group

2.4.3.1 The purpose of the TAG is to provide advice and recommendations to the NCTPC Participants to aid in the development of an annual Collaborative Transmission Plan. The TAG participants may propose enhanced transmission access projects for evaluation as described in Section 4.2.2 hereof. The TAG Voting Members select which of those projects should be evaluated. The TAG participants also provide input on the annual study scope elements of both the Reliability Planning Process as well as the Enhanced Transmission Access Planning Process, including input on the following: Study Assumptions; Study Criteria; Study Methodology; Case Development and Technical Analysis; Problem Identification; Assessment and Development of Solutions (including proposing alternative solutions for evaluation); Comparison and Selection of the Preferred Transmission Plan; and the Transmission Plan Study Results Report. A full list of the TAG's responsibilities is found in *Scope - Transmission Advisory Group,* which is located on the NCTPC Website.

2.4.3.2 The ITP will chair the TAG meetings and serve as a facilitator for the group. TAG decision-making is by consensus among the TAG participants. However, in the event consensus cannot be reached, voting will be conducted with each TAG Voting Member represented at the meeting (either physically present or participating via phone) receiving one vote. As to matters that must be resolved by vote, rather than by consensus, majority and minority positions will be forwarded to the OSC for their consideration on the issue. The independent third-party will provide notices to the TAG participants in advance of the TAG meeting that specific votes will be taken during the TAG meeting.

Only TAG Voting Members participating in the meeting will be allowed to participate in the voting. A single person may represent more than one TAG Voting Member.

2.4.4. Independent Third Party

2.4.4.1 The ITP facilitates the overall NCTPC Process.

2.4.4.2 A list of the ITP's primary responsibilities is found in *Scope - Planning Working Group* and *Scope - Oversight/Steering Committee*.

2.4.4.3 The ITP also provides the leadership role in developing the Enhanced Transmission Access Planning (ETAP) Process, subject to the oversight of the OSC.

2.4.4.4 The ITP maintains the NCTPC Website.

2.4.4.5 The ITP's role in decision-making varies based on which group s/he is participating as documented in the NCTPC documents posted on the NCTPC Website.

2.5 Participation of State Regulators

State regulators, including state-sanctioned entities representing the public, like other members of the public, may choose to be TAG participants. State public utility regulatory commissions also may seek to receive periodic status updates and the progress reports on the NCTPC Process.

3. NOTICE PROCEDURES, MEETINGS, AND PLANNING-RELATED COMMUNICATIONS

All information regarding transmission planning meetings and communications are located on the NCTPC Website.

3.1 Notice

3.1.1 Notice of all meetings of a component (TAG, PWG, OSC) will be by email to such component.

All TAG meeting notices and agendas will be posted on the NCTPC Website.

3.1.2 Information about signing up to be a TAG participant and to receive email communications is posted on the NCTPC Website. Information about applying to be a TAG Voting Member also is available.

3.1.3 The OSC will publish highlights of its meetings on the NCTPC Website.

3.2 Location

3.2.1 The location of an OSC or PWG meeting will be determined by the component.

3.2.2 The location of a TAG meeting will be determined by the OSC.

3.2.3 Conference call dial-in technology will be available for meetings upon request.

3.3 Meeting Protocols

3.3.1 OSC

3.3.1.1 The OSC chair schedules meetings, provides notice, ensures that meeting minutes are taken, develops the agenda, chairs the meetings.

3.3.1.2 The OSC generally will meet at least monthly, and more frequently as necessary.

3.3.1.3 OSC meetings are open to the OSC members (including the ITP), their alternates, PWG members, and, if approved, guests.

3.3.2 PWG

3.3.2.1 The PWG chair schedules meetings, provides notice, ensures that meeting minutes are taken, develops the agenda, and chairs the meetings.

3.3.2.2 The PWG generally meets at least monthly, and more frequently as necessary.

3.3.2.3 PWG meetings are open to the PWG members, the ITP, the OSC (and their alternates), and, if approved, guests.

3.3.3 TAG

3.3.3.1 TAG meetings are chaired and facilitated by the ITP.

3.3.3.2 The TAG generally meets four times a year.

3.3.3.3 Meetings of the TAG generally are open to the public, i.e., TAG participants. When necessary, TAG meetings may be restricted by the ITP to representatives of TAG Voting Members that are qualified to receive Confidential Information.

3.3.3.4 A yearly meeting and activity schedule is proposed, discussed with, and provided to TAG participants annually.

4. DESCRIPTION OF THE METHODOLOGY, CRITERIA, AND PROCESSES USED TO DEVELOP TRANSMISSION PLANS

The NCTPC Process is a coordinated regional planning process that includes both a "Reliability Planning" and an "Enhanced Transmission Access Planning" (ETAP) process, both of which ultimately result in the development of a Collaborative Transmission Plan. The entire, iterative process ultimately results in a single Collaborative Transmission Plan that appropriately balances the costs, benefits and risks associated with the use of transmission, generation, and demand-side resources.

4.1 Overview of Reliability Planning Process

The Reliability Planning Process addresses transmission upgrades needed to maintain reliability and to integrate new generation resources and/or loads. The Reliability Planning Process includes a base reliability study (base case) that evaluates each Transmission System's ability to meet projected load with a defined set of resources as well as the needs of firm point-to-point customers, whose needs are reflected in their transmission contracts and reservations. A resource supply analysis also is conducted to evaluate transmission system impacts for other potential resource supply options to meet future load requirements. The final results of the Reliability Planning Process include summaries of the estimated costs and schedules to provide any transmission upgrades and/or additions needed to maintain a sufficient level of reliability necessary to serve customers.

4.2 Overview of Enhanced Transmission Access Planning Process

4.2.1 The ETAP Process is the economic planning process that allows the TAG participants to propose economic upgrades to be studied as part of the transmission planning process. The ETAP Process evaluates the means to increase transmission access to potential supply resources inside and outside the Control Areas of the Transmission Providers. This economic analysis provides the opportunity to study what transmission upgrades would be required to reliably integrate new resources. In addition, this economic analysis would include, if requested, the evaluation of Regional Economic Transmission Paths (RETPs) that would facilitate potential regional point-to-point economic transactions. RETPs are described in more detail below and in the document entitled *NCTPC Transmission Cost Allocation* on the NCTPC Website.

4.2.2 The ETAP Process begins with the TAG participants proposing scenarios and interfaces to be studied. The information required and the form necessary to submit a request as well as the submittal deadline is reviewed and discussed with the TAG participants early in the annual planning cycle. The form is posted on the NCTPC Website. The PWG will determine if it would be efficient to combine and/or cluster any of the proposed scenarios and will also determine if any of the proposed scenarios are of an Inter-Regional nature. The OSC will direct the TAG participants to submit the Inter-Regional study requests to the Southeast

Inter-Regional Participation Process since those studies would have to be evaluated within that forum.

4.2.3 The OSC will review the PWG analysis, approve the compiled study list, and provide the study list to the TAG. For the study scenarios that impact the NCTPC region, but are not Inter-Regional in nature, the TAG Voting Members will select a maximum of five scenarios that will be studied within the current NCTPC planning cycle. TAG Voting Members will be permitted to cast one vote in support of any particular scenario and may vote for up to a maximum of five study scenarios. There may be multiple representatives of TAG Voting Members within the TAG; however, for voting purposes, each TAG Voting Member can only submit one vote. The five study scenarios that receive the largest number of votes will be the study scenarios that are selected to be studied within the current NCPTC planning cycle. To be able to vote, the TAG Voting Member must participate in the meeting, either by having a representative physically present at the meeting or through participation by phone. No representative of a TAG Voting Member shall be permitted to cast a vote of another TAG Voting Member that has no participating representative.

4.2.4 There will be no charge to the TAG participants for the five studies selected by the TAG Voting Members. However, if a particular TAG participant wants the NCTPC to evaluate a scenario that was not chosen by the TAG Voting Members, then the TAG participant can request to have the NCTPC conduct the study. The NCTPC will evaluate this request and will conduct the study if the study can be reasonably accommodated, however the cost of conducting this additional study will be allocated to that specific TAG participant.

4.2.5 RETPs

4.2.5.1 As part of the ETAP, TAG Voting Members may propose that a particular RETP be studied. The creation of an RETP would permit energy to be transferred on a Point-to Point basis from an interface or a Point of Receipt on one Transmission Provider's system to an interface or a Point of Delivery on another Transmission Provider's system for a specific period of time. A subscriber to an RETP is under no obligation to use the complete RETP, it may resell its rights to portions of the RETP. An RETP ensures that Point-to-Point Transmission Service can be provided over the Duke and/or Progress systems. The costs of the projects necessary to create an RETP will be subject to the "requestor pays" cost allocation methodology described *infra*. A network customer may seek to use an RETP as the firm Point-to-Point Transmission Service necessary to support a designated network resource external to the Control Area in which its load is located.

4.2.5.2 The TAG Voting Members will identify RETPs that they would like studied. There would be a need for an initial study of an RETP

("Initial RETP Study"). If a proposed RETP would be solely contained within the NCTPC, then the NCTPC Process would be used to address the RETP. However, if a proposed RETP would impact transmission providers outside the NCTPC, there will be a need to coordinate such an initial study with other transmission providers.

4.2.5.3 If an Initial RETP Study is performed, it would identify any transmission system problems/limitations related to the Transmission Providers impacted by the RETP and would identify the transmission solutions/upgrades that would be needed to accommodate the RETP. An RETP would be evaluated in the Initial RETP Study as if it was a request for Point-to Point Transmission Service from a source control area (Point of Receipt) to a sink control area (Point of Delivery) over a specific period of time (the TAG Voting Members requesting the study would determine the time period), but it will not be considered to be a request that is in the transmission queue. The Point of Receipt and Point of Delivery can be interfaces.

4.2.5.4 The Initial RETP Study would only provide preliminary information on the projected cost and scope of the facilities that would be needed to create the RETP, and the time it would take to complete the RETP. In the Initial RETP Study, each Transmission Provider along the RETP would identify the estimated costs for any upgrades necessary to provide service over the RETP.

4.2.5.5 If the RETP was totally contained within the NCTPC, then the following process would be used to move the RETP through the study to potential project commitment phases. Once the Initial RETP Study is complete, a determination would be made as to whether there is sufficient interest in the project to move the RETP from the "initial study" mode to the establishment of an "Open Season" for the RETP. The Open Season will provide the structure whereby Duke and Progress will be able to process these RETP Point-to Point Transmission Service requests for the entire proposed MW of the RETP from the source control area to the sink control area for the relevant time period. During this Open Season all potential transmission customers would have a 60-day window to put in their request to subscribe to all or a portion of the MW of service being made available along the RETP.

4.2.5.6 When the Open Season process is initiated by Duke and Progress, the transmission queue positions for these RETP requests will be established.

4.2.5.7 Through the Open Season process, which will be iterative, if the RETP is fully subscribed, it would move forward to a Facilities

Study stage. After such stage, if it remained fully subscribed, the RETP would be included in the Collaborative Transmission Plan (and/or a supplement to such Plan) and Service Agreements will be executed (or filed on an unexecuted basis).

4.2.5.8 If an RETP encompasses Transmission Providers outside the NCTPC, the impacted Transmission Providers will work individually and through applicable stakeholder forums to perform the necessary studies and develop the processes that would be used to move from a study of a RETP to actual transmission reservations that would be needed to support the RETP. The above study and Open Season concepts could be used by these larger inter-regional transmission provider groups.

4.2.6 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 and discussed with the TAG participants.

4.3 Overview of the Steps in the Planning Processes

4.3.1 Each year, the OSC will initiate the process to develop the annual Collaborative Transmission Plan.

4.3.2 The OSC will provide notice of the commencement of the process to develop the annual Collaborative Transmission Plan via e-mail to the TAG and posts a notice on the NCTPC Website.

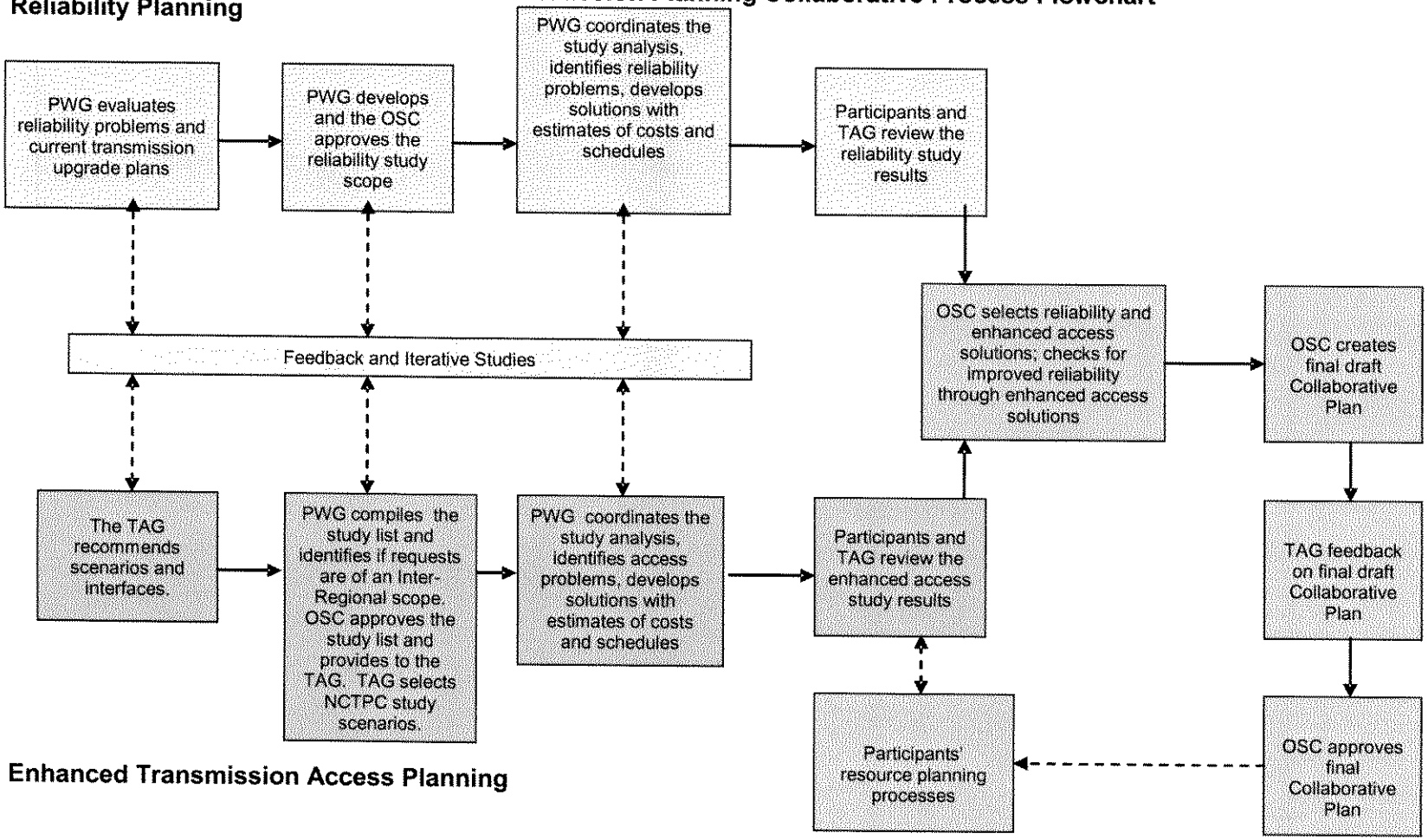
4.3.3 The process will allow for flexibility to make modifications to the development of the plan throughout the year as needs change, new needs arise, or new solutions to problems are identified.

4.3.4 The schedule for all of the activities will be set by the PWG and OSC, but will vary from year to year. The basic order of events is as set forth in Section 5, although the planning process is an iterative one. A list of relevant dates established for planning cycle will be posted on the NCTPC website.

4.4 Summary Flow Chart of Process

The following page contains a flow chart of the NCTPC Process.

Figure 1
North Carolina Transmission Planning Collaborative Process Flowchart



5. CRITERIA, ASSUMPTIONS, AND DATA UNDERLYING THE PLAN AND METHOD OF DISCLOSURE OF TRANSMISSION PLANS AND STUDIES

5.1 Study Assumptions

5.1.1 The PWG will select the study assumptions for the analysis based on direction provided by the OSC.

5.1.2 Once the PWG identifies the study assumptions, they will be reviewed with the TAG participants before the set of final assumptions are approved by the OSC. The process for this dialogue is in-person meetings, written submissions, and/or other forms of communication selected by TAG participants. Input should be provided in the timeframes agreed upon.

5.1.3 The study assumptions shall be set forth in an annual *Study Scope Document.*

5.1.4 The Transmission Providers will prepare the base case models. These models will be reviewed with the PWG to ensure that they represent the study assumptions approved by the OSC.

5.1.5 The Transmission Providers will also develop the necessary change case models as required to evaluate different resource supply scenarios and enhanced transmission access scenarios as directed by the OSC. Such change case models will also be reviewed with the PWG to ensure that they represent the study assumptions approved by the OSC.

5.2 Study Criteria

5.2.1 The PWG establishes the planning criteria by which the study results will be measured, in accordance with NERC and SERC Reliability Standards and individual Transmission Provider criteria. TAG participants may review and comment on the planning criteria.

5.2.2 Transmission System planning documents of Duke and Progress will be posted on their respective OASIS sites. Some planning documents may not be posted due to CEII and confidentiality concerns, but will be identified such that they can be requested via the methodology posted on the relevant OASIS.

5.3 Data Collection and Case Development

5.3.1 The most current Multi-Regional Modeling Working Group (MMWG) or SERC Long-Term Study Group model will be used for the systems external to Duke and Progress as a starting point for the base case to be used by both Progress and Duke. The base case will include the detailed internal models for Progress and Duke and will include current transmission additions planned to be in-service for given years.

5.3.2 The following data are relevant to the development of internal models for Progress and Duke:

Load and resource projections provided by network customers (including the native load of the NCTPC Participants);

Confirmed, firm point-to-point transmission service reservations (including rollover rights);

Generation real and reactive capacity data;

Generation dispatch priority data;

Transmission facility impedance and rating data; and

Interchange data adjusted to correctly model transfers associated with designated network resources from outside the Transmission Providers' Control Areas.

5.3.3 The Transmission Providers collect the necessary planning data and information that are not already in their possession. One element of this data collection process will be the annual collection of data from Network Customers required by this Tariff. Any guidelines, data formats, and schedules for any data and information exchanges will be established by the PWG. Aside from the annual submission of data by Network Customers, the timing of this data collection process is established as part of the development of the annual study work plan that is prepared by the PWG, reviewed with the TAG participants, and approved by the OSC.

5.3.4 TAG participants may provide additional input into the data collection process (i.e., the provision of data not required to be submitted under this Tariff), such as providing information on future point-to-point transmission service scenarios. Such non-required information may be used in the appropriate study process.

5.3.5 Transmission customers should provide the Transmission Providers with timely written notice of material changes in any information previously provided relating to load, resources, or other aspects of its facilities or operations affecting the Transmission Provider's ability to provide service. Network customers may provide revised versions of previously submitted annual data reporting forms.

5.3.6 Additional cases will be developed as required for different scenarios to evaluate other options to meet load demand forecasts in the study, including where fictitious or as yet undesignated network resources are deemed to be designated. Other cases may be developed and approved by the OSC to evaluate enhanced access scenarios, such as predicted future point-to-point transmission uses, as submitted by the TAG participants.

5.3.7 The Case Development details will be identified in the annual *Study Scope Document.*

5.3.8 Sufficient information will be made available, subject to CEII and confidentiality restrictions, to enable TAG Voting Members to replicate the results of planning studies. A TAG Voting Member seeking data and information that would allow it to replicate the NCTPC planning studies should provide such request to the ITP, who will verify that confidentiality requirements described in Section 9 have been met before providing such information.

5.4 Methodology

5.4.1 The PWG determines the methodologies that will be used to carry out the technical analysis required for the approved studies. The PWG also determines the specific software and models that will be utilized to perform the technical analysis. The study methodology will be identified in the annual *Study Scope Document*. TAG participants may review and comment on the study methodology.

5.5 Technical Analysis and Study Results

5.5.1 The PWG performs the technical study analysis in accordance with the OSC approved study methodology and produces the study results.

5.5.2 Results from the technical analysis are reported to identify transmission elements approaching their limits such that all NCTPC Participants are made aware of potential issues and appropriate steps can be identified to correct these issues, including the potential of identifying previously undetected problems.

5.5.3 Study results are made available to the TAG participants for review and comment.

5.6 Assessment and Problem Identification

5.6.1 The Transmission Providers provide the summary data identifying the reliability problems and causes resulting from their assessments and comprehensively review the information with the PWG. The PWG evaluates the technical results provided by the Transmission Providers to identify problems and issues and reports to the OSC.

5.6.2 TAG participants are provided information relating to technical assessments and problem identification.

5.7 Solution Development

5.7.1 The PWG identifies potential solutions to the transmission problems identified and will test the effectiveness of the potential solutions through additional analysis as required and ensure that the solutions meet the study criteria previously developed.

5.7.2 TAG participants will have the opportunity to suggest alternative solutions.

5.7.3 All options that satisfactorily resolve an identified reliability problem would be given consideration.

5.7.4 The Transmission Providers estimate the costs for each of the proposed transmission solutions (e.g., cost, cash flow, present value) and develop a rough schedule estimate to complete the construction of the proposed facility. This information is reviewed and discussed by the PWG.

5.8 Selection of Preferred Transmission Plan

5.8.1 The PWG compares all of the alternatives and select the preferred solution by balancing the project cost, benefit, and associated risks.

5.8.2 The PWG selects a preferred set of transmission improvements that provides the most reliable and cost effective transmission solution while prudently managing the associated risks.

5.8.3 The PWG provides the OSC and the TAG participants with their recommendations based on this selection process in order to obtain their input.

5.9 Collaborative Transmission Plan Report

5.9.1 The PWG prepares a draft "Collaborative Transmission Plan Report" based on the study results and the recommended transmission solutions and provides to the OSC for review. The draft Report describes the plan in a manner that is understandable to the TAG participants (*e.g.*, describing any needs, the underlying assumptions, applicable planning criteria, and methodology used to determine the need), rather than simply reporting engineering results. The report includes a comprehensive summary of all the study activities as well as the recommended transmission improvements including estimates of costs and construction schedules.

5.9.2 The OSC forwards the draft report to the TAG participants for their review and discussion. The PWG members are the technical points of contact that can respond to questions regarding modeling criteria, assumptions, and data underlying the Report. The TAG participants may discuss, question, or propose alternatives for any upgrades identified by the draft Report.

5.9.3 The OSC evaluates the results and the PWG recommendations and the TAG participants' input. The OSC approves the final Collaborative Transmission Plan for posting on the NCTPC Website. The Plan also is posted on the Transmission Providers' OASIS and distributed to the TAG participants.

5.9.4 The Collaborative Transmission Plan Report allows the NCTPC Participants to identify alternative, least-cost resources to include with their respective Integrated Resource Plans. Others can similarly use this information for their own resource planning purposes.

5.10 Status Reports

5.10.1 As part of the NCTPC Process, the Transmission Providers periodically provide the TAG participants a report on the status of the transmission upgrades presented in the previous Collaborative Transmission Plans. The update is posted on the NCPTC Website and includes the following information: the name of the project, the issue it resolves, the name of the relevant Transmission Provider(s), the original planned in-service date and the current expected in-service date.

6. DISPUTE RESOLUTION MECHANISM

6.1 NCTPC Process Disputes

6.1.1 The OSC voting structure allows the ITP to cast a tie breaking vote if necessary to decide on a particular issue.

6.1.2 A Transmission Provider has the right to reject an OSC decision if it believes that it would harm reliability.

6.1.3 Any NCTPC Participant or TAG Voting Member has the right to seek assistance from the NCUC Public Staff to mediate an issue and render a non-binding opinion on any disputed decision.

6.1.4 If the Participants cannot resolve a disputed decision by NCUC Public Staff facilitation, they may seek review from a judicial or regulatory body that has jurisdiction.

6.2 Transmission Siting Disputes

6.2.1 The South Carolina Code of Laws Section 58, Chapter 33 addresses disputes involving utilities' transmission projects that require South Carolina authorization through the certificates of public convenience and necessity process.

6.2.2 NCUC Rule R8-62 addresses disputes involving utilities' transmission projects that require North Carolina authorization through the certificates of public convenience and necessity process.

6.3 Integrated Resource Planning Disputes

6.3.1 The NCUC allows public participation in and may hold hearings regarding matters related to integrated resource planning.

6.3.2 The SC PSC allows public participation in and may hold hearings regarding matters related to integrated resource planning.

6.4 Tariff Disputes

6.4.1 The dispute resolution process provisions included in this Tariff apply to disputes involving compliance with the Commission's transmission planning obligations set forth in Order No. 890. Matters over which the Commission does not have jurisdiction, including planning to meet retail native load of the Transmission Providers shall not be within the scope of the dispute resolution process of this Tariff.

6.5 Regional Reliability Project Planning Disputes

6.5.1 The Commission's Dispute Resolution Service would be used to settle any issues arising from the cost allocation related to Regional Reliability Projects, discussed *infra,* that involve transmission providers outside the NCTPC.

7. TRANSMISSION COST ALLOCATION

7.1 OATT Cost Allocation

7.1.1 The costs of Reliability Projects included in the Collaborative Transmission Plan are allocated in accordance with this Tariff. "Regional Reliability Projects," as discussed below, are an exception to this rule.

7.1.2 While the Transmission Providers study economic upgrades through ETAP, they do not have an obligation to build or fund such projects and thus the projects studied are not included in the Collaborative Transmission Plan, unless and until either: 1) a transmission service request is submitted to the appropriate Transmission Provider(s) or 2) an RETP is fully subscribed.

7.1.3 If a transmission service request is submitted under this Tariff for an economic project, its costs will be allocated in accordance with this Tariff.

7.2 Regional Reliability Project Cost Allocation

7.2.1 An "avoided cost" cost allocation methodology will apply to reliability projects where there is a demonstration that a regional transmission solution and regional approach to cost allocation results in cost savings.

7.2.2 The NCTPC Planning Process results in a set of projects that satisfy the reliability criteria of the Transmission Providers who are a party to the Participation Agreement (i.e., Reliability Projects). Through this process, a project may be identified that meets a reliability need in a more cost-effective manner than if each Transmission Provider were only considering projects on its system to meet its reliability criteria. A Regional Reliability Project can be defined as any reliability project that

requires an upgrade to a Transmission Provider's system that would not have otherwise been made based upon the reliability needs of the Transmission Provider. A Regional Reliability Project must have a cost of at least $1 million to be subject to the avoided-cost cost allocation methodology. The costs of a Regional Reliability Project with a cost of less than $1 million would be borne by each Transmission Provider based on the costs incurred on its system.

7.2.3 Unless a Regional Reliability Project is determined by the NCTPC to be the most cost-effective solution to a reliability need, it will not be selected to be included in the Collaborative Transmission Plan. But, if a Regional Reliability Project is cost effective, it will have its costs allocated based on an avoided cost approach, whereby each Transmission Provider looks at the stand-alone approach to maintaining reliable service and shares the savings of not implementing the stand-alone approach on a pro-rata basis. The avoided cost approach formula can be expressed as follow:

(Transmission Provider$_x$'s Avoided Cost/Total Avoided Cost) * cost of Regional Reliability Project = Transmission Provider$_x$'s Cost Allocation

(Transmission Provider$_y$'s Avoided Cost/Total Avoided Cost) * cost of Regional Reliability Project = Transmission Provider$_y$'s Cost Allocation

These cost responsibility determinations will then be reflected in transmission rates. The avoided cost approach also will take into account in determining avoided costs, the acceleration or delay of Reliability Projects. Examples of the application of the avoided-cost approach may be found in *NCTPC Transmission Cost Allocation*.

7.2.4 If a Regional Reliability Project that is suitable for this alternate cost allocation approach involves a Transmission System(s) outside the NCTPC, the costs should be fairly allocated among the affected Transmission Providers based on good-faith negotiation among the parties involved using the "avoided cost" approach outlined above used as a starting point in the negotiations. The resulting transmission costs and the associated revenue requirements of each Transmission Provider will be recovered through their respective existing rate structures at the time.

7.3 RETP Cost Allocation

7.3.1 The costs of upgrades or facilities that result from RETPs are allocated on a "requestor pays" basis.

7.3.2 Transmission customer(s) that are subscribing to the RETP would provide the up-front funding of any transmission construction that was required to

ensure that the path was available for the relevant time period. These "requestor(s)" would be the transmission customers that were awarded the MW as a result of the successful subscription during the Open Season process. On the Duke and/or Progress systems, the transmission customer would receive a levelized repayment of this initial funding amount from Duke and/or Progress in the form of monthly transmission credits over a maximum 20-year period. The Transmission Providers will be permitted to work with the transmission customers to provide shorter or different crediting. As credits are paid, Duke and Progress would have the opportunity to include the costs of upgrades that were needed for the RETP in transmission rates, similar to the Generator Interconnection pricing/rate approach.

7.3.3 As part of the RETP process, a network customer may ensure that power can be delivered from an interface on an RETP to network load. Such network transmission service would not be subject to the requestor pays approach. This transmission cost allocation would be in accordance with OATT provisions for network service.

7.3.4 No compensation is provided to the "requestors" of the RETPs for any "head-room" that would be created on the Transmission Systems. The total project cost for the transmission expansion required due to an RETP will be adjusted to provide compensation for the positive transmission impacts that the RETP would provide, given the existing Collaborative Transmission Plan.

7.3.5 This RETP concept and cost allocation methodology applies to the NCTPC footprint, which consists of the Duke and Progress Control Areas. Pursuant to Order No. 890, other regions will adopt cost methodologies that apply to the costs of facilities located in their region.

8. COST ALLOCATION FOR PLANNING COSTS

8.1 NCTPC-Related Planning Costs

8.1.1 Each NCTPC Participant bears its own expenses.

8.1.2 TAG participants and TAG Voting Members bear their own expenses.

8.1.3 The costs of the NCTPC base reliability studies are born by Duke and Progress.

8.1.4 Costs associated with incremental reliability studies, the ITP's costs, and the costs of the ETAP are all allocated to NCTPC Participants in the manner set forth in the *Participation Agreement*.

8.1.5 Pursuant to Section 4, costs associated with economic studies that are outside the scope of the ETAP, will be borne by the study requestor.

8.1.6 NCTPC Participants may challenge the correctness of NCTPC cost allocations.

8.1.7 For the Transmission Providers, transmission planning costs are a routine cost-of-service item that would be reflected in both wholesale and retail transmission rates. There is no plan to allocate planning costs to customers, other than as described above, or as contemplated by this Tariff when a customer makes a specific request that must be studied.

8.2 Non-NCTPC-Related Planning Costs

Each Transmission Provider will bear its own costs of planning-related activities that are not occurring through the rubric of the NCTPC Process, which costs may be recovered in rates, pursuant to the then-applicable ratemaking policies.

9. CONFIDENTIALITY

9.1 The Transmission Providers will take appropriate steps to protect CEII information, which is one form of Confidential Information.

9.2 Identification of Confidential Information

The confidentiality of information is determined in the first instance by a NCTPC Participant, TAG Voting Member, or TAG participant providing the information. Examples of Confidential Information, other than CEII, include commercially sensitive information and customer-related information that is proprietary to a particular wholesale or retail customer. The NCTPC Participant, TAG Voting Member, or TAG participant providing Confidential Information must indicate whether the Confidential Information is permitted to be released to the representatives of TAG Voting Members that have abided by the procedures in Section 9.4.3.

9.3 Availability of Confidential Information

9.3.1 The NCTPC Participants will mask all Confidential Information in documents that are released to the public.

9.3.2 Confidential Information will be made available, to the extent not prohibited by law or government policy, to the NCTPC Participants, as limited by the *Participation Agreement*. Each NCTPC Participant is restricted from sharing or giving access to Confidential Information with any employee, representative, and/or organization directly involved in the sale and/or resale of electricity in the wholesale electricity such that they do not receive preferential treatment or a competitive advantage.

9.3.3 Representatives of the TAG Voting Members may be provided Confidential Information if the providing NCTPC Participant, TAG Voting Member, or TAG participant has consented to its release.

9.4 Obtaining CEII or non-CEII Confidential Information

9.4.1 The ITP is tasked with ensuring that no marketing/brokering organizations receive preferential treatment or achieve competitive advantage through the distribution of any transmission-related information in the TAG. Only persons representing TAG Voting Members may have access to Confidential Information.

9.4.2 The ITP ensures that the confidentiality of information and Standards/Code of Conduct requirements are being adhered to within the TAG process, to the extent necessary.

9.4.3 If a representative of a TAG Voting Member seeks Confidential Information, s/he must formally request the data from the ITP and demonstrate that s/he has:

9.4.3.1 Been authorized by FERC to receive the CEII-protected version of Form 715 for both Duke and Progress.

9.4.3.2 Is a representative of a TAG Voting Member that has signed the SERC Confidentiality Agreement.

9.4.3.3 Signed Attachment A to the TAG Voting Member Confidentiality Agreement.

9.4.4 The NCTPC ITP will process the above requests, approve/deny the request, and if approved, provide the data to the representative of the TAG Voting Member.

10. INTER-REGIONAL COORDINATION

The Transmission Providers will coordinate with other transmission systems primarily through participation in SERC, other inter-regional study groups, and bilateral agreements between Duke and/or Progress and transmission systems to which they are interconnected.

10.1 Description of SERC Coordination Activities

10.1.1 All transmission providers within SERC coordinate with other interconnected systems in SERC by sharing their modeling data, assumptions, and transmission expansion plans that results from their own regional planning processes. The results of such coordinated efforts will be addressed with the TAG participants.

10.1.2 The Transmission Providers will participate in SERC studies conducted to assess the performance of the interconnected system under both normal and contingency conditions and to assess the ability of the interconnected system to support large power transfers across subregions.

10.1.3 Duke and Progress must abide by SERC's own confidentiality requirements.

10.2 Description of ERAG & SERC-RFC East Coordination Activities

10.2.1 SERC is a Member of the Eastern Interconnection Reliability Assessment Group (ERAG) along with the Florida Reliability Coordinating Council, Inc., the Midwest Reliability Organization, the Northeast Power Coordinating Council, Inc., ReliabilityFirst Corporation, and the Southwest Power Pool. ERAG augments the reliability of the bulk-power system through periodic reviews of generation and transmission expansion programs and forecasted system conditions within the regions served by ERAG members.

10.2.2 The Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group (MMWG) administers the development of a library of power-flow base case models for the benefit of members.

10.2.3 The SERC-RFC East study group was established in 2006 and is a sub-group within the ERAG structure. Through the SERC-RFC East study group, coordination of plans, data and assumptions is achieved between Tennessee Valley Authority, VACAR, and the transmission systems of the eastern portion of PJM.

10.3 Description of VACAR Coordination Activities

10.3.1 The Transmission Providers both participate with Fayetteville, NCEMC, North Carolina Municipal Power Agency #1, North Carolina Eastern Municipal Power Agency, South Carolina Electric & Gas Company, South Carolina Public Service Authority, Southeastern Power Administration, Dominion Virginia Power, and Alcoa Power Generating, Inc. in the VACAR Planning Task Force.

10.3.2 A VACAR contract agreement provides for coordination between the various entities within the VACAR region.

10.3.3 As members of the VACAR Planning Task Force, the Transmission Providers will engage in studies of the bulk power supply system. VACAR typically analyzes the performance of their proposed future transmission systems based on five- or ten-year projections. VACAR studies are similar to those conducted for SERC, but are focused on the VACAR subregion, although VACAR coordinates with Southern and TVA under existing agreements.

10.4 Bilateral Coordination Activities

Through bilateral interconnection agreements or joint operating agreements with the interconnected transmission systems of American Electric Power, TVA, Southern Companies, PJM, Dominion, SCE&G, Santee Cooper, and Yadkin, Duke and Progress perform coordinated studies on an as-needed basis.

10.5 Description of Southeast Inter-Regional Participation Process Activities

10.5.1 Duke and Progress have joined with a group of southeast utilities to develop the Southeast Inter-Regional Participation Process. This process provides valid stakeholders the ability to request economic studies that would be evaluated on an inter-regional basis. The framework for this process is provided in a document entitled "Southeast Inter-Regional Participation Process" which is attached as Appendix 1. The purpose of the Southeast Inter-Regional Participation Process is to facilitate the development of inter-regional economic planning studies.

11. INTEGRATED RESOURCE PLANNING

In addition to the NCTPC Process, the Transmission Providers must abide by state laws regarding Integrated Resource Planning (IRP). The information provided below is intended to assist persons who may want to participate in state IRP and siting proceedings.

11.1 North Carolina

North Carolina Utilities Commission (NCUC) analyzes the probable growth in the use of electricity and the long-range need for future generating capacity in North Carolina. Duke and Progress annually furnish the NCUC a report of their respective resource plans, which contain a ten-year forecast of loads and generating capacity. The report describes all generating facilities and known transmission facilities with operating voltage of 161 kV or more which, in the judgment of the utility, will be required to supply system demands during the 10-year forecast period. Such filings must include a section containing a comprehensive analysis of their Demand-Side Management (DSM) plans and activities.

11.2 South Carolina

Section 58-37-40 of the South Carolina Code of Laws requires that all electrical utilities prepare integrated resource plans and submit them to the State Energy Office. The plans must be submitted every three years and must be updated on an annual basis. For electrical utilities subject to the jurisdiction of the SC PSC, submission of the IRP plans required by the SC PSC (which similarly are submitted triennially and updated at least annually) constitutes compliance with the state law. The SC PSC requires that the plans submitted cover 15 years and evaluate the cost effectiveness of supply-side and demand-side options in an economic and reliable manner that considers relevant costs and benefits.

12. LOCAL PLANNING

The Transmission Providers coordinate with their network and native load customers to ensure adequate and reliable electric service to all points of delivery within their control areas. The focus of the NCTPC is planning higher-voltage facilities and transfers of bulk power and thus "local planning" focuses on lower-voltage facilities and the delivery of energy to customer locations. Customer meetings may be held, when necessary, to discuss the respective plans of the customer and the provider and how such plans impact local areas. Any local area plans developed by a Transmission Provider are rolled into the power system models of the transmission providers and these models subsequently roll up to the NCTPC transmission

models. The same data and assumptions would be used in local planning as are used in the NCTPC Process.

Appendix 1
Southeast Inter-Regional Participation Process

November 30, 2007

Introduction:

In an effort to more fully address the regional participation principle outlined in the Order 890 Attachment K Tariff requirements and the related guidance contained in the FERC Transmission Planning Process Staff White Paper (dated August 2, 2007), this Southeast Inter-Regional Participation Process expands upon the existing processes for regional planning in the Southeast. This document outlines an inter-regional process among various Southeastern interconnected transmission owners. The inter-regional process described herein is incorporated into each Participating Transmission Owner's[6] planning process and OATT Attachment K (for those transmission owners that have a regulatory requirement to file an Attachment K).

Purpose:

This inter-regional process complements the regional planning processes developed by the Participating Transmission Owners in the Southeast. For the purpose of this document, the term "Southeast Inter-Regional Participation Process" ("SIRPP") is defined as a new process to more fully address the regional participation principle of Order 890 for multiple transmission systems in the Southeast. The term "Regional Planning Processes" refers to the regional transmission planning processes a Transmission Owner has established within its particular region for Attachment K purposes. Importantly, the Economic Planning Studies discussed herein are hypothetical studies that do not affect the transmission queue for purposes of System Impact Studies, Facilities Studies, or interconnection studies performed under other portions of the OATT.

Current Inter-Regional Planning Process:

Each Southeastern transmission owner currently develops a transmission plan to account for service to its native load and other firm transmission service commitments on its transmission system. This plan development is the responsibility of each transmission planner individually and does not directly involve the Regional Reliability Organization (e.g. SERC). Once developed, the Participating Transmission Owners collectively conduct inter-regional reliability transmission assessments, which include the sharing of the individual transmission system plans, providing information on the assumptions and data inputs used in the development of those plans and assessing whether the plans are simultaneously feasible.

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6 The sponsors of the Southeast Inter-Regional Participation Process are referred to as transmission owners, rather than transmission providers, because not all of the sponsors are "Transmission Providers" for purposes of the *pro forma* OATT.

Participating Transmission Owners:

Due to the additional regional planning coordination principals that have been announced in Order 890 and the associated Transmission Planning White Paper, several transmission owners have agreed to provide additional transmission planning coordination, as further described in this document. The "Participating Transmission Owners" are listed on the SIRPP website (http://www.southeastirpp.com):

Southeast Inter-Regional Participation Process:

The Southeast Inter-Regional Participation Process is outlined in the attached diagram. As shown in that diagram, this process will provide a means for conducting stakeholder requested Economic Planning Studies across multiple interconnected systems. In addition, this process will build on the current inter-regional, reliability planning processes required by existing multi-party reliability agreements to allow for additional participation by stakeholders.

The established Regional Planning Processes outlined in the Participating Transmission Owners' Attachment Ks will be utilized for collecting data, coordinating planning assumptions, and addressing stakeholder requested Economic Planning Studies internal to their respective regions. The data and assumptions developed at the regional level will then be consolidated and used in the development of models for use in the Inter-Regional Participation Process. This will ensure consistency in the planning data and assumptions used in local, regional, and inter-regional planning processes.

These established Attachment K processes may also serve as a mechanism to collect requests for inter-regional Economic Planning Studies by a participant's stakeholders group. The Economic Planning Studies requested through each participant's Attachment K process that involve impacts on multiple systems between Regional Planning Processes will be consolidated and evaluated as part of the Southeast Inter-Regional Participation Process. Stakeholders will also be provided the opportunity to submit their requests for inter-regional Economic Planning Studies directly to the Inter-Regional process.

The Participating Transmission Owners recognize the importance of coordination with neighboring (external) planning processes. Therefore, seams coordination will take place at the regional level where external regional planning processes adjoin the Southeast Inter-Regional Participation Process (e.g. Southeastern Regional Planning Process coordinating with FRCC Regional Planning Process, Entergy coordinating with SPP, TVA coordinating with MISO and PJM, and the North Carolina Transmission Planning Collaborative coordinating with PJM). External coordination is intended to include planning assumptions from neighboring processes and the coordination of transmission enhancements and stakeholder requested Economic Planning Studies to support the development of simultaneously feasible transmission plans both internal and external to the Southeast Inter-Regional Participation Process.

With regard to the development of the stakeholder requested inter-regional Economic Planning Studies, the Participating Transmission Owners will each provide staff (transmission planners) to serve on the study coordination team. The study coordination team will lead the development of study assumptions (and coordinate with stakeholders, as discussed further below), perform model development, and perform any other coordination efforts with stakeholders and impacted external planning processes. During the study process, the study coordination team will also be

responsible for performing analysis, developing solution options, evaluating stakeholder suggested solution options, and developing a report(s) once the study(ies) is completed. Once the study(ies) is completed, the study coordination team will distribute the report(s) to all Participating Transmission Owners and the stakeholders.

With regard to coordinating with stakeholders in the development of the inter-regional Economic Planning Study(ies), in each cycle of the Southeast Inter-Regional Participation Process, the Participating Transmission Owners will conduct the "1st Inter-Regional Stakeholder Meeting", as shown in the attached diagram. At this meeting, a review of all of the Economic Planning Study(ies) submitted through the participants' Regional Planning Processes or directly to the Inter-Regional process, along with any additional Economic Planning Study requests that are submitted at this 1st meeting, will be conducted. During this meeting, the stakeholders will select up to five studies that will be evaluated within the planning cycle. The study coordination team will coordinate with the stakeholders regarding the study assumptions underlying the identified stakeholder requested inter-regional Economic Planning Study(ies). Through this process, stakeholders will be provided an opportunity to comment and provide input regarding those assumptions. Following that meeting, and once the study coordination team has an opportunity to perform its initial analyses of the inter-regional Economic Planning Study(ies), the Participating Transmission Owners will then conduct the "2nd Inter-Regional Stakeholder Meeting." At this meeting, the study coordination team will review the results of such initial analysis, and stakeholders will be provided an opportunity to comment and provide input regarding that initial analysis. The study coordination team will then finalize its analysis of the inter-regional study(ies) and draft the Economic Planning Study(ies) report(s), which will be presented to the stakeholders at the "3rd Inter-Regional Stakeholder Meeting." Stakeholders will be provided an opportunity to comment and provide input regarding the draft report(s). Subsequent to that meeting, the study coordination team will then finalize the report(s), which will be issued to the Participating Transmission Owners and stakeholders.

In addition to performing inter-regional Economic Planning Studies, the Southeast Inter-Regional Participation Process will also provide a means for the Participating Transmission Owners to review, at the Southeast Inter-Regional Participation Process stakeholder meetings, the regional data, assumptions, and assessments that are then being performed on an inter-regional basis.

Southeast Inter-Regional Participation Process Cycle:

The Southeast Inter-Regional Participation Process will be performed annually. Due to the expected scope of the requested studies and size of the geographical region encompassed, the Participating Transmission Owners will perform up to five (5) inter-regional Economic Planning Studies annually, which could encompass both Step 1 and Step 2 evaluations. A Step 1 evaluation will consist of a high level screen of the requested transfer and will be performed during a single year's planning cycle. The high level screen will identify transfer constraints and likely transmission enhancements to resolve the identified constraints. The Participating Transmission Owners will also provide approximate costs and timelines associated with the identified transmission enhancements to facilitate the stakeholders' determination of whether they have sufficient interest to pursue a Step 2 evaluation. Once a Step 1 evaluation has been completed for a particular transfer, the stakeholders have the option to request a Step 2 evaluation for that transfer to be performed during the subsequent year's Inter-Regional Participation Process Cycle. If the stakeholders opt to not pursue Step 2 evaluation for the

requested transfer during the subsequent year's Inter-Regional Participation Process Cycle, an Economic Planning Study of that request may be re-evaluated in the future by being submitted for a new Step 1 evaluation. In the event that the stakeholders request a Step 2 evaluation, the Participating Transmission Owners will then perform additional analysis, which may include additional coordination with external processes. The Participating Transmission Owners will then develop detailed cost estimates and timelines associated with the final transmission enhancements. The Step 2 evaluation will ensure that sufficient coordination can occur with stakeholders and among the impacted Participating Transmission Owners. In addition, the Step 2 evaluation will provide sufficient time to ensure that the inter-regional study results are meaningful and meet the needs of the stakeholders.

It is important to note that the Participating Transmission Owners expect that a Step 2 evaluation will be completed prior to interested parties requesting to sponsor transmission enhancements identified in an Economic Planning Study. However, the Participating Transmission Owners will work with stakeholders if a situation develops where interested parties attempt to sponsor projects identified in a Step 1 evaluation and there is a compelling reason (*e.g.* where time is of the essence).

Inter-Regional Cost Allocation:

The cost allocation for Inter-Regional Economic Upgrade projects will be determined by each region in which the construction of such upgrades (in whole or in part) would occur.

Inter-Regional Coordination of Economic Transmission Project Development:

Once an Economic Planning Study report has been finalized, multiple stakeholders may be interested in jointly participating in the project development. An Inter-Regional process addressing each such economic upgrade request will be developed that will formalize the process of determining if there is sufficient stakeholder interest to pursue economic project development and the coordination that will be required of the impacted Transmission Owners to support this process. The Participating Transmission Owners and the stakeholders will support this process development activity beginning in 2008.

Stakeholder Participation in the Southeast Inter-Regional Participation Process:

Purpose
The purpose of the Southeast Inter-Regional Participation Process Stakeholder Group (SIRPPSG) is to provide a structure to facilitate the stakeholders' participation in the Southeast Inter-Regional Participation Process. Importantly, the SIRPPSG shall have the flexibility to change the "Meeting Procedures" section discussed below but cannot change the Purpose, Responsibilities, Membership, or Data and Information Release Protocol sections absent an appropriate filing with (and order by) FERC to amend the OATT.

Responsibilities
In general, the SIRPPSG is responsible for working with the Participating Transmission Owners on Inter-Regional Economic Planning Study requests so as to facilitate the development of such studies that meet the goals of the stakeholders. The specific responsibilities of this group include:

1. Adherence to the intent of the FERC Standards of Conduct requirements in all discussions.
2. Develop the SIRPPSG annual work plan and activity schedule.
3. Propose and select the Economic Planning Study(ies) to be evaluated (five annually).
    a. Step 1 evaluations
    b. Step 2 evaluations
4. Provide timely input on the annual Economic Planning Study(ies) scope elements, including the following:
    a. Study Assumptions, Criteria and Methodology
    b. Case Development and Technical Analysis
    c. Problem Identification, Assessment and Development of Solutions (including proposing alternative solutions for evaluation)
    d. Comparison and Selection of the Preferred Solution Options
    e. Economic Planning Study Results Report.
5. Providing advice and recommendations to the Participating Transmission Owners on the Southeast Inter-Regional Participation Process.

Membership

The SIRPPSG membership is open to any valid stakeholder in the SIRPP. For the SIRPP a valid stakeholder is defined as any Eligible Customer, generation owner/development company, state or federal agency, and any organization capable of providing Ancillary Services under one of the Participating Transmission Owners' OATTs. In addition, any Transmission Owner, Transmission Operator, or Transmission Planner as those terms or their successors are used under the NERC Functional Model, as may be amended from time to time, are eligible to be stakeholders under this SIRPP. Authorized agents of the above identified stakeholder organizations will also be permitted to represent those organizations in the SIRPP. Any individual wishing to become an SIRPPSG member can make an application for membership on the SIRPP website (http://www.southeastirpp.com). On the application for SIRPPSG membership, the applicant must provide their name, their organization affiliation, and an explanation of how they meet at least one of the categories listed in the above valid stakeholder definition.

Meeting Procedures

The SIRPPSG may change the Meeting Procedures criteria provided below pursuant to the voting structure in place for the SIRPPSG at that time. The currently effective Meeting Procedures for the SIRPPSG shall be provided to the Participating Transmission Owners to be posted on the SIRPP website and shall become effective once posted on that website (http://www.southeastirpp.com), which postings shall be made within a reasonable amount of time upon receipt by the Transmission Owners. Accordingly, the following provisions contained under this Meeting Procedures heading provide a starting-point structure for the SIRPPSG, which the SIRPPSG shall be allowed to change.

Meeting Chair

A stakeholder elected member of the SIRPPSG will chair the SIRPPSG meetings and serve as a facilitator for the group by working to bring consensus within the group. In addition, the duties of the SIRPPSG chair will include:

1. Developing mechanisms to solicit and obtain the input of all interested stakeholders related to inter-regional Economic Planning Studies.

2. Ensuring that SIRPPSG meeting notes are taken and meeting highlights are posted on the SIRPP website (http://www.southeastirpp.com) for the information of the participants after all SIRPPSG meetings.

Meetings
Meetings of the SIRPPSG shall be open to all SIRPPSG members interested in inter-regional Economic Planning Studies across the respective service territories of the Participating Transmission Owners. There are no restrictions on the number of people attending SIRPPSG meetings from any organization.

Quorum
Since SIRPPSG membership is open to all valid stakeholders, there are no quorum requirements for SIRPPSG meetings.

Voting
In attempting to resolve any issue, the goal is for the SIRPPSG to develop consensus solutions. However, in the event consensus cannot be reached, voting will be conducted with each SIRPPSG member's organization represented at the meeting (either physically present or participating via phone) receiving one vote. The SIRPPSG chair will provide notices to the SIRPPSG members in advance of the SIRPPSG meeting that specific votes will be taken during the SIRPPSG meeting. Only SIRPPSG members participating in the meeting will be allowed to participate in the voting. No proxy votes will be allowed. During each SIRPP cycle, the SIRPPSG members will propose and select the inter-regional Economic Planning Studies that will be performed during that particular SIRPP cycle. The SIRPPSG will annually select up to five (5) inter-regional Economic Planning Studies, including both Step 1 evaluation(s) and any Step 2 evaluations, with any such Step 2 evaluations being performed for the previous years Step 1 studies for the pertinent transfers. Each organization represented by their SIRPPSG members will be able to cast a single vote for up to five Economic Planning Studies that their organization would like to be studied within the SIRPP cycle. If needed, repeat voting will be conducted until there are clear selections for the five Economic Planning Studies to be conducted.

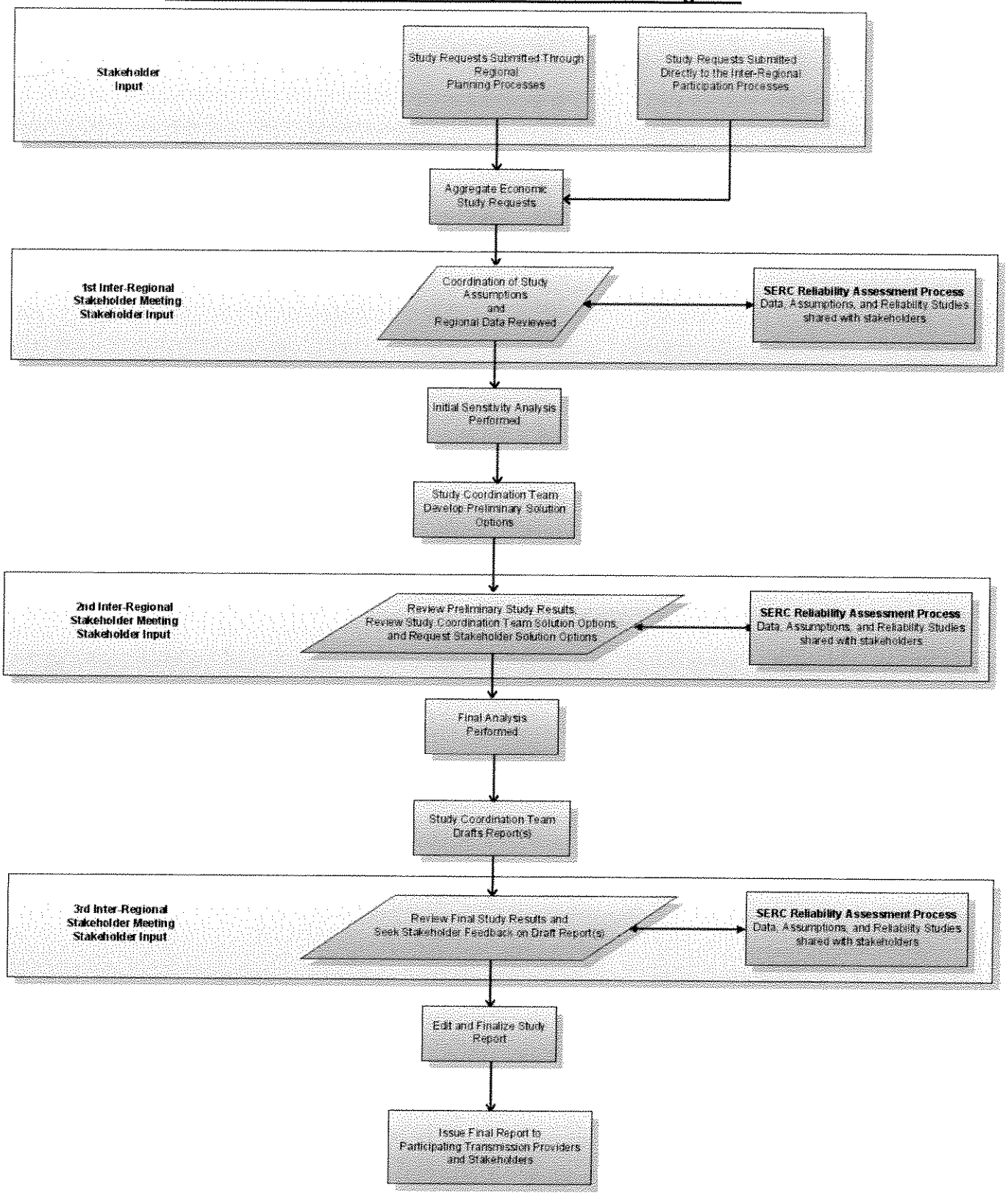
Meeting Protocol
In the absence of specific provisions in this document, the SIRPPSG shall conduct its meetings guided by the most recent edition of *Robert's Rules of Order, Newly Revised.*

Data and Information Release Protocol
SIRPPSG members can request data and information that would facilitate their ability to replicate the SIRPP inter-regional Economic Planning studies while ensuring that CEII and other confidential data is protected. The following outlines the process the SIRPPSG members would use to obtain the data and information.

1. Request and obtain from FERC the FERC Form No. 715 data (that includes CEII data) for the Participating Transmission Owners, where applicable.
2. Have a current SERC Confidentiality Agreement in place.
3. Have a current SIRPP Confidentiality Agreement in place.
4. Formally request the data on the SIRPP website (http://www.southeastirpp.com) with attestations that they have fulfilled the above 3 steps.

The SIRPP Participating Transmission Owners will process the above requests, approve/deny the request, and if approved, provide the data to the SIRPPSG member.

Southeast Inter-Regional Participation Process Diagram:



ATTACHMENT C

NCTPC PARTICIPATION AGREEMENT

FIRST REVISED
NORTH CAROLINA TRANSMISSION PLANNING COLLABORATIVE
PARTICIPATION AGREEMENT

This Participation Agreement ("Agreement") dated this 20th day of May, 2005, as revised this __ day of _____, 2007, is entered into by and among: Duke Energy Carolinas, LLC ("Duke"); Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. ("Progress"); North Carolina Electric Membership Corporation ("NCEMC"); and ElectriCities of North Carolina, Inc. ("ElectriCities"), each of which may hereinafter be referred to singularly as a "Participant" and collectively as "Participants".

RECITALS

WHEREAS, as a result of a review of issues concerning the adequacy of electric transmission infrastructure facilitated by the North Carolina Utilities Commission (the "Commission"), Duke, Progress, ElectriCities, acting for and on behalf of its member municipalities serving retail North Carolina customers, and NCEMC, acting for and on behalf of the electric cooperatives serving retail North Carolina customers, all being geographically located in the control areas of Duke and/or Progress, desire by entering into this Agreement to create and implement a collaborative electric transmission planning process for their respective service territories in North Carolina and South Carolina (the "Process"); and

WHEREAS, in order to create and implement the Process each Participant is willing to: (i) share confidential and proprietary transmission, load forecasts and other information with other Participants to the extent required to implement the Process; (ii) protect all such confidential and proprietary information from disclosure to the public, as provided herein, and to each Participant's marketing and/or brokering employees and representatives consistent with the Federal Energy Regulatory Commission's Standards of Conduct and Codes of Conduct; (iii) pay its fair share of the administrative costs to implement the Process; and (iv) cooperate in good faith with all other Participants to accomplish the goals of the Process and reach mutually acceptable resolution of transmission planning issues so as to minimize the need to initiate regulatory proceedings to resolve transmission adequacy issues; and

WHEREAS, the Participants desire to create an Oversight Steering Committee ("OSC") and a Planning Working Group ("PWG"), each of which will be organized and operated pursuant to the provisions of this Agreement to perform much of the work to create and implement the Process; and

WHEREAS, the Participants, through the OSC, desire to select an independent third party consultant ("ITP") to act as a facilitator for the development and conduct of the Process, including the solicitation of input from other stakeholders through the Transmission Advisory Group; and

WHEREAS, the Participants desire that the functions of the OSC and PWG be carried out in an atmosphere of full and complete cooperation and disclosure, but one which also protects the confidential and proprietary nature of the information made available to each Participant, the OSC, the PWG and the ITP as provided herein;

NOW THEREFORE, in consideration of the foregoing, the undertakings set forth herein and such other good and valuable consideration, the receipt and adequacy of which is hereby acknowledged, the Participants agree as follows:

1. **Intent of the Participants.** The Participants will exert reasonable best efforts to create and implement the Process as described herein. The objectives of the Process are to:

    a. provide load-serving entities that are served from the Duke or Progress transmission systems an opportunity to fully participate in the electric transmission planning process;

    b. preserve the integrity of the current reliability and least-cost integrated resource planning process utilized to plan the expansion of the Duke and Progress (sometimes hereinafter collectively referred to as the "investor-owned utilities") transmission systems, which process shall be known as the "Reliability Planning Process;"

    c. expand the transmission planning process to include analysis and consideration of: (i) increased transmission import capability to provide

greater access to generation resources outside the investor-owned utilities' control areas; (ii) potential enhancements to the Duke and Progress transmission systems in order to enhance access to generation resources within the existing control areas for which there are no existing contractual arrangements; and (iii) increased transmission capability to provide for transactions that go through or out of the investor-owned utilities' control areas to an external control area, which together shall be known as the "Enhanced Transmission Access Planning Process";

d. integrate the Reliability Planning Process and the Enhanced Transmission Access Planning Process for the areas that are served by the Participants for the purpose of ultimately developing a single coordinated transmission expansion plan that appropriately balances costs, benefits and risks associated with the use of transmission and generation resources;

e. create the OSC, consisting of representatives from the participating investor-owned utilities, municipalities and electric cooperatives and the ITP, as provided for herein and in the document entitled "Scope – Oversight/Steering Committee (OSC)" (the "OSC Scope Document");

f. create the PWG, consisting of representatives from the participating investor-owned utilities, municipalities and electric cooperatives and the ITP, as provided for herein and in the document entitled "Scope – Planning Working Group (PWG)" (the "PWG Scope Document");

g. fulfill the direction of FERC Order 888-A that "network service is founded on the notion that the transmission provider has a duty to plan and construct the transmission system to meet the present and future needs of its native load and, by comparability, its third-party network customers";

h. fulfill the direction of FERC Order 890 that "to represent good utility practice and provide comparable service, the transmission planning process under the pro forma OATT must consider both reliability and economic considerations";

i fulfill the direction of FERC Order 890 to implement a coordinated and regional planning process that complies with the planning principles set forth by FERC; and

j. fulfill the direction of N.C. Gen. Stat. §62-110.1(c) and North Carolina Utilities Commission Rule R8-60, in expanding the integrated resource planning process required of the utilities and electric cooperatives by providing for the results of the Process to be considered in the annual resource plans which are reviewed by the Commission, and assist the Commission in fulfilling its responsibilities to develop, publicize and keep current an analysis of the long-range needs for electricity of the citizens of North Carolina.

2. **The Oversight/Steering Committee:** The OSC will consist of eight (8) appointed members plus ex officio members as approved by the OSC. Duke, Progress, ElectriCities and the electric cooperatives shall each appoint two (2) members to the OSC and may each appoint up to two (2) alternate members, all of whose qualifications shall be materially consistent with the guidelines for OSC membership set forth in the OSC Scope Document. The alternates shall act in the absence of the appointed members, including participating in voting. The appointed members of the OSC shall select a chair and vice-chair pursuant to the procedures contained in the OSC Scope Document. Additionally, the appointed members of the OSC shall select the ITP and a representative from the ITP to be an ex officio member of the OSC (the "ITP Member"). The ITP Member shall act as a facilitator for the OSC and shall assist the chair and vice-chair in the performance of their duties as reasonably requested. The members of the OSC shall use reasonable good faith efforts to reach decisions via consensus. However, in the event that the OSC is unable to reach a decision by consensus then a decision will be reached by majority vote. When voting is conducted, each of the OSC members (or designated alternates) except the ex officio members shall have one vote. In the event of a tie vote, the ITP Member shall be entitled to one vote to break the tie. However, notwithstanding any other provisions herein, the investor-owned utilities shall not be bound by decisions of the OSC to the

extent each of the investor-owned utilities reasonably determine such decisions, as related to reliability planning, are inconsistent with good utility practice or SERC and NERC established criteria or least-cost integrated resource planning principles. The investor-owned utilities shall each retain decision making authority for such decisions related to reliability planning consistent with their statutory responsibilities for reliability, subject to normal regulatory oversight.

3. **OSC Duties:** As detailed in the OSC Scope Document, the duties of the OSC shall be to:

   a. review and approve transmission planning criteria and critical assumptions for the bulk transmission system (i.e., 230 kV facilities and above plus lower voltage facilities that substantively affect the Reliability Planning Process and the Enhanced Transmission Access Planning Process) and, where appropriate, develop and recommend such criteria and assumptions to be used by the PWG; provided that each transmission owner may reject any such criteria, critical assumption or recommendation if (i) it determines, in good faith, that such recommendation is not consistent with SERC and NERC established criteria, including NERC planning standards, or with good utility practice and least-cost integrated resource planning principles; or (ii) if the senior management of such transmission owner rejects such criteria and/or assumptions. In the event of such a rejection, the transmission owner's OSC member shall provide a brief, reasonably descriptive written statement of the reasons for such rejection to the OSC. The OSC shall promote consistency among the planning criteria and critical assumptions used in the Process, provided that in recognition of the differences between transmission systems, (i) the fact that a criterion or assumption differs between participating transmission systems shall not by itself constitute sufficient reason to change such a criterion or assumption; and (ii) the uniform application of any new criteria and/or assumptions to all participating transmission systems shall be determined on a case-by-case basis by the OSC;

b. promote the application of such planning criteria and/or assumptions within the territories served by the Participants;

c. review and recommend revisions to transfer capability, transmission reserve margin (TRM) and capacity benefit margin (CBM) criteria and calculations of the investor-owned utilities for consistency with SERC and NERC established criteria as well as good utility practice; recommend transfer capability, TRM and CBM criteria or methodologies which would be applied consistently in the Process, adjusted as appropriate, to accommodate local conditions that merit special consideration; provided that each transmission owner may reject any such recommendation if (i) it determines, in good faith, that such recommendation is not consistent with SERC and NERC established criteria, including NERC planning standards, or with good utility practice and least-cost integrated resource planning principles; or (ii) if the senior management of such transmission owner rejects such recommendation. In the event of such a rejection, the transmission owner's OSC member shall provide a brief, reasonably descriptive written statement of the reasons for such rejection to the OSC;

d. for the areas served by the Participants, participate in the Reliability Planning Process, and oversee the development of the Enhanced Transmission Access Planning Process consistent with the goals set forth in Paragraph 1 hereof; and

e. direct the activities of and provide oversight for the PWG.

4. **The Planning Working Group:** The PWG will consist of up to twelve (12) members. Duke, Progress, ElectriCities and the electric cooperatives shall each nominate at least one and up to three members to the PWG by written notice to the OSC. The OSC shall approve the nominations of the PWG members so long as they materially meet the guidelines described in the PWG Scope Document. The appointed members of the PWG shall select a chair and a vice-chair pursuant to the procedures contained in the PWG Scope Document. Additionally, the OSC shall appoint a representative from the ITP to the PWG. The PWG shall use reasonable good faith efforts to reach decisions via consensus. However, in the

event the PWG is unable to reach a decision by consensus, the decision will be referred to the OSC for resolution.

5. **PWG Duties:** The PWG shall be responsible, under the general direction of the OSC, for evaluation and administration of the criteria and critical assumptions used in problem identification, solution development and plan compilation in the Reliability Planning Process and the Enhanced Transmission Access Planning Process developed in accordance with the provisions of this Participation Agreement, the PWG Scope Document, and the North Carolina Transmission Planning Collaborative Process document. These documents are on the NCTPC Website. Simulations required by the PWG to discharge said responsibility will be performed by the investor-owned utilities with oversight by the PWG.

6. **Reliability Planning and Enhanced Transmission Access Planning.** The Process shall consist of the integrated application of the Reliability Planning Process and the Enhanced Transmission Access Planning Process. The Reliability Planning Process will involve the creation of a transmission expansion plan based upon reliability requirements for firm load and resource projections. The OSC shall have primary responsibility for the Reliability Planning Process. The Enhanced Transmission Access Planning Process will involve the analysis of potential transmission expansion projects that would provide enhanced access to generation resources and markets inside and outside of the Duke and Progress control areas and to transactions that go through or out of the investor-owned utilities' control areas to an external control area, and the development of corresponding transmission expansion options including the costs and schedules associated with such options. The ITP shall have primary responsibility for the Enhanced Transmission Access Planning Process, subject to oversight by the OSC. The ITP's role in developing the enhanced transmission access options shall include the development of a mechanism to solicit and obtain input through the Transmission Advisory Group ("TAG"). Cost responsibility for transmission projects identified pursuant to the Process is described in the NCTPC Transmission Cost Allocation document that is posted on the NCTPC Website.

7. **Decisions of the OSC:** Subject to the provisions of Paragraphs 2 and 3 above, the Participants will abide by the decisions of the OSC. However, any Participant may request that the North Carolina Utilities Commission Public Staff ("Public Staff") render a non-binding opinion with regard to any disputed decision of the OSC and any decision of the investor-owned utility superseding a decision by the OSC ("Disputed Decision"). Should the parties be unable to resolve the Disputed Decision through such facilitation by the Public Staff, any Participant may seek review of the Disputed Decision by any regulatory or judicial body with jurisdiction over the subject matter of the Disputed Decision.

8. **Definition of Confidential Information:** For purposes of this Participation Agreement, the term "Confidential Information" means any and all information designated by a Participant as proprietary and confidential that is provided to another Participant, the OSC and/or the PWG, and confidential and proprietary information developed by the OSC, the PWG and/or the ITP, whether printed, written, oral, electronic or on software. All transmission information shall be considered "Confidential Information" regardless of whether a Participant has specifically designated it as confidential or proprietary. Notwithstanding the preceding provisions of this paragraph, the term "Confidential Information" shall not include any information that a Participant can demonstrate (a) is or has been independently developed by that Participant, or is lawfully received by that Participant from another source having the right to furnish such information to either; (b) has become generally available to the public without breach of this Participation Agreement by that Participant; or (c) that Participant was rightfully in possession of for some other lawful purpose and without restrictions on its use prior to the time the Participant became involved in the Process.

9. **Obligation of Confidentiality:** The Participants shall not discuss among themselves specific products and/or services made available to them or offered by them, or prices or terms of such products and/or services. If the identity of or other information about specific generation resources is required in order to conduct reliability or enhanced transmission access studies, such information may

be disclosed among the Participants, but shall be masked to the extent reasonably possible. Each Participant shall ensure that all Confidential Information to which it has access shall be kept confidential by the Participant and by its employees, attorneys, accountants, financial advisors, consultants, and in the case of the municipalities and electric co-ops, representatives or members (collectively, "Representatives"), to the extent permitted by law. Among other things, each Participant shall ensure that, except with the prior written consent of the Participant from whom the Confidential Information was obtained, which consent may be withheld in the sole discretion of such Participant, the Confidential Information shall not: (a) be used for any purpose or proceeding whatsoever other than performing duties and/or actions directly related to the Process; (b) be distributed or disclosed in any manner whatsoever except as required by law or as permitted by this Participation Agreement; or (c) be distributed to any Representatives of a Participant who are not, consistent with this Participation Agreement, normally involved with the Process (except to the extent said Representatives require access to the Confidential Information to perform duties or obligations directly related to the Process); or (d) be distributed to any third party except as required by law or as specifically permitted hereunder. However, the receiving Participant may transmit Confidential Information to such Representatives who need to know the Confidential Information for the purposes of the receiving Participant performing its duties and obligations associated with the Process, provided that the Participant and said Representatives comply with the provisions of Paragraph 10 below.

10. **Obligations of Participants and Representatives:** To meet its confidentiality obligations under this Participation Agreement, particularly those set out in Paragraph 9, above, each Participant shall maintain a list of each of its Representatives who have access to Confidential Information. Each such Representative on the list shall be informed of and instructed in the terms of this Participation Agreement by the Participant, instructed by the Participant that they are to comply with those terms and shall acknowledge in writing that they have read this Participation Agreement and understand its terms prior to receiving

access to any Confidential Information. If a Representative of a Participant acts in a manner that results in the Representative breaching the confidentiality terms of this Participation Agreement, the Participant will (a) immediately upon learning of such breach notify the OSC; (b) review its internal policies and procedures to determine the cause of such breach; (c) implement actions reasonably designed to prevent a recurrence of such breach; and (d) promptly notify the OSC as to the cause of such breach and actions taken pursuant to (c).

11. **Ownership of Confidential Information:** All Confidential Information developed or furnished by a Participant shall be and will remain the property of such Participant. All Confidential Information developed or produced by the OSC and/or the PWG shall be and will remain the property of all Participants. Nothing contained in this Participation Agreement shall be construed as granting or conferring upon any Participant any rights by license or otherwise, express or implied, to the Confidential Information.

12. **Disclosures Required by Court Order or Law:** In the event that any Participant receives a request to disclose any or all of the Confidential Information under the terms of (a) a state freedom of information act, public records act or similar statute, (b) the Federal Freedom of Information Act, (c) a valid and effective subpoena or order issued by a court or governmental body or agency having jurisdiction over a Participant, or (d) pursuant to an appropriate request for production of documents in any proceeding before an administrative agency or court having jurisdiction over a Participant, such Participant shall notify all other Participants and the OSC immediately of the existence, terms and circumstances surrounding such a request so that one or more of the Participants may seek an appropriate protective order or take such other action as it deems appropriate to protect against the release of Confidential Information. If the Participant is compelled to disclose any of the Confidential Information, only that portion thereof compelled to be disclosed will be disclosed, and the Participant shall use reasonable best efforts to obtain an order or other reliable assurance that

confidential treatment shall be accorded to the Confidential Information so disclosed.

13. **Remedies.** Each Participant agrees that any threatened or existing violation of the confidentiality provisions of this Participation Agreement would cause the other Participants irreparable harm for which they would not have an adequate remedy at law, and that the other Participants shall be entitled to seek immediate injunctive relief prohibiting such violation. In the event that Confidential Information is disclosed in violation of this Participation Agreement, nothing contained herein shall preclude any Participant from pursuing an action for damages or for enforcement of any other rights or remedies available to them at law or in equity.

14. **Return of Confidential Information:** Upon the written or electronically transmitted request of the Participant from whom the Confidential Information was obtained, all documents, records, materials and similar repositories of Confidential Information, including any and all copies thereof in possession of another Participant obtained by such Participant in the course of performing duties and/or obligations associated with the Process, or obtained by the OSC or PWG, shall be promptly surrendered and delivered to the Participant from whom the Confidential Information was obtained. Confidential Information developed or produced by the OSC and/or the PWG shall be promptly returned to all Participants at such time that the OSC and/or PWG deems it to be appropriate.

15. **Standards/Code of Conduct:** Each Participant shall prohibit the sharing of any Confidential Information with any employee, Representative, and/or organization directly involved in the sale and/or resale of electricity in the wholesale electricity market; prohibit its employees, Representatives, and/or organizations involved directly in the sale and/or resale of electricity in the wholesale electricity market from having access to any Confidential Information; and ensure its employees, Representatives, and/or organizations involved directly in the sale and/or resale of electricity in the wholesale electricity market do not receive preferential treatment

nor a competitive advantage through access to Confidential Information. If any Participant acts in a manner contrary to such rules, inadvertently or otherwise, the Participant will (a) immediately upon learning of such incident notify the OSC; (b) review its internal policies and procedures to determine the cause of such incident; (c) implement actions reasonably designed to prevent a recurrence of such incident; and (d) promptly notify the OSC as to the cause of such incident and actions taken pursuant to (c). A breach of this Paragraph 15 may, subject to a majority vote of the OSC, result in the breaching Participant and its employees and Representatives being prohibited from participating in the Process.

16. **Cost Responsibility:** Each Participant shall bear its individual expenses of participation such as travel expenses. The costs associated with the creation and implementation of the Process, including, but not limited to, the costs associated with the OSC, the PWG, and the ITP, shall be the responsibility of all Participants as outlined below:

a. Costs associated with base reliability studies as defined by the OSC shall be the responsibility of the investor-owned utilities.

b. Costs associated with proposed incremental reliability studies which are approved by the OSC will be allocated among the Participants. Duke and Progress will each be responsible for one-third of such costs, and NCEMC and ElectriCities will each be responsible for one-sixth of such costs. If the OSC does not so approve a proposed incremental reliability study, the requesting party may request that the OSC authorize that the study be performed at the cost of the requesting party or parties, and the OSC shall consider such a request.

c. Costs associated with the ITP will be allocated among the Participants. Duke and Progress will each be responsible for one-third of such costs, and NCEMC and ElectriCities will each be responsible for one-sixth of such costs.

d. Costs associated with enhanced transmission access planning, including a maximum number of enhanced transmission access studies that are selected

during each planning cycle by the TAG Voting Members, will be allocated among the Participants. Duke and Progress will each be responsible for one-third of such costs, and NCEMC and ElectriCities will each be responsible for one-sixth of such costs. If a particular proposed enhanced transmission access study is not selected to be studied by the TAG Voting Members, the requesting TAG participants(s) may request that the study be performed at the cost of the requesting TAG participant(s). The OSC shall consider such a request and grant the request if this additional study can reasonably be accommodated.

e. The results of studies performed pursuant to this Participation Agreement shall be available to all Participants and to the TAG.

17. **Administration of Receipts and Disbursements:**

a. At its first meeting the OSC shall appoint a Participant or a third-party to act as treasurer (provided that such Participant or third-party agrees to serve as treasurer), the appointment of which may be changed by the OSC at any time upon reasonable notice to the Participants. The treasurer may resign upon 90 days written notice to the OSC, and upon such notice the OSC will designate a new treasurer upon reasonable notice to the Participants (provided that such Participant or third-party agrees to serve as treasurer). The treasurer shall receive and disburse funds and carry out such other reasonable responsibilities as the OSC shall establish, including, but not limited to, providing periodic (as defined by the OSC) reports to each of the Participants of all receipts and disbursements.

b. Any Participant may, in good faith, challenge before the OSC the correctness or appropriateness of any costs to be allocated among the Participants or any allocations thereof. Any Participant or third party submitting a bill for which costs are to be allocated shall provide reasonable and customary documentation with the bill. Any revisions or adjustments may be in the form of an adjustment of subsequent bills or refund requests.

18. **Term and Withdrawal from Process.** Participation by the Participants in the Process is voluntary. This Participation Agreement shall have an initial term of two years from the date first above written and may be renewed upon prior agreement of the Participants. The Participants will review the Participation Agreement approximately six months prior to the expiration of the initial term in anticipation of a potential decision to renew this Participation Agreement. Additionally, any Participant shall be free to withdraw from the Process and this Participation Agreement at any time for any reason upon 180 days' prior written notice to the other Participants, provided, however, that any Participant withdrawing from the Process shall continue to be responsible for the payment of all costs of the Process properly allocable to such Participant pursuant to Paragraph 16 that were incurred prior to the effective date of withdrawal, and shall complete all actions and tasks which the Participant is either performing or has agreed to perform as a result of the Process as of the date of such Participant's notice of withdrawal. Additionally, any Participant shall be free to withdraw from the Process and this Participation Agreement at any time upon written notice to the other Participants, if the withdrawing Participant's continued participation is rendered illegal, impossible or inappropriate by action of any regulator of said Participant.

19. **Entire Agreement.** The following documents set forth the entire agreement: the Participation Agreement; the scope documents for the OSC, PWG and TAG; the NC Transmission Planning Collaborative Process document; and the NCTPC Transmission Cost Allocation document. These documents set forth the entire agreement and understanding of the Participants concerning the subject matter hereof, and no representation, promise, inducement or statement of intention not set forth in these documents has been made by or on behalf of any Participant hereto. In the event that the provisions of this Participation Agreement conflict with any of the other listed documents, this Participation Agreement shall control unless otherwise unanimously agreed upon by the OSC.

20. **Severability.** Subject to the provisions of Paragraph 18 hereof, if any provision of this Participation Agreement is held to be illegal, invalid or unenforceable, such provisions shall be fully severable and this Participation Agreement shall be construed as if the illegal, invalid and unenforceable provision had never been a part of this Participation Agreement and the remaining provisions of this Participation Agreement shall be given full force and effect.

21. **Survival.** The restrictions and obligations of this Participation Agreement shall survive any expiration, termination or cancellation of this Participation Agreement and shall continue to bind the Participants and their successors and permitted assigns.

22. **Assignment.** No Participant shall assign any of its rights or delegate any of its duties hereunder to a third party without the prior written consent of all other Participants, such consent not to be unreasonably withheld.

23. **Governing Law.** This Participation Agreement shall be governed by and construed in accordance with the laws of the State of North Carolina.

IN WITNESS WHEREOF, each of the Participants, intending to be legally bound by the provisions of this Participation Agreement, has caused its duly authorized representatives to execute this Participation Agreement as of the date set forth above.

PROGRESS ENERGY CAROLINAS, INC.

By: _____

Title: _____

DUKE ENERGY CAROLINAS, LLC

By: _____

Title: _____

NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION

By: _____

Title: _____

ELECTRICITIES OF NORTH CAROLINA, INC.

By: _____

Title: _____

ATTACHMENT D

NORTH CAROLINA TRANSMISSION PLANNING COLLABORATIVE PROCESS

North Carolina Transmission Planning Collaborative Process

Overview

The purpose of the North Carolina Transmission Planning Collaborative (NCTPC) Process is more fully described in the Participation Agreement. In general, however, the NCTPC Process was established to:

1) provide the Participants (Duke Energy Carolinas, LLC (Duke), Progress Energy Carolinas, Inc. (Progress), North Carolina Electric Membership Corporation and ElectriCities of North Carolina) and other interested parties an opportunity to participate in the electric transmission planning process for the areas of North Carolina and South Carolina served by the Participants,
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,
4) expand the transmission planning process to include analysis of increasing the transmission capability to provide for transactions that go through or out of Duke's and/or Progress' control areas to an external control area, and
5) develop a single coordinated transmission plan for the areas of North Carolina and South Carolina served by the Participants that includes reliability and enhanced transmission access considerations while appropriately balancing costs, benefits and risks associated with the use of transmission, generation, and demand-side resources.

The overall NCTPC Process includes the Reliability Planning and Enhanced Transmission Access Planning (ETAP) Processes, whose studies will be concurrent and iterative in nature. The general scope of these studies is outlined in the attached Appendix. It is expected 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) will manage the NCTPC Process. The Planning Working Group (PWG) will support the development of the NCTPC Process and coordinate the study development. The Transmission Advisory Group (TAG) provides a structure whereby interested parties can participate in the NCTPC process. The scope documents of the OSC, PWG and TAG more fully describe the roles and responsibilities of each of these groups

Figure 1 below illustrates the major steps associated with the NCTPC Process.

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 NCTPC Participants and input from interested parties through the TAG.

The Reliability Planning Process will follow the steps outlined in Figure 1. The OSC will approve the scope of the reliability study, oversee the study analysis being performed by the PWG, evaluate the study results, and approve the final reliability study results. The PWG will coordinate the development of the reliability studies based upon the OSC-approved scope and prepare a report with the recommended transmission reliability solutions. The TAG participates in the Reliability Planning Process by providing timely input on the annual study scope elements associated with the development of the reliability transmission planning process as outlined in the TAG annual work plan.

The final results of the Reliability Planning Process will include summaries of the estimated costs and schedules to provide any transmission upgrades and/or additions needed to maintain a sufficient level of reliability necessary to serve the native load of all Participants. The reliability study results will be reviewed with the TAG. The TAG members are responsible for providing feedback to the OSC on the results.

Enhanced Transmission Access Planning Process

The ETAP Process will evaluate the means to increase transmission access to potential LSE network resources inside and outside the control areas of Duke and Progress as well as evaluate the means to increase transmission capability to provide for transactions that go through, in, or out of Duke and/or Progress.

The ETAP Process will follow the steps outlined in Figure 1. The ETAP Process will begin with the TAG participants proposing scenarios and interfaces to be studied. The proposed scenarios and interfaces will be compiled by the PWG. The PWG will determine if it would be efficient to combine and/or cluster any of the proposed scenarios and will also determine if any of the proposed scenarios are of an inter-regional nature. The OSC will review the PWG analysis, approve the compiled study list, and provide the study list to the TAG. The OSC will direct the TAG participants to submit the inter-regional study requests to the Southeast Inter-Regional Participation Process since those studies would have to be evaluated within that forum.

For the remaining study scenarios that impact the NCTPC region, the TAG Voting Members will select a maximum of five scenarios that will be studied within the current NCTPC planning cycle. TAG Voting Members will be permitted to cast one vote for a maximum of five study scenarios. There may be multiple representatives of TAG Voting Members; however, for voting purposes, each TAG Voting Member can only submit one vote. The top five study scenarios that receive the majority number of votes will be the study scenarios that are selected to be studied within the current NCTPC planning cycle. To be able to vote, the TAG Voting Member must participate in the meeting, either by

being physically present at the meeting or through participation by phone. There will be no charge to the TAG Voting Members for the five studies selected. However, if a particular TAG participant wants the NCTPC to evaluate a scenario that was not chosen by the TAG Voting Members, then that participant's organization can request to have the NCTPC conduct the study. The NCTPC will evaluate this request and will conduct the study if the study can be reasonably accommodated, however the cost of conducting this additional study will be allocated to that specific organization.

The ETAP would include, if requested, the evaluation of Regional Economic Transmission Paths (RETPs) that would facilitate potential regional point-to-point economic transactions, including point-to-point transactions that support the designation of network resources. If the TAG Voting Members request an Initial RETP Study, once that Initial RETP Study is complete, a determination would be made as to whether there is sufficient interest in the project to move the RETP from the "initial study" mode to the establishment of an "Open Season" for the RETP. The Open Season will provide the structure whereby Duke and Progress will be able to process these RETP Point-to Point Transmission Service requests for the entire proposed MW of the RETP from the source control area to the sink control area for the relevant time period. During this Open Season all potential transmission customers would have a 60-day window to put in their request to subscribe to all or a portion of the MW of service being made available along the RETP. RETPs are described in more detail in the document entitled *NCTPC Transmission Cost Allocation.*

The OSC will establish the annual scope of the ETAP study based upon the scenarios selected by the TAG Voting Members (including any changes in the assumptions and study criteria for the studies used in the reliability analysis), oversee the study analysis being coordinated by the PWG, evaluate the study results, and approve the final ETAP study results. The PWG will coordinate the development of the enhanced transmission access studies and prepare a report which will identify recommended transmission solutions that could increase transmission access. The TAG participates in the ETAP Process by providing timely input on the annual study scope elements associated with the development of the economic transmission planning process as outlined in the TAG annual work plan.

The final results of the ETAP Process will include the estimated costs and schedules to provide the increased transmission capabilities. The enhanced transmission access study results will be reviewed with the TAG. The TAG members are responsible for providing feedback to the OSC on the results.

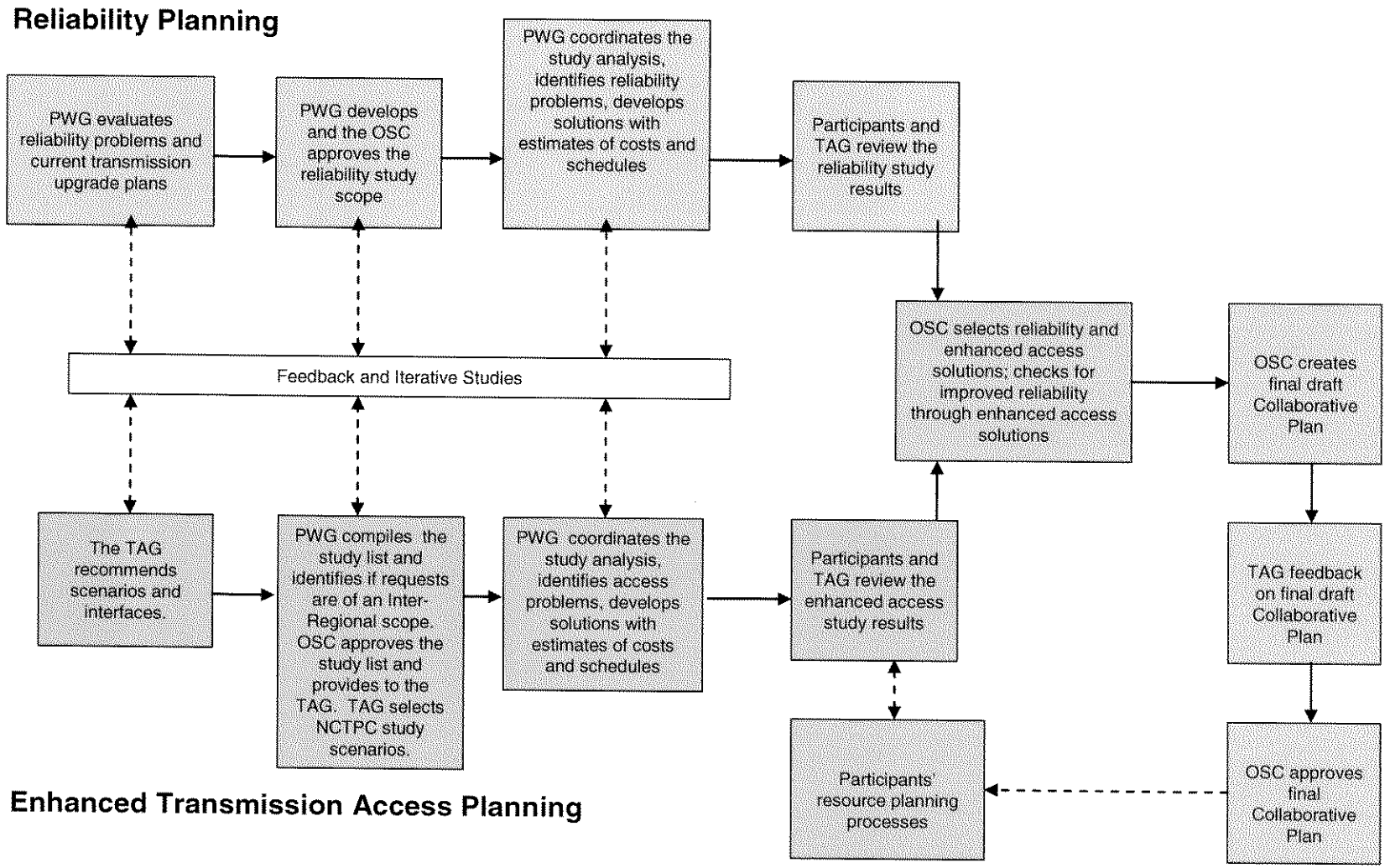
Collaborative Transmission Plan

Once the reliability and ETAP studies are completed, the OSC will evaluate the results and the PWG recommendations to determine if any proposed enhanced transmission access projects, other than RETPs, will be implemented. If so, the initial reliability study will be modified accordingly. As to RETPs, the Open Season determines whether the RETP will move forward. If the RETP is fully subscribed, it would move forward to a Facilities Study stage. After such stage, if it remained fully subscribed, the RETP would

be included in the Collaborative Transmission Plan and Service Agreements will be executed (or filed on an unexecuted basis). This process will result 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 will be reviewed with the TAG.

The Collaborative Transmission Plan information will be available for NCTPC Participants to identify any alternative least cost resources to include with their respective Integrated Resource Plans. Other interested parties can similarly use the information provided within this process to support their business interests.

Figure 1
North Carolina Transmission Planning Collaborative Process Flowchart



Appendix

North Carolina Transmission Planning Collaborative Process

Transmission Planning Study Process - General Scope

The scope of the study processes for both the Reliability Planning and the Enhanced Transmission Access Planning activities are very similar and share many of the same steps such as assumptions, study criteria, methodology, etc.

The typical study process includes the following steps:

1. Assumptions

- Select the study assumptions for the analysis
- The study assumptions normally include the following:
  - Years to study
  - Load levels to be studied (e.g., peak, shoulder and light loads)
  - Load forecasts
  - Resource supply projections
  - Interchange capabilities
  - Firm reservations including TRM / CBM
  - Transmission contingencies
  - Special protection schemes, special operating schemes
  - Financial (e.g., time value of money, financing costs, duration of analysis for present value analyses, etc.)

2. Study Criteria

- Establish the criteria by which the study results will be measured
- The criteria should promote consistency in the planning criteria used by all Participants, while allowing for circumstances that are unique to individual systems
- Typical study criteria involve the following elements:
  - NERC reliability standards
  - SERC Requirements
  - Individual company criteria (voltage, thermal, stability, short circuit, and phase angle)

3. Case Development

- Prepare the base case model
- Develop change case models as required to evaluate different resource supply scenarios

4. Methodology

- Determine the methodologies that will be used to carry out the study
- Determine the specific software programs that will be utilized to perform the analysis

5. Technical Analysis and Study Results

- Perform the study analysis (thermal, voltage, stability and short circuit) and produce the results
  - Study thermal and voltage limits first thermal limits are typically the most difficult to resolve and the most limiting, with voltage issues usually being identified within the same power-flow analyses
  - Study stability and short circuit analysis as needed

6. Assessment and Problem Identification

- Evaluate the results to identify problems / issues. The key questions are:
  - What causes the issues / limits?
  - If the limit were removed or increased, what would the next limit be and what would limit it?

7. Solution Development

- Identify potential solutions to the problems / issues
- Test the effectiveness of the potential solutions through additional studies (thermal, voltage, stability, short circuit) and modify the solutions as necessary such that all study criteria are met
- Perform financial analysis and rough scheduling estimation for each of the proposed transmission solutions (e.g., cost, cash flow, present value)

8. Selection of Preferred Transmission Plan

- Compare alternatives and select the preferred solution alternatives – balancing of cost / benefit / risk

- Select a preferred set of transmission improvements that provides the most reliable and cost effective transmission solution while prudently managing the associated risks

9. Report on the Study Results

- Prepare a report on the results and recommended solutions for the final plan

ATTACHMENT E

SCOPE – OVERSIGHT/STEERING COMMITTEE

Scope – Oversight/Steering Committee (OSC)

Purpose

The OSC manages the NCTPC Participants' Transmission Planning Process.

The duties of the OSC include the following:

a. for the areas of the State of North Carolina and South Carolina served by the NCTPC Participants, participate in the Reliability Planning Process, and oversee the development of the Enhanced Transmission Access Planning Process;

b. review and approve transmission planning criteria and critical assumptions for the bulk transmission system (*i.e.*, 230 kV and above plus lower voltage facilities that substantively affect the Reliability Planning Process and the Enhanced Transmission Access Planning Process) and, where appropriate, develop and recommend such criteria and assumptions to be used by the Planning Working Group (PWG);

c. promote the application of such planning criteria and/or assumptions within the territories served by the NCTPC Participants;

d. review and recommend revisions to the transfer capability, transmission reserve margin (TRM) and capacity benefit margin (CBM) criteria and calculations of the investor-owned utilities for consistency with SERC and NERC established criteria as well as good utility practice; recommend transfer capability, TRM and CBM criteria or methodologies which would be applied consistently in the Process, adjusted as appropriate, to accommodate local conditions that merit special consideration;

e. direct the activities of and provide oversight for the PWG;

f. nominate and approve the PWG members. Duke, Progress, ElectriCities and the electric cooperatives shall each nominate at least one and up to three members to the PWG by written notice to the OSC. The OSC shall approve the nominations of the PWG members so long as they materially meet the membership guidelines described in the PWG Scope Document;

g. Select the independent third-party (ITP) consultant and provide oversight direction of the work of the ITP consultant;

h. Develop an annual business plan with an associated budget each year and monitor budget versus actual expenditures throughout the year;

i. Keep the NCUC and non-LSE stakeholders informed concerning the work undertaken by this process;

Subcommittees

The OSC has the authority to form subcommittees as necessary. A scope document for each subcommittee shall be developed and approved by the OSC before the subcommittee begins its work.

The Planning Working Group will be a standing subcommittee that works under the direction of the OSC and will operate within the parameters as identified within its defined scope of work (*e.g.*, its scope document).

Membership

The OSC will consist of eight (8) appointed members plus ex officio members as approved by the OSC. Duke, Progress, .ElectriCities and the electric cooperatives shall each appoint two (2) members to the OSC and may each appoint up to two (2) alternate members, all of whose qualifications shall be materially consistent with the guidelines for OSC membership set forth in this section. The electric cooperatives and municipalities' industry segments shall establish rules for electing and replacing its representatives to the OSC consistent with the guidelines provided in this section. The ITP shall be an ex officio member of the OSC.

1. **OSC & ITP Membership Guidelines**

   a) Possess a broad knowledge of transmission grid planning, system operations and resource planning including the following:
      i) Understanding of the process for load serving entities to acquire resources and request proposals for capacity and energy
   b) Broad understanding of electric industry and utility issues
   c) Possess a reasonable understanding of NERC and SERC Planning Standards and good utility practices
   d) Possess a reasonable understanding of FERC regulations and OATT requirements including the following:
      i) FERC Standards of Conduct and Code of Conduct
      ii) Processes for Requesting Transmission Service
      iii) Processes for Requesting Interconnection Service
   e) Possess a reasonable understanding of interregional study processes and results
   f) Possess a reasonable understanding of transfer capability, TRM, CBM principles
   g) Possess a reasonable understanding of the state regulatory process including the following:
      i) Integrated Resource Plans (IRP) process
      ii) Transmission siting approval process
   h) Ability to comply with Standards of Conduct requirements stated in the Participation Agreement/no involvement in market activities
   i) Authority to speak and vote on their company's behalf

2. **Changes in OSC Membership**
   Changes in the OSC membership may be made by the industry segment making the change providing written notification of the change to the OSC chair. The industry segment making the change is responsible for providing a replacement representative from their industry segment.

Membership Terms

An OSC member and their alternate will serve on the OSC until replaced through either the election or appointment process in place for their representative segment or until the member or alternate resigns.

The OSC members shall periodically evaluate the performance of the ITP and shall determine if the contract with the consultant should be renewed or if another consultant should be selected.

OSC Committee Structure

The OSC shall select its chair and vice chair from among its members. The term of office for these positions is two years. The officer positions will be rotated among the two participating investor-owned utilities, electric membership cooperatives and municipalities segments (*e.g.*, officer rotation would occur every two years among the four groups).

Committee Chair

In addition to the duties, rights, and privileges discussed elsewhere in this document, the OSC chair has the responsibility to:

- Provide general supervision of OSC activities
- Schedule all OSC meetings
- Prepare, distribute and post notices of OSC meetings, ensure that meeting minutes are recorded, and distribute meeting minutes, as appropriate
- Develop OSC agendas, and rule on any deviation, addition, or deletion from a published agenda
- Preside at OSC meetings
- Manage the progress of all OSC meetings, including the nature and length of discussion, recognition of speakers, motions, and voting
- Act as spokesperson for the OSC
- Report on OSC activities to the NCUC
- Maintain a record of all OSC proceedings, including responses, voting records and correspondence
- Maintain OSC membership records
- Perform other duties as directed by consensus of the OSC members

Committee Vice Chair

The OSC vice chair shall act as the OSC chair if requested by the chair (for brief periods of time) or if the chair, is absent or unable to perform the duties of the chair. If the chair is permanently unable to perform his or her duties, the OSC vice chair shall act as the chair until the OSC selects a new chair.

The vice-chair has the responsibility to:

- Assist the OSC chair
- Perform duties of the OSC chair when the OSC cannot otherwise support these duties

Treasurer

The OSC shall select a Treasurer. The Treasurer may be one of the NCTPC Participants or this function may be outsourced to a third-party. The OSC is authorized to make changes in the designation of the Treasurer as conditions warrant.

The Treasurer has responsibility to:

- Receive and disburse funds
- Periodically disclose all receipts and disbursements to each NCTPC Participant

Committee Members

OSC members have the responsibility to:

- Represent their industry segment
- Provide knowledge and expertise representative of their industry segment
- Provide their industry segment feedback on OSC activities
- Respond promptly to all OSC requests for reviews, comments, and voting
- Arrange for alternates to attend and vote at OSC meetings in their absence
- Respond promptly to all requests regarding scheduling OSC meetings

Independent Third-Party (ITP) Consultant

The ITP has the following general responsibilities:

- Serve as a facilitator for the group by working to bring consensus within the group
- Provide transmission planning expertise
- Provide an independent third-party view
- Assist the Chair and Vice-Chair in the performance of their duties as requested

The ITP also provides the leadership role in developing the Enhanced Transmission Access Planning Process, subject to the oversight of the OSC and normal regulatory oversight. In fulfilling these duties the ITC performs the following:

- Develops the mechanisms to solicit and obtain the input of all TAG participants related to the Enhanced Transmission Access Planning Process.
- Takes all reasonable action to ensure that no member or non-member marketing / brokering organizations receive preferential treatment or achieve competitive advantage through access to transmission-related information.
- Ensures that confidentiality of information and Standards of Conduct requirements are being adhered to within the OSC process.

Meeting Procedures

Meetings

Meetings of the OSC shall be open to OSC members and their alternates, the ITP Member, representatives from voting and authorized non-voting LSEs, approved guests as discussed below, and members of the PWG. Representatives from non-voting LSEs will be authorized to attend these meetings under the following conditions: the LSE serves load within the boundaries of the NCTPC Participants; the LSE has signed the necessary confidentiality agreements and meets FERC's Code of Conduct requirements; and the LSE has provided appropriate prior notice of its intention of sending a representative(s) to a particular meeting.

Only voting members or their alternates may act on items before the OSC.

In the absence of specific provisions in this scope document, the OSC shall conduct its meetings guided by the most recent edition of *Robert's Rules of Order, Newly Revised.*

Quorum

A quorum requires one voting member or their alternate from each of the industry segments represented in this process (*e.g.*, a total of four voting members must be present with one member being from Duke, Progress, ElectriCities, and the electric cooperatives).

Proxy

If an OSC voting member or their alternate is not able to participate in a particular meeting, the OSC voting member, or their alternate may assign their vote to another OSC voting member or their alternate. A written notification of this assignment of the voting privileges must either be provided to the OSC Chair before the meeting or the voting member or alternate that has been given the proxy must provide such written confirmation of this assignment at the beginning of the meeting where the assignment would apply.

Voting

Voting requires a quorum and may take place during formal meetings or may take place through electronic means.

The members of the OSC shall use reasonable good faith efforts to reach decisions via consensus. However, in the event that the OSC is unable to reach a decision by consensus then a decision will be reached by majority vote. When voting is conducted, each of the OSC members (or their designated alternatives) except the ex officio members shall have one vote. In the event of a tie vote, the ITP Member shall be entitled to one vote to break the tie. However, the investor-owned utilities shall not be bound by decisions of the OSC to the extent the investor-owned utilities reasonably determine such decisions, as related to reliability planning, are inconsistent with good utility practice or SERC and NERC established criteria or least-cost integrated resource planning principles. The investor-owned utilities shall each retain decision making authority for such decisions, related to reliability, consistent with their statutory responsibilities for reliability, subject to normal regulatory oversight.

It is anticipated that all parties will abide by the decisions of the OSC. However, any NCTPC Participant may request that the North Carolina Utilities Commission Public Staff ("Public Staff") render a non-binding opinion with regard to any disputed decision of the OSC and any decision of the investor-owned utility superseding a decision by the OSC ("Disputed Decision"). Should the parties be unable to resolve the Disputed Decision through such facilitation by the Public Staff, any NCTPC Participant may seek review of the Disputed Decision by any regulatory or judicial body with jurisdiction over the subject matter of the Disputed Decision.

Each individual member's vote for each action taken shall be included in the minutes of each meeting.

Guests

Guests are permitted to attend OSC meetings with prior approval. If a member of the OSC (or their alternate) would like to invite a guest to a particular OSC meeting, the member/alternate shall submit this request to the Chair of the OSC. The OSC member/alternate shall identify the name and his or her affiliation in the request to the OSC Chair. The OSC Chair may approve the request on their own motion or after consultation with the OSC membership.

ATTACHMENT F

SCOPE – PLANNING WORKING GROUP

Scope – Planning Working Group (PWG)

Purpose

The PWG coordinates the development of the transmission studies needed to support the North Carolina Load Serving Entities' Transmission Planning Process.

The duties of the PWG include the following:

a. develop data inputs for the study simulations;

b. determine the appropriate study simulations to be performed;

c. coordinate the execution of the study simulations (the simulations will be performed by the investor-owned utilities with all aspects overseen by the PWG);

d. analyze study results;

e. prepare recommendations and reports;

f. develop input to the OSC's annual business plan and associated budget and monitor PWG related budget versus actual expenditures throughout the year.

Reporting

The Oversight/Steering Committee (OSC) provides direction to the PWG.

Membership

The Planning Working Group (PWG) will consist of up to twelve (12) members. Duke, Progress, ElectriCities and the electric cooperatives shall each nominate at least one and up to three members to the PWG by written notice to the OSC. The OSC shall approve the nominations of the PWG members so long as they materially meet the membership guidelines described in this section. Additionally, the OSC shall appoint a representative from the Independent Third Party (ITP) to the PWG.

1. **PWG & ITP Membership Guidelines**
   a. BS Electrical Engineering (Power System emphasis – PE registration preferred)
   b. Minimum 3 years transmission planning experience, evaluation of system thermal, voltage & stability performance, and solution development
   c. Possess a general knowledge of transmission grid operations, system operations and resource planning
   d. Working knowledge of PSS-E
   e. Working knowledge of MUST
   f. Possess a detailed understanding of NERC and SERC Planning Standards and good utility practice
   g. Possess a reasonable understanding of FERC regulations and OATT requirements
   h. Understanding of the transmission system model development process
   i. Possess a reasonable understanding of interregional study processes and results
   j. Understanding of transfer capability, TTC, TRM, CBM principles

k. Ability to comply with Standards of Conduct requirements stated in the Participation Agreement/no involvement in market activities
l. Possess a reasonable understanding of the state regulatory process.

2. **Changes in PWG Membership**
Changes in the PWG membership may be made by the industry segment making the change providing written notification of the proposed change to the OSC Chair. The industry segment making the change is responsible for providing a replacement representative from their industry segment. The OSC Chair will seek approval for the change from the OSC members, who will approve the change as long as the replacement representative materially meets the PWG membership guidelines.

Membership Terms
A PWG member will serve on the PWG until either they are replaced by their representative segment or until the member resigns.

PWG Committee Structure

The PWG shall select its chair and vice chair from among its members. The term of office for these positions is two years.

Committee Chair
In addition to the duties, rights, and privileges discussed elsewhere in this document, the PWG chair has the responsibility to:

- Provide general supervision of PWG activities
- Schedule all PWG meetings
- Prepare, distribute and post notices of PWG meetings, ensure that meeting minutes are recorded, and distribute meeting minutes, as appropriate
- Develop PWG agendas, and rule on any deviation, addition, or deletion from a published agenda
- Preside at PWG meetings
- Manage the progress of all PWG meetings, including the nature and length of discussion and recognition of speakers
- Act as the interface to the OSC
- Maintain a record of all PWG proceedings, including responses and correspondence
- Maintain PWG membership records
- Perform other duties as directed by consensus of the PWG members

Committee Vice Chair
The PWG vice chair shall act as the PWG chair if requested by the chair (for brief periods of time) or if the chair is absent or unable to perform the duties of the chair. If the chair is permanently unable to perform his or her duties, the PWG vice chair shall act as the chair until the PWG selects a new chair.

The vice chair has the responsibility to:

- Assist the PWG chair
- Perform duties of the PWG chair when the PWG cannot otherwise support these duties

Committee Members
PWG members have the responsibility to:

- Represent their industry segment
- Provide knowledge and expertise representative of their industry segment
- Provide their industry segment feedback on PWG activities
- Respond promptly to all PWG requests for reviews and comments
- Respond promptly to all requests regarding scheduling PWG meetings

Independent Third-Party (ITP) Consultant
The ITP has the following general responsibilities:

- Serve as a facilitator for the group by working to bring consensus within the group
- Provide transmission planning expertise
- Provide an independent third-party view
- Assist the chair and vice chair in the performance of their duties as requested

The ITP also provides the leadership role in developing the Enhanced Transmission Access Planning Process, subject to the oversight of the OSC and normal regulatory oversight. In fulfilling these duties, the ITP performs the following:

- Develops the mechanisms to solicit and obtain the input of all market participants related to the Enhanced Transmission Access Process.
- Takes all reasonable action to ensure that no member or non-member marketing/brokering organizations receive preferential treatment or achieve competitive advantage through access to transmission-related information.
- Ensures that confidentiality of information and Standards of Conduct requirements are being adhered to within the PWG process.

Meeting Procedures

Meetings
Meetings of the PWG shall be open to PWG members, the ITP Member and OSC members and their alternates. After consulting with the PWG members, the Chair of the PWG has the discretion to invite guests to attend the PWG meeting (or a portion of the meeting as appropriate) provided that those guests execute a confidentiality agreement that is consistent with the confidentially requirements and the Standards of Conduct requirements of the Participation Agreement.

The PWG shall use reasonable good faith efforts to reach decisions via consensus. However, in the event the PWG is unable to reach a decision by consensus, the decision will be referred to the OSC for resolution.

In the absence of specific provisions in this scope document, the PWG shall conduct its meetings guided by the most recent edition of *Robert's Rules of Order, Newly Revised.*

Quorum
A quorum requires at least one member from each of the industry segments represented in this process (e.g. a total of four members must be present with one member being from Duke, Progress, ElectriCities, and the electric cooperatives).

ATTACHMENT G

TRANSMISSION ADVISORY GROUP - SCOPE

Transmission Advisory Group

Scope

Purpose

The Transmission Advisory Group (TAG) is formed from the North Carolina Transmission Planning Collaborative Participation Agreement ("Agreement") among the following Participants: Duke Energy Carolinas, LLC, Progress Energy Carolinas, Inc., North Carolina Electric Membership Corporation, and ElectriCities of North Carolina, Inc. The purpose of the TAG is to provide a structure whereby interested parties can participate in the NCTPC Process.

Responsibilities

In general, the TAG is responsible for working with the NCTPC Participants to develop a transmission planning process that results in a single coordinated transmission plan which reliably and efficiently meets the needs of the electric consumers within the service territory of the NCTPC Participants (portions of North Carolina and South Carolina). The specific responsibilities of the TAG participants include:

1. Adherence to the intent of the FERC Standards of Conduct requirements in all discussions.
2. Participation in the TAG meetings in a constructive and professional manner.
3. Assisting in the development of the TAG annual work plan and activity schedule.
4. Providing timely input on the annual study scope elements of both the Reliability Planning as well as the Enhanced Transmission Access Planning Process which includes the following:
    a. Study Assumptions, Criteria and Methodology
    b. Case Development and Technical Analysis
    c. Problem Identification, Assessment and Development of Solutions (including proposing alternative solutions for evaluation)

d. Comparison and Selection of the Preferred Transmission Plan
e. Transmission Plan Study Results Report.

5. Proposing the enhanced transmission access projects for evaluation.
6. Providing advice and recommendations to the Oversight Steering Committee of the NCTPC Participants on the NCTPC Process.

In addition, TAG Voting Members will select enhanced transmission access projects for evaluation.

Membership and Participation

The TAG is open to the public and any individual may be a TAG participant. In addition, any valid stakeholder in the NCTPC process may become a TAG Voting Member. For purposes of the NCTPC Process, a valid stakeholder is defined as any Eligible Customer, generation owner/generation development company, and any organization capable of providing Ancillary Services under the Duke Energy Carolinas or Progress Energy Carolinas OATTs. In addition, any Transmission Owner, Transmission Operator, or Transmission Planner as those terms or their successors are used under the NERC Functional Model, as may be amended from time to time, are valid stakeholders under this NCTPC Process. Authorized agents of any valid stakeholder organizations will also be permitted to represent a TAG Voting Member in the NCTPC Process. The transmission function of a NCTPC Participant may not be a TAG Voting Member, but the merchant function of an NCTPC Participant may be a TAG Voting Member.

Any TAG participant can register on the NCTPC website to receive email notifications directed at the TAG (www.nctpc.org/nctpc). Any organization seeking to become a TAG Voting Member must submit an application for membership to the NCTPC's Independent Third-Party through the application process on the NCTPC website (www.nctpc.org/nctpc). On the application for TAG Voting Membership, the applicant should provide the name of the TAG Voting Member the primary contact individual, and an explanation of how it meets at least one of the categories listed in the above valid stakeholder definition.

Meeting Procedures

Meeting Chair

The independent third-party consultant will chair the TAG meetings and serve as a facilitator for the group by working to bring consensus within the group. In addition, the duties of the independent third-party consultant include:

1. Developing mechanisms to solicit and obtain the input of all interested parties related to transmission planning options.
2. Taking all reasonable action to ensure that no marketing / brokering organizations receive preferential treatment or achieve competitive advantage through the distribution of any transmission-related information in the TAG.
3. Ensuring that confidentiality of information and Standards of Conduct requirements are being adhered to within the TAG process.
4. Ensuring that TAG meeting notes are taken and meeting highlights are posted for the information of the participants after all TAG meetings.

Meetings

Meetings of the TAG shall be open to anyone interested in the development of a coordinated transmission plan across the respective service territories of the Participants. There are no restrictions on the number of people attending TAG meetings from any organization. The ITP may close a TAG meeting to TAG Voting Member representatives that are permitted to access confidential and/or CEII information, if necessary.

Quorum

There are no quorum requirements for TAG meetings.

Voting

In attempting to resolve issues, the goal is for the TAG to develop consensus solutions. However, in the event consensus cannot be reached, voting will be conducted with each

TAG Voting Member represented at the meeting (either physically present or participating via phone) receiving one vote. The independent third-party will provide notices to the TAG participants in advance of the TAG meeting that specific votes will be taken during the TAG meeting. Only TAG Voting Members participating in the meeting will be allowed to participate in the voting. A single person may represent more than one TAG Voting Member. The selection of the enhanced transmission access studies will always be conducted by a vote.

During each transmission planning cycle, the TAG participants will propose the enhanced transmission access studies that will be performed during that particular planning cycle. Study scenarios that are of an inter-regional nature will be identified during this process and the organization that is responsible for requesting such studies will be directed to forward their study request to the Southeast Inter-Regional Participation Process since the study would have to be evaluated within that forum.

For the remaining study scenarios that impact the NCTPC region, the TAG Voting Members will select a maximum of five scenarios that will be studied within the current NCTPC planning cycle. Each TAG Voting Member will be able to cast a single vote for up to five scenarios that their organization would like to be studied within the NCTPC planning cycle. If needed, repeat voting will be conducted until there are clear winners for the top five study scenarios.

Meeting Protocol

In the absence of specific provisions in this document, the TAG shall conduct its meetings guided by the most recent edition of *Robert's Rules of Order, Newly Revised.*

Data and Information Release Protocol

TAG Voting Members can request data and information that would allow them to replicate the NCTPC planning studies while ensuring that CEII and other confidential

data is protected. The below steps outline the process that representatives of TAG Voting Members would use to obtain the data and information.

1. Been authorized by FERC to obtain from FERC the Form 715 data (that includes CEII data) for both Duke Energy Carolinas and Progress Energy Carolinas.

2. Have a current SERC Confidentiality Agreement in place.

3. Have a current TAG Voting Member Confidentiality Agreement in place.

4. Formally request the data from the NCTPC Independent Third Party (ITP) with attestations that they have fulfilled the above 3 steps.

The NCTPC ITP will process the above requests, approve/deny the request, and if approved, provide the data to the TAG member.

ATTACHMENT H

NCTPC TRANSMISSION COST ALLOCATION

NCTPC TRANSMISSION COST ALLOCATION
(December 7, 2007)

I. COST ALLOCATION REQUIREMENTS OF ORDER NO. 890

In Order No. 890, *Preventing Undue Discrimination and Preference in Transmission Service*, the Federal Energy Regulatory Commission (Commission or FERC) provided the following guidance regarding transmission cost allocation:

1. Transmission Providers must develop cost allocation principles that apply to regional projects that do not fit under the existing open access transmission tariff (OATT) cost allocation structures.

2. Each regional transmission planning process can develop its own cost allocation criteria and solution as long as it follows these three general principles:

   a) Fairly assigns costs to those who caused the problem as well as to those who will benefit from the solution.

   b) Provides adequate incentives to the Transmission Providers to construct.

   c) Generally is supported by the states and participants across the planning region.

3. Each planning process must address the cost allocation principle upfront.

II. SUMMARY OF COST ALLOCATION

Transmission cost allocation typically is governed by the OATT of each Transmission Provider. The NCTPC Participants have developed cost allocation methodologies that apply in special circumstances that are described in this document.

The NCTPC Participants have developed an "avoided cost" cost allocation methodology that applies to reliability projects where there is a demonstration that a regional transmission solution and regional approach to cost allocation results in cost savings. Such "Regional Reliability Projects" are projects that are proposed in lieu of "Reliability Projects," which are projects required to preserve system reliability. The NCTPC Participants also have developed a "requestor pays" cost allocation methodology that applies to Regional Economic Transmission Paths ("RETPs") which improve economic power transfers between control areas. These two cost allocation methodologies apply to projects that are within the scope of the planning performed by the NCTPC, which focuses on the bulk transmission system (i.e., 230 kV and above facilities and lower-voltage facilities that substantively affect the Reliability Planning Process and Enhanced Transmission Access Planning Process).

Please note that for purposes of the following cost allocation discussion, all monetary amounts are net present value (NPV) amounts, unless otherwise noted.

III. OATT COST ALLOCATION FOR RELIABILITY PROJECTS

A transmission system is a complex system where each Transmission Provider's system reliability is also dependent upon its neighboring transmission systems. In recognition of this interdependence, reliability issues affecting one transmission system may require transmission upgrades on an adjacent transmission system. In addition, the reliability needs of a transmission system will change over time as a result of network and native load growth, the addition of new generation resources, the retirement of generation, and the provision of additional long-term firm point-to-point transmission service. FERC's OATT requires that Transmission Providers construct the facilities necessary to maintain reliable service in light of these needs. Any such facilities that are integrated network transmission facilities are denominated "Reliability Projects" herein. The various types of "Reliability Projects" are described briefly below.

A. Generation Interconnection Network Upgrade Projects

Generation interconnection network upgrade projects are Reliability Projects that consist of the integrated transmission facilities required to reliably connect a new generating plant into the transmission system and reliably dispatch its output into the network. For these projects, the upfront costs are allocated to the generation developer in accordance with the OATT, subject to crediting when transmission service is obtained from the relevant resource.

B. Transmission Service Projects

It is each Transmission Provider's responsibility to plan and operate a reliable transmission system in accordance with NERC and its applicable regional reliability standards. Reliability Projects that are required to provide transmission service fall into two categories -- Existing Transmission Service Projects and New Transmission Service Projects.

Existing Transmission Service Projects include the transmission facilities required for maintaining system reliability to serve network and native load and to meet existing firm point-to-point service obligations. As load grows and the existing transmission facilities age, new projects and upgrades may be necessary to ensure reliable service. New Transmission Service Projects include facilities required to fulfill new long-term firm point-to-point transmission requests and projects related to requests to designate new Network Resources.

Currently, for both New and Existing Transmission Service Projects, the Transmission Provider is responsible for incurring those transmission costs and recovering its costs through its transmission revenue requirement under its existing OATT rate structures. For Network Customers, these transmission costs typically are allocated to all Network Load on a load-ratio share. Point-to-point customers pay the higher of a rolled-in rate or an incremental rate.

IV. "AVOIDED COST" COST ALLOCATION METHODOLOGY FOR RELIABILITY PROJECTS THAT QUALIFY AS "REGIONAL RELIABILITY PROJECTS"

A. Identification of Regional Reliability Projects Subject to Avoided-Cost Cost Allocation

While individual Reliability Projects may arguably (and alternately) benefit customers on a neighboring system or may benefit some customers on one system more than others on the same system, the NCTPC believes that Reliability Projects generally benefit all customers within the relevant service territory of the Transmission Provider and that therefore the costs should be allocated in accordance with the "or" pricing policy currently included in the Commission's *pro forma* OATT. The NCTPC, however, recognizes an exception to the general rule that the costs of projects needed for reliability should be allocated to a particular Transmission Provider's customers. Specifically, Regional Reliability Projects, which can be identified through the NCTPC's regional planning process, should have their costs allocated on an avoided-cost basis.

The NCTPC Planning Process results in a set of projects that satisfy the reliability criteria of the Transmission Providers who are a party to the NCTPC agreement (i.e., Reliability Projects). Through this process, a project may be identified that meets a reliability need in a more cost-effective manner than if each Transmission Provider were only considering projects on its system to meet its reliability criteria. For purposes of eligibility, a Regional Reliability Project can be defined as any reliability project that requires an upgrade to a Transmission Provider's system that would not have otherwise been made at that time based upon the reliability needs of the Transmission Provider. For example, assume that there is a reliability issue on the system of Duke, and this issue can be addressed by: Option 1 - a project that consists of upgrades solely on the system of Duke; Option 2 - a project that consists of upgrades solely on the system of Progress; or Option 3 - a project that encompasses upgrades on both the Duke and Progress systems. Options (2) and (3) would qualify as Regional Reliability Projects, if they are lower cost than Option (1). In both cases, there is an upgrade that is not needed to maintain reliability on the transmission system of at least one of the Transmission Provider's whose system is being upgraded. In addition, if accelerating a Reliability Project on the Progress system results in the elimination of an upgrade

on the Duke system, the cost of the acceleration will be designated a Regional Reliability Project. A Regional Reliability Project must have a cost of at least $1 million to be subject to the cost allocation proposal described below. The costs of a Regional Reliability Project with a cost of less than $1 million would be borne by each Transmission Provider based on the costs incurred on its system.

B. Avoided Cost Methodology

As noted, unless a Regional Reliability Project is determined by the NCTPC to be the most cost-effective solution to a reliability need, it will not be selected to be included in the Plan of the NCTPC. But, if a Regional Reliability Project is included, it will have its costs allocated based on an avoided cost approach, whereby each Transmission Provider looks at the next-best approach to maintaining reliable service and shares the savings on a pro-rata basis. These cost responsibility determinations will then be reflected in transmission rates. Each Transmission Provider will be reimbursed for its investment for the Regional Reliability Project based on a transmission levelized fixed charge rate filed with FERC. Where practical, Regional Reliability Projects may be grouped to net out allocations across Transmission Provider borders.

C. Example 1: A Regional Reliability Project on system of one Transmission Provider solves reliability issue on system of other Transmission Provider.

(1) Transmission Provider	(2) Cost to Meet Reliability Needs on a Stand Alone Basis (MM)	(3) Cost of Regional Reliability Project (MM)	(4) Avoided Transmission Project Cost (MM)	(5) Costs to Meet Reliability Needs on a Regional Basis (MM) (2) + (3) - (4) = (5)
Duke	$500	0	$50	$450
Progress	$400	$30	0	$430
Total	**$900**	**$30**	**$50**	**$880**

In this example, Duke needs to spend $500 million to meet all of its Reliability Project needs, assuming it does not have the option of meeting its reliability need with a project on system of Progress. The $500 million includes $50 million for a Reliability Project on its system. But, by Progress spending $30 million on a Regional Reliability Project, Duke

could avoid building that $50 million project. Progress needs to spend $400 million for Reliability Projects on its system to meet its needs. Progress also will spend an additional $30 million on its system to meet the Duke reliability need.

The avoided cost methodology for allocating cost responsibility would apply as follows:

(Duke's Avoided Cost/Total Avoided Cost) * cost of Regional Reliability Project

($50 million/$50 million) * $30 million = $30 million

(Progress Avoided Cost/Total Avoided Cost) * cost of Regional Reliability Project

($0 million/$50 million) * $30 million = $0

In sum, from a cost incurrence perspective, Duke spends $450 million and Progress spends $430 million. But, from a cost responsibility perspective Duke is allocated $30 million of Progress' costs.

D. Example 2: A Regional Reliability Project on system of two Transmission Providers solves reliability issue on system of one Transmission Provider.

(1) Transmission Provider	(2) Cost to Meet Reliability Needs on a Stand Alone Basis (MM)	(3) Cost of Regional Reliability Project (MM)	(4) Avoided Transmission Project Cost (MM)	(5) Costs to Meet Reliability Needs on a Regional Basis (MM) (2) + (3) - (4) = (5)
Duke	$500	$20	$50	$470
Progress	$400	$10	0	$410
Total	**$900**	**$30**	**$50**	**$880**

In this example, Duke needs to spend $500 million to meet all of its Reliability Project needs, assuming it does not have the option of meeting its reliability need with a project on system of Progress. The $500 million includes $50 million for a Reliability Project on its system. But, by Progress spending $10 million on a Regional Reliability Project and Duke spending $20 million on the same project, Duke could avoid building that

$50 million project. Progress needs to spend $400 million for Reliability Projects on its system to meet its needs. Progress also will spend an additional $10 million on its system to meet the Duke reliability need.

The avoided cost methodology for allocating cost responsibility would apply as follows:

(Duke's Avoided Cost/Total Avoided Cost) * cost of Regional Reliability Project

($50 million/$50 million) * $30 million = $30 million

(Progress Avoided Cost/Total Avoided Cost) * cost of Regional Reliability Project

($0 million/$50 million) * $30 million = $0

In sum, from a cost incurrence perspective, Duke spends $470 million and Progress spends $410 million. But, from a cost responsibility perspective Duke is allocated $10 million of Progress' costs.

E. Example 3: A Regional Reliability Project on system of two Transmission Providers solves reliability issues on systems of both Transmission Providers.

(1) Transmission Provider	(2) Cost to Meet Reliability Needs on a Stand Alone Basis (MM)	(3) Cost of Regional Reliability Project (MM)	(4) Avoided Transmission Project Cost (MM)	(5) Costs to Meet Reliability Needs on a Regional Basis (MM) (2) + (3) - (4) = (5)
Duke	$500	$20	$50	$470
Progress	$400	$10	$5	$405
Total	**$900**	**$30**	**$55**	**$875**

In this example, Duke needs to spend $500 million to meet all of its Reliability Project needs, assuming it does not have the option of meeting its reliability need with a project on system of Progress. The $500 million includes $50 million for a Reliability Project on its system. But, by Progress spending $10 million on a Regional Reliability Project and Duke

spending $20 million on the same project, Duke could avoid building that $50 million project. Progress needs to spend $400 million for Reliability Projects on its system to meet its needs. But, as a result of the same Regional Reliability Project, Progress can avoid spending $5 million to meet its own reliability needs.

The avoided cost methodology for allocating cost responsibility would apply as follows:

(Duke's Avoided Cost/Total Avoided Cost) * cost of Regional Reliability Project

($50 million/$55 million) * $30 million = $27.3 million

(Progress Avoided Cost/Total Avoided Cost) * cost of Regional Reliability Project

($5 million/$55 million) * $30 million = $2.7 million

In sum, from a cost incurrence perspective, Duke spends $470 million and Progress spends $405 million. But, from a cost responsibility perspective Duke is allocated $7.3 million of Progress' costs.

F. Example 4: Accelerating a Reliability Project on one Transmission Providers' system solves reliability issues on another Transmission Providers' system.

(1) Transmission Provider	(2) Cost to Meet Reliability Needs on a Stand Alone Basis (MM)	(3) Cost of Regional Reliability Project (MM) (Cost of Acceleration)	(4) Avoided Transmission Project Cost (MM)	(5) Costs to Meet Reliability Needs on a Regional Basis (MM) (2) + (3) - (4) = (5)
Duke	$500	$20	$0	$520
Progress	$400	$0	$50	$350
Total	**$900**	**$20**	**$50**	**$870**

In this example, Duke needs to spend $500 million to meet all of its Reliability Project needs. The $500 million includes $120 million for a Reliability Project on its system. Progress needs to spend $400 million to meet all of its Reliability Project needs, including $50 million for a Reliability Project on its system. However, if Duke accelerates the $120 million project by 5 years, Progress could avoid building its $50 million project. The cost of accelerating the Reliability Project by 5 years is a lower cost solution and thus is designated as a Regional Reliability Project. The cost of the Regional Reliability Project is the cost of the 5-year acceleration of the $120 million Reliability Project, or $20 million, which is calculated by subtracting the NPV of completing the project in 5 years from the NPV of completing the project in 10 years.

The avoided cost methodology for allocating cost responsibility would apply as follows:

(Duke's Avoided Cost/Total Avoided Cost) * cost of Regional Reliability Project

($0 million/$50 million) * $20 million = $0

(Progress Avoided Cost/Total Avoided Cost) * cost of Regional Reliability Project

($50 million/$50 million) * $20 million = $20 million

In sum, from a cost incurrence perspective, Duke spends $520 million and Progress spends $350 million. But, from a cost responsibility perspective Progress is allocated $20 million of Duke's costs.

G. Regional Reliability Projects that Include Transmission Providers Outside the NCTPC Footprint

If a Regional Reliability Project that is suitable for this alternate cost allocation approach involves a Transmission System(s) outside the NCTPC, the costs should be fairly allocated among the affected Transmission Providers based on good-faith negotiation among the parties involved. It would be the intent of the NCTPC Participants that the "avoided cost" approach outlined above be used as a starting point in the negotiations. The resulting transmission costs and the associated revenue requirements of each Transmission Provider will be recovered through their respective existing rate structures at the time. In the event that the affected Transmission Providers are unable to reach a negotiated solution then the NCTPC would propose that the parties utilize the Commission's Dispute Resolution Service to settle any issues.

V. "REQUESTOR PAYS" COST ALLOCATION METHODOLOGY FOR PROJECTS ASSOCIATED WITH REGIONAL ECONOMIC TRANMISSION PATHS ("RETPs")

A. Background

In Order No. 890, FERC asked Transmission Providers to develop a cost allocation methodology intended to apply to economic projects that do not fit under the existing OATT structure and that will reduce congestion or enable groups of customers to access new generation. The NCTPC is not proposing a cost allocation methodology for "economic projects" within a single Transmission Provider's system because there are no internal constraints within the Duke or Progress systems as demonstrated by the fact that ATC values are posted only at their interfaces with other control areas. That is, there is no need for a cost allocation methodology that would apply to projects that relieve constraints within a single Transmission Provider's control area. Thus, the relevant "economic projects" are those projects required to permit Transmission Providers to ensure that point-to-point ("PTP") transmission service can be provided over the systems of two or more Transmission Providers. Such PTP service may in turn be used to support the designation of "external" network resources, i.e., network resources located outside of the control area where the network load is located.

The NCTPC has designated "projects" that would ensure that PTP service can be provided over the Duke and/or Progress systems as Regional Economic Transmission Paths ("RETPs"). NCTPC Transmission Advisory Group ("TAG") participants will propose that RETPs be created and the costs of the projects necessary to create such RETPs will be subject to the "requestor pays" cost allocation methodology described herein. The creation of an RETP would permit energy to be transferred on a PTP basis from an interface (or a Point of Receipt) on one Transmission Provider's system to an interface on another Transmission Provider's system (or a Point of Delivery) for a specific period of time. In the discussion below, the NCTPC Participants define how this methodology could be applied in the NCTPC.

As just noted, RETPs are defined as multi-Transmission Provider point-to-point transmission paths. NCTPC cannot impose the RETP concept and requestor-pays cost allocation methodology discussed below on Transmission Providers outside the NCTPC footprint. However, the NCTPC Participants can work within other forums to attempt to reach coordinated solutions that will work for broader transmission regions. For example, the NCTPC Participants are participating in the Southeast Inter-Regional Participation Process ("SIRPP"). The SIRPP will support the development of a process to determine if there is sufficient stakeholder interest to pursue economic project development and the coordination that will be required of the impacted transmission owners to support such a process beginning in 2008. Therefore, these concepts will be more fully developed within the SIRPP as that process matures.

The NCTPC Participants are amenable to modifying the RETP concepts identified in this document if broader inter-regional solutions to these concepts are adopted. However, it should be noted that a broader inter-regional solution may be developed to support the movement of an economic project from the study phase to a project development phase, but the cost allocation for a particular economic project may be unique to the particular region. Therefore the RETP cost allocation identified in this document may be maintained in the future even if the Open Season type of concepts in this document are revised.

B. Identification and Initial Study of RETPs

It is envisioned that the request to study RETPs would be identified through the relevant stakeholder processes. If an RETP is limited to the NCTPC footprint, the relevant study request will be made through the Transmission Advisory Group ("TAG") process. The SIRPP stakeholder process will have a similar process for the identification of projects that would impact that regional footprint.

There would be a need for an Initial Study of an RETP ("Initial RETP Study"). If a proposed regional path would impact Transmission Providers outside the

NCTPC that are not willing to participate in a uniform RETP process, there will need to be coordination of such an initial study with other transmission neighbors.. Because it cannot be predicted which Transmission Providers outside the NCTPC might consider the RETP approach, the discussions herein of the study process, Open Season, and cost allocation largely assume that the RETP concept will spread beyond the NCTPC. This assumption is merely for convenience.

The Initial RETP Study would identify any transmission system problems/limitations related to all Transmission Providers along the RETP providing PTP service and would identify the transmission solutions/upgrades that would be needed to accommodate the RETP. An RETP would be evaluated in the Initial RETP Study as if it was a request for PTP transmission service from a source control area (Point of Receipt) to a sink control area (Point of Delivery) over a specific period of time (the stakeholders requesting the study would determine the time period). The Point of Receipt and Point of Delivery can be interfaces. (If those points are interfaces, entities seeking to use the RETP would have to separately request transmission service, if necessary, to move power from their generating resources to the interfaces. Given the unconstrained nature of the Transmission Systems in the NCTPC, such service should typically be available.)

The Initial RETP Study would only provide preliminary information on the projected cost and scope of the facilities that would be needed to create the RETP, and the time it would take to complete the RETP. Each Transmission Provider along the RETP would identify its own estimated costs. The reason that the study must be preliminary in nature is that the study request will not be treated as if it is a queued transmission service request; later transmission requests may impact the cost estimates. It would be premature to "queue" the proposed RETP (thus potentially taking existing ATC "off the market"), until the decision to hold an Open Season is made.

Once the Initial RETP Study and any RETP-Related DNR Studies are complete, the relevant stakeholder processes would determine if there is sufficient interest in the project to move the RETP from the "initial study" mode to the establishment of an "Open Season" for the RETP. This decision would have to be carefully considered by the stakeholders, as it could result in ATC being made unavailable for what may be several months. For example, assume an RETP is proposed as a 1000 MW path from an interface on the Florida-Southern border to an interface on the Duke-PJM border that would be operational in 2015. Assume further that on the Duke system, 300 MW of existing ATC is available in 2015, but that Duke would have to upgrade its system to ensure the remaining 700 MW of the 1000 MW path. Once the Open Season commences, Duke will assume in reviewing new transmission service requests (and rollover rights of such new requests) that the 300 MW of ATC is no longer available in 2015.

C. Open Season for RETPs

After an RETP has been identified, the Initial RETP Study completed, and it is determined by the relevant stakeholder body that there is sufficient interest in moving this project to the next level of consideration; an "Open Season" will be established to determine if there is sufficient interest in funding the upgrades necessary to create the RETP.

All Transmission Providers impacted by the RETP would establish the same "Open Season" for the RETP. The Open Season will have a similar impact to someone queuing a PTP service request for the entire proposed MW of the RETP from the source control area to the sink control area for the relevant time period. To the extent that there is ATC available that will form part of the new RETP, this ATC would be available only to Open Season participants, not to Transmission Customers who hold transmission queue positions based on service requests submitted after the start date of the Open Season. Thus, returning to the example of the new 1000 MW Florida-PJM RETP, to the extent Duke planned to use 300 MW of ATC that were otherwise available in 2015, Duke would consider this 300 MW unavailable to requestors in its transmission queue that post-dated the Open Season. This approach would be important to ensure that Transmission Customers who were familiar with the RETPs that were under consideration would not be able to cherry-pick PTP transmission reservations along the path of an RETP. If the Open Season resulted in the RETP not going forward, the 300 MW of ATC would again be available to those that entered the transmission queue after the date of the Open Season.

During this Open Season all potential Transmission Customers would have a 60-day window to put in their request to subscribe to all or a portion of the MW of service being made available along the RETP.

If the RETP was not fully subscribed (i.e., 100% of the MW reserved), the Open Season will be extended by another 30 days if there is a subscription to 80% of the MW or higher. If the RETP was oversubscribed, then the RETP subscription would be distributed in a *pro rata* fashion. When oversubscription occurs, the participating Transmission Customers will be notified. All of these Transmission Customers will be given the opportunity to proceed with a firm PTP transmission subscription based on these pro rata allocations of the transmission service. However, one or more of the participating Transmission Customers may choose not to move forward due to their determination that fulfilling only a portion of their desired transmission allocation would not meet their business needs. To accommodate this situation, a "reallocation window" would be established to allow for the Transmission Customer to withdraw or adjust their transmission allocation requests. All Transmission Customers are eligible to participate in this reallocation window. The reallocation window would be no greater than 30 days.

All such processes will be open and transparent, which will allow Transmission Customers to work among themselves to determine how they can get the RETPs built.

Example:

- RETP was identified as a transmission path between Entergy and PJM with a 500 MW capacity.
- Through the RETP Initial Study, all of the Transmission Providers identify their estimated costs and potential rate impacts on transmission service so that Transmission Customers can evaluate the financial impact of subscribing to the RETP.
- Potential Transmission Customers are given a 60 day window to identify their desire to be a subscriber for this RETP.
- Open Season Results:
  - Sufficient Subscription – Case 1. Transmission Customer 1 – Willing to subscribe for entire amount – 500 MW of PTP service. Sufficient subscription, RETP moves forward.
  - Sufficient Subscription – Case 2. Transmission Customer 1 – Willing to subscribe for 250 MW. Transmission Customer 2 – Willing to subscribe for 250 MW of PTP service. Sufficient subscription, RETP moves forward.
  - Insufficient Subscription – Case 1. Transmission Customer 1 – Willing to subscribe for 250 MW. No other Transmission Customers agree to subscribe to the RETP, therefore RETP does not move forward.
  - Insufficient Subscription – Case 2. Transmission Customer 1 – Willing to subscribe for 450 MW. No other Transmission Customers agree to subscribe to the RETP. Reallocation window of 30 days because RETP 90% subscribed (greater than 80% threshold).
    - Case 2.a – No one responds to reallocation window:
      - Transmission Customer 1 is offered the opportunity to subscribe to the other 50 MW (i.e., pay the full price of the upgrade). If the customer accepts, the RETP goes

forward. If the customer does not accept, the RETP does not go forward.

- Case 2.b – Transmission Customer 2 is willing to subscribe to 30 MW of the 50 unsubscribed MW.
    - Transmission Customer 1 and 2 are offered the opportunity to subscribe to the other 20 MW on a pro rata basis (Transmission Customer 1 would receive an additional 19 MW; Transmission Customer 2 would receive an additional 1 MW). If the Customers accept, the RETP goes forward. If the customers do not accept, the RETP does not go forward.
- Case 2.c – Transmission Customer 2 is willing to subscribe to 30 MW and Transmission Customer 3 is willing to subscribe to 30 MW
    - The Customers are offered a pro rata share (25 MW each). If the Customers accept, the RETP goes forward. If the customers do not accept, the RETP does not go forward.

- Over-subscription.

  Initial Open Season Iteration: Transmission Customer 1 – Willing to subscribe for 250 MW. Transmission Customer 2 – Willing to subscribe for 250 MW. Transmission Customer 3 – Willing to subscribe for 250 MW. Pro-rata subscription is provided and Transmission Customers 1, 2 and 3 all get 167 MW. Transmission Customers would be free to negotiate with each other on a different allocation. Transmission Customers 1, 2 and 3 are given the opportunity to move forward with this RETP at their prorated allocation levels. If one or more of these customers choose not to move forward, then the reallocation window would be started.

  Reallocation window: Potential Transmission Customers are given a 30-day window to identify their desire to be a participant in this iteration. Transmission Customers 1 and 2 decide to move forward, even if limited to 167 MW; Transmission Customer 3 decides to withdraw. The 167 MW of Transmission Customer 3's is "re-opened." Transmission Customer 4 decides to enter the Open Season and:

- Transmission Customer 1 – Willing to subscribe for 83 MW (i.e., the 83 MW it did not get in first Open Season).
- Transmission Customer 2 – Willing to subscribe for 167 MW (i.e., the 83 MW it did not get in first Open Season plus additional 84 MW).
- Transmission Customer 4 – Willing to subscribe for 167 MW.
- Pro-rata subscription is provided as follows (rounded to whole MW):
  - Transmission Customers 1 – 33 MW
  - Transmission Customer 2 – 67 MW
  - Transmission Customer 4 – 67 MW
  - Transmission Customers would be free to negotiate with each other on a different allocation.
- Transmission Customers 1, 2 and 4 are given the opportunity to move forward with this RETP at their pro-rated allocation levels. If all of these Transmission Customers agree to move forward with this RETP at their pro-rated amounts then the project moves forward with firm PTP transmission reservations being granted at the allocated levels. If one or more of these customers choose not to move forward, then the RETP will not move forward.

If an RETP is fully subscribed, the more detailed studies, i.e., a Facilities Study will be performed by each impacted Transmission Provider that must provide service along the RETP.

Once the RETP Facilities Study is completed, the Transmission Customers may opt out of their subscriptions if such notice is received within 15 days of the completed study. If Transmission Customers whose initial requests were only filled pro rata are willing to step in, they will have first priority to any capacity made available (on a pro-rata basis as necessary). If the RETP is not fully subscribed after such step, another 30-day iteration should be held if to determine if other entities are willing to fill the subscription. If not, the RETP will not move forward. All reserved ATC related to the RETP will be released. If the RETP is subscribed, Service Agreements will be executed or filed on an executed basis.

D. "Requestor Pays" Cost Allocation Approach

"Requestor Pays" is the proposed approach to cost allocation under which the Transmission Customer(s) that are subscribing to the RETP would provide the up-

front funding of any transmission construction that was required to ensure that the path was available for the relevant time period. These "requestor(s)" would be the Transmission Customers that were awarded the MW as a result of the successful subscription during the Open Season process. Four examples are provided in Section V.G. At least on the Duke and Progress systems, subscribers would pay for firm PTP transmission service on each Transmission System along the path of the RETP at the embedded cost rate. If the RETP concept is adopted beyond the NCTPC, other Transmission Providers could propose alternate cost allocation approaches for their segments of the RETP, although such approaches would have to be consistent with the NCTPC approach.

On the Duke and/or Progress systems, the Transmission Customer would receive a levelized repayment of this initial funding amount from Duke and/or Progress in the form of monthly transmission credits over a maximum 20-year period. The Transmission Providers will be permitted to work with the Transmission Customers to provide shorter or different crediting. As credits are paid, Duke and Progress could have the opportunity to include the costs of upgrades that were needed for the RETP in transmission rates, similar to the Generator Interconnection pricing/rate approach.

Transmission projects that are constructed for particular transmission expansion needs typically results in additional "head-room" being created in the transmission system as a result of the transmission construction. There is no attempt within this requestor pays cost allocation methodology to provide compensation to the "funders" of the RETPs for the head-room that would be created on the Transmission System. This is comparable and equitable to how other transmission expansion projects are handled within the normal transmission planning environment. Moreover, there will be situations in which one particular Transmission Provider along the RETP evaluation does not have to incur transmission construction in order to satisfy the provision of service on its portion of the RETP. In that situation, the Transmission Customer would not be assessed any transmission expansion cost for that particular portion of the path. In those situations, the Transmission Customer would be benefiting from some of the "head-room" that was created in the system as a result of other transmission projects. Hence this treatment of the potential "head-room" created by RETPs is comparable and equitable to other transmission expansion performed by the Transmission Providers.

All customers are free to resell portions of the RETP that they do not use under the OATT procedures for transmission resales.

E. Adjustments to Costs to Reflect Impacts of RETPs on Reliability Projects Included in Transmission Plans

The total project cost for the transmission expansion required due to an RETP will be adjusted to provide compensation for the positive impacts that the RETP would provide, given the existing Collaborative Transmission Plan. Specifically, if the RETP resulted in the delay of Reliability Projects, the net present value of this would be computed and subtracted from the net present value of the computed total project cost for the transmission expansion. For example, if the cost for the RETP on the system of one Transmission Provider was computed to be $100 million, but this project would eliminate the need for a $25 million Reliability Project, then this positive impact would be subtracted from the total estimated cost of the RETP and requestor(s) would be assessed a transmission expansion funding amount equivalent to $75 million NPV ($100 million - $25 million).

F. Additional Coordination Needed

In order to implement this cost allocation proposal, coordination of RETPs studies is necessary. The SIRPP will address this for the southern Transmission Provider neighbors. Additional coordination would be needed with PJM, as the PJM system adjoins the transmission systems of Duke and Progress.

Also, additional coordination would need to be provided to support a single "Open Season" for an RETP. The Transmission Providers would need to develop a coordination procedure that could be utilized each time an Open Season was needed for a particular RETP. The coordination procedure would define how the Open Season would be conducted and coordinated. This level of coordination is needed to ensure that the impacted Transmission Providers are all evaluating the RETP within the same timeframe which is very important due to the impact that these projects could have on other transmission requests that would be in the transmission queue.

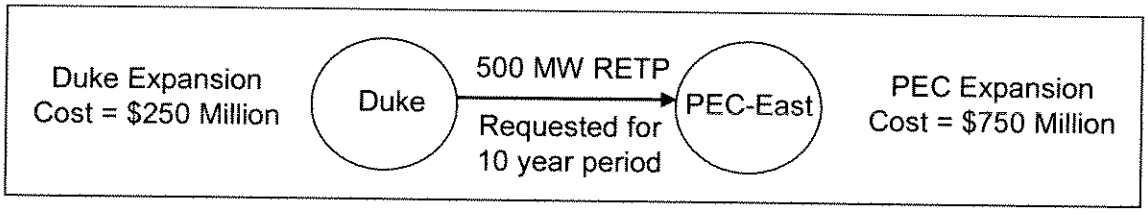
G. Examples

Four examples are provided to show how the NCTPC would be utilized in the following scenarios: RETPs that flow "into" the NCTPC footprint; RETPs that flow "out of" the NCTPC footprint; RETPs that "pass-through" the NCTPC footprint; and RETPs that are contained totally "within" the NCTPC footprint. All of these examples assume that all impacted Transmission Providers have agreed to use the Open Season process for RETPs projects. The examples described below build on each other, so the order of the examples is as follows:

1. Example 1 – "Within NCTPC" – Duke to PEC-East – Increase interface by 500 MW

2. Example 2 – "Into NCTPC" – Into PEC-East – Increase PEC-East interface with SCE&G by 500 MW (uses info from Example 1)
3. Example 3 – "Out of NCTPC" – Duke to PJM of 500 MW (uses info from Example 1)
4. Example 4 – "Through NCTPC" – Entergy to PJM of 1,000 MW

1. Example 1 – "Within NCTPC" – Duke to PEC-East – Increase interface by 500 MW



- Assumptions:
  - This RETP will require projects that increase the Duke to PEC-East interface capability by 500 MW for 10 years.
    - Transmission Customer 1 subscribes to 200 MW.
    - Transmission Customer 2 subscribes to 300 MW.
  - Total up-front funding requirement of $1 billion
    - Duke investment of $250 million
    - Progress investment of $750 million
  - Transmission Customer allocations for this funding:
    - TC 1 pays up-front payment of $400 million with a payment of 25% of these funds ($100 million) going to Duke and 75% of these funds going to Progress ($300 million)
    - TC 2 pays up-front payment of $600 million with a payment of 25% of these funds ($150 million) going to Duke and 75% of these funds going to Progress ($450 million)
- RETP would be identified through the NCTPC TAG, approved for initial study by the TAG study voting process (or as a result of TAG participant volunteering to pay for initial study), and evaluated through the NCTPC study process. NCTPC process would determine the project cost (on both the Duke and Progress system), scope of the solution, and timing requirements for the implementation of the

necessary upgrades as identified above in the "Identification and Initial Study of RETPs" section.

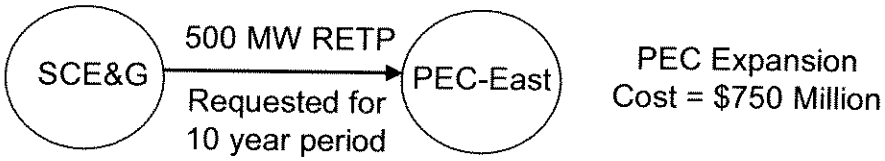
- Transmission cost considerations for this project –
    - Transmission Customers would be asked to provide the up-front funding of this transmission construction – total of $1 billion.
- NCTPC TAG Voting Members would determine if there was sufficient interest to move the RETP from study mode to holding an Open Season. If the NCTPC TAG Voting Members determine that an Open Season should be conducted the below steps would be taken.
- Open Season
    - Duke would hold an Open Season process for the 500 MW PTP Transmission Service reservation for the defined 10-year period from Duke into PEC-East.
    - Transmission Customers would have 60 days to determine if they want to participate in this Open Season.
    - For this example we will assume that there were adequate subscriptions as listed below:
        - Transmission Customer 1 – Willing to subscribe for 200 MW of PTP service
        - Transmission Customer 2 – Willing to subscribe for 300 MW of PTP service
        - Sufficient subscription, RETP moves forward.
    - Transmission Customer 1 is granted 200 MW of firm PTP Transmission Service from Duke to PEC-East for the 10 year period.
    - Transmission Customer 2 is granted 300 MW of firm PTP Transmission Service from Duke to PEC-East for the 10 year period.
    - Transmission Customers pay the up-front transmission construction costs – $250 million to Duke and $750 million to PEC.
    - Transmission Customer pays Duke for the PTP Transmission Service each month at the Duke embedded cost transmission rate.
    - Transmission Customers would receives credits back as follows:
        - Duke and Progress would both provide an annualized repayment of the initial funding of the transmission projects on their respective systems.

- Duke will net their annualized repayment of the initial funding against the Transmission Customers charges for their PTP service that they take PTP service each month.

- Impact to Duke and Progress transmission rate base:
  - Duke and Progress will have the opportunity to include within their respective transmission rate bases the transmission that was constructed for the RETPs as the initial funding is repaid to the Transmission Customers over a 20 year period.

2. Example 2 – "Into NCTPC" – Into PEC-East – Increase PEC-East interface with SCE&G by 500 MW

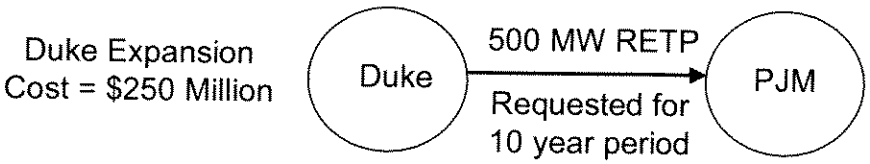
Example assumes SCE&G/SIRPP adopts RETP concept.



- This example builds off of Example 1. The differences in this example from Example 1 are as follows: Duke is not involved (i.e., Duke upgrades are not required and there is no Duke PTP service related to this example; and SCE&G is involved in the project (i.e., a Transmission Provider outside the NCTPC footprint). However, the Progress impacts are the same as were identified in Example 1.
- Since this example involves southeastern Transmission Providers outside of the NCTPC footprint (e.g. SCE&G), the SIRPP would be used to evaluate this project and provide for an Open Season mechanism to determine if there was sufficient interest in moving forward with the RETP. Refer to Example 4 for an explanation of how those processes would work.

3. Example 3 – "Out of NCTPC" – Duke to PJM of 500 MW

Example assumes PJM adopts RETP concept.

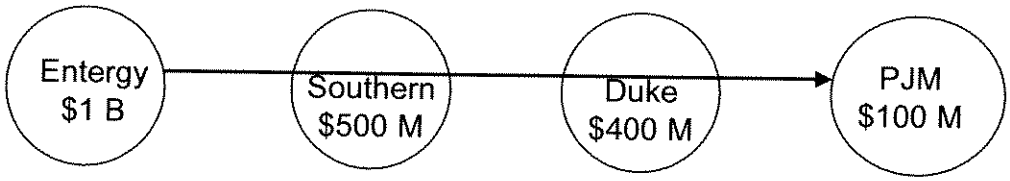


- This example builds off of Example 1. The differences in this example from Example 1 are as follows: Progress is not involved (i.e., there are no Progress upgrades required); and PJM is involved in the RETP (i.e., a northern Transmission Provider outside the NCTPC footprint). However the Duke impacts are the same as were identified in Example 1.
- Since this example involves Transmission Providers outside of the NCTPC footprint (i.e., PJM), Duke would work with PJM to evaluate this RETP and provide for an Open Season mechanism to determine if there was interest in moving forward with the project.

4. Example 4 – "Through NCTPC" – Entergy to PJM of 1,000 MW

Example assumes PJM/SIRPP adopts RETP concept.

Entergy to PJM 1,000 MW RETP requested for a 20 year period.



- **Assumptions:**
  - Through the SIRPP process an RETP was identified. This RETP was for the 1,000 MW coming from Entergy and being delivered to PJM for a 20 year period. This RETP would result in a 1,000 MW of PTP transmission service to be provided by the following Transmission Providers for 20 years: Entergy, Southern, and Duke. However, PJM would also need to participate in the study evaluation to determine if they had sufficient transmission interface to support this transaction.
  - Three Transmission Customers sign-up to participate in the RETP
    - Transmission Customer 1 subscribes at a level of 200 MW

        - Transmission Customer 2 subscribes to 300 MW
        - Transmission Customer 3 subscribes to 500 MW
    - Total up-front funding requirement of $2 billion
        - Entergy investment of $1billion
        - Southern investment of $500 million
        - Duke investment of $400 million
        - PJM investment of $100 million
        - The NCTPC only controls how Duke will handle the treatment of their initial funding of this economic project. The Transmission Customer would work with Entergy, Southern and PJM through this process concerning their initial funding requirements and potential rate impacts.

- RETP would be identified, approved, and evaluated through the SIRPP. The SIRPP would determine the RETP cost scope of the solution, and timing requirements for the implementation of the projects needed for the RETP as identified above in the "Identification and Initial Study of RETPs" section.
- Transmission cost considerations for Duke related to this project –
    - Transmission Customers would be asked to provide the up-front funding of the Duke transmission construction required by this RETP – $400 million.
- SIRPP would determine if there was sufficient interest to move the RETP from study mode to holding an Open Season for the RETP. If the stakeholder group determines that an Open Season should be conducted the below steps would be taken.
- Open Season
    - A coordinated Open Season for this RETP would be held by Entergy, Southern and Duke for the 1,000 MW PTP Transmission Service Reservation for the defined 20-year period from Entergy into PJM.
    - Transmission Customers would have 60 days to determine if they want to participate in this Open Season.
- For this example we will assume that there were adequate subscriptions as listed below:
    - Transmission Customer 1 subscribes at a level of 200 MW
    - Transmission Customer 2 subscribes to 300 MW
    - Transmission Customer 3 subscribes to 500 MW

- Transmission Customer 1 is granted 200 MW of firm PTP Transmission Service from Entergy to PJM for the 20 year period.
- Transmission Customer 2 is granted 300 MW of firm PTP Transmission Service from Entergy to PJM for the 20 year period.
- Transmission Customer 3 is granted 500 MW of firm PTP Transmission Service from Entergy to PJM for the 20 year period.
- The above three Transmission Customers would pay Duke for the PTP Transmission Service each month at the Duke embedded cost transmission rate.
- Transmission Customers would receives credits back as follows:
    - Duke would provide an annualized repayment of the initial funding of the transmission projects
    - Duke will net their annualized repayment of the initial funding against the Transmission Customers' charges for their PTP service that they take each month.
- Impact to the Duke transmission rate base:
    - Duke will have the opportunity to include within their transmission rate base the transmission that was constructed for the RETP as the initial funding is repaid to the Transmission Customers over a 20 year period.

ATTACHMENT I

RELIABILITY PLANNING IN THE SOUTHEAST

Reliability Planning in the Southeast and the Relationship between Reliability and Economic Planning

I. Purpose:

The purpose of this white paper is to discuss (1) the relationship between the existing regional and inter-regional reliability planning processes, (2) the interaction between these reliability processes and regional and inter-regional economic planning processes, and (3) the means by which stakeholders participate in the reliability planning processes.[1]

II. Executive Summary:

The inter-regional reliability planning process performed in the Southeast is a "bottom-up" process. Specifically, the bulk of the substantive transmission planning occurs as transmission owners[2] develop their reliability expansion plans, while the SERC-wide reliability assessment essentially consists of a process that assesses whether the individual reliability expansion plans are simultaneously feasible. In accordance with Order No. 890, stakeholders are able to participate in this process by providing input into the development of the regional reliability plans. Furthermore, should the SERC-wide assessment identify projected planning criteria concerns that were not addressed in the regional reliability plans, then any such additional issues (and the corresponding solutions) are addressed at the regional level, with the stakeholders providing input in these regional forums.

With regard to the relationship between the reliability and economic planning, the basis for all economic transmission studies is a common set of transmission models developed for the reliability studies. The economic transmission studies thus identify potential economic transmission projects above and beyond those reliability-driven upgrades identified in the reliability studies, with those economic studies also analyzing the potential to advance, delay and/or modify such upgrades identified in the base reliability transmission plans. Furthermore, it remains probable that significant economic upgrades will be addressed in the same manner that they historically have been, which is that an entity desiring an upgrade to address an economic issue (e.g., congestion) will enter into a binding commitment for firm service in order to ensure that the upgrade is built. In that manner, the "economic" upgrade becomes a "reliability" upgrade that is analyzed in future reliability planning studies.

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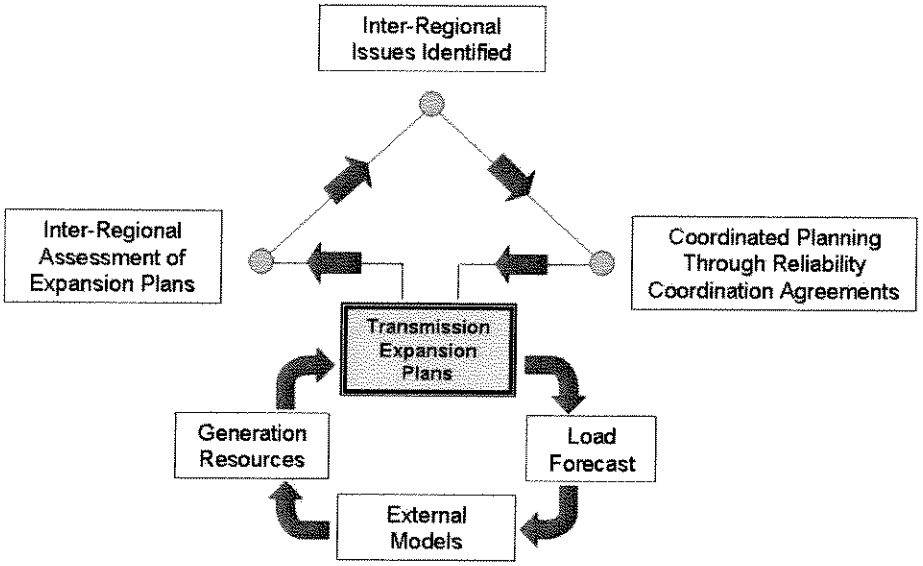
[1] Stakeholder participation in regional planning processes is described in detail in each region's planning process and in the Southeast Inter-Regional Participation document. Stakeholders wanting to participate in SERC should contact SERC for meeting and membership information.

[2] Not all of the sponsors of this inter-regional participation process are transmission providers for purposes of the *pro forma* OATT, so the sponsors of this process are referred to as transmission owners for purposes of this paper.

III. Regional Reliability Planning:

The reliability plan for each region is developed by determining the required 10-year transmission expansion plan to satisfy load, resources, and transmission service commitments throughout the 10-year reliability planning horizon. The development of each regional reliability plan is facilitated through the creation of transmission models (base cases) that incorporate the current 10-year transmission expansion plan, load projections, resource assumptions (generation, demand response, and imports), and transmission service commitments within the region. The transmission models also incorporate external regional models (at a minimum the current SERC models)[3] that are developed using similar assumptions. Importantly, in the context of Order No. 890, stakeholders may provide input regarding the development of the regional reliability plan through the coordinated, open, and transparent regional planning processes.



[3] The SERC Model Development Process is discussed in additional detail later in the white paper. A copy of the SERC LTWG Procedure Manual that describes the SERC model development process in detail can be obtained from SERC.

A. *Regional Reliability Study Process:*

The transmission models created for use in developing the regional reliability 10-year transmission expansion plan are analyzed to determine if any planning criteria concerns (including, at a minimum, NERC planning criteria)[4] are projected. In the event one or more planning criteria concerns are identified at the regional level, the transmission owners will develop solutions for these projected limitations. As a part of this study process, the transmission owners will reexamine the current regional reliability 10-year transmission expansion plan (determined through the previous year's regional reliability planning process) to determine if the current plan can be optimized based on the updated assumptions and any new planning criteria concerns identified in the analysis. The optimization process may include the deletion and/or modification to any of the existing reliability transmission enhancements identified in the previous year's reliability planning process. In the context of Order No. 890, projected limitations and the corresponding solutions are reviewed with stakeholders, who may propose alternative solutions, through the coordinated, open, and transparent regional planning processes.

B. *Identification of Regional Reliability Transmission Enhancements:*

Once a planning criteria concern is identified or the optimization process identifies the potential for a superior solution, the transmission owner will then determine if any neighboring planning process is potentially impacted by the projected limitation. Potentially impacted regions are then contacted to determine if there is a need for an inter-regional reliability joint study. In the event one or more neighboring region agrees that they would be impacted by the projected limitation or identifies the potential for a superior inter-regional reliability solution, based on transmission enhancements in their current regional reliability plan, an inter-regional reliability joint study is initiated (via existing Reliability Coordination Agreements). In the event that no inter-regional impacts are identified, or if once contacted the potentially impacted regions(s) determine that they will not actually be impacted, the initiating transmission owner will move forward to conduct a reliability study to determine the solution for the projected planning criteria concern as described in the paragraph above. In either case, once the study has been completed, the identified reliability transmission enhancements will then be incorporated into the region's(s') 10-year expansion plan as a reliability project. Again, in the context of Order No. 890, projected limitations and the corresponding solutions are reviewed with stakeholders, who may propose alternatives, through the coordinated, open, and transparent regional planning processes.

[4] Regional Planning Criteria posted on websites (Check with your respective regional planning process for further information)

IV. Inter-Regional Assessments (SERC-wide) and Inter-Regional Reliability Planning Activities:

After the regional transmission models are developed, the transmission owners within SERC create a SERC-wide transmission model and conduct a long-term reliability assessment. The intent of the SERC-wide reliability assessment is to determine if the different regional reliability transmission expansion plans are simultaneously feasible and to otherwise ensure that the transmission owners are using consistent models and data. Additionally, the reliability assessment measures and reports the transfer capabilities between regions and transmission owners within SERC. The SERC-wide assessment serves as a valuable tool for each of the transmission owners to reassess the need for additional inter-regional reliability joint studies.

A. *SERC Transmission Model Development:*

The construction of the SERC transmission model is a "bottom-up" process. In particular, SERC transmission models are developed by the transmission owners in SERC through an annual model development process[5]. Each transmission owner in SERC, incorporating input from their regional planning process, develops and submits their transmission models to a model development databank. The databank then joins the models to create a SERC-wide model for use in the reliability assessment. Additionally, the SERC-wide models are then used in each regional planning process as an update (if needed) to the current transmission models and as a foundation (along with the MMWG models) for the development of next year's transmission models. Importantly, given that the construction of the SERC-wide model is a bottom-up process, stakeholders provide input into this process in accordance with Order No. 890 by participating in the development of the regional reliability models discussed above.[6] In addition, as discussed in the Southeast Inter-Regional Participation White Paper, the participating transmission owners in that process will review with stakeholders at the inter-regional level the data, assumptions, and assessments that are then being conducted on a SERC-wide basis.

B. *Additional Inter-Regional Reliability Joint Studies:*

As mentioned above, the SERC-wide reliability assessment serves as a valuable tool for the transmission owners to reassess the need for additional inter-regional reliability joint studies. If the SERC-wide reliability model projects additional planning criteria concerns that were not identified in the regional reliability studies, then the impacted transmission owners will initiate one or more inter-regional joint study(ies) (in accordance with existing Reliability Coordination Agreements) to better identify the planning criteria

[5] The SERC LTWG Procedure Manual that describes the SERC model development process in detail can be obtained from SERC.

[6] Again, at the SERC-wide level, the model development essentially consists of ensuring that the different regional reliability models are compatible at the SERC-wide level, meaning that substantive transmission planning is performed at the regional level where stakeholders may provide input.

concerns and determine the optimal inter-regional reliability transmission enhancements to resolve the limitations. Once the study(ies) are completed, required reliability transmission enhancements will be incorporated into the region's 10-year expansion plan as a reliability project. Accordingly, planning criteria concerns identified at the SERC-wide level are "pushed down" to the transmission owner level for detailed resolution. In accordance with Order No. 890, identified planning concerns and corresponding solutions are reviewed with stakeholders, who may propose alternative solutions, through the coordinated, open, and transparent regional planning processes.

V. Inter-Regional and Regional Economic Planning and Its Relationship to Reliability Planning:

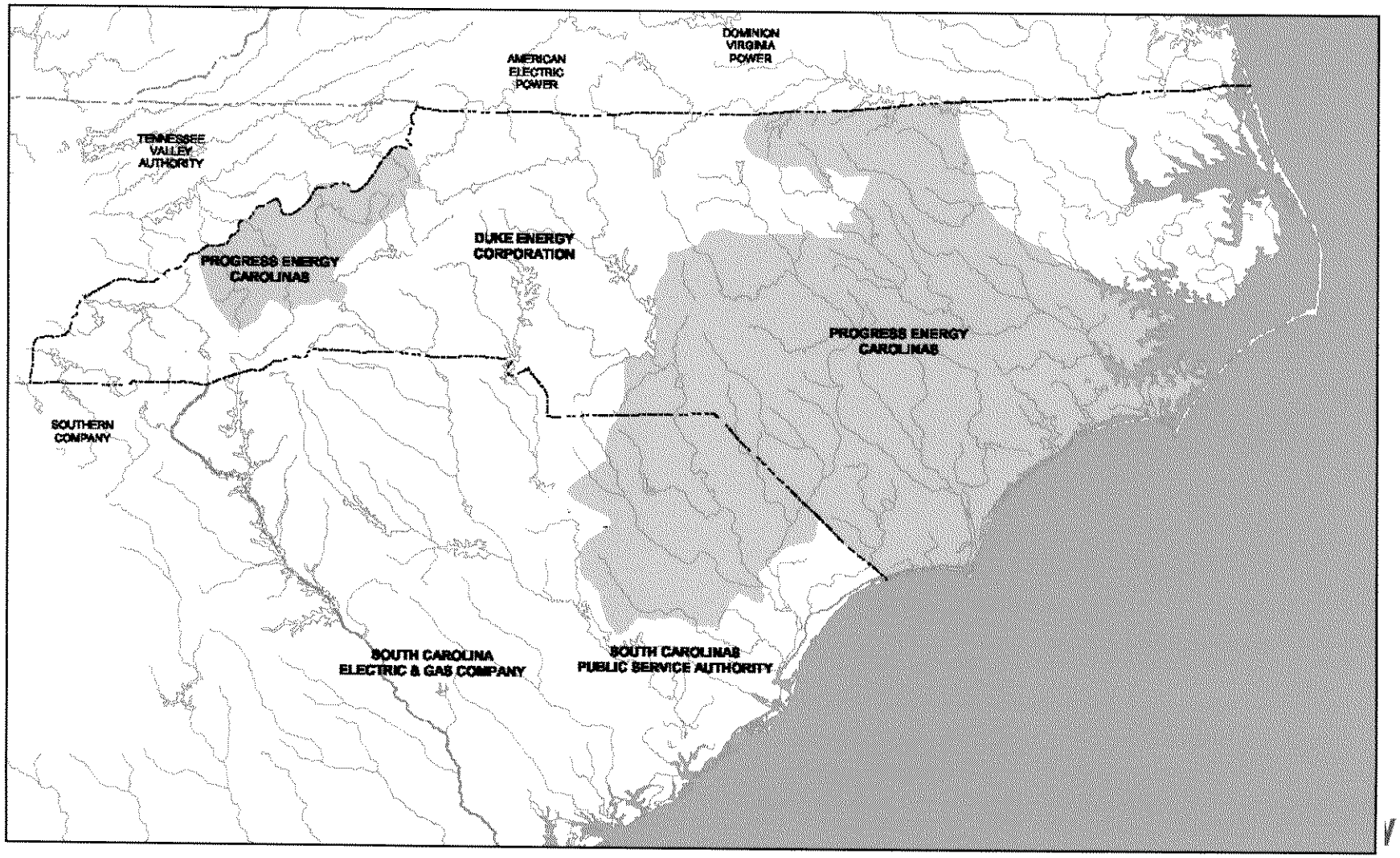
Stakeholder-requested regional economic studies will be conducted in accordance with each region's planning process. Studies that are inter-regional in nature will be conducted in accordance with the Southeast Inter-Regional Participation Process. The basis for all economic transmission studies (regional and inter-regional) will be the same transmission models developed for use in reliability planning studies and assessments. The intent of the stakeholder-requested economic transmission studies is to identify potential economic transmission projects that are above and beyond the base reliability transmission expansion plan. Additionally, the stakeholder-requested economic transmission studies will investigate the potential for the advancement and/or the modification of existing reliability enhancements; however, only the difference between the reliability upgrade and the new transmission enhancement will be identified as an economic transmission project as part of the stakeholder-requested economic transmission study.

Importantly, it remains probable that significant economic upgrades will be addressed in the same manner that they historically have been. Specifically, the traditional approach has been for an entity that would like a particular upgrade to be constructed to address an economic issue (e.g., congestion) to enter into a binding commitment for long-term firm service (e.g., point-to-point transmission service or the addition of a new network resource under the OATT) to ensure that the upgrade is built. Once such a firm commitment is made, such "economic" upgrades automatically become "reliability" upgrades that are included in the region(s) reliability transmission plan. While Order No. 890 contemplates the identification and cost allocation for the construction of economic upgrades separate from traditional OATT service requests, the traditional OATT process remains a viable option for pursuing the construction of economic upgrades that are identified in the economic planning studies that are performed pursuant to Attachment K.

ATTACHMENT J

MAP OF NCTPC REGION

Duke and Progress Service Territories



January 1, 2008