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November 1, 2023

<u>By eTariff</u>
Kimberly D. Bose, Secretary
Debbie-Anne A. Reese, Esq., Deputy Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: ***Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*** **– Proposed Revisions to Local Transmission Planning Process in Attachment N-1 of Joint OATT**
Docket No. ER24-____-000

Dear Secretaries:

Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, "Duke Energy") hereby submit modifications to Attachment N-1 of the Duke Energy Joint Open Access Transmission Tariff (the "Joint OATT") for acceptance by the Federal Energy Regulatory Commission ("FERC" or "Commission") under Section 205(c) of the Federal Power Act ("FPA") and Part 35 of the Commission's regulations.[1] Duke Energy request an effective date 60 days after filing, or January 1, 2024

The modifications to Attachment N-1 proposed herein seek to improve Duke Energy's local transmission planning process so that it is better positioned to timely address transmission needs as the grid transitions to support a new resource mix, retire generation, and respond to changing dynamics in energy use and demands ("Tariff Revisions"). The proposed improvements would establish a process to study a new category of local transmission projects, Multi-Value Strategic Transmission Projects.[2] This new process would create an avenue for transmission planners to evaluate different Strategic Planning Scenarios and use that scenario planning analysis to identify Local Projects that will integrate new generation resources and/or loads and provide other benefits in a least cost manner. Additionally, in recognition of the growing importance and interest in transmission planning, the proposed improvements to the local transmission planning process would establish a more detailed stakeholder meeting schedule and clearer timelines for stakeholder input on assumptions, models, and criteria used in the transmission planning process, as well as transmission needs and potential solutions.

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[1] 16 U.S.C. § 824d(c) (2018); 18 C.F.R. pt. 35 (2022).

[2] Capitalized terms not defined herein have the meaning assigned in the Joint OATT or proposed Tariff Revisions.

I. BACKGROUND

A. Duke Energy

DEC, a wholly owned subsidiary of Duke Energy Corporation, is a vertically integrated electric utility that generates, transmits, distributes, and sells electricity to approximately 2.8 million customers within its 24,000-square-mile franchised service territory in central and western North Carolina and western South Carolina. DEC currently meets energy demand primarily from its fleet of electric generation assets amounting to approximately 20,000 MW; by purchases of electricity from the open market; and through purchased power contracts with third parties.

DEP, a wholly owned subsidiary of Duke Energy Corporation, is a vertically integrated electric utility that generates, transmits, distributes, and sells electricity to approximately 1.7 million customers within its 29,000-square-mile franchised service territory in eastern and western North Carolina and eastern South Carolina. DEC currently meets energy demand primarily from its fleet of electric generation assets amounting to approximately 12,500 MW; by purchases of electricity from the open market; and through purchased power contracts with third parties.

Retail service provided by DEC and DEP are subject to the regulatory jurisdiction of the North Carolina Utilities Commission ("NCUC") and the Public Service Commission of South Carolina ("SCPSC"). DEC's and DEP's sales of wholesale energy and capacity and their provision of open-access transmission service are subject to the jurisdiction of the Commission.

B. Current Local Transmission Planning Process

Attachment N-1 of the Joint OATT describes Duke Energy's current local transmission planning process. Pursuant to Attachment N-1, DEC and DEP are each a Participant in the North Carolina Transmission Planning Collaborative ("NCTPC"). The NCTPC local transmission planning process identifies transmission upgrades needed to maintain reliability and to integrate new generation resources and/or loads in DEC's and DEP's North Carolina and South Carolina service areas. The local planning process includes a base reliability study ("Base Case") that evaluates DEC's and DEP's respective Transmission System's ability to meet projected load, including both retail and Network Load, with a defined set of resources, as well as the needs of firm point-to-point transmission service customers, whose needs are reflected in their transmission contracts and reservations. A resource supply analysis is also conducted to evaluate transmission system impacts for other potential resource supply options to meet future load requirements. The NCTPC Local Planning Process also provides a pathway for studying economic projects and projects driven by Public Policy Requirements. The NCTPC annually develops a single, coordinated local 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 Load Serving Entities as well as Transmission Customers under the OATT. The NCTPC transmission planning process is iterative, with updates to the annual local transmission plan continually evaluated.

DEC and DEP participate in the NCTPC local transmission planning process as members of the Oversight/Steering Committee ("OSC") and Planning Working Group ("PWG"). Two other load-serving entities and two of Duke Energy's largest wholesale customers—Electricities of North Carolina ("Electricities") and North Carolina Electric Membership Corporation ("NCEMC")—are also members of the OSC and PWG. Consistent with the terms of Attachment N-1, the OSC and PWG engage with the Transmission Advisory Group ("TAG"), composed of interested stakeholders, to solicit input and recommendations to incorporate into the Local Transmission Plan. TAG participants have the opportunity to propose alternative transmission, generation, and/or demand response solutions to address reliability, economic, and/or public policy transmission needs.

As detailed below, the NCTPC transmission planning process pre-dates Order No. 890, but has evolved over time to satisfy the requirements of Order No. 890 and Order No. 1000. The Tariff Revisions proposed herein reflect the next evolution of the local transmission planning process to address changing transmission needs.

C. History of the NCTPC

Beginning in 2005, DEC and Progress Energy Carolinas ("PEC", which is now DEP) helped create the NCTPC to improve collaboration among the utilities and their load-serving network customers.[3] The original NCTPC members included DEC and PEC, who were unaffiliated at the time, as well as Electricities and NCEMC. Since its inception, the NCTPC has addressed planning for the entirety of DEC's and PEC's transmission system, including facilities in South Carolina, and provided a uniquely collaborative transmission planning model for both transmission providers and load-serving entities that serve customers within the relevant region.[4]

In 2007, FERC issued Order No. 890, requiring each transmission provider to address in its OATT how its transmission planning process complies with nine principles: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; (7) regional participation; (8) economic planning studies; and (9) cost allocation for new projects.[5] To comply with Order No. 890 and the nine planning principles, DEC and PEC memorialized the NCTPC transmission planning process in their OATTs with certain modifications.[6]

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[3] *See Duke Energy Carolinas, LLC and Progress Energy Carolinas*, *Inc.*, Joint Order No. 890 Compliance Filing, Docket No. OA08-50-000 at 3-5 (filed Dec. 7, 2007) ("DEC/PEC Order No. 890 Compliance Filing") (describing history of NCTPC); *Duke Energy Carolinas, LLC and Carolina Power & Light Co*., Order No. 1000 Compliance Filing, Docket No. ER13-83-000 at 2-3 (filed Oct. 11, 2012) ("DEC/CP&L Order No. 1000 Compliance Filing") (same).

[4] DEC/CP&L Order No. 1000 Compliance Filing at 2-3.

[5] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, *order on reh'g,* Order No. 890-A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g and clarification*, Order No. 890-B, 73 FR 39092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 74 FR 12540 (Mar. 25, 2009), 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 74 FR 61511 (Nov. 25, 2009), 129 FERC ¶ 61,126 (2009).

[6] *Duke Energy Carolinas, LLC and Progress Energy Carolinas, Inc.*, 124 FERC ¶ 61,267 (2008) ("First Order No. 890 Compliance Order") (accepting the DEC/PEC Order No. 890 Compliance Filing, with certain modifications), *order accepting compliance filing*, 127 FERC ¶ 61,281 (2009) ("Second Order No. 890 Compliance Order"); *Duke Energy Carolinas, LLC and Progress Energy Carolinas, Inc.*, Docket No. OA08-50-005 (Letter Order issued Feb. 2, 2010) (accepting DEC's and PEC's respective OATT attachments as in compliance with Order No. 890).

In 2011, FERC issued Order No. 1000, which built upon Order No. 890's transmission planning reforms.[7] Among Order No. 1000's new requirements, each regional transmission planning process had to produce a regional plan, and the regional planning process must establish methods for selecting projects to be included in the regional plan for purposes of cost allocation.[8]

To comply with Order No. 1000, DEC and PEC initially proposed the continued use of the NCTPC process as their regional transmission planning process.[9] However, during the development of Order No. 1000 compliance filings in 2011 and 2012, DEC and PEC filed to merge, and FERC approved the DEC/PEC merger, resulting in DEC and PEC as separate, but affiliated, utilities. Pointing to the fact that DEC and PEC were no longer unaffiliated when addressing DEC's and PEC's Order No. 1000 compliance filing, FERC rejected the proposal to use the NCTPC process as a regional transmission planning process.[10] As a result, DEC and PEC filed to retain the NCTPC process as their local transmission planning process and join the Southeast Regional Transmission Planning Process to comply with Order No. 1000. FERC accepted that proposal in June 2014.[11] Aside from a ministerial filing to reflect DEP's name change, there have been no substantive changes to Duke Energy's transmission planning process since 2014.[12]

D. Evolving Local Transmission Planning Demands

In recent years, Duke Energy has seen that planned coal retirements, the need for replacement resources, compliance with state and federal laws, and continued economic development in North Carolina and South Carolina are testing the ability of the current NCTPC transmission planning process to keep aligned with resource planning driven by its states' integrated resource planning. If the transmission planning and resource planning processes are misaligned leading to insufficient transmission development on a timely basis, the lack of transmission infrastructure to reliably support coal retirements and integrate significant amounts of new generation puts the energy transition execution at risk. Misalignment between these processes can also complicate compliance with state and federal laws or delay economic development efforts.

To date, Duke Energy and the NCTPC have managed this challenge through its resource supply analysis and reliance on past generator interconnection requests and studies. For example, in 2020, DEC's and DEP's integrated resource plans filed in North Carolina and South Carolina

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[7] *Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051 (2011) ("Order No. 1000"), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

[8] Order No. 1000 at PP 6, 7.

[9] DEC/CP&L Order No. 1000 Compliance Filing at 4-7.

[10] *Duke Energy Carolinas LLC.*, 142 FERC ⁋ 61,130, at PP 26-27, 33 (2013).

[11] *Duke Energy Carolinas, LLC*, 147 FERC ⁋ 61,241 (2014).

[12] *See Duke Energy Progress, LLC*, Docket No. ER15-2567-000 (Letter Order issued Oct. 29, 2015).

identified a need to interconnect over 4,500 MW of incremental solar generation between 2026 and 2030. The 2022 resource plan identified the need to interconnect up to 5,400 MW of incremental solar generation by 2030. This anticipated exponential growth in solar generation, coupled with the planned retirement of 8,400 MW of coal-fired generation, presented a transmission challenge of how to enable a reliable and timely generation transition.

To solve this challenge, Duke Energy identified the need to proactively develop and construct transmission facilities. Since 2018, serial generator interconnection studies had persistently shown transmission constraints in certain "red zones" where solar generation preferred to interconnect.[13] Therefore, Duke Energy had several years of prior serial generator interconnection studies demonstrating transmission constraints and identifying required Network Upgrades to reliably interconnect additional solar generation in areas with the greatest solar viability.[14] Using this data, Duke Energy and the NCTPC identified 14 transmission projects that not only reduced transmission congestion in high solar viability areas of the Duke Energy systems for a cost effective path to execute the resource plan, but were also independently justified on a benefit-to-cost basis—specifically the material reliability and resiliency benefits for transmission customers from replacing aging infrastructure. Based on this analysis, during the 2022 NCTPC planning cycle, Duke Energy proposed a first set of Red-Zone Expansion Plan Projects ("RZEP Projects").[15]

At the same time, proceedings before the North Carolina Utilities Commission ("NCUC") were also underway to decide upon Duke Energy's first Carbon Plan to comply North Carolina's carbon dioxide emissions reduction mandates of House Bill 951. In that proceeding, Duke Energy provided supplemental studies that used cluster-type studies of the most recent generator interconnection requests up to 5,400 MW. This historical data served as a proxy for the MW size and location of future generation.[16] The results of the supplemental studies reinforced the need

[13] *Id.*

[14] Duke Energy's cluster studies process for generator interconnection was approved by FERC on August 6, 2021. *Duke Energy Carolinas, LLC,* 176 FERC ¶ 61,075 (2021). Duke Energy's first cluster study window opened January 1, 2022 and closed June 29, 2022, and Phase I of the first cluster study for generator interconnection was completed November 23, 2022.

[15] *See* North Carolina Transmission Planning Collaborative, NCTPC Review of Red Zone Expansion Plan Projects (Aug. 15, 2022), http://www.nctpc.org/nctpc/document/REF/2022-08-15/Status%20of%20NCTPC%20Review%20of%20Red%20Zone%20Expansion%20Plan%20Projects%208-15-2022.pdf (describing RZEP Project proposal, applicable Attachment N-1 processes, and supporting studies to justify RZEP Projects). North Carolina Transmission Planning Collaborative, TAG Meeting Presentation, 21-49 (June 27, 2022) Presentation, http://www.nctpc.org/nctpc/document/TAG/2022-06-27/M_Mat/TAG_Meeting_Presentation_for_06-27_2022_FINAL.pdf; Study Mapping to Red-Zone Transmission Expansion Projects 2022, http://www.nctpc.org/nctpc/document/TAG/2022-06-27/M_Mat/Study%20Mapping%20to%20Red-Zone%20Transmission%20Expansion%20Plan%20Projects%202022.xlsx.

[16] *Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plan And Carbon Plan*, Direct Testimony of Dewey S. Roberts II and Maura Farver, NCUC Docket No. E-100, SUB 179 at 28-35 (filed Aug. 19, 2022) https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=21832e6f-b443-41e0-8c83-b540f6484cf8.

for most of the originally proposed RZEP Projects.[17] Duke Energy presented the results of these supplemental studies to TAG stakeholders in October 2022.[18]

Using this historical data from years of past generator interconnection requests and studies, Duke Energy was able to demonstrate the need for a first set of RZEP Projects, as well as provide support for why those RZEP Projects would be cost-effective and provide reliability benefits by replacing aging infrastructure. A first set of RZEP Projects was included in the 2022 Local Transmission Plan that was approved by the NCTPC in early 2023.

While the process for RZEP Projects was an initial step towards proactive transmission planning, the process was dependent on several years of past generator interconnection study requests and data. To be positioned to reliably address the many dynamic demands facing the transmission grid, including not just the generation transition, but greater electrification, increased electric vehicle adoption, and new economic development, including from prospective customers with significant energy demands to power data centers or manufacturing hubs, Duke Energy needs to evolve its planning process from siloed planning for reliability, economics, and public policy.[19] As discussed below, the proposed process for Multi-Value Strategic Transmission Projects is intended to provide for scenario-based planning capable of studying different transmission drivers and cost-effective identifying transmission solutions that offer a variety of benefits.

E. Growing Stakeholder Interest and Stakeholder Involvement in Local Transmission Process Improvements

In light of these new and dynamic transmission planning demands and intertwined impacts on resource planning, Duke Energy and the NCTPC have seen significantly more interest from stakeholders and participation in TAG than it has historically. From 2020 to 2023, the number of individuals registering for the NCTPC's TAG stakeholder meetings increased by approximately 400 percent, up from approximately ten individuals per meeting to more than forty or more individuals. To manage this heightened interest in the local transmission planning process, Duke Energy is proposing several Tariff Revisions, described below, to adopt a more detailed stakeholder meeting schedule with defined timelines for stakeholder input.

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[17] *Id.*

[18] *See* North Carolina Transmission Planning Collaborative, TAG Meeting Presentations, 26-35 (Oct. 18, 2022), http://www.nctpc.org/nctpc/document/TAG/2022-10-18/M_Mat/TAG_Meeting_Presentation_for_10-18_2022_FINAL.pdf ("October 18, 2022 TAG Presentation").

[19] While the need to evolve Duke Energy's local transmission planning process is driven by a variety of changing supply and demand dynamics, the NCUC has also recognized a need to evolve the process. *See In the Matter of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan*, Order Adopting Initial Carbon Plan and Providing Direction for Future Planning, NCUC Docket No. E-100, SUB 179 at 121, https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=7b947adf-b340-4c20-9368-9780dd88107a (NCUC encouraging Duke Energy to make changes to its transmission planning process to reliably implement the Carbon Plan and assure a least cost path to achieving carbon dioxide emissions reduction requirements).

In developing the Tariff Revisions and improvements to the local transmission planning process, Duke Energy has also solicited input from TAG stakeholders. An initial proposal for revisions to Attachment N-1 was posted publicly and shared with TAG stakeholders on August 9, 2023.[20] Several TAG stakeholders provided feedback, which was reviewed and discussed during the September 14, 2023 TAG meeting.[21]

II. PROPOSED TARIFF REVISIONS

The proposed Tariff Revisions are described below in more detail to explain why the revisions are just, reasonable, and not unduly discriminatory or preferential. The proposed Tariff Revisions are also consistent with or superior to the *pro forma* OATT and the requirements of Order Nos. 890 and 1000 because they go above and beyond the requirements of Order Nos. 890 and 1000 to enable Duke Energy to perform scenario-based local transmission planning analyses necessary to meet the dynamic challenges facing today's grid. The proposed Tariff Revisions couple the scenario-based planning improvements with changes to create more opportunities for stakeholder involvement to meet the increased interest in transmission planning as it evolves to stay aligned with resource planning and changing demands on the grid. This ensures that as Duke Energy's local transmission planning processes evolve, the processes remain open, transparent, and coordinated, as required by Order No. 890.

Importantly, there are many aspects of Attachment N-1 that would remain unchanged by this filing. Duke Energy's local transmission planning process would continue to satisfy the Commission's requirements because the proposed Tariff Revisions largely build upon pre-existing processes the Commission has found compliant with Order No. 890 and Order No. 1000. For example, there are no changes to the eligibility to participate in TAG, which remains open to anyone to participate, including state regulators and consumer advocates.[22] Therefore, CTPC local transmission planning process continues to comply with Order No. 890's openness principle.[23] Additionally, there are no changes proposed to Duke Energy's regional transmission planning process via SERTP, which the Commission has previously approved as compliant with Order No.

[20] North Carolina Transmission Planning Collaborative, Reference Materials, Attachment N-1 Transmission Planning Process REDLINED, http://www.nctpc.org/nctpc/document/REF/2023-08-09/REDLINE_ATTACHMENT_N-1_with_Proposed_Revisions_to_10.0.0_(8.8.2023).pdf.

[21] North Carolina Transmission Planning Collaborative, TAG Meeting Presentation (Sept. 14, 2023), http://www.nctpc.org/nctpc/document/TAG/2023-09-14/M_Mat/TAG_Meeting_Presentation_for_09-14_2023_FINAL.pdf.

[22] Joint OATT, Attachment N-1, Section 2.5. Language has been added to Section 2.5 to clarify that participation of state public utility regulatory commissions is at their discretion.

[23] Joint OATT, Attachment N-1, Section 2.3.2.3.

890 and Order No. 1000.[24] Stakeholders can still request regional planning studies through SERTP.[25]

Although there are ministerial revisions to create defined terms for the different local planning process study pathways and revisions to conform to the new meeting structure discussed below,[26] the Commission-required local planning processes for reliability, economic, public policy projects are retained in the Tariff Revisions.[27] Lastly, Duke Energy's compliance with Order No. 890's cost allocation principle is not affected by this filing because Duke Energy is only proposing changes to its local planning process, and Order No. 890's cost allocation principle relates only to projects like regional projects that would not fit under existing rate structures.[28]

Although many aspects of the local transmission planning process will remain unchanged and will continue to comply with the Commission's transmission planning requirements, the need for each of the proposed Tariff Revisions is described below.

A. Renaming Process Carolinas Transmission Planning Collaborative (CTPC)

The Tariff Revisions include revisions throughout Attachment N-1 to change the name of Duke Energy's local transmission planning process from the North Carolina Transmission Planning Collaborative (NCTPC) to the Carolinas Transmission Planning Collaborative (CTPC). As new stakeholders began to participate in the local transmission planning process in recent years, the name caused confusion over the scope of transmission planning conducted by the collaborative. Revising the name to the CTPC eliminates that confusion and reflects the fact that the collaborative, since its inception in 2005, has always planned for the DEC and DEP dual-state transmission systems in North Carolina and South Carolina. Section 1 of Attachment N-1 has also been revised to clarify what has always been the case—that any load-serving entity within Duke Energy's North Carolina or South Carolina footprint may join as a CTPC Participant.

B. New Process for Multi-Value Strategic Transmission Projects

As discussed above, a significant driver of these local transmission planning process improvements is the need to ensure alignment of transmission planning and resource planning, while also navigating other dynamics of the changing grid, such as increased electrification, new

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[24] *See supra* nn. 6 and 11.

[25] Joint OATT, Attachment N-1, Section 18.1. In addition, to the extent TAG participants identify Strategic Planning Scenarios, discussed below, that present issues of a regional nature, the OSC may also direct the TAG participant to submit the request to SERTP. Tariff Revisions at Section 4.5.4.

[26] Tariff Revisions at Section 4.1.

[27] Joint OATT, Attachment N-1, Sections 4.2, 4.3, and 4.4. Duke Energy anticipates that planning for Local Reliability Projects and compliance with NERC Reliability Standards will remain a significant portion of the Local Transmission Plan and scenario-planning analysis for Multi-Value Strategic Transmission Project may make the siloed categories of economic planning or public policy projects redundant.

[28] *See supra nn.* 10 and 11; Order No. 890 at P 558 (emphasizing that Order No. 890 did not "modif[y] the existing mechanisms to allocate costs for projects that are constructed by a single transmission owner and billed under existing rate structures" such as DEC's and DEP's existing transmission formula rates).

state and federal compliance requirements, and economic development initiatives to serve large energy users. To enable a holistic review of these various transmission drivers, the Tariff Revisions propose a new local planning process for studying Multi-Value Strategic Transmission Projects, which is not contemplated by Order No. 890 or Order No. 1000.[29]

Specifically, Duke Energy proposes that on at least a triennial basis, the CTPC will conduct a scenario-planning study process.[30] Strategic Planning Scenarios will be developed in coordination with the OSC, PWG, and TAG stakeholders.[31] As set out in Section 4.5.1 of the Tariff Revisions, Strategic Planning Scenarios:

> may consider, but are not limited to considering, (1) federal and state laws and regulations that affect the future resource mix and demand; (2) federal and state laws and regulations that affect decarbonization and electrification; (3) utility integrated resource plans approved pursuant to either N.C. G.S. § 62-110.1 or S.C. Code Ann. § 58-37-40 and long-term expected supply obligations for load serving entities; (4) trends in technology and fuel costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation; (5) resource retirements and replacements or expiration of power purchase agreements; (6) generator interconnection requests and withdrawals, and/or (7) the need for transmission during high-impact, low frequency events.

Although this proposal is focused on local transmission planning improvements, the definition of Strategic Planning Scenarios is largely based upon the Commission's proposal in its pending Notice of Proposed Rulemaking for regional transmission planning reforms and the proposed categories of factors that transmission providers should use to develop regional long-term planning scenarios.[32] The proposed definition is just and reasonable because it is adapted to Duke Energy's local transmission planning needs and goes beyond the requirements of Order No. 890 and Order No. 1000.

Using the Transmission NOPR's categories as a starting point, the proposed definition deviates from the language in the Transmission NOPR in certain ways. Specifically, the definition deviates from the Transmission NOPR proposal by expressly adding, at the suggestion of a TAG stakeholder, consideration of resource replacements. The definition also deviates by adding as one of the potential considerations high-impact, low frequency events, which were addressed in the Transmission NOPR as a separate requirement.[33] The proposed definition also does not specifically enumerate utility and corporate commitments and federal, state, and local goals that affect the future resource mix and demand as a factor. As Duke Energy explained in its comments

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[29] Tariff Revisions at Section 4.1(iv) and 4.5.

[30] *Id*. at Section 4.5.1.

[31] *Id*. Tariff Revisions at Sections 4.5.1, 4.5.2, and 4.5.3.

[32] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028, at P 104 (2022) ("Transmission NOPR").

[33] *Id.* at P 124.

on the Transmission NOPR, corporate commitments and local goals are more speculative, difficult to track, and may not be binding.[34]

Notably, the Tariff Revisions state that the enumerated list includes factors the Strategic Planning Scenarios may consider, *"but are not limited to considering*."[35] The Tariff Revisions were drafted in this way to preserve flexibility for OSC members and TAG participants to offer potential Strategic Planning Scenarios that do not necessarily fall within the enumerated categories so that the Multi-Value Strategic Transmission Planning Process can adapt over time to address the different dynamics of the changing grid.[36] The Tariff Revisions rely on the CTPC processes, including the technical expertise of the transmission planners involved in the PWG and the pre-existing TAG voting process, to build consensus over which proposed Strategic Planning Scenarios are most plausible and supported with objective and reliable data.[37] For each Multi-Value Strategic Transmission Project study process, the CTPC will study a minimum of three Strategic Planning Scenarios from those proposed by the OSC and TAG participants.[38]

Consistent with Section 5.1.4 of the Tariff Revisions, the criteria, assumptions, and methodology, including but not limited to the applicable planning horizon, for studying Multi-Value Strategic Transmission Projects will be documented in a Study Scope Document. This requirement not only provides the necessary transparency and opportunity for input from TAG Stakeholders, but it preserves flexibility for the local transmission planning process to select a planning horizon timeframe that is best suited for the Strategic Planning Scenarios selected and tailored to what reliable data is available. After the required Assumptions, Needs, and Solutions Meetings, described below, the CTPC will produce a Local Transmission Plan Report to capture the study results and recommendations on preferred solutions, their costs, benefits, and associate risks.[39]

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[34] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Comments of Duke Energy Corporation, Docket No. RM21-17-000 at 13-14 (filed Aug. 17, 2022).

[35] Tariff Revisions at Section 4.5.1 (emphasis added).

[36] Tariff Revisions at Sections 4.5.2 and 4.5.3 (providing opportunities for both TAG participants and OSC members to identify Strategic Planning Scenarios).

[37] Tariff Revisions at Sections 4.5.4 and 4.5.5. The members of the OSC and PWG include representatives from DEC, DEP, NCEMC, and Electricities.

[38] Tariff Revisions at Section 4.5.5. If TAG participants propose more than three Strategic Planning Scenarios, TAG participants will be asked to use the pre-existing TAG Sector Voting Process to narrow the Strategic Planning Scenarios proposed by TAG participants to three scenarios. *Id.*

[39] *See* Tariff Revisions at Sections 5.4.2, 5.5.1, and 5.6. Although the Local Transmission Plan Report will document the benefits of projects included in the Local Transmission Plan, the Tariff Revisions do not dictate the specific category of benefits to evaluate or how they will be measured. Neither Order No. 890 nor Order No. 1000 require inclusion of specific benefit categories for the type of local transmission planning process proposed herein. As proposed, the Tariff Revisions retain flexibility to tailor a benefits assessment to the Strategic Planning Scenarios that are studied and the benefits metrics most useful and relevant to justifying inclusion of a Local Project in the Local Transmission Plan. As an example of how benefits may be evaluated, for the RZEP Projects discussed above, Duke Energy developed cost-benefit assessment scores using an industry wide application, the Interruption Cost Estimate. *See* October 18, 2022 TAG Presentation at 35.

C. Transparency and Coordination Improvements

As interest and participation in the CTPC transmission planning process have grown exponentially in recent years, Duke Energy identified a need to establish a more detailed schedule for meeting and stakeholder input to improve transparency and coordination with stakeholders. To facilitate a more transparent and coordinated approach, the Tariff Revisions adopt a process similar to stakeholder processes the Commission has approved for other transmission owners and that the Commission proposed in the Transmission NOPR.[40] Specifically, the Tariff Revisions propose the following meeting process: 1) an Assumptions Meeting with the TAG participants to review the criteria, assumptions and models CTPC plans to use to study and identify local transmission system needs;[41] 2) a Needs Meeting with TAG participants to review identified transmission system constraints and associated transmission system needs;[42] and 3) a Solutions Meeting with TAG participants to review the identification of potential solutions to the transmission system constraints and system needs as well as alternative solutions considered.[43] To improve transparency and coordination with TAG participants, the Tariff Revisions include posting requirements for each meeting and minimum time periods between these meetings, which align with requirements and timelines that Commission has approved for other transmission owners.[44]

Following these series of meetings, the PWG will prepare a draft Local Transmission Plan Report, which will be provided to TAG stakeholders for their review and comment.[45] Duke Energy will also schedule a TAG stakeholder meeting to review the draft Local Transmission Plan Report.[46] This ensures that there will be at least four meetings a year, but potentially more if additional needs and solutions are identified, requiring additional meetings.[47]

At each meeting step, there are opportunities for TAG stakeholders to provide input and clearly defined timelines for Duke Energy and the CTPC to share information with the TAG

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[40] *See Monongahela Power Co.*, 162 FERC ⁋ 61,129 (2018) ("Attachment M-3 Order") (accepting PJM Transmission Owner's Attachment M-3 process for local transmission planning), *order on reh'g and compliance*, 164 FERC ⁋ 61,217 (2018) ("Attachment M-3 Rehearing Order"); Transmission NOPR at PP 400-402 (proposing minimum standards for an Assumptions, Needs, and Solutions Meeting to ensure stakeholders' opportunity for meaningful input).

[41] Tariff Revisions at Section 5.1.

[42] *Id*. at Section 5.3.

[43] *Id*. at Section 5.4. Importantly, the ability for TAG stakeholders to propose solutions, including alternative transmission projects or non-wire alternatives solutions, such as generation, energy storage, or demand response, is retained in the Tariff Revisions. *Compare* Joint OATT, Attachment N-1, Section 5.7.2 (currently effective version), *and* Tariff Revisions at Section 5.4.2.

[44] Attachment M-3 Rehearing Order at P 46 (approving time periods that are equal to or shorter than the time periods proposed in the Tariff Revisions).

[45] Tariff Revisions at Sections 5.6.1-5.6.2.

[46] *Id.* at Section 5.6.2.

[47] *Id.*at Section 5.7.

stakeholders and for TAG stakeholders to respond, ensuring continued compliance with Order No. 890's coordination principle.[48] The timelines are consistent with local planning processes the Commission has approved for other transmission owners.[49]

The PWG and OSC continue to retain the authority to select and approve a preferred set of solutions for the Local Transmission Plan.[50] Therefore, consistent with the Commission's requirements for open, transparent, and coordinated processes, not particular planning outcomes, the PWG and OSC may elect to not include Local Economic Projects, Local Public Policy Projects, and Multi-Value Strategic Transmission Projects in the Local Transmission Plan.[51]

D. Other Updates and Ministerial Revisions

The Tariff Revisions proposed here reflect the first substantive updates to Duke Energy's local transmission planning process in nearly a decade. As such, the Tariff Revisions include a number of changes to add more clarity to the procedures, as well as incorporate provisions to resolve questions about the local transmission planning process the CTPC has received in the past and to ensure the tariff accurately details current practices. The Tariff Revisions also include updates to conform to Commission precedent that has developed since the last substantive updates and ministerial revisions to adapt existing language to the improvements discussed above.[52] These updates and ministerial revisions are described below.

- Section 1: Duke Energy has added language to clarify the computation of time and deadlines for Attachment N-1.

- Sections 2.4.1.4, 2.4.3.2, 2.4.3.3, 3.2.3, 3.3.1.3, and 3.3.2.3: These new and revised sections reflect current practices for the Administrator's and guests' roles in OSC and TAG meetings, as well as the use of electronic and web-based communication platforms for meetings.

- Section 2.4.3.1: The revisions reflect ministerial changes to conform the tariff to the new processes described in Sections 4 and 5.

- Section 3.3.3.2 and 3.3.3.4: This revision is intended to conform the TAG meeting schedule to the requirements proposed in Section 5 and discussed above. Given the proposed requirement for at least one annual Assumption Meeting, Needs Meeting, Solutions Meeting, and a meeting to review the draft Local Transmission Plan, there will be at least four TAG

[48] *See* First Order No. 890 Compliance Order at P 18; Attachment M-3 Rehearing Order at P 26.

[49] Attachment M-3 Rehearing Order at P 46.

[50] Tariff Revisions at Sections 5.5.2 and 5.5.3. Duke Energy also retains the ability to reject OSC decisions it believes would harm reliability. Joint OATT, Attachment N-1, Section 6.1.1.

[51] Tariff Revisions at Sections 4.3.2.4, 4.4.2.4, and 4.5.7.

[52] The Tariff Revisions will also drive the need for changes to the various procedure and business practices referred to in the Joint OATT. Duke Energy is currently working with the other OSC members to update those procedures and business practices and will share the proposed revisions and updates on the CTPC website. Duke Energy plans to have final versions of the updated procedures and business practices finalized to coincide with the requested effective date for the Tariff Revisions.

meetings a year. The revised language also confirms that additional meetings beyond these four minimum meetings may be scheduled.[53]

- Section 3.3.3.3: The revision is intended to clarify the CTPC's procedures in light of the significant increase in participation in TAG meetings. The provision adopts a 'Chatham House Rule' to increase openness and discussion at TAG meetings, allowing TAG participants to freely use the information from the TAG meetings, but without attribution of any discussion to specific CTPC or TAG participants.

- Section 3.3.3.5: With the additional detail around opportunities and timelines for TAG written comments provided in Section 5, this section was added to clarify that written comments will be considered public and shared on the CTPC website, but without attribution. Only those submissions designated by the TAG participant as confidential will be treated confidentially and not shared or posted publicly.

- Section 4: Duke Energy has proposed additional language to clarify the scope of the local planning process based on Commission precedent issued since the last substantive revision to Attachment N-1. Specifically, the Commission confirmed that Order No. 890's requirements only apply to grid expansion activities, not asset management.[54] The Commission explained that asset management activities, such as "maintenance, compliance, work on infrastructure at the end-of-useful life, and infrastructure security", "may result in an incidental increase in transmission capacity that is not reasonably severable from the asset management project or activity."[55] The Commission found that incidental increases that are "not reasonably severable from" the asset management project do not render that asset management project as subject to the transmission planning requirements of Order No. 890.[56] Consistent with this precedent, Duke Energy has included additional prongs to the definition of Local Project to incorporate the standard from this Commission precedent to distinguish between, on one hand, asset management projects that *are not* subject to Order No. 890 and the CTPC process, and on the other hand, expansion activities that *are* subject to Order No. 890 and the CTPC process.

  Additionally, Duke Energy included in the Tariff Revisions a $5 million estimated cost threshold for Local Projects to be planned through the CTPC process. This is consistent with the cost threshold applicable to budgetary projections that DEC provides for local transmission plant anticipated to be placed in service in the next three years and included in transmission rates.[57] The threshold also ensures that all significant transmission expansion projects will be planned through the CTPC process. Of Duke Energy's transmission planning projects currently in active development or construction, which may include projects that do not expand or

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[53] *See also* Tariff Revisions at Section 5.7.

[54] *So. California Edison Co.*, 164 FERC ⁋ 61,160, at PP 31-34 (2018) ("California Order"); *Cal. Pub. Util. Comm'n v. Pac. Gas & Elec. Co.*, 164 FERC ¶ 61,161, at P 68 (2018); *PJM Interconnection, L.L.C.*, 172 FERC ⁋ 61,136 at P 89 (2020).

[55] California Order at PP 32-33.

[56] *Id.* at 33.

[57] Joint OATT, Schedule 10-B, Exhibit A, Section 2(g).

enhance the transmission grid, more than 92 percent of DEC projects and 93 percent of DEP projects are greater than $5 million.

- Section 4.1: The Tariff Revisions include ministerial revisions to establish defined terms for the four different types of Local Projects that are referred to throughout Attachment N-1.

- Section 4.1.4: This new provision is intended to retain a mid-year status update that under the current process occurs during the second TAG meeting.[58] The provision also clarifies and codifies current practice of allowing mid-year updates to the Local Transmission Plan to address emergent needs, as long as there has been an opportunity for TAG stakeholder review and comment.

- Section 4.2: Revisions in this Section reflect a reorganization of existing provisions, revisions to conform to the new meeting process proposed in the Tariff Revisions, and revisions to reflect additional detail as to data collection requirements based on past practice and current data needs.[59] The sub-sections of Section 4.2 are largely based off of existing language in the preamble of Attachment N-1, Section 4 that was approved to satisfy the comparability requirements of Order No. 890-A.[60] With the growth of demand response resources and behind-the-meter distributed energy resources, Duke Energy is proposing more specific definitions to ensure data provided will accurately reflect load forecast projections and be comparable to data the Duke Energy uses for its load forecast projections. The proposed revisions also expand the resources that Duke Energy will consider as an alternative to transmission expansion, adding reasonable combinations of demand response and generation resources and/or other technology solutions.[61]

- Section 5.2.4: In light of the additional participation in TAG and the expanded study options proposed in the Tariff Revisions, this section adds details on the process and deadlines for submission of data required under a Study Scope Document. Duke Energy has found that if a study requires a TAG participant or third-party to provide data, and that data is not provided in a timely basis, there is confusion on delays and obligations to continue the study. The Tariff Revisions propose that the Study Scope Document will adopt reasonable deadlines; failure to meet those deadlines may be cured within 30 days; and if the data is still not provided, then there will be no obligation to continue the study during that planning cycle. TAG participants or other study sponsors would be free to submit the study request in accordance with the Attachment N-1 procedures the following annual cycle.

- Section 6: In addition to ministerial revisions to re-order the dispute resolution section, the Tariff Revisions remove the role of NCUC Public Staff as a mediator of CTPC Participant

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[58] *See* Joint OATT, Attachment N-1, Section 5.4.9.

[59] *See Id*., Attachment N-1, Section 4.

[60] *See* First Order No. 890 Compliance Order at P 36; *Duke Energy Carolinas, LLC, and Progress Energy Carolinas, Inc.*, Attachment K Compliance Filing, Docket Nos. OA08-50-001 at 7 (filed Dec. 17, 2008); Second Order No. 890 Compliance Order at PP 35-37.

[61] Tariff Revisions at Section 4.2.2.3.

disputes to better reflect the dual-state nature of Duke Energy's system. Instead, the existing dispute resolution procedures under Section 12.1 will apply.[62]

- Section 9.4.1: The Tariff Revisions reflect the fact that the OSC Vice Chair may be a non-FERC jurisdictional representative, but Duke Energy remains obligated under the tariff to ensure compliance with Standard of Conduct rules.

- Section 9.4.3 and 9.4.4: The Tariff Revisions reflect a change from using the SERC confidentiality agreement to the CTPC Process Confidentiality Agreement, which is the same process for providing confidential information Duke Energy applies in the generator interconnection context. The changes also place Duke Energy representatives in the role of administering the confidentiality provisions, instead of the OSC Vice Chair. Similar to the change in Section 9.4.1, this Tariff Revisions reflects the fact that the OSC Vice Chair may be a non-FERC jurisdictional representative for one of the other CTPC Participants.

- Section 10.1: The Tariff Revisions streamline this section to update and cross-reference to the current state integrated resource planning statutes.

- Section 11.3: The Tariff Revisions delete Section 11.3, which described Duke Energy's coordination activities within VACAR. Duke Energy is not actively engaged in transmission planning coordination activities via VACAR because such coordination now takes places within SERTP or via the bilateral Carolinas Transmission Coordination Arrangement with Dominion Energy South Carolina and South Carolina Public Service Authority.[63]

III. CONTENTS OF FILING

The following documents are included in this filing in addition to the relevant tariff records:

- This transmittal letter;

- Clean copy of the proposed tariff sheets for inclusion in the Joint OATT; and

- Marked copy showing modifications to the currently effective tariff sheets in the proposed tariff sheets.

IV. REQUEST FOR WAIVERS

The information submitted with this filing substantially complies with the requirements of Part 35 of the Commission's rules and regulations applicable to filings of this type. To the extent necessary, Duke Energy requests waiver of the requirement to submit the cost of service data required by 18 C.F.R. § 35.13. Further, Duke Energy requests a waiver of any applicable

[62] *Id*. at Sections 6.1.2 - 6.1.3.

[63] *See* Joint OATT, Attachment N-1 Section 11.4 (referring to bilateral coordination activities).

requirement of Part 35 for which a waiver is not specifically requested, if necessary, in order to permit this filing to become effective as proposed.

V. REQUESTED EFFECTIVE DATE

Duke Energy seeks an effective date 60 days after filing on January 1, 2024.

VI. COMMUNICATIONS

All correspondence, communications, pleadings, and other documents related to this proceeding should be addressed to the person listed below.

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VII. PERSONS SERVED

Pursuant to 18 C.F.R. § 385.2010(f)(i) of the Commission's regulations, a copy of this filing is being served by electronic means on all customers taking service under the Joint OATT, as well as the following entities:

Public Service Commission of South Carolina
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VIII. CONCLUSION

For the reasons stated herein, Duke Energy respectfully requests that the Commission issue an order accepting the Tariff Revisions effective January 1, 2024.

Respectfully submitted,

/s/ Molly Suda

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ATTACHMENT N-1

TRANSMISSION PLANNING PROCESS
(DEP Zone and DEC Zone)

1. INTRODUCTION

Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP) (sometimes referred to individually as Company and collectively Companies), entities 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 local transmission planning requirements imposed by Order Nos. 890 and 1000 through the process developed and implemented by the Carolinas Transmission Planning Collaborative (CTPC Process or Local Planning Process). The Carolinas Transmission Planning Collaborative includes load serving entities (LSE) in the States of North Carolina and South Carolina (collectively, CTPC Participants or Participants) within the DEC and DEP footprint.

The Companies ensure that their Transmission Systems are planned in accordance with the regional planning requirements imposed by Order No. 1000 through participation in the Southeastern Regional Transmission Planning Process (SERTP or SERTP Process).

In addition to engaging in local transmission planning through the CTPC Process and regional transmission planning through the SERTP Process, the Companies engage in additional coordination activities with transmission providers located inside and outside their region, as discussed in Section 11. Such activities include participation in SERC Reliability Corporation (SERC), which focuses on reliability assessments. The SERTP engages in interregional coordination as described in Attachment N-1 – FRCC, Attachment N-1 – MISO, Attachment N-1 – PJM, Attachment N-1 – SCRTP, and Attachment N-1 – SPP.

Unless noted otherwise, Section references in this Attachment N-1 refer to Sections within this Attachment N-1.

For purposes of computation of time, all references in this document shall be calendar days. If any of the deadlines set forth in this document should fall on a weekend or holiday recognized by FERC, then the deadline shall fall on the next business day.

PART I -- LOCAL PLANNING PROCESS

2. CTPC PROCESS OVERVIEW INCLUDING THE PROCESS FOR CONSULTING WITH TAG PARTICIPANTS

The CTPC shall annually develop a single, coordinated local transmission plan (Local 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 Carolinas Transmission Planning Collaborative Participation Agreement (Participation Agreement) governs the participation in the

CTPC and the CTPC Process. The Participation Agreement is located on the CTPC's Website (http://www.nctpc.org/nctpc/).

2.2 The CTPC Process is summarized in a document entitled *Carolinas Transmission Planning Collaborative Process* that is located on the CTPC's Website.

2.3 Participation in the CTPC

2.3.1 Pursuant to the *Participation Agreement*, the CTPC has three components: the Oversight/Steering Committee (OSC), the Planning Working Group (PWG), and the Transmission Advisory Group (TAG).

2.3.2 Eligibility for participation in the three CTPC components is as follows:

2.3.2.1 The appointment of OSC members by the CTPC Participants is governed by the *Participation Agreement*. The qualifications required to serve on the OSC are set forth in a document entitled *Scope - Oversight/Steering Committee* that is located on the CTPC's Website.

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

2.3.2.3 Anyone may participate in TAG meetings and sign-up to receive TAG communications. The TAG is comprised of TAG participants. An employee or agent of a CTPC Participant who 1) performs or supervises transmission planning activities or 2) is a member of the OSC or PWG may not be a TAG participant, but employees or agents of CTPC Participants that perform activities other than transmission planning activities may be TAG participants.

2.4 Responsibilities and Decision-Making of CTPC Components

The responsibilities of the components within the CTPC 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 CTPC 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.*

2.4.1.4 The OSC is responsible for selecting an Administrator in the manner set forth in the *Participation Agreement.* The Administrator shall act as a facilitator for the OSC and TAG and shall assist the chair and vice-chair in the performance of their duties as reasonably requested.

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 CTPC Participants to aid in the development of an annual Local Transmission Plan. Opportunities for input from TAG participants are detailed in Sections 4 and 5 hereof. A full list of the TAG's responsibilities is found in *Scope - Transmission Advisory Group,* which is located on the CTPC's Website.

2.4.3.2 The OSC chair will chair the TAG meetings. The Administrator will serve as the facilitator for the TAG meetings. TAG decision-making is by consensus among the TAG participants. However, in the event consensus cannot be reached, voting will be conducted through the TAG Sector Voting Process. The Administrator will provide notice to the TAG participants in advance of the TAG meeting that specific votes will be taken during the TAG meeting.

2.4.3.3 Only TAG participants attending the meeting (in person or by telephone, electronic or other communication facilities that permit all participants to communicate with each other during the meeting) will be allowed to participate in the TAG Sector Voting Process. No voting by proxy is permitted.

2.4.4 TAG Sector Voting Process.

2.4.4.1 In order for a TAG participant to participate in the TAG Sector Voting Process, the TAG participant must have registered with the Companies at least two weeks prior to the first meeting at which the TAG participant intends to vote. Such web-based registration will require the TAG participant to provide the following information to the Companies: name, home or business address, place of employment (if any), email address (if any), and telephone number. The registration form will require the TAG participant to indicate whether the TAG participant is registering as an "Individual" or as an agent or employee of a "TAG Sector Entity." If the TAG participant registers as an agent, member, or employee of a TAG Sector Entity, s/he must identify such TAG Sector Entity. An individual TAG participant may register as an agent, member, or employee of more than one TAG Sector Entity.

2.4.4.2 A TAG Sector Entity may be any organized group (e.g., corporation, partnership, association, trust, agency, government body, etc.) but cannot be an individual person. A TAG Sector Entity may be a member of only one TAG Sector. A TAG Sector Entity and its affiliates or member organizations all may register as separate TAG Sector Entities, as long as such affiliates or member organizations meet the definition of a TAG Sector Entity.

2.4.4.3 A TAG Sector Entity should elect to be a member of one of the following TAG Sectors: Cooperative LSEs that serve load in the CTPC footprint; Municipal LSEs that serve load in the CTPC footprint; Investor-Owned LSEs that serve load in the CTPC footprint; Transmission Providers/Transmission Owners that are not LSEs in the CTPC footprint; Transmission Customers a customer taking Transmission Service from at least one Company in the CTPC; Generator Interconnection Customers (a customer taking FERC- or state- jurisdictional generator interconnection service from at least one of the Companies in the CTPC); Eligible Customers and Ancillary Service Providers (includes developers, ancillary service providers, power marketers not currently taking transmission service, and demand response providers); and General Public. An Individual is only eligible to join the General Public Sector.

2.4.4.4 Only one individual TAG participant that has registered as an agent or employee of a TAG Sector Entity may vote on behalf of a particular TAG Sector Entity with regard to any particular vote. An individual TAG participant may vote on behalf of more than one TAG Sector Entity, if authorized to do so. Questions to be voted on will be answerable with a Yes or No.

2.4.4.5 If a vote is to be taken, each TAG Sector that has at least one TAG Sector Entity representative, or at least one Individual or TAG Sector Entity representative in the case of the General Public Sector, present will receive a Sector Vote with a worth of 1.00. A Sector Vote is divisible. The vote of each TAG participant eligible to vote in a Sector Vote is not divisible. The vote of each TAG participant in a TAG Sector will be multiplied by 1.00 divided by the total number of TAG participants voting in such Sector to determine how the Sector Vote with a total worth of 1.00 will be allocated between "Sector Yes Votes" and "Sector No Votes." That is, each Sector Vote will be allocated such that the Sector Yes Vote(s) and Sector No Vote(s) totals 1.00. The Sector Yes Vote and Sector No Vote for each TAG Sector will then each be weighted by multiplying each of them by 1.00 divided by the number of TAG Sectors participating in the relevant vote. The results will be called "Weighted Sector Yes Vote" and "Weighted Sector No Vote." The winning position will be the larger of the Weighted Sector Yes Vote and Weighted Sector No Vote. Appendix 3 contains an example of the voting process.

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. If they choose to be a TAG participant, state public utility regulatory commissions would be TAG Sector Entities in the General Public Sector. State public utility regulatory commissions also may seek to receive periodic status updates and the progress reports on the CTPC Process.

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

All information regarding local transmission planning meetings and communications are located on the CTPC 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 CTPC website.

3.1.2 Information about signing up to be a TAG participant and to receive email communications will be posted on the CTPC Website.

3.1.3 The OSC will publish highlights of its meetings on the CTPC 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 or other web-based 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, and 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, their alternates, PWG members, and, if approved, guests. Guests will be approved in accordance with the Scope of the OSC document as posted to the CTPC website.

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 OSC and their alternatives, and, if approved, guests. Guests will be approved in accordance with the Scope of the PWG document as posted to the CTPC website.

3.3.3 TAG

3.3.3.1 TAG meetings are chaired by the OSC chair and facilitated by the Administrator.

3.3.3.2 The TAG generally meets four times a year in accordance with the procedures set forth in Section 5.

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 to TAG participants that are qualified to receive Confidential Information. TAG Participants are free to use information from the TAG meeting discussion, but are not permitted to attribute any particular discussion comment(s) to a specific CTPC or TAG Participant.

3.3.3.4 A yearly meeting and activity schedule is proposed, discussed with, and provided to TAG participants annually. Additional TAG meetings may be scheduled on an as needed basis, in conformity with Section 5.

3.3.3.5 Any submissions by TAG participants to the PWG, OSC, or CTPC Participants pursuant to the procedures in Section 5 will be deemed public and will be posted on the CTPC Website for other TAG participants. However, TAG participants may designate all or part of its submission as confidential information, pursuant to Section 9.2. Additionally, for all public postings of submissions by TAG participants, the identity of the TAG participant who made the submission will be treated as confidential information and will be posted publicly only by consent of the TAG participant upon submission.

4. DESCRIPTION OF THE LOCAL PLANNING PROCESS

The CTPC Process is a coordinated local transmission planning process. The entire iterative process ultimately results in a single Local Transmission Plan that appropriately balances the costs, benefits and risks associated with the use of transmission, generation, and demand-side resources. The Local Transmission Plan will identify local transmission projects (Local Projects). A Local Project is defined as a transmission facility that (1) is located solely within the footprint of the DEC or DEP Transmission Systems, (2) is not selected in the regional transmission plan for purposes of regional cost allocation; (3) is either an expansion or enhancement to the DEC or DEP Transmission System; (4) is estimated to cost greater than $5 million; and (5) is not a project to maintain, repair, or replace existing transmission facilities in order to maintain a safe, reliable, and compliant grid, even if such project results in an incidental increase in transmission capacity that is not reasonably severable from work to maintain, repair, or replace the existing transmission facility.

4.1 Overview of Local Planning Process

As described in Sections 4.2 through 4.5, the Local Planning Process performs studies to identify:

- (i) Local Projects that are necessary to preserve reliability and comply with applicable reliability standards (“Local Reliability Projects”);
- (ii) Local Projects that will increase transmission access to potential supply resources inside and outside the Control Areas of the Companies based on Participant or TAG participant requested economic studies (“Local Economic Projects”);
- (iii) Local Projects to satisfy Public Policy Requirements (“Public Policy Projects”); and/or
- (iv) Local Projects that will integrate new generation resources and/or loads and provide other benefits in a least-cost manner (“Multi-Value Strategic Transmission Projects”).

The following are the general steps in the Local Planning Process

4.1.1 Each year, the OSC will initiate the process to develop the annual Local Transmission Plan through the study processes defined herein.

4.1.2 The OSC will provide notice of the commencement of the process to develop the annual Local Transmission Plan via e-mail to the TAG and posts a notice on the CTPC website.

4.1.3 The process will allow for flexibility to make modifications to the Local Transmission Plan throughout the year as needs change, new needs arise, or new solutions to problems are identified.

4.1.4 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 for each type of Local Project is an iterative one. A list of relevant dates established for the planning cycle will be posted on the CTPC website.

4.1.5 At the approximate mid-point of the annual Local Transmission Planning process, but no later than August 15 of each year, the Companies will provide a written report on the status of the Local Projects presented in the previous Local Transmission Plan (the "Mid-Year Update Report"). The Mid-Year Update Report will be posted on the CTPC website and will include the following information: the name of the project, the detailed issue it resolves, the name of the relevant Company(s), the original planned in-service date and the current expected in-service date, an explanation of the reasons for any change, the scope of the project, and updated cost estimates for the Local Projects. Prior to OSC approval, the Mid-Year Update Report will be reviewed at a TAG meeting scheduled at the approximate mid-point of the annual planning process. The Mid-Year Update Report may include new Local Projects added since the previous annual Local Transmission Plan to address an emergent need, as long as the emergent need has been presented to TAG participants for review and comment prior to the OSC's approval of the Mid-Year Update Report.

4.2 Overview of Study Process for Local Reliability Projects

4.2.1 The Local Planning Process starts with a base reliability study (Base Case) that evaluates each Transmission System's ability to meet projected load with a defined set of resources for network transmission customers as well as the needs of firm point-to-point customers, whose needs are reflected in their transmission contracts and reservations.

4.2.2 In order to ensure comparability and consistency with the Data Collection requirements in Section 5:

4.2.2.1 Customers taking Network Transmission Service are expected to accurately reflect in their annual load forecast projections: (i) demand response resources, including but not limited, to any activities by load-serving entities to reduce, interrupt, or otherwise manage end-use customer load through the use of centralized control and/or by supplying load signal information, real-time pricing signals, or specific instruction; (ii) energy efficiency; and (iii) distributed energy resources, which is a kW/MW resource that nets with customer demand if behind the meter and must be specified separately.

4.2.2.2 Eligible Customers and Transmission Customers (a) providing information about current and potential needs for Point-to-Point Transmission Service and (b) when submitting their request for Point-to-Point Transmission Service are expected to accurately reflect: (i) demand response resources, including but not limited, to any activities by load-serving entities to reduce, interrupt, or otherwise manage end-use customer load through the use of centralized control and/or by supplying load signal information, real-time pricing signals, or specific instruction; (ii) energy efficiency; and (iii) distributed energy resources, which is a kW/MW resource that nets with customer demand if behind the meter and must be specified separately.

4.2.2.3 To the extent a TAG participant has a demand response resource, a generation resource, and/or any other reasonable combination of alternative resources and/or technology solutions ("Alternate Proposal") that the TAG participant desires the CTPC to specifically consider as an alternative to transmission expansion, or otherwise in conjunction with the CTPC Process, such TAG participant sponsoring such Alternate Proposal shall provide within 14 calendar days of the Needs Meeting the necessary information (cost, performance, lead time to install, etc.) in order for the CTPC to consider such Alternate Proposal comparably with other alternatives.

4.3 Overview of Study Process for Local Economic Projects

4.3.1 The Local Economic Study Process is the process that allows the TAG participants to propose economic upgrades to be studied as part of the Local Planning Process. The Local Economic Study Process evaluates the means to increase transmission access to potential supply resources inside and outside the Control Areas of the Companies. This economic analysis provides the opportunity to study what transmission upgrades would be required to reliably integrate new resources.

4.3.2 The Local Economic Study Process begins with the TAG participants proposing scenarios and interfaces to be studied at least 30 calendar days prior to the Assumptions Meeting described in Section 5.1.3. 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 CTPC 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 a regional nature. The OSC will direct the TAG participants to submit any regional study requests to the SERTP. Throughout the Local Economic Study Process, TAG participants (including TAG participants representing transmission solutions, generation solutions, and solutions utilizing demand resources) may participate.

4.3.2.1 The OSC will review the PWG analysis, approve the compiled study list, and provide the study list, including study criteria, assumptions, and methodology to the TAG in accordance with the procedures set forth in Section 5.1.3 for the Assumptions Meeting(s) applicable to the Local Economic Project Study Process. For the study scenarios that impact the CTPC footprint, but are not Regional in nature, the TAG participants will select within 14 calendar days of the Assumptions Meeting a maximum of three scenarios that will be studied within a single CTPC planning cycle. If consensus cannot be reached as to which scenarios to study within 14 calendar days of the Assumptions Meeting, the choice will be resolved through the TAG Sector Voting Process. The TAG participants may request that the maximum of the three scenarios be combined or clustered.

4.3.2.2 There will be no charge to the TAG participants for the three studies selected by the TAG participants. However, if a particular TAG participant wants the CTPC to evaluate a scenario that was not chosen by the TAG participants, then the TAG participant can request to have the CTPC conduct the study. The CTPC Participants 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.

4.3.2.3 The final results of the Local Economic Study Process include the estimated costs and schedules to provide the increased transmission capabilities. The Local Economic Study Process results are reviewed and discussed with the TAG participants in accordance with the procedures set forth in Section 5.4.2 for the Solutions Meeting(s) applicable to the Local Economic Project Study Process.

4.3.2.4 Only Local Economic Projects approved pursuant to Section 5.6 are included in the Local Transmission Plan.

4.4 Overview of Study Process for Public Policy Projects.

4.4.1 Each year, the OSC will determine if there are any public policies driving the need for local transmission.

4.4.2 Criteria for determining if public policy drives local transmission need.

4.4.2.1 Public policy must be reflected in state, federal, or local law or regulation (including order of a state, federal, or local agency).

4.4.2.2 At least 30 calendar days prior to the Assumptions Meeting described in Section 5.1.3 the OSC will seek input (e.g. written comments) from TAG participants, asking that they (i) identify any public policies that are driving the need for local transmission, pursuant to the criteria below, and (ii) propose study criteria, assumptions, and methodology to evaluate the need for local transmission driven by the identified public policy ("Public Policy Study Proposal").

4.4.2.3 The OSC may itself identify a Public Policy Study Proposal.

4.4.2.4 Public Policy Study Proposals will be reviewed in accordance with Section 5.1.

4.4.3 Within two weeks following the Assumptions Meeting, the OSC will post on the CTPC website an explanation of (1) those local transmission needs driven by Public Policy Requirements that have been identified for evaluation for potential transmission projects in the then-current planning cycle; and (2) the reason(s) why other suggested, possible transmission needs driven by Public Policy Requirements proposed by the TAG participants or the OSC were not selected for further evaluation. If one or more public policies are identified as driving local transmission needs, the Companies shall follow the procedures set forth in Section 5.3, and TAG participants may suggest projects to meet those needs in accordance with procedures set forth in Section 5.4. If no public policies are identified for the planning year, TAG participants will be unable to propose Public Policy Project solutions.

4.4.4 Only Public Policy Projects approved pursuant to Section 5.6 are included in the Local Transmission Plan.

4.5 Overview of Study Process for Multi-Value Strategic Transmission Projects

4.5.1 On at least a triennial basis, the study process for Multi-Value Strategic Transmission Projects allows the OSC and TAG participants to propose different scenarios for evaluation of new resource supply options, changing load dynamics, transmission solutions requiring longer lead times, generator retirements, and/or economic development opportunities ("Strategic Planning Scenarios"). Strategic Planning Scenarios may consider, but are not limited to considering, (1) federal and state laws and regulations that affect the future resource mix and demand; (2) federal and state laws and regulations that affect decarbonization and electrification; (3) utility integrated resource plans approved pursuant to either N.C. G.S. § 62-110.1 or S.C. Code Ann. § 58-37-40 and long-term expected supply obligations for load serving entities; (4) trends in technology and fuel costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation; (5) resource retirements and replacements or expiration of power purchase agreements; (6) generator interconnection requests and withdrawals, and/or (7) the need for transmission during high-impact, low frequency events. At the beginning of each annual planning cycle, the PWG will recommend to the OSC and the OSC will decide whether or not to initiate a Multi-Value Strategic Transmission Project Study process more frequently than according to the minimum triennial basis.

4.5.2 At least 30 calendar days prior to the Assumptions Meeting described in Section 5.1.3, the OSC will seek input from TAG participants on Strategic Planning Scenarios to evaluate. The form to propose a Strategic Planning Scenario is posted on the CTPC Website. Proposed Strategic Planning Scenarios must specifically identify models, assumptions, and data proposed to be used in the study process. Proposed Strategic Planning Scenarios must also identify an appropriate planning horizon for the proposed scenario(s) to be studied.

4.5.3 The OSC may itself also identify Strategic Planning Scenarios to be presented at an Assumptions Meeting described in Section 5.1.3.

4.5.4 The PWG will determine if it would be efficient to combine and/or cluster any of the proposed Strategic Planning Scenarios and will also determine if any of the proposed Strategic Planning Scenarios are of a Regional nature. If the proposed Strategic Planning Scenario is regional in nature, the OSC will direct the TAG participants to submit the regional study requests to the SERTP.

4.5.5 The OSC will review the PWG analysis of the proposed Strategic Planning Scenarios to be studied, approve the compiled study list, and provide the study list, including study criteria, assumptions, and methodology to the TAG in accordance with the procedures set forth in Section 5.1.3 for the Assumptions Meeting(s) applicable to the Multi-Value Strategic Transmission Project Study Process. If there are more than three proposed Strategic Planning Scenarios proposed by TAG participants pursuant to Section 4.5.2 that impact the CTPC footprint, but are not Regional in nature presented at the Assumptions Meeting, the TAG participants will select within 14 calendar days of the Assumptions Meeting a maximum of three proposed Strategic Planning Scenarios that will be studied within a single CTPC planning cycle. If consensus cannot be reached as to which scenarios to study within 14 calendar days of the Assumptions Meeting, the choice will be resolved through the TAG Sector Voting Process. The TAG participants may request that the three scenarios be combined or clustered. A minimum of three Strategic Planning Scenarios will be evaluated for each Multi-Value Strategic Transmission Project study process.

4.5.5.1 There will be no charge to the TAG participants for the three proposed Strategic Planning Scenarios studies selected by the TAG participants. However, if a particular TAG participant wants the CTPC to evaluate a scenario that was not chosen by the TAG participants, then the TAG participant can request to have the CTPC conduct the study. The CTPC Participants 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.

4.5.6 The final results of the Multi-Value Strategic Transmission Project Study Process will include the estimated costs and schedules to provide the increased transmission capabilities. The Multi-Value Strategic Transmission Project Study results are reviewed and discussed with the TAG participants in accordance with the procedures set forth in Section 5.4 for the Solutions Meeting(s) applicable to the Local Economic Project Study Process.

4.5.7 Only Multi-Value Strategic Transmission Projects approved pursuant to Section 5.6 are included in the Local Transmission Plan.

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

5.1 Identification of Study Criteria, Assumptions, and Methodology

5.1.1 The PWG establishes the reliability planning criteria by which the study results will be measured to identify Local Reliability Projects for inclusion in the Local Transmission Plan, in accordance with North American Electric Reliability Corporation (NERC) and SERC Reliability Standards and individual Company criteria.

5.1.2 Study criteria, assumptions, and methodology for Local Economic Projects, Public Policy Projects, and Multi-Value Strategic Transmission Projects will be identified in accordance with the Sections 4.3, 4.4, and 4.5, respectively. Inclusion of Local Economic Projects, Public Policy Projects, and Multi-Value Strategic Transmission Projects in the Local Transmission Plan is subject to the procedures and OSC approval required by Section 5.6.

5.1.3 The Companies shall schedule and facilitate a minimum of one TAG meeting to review the criteria, assumptions, and methodology the PWG plans to use to identify needs and transmission solutions to include in the Local Transmission Plan ("Assumptions Meeting"). The Assumptions Meeting shall take place prior to the OSC's approval of the final set of study assumptions. The Companies shall provide the criteria, assumptions, and methodology to the Administrator for posting on the CTPC website at least 20 calendar days in advance of the Assumptions Meeting to provide TAG participants sufficient time to review this information. TAG participants may provide comments on the criteria, assumptions, and methodology to the PWG for consideration either prior to or following the Assumptions Meeting. The Companies shall review and consider comments that are received within 14 calendar days of the Assumptions Meeting and may respond or provide feedback as appropriate.

5.1.4 The final criteria, assumptions, and methodology, including but not limited to the applicable planning horizon, for studying Local Economic Projects, Public Policy Projects, and Multi-Value Strategic Transmission Projects shall be set forth in a *Study Scope Document* to be reviewed by the TAG and approved by the OSC and posted to the CTPC website.

5.1.5 Transmission System planning documents of DEC and DEP 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.

5.2 Data Collection and Case Development

5.2.1 The Companies will prepare the Base Case models. The most current Multi-Regional Modeling Working Group (MMWG) or SERC Long-Term Study Group model will be used for the systems external to DEC and DEP as a starting point for the Base Case to be used by both DEP and DEC. The Base Case will include the detailed internal models for DEP and DEC and will include current transmission additions planned to be in-service for given years.

5.2.2 The Companies will also develop the necessary Change Case models as required to evaluate scenarios directed by the *Study Scope Document* for Local Reliability Projects, Local Economic Projects, Public Policy Projects, and Multi-Value Strategic Transmission Projects. Such Change Case models will also be reviewed with the PWG to ensure that they represent the study criteria, assumptions, and methodology approved by the OSC in the *Study Scope Document*. Upon request, TAG participants will be provided the Change Case models, subject to CEII and confidentiality requirements. For Local Economic Projects, Public Policy Projects, and Multi-Value Strategic Transmission Projects, TAG participants may provide input to the PWG with regard to whether the models accurately represent the *Study Scope Document* approved by the OSC in accordance with the procedures set forth in Section 5.3.3 and during the Needs Meeting defined therein.

5.2.3 The following data are relevant to the development of internal models for the Companies:

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

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

Generation real and reactive capacity data;

Generation dispatch priority data;

Dispatch assumptions for variable energy resources and energy storage;

Transmission facility impedance and rating data;

Interchange data adjusted to correctly model transfers associated with designated network resources from outside the Companies' Control Areas;

Generation retirement;

Resource supply additions with locational information;

Import and export assumptions;

TRM and CRSG requirements; and

DER Aggregation modeling assumptions.

5.2.4 The Companies 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, Eligible Customers, and Transmission 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 at the Assumptions Meeting, approved by the OSC, and documented in the *Study Scope Document*. To the extent data is required from TAG participants to conduct the study processes for Local Economic Projects, Public Policy Projects, and/or Multi-Value Strategic Transmission Projects, TAG participants are obligated to provide such data to the Companies in accordance with the timelines documented in the *Study Scope Document.* Timelines for submission of data by TAG participants in the *Study Scope Document* set by the PWG shall be reasonable and may be amended if approved by the OSC. OSC approval of requests to extend timelines for submission of data shall not be unreasonably withheld. If required data is not provided in accordance with the timelines approved in the *Study Scope Document* or as amended by approval of the PWG, and the failure to provide the data is not cured within 30 days of the due date, the CTPC Participants shall have no obligation to continue with the study during the current planning cycle.

5.2.5 Transmission Customers should provide the Companies with timely written notice of material changes in any information previously provided relating to load, resources, or other aspects of their facilities or operations affecting the Company's ability to provide service that affect the Base Case models. Network customers may provide revised versions of previously submitted annual data reporting forms.

5.3 Technical Analysis and Identification of Transmission Needs

5.3.1 The PWG performs the technical analysis in accordance with the OSC approved study criteria, assumptions, and methodology in the *Study Scope Document* and produces the study results.

5.3.2 Results from the technical analysis are reported to identify transmission elements approaching their limits such that all CTPC 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.

5.3.3 The Companies shall schedule and facilitate a minimum of one TAG meeting per planning cycle to review the identified criteria violations, transmission elements approaching their limits, and resulting system needs, if any, that may drive the need for a Local Project (Needs Meeting). The Needs Meeting may be scheduled no fewer than 25 calendar days after the Assumptions Meeting. At the Needs Meeting, the Companies will review the identified system needs and the drivers of those needs, based on the application of its criteria, assumptions, and methodology in the *Study Scope Document*. The Companies shall share with the Administrator for posting to the CTPC website the identified criteria violations and drivers no fewer than 14 calendar days in advance of the Needs Meeting. TAG participants may provide comments on the criteria violations and drivers to the PWG for consideration prior to, at, or following the Needs Meeting. The Companies shall review and consider comments that are received within 14 calendar days of the Needs Meeting and may respond or provide feedback as appropriate.

5.3.4 Sufficient information will be made available, subject to CEII and confidentiality restrictions, to enable TAG participants to replicate the results of planning studies reviewed at the Needs Meeting. A TAG participant seeking data and information that would allow it to replicate the CTPC planning studies should provide such request to the Companies, who will verify that confidentiality requirements described in Section 9 have been met before providing such information.

5.4 Local Solution Development

5.4.1 The PWG identifies potential solutions to the transmission needs identified during the Needs Meeting 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.

5.4.2 No fewer than 25 calendar days after the Needs Meeting, the Companies shall schedule and facilitate a minimum of one TAG meeting per planning cycle to review potential solutions identified by the PWG pursuant to Section 5.4.1 (“Solutions Meeting”). The Companies shall share with the Administrator and post their potential solutions, as well as any alternatives, including non-wire alternatives, identified by the PWG or TAG participants, no fewer than 14 calendar days in advance of the Solutions Meeting. TAG participants may provide comments on the potential solutions to the PWG for consideration either prior to or following the Solutions Meeting, including but not limited to proposals for alternative transmission or non-wire alternative solutions to address the identified need, as well as other reliability, economic and/or public policy transmission needs. To the extent TAG participants propose alternative solutions, they shall provide to the PWG the necessary information (cost, performance, lead time to install, etc.) for the alternative solutions to be compared with other alternatives. The PWG shall review and consider comments and alternative solutions that are received within 14 calendar days of the Solutions Meeting and may respond or provide feedback as appropriate. To the extent a TAG participant proposes an alternative solution that is not selected by the PWG for the preferred Local Transmission Plan pursuant to Section 5.5, the draft “Local Transmission Plan Report” required by Section 5.6 will explain why the alternative was not selected.

5.4.3 All solution options that satisfactorily resolve an identified transmission need shall be given consideration on a comparable basis.

5.4.4 A solution that is seeking regional cost allocation must be submitted in accordance with the procedures set forth in Part II and will be evaluated through the SERTP Process.

5.4.5 The Companies will estimate the costs for each of the proposed Local Project (e.g., cost, cash flow, present value) and develop a rough schedule estimate to implement the solution. This information is reviewed and discussed by the PWG and during a Solutions Meeting.

5.5 Selection of Preferred Local Transmission Plan

5.5.1 The PWG compares all of the alternatives and selects the preferred solution by balancing the solutions' costs, benefits, and associated risks. Competing solutions will be evaluated against each other based on a comparison of their relative economics, timing, feasibility, and effectiveness of performance.

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

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

5.6 Local Transmission Plan Report

5.6.1 After the Solutions Meeting, the PWG prepares a draft "Local Transmission Plan Report" based on the study results and the recommended solutions and provides the draft 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 solutions including estimates of costs and construction schedules and a summary of the PWG's selection evaluation required by Section 5.5.

5.6.2 After review and approval by the OSC, the Administrator forwards the draft Local Transmission Plan Report to the TAG participants and posts the draft Local Transmission Plan Report on the CTPC website for their review. The Companies shall schedule and facilitate a meeting to review the draft Local Transmission Plan Report. TAG participants may provide comments to the PWG on the draft Local Transmission Plan Report. TAG participants shall have at least 14 calendar days after it is posted on the CTPC website to comment on the draft Local Transmission Plan Report. The PWG members are the technical points of contact that can respond to questions regarding modeling criteria, assumptions, and data underlying the Report. The PWG shall review and consider comments that are received on or before the 14th calendar day after the draft Local Transmission Plan Report is posted on the CTPC website.

5.6.3 The OSC evaluates the draft Local Transmission Plan Report, the PWG recommendations, and the TAG participants' input. No fewer than 14 calendar days after the draft Local Transmission Plan Report is posted on the CTPC website, the OSC approves the final Local Transmission Plan for posting on the CTPC Website. The Plan also is posted on the Companies' OASIS and distributed to the TAG participants.

5.6.4 The Local Transmission Plan allows the CTPC 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.

5.6.5 The Local Transmission Plan, and the associated models, serve as the basis for the models that the Companies provide as input to the development of the SERC-wide model as described in Section 11.

5.6.6 The Local Transmission Plan, which reflects the coordination described in Section 11, will be an input into the SERTP Process. Local Projects identified in a Local Transmission Plan may later be removed from a Local Transmission Plan due to, for example, the iterative nature of transmission planning in subsequent planning cycles, additional transmission planning coordination provided through the SERTP Process, or if a project seeking regional cost allocation has been selected in the regional transmission expansion plan to replace a Local Project.

5.7 No Limitation on Additional Meetings and Communications

5.7.1 Nothing in this Attachment N-1 precludes the Companies, the OSC, or the PWG from agreeing with an individual TAG participant or groups of TAG participants to have additional meetings or other communications regarding assumptions, needs, proposed solutions, or Local Projects.

6. CTPC DISPUTE RESOLUTION MECHANISM

6.1 CTPC Process Disputes

6.1.1 A Company has the right to reject an OSC decision if it believes that it would harm reliability. The Company rejecting the OSC decision on reliability grounds must provide data, studies, or other evidence to the OSC to support its rejection.

6.1.2 The dispute resolution process provisions included in this Tariff apply to disputes involving compliance with the Commission's local transmission planning obligations set forth in Order No. 890. Any TAG participant, not just a TAG participant that is a Transmission Customer, may avail itself of the dispute resolution provision of the Tariff, as that process is modified below.

6.1.3 If a TAG participant has completed the negotiation step set forth in Section 12.1 of this Tariff, a TAG participant may ask to have the issue mediated on a non-binding basis before the next step (i.e., arbitration) commences. A request for mediation must be made within 30 calendar days of the agreed-upon conclusion of the negotiation step. If the mediation step is concluded without resolution, the disputing party has 30 calendar days to inform the Company(ies) that it seeks to commence the arbitration step set forth in Tariff Section 12.2. If this mediation option is selected, the parties to the dispute will use the Commission's Dispute Resolution Service as the forum for mediation.

6.1.4 Matters over which the Commission does not have jurisdiction, including planning to meet retail native load of the Companies, shall not be within the scope of the dispute resolution process of this Tariff.

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 Public Service Commission 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 Utilities Commission 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 South Carolina Public Service Commission allows public participation in and may hold hearings regarding matters related to integrated resource planning.

7. TRANSMISSION COST ALLOCATION FOR JOINT LOCAL PROJECTS

7.1 OATT Cost Allocation

With the exception of "Joint Local Reliability Projects" and "Joint Local Economic Projects" nothing in this Attachment is intended to alter the cost allocation policies of the Tariff.

7.2 Joint Local Reliability Project Cost Allocation

7.2.1 A Joint Local Reliability Project is defined as any reliability project that requires an upgrade to a Company's system that would not have otherwise been made based upon the reliability needs of the Company.

7.2.2 An "avoided cost" cost allocation methodology will apply to reliability projects where there is a demonstration that a Local Project meets the criteria for a Joint Local Reliability Project.

7.2.3 The CTPC Process results in a set of projects that satisfy the reliability criteria of the Companies who are parties to the Participation Agreement (i.e., Local Reliability Projects). Through this process, a project may be identified that meets a reliability need in a more cost-effective manner than if each Company were only considering projects on its system to meet its reliability criteria. A Joint Local 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 Joint Local Reliability Project with a cost of less than $1 million would be borne by each Company based on the costs incurred on its system.

7.2.4 Unless a Joint Local Reliability Project is determined by the CTPC

Participants to be the most cost-effective solution to a reliability need, it will not be selected to be included in the Local Transmission Plan. But, if a Joint Local Reliability Project is determined by the CTPC Participants to be the most cost effective solution, it will have its costs allocated based on an avoided cost approach, whereby each Company 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:

(Company X's Avoided Cost/Total Avoided Cost) * cost of Joint Local Reliability Project = Company X's Cost Allocation

(Company Y's Avoided Cost/Total Avoided Cost) * cost of Joint Local Reliability Project = Company 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 Joint Local Reliability Projects. Examples of the application of the avoided-cost approach may be found in *CTPC Transmission Cost Allocation*.

7.3 Joint Local Economic Project Cost Allocation

7.3.1 A Joint Local Economic Project is a project that permits energy to be transferred on a Point-to Point basis from an interface or a Point of Receipt on a Company's system to an interface or a Point of Delivery on another Company's system for a specified time period.

7.3.2 The costs of Joint Local Economic Projects are allocated on a "requestor pays" basis.

7.3.3 Transmission Customer(s) that are requesting a Joint Local Economic Project would provide the up-front funding of any transmission construction that was required to ensure that the transmission path capability that was created by the Joint Local Economic Project was available for the relevant time period. On the DEC and/or DEP systems, the Transmission Customer would receive a levelized repayment of this initial funding amount from DEC and/or DEP in the form of monthly transmission credits over a maximum 20-year period. The Companies will be permitted to work with the Transmission Customers to provide shorter or different crediting. As credits are paid, DEC and DEP would have the opportunity to include the costs of upgrades that were needed for the Joint Local Economic Project(s) in transmission rates, similar to the Generator Interconnection pricing/rate approach.

7.3.4 As part of the Joint Local Economic Project process, a network customer may ensure that power can be delivered from an interface on, or utilizing transmission capability created by, a Joint Local Economic Project 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.

7.3.5 No additional compensation is provided to the "requestors" of the Joint Local Economic Project for any "head-room" or excess transmission capability that would be created on the Transmission Systems. The total project cost for the transmission expansion required due to a Joint Local Economic Project will be reduced to provide compensation for the
7.3.6 positive transmission impacts that the Joint Local Economic Project would provide, compared to the existing Local Transmission Plan.

7.3.7 This Joint Local Economic Project concept and cost allocation methodology applies to the CTPC footprint, which consists of the DEC and DEP Control Areas.

8. COST ALLOCATION FOR PLANNING COSTS

8.1 CTPC-Related Planning Process Costs

8.1.1 Each CTPC Participant bears its own expenses.

8.1.2 TAG participants bear their own expenses.

8.1.3 The costs of the CTPC base reliability studies are borne by DEC and DEP.

8.1.4 Costs associated with the study process for Local Economic Projects, Public Policy Projects, and Multi-Value Strategic Transmission Projects are all allocated to CTPC Participants in the manner set forth in the *Participation Agreement*.

8.1.5 Pursuant to Section 4, costs associated with the Local Economic Project Study Process and Multi-Value Strategic Transmission Project Study Process that are outside the scope of Section 4, will be borne by the study requestor.

8.1.6 CTPC Participants may challenge the correctness of CTPC Process cost allocations.

8.1.7 For the Companies, 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-CTPC-Related Planning Costs

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

9. CONFIDENTIALITY

9.1 The Companies 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 CTPC Participant 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 CTPC Participant or TAG participant providing Confidential Information acknowledges that such Confidential Information may be released to the representatives of TAG participants that have abided by the procedures in Section 9.4.3. If the information is Confidential Information only because it is CEII, the CTPC Participant or TAG participant should indicate that such information may be released to TAG participants eligible to receive CEII.

9.3 Availability of Confidential Information

9.3.1 The CTPC 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 CTPC Participants, as limited by the *Participation Agreement*. Each CTPC 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 market such that they do not receive preferential treatment or a competitive advantage.

9.3.3 TAG participants may be provided Confidential Information, in accordance with Section 9.4.3/9.4.4. In cases where the information is Confidential Information only because it is CEII, the TAG participants may be provided such information in accordance with Section 9.4.4.

9.4 Obtaining Confidential Information

9.4.1 Each Company 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.

9.4.2 Each Company ensures that the confidentiality of information principles reflected in Order No. 890 as well as any Standards of Conduct or Code of Conduct requirements are being adhered to within the TAG process, to the extent applicable and/or necessary.

9.4.3 If a TAG participant seeks non-CEII Confidential Information, s/he must formally request the data from the Company OSC representatives representing the non-CEII Confidential Information and the CTPC Administrator and demonstrate that s/he:

9.4.3.1 Is a representative of a TAG Sector Entity that has signed the CTPC Process Confidentiality Agreement or is an Individual that has signed the CTPC Process Confidentiality Agreement.

9.4.3.2 Is listed on Attachment A to a TAG Sector Entity's TAG Confidentiality Agreement as a representative of a TAG Sector Entity or is an Individual that has signed the CTPC Process Confidentiality Agreement.

9.4.4 If a TAG participant seeks CEII, s/he must formally request the data from the Company OSC representatives representing the CEII and the CTPC Administrator and demonstrate that s/he:

9.4.4.1 Is a representative of a TAG Sector Entity that has signed the CTPC Process Confidentiality Agreement or is an Individual that has signed the CTPC Process Confidentiality Agreement.

9.4.4.2 Is listed on Attachment A of a TAG Sector Entity's CTPC Process Confidentiality Agreement as a representative of a TAG Sector Entity or is an Individual that has signed the CTPC Process Confidentiality Agreement.

9.4.4.3 Each Company will process the above requests, approve/deny the request, and if approved, provide the data to a TAG participant.

10. INTEGRATED RESOURCE AND SUB-LOCAL PLANNING

10.1 Integrated Resource Planning

In addition to the CTPC Process, the Companies must abide by state laws and regulations regarding Integrated Resource Planning (IRP) pursuant to N.C. G.S. § 62-110.1 and S.C. Code Ann. § 58-37-40.

10.2 Sub-Local Planning

The Companies 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 CTPC Process is planning higher-voltage facilities and transfers of bulk power and thus "sub-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 sub-local area plans developed by a Company are rolled into the CTPC transmission Base Case models. The same data and assumptions would be used in sub-local planning as are used in the CTPC Process.

11. ADDITIONAL COORDINATION

11.1 Coordination Activities Within SERC

DEC and DEP are members of the SERC Reliability Corporation (SERC) and coordinate with other SERC members registered as Transmission Planners. SERC is the entity responsible for promoting and improving the reliability, adequacy, and critical infrastructure of the bulk power supply systems in the area served by its member systems. SERC membership is open to any entity that is a user, owner, or operator of the Bulk-Power System and is subject to the jurisdiction of FERC for the purpose of complying with Reliability Standards. SERC membership is comprised of investor-owned, municipal, cooperative, state and federal systems, RTOs/ISOs, merchant electricity generators, and power marketers. SERC has in place various committees and subcommittees that perform the identified SERC functions, including the promotion of the reliability and adequacy of the bulk power system as related to the planning and engineering of the electric systems. The SERC committees are identified on SERC's website. The particular activities that are coordinated among the Transmission Planners include the creation of a SERC-wide model and the preparation of a simultaneous feasibility assessment, which are discussed in further detail below.

11.1.1 Reliability Planning by Transmission Planners Located in SERC: A Transmission Planner's 10-year transmission expansion plan is the basis for models used for its own reliability planning process(es), such as the CTPC Process, as well as serving as a Transmission Planner's input into the development of the SERC-wide model.

Substantive transmission planning occurs as Transmission Planners develop reliability transmission expansions plans through their planning process(es), such as the CTPC Process. In this regard, the reliability plan for each planning process is generally developed by determining therequired 10-year transmission expansion plan to satisfy load, resources, and transmission service commitments throughout the 10-year reliability planning horizon. The development of each 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. The transmission models also incorporate external models (at a minimum the current SERC models) that are developed using similar assumptions.

The transmission models created for use in developing the reliability 10-year transmission expansion plan are analyzed to determine if any planning criteria concerns are projected. In the event one or more planning criteria concerns are identified, the relevant Transmission Planners will develop solutions for these projected limitations in accordance with the planning process to which they belong. As a part of this study process, the Transmission Planners, in accordance with the process to which they belong, will reexamine the current reliability 10-year transmission expansion plan (determined through the previous year's 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 of any of the existing reliability transmission enhancements identified in the previous year's reliability planning process.

11.1.2 Coordination by Transmission Planners with Affected Systems: Once a planning criteria concern is identified and the optimization process identifies the potential solution, the Transmission Planner(s), here DEC and DEP, determine if any other Transmission Planner is potentially impacted by the projected solution. Potentially impacted Transmission Planners are then contacted to determine if there is a need for an *ad hoc* coordinated study. In the event one or more neighboring Transmission Planners agrees that they would be impacted by the projected limitation or identifies the potential for a superior reliability solution, based on transmission enhancements in their current reliability plan, an *ad hoc* coordinated study is initiated. In the event that no impacts are identified, or if once contacted the potentially impacted Transmission Planner(s) determine that they will not actually be impacted, the initiating Transmission Planner will move forward to conduct a reliability study to determine the solution for the projected planning criteria concern. In either case, once the study has been completed, the identified reliability transmission enhancements will then be incorporated into the 10-year transmission expansion plan as a reliability project.

11.1.3 SERC-Wide Reliability Assessment by Transmission Planners: After the transmission models are developed through the planning processes, the Transmission Planners 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 reliability transmission expansion plans are simultaneously feasible and to otherwise ensure that these processes are using consistent models and data. Additionally, the reliability assessment measures and reports the transfer capabilities within SERC. The SERC-wide assessment serves as a valuable tool for each of the Transmission Planners to reassess the need for additional reliability joint studies.

11.1.4 Other Coordination Activities Within SERC

11.1.4.1 Transmission Model Development: SERC transmission models are developed by the Transmission Planners in SERC through an annual model development process. Each Transmission Planner in SERC, incorporating input from their planning process(es), develops and submits their 10-year transmission models to a model development databank. The databank then joins the models to create SERC-wide models for use in reliability assessment. Additionally, the SERC-wide models are then used in each 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.

11.1.4.2 Additional Reliability Joint Studies: As mentioned above, the SERC-wide reliability assessment serves as a valuable tool for the Transmission Planners, in accordance with their planning process(es), to reassess the need for additional reliability joint studies. If the SERC-wide reliability model projects additional planning criteria concerns that were not identified in the reliability studies, then the impacted Transmission Planners may initiate one or more *ad hoc* coordinated study(ies) (in accordance with existing Reliability Coordination Agreements) to better identify the planning criteria concerns and determine the optimal reliability transmission enhancements to resolve the limitations. Once the study(ies) is completed, required reliability transmission enhancements will be incorporated into the 10-year expansion plan as a reliability project. Accordingly, planning criteria concerns identified at the SERC-wide level are "pushed down" to the Local Planning Process for detailed resolution.

11.1.5 Stakeholder Participation in Planning and Coordination Activities:

Since the bulk of the reliability transmission planning occurs at the local planning level as a "bottom up" process in the development of the various 10-year transmission expansion plans, stakeholders in the CTPC footprint may provide input into the coordination activities by participating in the CTPC Process and any other planning processes that they choose to participate in. Specifically, the 10-year Local Transmission Plan developed in the CTPC Process described in this Attachment is the basis for DEC's and DEP's input into the SERC model development. As discussed in Sections 4 and 5, the TAG participants are provided a number of opportunities to review and comment on and allowed to propose alternatives concerning the development of this transmission expansion plan. The results of coordination activities will be shared and discussed with TAG participants.

11.2 ERAG & SERC-RFC East Coordination Activities

11.2.1 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 areas served by ERAG members.

11.2.2 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.

11.2.3 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.

11.3 Bilateral Coordination Activities

Through bilateral agreements with neighboring transmission systems, DEC and DEP will perform coordinated studies with such transmission systems on an as-needed basis.

PART II -- REGIONAL TRANSMISSION PLANNING

12. OVERVIEW OF REGIONAL TRANSMISSION PLANNING

Duke and Progress, referred to collectively for the purposes of regional transmission planning as the "Duke Transmission Provider" participate in the SERTP Process described herein and on the Regional Planning Website, a link to which is found on the Duke and Progress OASIS sites. The Duke Transmission Provider and the other transmission owners and transmission providers that participate in this SERTP Process are identified on the Regional Planning Website (Sponsors).[1]

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[1] Duke and Progress are each separate "transmission providers" as that term is defined in this Tariff and under the Code of Federal Regulations. They are referred to here as the Duke Transmission Provider only for the purpose of Order No. 1000-mandated regional planning. The Duke Transmission Provider notes that the Duke Transmission Provider's participation in the SERTP is for purposes of regional planning only, since local planning is conducted in accordance with the Local Planning Process as described in Sections 1-11 of this Attachment N-1. While this Attachment N-1 discusses the Duke Transmission Provider largely effectuating the activities of the SERTP Process that are discussed herein, the Duke Transmission Provider expects that the other Sponsors will also sponsor those activities. For example, while this Attachment N-1 discusses the Duke Transmission Provider hosting the Annual Transmission Planning Meetings, the Duke Transmission Provider expects that it will be co-hosting such meetings with the other Sponsors. Accordingly, many of the duties described herein as being performed by the Duke Transmission Provider may be performed in conjunction with one or more other Sponsors or may be performed entirely by, or be applicable only to, one or more other Sponsors. Likewise, while this Attachment N-1 discusses the transmission expansion plan of the Duke Transmission Provider, the Duke Transmission Provider expects that transmission expansion plans of the other Sponsors shall also be discussed, particularly since the transmission expansion plans of the other Sponsors are expected to be included in the regional transmission plan that is to be developed in each planning cycle for purposes of Order No. 1000. To the extent that this Attachment N-1 makes statements that might be construed to imply establishing duties or obligations upon other Sponsors, no such duty or obligation is intended. Rather, such statements are intended to only mean that it is the Duke Transmission Provider's expectation that

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The Duke Transmission Provider participates in the SERTP through which transmission facilities and non-transmission alternatives may be proposed and evaluated. This regional transmission planning process develops a regional transmission plan that identifies the transmission facilities necessary to meet the needs of transmission providers and transmission customers in the transmission planning region for purposes of Order No. 1000. This regional transmission planning process is consistent with the provision of Commission-jurisdictional services at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential, as described in Order No. 1000.

This regional transmission planning process satisfies the following seven principles, as set out and explained in Order No. 1000: coordination, openness, transparency, information exchange, comparability,[2] dispute resolution, and economic planning studies. This transmission planning process includes at Sections 4.3 and 19 the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000. Transmission needs consist of the physical transmission system delivery capacity requirements necessary to reliably and economically satisfy the load projections; resource assumptions, including on-system and off-system supplies for current and future native load and network customer needs; public policy requirements; and transmission service commitments within the region. [3] This transmission planning process provides at Section 8 a mechanism for the recovery and allocation of planning costs consistent with Order Nos. 890 and 1000. This regional transmission planning process includes at Section 22 a clear enrollment process for public and non-public utility transmission providers that make the choice to become part of a transmission planning region for purposes of regional cost allocation. This regional transmission

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other Sponsors will engage in such activities. Accordingly, this Attachment N-1 only establishes the duties and obligations of the Duke Transmission Provider and the means by which Stakeholders may interact with the Duke Transmission Provider with respect to regional planning through the SERTP Process described herein. The term "Stakeholder" as used in this Attachment N-1 means any party interested in the Southeastern Regional Transmission Planning Process, including but not limited to transmission and interconnection customers, generation owners/development companies, developers of alternative resources, or state commissions.

[2] The Duke Transmission Provider is committed to providing comparable and non-discriminatory transmission service. As such, comparability is not separately addressed in a stand-alone Section of this Attachment N-1 but instead permeates the SERTP Process described in this Attachment N-1.

[3] As provided herein, Transmission Customers can provide input regarding updates to these needs assumptions consistent with Data Collection and Case Development provisions of Section 5.3 and the Information Exchange provisions of Section 16. Additionally, Stakeholder input is considered in the determination of transmission needs consistent with the Data Collection and Case Development provisions of Section 5.3 and through input regarding the transmission planning modeling assumptions consistent with the Coordination provisions of Section 13 and specifically related to transmission needs driven by public policy requirements consistent with Sections 4.3 and 19.2. Stakeholders can also provide input on Economic Planning Studies pursuant to Sections 4.2 and 18.

planning process subjects enrollees to cost allocation if they are found to be Beneficiaries of new transmission facilities selected in the regional transmission plan for purposes of cost allocation.[4]

Attachment N-3 contains a list of Enrollees as of the effective date of such tariff record. The relevant cost allocation method or methods that satisfy the six regional cost allocation principles set forth in Order No. 1000 are described in Sections 26-27 of this Attachment N-1. Nothing in this regional transmission planning process includes an unduly discriminatory or preferential process for transmission project submission and selection. As provided below, with respect to regional planning, the SERTP includes sufficient detail to enable Transmission Customers to understand:

12.1 The process for enrollment and terminating enrollment in the SERTP, which is set forth in Section 22 of this Attachment N-1;

12.2 The process for consulting with customers regarding regional transmission planning, which is set forth in Section 13 of this Attachment N-1;

12.3 The notice procedures and anticipated frequency of regional transmission planning meetings, which is set forth in Sections 13 and 14 of this Attachment N-1;

12.4 The Duke Transmission Provider's regional transmission planning methodology, criteria, and processes, which are set forth in Section 15 of this Attachment N-1;

12.5 The method of disclosure of regional transmission planning criteria, assumptions and underlying data, which is set forth in Sections 14 and 15 of this Attachment N-1;

12.6 The obligations of and methods for Transmission Customers to submit data if necessary to support the regional transmission planning process, which are set forth in Section 16 of this Attachment N-1;

12.7 The process for submission of data by nonincumbent developers of transmission projects that wish to participate in the regional transmission planning process and seek regional cost allocation for purposes of Order No. 1000, which is set forth in Sections 23-31 of this Attachment N-1;

12.8 The process for submission of data by merchant transmission developers that wish to participate in the regional transmission planning process, which is set forth in Section 21 of this Attachment N-1;

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[4] Enrollees that are identified pursuant to Section 26 to potentially receive cost savings (associated with the regional cost allocation components in Section 27) due to the transmission developer's proposed transmission project for possible selection in a regional transmission plan for regional cost allocation purposes ("RCAP") shall be referred to as "Beneficiaries."

12.9 The regional dispute resolution process, which is set forth in Section 17 of this Attachment N-1;

12.10 The study procedures for regional economic upgrades to address congestion or the integration of new resources, which is set forth in Section 18 of this Attachment N-1;

12.11 The procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000, which are set forth in Section 19 of this Attachment N-1; and

12.12 The relevant regional cost allocation method or methods satisfying the six regional cost allocation principles set forth in Order No. 1000, which is set forth at Section 26-27.

12.13 The process for interregional coordination as described in Attachment N-1 – FRCC, Attachment N-1 – MISO, Attachment N-1 – PJM, Attachment N-1 – SCRTP, and Attachment N-1 – SPP.

13. COORDINATION

13.1 General: The SERTP Process is designed to eliminate the potential for undue discrimination in planning by establishing appropriate lines of communication between the Duke Transmission Provider, its transmission-providing neighbors, affected state authorities, Transmission Customers, and other Stakeholders regarding transmission planning issues.

13.2 Meeting Structure: Each calendar year, the SERTP Process will generally conduct and facilitate four (4) meetings (Annual Transmission Planning Meetings) that are open to all Stakeholders. However, the number of Annual Transmission Planning Meetings, or duration of any particular meeting, may be adjusted by announcement upon the Regional Planning Website, provided that any decision to reduce the number of Annual Transmission Planning Meetings must first be approved by the Sponsors and by the Regional Planning Stakeholders' Group (RPSG). These meetings can be done in person, through phone conferences, or through other telecommunications or technical means that may be available. The details regarding any such meeting will be posted on the Regional Planning Website, with a projected meeting schedule for a calendar year being posted on the Regional Planning Website on or before December 31st of the prior calendar year, with firm dates for all Annual Transmission Planning Meetings being posted at least 60 calendar days prior to a particular meeting. The general structure and purpose of these four (4) meetings will be as follows:

13.2.1 First RPSG Meeting and Interactive Training Session: At this meeting, which will be held in the first quarter of each calendar year, the RPSG will be formed for purposes of that year. In addition, the Duke Transmission Provider will meet with the RPSG and any other interested Stakeholders for the purposes of allowing the RPSG to select up to five

(5) Stakeholder requested Economic Planning Studies[5] that they would like to have studied by the Duke Transmission Provider and the Sponsors. At this meeting, the Duke Transmission Provider will work with the RPSG to assist the RPSG in formulating these Economic Planning Study requests. The Duke Transmission Provider will also conduct an interactive training session regarding its transmission planning for all interested Stakeholders. This session will explain and discuss the underlying methodology and criteria that will be utilized to develop the transmission expansion plan[6] before that methodology and criteria are finalized for purposes of the development of that year's transmission expansion plan (*i.e.*, the expansion plan that is intended to be implemented the following calendar year).[7] Stakeholders may submit comments to the Duke Transmission Provider regarding the Duke Transmission Provider's criteria and methodology during the discussion at the meeting or within ten (10) business days after the meeting, and the Duke Transmission Provider will consider such comments. Depending upon the major transmission planning issues presented at that time, the Duke Transmission Provider will provide various technical experts that will lead the discussion of pertinent transmission planning topics, respond to Stakeholder questions, and provide technical guidance regarding transmission planning matters. It is foreseeable that it may prove appropriate to shorten the training sessions as Stakeholders become increasingly knowledgeable regarding the Duke Transmission Provider's transmission planning process and no longer need detailed training in this regard.

The Duke Transmission Provider will also address transmission planning issues that the Stakeholders may raise.

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[5] As indicated *infra* at footnote 1, the Economic Planning Studies discussed in the regional planning portion of this Attachment N-1 (Sections 12-31) refer to the regional Economic Planning Studies conducted through the SERTP Process.

[6] The expectation is that in any given planning cycle, the Duke Transmission Provider's ten year transmission expansion plan along with those of the other Sponsors, will be included in the regional transmission plan. Moreover, the iterative nature of transmission planning bears emphasis, with underlying assumptions, needs, and data inputs continually changing to reflect market decisions, load service requirements, and other developments. A transmission plan, thus, only represents the status of transmission planning when the plan was prepared.

[7] A regional transmission expansion plan completed during one calendar year (and presented to Stakeholders at that calendar year's Annual Transmission Planning Summit) is intended to be the starting point plan for the following calendar year. For example, the regional transmission expansion plan developed during 2014 and presented at the 2014 Annual Transmission Planning Summit is for the 2015 calendar year.

13.2.2 Preliminary Expansion Plan Meeting: During the second quarter of each calendar year, the Duke Transmission Provider will meet with all interested Stakeholders to explain and discuss: the Duke Transmission Provider's preliminary transmission expansion plan, which is also input into that year's SERC (or other applicable NERC region's) regional model; internal model updating and any other then-current coordination study activities with the transmission providers in the Florida Reliability Coordinating Council (FRCC); and any *ad hoc* coordination study activities that might be occurring. These preliminary transmission expansion plan, internal model updating, and coordination study activities will be described to the Stakeholders, with this meeting providing them an opportunity to supply their input and feedback, including the transmission plan/enhancement alternatives that the Stakeholders would like the Duke Transmission Provider and the Sponsors to consider. The Duke Transmission Provider will also provide an update as to the status of its regional planning analyses performed pursuant to Section 20. In addition, the Duke Transmission Provider will address transmission planning issues that the Stakeholders may raise and otherwise discuss with Stakeholders developments as part of the SERC (or other applicable NERC region's) reliability assessment process.

13.2.3 Second RPSG Meeting: During the third quarter of each calendar year, the Duke Transmission Provider will meet with the RPSG and any other interested Stakeholders to report the preliminary results for the Economic Planning Studies requested by the RPSG at the First RPSG Meeting and Interactive Training Session. This meeting will give the RPSG an opportunity to provide input and feedback regarding those preliminary results, including alternatives for possible transmission solutions that have been identified. At this meeting, the Duke Transmission Provider shall provide feedback to the Stakeholders regarding transmission expansion plan alternatives that the Stakeholders may have provided at the Preliminary Expansion Plan Meeting, or within a designated time following that meeting. The Duke Transmission Provider will also discuss with the Stakeholders the results of the SERC (or other applicable NERC region's) regional model development for that year (with the Duke Transmission Provider's input into that model being its ten (10) year transmission expansion plan); any on-going coordination study activities with the FRCC transmission providers; and any *ad hoc* coordination study activities. In addition, the Duke Transmission Provider will address transmission planning issues that the Stakeholders may raise.

13.2.4 Annual Transmission Planning Summit and Assumptions Input Meeting: During the fourth quarter of each calendar year, the Duke Transmission Provider will host the annual Transmission Planning Summit and Assumptions Input Meeting.

13.2.4.1 Annual Transmission Planning Summit: At the Annual Transmission Planning Summit aspect of the Annual Transmission Planning Summit and Assumptions Input Meeting, the Duke Transmission Provider will present the final results for the Economic Planning Studies. The Duke Transmission Provider will also provide an overview of the ten (10) year transmission expansion plan, which reflects the results of planning analyses performed in the then-current planning cycle, including analyses performed pursuant to Section 20. The Duke Transmission Provider will also provide an overview of the regional transmission plan for Order No. 1000 purposes, which should include the ten (10) year transmission expansion plan of the Duke Transmission Provider. In addition, the Duke Transmission Provider will address transmission planning issues that the Stakeholders may raise.

13.2.4.2 Assumptions Input Session: The Assumptions Input Session aspect of the Annual Transmission Planning Summit and Assumptions Input Meeting will take place following the annual Transmission Planning Summit and will provide an open forum for discussion with, and input from, the Stakeholders regarding: the data gathering and transmission model assumptions that will be used for the development of the Duke Transmission Provider's following year's ten (10) year transmission expansion plan, which includes the Duke Transmission Provider's input, to the extent applicable, into that year's SERC regional model development; internal model updating and any other then-current coordination study activities with the transmission providers in the FRCC; and any *ad hoc* coordination study activities that might be occurring. This meeting may also serve to address miscellaneous transmission planning issues, such as reviewing the previous year's regional planning process, and to address specific transmission planning issues that may be raised by Stakeholders.

13.3 Committee Structure - the RPSG: The RPSG has two primary purposes. First, the RPSG is charged with determining and proposing up to five (5) Economic Planning Studies on an annual basis and should consider clustering similar Economic Planning Study requests. Second, the RPSG serves as the representative in interactions with the Duke Transmission Provider and Sponsors for the eight (8) industry sectors identified below.

13.3.1 RPSG Sector Representation: The Stakeholders are organized into the following eight (8) sectors for voting purposes within the RPSG:

(1) Transmission Owners/Operators[8]

(2) Transmission Service Customers

(3) Cooperative Utilities

(4) Municipal Utilities

(5) Power Marketers

(6) Generation Owners/Developers

(7) ISO/RTOs

(8) Demand Side Management/Demand Side Response

13.3.2 Sector Representation Requirements: Representation within each sector is limited to two members, with the total membership within the RPSG being capped at 16 members (Sector Members). The Sector Members, each of whom must be a Stakeholder, are elected by Stakeholders, as discussed below. A single company, and all of its affiliates, subsidiaries, and parent company, is limited to participating in a single sector.

13.3.3 Annual Reformulation: The RPSG will be reformed annually at each First RPSG Meeting and Interactive Training Session discussed in Section 13.2.1. Specifically, the Sector Members will be elected for a term of approximately one year that will terminate upon the convening of the following year's First RPSG Meeting and Interactive Training Session. Sector Members shall be elected by the Stakeholders physically present at the First RPSG Meeting and Interactive Training Session (voting by sector for the respective Sector Members). If elected, Sector Members may serve consecutive, one-year terms, and there is no limit on the number of terms that a Sector Member may serve.

13.3.4 Simple Majority Voting: RPSG decision-making that will be recognized by the Duke Transmission Provider for purposes of this Attachment N-1 shall be those authorized by a simple majority vote by the then-current Sector Members, with voting by proxy being permitted for a Sector Member that is unable to attend a particular meeting. The Duke Transmission Provider will notify the RPSG of the matters upon which

[8] The Sponsors will not have a vote within the Transmission Owners/Operators sector, although they (or their affiliates, subsidiaries or parent company) shall have the right to participate in other sectors.

an RPSG vote is required and will use reasonable efforts to identify upon the Regional Planning Website the matters for which an RPSG decision by simple majority vote is required prior to the vote, recognizing that developments might occur at a particular Annual Transmission Planning Meeting for which an RPSG vote is required but that could not be reasonably foreseen in advance. If the RPSG is unable to achieve a majority vote, or should the RPSG miss any of the deadlines prescribed herein or clearly identified on the Regional Planning Website and/or at a particular meeting to take any action, then the Duke Transmission Provider will be relieved of any obligation that is associated with such RPSG action.

13.3.5 RPSG Guidelines/Protocols: The RPSG is a self-governing entity subject to the following requirements that may not be altered absent an appropriate filing with the Commission to amend this aspect of the Tariff: (i) the RPSG shall consist of the above-specified eight (8) sectors; (ii) each company, its affiliates, subsidiaries, and parent company, may only participate in a single sector; (iii) the RPSG shall be reformed annually, with the Sector Members serving terms of a single year; and (iv) RPSG decision-making shall be by a simple majority vote (*i.e.*, more than 50%) by the Sector Members, with voting by written proxy being recognized for a Sector Member unable to attend a particular meeting. There are no formal incorporating documents for the RPSG, nor are there formal agreements between the RPSG and the Duke Transmission Provider. As a self-governing entity, to the extent that the RPSG desires to adopt other internal rules and/or protocols, or establish subcommittees or other structures, it may do so provided that any such rule, protocol, etc., does not conflict with or otherwise impede the foregoing requirements or other aspects of the Tariff. Any such additional action by the RPSG shall not impose additional burdens upon the Duke Transmission Provider unless it agrees in advance to such in writing, and the costs of any such action shall not be borne or otherwise imposed upon the Duke Transmission Provider unless the Duke Transmission Provider agrees in advance to such in writing.

13.4 The Role of the Duke Transmission Provider in Coordinating the Activities of the SERTP Process Meetings and of the Functions of the RPSG: The Duke Transmission Provider will host and conduct the above-described Annual Transmission Planning Meetings with Stakeholders.[9]

13.5 Procedures Used to Notice Meetings and Other Planning-Related Communications: Meetings notices, data, stakeholder questions, reports, announcements, registration for inclusion in distribution lists, means for being

[9] As previously discussed, the Duke Transmission Provider expects that the other Sponsors will also be hosts and sponsors of these activities.

certified to receive Critical Energy Infrastructure Information (CEII), and other transmission planning-related information will be posted on the Regional Planning Website. Stakeholders will also be provided notice regarding the annual meetings by e-mail messages (if they have appropriately registered on the Regional Planning Website to be so notified). Accordingly, interested Stakeholders may register on the Regional Planning Website to be included in e-mail distribution lists (Registered Stakeholder). For purposes of clarification, a Stakeholder does not have to have received certification to access CEII in order to be a Registered Stakeholder.

13.6 Procedures to Obtain CEII Information: For access to information considered to be CEII, there will be a password protected area that contains such CEII information. Any Stakeholder may seek certification to have access to this CEII data area.

13.7 The Regional Planning Website: The Regional Planning Website will contain information regarding the SERTP Process, including:

13.7.1 Notice procedures and e-mail addresses for contacting the Sponsors and for questions;

13.7.2 A calendar of meetings and other significant events, such as release of draft reports, final reports, data, etc.;

13.7.3 A registration page that allows Stakeholders to register to be placed upon an e-mail distribution list to receive meetings notices and other announcements electronically; and

13.7.4 The form in which meetings will occur (*i.e.*, in person, teleconference, webinar, *etc*.).

14. OPENNESS

14.1 General: The Annual Transmission Planning Meetings, whether consisting of in-person meetings, conference calls, or other communicative mediums, will be open to all Stakeholders. The Regional Planning Website will provide announcements of upcoming events, with Stakeholders being notified regarding the Annual Transmission Planning Meetings by such postings. In addition, Registered Stakeholders will also be notified by e-mail messages. Should any of the Annual Transmission Planning Meetings become too large or otherwise become unmanageable for the intended purpose(s), smaller breakout meetings may be utilized.

14.2 Links to OASIS: In addition to open meetings, the publicly available information, CEII-secured information (the latter of which is available to any Stakeholder certified to receive CEII), and certain confidential non-CEII information (as set forth below) shall be made available on the Regional Planning Website, a link to which is found on the Duke Transmission Provider's OASIS website, so as to further facilitate the availability of this transmission planning information on an open and comparable basis.

14.3 CEII Information

14.3.1 Criteria and Description of CEII: The Commission has defined CEII as being specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure (physical or virtual) that:

14.3.1.1 Relates details about the production, generation, transmission, or distribution of energy;

14.3.1.2 Could be useful to a person planning an attack on critical infrastructure;

14.3.1.3 Is exempt from mandatory disclosure under the Freedom of Information Act; and

14.3.1.4 Does not simply give the general location of the critical infrastructure.

14.3.2 Secured Access to CEII Data: The Regional Planning Website will have a secured area containing the CEII data involved in the SERTP Process that will be password accessible to Stakeholders that have been certified to be eligible to receive CEII data. For CEII data involved in the SERTP Process that did not originate with the Duke Transmission Provider, the duty is incumbent upon the entity that submitted the CEII data to have clearly marked it as CEII.

14.3.3 CEII Certification: In order for a Stakeholder to be certified and be eligible for access to the CEII data involved in the SERTP Process, the Stakeholder must follow the CEII certification procedures posted on the Regional Planning Website (*e.g.*, authorize background checks and execute the SERTP CEII Confidentiality Agreement posted on the Regional Planning Website). The Duke Transmission Provider reserves the discretionary right to waive the certification process, in whole or in part, for anyone that the Duke Transmission Provider deems appropriate to receive CEII information. The Duke Transmission Provider also reserves the discretionary right to reject a request for CEII; upon such rejection, the requestor may pursue the dispute resolution procedures of Section 17.

14.3.4 Discussions of CEII Data at the Annual Transmission Planning Meetings: While the Annual Transmission Planning Meetings are open to all Stakeholders, if CEII information is to be discussed during a portion of such a meeting, those discussions will be limited to being only with those Stakeholders who have been certified eligible to have access to CEII information, with the Duke Transmission Provider reserving the discretionary right at such meeting to certify a Stakeholder as being eligible if the Duke Transmission Provider deems it appropriate to do so.

14.4 Other Sponsor- and Stakeholder- Submitted Confidential Information: The other Sponsors and Stakeholders that provide information to the Duke Transmission Provider that foreseeably could implicate transmission planning should expect that such information will be made publicly available on the Regional Planning Website or may otherwise be provided to Stakeholders in accordance with the terms of this Attachment N-1. Should another Sponsor or Stakeholder consider any such information to be CEII, it shall clearly mark that information as CEII and bring that classification to the Duke Transmission Provider's attention at, or prior to, submittal. Should another Sponsor or Stakeholder consider any information to be submitted to the Duke Transmission Provider to otherwise be confidential (*e.g.*, competitively sensitive), it shall clearly mark that information as such and notify the Duke Transmission Provider in writing at, or prior to, submittal, recognizing that any such designation shall not result in any material delay in the development of the transmission expansion plan or any other transmission plan that the Duke Transmission Provider (in whole or in part) is required to produce.

14.5 Procedures to Obtain Confidential Non-CEII Information

14.5.1 The Duke Transmission Provider shall make all reasonable efforts to preserve the confidentiality of information in accordance with the provisions of the Tariff, the requirements of (and/or agreements with) NERC, the requirements of (and/or agreements with) SERC or other applicable NERC region, the provisions of any agreements with the other Sponsors, and/or in accordance with any other contractual or legal confidentiality requirements.

14.5.2 Without limiting the applicability of Section 14.5.1, to the extent competitively sensitive and/or otherwise confidential information (other than information that is confidential solely due to its being CEII) is provided in the transmission planning process and is needed to participate in the transmission planning process and to replicate transmission planning studies, it will be made available to those Stakeholders who have executed the SERTP Non-CEII Confidentiality Agreement (which agreement is posted on the Regional Planning Website). Importantly, if information should prove to contain both competitively sensitive/otherwise confidential information and CEII, then the requirements of both Section 14.3 and Section 14.5 would apply.

14.5.3 Other transmission planning information shall be posted on the Regional Planning Website and may be password protected, as appropriate.

15. TRANSPARENCY

15.1 General**:** Through the Annual Transmission Planning Meetings and postings made on the Regional Planning Website, the Duke Transmission Provider will disclose to its Transmission Customers and other Stakeholders the basic criteria, assumptions, and data that underlie its transmission expansion plan, as well as information regarding the status of upgrades identified in the transmission plan. The process for notifying stakeholders of changes or updates in the data bases used for transmission planning shall be through the Annual Transmission Planning Meetings and/or by postings on the Regional Planning Website.

15.2 The Availability of the Basic Methodology, Criteria, and Process the Duke Transmission Provider Uses to Develop its Transmission Plan: In an effort to enable Stakeholders to replicate the results of the Duke Transmission Provider's transmission planning studies, and thereby reduce the incidences of after-the-fact disputes regarding whether transmission planning has been conducted in an unduly discriminatory fashion, the Duke Transmission Provider will provide the following information, or links thereto, on the Regional Planning Website:

15.2.1 The Electric Reliability Organization and Regional Entity reliability standards that the Duke Transmission Provider utilizes, and complies with, in performing transmission planning.

15.2.2 The Duke Transmission Provider's internal policies, criteria, and guidelines that it utilizes in performing transmission planning.

15.2.3 Software titles and version numbers that may be used to access and perform transmission analyses on the then-current posted data bases.

Any additional information necessary to replicate the results of the Duke Transmission Provider's planning studies will be provided in accordance with, and subject to, the CEII and confidentiality provisions specified in this Attachment N-1.

15.3 Additional Transmission Planning-Related Information: In an effort to facilitate the Stakeholders' understanding of the Transmission System, the Duke Transmission Provider will also post additional transmission planning-related information that it deems appropriate on the Regional Planning Website.

15.4 Additional Transmission Planning Business Practice Information: In an effort to facilitate the Stakeholders' understanding of the Business Practices related to Transmission Planning, the Duke Transmission Provider will also post the following information on the Regional Planning Website:

15.4.1 Means for contacting the Duke Transmission Provider.

15.4.2 Procedures for submittal of questions regarding transmission planning to the Duke Transmission Provider (in general, questions of a nonimmediate nature will be collected and addressed through the Annual Transmission Planning Meeting process).

15.4.3 Instructions for how Stakeholders may obtain transmission base cases and other underlying data used for transmission planning.

15.4.4 Means for Transmission Customers having Service Agreements for Network Integration Transmission Service to provide load and resource assumptions to the Duke Transmission Provider; provided that if there are specific means defined in a Transmission Customer's Service Agreement for Network Integration Transmission Service (NITSA), then the NITSA shall control.

15.4.5 Means for Transmission Customers having Long-Term Service Agreements for Point-To-Point Transmission Service to provide to the Duke Transmission Provider projections of their need for service over the planning horizon (including any potential rollover periods, if applicable), including transmission capacity, duration, receipt and delivery points, likely redirects, and resource assumptions; provided that if there are specific means defined in a Transmission Customer's Long-Term Transmission Service Agreement for Point-To-Point Transmission Service, then the Service Agreement shall control.

15.5 Transparency Provided Through the Annual Transmission Planning Meetings

15.5.1 The First RPSG Meeting and Interactive Training Session

15.5.1.1 An Interactive Training Session Regarding the Duke Transmission Provider's Transmission Planning Methodologies and Criteria: As discussed in (and subject to) Section 13.2.1, at the First RPSG Meeting and Interactive Training Session, the Duke Transmission Provider will, among other things, conduct an interactive, training and input session for the Stakeholders regarding the methodologies and criteria that the Duke Transmission Provider utilizes in conducting its transmission planning analyses. The purpose of these training and interactive sessions is to facilitate the Stakeholders' ability to replicate transmission planning study results to those of the Duke Transmission Provider.

15.5.1.2 Presentation and Explanation of Underlying Transmission Planning Study Methodologies: During the training session in the First RPSG Meeting and Interactive Training Session, the Duke Transmission Provider will present and explain its transmission study methodologies. While not all of the following methodologies may be addressed at any single meeting, these presentations may include explanations of the methodologies for the following types of studies:

(1) Steady state thermal analysis.

(2) Steady state voltage analysis.

(3) Stability analysis.

(4) Short-circuit analysis.

(5) Nuclear plant off-site power requirements.

(6) Interface analysis (*i.e.*, import and export capability).

15.5.2 Presentation of Preliminary Modeling Assumptions: At the Annual Transmission Planning Summit, the Duke Transmission Provider will also provide to the Stakeholders its preliminary modeling assumptions for the development of the Duke Transmission Provider's following year's ten (10) year transmission expansion plan. This information will be made available on the Regional Planning Website, with CEII information being secured by password access. The preliminary modeling assumptions that will be provided may include:

15.5.2.1 Study case definitions, including load levels studied and planning horizon information.

15.5.2.2 Resource assumptions, including on-system and off-system supplies for current and future native load and network customer needs.

15.5.2.3 Planned resource retirements.

15.5.2.4 Renewable resources under consideration.

15.5.2.5 Demand side options under consideration.

15.5.2.6 Long-term firm transmission service agreements.

15.5.2.7 Current TRM and CBM values.

15.5.3 The Transmission Expansion Review and Input Process: The Annual Transmission Planning Meetings will provide an interactive process over a calendar year for the Stakeholders to receive information and updates, as well as to provide input, regarding the Duke Transmission Provider's development of its transmission expansion plan. This dynamic process will generally be provided as follows:

15.5.3.1 At the Annual Transmission Planning Summit and Assumptions Input Meeting, the Duke Transmission Provider will describe and explain to the Stakeholders the database assumptions for the ten (10) year transmission expansion plan that will be developed during the upcoming year. The Stakeholders will be allowed to provide input regarding the ten (10) year transmission expansion plan assumptions.

15.5.3.2 At the First RPSG Meeting and Interactive Training Session, the Duke Transmission Provider will provide interactive training to the Stakeholders regarding the underlying criteria and methodologies utilized to develop the transmission expansion plan. The databases utilized by the Duke Transmission Provider will be posted on the secured area of the Regional Planning Website.

15.5.3.3 To the extent that Stakeholders have transmission expansion plan/enhancement alternatives that they would like for the Duke Transmission Provider and other Sponsors to consider, the Stakeholders shall perform analysis prior to, and provide any such analysis at, the Preliminary Expansion Plan Meeting. At the Preliminary Expansion Plan Meeting, the Duke Transmission Provider will present its preliminary transmission expansion plan for the current ten (10) year planning horizon, including updates on the status of regional assessments being performed pursuant to Section 20. The Duke Transmission Provider and Stakeholders will engage in interactive expansion plan discussions regarding this preliminary analysis. This preliminary transmission expansion plan will be posted on the secure/CEII area of the Regional Planning Website at least 10 calendar days prior to the Preliminary Expansion Plan meeting.

15.5.3.4 The transmission expansion plan/enhancement alternatives suggested by the Stakeholders will be considered by the Duke Transmission Provider for possible inclusion in the transmission expansion plan. When evaluating such proposed alternatives, the Duke Transmission Provider will, from a transmission planning perspective, take into account factors such as, but not limited to, the proposed alternatives' impacts on reliability, relative economics, effectiveness of performance, impact on transmission service (and/or cost of transmission service) to other customers and on third-party systems, project feasibility/viability and lead time to install.

15.5.3.5 At the Second RPSG Meeting, the Duke Transmission Provider will report to the Stakeholders regarding the suggestions/alternatives suggested by the Stakeholders at the

Preliminary Expansion Plan Meeting. The then-current version of the transmission expansion plan will be posted on the secure/CEII area of the regional planning website at least 10 calendar days prior to the Second RPSG Meeting.

15.5.3.6 At the Annual Transmission Planning Summit, the ten (10) year transmission expansion plan that is intended to be implemented the following year will be presented to the Stakeholders along with the regional transmission plan for purposes of Order No. 1000. The Transmission Planning Summit presentations and the regional transmission plan, which is expected to include the ten (10) year transmission expansion plan will be posted on the Regional Planning Website at least 10 calendar days prior to the Annual Transmission Planning Summit.

15.5.4 Flowchart Diagramming the Steps of the SERTP Process: A flowchart diagramming the SERTP Process, as well as providing the general timelines and milestones for the performance of the activities described herein, is provided in Appendix 2.

16. INFORMATION EXCHANGE

To the extent that the information described in this Section 16 has not already been exchanged pursuant to the Companies' Local Planning Process described in Sections 2-10 herein, the Duke Transmission Provider may request that Transmission Customers and/or other interested parties provide additional information pursuant to this Section 16 in support of regional transmission planning pursuant to Sections 12-31 herein.

16.1 General: Transmission Customers having Service Agreements for Network Integration Transmission Service are required to submit information on their projected loads and resources on a comparable basis (*e.g.*, planning horizon and format) as used by transmission providers in planning for their native load. Transmission Customers having Service Agreements for Point-To-Point Transmission Service are required to submit any projections they have a need for service over the planning horizon and at what receipt and delivery points. Interconnection Customers having Interconnection Agreements under the Tariff are required to submit projected changes to their generating facility that could impact the Duke Transmission Provider's performance of transmission planning studies. The purpose of this information that is provided by each class of customers is to facilitate the Duke Transmission Provider's transmission planning process, with the September 1 due date of these data submissions by customers being timed to facilitate the Duke Transmission Provider's development of its databases and model building for the following year's ten (10) year transmission expansion plan.

16.2 Network Integration Transmission Service Customers: By September 1 of each year, each Transmission Customer having Service Agreement[s] for Network Integration Transmission Service shall provide to the Duke Transmission Provider an annual update of that Transmission Customer's Network Load and Network Resource forecasts for the following ten (10) years consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff.

16.3 Point-to-Point Transmission Service Customers: By September 1 of each year, each Transmission Customers having Service Agreement[s] for long-term Firm Point-To-Point Transmission Service shall provide to the Duke Transmission Provider usage projections for the term of service. Those projections shall include any projected redirects of that transmission service, and any projected resells or reassignments of the underlying transmission capacity. In addition, should the Transmission Customer have rollover rights associated with any such service agreement, the Transmission Customer shall also provide non-binding usage projections of any such rollover rights.

16.4 Demand Resource Projects: The Duke Transmission Provider expects that Transmission Customers having Service Agreements for Network Integration Transmission Service that have demand resource assets will appropriately reflect those assets in those customers' load projections. Should a Stakeholder have a demand resource asset that is not associated with such load projections that the Stakeholder would like to have considered for purposes of the transmission expansion plan, then the Stakeholder shall provide the necessary information *(e.g.* technical and operational characteristics, affected loads, cost, performance, lead time to install) in order for the Duke Transmission Provider to consider such demand response resource comparably with other alternatives. The Stakeholder shall provide this information to the Duke Transmission Provider by the Annual Transmission Planning Summit and Assumptions Input Meeting of the year prior to the implementation of the pertinent ten (10) year transmission expansion plan, and the Stakeholder should then continue to participate in this SERTP Process. To the extent similarly situated, the Duke Transmission Provider shall treat such Stakeholder submitted demand resource projects on a comparable basis for transmission planning purposes.

16.5 Interconnection Customers: By September 1 of each year, each Interconnection Customer having an Interconnection Agreement[s] under the Tariff shall provide to the Duke Transmission Provider annual updates of that Interconnection Customer's planned addition or upgrades (including status and expected in-service date), planned retirements, and environmental restrictions.

16.6 Notice of Material Change: Transmission Customers and Interconnection Customers shall provide the Duke Transmission Provider with timely written notice of material changes in any information previously provided related to any such customer's load, resources, or other aspects of its facilities, operations, or conditions of service materially affecting the Duke Transmission Provider's ability to provide transmission service or materially affecting the Transmission

System.

17. DISPUTE RESOLUTION[10]

17.1 Negotiation: Any substantive or procedural dispute between the Duke Transmission Provider and one or more Stakeholders (collectively, the "Parties") that arises from the Attachment N-1 transmission planning process generally shall be referred to a designated senior representative of the Duke Transmission Provider and a senior representative of the pertinent Stakeholder(s) for resolution on an informal basis as promptly as practicable. Should the dispute also involve one or more other Sponsors of this SERTP Process, then such entity(ies) shall have the right to be included in "Parties" for purposes of this Section and for purposes of that dispute, and any such entity shall also include a designated senior representative in the above discussed negotiations in an effort to resolve the dispute on an informal basis as promptly as practicable. In the event that the designated representatives are unable to resolve the dispute within thirty (30) days, or such other period as the Parties may unanimously agree upon, by unanimous agreement among the Parties such dispute may be voluntarily submitted to the use of the Commission's Alternative Means of Dispute Resolution (18 C.F.R. § 385.604, as those regulations may be amended from time to time), the Commission's Arbitration process (18 C.F.R. § 385.605, as those regulations may be amended from time to time) (collectively, "Commission ADR"), or such other dispute resolution process that the Parties may unanimously agree to utilize.

17.2 Use of Dispute Resolution Processes: In the event that the Parties voluntarily and unanimously agree to the use of a Commission ADR process or other dispute resolution procedure, then the Duke Transmission Provider will have a notice posted to this effect on the Regional Planning Website, and an e-mail notice in that regard will be sent to Registered Stakeholders. In addition to the Parties, all Stakeholders and Sponsors shall be eligible to participate in any Commission ADR process as "participants", as that or its successor term in meaning is used in 18 C.F.R. §§ 385.604, 385.605 as may be amended from time to time, for purposes of the Commission ADR process; provided, however, any such Stakeholder or Sponsor must first have provided written notice to the Duke Transmission Provider within thirty (30) calendar days of the posting on the Regional Planning Website of the Parties' notice of their intent to utilize a Commission ADR Process.

17.3 Costs: Each Party involved in a dispute resolution process hereunder, and each

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[10] Any dispute, claim or controversy amongst Duke or Progress and/or a stakeholder regarding application of, or results from the local transmission planning process contained in Sections 2-11 herein (each a "Dispute") shall be resolved in accordance with the procedures set forth in Section 6 herein. Any procedural or substantive dispute that arises from the SERTP will be addressed by the regional Dispute Resolution Measures contained in this Section 17.

"participant" in a Commission ADR Process utilized in accordance with Section 17.2, shall be responsible for its own costs incurred during the dispute resolution process. Should additional costs be incurred during the dispute resolution process that are not directly attributable to a single Party/participant, then the Parties/participants shall each bear an equal share of such cost.

17.4 Rights under the Federal Power Act: Nothing in this Section 17 shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

18. REGIONAL ECONOMIC PLANNING STUDIES[11]

18.1 General - Economic Planning Study Requests: Stakeholders will be allowed to request that the Duke Transmission Provider perform up to five (5) Stakeholder requested economic planning studies (Economic Planning Studies) on an annual basis.

18.2 Parameters for the Economic Planning Studies: These Economic Planning Studies shall be confined to sensitivity requests for bulk power transfers and/or to evaluate potential upgrades or other investments on the Transmission System that could reduce congestion or integrate new resources. Bulk power transfers from one area to another area with the region encompassed by this SERTP Process (the "Region") shall also constitute valid requests. The operative theory for the Economic Planning Studies is for them to identify meaningful information regarding the requirements for moving large amounts of power beyond that currently feasible, whether such transfers are internal to the Region or from this Region to interconnected regions.

18.3 Other Tariff Studies: The Economic Planning Studies are not intended to replace System Impact Studies, Facility Studies, or any of the studies that are performed for transmission delivery service or interconnection service under the Tariff.

18.4 Clustering: The RPSG should consider clustering similar Economic Planning Study requests. In this regard, if two or more of the RPSG requests are similar in nature and the Duke Transmission Provider concludes that clustering of such requests and studies is appropriate, the Duke Transmission Provider may, following communications with the RPSG, cluster those studies for purposes of the transmission evaluation.

18.5 Additional Economic Planning Studies: Should a Stakeholder(s) request the performance of an Economic Planning Study in addition to the above-described five (5) Economic Planning Studies that the RPSG may request during a calendar year, then any such additional Economic Planning Study will only be performed if

[11] The economic planning studies undertaken pursuant to this Section 18 are regional. Local economic studies are undertaken pursuant to Section 4.2 herein.

such Stakeholder(s) first agrees to bear the Duke Transmission Provider's actual costs for doing so and the costs incurred by any other Sponsor to perform such Economic Planning Study, recognizing that the Duke Transmission Provider may only conduct a reasonable number of transmission planning studies per year. If affected by the request for such an additional Economic Planning Study, the Duke Transmission Provider will provide to the requesting Stakeholder(s) a non-binding but good faith estimate of what the Duke Transmission Provider expects its costs to be to perform the study prior to the Stakeholder(s) having to agree to bear those costs. Should the Stakeholder(s) decide to proceed with the additional study, then it shall pay the Duke Transmission Provider's and other affected Sponsor[s]' estimated study costs up-front, with those costs being trued-up to the Duke Transmission Provider's and other affected Sponsor[s]' actual costs upon the completion of the additional Economic Planning Study.

18.6 Economic Planning Study Process

18.6.1 Stakeholders will be prompted at the Annual Transmission Planning Summit to provide requests for the performance of Economic Planning Studies. Corresponding announcements will also be posted on the Regional Planning Website, and Registered Stakeholders will also receive e-mail notifications to provide such requests. An Economic Planning Study Request Form will be made available on the Regional Planning Website, and interested Stakeholders may submit any such completed request form on the non-secure area of the Regional Planning Website (unless such study request contains CEII, in which case the study request shall be provided to the Duke Transmission Provider with the CEII identified, and the study request shall then be posted on the secure area of the Regional Planning Website).

18.6.2 Prior to each First RPSG Meeting, the RPSG shall compile the Economic Planning Study requests. At the First RPSG Meeting, the RPSG shall meet to discuss and select up to five (5) Economic Planning Studies to be requested to be performed. At the First RPSG Meeting, the Duke Transmission Provider will coordinate with the RPSG and any interested Stakeholders to facilitate the RPSG's efforts regarding its development and selection of the Economic Planning Study requests. Once the RPSG selects the Economic Planning Study(ies) (up to five annually), the RPSG will notify the Duke Transmission Provider, who will post the results on the Regional Planning Website.

18.6.3 The Duke Transmission Provider will post on the secure area of the Regional Planning Website the study assumptions for the five (5) Economic Planning Studies within thirty (30) days of the postings of the selected Economic Planning Studies on the Regional Planning Website. Registered Stakeholders will receive an e-mail notification of this posting, and an announcement will also be posted on the Regional Planning Website.

18.6.4 Stakeholders will have thirty (30) calendar days from the Duke Transmission Provider's posting of the assumptions for the RPSG to provide comments regarding those assumptions. Any such comments shall be posted on the secure area of the Regional Planning Website if the comments concern CEII.

18.6.5 The preliminary results of the Economic Planning Studies will be presented at the Second RPSG Meeting. These results and related data will be posted on the secure area of the Regional Planning Website a minimum of 10 calendar days prior to the Second RPSG Meeting. The Second RPSG Meeting will be an interactive session with the RPSG and other interested Stakeholders in which the Duke Transmission Provider will explain the results, alternatives, methodology, criteria, and related considerations pertaining to those preliminary results. At that meeting, the Stakeholders may submit alternatives to the enhancement solutions identified in those preliminary results. All such alternatives must be submitted by Stakeholders within thirty (30) calendar days from the close of the Second RPSG Meeting. The Duke Transmission Provider will consider the alternatives provided by the Stakeholders.

18.6.6 The final results of the Economic Planning Studies will be presented at the Annual Transmission Planning Summit, and the Duke Transmission Provider will report regarding its consideration of the alternatives provided by Stakeholders. These final results will be posted on the secure area of the Regional Planning Website a minimum of 10 calendar days prior to the Transmission Planning Summit.

18.6.7 The final results of the Economic Planning Studies will be non-binding upon the Duke Transmission Provider and will provide general non-binding estimations of the required transmission upgrades, timing for their construction, and costs for completion.

19. CONSIDERATION OF TRANSMISSION NEEDS DRIVEN BY PUBLIC POLICY REQUIREMENTS

19.1 Procedures for the Consideration of Transmission Needs Driven by Public Policy Requirements: The Duke Transmission Provider addresses transmission needs driven by enacted state, federal and local laws and/or regulations (Public Policy Requirements) in its routine planning, design, construction, operation, and maintenance of the Transmission System.

19.2 The Consideration of Transmission Needs Driven by Public Policy Requirements Identified Through Stakeholder Input and Proposals

19.2.1 Requisite Information: In order for the Duke Transmission Provider to consider possible transmission needs driven by Public Policy Requirements that are proposed by a Stakeholder, the Stakeholder must provide the following information in accordance with the submittal instructions provided on the Regional Planning Website:

19.2.1.1 The applicable Public Policy Requirement, which must be a requirement established by an enacted state, federal or local law(s) and/or regulation(s); and

19.2.1.2 An explanation of the possible transmission need(s) driven by the Public Policy Requirement identified in subsection (19.2.1.1) (*e.g.,* the situation or system condition for which possible solutions may be needed, as opposed to a specific transmission project).

19.2.2 Deadline for Providing Such Information: Stakeholders that propose a possible transmission need driven by a Public Policy Requirement for evaluation by the Duke Transmission Provider in the current transmission planning cycle must provide the requisite information identified in Section 19.2.1 to the Duke Transmission Provider no later than 60 calendar days after the SERTP Annual Transmission Planning Summit and Input Assumptions Meeting for the previous transmission planning cycle.

19.3 Duke Transmission Provider Evaluation of SERTP Stakeholder Input Regarding Possible Transmission Needs Driven by Public Policy Requirements

19.3.1 Identification of Public Policy-Driven Transmission Needs: In order to identify, out of the set of possible transmission needs driven by Public Policy Requirements proposed by Stakeholders, those transmission needs for which transmission solutions will be evaluated in the current planning cycle, the Duke Transmission Provider will assess:

19.3.1.1 Whether the Stakeholder-identified Public Policy Requirement is an enacted local, state, or federal law(s) and/or regulation(s);

19.3.1.2 Whether the Stakeholder-identified Public Policy Requirement drives a transmission need(s); and

19.3.1.3 If the answers to the foregoing questions 1) and 2) are affirmative, whether the transmission need(s) driven by the Public Policy Requirement is already addressed or otherwise being evaluated in the then-current planning cycle.

19.3.2 Identification and Evaluation of Possible Transmission Solutions for Public Policy-Driven Transmission Needs that Have Not Already Been Addressed: If a Public Policy-driven transmission need is identified that is not already addressed, or that is not already being evaluated in the transmission expansion planning process, the Duke Transmission Provider will identify a transmission solution(s) to address the aforementioned need in the planning processes. The potential transmission solutions will be evaluated consistent with Section 20.

19.4 Stakeholder Input During the Evaluation of Public Policy-Driven Transmission Needs and Possible Transmission Solutions

19.4.1 Typically at the First RPSG Meeting and Interactive Training Session, but not later than the Preliminary Expansion Plan Meeting, for the given transmission planning cycle, the Duke Transmission Provider will review the Stakeholder-proposed transmission needs driven by Public Policy Requirements to be evaluated in the then-current planning cycle. Prior to the meeting at which transmission needs driven by Public Policy Requirements will be reviewed, the Duke Transmission Provider will identify, on the Regional Planning Website, which possible transmission needs driven by Public Policy Requirements proposed by Stakeholders (if any) are transmission needs(s) that are not already addressed in the planning process and will, pursuant to Sections 19.3.1 and 19.3.2, be addressed in the current planning cycle.

19.4.2 Stakeholders, including those who are not Transmission Customers, may provide input regarding Stakeholder-proposed possible transmission need(s) and may provide input during the evaluation of potential transmission solutions to identified transmission needs driven by Public Policy Requirements. Specifically with regard to the evaluation of such potential transmission solutions, a Stakeholder may provide input at the Preliminary Expansion Plan Meeting. If a Stakeholder has performed analysis regarding such a potential transmission solution, the Stakeholder may provide any such analysis at that time.

19.4.3 Stakeholder input regarding possible transmission needs driven by Public Policy Requirements may be directed to the governing Tariff process as appropriate. For example, if the possible transmission need identified by the Stakeholder is essentially a request by a network customer to integrate a new network resource, the request would be directed to that existing Tariff process.

19.5 Posting Requirement: The Duke Transmission Provider will provide and post on the Regional Planning Website an explanation of (1) those transmission needs driven by Public Policy Requirements that have been identified for evaluation for potential transmission projects in the then-current planning cycle; and (2) why other suggested, possible transmission needs driven by Public Policy Requirements proposed by Stakeholders were not selected for further evaluation.

20. REGIONAL ANALYSES OF POTENTIALLY MORE EFFICIENT OR COST EFFECTIVE TRANSMISSION SOLUTIONS

20.1 Regional Planning Analyses

20.1.1 During the course of each transmission planning cycle, the Duke Transmission Provider will conduct regional transmission analyses to assess if the then-current regional transmission plan addresses the Duke Transmission Provider's transmission needs, including those of its Transmission Customers and those which may be driven, in whole or in part, by economic considerations or Public Policy Requirements. This regional analysis will include assessing whether there may be more efficient or cost effective transmission projects to address transmission needs than transmission projects included in the latest regional transmission plan (including projects selected in a regional transmission plan for RCAP pursuant to Section 26).

20.1.2 The Duke Transmission Provider will perform power flow, dynamic, and short circuit analyses, as necessary, to assess whether the then-current regional transmission plan would provide for the physical transmission capacity required to address the Duke Transmission Provider's transmission needs, including those transmission needs of its Transmission Customers and those driven by economic considerations and Public Policy Requirements. Such analysis will also evaluate those potential transmission needs driven by Public Policy Requirements identified by Stakeholders pursuant to Section 19.3.1. If the Duke Transmission Provider determines that the on-going planning being performed for the then-current cycle would not provide sufficient physical transmission capacity to address a transmission need(s), the Duke Transmission Provider will identify potential transmission projects to address the transmission need(s).

20.2 Identification and Evaluation of More Efficient or Cost Effective Transmission Project Alternatives

20.2.1 The Duke Transmission Provider will look for potential regional transmission projects that may be more efficient or cost effective solutions to address transmission needs than transmission projects included in the latest regional transmission plan or otherwise under consideration in the then-current transmission planning process for the ten (10) year planning horizon. Consistent with Section 20.1, through power flow, dynamic, and short circuit analyses, as necessary, the Duke Transmission Provider will evaluate regional transmission projects identified to be potentially more efficient or cost effective solutions to address transmission needs, including those transmission alternatives proposed by Stakeholders pursuant to Section 15.5.3.3 and transmission projects proposed for RCAP pursuant to Section 25. The evaluation of transmission projects in these regional assessments throughout the then-current planning cycle will be based upon their effectiveness in addressing transmission needs, including those driven by Public Policy Requirements, reliability and/or economic considerations. Such analysis will be in accordance with, and subject to (among other things), state law pertaining to transmission ownership, siting, and construction. In assessing whether transmission alternatives are more efficient and/or cost effective transmission solutions, the Duke Transmission Provider shall consider factors such as, but not limited to, a transmission project's:

20.2.1.1 Impact on reliability.

20.2.1.2 Feasibility, including the viability of constructing and tying in the proposed project by the required in-service date.

20.2.1.3 Relative transmission cost, as compared to other transmission project alternatives to reliably address transmission needs.

20.2.1.4 Ability to reduce real power transmission losses on the transmission system(s) within the SERTP region, as compared to other transmission project alternatives to reliably address transmission needs.

20.2.2 Stakeholder Input: Stakeholders may provide input on potential transmission alternatives for the Duke Transmission Provider to consider throughout the SERTP planning process for each planning cycle in accordance with Section 15.5.3.

21. MERCHANT TRANSMISSION DEVELOPERS PROPOSING TRANSMISSION FACILITIES IMPACTING THE SERTP:

Merchant transmission developers not seeking regional cost allocation pursuant to Sections 25-31 (Merchant Transmission Developers) who propose to develop a transmission project(s) potentially impacting the Transmission System and/or transmission system(s) within the SERTP region shall provide information and data necessary for the Duke Transmission Provider to assess the potential reliability and operational impacts of those proposed transmission facilities. That information should include:

- Transmission project timing, scope, network terminations, load flow data, stability data, HVDC data (as applicable), and other technical data necessary to assess potential impacts.

22. ENROLLMENT

22.1 General Eligibility for Enrollment: A public utility or non-public utility transmission service provider and/or transmission owner who is registered with NERC as a Transmission Owner or a Transmission Service Provider may enroll in the SERTP. Such Transmission Service Providers and Transmission Owners are thus potential Beneficiaries for cost allocation purposes on behalf of their transmission customers. Entities that do not enroll will nevertheless be permitted to participate as Stakeholders in the SERTP.

22.2 Enrollment Requirement In Order to Seek Regional Cost Allocation: While enrollment is not generally required in order for a transmission developer to be eligible to propose a transmission project for evaluation and potential selection in a regional transmission plan for RCAP pursuant to Sections 25-31, a potential transmission developer must enroll in the SERTP in order to be eligible to propose a transmission project for potential selection in a regional transmission plan for RCAP if it, an affiliate, subsidiary, member, owner or parent company has load in the SERTP.

22.3 Means to Enroll: Entities that satisfy the general eligibility requirements of Section 22.1 or are required to enroll in accordance with Section 22.2 may provide an application to enroll by submitting the form of enrollment posted on the Regional Planning Website.

22.4 List of Enrollees in the SERTP: Attachment N-3 provides the list of the entities who have enrolled in the SERTP in accordance with the foregoing provisions (Enrollees). Attachment N-3 is effective as of the effective date of the tariff record (and subject to Section 22.5, below) that contains Attachment N-3. In the event a non-public utility listed in Attachment N-3 provides the Duke Transmission Provider with notice that it chooses not to enroll in, or is withdrawing from, the SERTP pursuant to Section 22.5 or Section 22.6, as applicable, such action shall be effective as of the date prescribed in accordance with that respective Section. In such an event, the Duke Transmission Provider shall file revisions to the lists of Enrollees in Attachment N-3 within fifteen business days of such notice. The effective date of any such revised tariff record shall be the effective date of the non-public utility's election to not enroll or to withdraw as provided in Section 22.5 or 22.6, as applicable.

22.5 Enrollment, Conditions Precedent, Conditions Subsequent, and Cost Allocation Responsibility: Enrollment will subject Enrollees to cost allocation if, during the period in which they are enrolled, it is determined in accordance with this Attachment N-1 that the Enrollee is a Beneficiary of a transmission project(s) selected in the regional transmission plan for RCAP; subject to the following:

22.5.1 Upon Order on Compliance Filing: The initial non-public utilities that satisfy the general eligibility requirements of 22.1 and who have made the decision to enroll at the time of the Duke Transmission Provider's compliance filing in response to FERC's July 18, 2013 Order on Compliance Filings in Docket Nos. ER13-897, ER13-908, and ER13-913, 144 FERC ¶ 61,054, do so on the condition precedent that the Commission accepts: i) that compliance filing without modification and without setting it for hearing or suspension and ii) the Duke Transmission Provider's July 10, 2013 compliance filing made in Docket Nos. ER13-1928, ER13-1930, ER13-1940, and ER13-1941 without modification and without setting it for hearing or suspension. Should the Commission take any such action upon review of such compliance filings or in any way otherwise modify, alter, or impose amendments to this Attachment N-1, then each such non-public utility shall be under no obligation to enroll in the SERTP and shall have sixty (60) days following such an order or action to provide written notice to the Duke Transmission Provider of whether it will, in fact, enroll in the SERTP. If, in that event, such non-public utility gives notice to the Duke Transmission Provider that it will not enroll, such non-public utility shall not be subject to cost allocation under this Attachment N-1 (unless it enrolls at a later date).

22.5.2 Upon Future Regulatory Action: Notwithstanding anything herein to the contrary, should the Commission, a Court, or any other governmental entity having the requisite authority modify, alter, or impose amendments to this Attachment N-1, then an enrolled non-public utility may immediately withdraw from this Attachment N-1 by providing written notice within sixty (60) days of that order or action, with the non-public utility's termination being effective as of the close of business the prior business day before said modification, alteration, or amendment occurred (although if the Commission has not acted by that prior business day upon both of the compliance filings identified in Section 22.5.1, then the non-public utility shall never have been deemed to have enrolled in the SERTP). In the event of such a withdrawal due to such a future regulatory and/or judicial action, the withdrawing Enrollee will be subject to cost allocations, if any, that were determined in accordance with this Attachment N-1 during the period in which it was enrolled and that determined that the withdrawing Enrollee would be a Beneficiary of new transmission projects selected in the regional transmission plan for RCAP.

22.6 Notification of Withdrawal: An Enrollee choosing to withdraw its enrollment in the SERTP may do so by providing written notification of such intent to the Duke Transmission Provider. Except for non-public utilities electing to not enroll or withdraw pursuant to Section 22.5, a non-public utility Enrollee's withdrawal shall be effective as of the date the notice of withdrawal is provided to the Duke Transmission Provider pursuant to this Section 22.6. For public utility Enrollees, the withdrawal shall be effective at the end of the then-current transmission planning cycle provided that the notification of withdrawal is provided to the Duke Transmission Provider at least sixty (60) days prior to the Annual Transmission Planning Summit and Assumptions Input Meeting for that transmission planning cycle.

22.7 Cost Allocation After Withdrawal: Any withdrawing Enrollee will not be allocated costs for transmission projects selected in a regional transmission plan for RCAP after its termination of enrollment becomes effective in accordance with the provisions of Section 22.5 or Section 22.6. However, the withdrawing Enrollee will be subject to cost allocations determined in accordance with this Attachment N-1 during the period it was enrolled, if any, for which the Enrollee was identified as a Beneficiary of new transmission projects selected in the regional transmission plan for RCAP.

23. PRE-QUALIFICATION CRITERIA FOR A TRANSMISSION DEVELOPER TO BE ELIGIBLE TO SUBMIT A REGIONAL TRANSMISSION PROJECT PROPOSAL FOR POTENTIAL SELECTION IN A REGIONAL TRANSMISSION PLAN FOR RCAP

23.1 Transmission Developer Pre-Qualification Criteria: In order to be eligible to propose a transmission project (that the transmission developer intends to develop) for consideration for selection in a regional transmission plan for RCAP in the upcoming planning cycle, a transmission developer (including the Duke Transmission Provider and nonincumbents) or a parent company (as defined in Section 23.1.2.2 below), as applicable, must submit a pre-qualification application by August 1st of the then-current planning cycle. To demonstrate that the transmission developer will be able to satisfy the minimum financial capability and technical expertise requirements, the pre-qualification application must provide the following:

23.1.1 A non-refundable administrative fee of $25,000 to off-set the cost to review, process, and evaluate the transmission developer's pre-qualification application;

23.1.2 Demonstration that at least one of the following criteria is satisfied:

23.1.2.1 The transmission developer must have and maintain a Credit Rating (defined below) of BBB- or better from Standard & Poor's Financial Services LLC, a part of McGraw Hill Financial (S&P), a Credit Rating of Baa3 or better from Moody's Investors Service, Inc. (Moody's) and/or a Credit Rating of BBB- or better from Fitch Ratings, Inc. (Fitch, collectively with S&P and Moody's and/or their successors, the "Rating Agencies") and not have or obtain less than any such Credit Rating by S&P, Moody's or Fitch. The senior unsecured debt (or similar) rating for the relevant entity from the Rating Agencies will be considered the "Credit Rating". In the event of multiple Credit Ratings from one Rating Agency or Credit Ratings from more than one Rating Agency, the lowest of those Credit Ratings will be used by the Duke Transmission Provider for its evaluation. However, if such a senior unsecured debt (or similar) rating is unavailable, the Duke Transmission Provider will consider Rating Agencies' issuer (or similar) ratings as the Credit Rating.

23.1.2.2 If a transmission developer does not have a Credit Rating from S&P, Moody's or Fitch, it shall be considered "Unrated", and an Unrated transmission developer's parent company or the entity that plans to create a new subsidiary that will be the transmission developer (both hereinafter "parent company") must have and maintain a Credit Rating of BBB- or better from

S&P, Baa3 or better from Moody's and/or BBB- or better from Fitch, not have or obtain less than any such Credit Rating by S&P, Moody's or Fitch, and the parent company must commit in writing to provide an acceptable guaranty to the Duke Transmission Provider meeting the requirements of Section 31 for the transmission developer if a proposed transmission project is selected in a regional transmission plan for RCAP. If there is more than one parent company, the parent company(ies) committing to provide the guaranty must meet the requirements set forth herein.

23.1.2.3 For an Unrated transmission developer, unless its parent company satisfies the requirements under B. above, such transmission developer must have and maintain a Rating Equivalent (defined below) of BBB- or better. Upon an Unrated transmission developer's request, a credit rating will be determined for such Unrated transmission developer comparable to a Rating Agency credit rating (Rating Equivalent) based upon the process outlined below:

(1) Each Unrated transmission developer will be required to pay a non-refundable annual fee of $15,000.00 for its credit to be evaluated/reevaluated on an annual basis.

(2) Upon request by the Duke Transmission Provider, an Unrated transmission developer must submit to the Duke Transmission Provider for the determination of a Rating Equivalent, and not less than annually thereafter, the following information with respect to the transmission developer, as applicable:

(A) financial statements (audited if available) for each completed fiscal quarter of the then current fiscal year including the most recent fiscal quarter, as well as the most recent three (3) fiscal years;

(i) For Unrated transmission developers with publicly-traded stock, this information must include:

(a) Annual reports on Form 10-K (or successor form) for the three (3) fiscal years most recently ended, and quarterly reports on Form 10-Q (or successor form) for each completed quarter of the then current fiscal year, together with any amendments thereto, and

(b) Form 8-K (or successor form) reports disclosing material changes, if any, that have been filed since the most recent Form 10-K (or successor form), if applicable;

(ii) For Unrated transmission developers that are privately held, this information must include:

(a) Financial Statements, including balance sheets, income statements, statement of cash flows, and statement of stockholder's equity,

(b) Report of Independent Accountants,

(c) Management's Discussion and Analysis, and

(d) Notes to financial statements;

(B) its Standard Industrial Classification and North American Industry Classification System codes;

(C) at least one (1) bank and three (3) acceptable trade references;

(D) information as to any material litigation, commitments or contingencies as well as any prior bankruptcy declarations or material defaults or defalcations by, against or involving the transmission developer or its predecessors, subsidiaries or affiliates, if any;

(E) information as to the ability to recover investment in and return on its projects;

(F) information as to the financial protections afforded to unsecured creditors contained in its contracts and other legal documents related to its formation and governance;

(G) information as to the number and composition of its members or customers;

(H) its exposure to price and market risk;

(I) information as to the scope and nature of its business; and

(J) any additional information, materials and documentation which such Unrated transmission developer deems relevant evidencing such Unrated transmission developer's financial capability to develop, construct, operate and maintain transmission developer's projects for the life of the projects.

(3) The Duke Transmission Provider will notify an Unrated transmission developer after the determination of its Rating Equivalent. Upon request, the Duke Transmission Provider will provide the Unrated transmission developer with information regarding the procedures, products and/or tools used to determine such Rating Equivalent (*e.g.*, Moody's RiskCalc™ or other product or tool, if used).

(4) An Unrated transmission developer desiring an explanation of its Rating Equivalent must request such an explanation in writing within five (5) business days of receiving its Rating Equivalent. The Duke Transmission Provider will respond within fifteen (15) business days of receipt of such request with a summary of the analysis supporting the Rating Equivalent decision.

23.1.3 Evidence that the transmission developer has the capability to develop, construct, operate, and maintain significant U.S. electric transmission projects. The transmission developer should provide, at a minimum, the following information about the transmission developer. If the transmission developer is relying on the experience or technical expertise of its parent company or affiliate(s) to meet the requirements of this subsection 3, the following information should be provided about the transmission developer's parent company and its affiliates, as applicable:

23.1.3.1 Information regarding the transmission developer's or other relevant experience regarding transmission projects in-service, under construction, and/or abandoned or otherwise not completed including locations, operating voltages, mileages, development schedules, and approximate installed costs; whether delays in project completion were encountered; and how these facilities are owned, operated and maintained;

23.1.3.2 Evidence demonstrating the ability to address and timely remedy failure of transmission facilities;

23.1.3.3 Violations of NERC and/or Regional Entity reliability standard(s) and/or violations of regulatory requirement(s) that have been made public pertaining to the development, construction, ownership, operation, and/or maintenance of electric transmission infrastructure facilities (provided that violations of CIP standards are not required to be identified), and, if so, an explanation of such violations; and

23.1.3.4 A description of the experience of the transmission developer in acquiring rights of way.

23.1.4 Evidence of how long the transmission developer and its parent company, if relevant, have been in existence.

23.2 Review of Pre-Qualification Applications: No later than November 1st of the then-current planning cycle, the Duke Transmission Provider will notify transmission developers that submitted pre-qualification applications or updated information by August 1st, whether they have pre-qualified as eligible to propose a transmission project for consideration for selection in a regional transmission plan for RCAP in the upcoming planning cycle. A list of transmission developers that have pre-qualified for the upcoming planning cycle will be posted on the Regional Planning Website.

23.3 Opportunity for Cure for Pre-Qualification Applications: If a transmission developer does not meet the pre-qualification criteria or provides an incomplete application, then following notification by the Duke Transmission Provider, the transmission developer will have 15 calendar days to resubmit the necessary supporting documentation to remedy the identified deficiency. The Duke Transmission Provider will notify the transmission developer, whether they are, or will continue to be, pre-qualified within 30 calendar days of the resubmittal, provided that the Duke Transmission Provider shall not be required to provide such a response prior to November 1st of the then-current planning cycle.

23.4 Pre-Qualification Renewal: If a transmission developer is pre-qualified as eligible to propose a transmission project for consideration for selection in a regional transmission plan for RCAP in the then-current planning cycle, such transmission developer may not be required to re-submit information to pre-qualify with respect to the upcoming planning cycle. In the event any information on which the entity's pre-qualification is based has changed, such entity must submit all updated information by the August 1st deadline. In addition, all transmission developers must submit a full pre-qualification application once every 3 years.

23.5 Enrollment Requirement to Pre-Qualify as Eligible to Propose a Transmission Project for Potential Selection in a Regional Transmission Plan for RCAP: If a transmission developer or its parent company or owner or any affiliate, member or subsidiary has load in the SERTP region, the transmission developer must have enrolled in the SERTP in accordance with Section 22.2 to be eligible to pre-qualify to propose a transmission project for potential selection in a regional transmission plan for RCAP.

24. TRANSMISSION PROJECTS POTENTIALLY ELIGIBLE FOR SELECTION IN A REGIONAL TRANSMISSION PLAN FOR RCAP:

24.1 In order for a transmission project proposed by a transmission developer, whether incumbent or non-incumbent, to be considered for evaluation and potential selection in a regional transmission plan for RCAP, the project must be regional in nature in that it must be a transmission project effectuating significant bulk electric transfers across the SERTP region and addressing significant electrical needs in that it:

24.1.1 operates at a voltage of 300 kV or greater;

24.1.2 is a transmission line located in the SERTP region; and

24.1.3 spans at least 50 miles.

24.2 In addition to satisfying the requirements of Section 24.1, the proposed regional transmission project must not contravene state or local laws with regard to rights-of-way or construction of transmission facilities. The proposed transmission project also cannot be an upgrade to an existing facility. A transmission upgrade includes any expansion, partial replacement, or modification, for any purpose, made to existing transmission facilities, including, but not limited to:

24.2.1 transmission line reconductors;

24.2.2 the addition, modification, and/or replacement of transmission line structures and equipment;

24.2.3 increasing the nominal operating voltage of a transmission line;

24.2.4 the addition, replacement, and/or reconfiguration of facilities within an existing substation site;

24.2.5 the interconnection/addition of new terminal equipment onto existing transmission lines.

For purposes of clarification, a transmission project proposed for potential selection in a regional transmission plan for RCAP may rely on the implementation of one or more transmission upgrades (as defined above) by the Impacted Utilities in order to reliably implement the proposed transmission project.

24.3 In order for the proposed transmission project to be a more efficient or cost effective alternative to the transmission projects identified by the transmission providers through their planning processes, it should be materially different than projects already under consideration in the expansion planning process. A project will be deemed materially different, as compared to another transmission alternative(s) under consideration, if the proposal consists of significant geographical or electrical differences in the alternative's proposed interconnection point(s) or transmission line routing. Should the proposed transmission project be deemed not materially different than projects already under consideration in the transmission expansion planning process, the Duke Transmission Provider will provide a sufficiently detailed explanation on the Regional Planning Website for Stakeholders to understand why such determination was made.

25. SUBMISSION OF PROPOSALS FOR POTENTIAL SELECTION IN A REGIONAL TRANSMISSION PLAN FOR RCAP

Any entity may propose a transmission project for consideration by the Duke Transmission Provider for potential selection in a regional transmission plan for RCAP.[12] An entity that wants to propose a transmission project for potential selection in a regional transmission plan for RCAP but does not intend to develop the transmission project may propose such transmission project in accordance with Section 25.6.

25.1 Materials to be Submitted: In order for a transmission project to be considered for RCAP, a pre-qualified transmission developer proposing the transmission project (including an incumbent or nonincumbent transmission developer) must provide to the Duke Transmission Provider the following information:

25.1.1 Sufficient information for the Duke Transmission Provider to determine that the potential transmission project satisfies the regional eligibility requirements of Section 24;

25.1.2 A description of the proposed transmission project that details the intended scope (including the various stages of the project development such as engineering, ROW acquisition, construction, recommended in-service date, etc.);

25.1.3 A capital cost estimate of the proposed transmission project. If the cost estimate differs greatly from generally accepted estimates of projects of comparable scope, the transmission developer may be asked to support such differences with supplemental information;

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[12] The regional cost allocation process provided hereunder in accordance with Sections 25-31 does not limit the ability of the Duke Transmission Provider and other entities to negotiate alternative cost sharing arrangements voluntarily and separately from this regional cost allocation method.

25.1.4 Data and/or files necessary to appropriately model the proposed transmission project;

25.1.5 Documentation of the specific transmission need(s) that the proposed transmission project is intended to address. This documentation should include a description of the transmission need(s), timing of the transmission need(s), and may include, the technical analysis performed to support that the proposed transmission project addresses the specified transmission need(s);

25.1.6 A description of why the proposed transmission project is expected to be more efficient or cost effective than other transmission projects included in the then-current regional transmission plan. If available, and to facilitate the evaluation of the proposal and to mitigate the potential for disputes, the entity proposing the project for potential selection in a regional transmission plan for RCAP may submit documentation of detailed technical analyses performed that supports the position that the proposed transmission project addresses the specified transmission needs more efficiently or cost-effectively. Such optional documentation could include the following:

25.1.6.1 Transmission projects in the latest transmission expansion plan or regional transmission plan that would be displaced by the proposed project,

25.1.6.2 Any additional projects that may be required in order to implement the proposed project, or

25.1.6.3 Any reduction/increase in real-power transmission system losses;

25.1.7 The transmission developer must provide a reasonable explanation of, as it pertains to its proposed project, its planned approach to satisfy applicable regulatory requirements and its planned approach to obtain requisite authorizations necessary to acquire rights of way and to construct, operate, and maintain the proposed facility in the relevant jurisdictions;

25.1.7.1 The transmission developer should not expect to use the Duke Transmission Provider's right of eminent domain for ROW acquisition;

25.1.8 How the transmission developer intends to comply with all applicable standards and obtain the appropriate NERC certifications,

25.1.8.1 If it or a parent, owner, affiliate, or member who will be performing work in connection with the potential transmission project is registered with NERC or other industry organizations pertaining to electric reliability and/or the development, construction, ownership, or operation, and/or maintenance of electric infrastructure facilities, a list of those registrations;

25.1.9 The experience of the transmission developer specific to developing, constructing, maintaining, and operating the type of transmission facilities contained in the transmission project proposed for potential selection in a regional transmission plan for RCAP,

25.1.9.1 Including verifiable past achievements of containing costs and adhering to construction schedules for transmission projects of similar size and scope as the proposed transmission project, and

25.1.9.2 Including a description of emergency response and restoration of damaged equipment capability

25.1.10 The planned or proposed project implementation management teams and the types of resources, including relevant capability and experience, contemplated for use in the development and construction of the proposed project;

25.1.11 A written commitment to comply with all applicable standards, including Good Utility Practices, governing the engineering, design, construction, operation, and maintenance of transmission projects in the SERTP region; and

25.1.12 Evidence of the ability of the transmission developer, its affiliate, partner or parent company to secure a financial commitment from an approved financial institution(s) agreeing to finance the construction, operation, and maintenance of the transmission project if selected in a regional transmission plan for RCAP.

25.2 Administrative Fee: An administrative fee of $25,000 to off-set the costs to review, process and evaluate each transmission project proposal. A refund of $15,000 will be provided to the transmission developer if:

25.2.1 The proposal is determined to not satisfy the qualification criteria in Section 25.1; or

25.2.2 The transmission developer withdraws its proposal by providing written notification of its intention to do so to the Duke Transmission Provider prior to the First RPSG Meeting and Interactive Training Session for that transmission planning cycle.

25.3 Deadline for Transmission Developer Submittals: In order for its transmission project to be considered for RCAP in the current transmission planning cycle, a transmission developer must provide the requisite information and payment identified in Sections 25.1-25.2 to the Duke Transmission Provider in accordance with the submittal instructions provided on the Regional Planning Website no later than 60 calendar days after the SERTP Annual Transmission Planning Summit and Input Assumptions Meeting for the previous transmission planning cycle.

25.4 Initial Review of Submittal and Opportunity for Cure: The Duke Transmission Provider will notify transmission developers who propose a transmission project for potential selection in a regional transmission plan for RCAP whose submittals do not meet the requirements specified in Sections 25.1-25.2, or who provide an incomplete submittal, within 45 calendar days of the submittal deadline to allow the transmission developer an opportunity to remedy any identified deficiency(ies). Transmission developers, so notified, will have 15 calendar days to resubmit the necessary supporting documentation to remedy the identified deficiency. The Duke Transmission Provider will notify the transmission developer, whether they have adequately remedied the deficiency within 30 calendar days of the resubmittal. Should the deficiency(ies) remain unremedied, then the transmission project will not be considered for RCAP.

25.5 Change in the Qualification Information or Circumstances:

25.5.1 The transmission developer proposing a transmission project for potential selection in a regional transmission plan for RCAP has an obligation to update and report in writing to the Duke Transmission Provider any change to its or its parent company's information that was provided as the basis for its satisfying the requirements of Sections 23 through 31, except that the transmission developer is not expected to update its technical analysis performed for purposes of Section 25.1.6 to reflect updated transmission planning data as the transmission planning cycle(s) progresses.

25.5.2 The transmission developer must inform the Duke Transmission Provider of the occurrence of any of the developments described in (1) or (2) below should the following apply (and within the prescribed time period): (i) within five (5) business days of the occurrence if the transmission developer has a pre-qualification application pending as of the date of the occurrence; (ii) upon the submission of a renewal request for pre-qualification should the development have occurred since the transmission developer was pre-qualified; (iii) prior to, or as part of, proposing a transmission project for potential selection in a regional transmission plan for RCAP pursuant to Section 25.1 should the development have occurred since the transmission developer was pre-qualified; and (iv) within five (5) business days of the occurrence if the transmission developer has a transmission project either selected or under consideration for selection in a regional transmission plan for RCAP. These notification requirements are applicable upon the occurrence of any of the following:

25.5.2.1 the existence of any material new or ongoing investigations against the transmission developer by the Commission, the Securities and Exchange Commission, or any other governing, regulatory, or standards body that has been or was required to be made public; if its parent company has been relied upon to meet the requirements of Section 23.1.2 or Section 31, such information must be provided for the parent company and, in any event, with respect to any affiliate that is a transmitting utility; and

25.5.2.2 any event or occurrence which could constitute a material adverse change in the transmission developer's (and, if the parent company has been relied upon to meet the requirements of Section 23.1.2 or Section 31, the parent company's) financial condition (Material Adverse Change) such as:

(1) A downgrade or suspension of any debt or issuer rating by any Rating Agency,

(2) Being placed on a credit watch with negative implications (or similar) by any Rating Agency,

(3) A bankruptcy filing or material default or defalcation,

(4) Insolvency,

(5) A quarterly or annual loss or a decline in earnings of twenty-five percent (25%) or more compared to the comparable year-ago period,

(6) Restatement of any prior financial statements, or

(7) Any government investigation or the filing of a lawsuit that reasonably would be expected to adversely impact any current or future financial results by twenty-five percent (25%) or more.

25.5.3 If at any time the Duke Transmission Provider concludes that a transmission developer or a potential transmission project proposed for possible selection in a regional transmission plan for RCAP no longer satisfies such requirements specified in Sections 23-25, then the Duke Transmission Provider will so notify the transmission developer or entity who will have fifteen (15) calendar days to cure. If the transmission developer does not meet the fifteen (15) day deadline to cure, or if the Duke Transmission Provider determines that the transmission developer continues to no longer satisfy the requirements specified in Sections 23-25 despite the transmission developer's efforts to cure, then the Duke Transmission Provider may, without limiting its other rights and remedies, immediately remove the transmission developer's potential transmission project(s) from consideration for potential selection in a regional transmission plan for RCAP and, if previously selected, from being selected in a regional transmission plan for RCAP, as applicable.

25.6 Projects Proposed for RCAP Where the Entity Making the Proposal Does Not Intend to be the Developer of the Project: Any Stakeholder may propose a potentially more cost effective or efficient transmission project for consideration in the transmission planning process in accordance with Section 15.5.3, and nothing herein limits the ability of a Stakeholder and other entities to negotiate alternative transmission development arrangements voluntarily and separately from the processes provided in this Attachment N-1. Should an entity propose a transmission project for potential selection in a regional transmission plan for RCAP but not intend to develop the project, then the following applies. Such an entity must submit the information required by Sections 25.1.1, 25.1.5, and 25.1.6 for a regional transmission project eligible for potential selection in a regional transmission plan for RCAP within the sixty (60) day window established in 25.3. Provided that the proposal complies with those requirements, the Duke Transmission Provider will make information describing the proposal available on the Regional Planning Website. The entity proposing the transmission project should coordinate with a transmission developer (either incumbent or nonincumbent) to have the developer submit the remaining information and materials required by Section 25. A pre-qualified transmission developer, should it decide to proceed, must submit the materials required by Section 25 within the sixty (60) day window established in Section 25.3 in order for the proposed transmission project to be considered for selection in a regional transmission plan for RCAP. If such a transmission project has not been so submitted within the sixty (60) day window established in Section 25.3, then the Duke Transmission Provider may treat the project as a Stakeholder-proposed transmission project alternative pursuant to Section 15.5.3. Furthermore, should the Duke Transmission Provider identify in the regional transmission planning process a regional transmission project that is selected in the regional transmission plan for RCAP that does not have a transmission developer that intends or is able to develop the project, the Duke Transmission Provider will identify such project on the Regional Planning Website. A prequalified transmission developer that desires to develop the project, whether incumbent or non-incumbent, may then propose the transmission project, pursuant to Sections 24 and 25, as the intended transmission developer for the project's on-going consideration in a regional transmission plan for RCAP.

26. EVALUATION AND POTENTIAL SELECTION OF PROPOSALS FOR SELECTION IN A REGIONAL TRANSMISSION PLAN FOR RCAP

26.1 Potential Transmission Projects Seeking RCAP Will be Evaluated in the Normal Course of the Transmission Planning Process: During the course of the then-current transmission expansion planning cycle (and thereby in conjunction with other system enhancements under consideration in the transmission planning process), the Duke Transmission Provider will evaluate current transmission needs and assess alternatives to address current needs including the potential transmission projects proposed for possible selection in a regional transmission plan for RCAP by transmission developers consistent with the regional evaluation process described in Section 20. Such evaluation will be in accordance with, and subject to (among other things), state law pertaining to transmission ownership, siting, and construction. Utilizing coordinated models and assumptions, the Duke Transmission Provider will perform analyses, including power flow, dynamic, and short circuit analyses, as necessary and, applying its planning guidelines and criteria to evaluate submittals, determine whether, throughout the ten (10) year planning horizon:

26.1.1 The proposed transmission project addresses an underlying transmission need(s);

26.1.2 The proposed transmission project addresses transmission needs that are currently being addressed with projects in the transmission planning process and if so, which projects could be displaced (consistent with the reevaluation of the projects included in a regional transmission plan as described in Section 28) by the proposed transmission project, including;

26.1.2.1 transmission projects in the Duke Transmission Provider's ten year transmission expansion plan,

26.1.2.2 transmission projects in the regional transmission plan, including those currently under consideration and/or selected for RCAP;

26.1.3 The proposed transmission project addresses a transmission need(s) for which no transmission project is currently included in the latest ten (10) year expansion plans and/or regional transmission plan. If so, the Duke Transmission Provider will identify an alternative transmission project(s) which would be required to fully and appropriately address the same transmission need(s) (*e.g.*, otherwise considered to be the more efficient or cost effective transmission alternative). The Duke Transmission Provider will identify and evaluate such an alternative transmission project(s) consistent with the processes described in Sections 1 to 11 and 20;

26.1.4 Any additional projects that would be required to implement the proposed transmission project;

26.1.5 The proposed transmission project reduces and/or increases real power transmission losses on the transmission system within the SERTP region.

Previous analysis may be used, either in part or in whole, if applicable to the evaluation of the proposed regional transmission project. Stakeholders may provide input into the evaluation of RCAP proposals throughout the SERTP process consistent with Section 15.5.3

26.2 Transmission Benefit-to-Cost Analysis Based Upon Planning Level Cost Estimates

26.2.1 Based upon the evaluation outlined in Section 26.1, the Duke Transmission Provider will assess whether the transmission developer's transmission project proposed for potential selection in a regional transmission plan for RCAP is considered at that point in time to yield meaningful, net regional benefits. Specifically, the proposed transmission project should yield a regional transmission benefit-to-cost ratio of at least 1.25 and no individual Impacted Utility should incur increased, unmitigated transmission costs.[13]

26.2.1.1 The benefit used in this calculation for purposes of assessing the transmission developer's proposed transmission project will be quantified by the Beneficiaries' total cost savings in the SERTP region associated with:

(1) All transmission projects in the ten (10) year transmission expansion plan which would be displaced, as identified pursuant to Section 26.1;

(2) All regional transmission projects included in the regional transmission plan which would be displaced, as identified pursuant to Section 26.1 and to the extent no overlap exists with those transmission projects identified as displaceable in the Duke Transmission Provider's ten (10) year transmission expansion plan. This includes transmission projects currently selected in the regional transmission plan for RCAP; and

(3) All alternative transmission project(s), as determined pursuant to Section 26.1 that would be required in lieu of the proposed regional transmission project, if the proposed regional transmission project addresses a

[13] An entity would incur increased, unmitigated transmission costs should it incur more costs than displaced benefits and not be compensated/made whole for those additional costs. For purposes of this Attachment N-1, the terms "Impacted Utilities" shall mean: i) the Beneficiaries identified in the evaluation of the proposed transmission project and ii) any entity identified in this Section 26.2.1 to potentially have increased costs on its transmission system located in the SERTP region in order to implement the proposal.

transmission need for which no transmission project is included in the latest ten (10) year expansion plan and/or regional transmission plan.

26.2.1.2 The cost used in this calculation will be quantified by the transmission cost within the SERTP region associated with:

(1) The project proposed for selection in a regional transmission plan for RCAP; and

(2) Any additional projects within the SERTP region on Impacted Utility transmission systems required to implement the proposal as identified pursuant to Section 26.1.

(3) For interregional transmission projects proposed for purposes of cost allocation between the SERTP and a neighboring region(s), the cost used in this calculation will be quantified by the transmission cost of the project multiplied by the allocation of the transmission project's costs (expressed as a fraction) to the SERTP region as specified in the applicable interregional cost allocation procedures, plus the transmission costs of any additional project within the SERTP region on Impacted Utility transmission systems required to implement the proposal as identified pursuant to Section 26.1.

26.2.1.3 If the initial BTC calculation results in a ratio equal to or greater than 1.0, then the Duke Transmission Provider will calculate the estimated change in real power transmission losses on the transmission system(s) of Impacted Utilities located in the SERTP. In that circumstance, an updated BTC ratio will be calculated consistent with Section 26.2. in which:

26.2.1.4 The cost savings associated with a calculated reduction of real power energy losses on the transmission system(s) will be added to the benefit; and

26.2.1.5 The cost increase associated with a calculated increase of real power energy losses on the transmission system(s) will be added to the cost.

26.2.2 The Duke Transmission Provider will develop planning level cost estimates for use in determining the regional benefit-to-cost ratio. Detailed engineering estimates may be used if available. If the Duke Transmission Provider uses a cost estimate different than a detailed cost estimate(s) provided by the transmission developer for use in performing the regional benefit-to-cost ratio, the Duke Transmission Provider will provide a detailed explanation of such difference to the transmission developer.

26.2.3 The cost savings and/or increase associated with real power losses on the transmission system(s) within the SERTP region with the implementation of the proposed regional transmission project will be estimated for each Impacted Utility throughout the ten (10) year transmission planning horizon as follows:

26.2.3.1 The Duke Transmission Provider will utilize power flow models to determine the change in real power losses on the transmission system at estimated average load levels.

(a) If the estimated change in real power transmission losses is less than 1 MW on a given transmission system of an Impacted Utility, no cost savings and/or cost increase for change in real power transmission losses on such system will be assigned to the proposal.

26.2.3.2 The Duke Transmission Provider will estimate the energy savings associated with the change in real power losses utilizing historical or forecasted data that is publicly available (*e.g.*, FERC Form 714).

26.2.4 Within 30 days of the Duke Transmission Provider completing the foregoing regional benefit-to-cost analysis, the Duke Transmission Provider will notify the transmission developer of the results of that analysis. For potential transmission projects found to satisfy the foregoing benefit-to-cost analysis, the Impacted Utilities will then consult with the transmission developer of that project to establish a schedule for the following activities specified below, with the schedule to be developed within 90 days of the notification: 1) the transmission developer providing detailed financial terms for its proposed project and 2) the proposed transmission project to be reviewed by the jurisdictional and/or governance authorities of the Impacted Utilities pursuant to Section 26.4 for potential selection in a regional transmission plan for RCAP.[14]

[14] The schedule established in accordance with Section 26.2.4 will reflect considerations such as the timing of those transmission needs the regional project may address as well as the lead-times of the regional project, transmission projects that must be implemented in support of the regional project, and projects that may be displaced by the regional project. This schedule may be revised by the Duke Transmission Provider and the Impacted Utilities, in consultation with the

(cont'd)

26.3 The Transmission Developer to Provide More Detailed Financial Terms and the Performance of a Detailed Transmission Benefit-to-Cost Analysis:

26.3.1 By the date specified in the schedule established in Section 26.2.4, the transmission developer shall identify the detailed financial terms for its proposed project, establishing in detail: (1) the total cost to be allocated to the Beneficiaries if the proposal were to be selected in a regional transmission plan for RCAP, and (2) the components that comprise that cost, such as the costs of:

26.3.1.1 Engineering, procurement, and construction consistent with Good Utility Practice and standards and specifications acceptable to the Duke Transmission Provider,

26.3.1.2 Financing costs, required rates of return, and any and all incentive-based (including performance based) rate treatments,

26.3.1.3 Ongoing operations and maintenance of the proposed transmission project,

26.3.1.4 Provisions for restoration, spare equipment and materials, and emergency repairs, and

26.3.1.5 Any applicable local, state, or federal taxes.

26.3.2 To determine whether the proposed project is considered at that time to remain a more efficient or cost effective alternative, the Duke Transmission Provider will then perform a more detailed 1.25 transmission benefit-to-cost analysis consistent with that performed pursuant to Section 26.2.1. This more detailed transmission benefit-to-cost analysis will be based upon the detailed financial terms[15] provided by the transmission developer, as may be modified by agreement of the transmission developer and Beneficiary(ies), and any additional, updated, and/or more detailed transmission planning, cost or benefit information/component(s) as provided by the Impacted Utilities that are applicable to/available for the proposed transmission project, the projects that would be displaced, any additional projects required to

(cont'd from previous page)
transmission developer, as appropriate to address, for example, changes in circumstances and/or underlying assumptions.

[15] The detailed financial terms are to be provided by the date specified in the schedule to be developed by the Impacted Utilities and the transmission developer in accordance with Section 26.2.4.

implement the proposal and real power transmission loss impacts.[16] Once the Duke Transmission Provider has determined the outcome of the aforementioned regional benefit-to-cost analysis, the Transmission Provider will notify the transmission developer within 30 days of the outcome.

26.3.3 To provide for an equitable comparison, the costs of the transmission projects that would be displaced and/or required to be implemented in such a detailed benefit-to-cost analysis will include comparable cost components as provided in the proposed project's detailed financial terms (and vice-versa), as applicable. The cost components of the transmission projects that would be displaced will be provided by the Duke Transmission Provider and/or other Impacted Utilities who would own the displaced transmission project. The cost components of the proposed transmission project and of the transmission projects that would be displaced will be reviewed and scrutinized in a comparable manner in performing the detailed benefit to cost analysis.

26.4 Jurisdictional and/or Governance Authority Review : Should the proposed transmission project be found to satisfy the more detailed benefit-to-cost analysis specified in Section 26.3, the state jurisdictional and/or governance authorities of the Impacted Utilities will be provided an opportunity to review the transmission project proposal and otherwise consult, collaborate, inform, and/or provide recommendations to the Duke Transmission Provider. The recommendations will inform the Duke Transmission Provider's selection decision for purposes of Section 26.5, and such a recommendation and/or selection of a project for inclusion in a regional transmission plan for RCAP shall not prejudice the state jurisdictional and/or governance authority's (authorities') exercise of any and all rights granted to them pursuant to state or Federal law with regard to any project evaluated and/or selected for RCAP that falls within such authority's (authorities') jurisdiction(s).

26.5 Selection of a Proposed Transmission Project for RCAP:

26.5.1 The Duke Transmission Provider will select a transmission project (proposed for RCAP) for inclusion in the regional transmission plan for RCAP for the then-current planning cycle if the Duke Transmission Provider determines that the project is a more efficient or cost effective

[16] The performance of this updated, detailed benefit-to-cost analysis might identify different Beneficiaries and/or Impacted Utilities than that identified in the initial benefit-to-cost analysis performed in accordance with Section 26.2.1.

transmission project as compared to other alternatives to reliably address transmission need(s).[17] Factors considered in this determination include:

26.5.1.1 Whether the project meets or exceeds the detailed benefit-to-cost analysis performed pursuant to Section 26.3. Such detailed benefit-to-cost analysis may be reassessed, as appropriate, based upon the then-current Beneficiaries and to otherwise reflect additional, updated, and/or more detailed transmission planning, cost or benefit information/component(s) that are applicable to/available for the proposed transmission project, the projects that would be displaced, any additional projects required to implement the proposal and real power transmission loss impacts;

26.5.1.2 Any recommendation provided by state jurisdictional and/or governance authorities in accordance with Section 26.4 including whether the transmission developer is considered reasonably able to construct the transmission project in the proposed jurisdiction(s);

26.5.1.3 Whether, based on the timing for the identified transmission need(s) and the stages of project development provided by the transmission developer in accordance with Section 25.1 and as otherwise may be updated, the transmission developer is considered to be reasonably able to construct and tie the proposed transmission project into the transmission system by the required in-service date;

26.5.1.4 Whether it is reasonably expected that the Impacted Utilities will be able to construct and tie-in any additional facilities on their systems located within the SERTP region that are necessary to reliably implement the proposed transmission project; and

26.5.1.5 Any updated qualification information regarding the transmission developer's finances or technical expertise, as detailed in Section 23.

[17] Being selected for RCAP in the then-current iteration of a regional transmission plan only provides how the costs of the transmission project may be allocated in Commission-approved rates should the project be built. Being selected in a regional transmission plan for RCAP provides no rights with regard to siting, construction, or ownership. The transmission developer must obtain all requisite approvals to site and build its transmission project. A transmission project may be removed from being selected in a regional transmission plan for RCAP in accordance with the provisions of Sections 25.4, 28, 29, 30 and 31.

The Duke Transmission Provider will post on the Regional Planning Website its determination regarding whether a proposed project will be selected for inclusion in the regional transmission plan for RCAP for that transmission planning cycle. The Duke Transmission Provider will document its determination in sufficient detail for Stakeholders to understand why a particular project was selected or not selected for RCAP and will make this supporting documentation available to the transmission developer or Stakeholders, subject to any applicable confidentiality requirements. For projects selected in the regional transmission plan for purposes of RCAP, the documentation will also include sufficient information regarding the application of the regional cost allocation method to determine the benefits and identify the Beneficiaries of the proposed regional transmission project.

26.5.2 If a regional transmission project is selected in the regional transmission plan for purposes of RCAP, the Duke Transmission Provider will perform analyses to determine whether, throughout the ten (10) year planning horizon, the proposed transmission project could potentially result in reliability impacts to the transmission system(s) of an adjacent neighboring transmission planning region(s). If a potential reliability impact is identified, the Duke Transmission Provider will coordinate with the neighboring planning region on any further evaluation. The costs associated with any required upgrades identified in neighboring planning regions will not be included for RCAP within the SERTP.

27. COST ALLOCATION TO THE BENEFICIARIES:

If a regional transmission project is selected in a regional transmission plan for RCAP in accordance with Section 26.5 and then constructed and placed into service, the Beneficiaries will be allocated the regional transmission project's costs based upon their cost savings calculated in accordance with Section 26.3 and associated with:

27.1 The displacement of one or more of the transmission projects previously included in their ten (10) year transmission expansion plan.

27.2 The displacement of one or more regional transmission projects previously included in the regional transmission plan. More specifically, if a regional transmission project addresses the same transmission need(s) as a transmission project selected in a regional transmission plan for RCAP and displaces the original RCAP project as a more efficient or cost effective alternative, this cost allocation component will be based upon the costs of the original RCAP project that were to be allocated to the Beneficiaries in accordance with the application of the regional cost allocation method to the transmission project being displaced.

27.3 Any alternative transmission project(s) that would be required in lieu of the regional transmission project, if the proposed regional transmission project addresses a transmission need for which no transmission project is included in the latest ten (10) year expansion plan and/or regional transmission plan.

27.4 The reduction of real power transmission losses on their transmission system.

28. ON-GOING EVALUATIONS OF PROPOSED PROJECTS:

28.1 In order to ensure that the Duke Transmission Provider can efficiently and cost effectively meet its respective reliability, duty to serve, and cost of service obligations, and to ensure that the proposed transmission project remains the more efficient or cost effective alternative, the Duke Transmission Provider will continue to reevaluate the regional transmission plan throughout the then-current planning cycle and in subsequent cycles. This continued reevaluation will assess, in subsequent expansion planning processes that reflect ongoing changes in actual and forecasted conditions, the then-current transmission needs and determine whether transmission projects included in the regional transmission plan (i) continue to be needed and (ii) are more efficient or cost effective as compared to alternatives.

28.1.1 These on-going assessments will include reassessing transmission projects that have been selected in the regional transmission plan for RCAP and any projects that are being considered for potential selection in a regional transmission plan for RCAP.

28.2 Even though a transmission project may have been selected in a regional transmission plan for RCAP in an earlier regional transmission plan, if it is determined that the transmission project is no longer needed and/or it is no longer more efficient or cost effective than alternatives, then the Duke Transmission Provider may notify the transmission developer and remove the proposed project from being selected in a regional transmission plan for RCAP.

28.3 The cost allocation of a regional transmission project selected in a regional transmission plan for RCAP that remains selected in the regional transmission plan for RCAP may be modified in subsequent planning cycles based upon:

28.3.1 The then-current determination of benefits (calculated consistent with Section 26.3),

28.3.2 Cost allocation modifications as mutually agreed by the Beneficiaries, or

28.3.3 Cost modifications, as found acceptable by both the transmission developer and the Beneficiary(ies).

All prudently incurred costs of the regional transmission project will be allocated if the project remains selected in the regional plan for RCAP.

28.4 The reevaluation of the regional transmission plan will include the reevaluation of a particular transmission project included in the regional transmission plan until it is no longer reasonably feasible to replace the proposed transmission project as a result of the proposed transmission project being in a material stage of construction and/or if it is no longer considered reasonably feasible for an alternative transmission project to be placed in service in time to address the underlying transmission need(s) the proposed project is intended to address.

29. DELAY OR ABANDONMENT:

29.1 The transmission developer shall promptly notify the Duke Transmission Provider should any material changes or delays be encountered in the development of a potential transmission project selected in a regional transmission plan for RCAP. As part of the Duke Transmission Provider's on-going transmission planning efforts, the Duke Transmission Provider will assess whether alternative transmission solutions may be required in addition to, or in place of, a potential transmission project selected in a regional transmission plan for RCAP due to the delay in its development or abandonment of the project. The identification and evaluation of potential transmission project alternative solutions may include transmission project alternatives identified by the Duke Transmission Provider to include in the ten year transmission expansion plan. Furthermore, nothing precludes the Duke Transmission Provider from proposing such alternatives for potential selection in a regional transmission plan for RCAP pursuant to Section 25.

29.2 Based upon the alternative transmission projects identified in such on-going transmission planning efforts, the Duke Transmission Provider will evaluate the transmission project alternatives consistent with the regional planning process. The Duke Transmission Provider will remove a delayed project from being selected in a regional transmission plan for RCAP if the project no longer:

29.2.1 Adequately addresses underlying transmission needs by the required transmission need dates; and/or

29.2.2 Remains more efficient or cost effective based upon a reevaluation of the detailed benefit-to-cost calculation. The BTC calculation will factor in any additional transmission solutions required to implement the proposal (*e.g.*, temporary fixes) and will also compare the project to identified transmission project alternatives.

30. MILESTONES OF REQUIRED STEPS NECESSARY TO MAINTAIN STATUS AS BEING SELECTED FOR RCAP:

30.1 Once a regional transmission project is selected in a regional transmission plan for RCAP, the transmission developer must submit a development schedule to the Duke Transmission Provider and the Impacted Utilities that establishes the milestones by which the necessary steps to develop and construct the transmission project must occur. These milestones include (to the extent not already accomplished) obtaining all necessary ROWs and requisite environmental, state, and other governmental approvals. A development schedule will also need to be established for any additional projects by Impacted Utilities that are determined necessary to integrate the transmission projects selected in a regional transmission plan for RCAP. The schedule and milestones must be satisfactory to the Duke Transmission Provider and the Impacted Utilities.

30.2 In addition, the Beneficiaries will also determine and establish the deadline(s) by which the transmission developer must provide security/collateral for the proposed project that has been selected in a regional transmission plan for RCAP to the Beneficiaries or otherwise satisfy requisite creditworthiness requirements. The security/collateral/creditworthiness requirements shall be as described or referenced in Section 31.

30.3 If such critical steps are not met by the specified milestones and then afterwards maintained, then the Duke Transmission Provider may remove the project from being selected in a regional transmission plan for RCAP.

31. CREDIT AND SECURITY REQUIREMENTS TO PROTECT THE BENEFICARIES AGAINST DELAY OR ABANDONMENT OF A TRANSMISSION PROJECT SELECTED IN A REGIONAL TRANSMISSION PLAN FOR RCAP

31.1 Demonstration of Financial Strength**:** In order for a project to be selected and remain selected in a regional transmission plan for RCAP, the transmission developer must satisfy the following:

31.1.1 Consistent with Sections 23.1 and 25.5.3, the transmission developer for such project or its parent company providing the Beneficiaries with a parent guaranty ("Parent Guarantor") must have and maintain a Credit Rating of BBB- (or equivalent) or better from one or more of the Rating Agencies and not have or obtain less than any such Credit Rating by any of the Rating Agencies, or the transmission developer must be Unrated and have and maintain a Rating Equivalent of BBB- or better.

31.1.2 In addition to the requirements of Section 31.1.1, the transmission developer must satisfy one of the following by and at all times after the deadline established pursuant to Section 30.2:

31.1.2.1 The transmission developer must (i) have and maintain a Credit Rating of BBB+ (or equivalent) or better from one or more of the Rating Agencies and not have or obtain less than any such Credit Rating by any of the Rating Agencies or (ii) be Unrated and have and maintain a Rating Equivalent of BBB+ or better; or

31.1.2.2 The transmission developer must provide to and maintain with the Beneficiaries Eligible Developer Collateral (as defined in Section 31.4 below) in an amount equal to twenty-five percent

(25%) of the total costs of the transmission developer's projects selected in a regional transmission plan for RCAP.

31.2 Limitation of Exposure

31.2.1 Notwithstanding the foregoing, the Beneficiaries may limit their exposure with respect to transmission projects selected in a regional transmission plan being developed by a transmission developer satisfying the requirements of Section 31.1.2.1 above if the aggregate costs of such projects are at any time in excess of the lesser of (a) 10% of the transmission developer's Tangible Net Worth if the transmission developer has a Tangible Net Worth of less than one billion dollars or (b) two hundred fifty million dollars (the "Cap"). In such event, the transmission developer must provide to and maintain with the Beneficiaries Eligible Developer Collateral in a dollar amount not less than the amount by which the aggregate costs of such projects exceed the Cap. Each transmission developer will provide and update the Beneficiaries with such information as is necessary to establish and confirm the transmission developer's Tangible Net Worth. For purposes hereof, "Tangible Net Worth" shall be equal to the relevant entity's total equity minus its intangible assets and also minus its goodwill.

31.2.2 Notwithstanding the foregoing, the Beneficiaries may limit their exposure with respect to transmission projects selected in a regional transmission plan being developed by a transmission developer or its affiliates who are satisfying the requirements of Section 31.1.2.2 or 31.2.1 above by providing and maintaining a Developer Parent Guaranty (as defined in Section 31.4 below) if the aggregate costs of such projects are at any time in excess of the lesser of (a) 10% of the Parent Guarantor's Tangible Net Worth if such Parent Guarantor has a Tangible Net Worth of less than one billion dollars or (b) two hundred fifty million dollars (the "Guarantor Cap"). In such event, the transmission developer must provide to and maintain with the Beneficiaries an acceptable Irrevocable Letter of Credit in a dollar amount not less than the amount by which the aggregate costs of such projects exceed the Guarantor Cap. Each transmission developer will provide and update the Beneficiaries with such information as is necessary to establish and confirm the Parent Guarantor's Tangible Net Worth.

31.3 Credit Evaluation/Updates

31.3.1 On at least an annual basis, a transmission developer with a transmission project selected in a regional transmission plan for RCAP will provide the Beneficiaries with an updated, completed application and the updated information described in Section 23.1.

31.3.2 On at least an annual basis, or more often if there is a Material Adverse Change in the financial condition and/or a relevant change in the Tangible Net Worth of the transmission developer or its Parent Guarantor or if there are issues or changes regarding a transmission project, the Beneficiaries may review the Credit Rating and review and update the Rating Equivalent, Cap, Guarantor Cap and Eligible Developer Collateral requirements for said transmission developer. In the event said transmission developer is required to provide additional Eligible Developer Collateral as a result of the Beneficiaries' review/update, the Beneficiaries will notify the transmission developer and such additional Eligible Developer Collateral must be provided within five (5) business days of such notice, all in amount and form approved by the Beneficiaries.

31.4 Eligible Developer Collateral: Acceptable forms of eligible collateral meeting the requirements referenced below and the Beneficiaries' approval (the "Eligible Developer Collateral") may be either in the form of an irrevocable letter of credit ("Irrevocable Letter of Credit") or parent guaranty issued by a Parent Guarantor who has and maintains a Credit Rating of BBB+ (or equivalent) or better from one or more of the Rating Agencies and does not have or obtain less than any such Credit Rating by any of the Rating Agencies ("Developer Parent Guaranty"). Acceptable forms of Eligible Developer Collateral and related requirements and practices will be posted and updated on the Regional Planning Website and/or provided to the relevant transmission developer directly.

31.4.1 Each Beneficiary shall require an Irrevocable Letter of Credit to be issued to it in a dollar amount equal to the percentage of the costs of a transmission developer's transmission projects allocated or proposed to be allocated to it ("Percentage") multiplied by the aggregate dollar amount of all Irrevocable Letters of Credit constituting or to constitute Eligible Developer Collateral for such transmission projects.

31.4.2 Each Beneficiary shall require a Developer Parent Guaranty to be issued to it in a dollar amount equal to its Percentage multiplied by the aggregate dollar amount of all Developer Parent Guaranties constituting or to constitute Eligible Developer Collateral for such transmission projects.

31.4.2.1 A transmission developer supplying a Developer Parent Guaranty must provide and continue to provide the same information regarding the Parent Guarantor as is required of a transmission developer, including rating information, financial statements and related information, references, litigation information and other disclosures, as applicable.

31.4.2.2 All costs associated with obtaining and maintaining Irrevocable Letters of Credit and/or Developer Parent

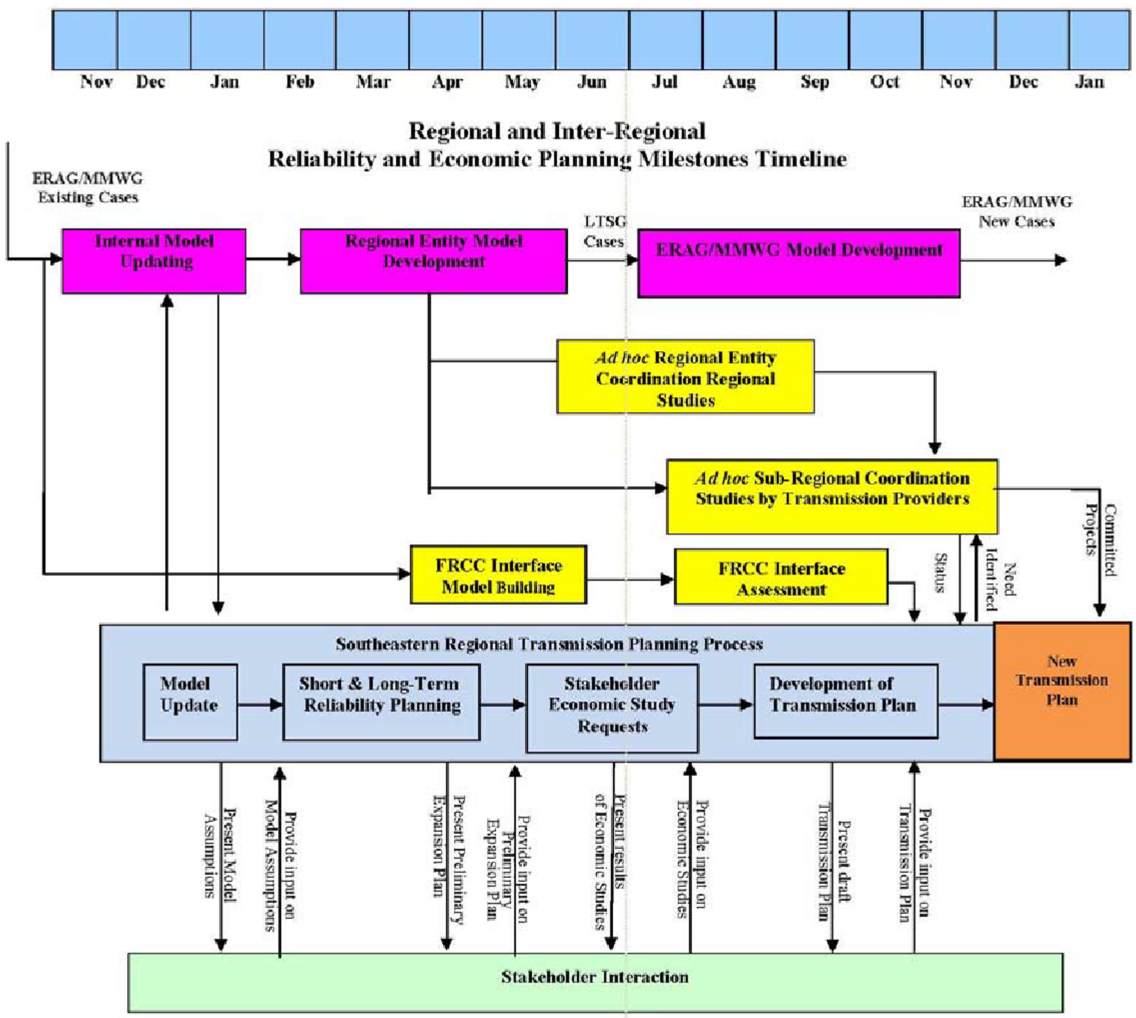
Guaranties and meeting the requirements of this Section 31 are the responsibility of the transmission developer.

31.4.2.3 The Beneficiaries reserve the right to deny, reject, or terminate acceptance and acceptability of any Irrevocable Letter of Credit or any Developer Parent Guaranty as Eligible Developer Collateral at any time for reasonable cause, including the occurrence of a Material Adverse Change or other change in circumstances.

31.5 Cure Periods/Default: If a transmission developer fails to comply with the requirements of this Section 31 and such failure is not cured within ten (10) business days after its initial occurrence, the Beneficiaries may declare such transmission developer to be in default hereunder and/or the Beneficiaries may, without limiting their other rights and remedies, revise the Cap, Guarantor Cap and Eligible Developer Collateral requirements; further, if such failure is not cured within an additional ten (10) business days, the Beneficiaries may, without limiting their other rights and remedies, immediately remove any or all of the transmission developer's projects from consideration for potential selection in the regional transmission plan for RCAP and, if previously selected, from being selected in a regional transmission plan for RCAP, as applicable.

Appendix 1
[Reserved]

Appendix 2


Nov
Dec
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Regional and Inter-Regional
Reliability and Economic Planning Milestones Timeline
ERAG/MMWG Existing Cases
Internal Model Updating
Regional Entity Model Development
LTSG Cases
ERAG/MMWG Model Development
ERAG/MMWG New Cases
Ad hoc Regional Entity Coordination Regional Studies
Ad hoc Sub-Regional Coordination Studies by Transmission Providers
Committed Projects
Status
Need Identified
FRCC Interface Model Building
FRCC Interface Assessment
Southeastern Regional Transmission Planning Process
Model Update
Short & Long-Term Reliability Planning
Stakeholder Economic Study Requests
Development of Transmission Plan
New Transmission Plan
Present Model Assumptions
Provide input on Model Assumptions
Present Preliminary Expansion Plan
Provide input on Preliminary Expansion Plan
Present results of Economic Studies
Provide input on Economic Studies
Present draft Transmission Plan
Provide input on Transmission Plan
Stakeholder Interaction

Appendix 3

Sector Voting Example

The example below illustrates the TAG Sector Voting Process. For purposes of explaining the example, we assume that the General Public (GP) Sector has 10 Individuals present. In addition to the 10 Individuals, there are 17 other TAG Sector Entities present, spread across four TAG Sectors (Cooperative LSEs (Coop LSE); Municipal LSEs (Muni LSE); Investor-Owned LSEs (IOU LSE); and Transmission Customers (TC)). These 17 TAG Sector Entities may each have several TAG participants present but only one may vote in one sector. Each Individual and TAG Sector Entity casts their vote, which vote is then weighted based on the number of persons/entities voting in the TAG Sector of which they are a member. E.g., since there are six Coop LSE voters present, each Coop LSE's vote is worth 1.00/6 or .166 (*see* Columns 4 and 5 for weighted vote). As the final step, the votes are weighted again, based on the number of TAG Sectors present. With five TAG Sectors present, each Sector Yes Vote and Sector No Vote is multiplied by 1.00/5 = .20. The weighted total is reported in columns 6 and 7. In the example, the No votes have won .53 to .47.

Column	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Sector	**No. of Voters**	**Yes Votes**	**No Votes**	**Sector Yes Vote**	**Sector No Vote**	**Weighted Sector Yes**	**Weighted Sector No Vote**
Coop LSE	6	6	0	1.00	0	.20	0
Muni LSE	8	2	6	.25	.75	.05	.15
IOU LSE	2	1	1	.50	.50	.10	.10
TP/TO	0	0	0	0	0	0	0
TCs	1	0	1	0	1.00	0	.20
GICs	0	0	0	0	0	0	0
ECs	0	0	0	0	0	0	0
GP	10	6	4	.60	.40	.12	.08
Total Vote						0.47	0.53

ATTACHMENT N-1

TRANSMISSION PLANNING PROCESS
(~~Progress~~DEP Zone and ~~Duke~~DEC Zone)

1. INTRODUCTION

Duke Energy Carolinas, LLC (~~Duke~~DEC) and Duke Energy Progress, LLC (~~Progress~~DEP~~   ~~) (sometimes referred to individually as ~~"~~Company~~"~~ and collectively ~~"~~Companies~~"),~~), entities 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 local transmission planning requirements imposed by Order Nos. 890 and 1000 through the process developed and implemented by the ~~North Carolina~~Carolinas Transmission Planning Collaborative (~~N~~CTPC Process or Local Planning Process). The ~~NCTPC was formed by the following~~Carolinas Transmission Planning Collaborative includes load serving entities (LSE~~s~~) in the States of North Carolina~~: Duke, Progress, ElectriCities of North Carolina (ElectriCities),~~ and ~~the North~~South Carolina ~~Electric Membership Corporation (NCEMC)~~ (collectively, ~~N~~CTPC Participants or Participants) ~~.~~ within the DEC and DEP footprint.

The Companies ensure that their Transmission Systems are planned in accordance with the regional planning requirements imposed by Order No. 1000 through participation in the Southeastern Regional Transmission Planning Process (SERTP or SERTP Process).

In addition to engaging in local transmission planning through the ~~N~~CTPC Process and regional transmission planning through the SERTP Process, the Companies engage in additional coordination activities with transmission providers located inside and outside their region, as discussed in Section 11. Such activities include participation in SERC Reliability Corporation (SERC), which focuses on reliability assessments. The SERTP engages in interregional coordination as described in Attachment N-1 – FRCC, Attachment N-1 – MISO, Attachment N-1 – PJM, Attachment N-1 – SCRTP, and Attachment N-1 – SPP.

Unless noted otherwise, Section references in this Attachment N-1 refer to Sections within this Attachment N-1.

For purposes of computation of time, all references in this document shall be calendar days. If any of the deadlines set forth in this document should fall on a weekend or holiday recognized by FERC, then the deadline shall fall on the next business day.

PART I -- LOCAL PLANNING PROCESS

2. ~~N~~CTPC PROCESS OVERVIEW INCLUDING THE PROCESS FOR CONSULTING WITH TAG PARTICIPANTS

The ~~NCTPC will~~CTPC shall annually develop a single, coordinated local transmission plan (Local 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~~Carolinas Transmission Planning Collaborative Participation Agreement (Participation Agreement) governs the ~~NCTPC~~participation in the CTPC and the ~~N~~CTPC Process. The Participation Agreement is located on the ~~N~~CTPC's Website (http://www.nctpc.org/nctpc/).

2.2 The ~~N~~CTPC Process is summarized in a document entitled *~~North Carolina~~Carolinas Transmission Planning Collaborative Process* that is located on the ~~NCTPTC~~CTPC's Website.

2.3 Participation in the ~~N~~CTPC

2.3.1 Pursuant to the *Participation Agreement*, the ~~N~~CTPC has three components: the Oversight/Steering Committee (OSC), the Planning Working Group (PWG), and the Transmission Advisory Group (TAG).

2.3.2 Eligibility for participation in the three ~~N~~CTPC components is as follows:

2.3.2.1 The appointment of OSC members by the ~~N~~CTPC Participants is governed by the *Participation Agreement*. The qualifications required to serve on the OSC are set forth in a document entitled *Scope - Oversight/Steering Committee* that is located on the ~~N~~CTPC's Website.

2.3.2.2 The appointment of PWG members by the ~~N~~CTPC Participants is governed by the *Participation Agreement*. The qualifications required to serve on the PWG are set forth in a document entitled *Scope - Planning Working Group* that is located on the ~~N~~CTPC's Website.

2.3.2.3 Anyone may participate in TAG meetings and sign-up to receive TAG communications. The TAG is comprised of TAG participants. An employee or agent of a ~~N~~CTPC Participant who 1) performs or supervises transmission planning activities or 2) is a member of the OSC or PWG may not be a TAG participant, but employees or agents of ~~N~~CTPC Participants that perform activities other than transmission planning activities may be TAG participants.

2.4 Responsibilities and Decision-Making of ~~N~~CTPC Components

The responsibilities of the components within the ~~N~~CTPC 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 ~~N~~CTPC 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.*

2.4.1.4 ~~.~~The OSC is responsible for selecting an Administrator in the manner set forth in the *Participation Agreement.* The Administrator shall act as a facilitator for the OSC and TAG and shall assist the chair and vice-chair in the performance of their duties as reasonably requested.

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 Local Transmission Plan. The TAG participants may propose economic studies for evaluation as described in Section 4.2.2 hereof. The TAG participants select which of those projects should be evaluated through the TAG Sector Voting Process. The TAG participants also provide input on the annual study scope elements of the Local Transmission Plan Development, including input on the following: Study Assumptions; Study Criteria; Study Methodology; Technical Analysis and Study Results; Assessment and Problem Identification; Assessment and Development of Solutions (including proposing alternative solutions for evaluation); Comparison and Selection of the Preferred Transmission Plan; and the Local Transmission Plan Report.~~CTPC Participants to aid in the development of an annual Local Transmission Plan. Opportunities for input from TAG participants are detailed in Sections 4 and 5 hereof. A full list of the TAG's responsibilities is found in *Scope - Transmission Advisory Group,* which is located on the

~~N~~CTPC's Website.

2.4.3.2 The OSC chair will chair the TAG meetings ~~and~~. The Administrator will serve as ~~a~~the facilitator for the ~~group~~TAG meetings. TAG decision-making is by consensus among the TAG participants. However, in the event consensus cannot be reached, voting will be conducted through the TAG Sector Voting Process. The ~~OSC chair~~Administrator will provide notice to the TAG participants in advance of the TAG meeting that specific votes will be taken during the TAG meeting.

2.4.3.3 Only TAG participants attending the meeting (in person or by telephone, electronic or other communication facilities that permit all participants to communicate with each other during the meeting) will be allowed to participate in the TAG Sector Voting Process. No voting by proxy is permitted.

2.4.4 TAG Sector Voting Process.

2.4.4.1 In order for a TAG participant to participate in the TAG Sector Voting Process, the TAG participant must have registered with the Companies at least two weeks prior to the first meeting at which the TAG participant intends to vote. Such web-based registration will require the TAG participant to provide the following information to the Companies: name, home or business address, place of employment (if any), email address (if any), and telephone number. The registration form will require the TAG participant to indicate whether the TAG participant is registering as an "Individual" or as an agent or employee of a "TAG Sector Entity." If the TAG participant registers as an agent, member, or employee of a TAG Sector Entity, s/he must identify such TAG Sector Entity. An individual TAG participant may register as an agent, member, or employee of more than one TAG Sector Entity.

2.4.4.2 A TAG Sector Entity may be any organized group (e.g., corporation, partnership, association, trust, agency, government body, etc.) but cannot be an individual person. A TAG Sector Entity may be a member of only one TAG Sector. A TAG Sector Entity and its affiliates or member organizations all may register as separate TAG Sector Entities, as long as such affiliates or member organizations meet the definition of a TAG Sector Entity.

2.4.4.3 A TAG Sector Entity should elect to be a member of one of the following TAG Sectors: Cooperative LSEs ~~(~~that serve load in the ~~N~~CTPC footprint~~);~~, Municipal LSEs ~~(~~that serve load in the ~~N~~CTPC footprint~~);~~, Investor-Owned LSEs ~~(~~that serve load in the ~~N~~CTPC footprint~~);~~, Transmission Providers/Transmission Owners ~~(~~that are not LSEs in the

~~N~~CTPC footprint~~)~~~~;~~, Transmission Customers ~~(~~a customer taking Transmission Service from at least one Company in the ~~N~~CTPC~~)~~; Generator Interconnection Customers (a customer taking FERC- or state- jurisdictional generator interconnection service from at least one of the Companies in the ~~N~~CTPC); Eligible Customers and Ancillary Service Providers (includes developers~~;~~, ancillary service providers~~;~~, power marketers not currently taking transmission service~~;~~, and demand response providers); and General Public. An Individual is only eligible to join the General Public Sector.

2.4.4.4

Only one individual TAG participant that has registered as an agent or employee of a TAG Sector Entity may vote on behalf of a particular TAG Sector Entity with regard to any particular vote. An individual TAG participant may vote on behalf of more than one TAG Sector Entity, if authorized to do so. Questions to be voted on will be answerable with a Yes or No.

2.4.4.5

If a vote is to be taken, each TAG Sector that has at least one TAG Sector Entity representative, or at least one Individual or TAG Sector Entity representative in the case of the General Public Sector, present will receive a Sector Vote with a worth of 1.00. A Sector Vote is divisible. The vote of each TAG participant eligible to vote in a Sector Vote is not divisible. The vote of each TAG participant in a TAG Sector will be multiplied by 1.00 divided by the total number ~~or~~of TAG participants voting in such Sector to determine how the Sector Vote with a total worth of 1.00 will be allocated between "Sector Yes Votes" and "Sector No Votes." That is, each Sector Vote will be allocated such that the Sector Yes Vote(s) and Sector No Vote(s) totals 1.00. The Sector Yes Vote and Sector No Vote for each TAG Sector will then each be weighted by multiplying each of them by 1.00 divided by the number of TAG Sectors participating in the relevant vote. The results will be called "Weighted Sector Yes Vote" and "Weighted Sector No Vote." The winning position will be the larger of the Weighted Sector Yes Vote and Weighted Sector No Vote. Appendix 3 contains an example of the voting process.

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. If they choose to be a TAG participant, state public utility regulatory commissions would be TAG Sector Entities in the General Public Sector. State public utility regulatory commissions also may seek to receive periodic status updates and the progress reports on the ~~N~~CTPC Process. ~~State public utility regulatory commissions may be TAG Sector Entities in the General Public Sector.~~

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

All information regarding local transmission planning meetings and communications are located on the ~~N~~CTPC 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~~CTPC website.

3.1.2 Information about signing up to be a TAG participant and to receive email communications ~~is~~will be posted on the ~~N~~CTPC Website.

3.1.3 The OSC will publish highlights of its meetings on the ~~NCTPC Website~~CTPC 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 or other web-based 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, and 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, their alternates, PWG members, and, if approved, guests. Guests will be approved in accordance with the Scope of the OSC document as posted to the CTPC website.

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 OSC and their alternatives, and, if approved, guests. -Guests will be approved in accordance with the Scope of the PWG document as posted to the CTPC website.

3.3.3 TAG

3.3.3.1 TAG meetings are chaired by the OSC chair and facilitated by the ~~OSC chair~~Administrator.

3.3.3.2 The TAG generally meets four times a year in accordance with the procedures set forth in Section 5.

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 to TAG participants that are qualified to receive Confidential Information. TAG Participants are free to use information from the TAG meeting discussion, but are not permitted to attribute any particular discussion comment(s) to a specific CTPC or TAG Participant.

3.3.3.4 A yearly meeting and activity schedule is proposed, discussed with, and provided to TAG participants annually. Additional TAG meetings may be scheduled on an as needed basis, in conformity with Section 5.

3.3.3.5 Any submissions by TAG participants to the PWG, OSC, or CTPC Participants pursuant to the procedures in Section 5 will be deemed public and will be posted on the CTPC Website for other TAG participants. However, TAG participants may designate all or part of its submission as confidential information, pursuant to Section 9.2. Additionally, for all public postings of submissions by TAG participants, the identity of the TAG participant who made the submission will be treated as confidential information and will be posted publicly only by consent of the TAG participant upon submission.

4. DESCRIPTION OF THE LOCAL PLANNING PROCESS

The ~~N~~CTPC Process is a coordinated local transmission planning process. The entire~~,~~ iterative process ultimately results in a single Local Transmission Plan that appropriately balances the costs, benefits and risks associated with the use of transmission, generation, and demand-side resources. The Local Transmission Plan will identify local transmission projects (Local Projects). A Local Project is defined as a transmission facility that ~~is~~ (1) is located solely within the ~~combined Duke-Progress transmission system~~ footprint of the DEC ~~and~~or ~~(2)~~DEP Transmission Systems, (2) is not selected in the regional transmission plan for purposes of regional cost allocation~~.~~; (3) is either an expansion or enhancement to the DEC or DEP Transmission System; (4) is estimated to cost greater than $5 million; and (5) is not a project to maintain, repair, or replace existing transmission facilities in order to maintain a safe, reliable, and compliant grid, even if such project results in an incidental increase in transmission capacity that is not reasonably severable from work to maintain, repair, or replace the existing transmission facility.

~~In order to ensure comparability, customers taking Network Transmission Service are expected to accurately reflect their demand response resources appropriately in their annual load forecast projections. Customers taking Point-to-Point Transmission Service are expected to accurately reflect their demand response resources in submitting their requests for Transmission Service and in submitting information about potential needs for Point-to-Point Transmission Service.~~

~~Eligible Customers providing information about potential needs for Point-to-Point Transmission Service are expected to accurately reflect their demand response resources in submitting information. To the extent a TAG participant has a demand response resource or a generation resource that the TAG participant desires the NCTPC to specifically consider as an alternative to transmission expansion, or otherwise in conjunction with the NCTPC Process, such TAG participant sponsoring such demand response resource or generation resource shall provide the necessary information (cost, performance, lead time to install, etc.) in order for the NCTPC to consider such demand response resource or generation resource alternatives comparably with other alternatives.~~

4.1 Overview of Local Planning Process

~~The~~As described in Sections 4.2 through 4.5, the Local Planning Process ~~addresses transmission upgrades needed~~performs studies to ~~maintain~~identify:

(i) Local Projects that are necessary to preserve reliability and ~~to~~comply with applicable reliability standards (“Local Reliability Projects”);

(ii) Local Projects that will increase transmission access to potential supply resources inside and outside the Control Areas of the Companies based on Participant or TAG participant requested economic studies (“Local Economic Projects”);

(iii) Local Projects to satisfy Public Policy Requirements (“Public Policy Projects”); and/or

~~(i)~~(iv) Local Projects that will integrate new generation resources and/or loads~~. The Local Planning Process includes~~ and provide other benefits in a ~~base reliability study (base case) that evaluates each~~least-cost manner (“Multi-Value Strategic Transmission ~~System's ability to meet projected load with a defined set of resources as well as the~~Projects”).

~~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 Local 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. Throughout the Local Planning Process, TAG participants (including TAG participants representing transmission solutions, generation solutions, and solutions utilizing demand resources) may participate.~~

The following are the general steps in the Local Planning Process~~es~~

4.1.1 Each year, the OSC will initiate the process to develop the annual Local Transmission Plan through the study processes defined herein.

4.1.2 The OSC will provide notice of the commencement of the process to develop the annual Local Transmission Plan via e-mail to the TAG and posts a notice on the ~~NCTPC Website~~CTPC website.

~~4.1.1~~4.1.3 The process will allow for flexibility to make modifications to the ~~development of the~~ Local Transmission Plan throughout the year as needs change, new needs arise, or new solutions to problems are identified.

~~4.1.2~~4.1.4 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 for each type of Local Project is an iterative one. A list of relevant dates established for the planning cycle will be posted on the ~~N~~CTPC website.

4.1.5 At the approximate mid-point of the annual Local Transmission Planning process, but no later than August 15 of each year, the Companies will provide a written report on the status of the Local Projects presented in the previous Local Transmission Plan (the "Mid-Year Update Report"). The Mid-Year Update Report will be posted on the CTPC website and will include the following information: the name of the project, the detailed issue it resolves, the name of the relevant Company(s), the original planned in-service date and the current expected in-service date, an explanation of the reasons for any change, the scope of the project, and updated cost estimates for the Local Projects. Prior to OSC approval, the Mid-Year Update Report will be reviewed at a TAG meeting scheduled at the approximate mid-point of the annual planning process. The Mid-Year Update Report may include new Local Projects added since the previous annual Local Transmission Plan to address an emergent need, as long as the emergent need has been presented to TAG participants for review and comment prior to the OSC's approval of the Mid-Year Update Report.

4.2 Overview of Study Process for Local Reliability Projects

4.2.1 The Local Planning Process starts with a base reliability study (Base Case) that evaluates each Transmission System's ability to meet projected load with a defined set of resources for network transmission customers as well as the needs of firm point-to-point customers, whose needs are reflected in their transmission contracts and reservations.

4.2.2 In order to ensure comparability and consistency with the Data Collection requirements in Section 5:

4.2.2.1 Customers taking Network Transmission Service are expected to accurately reflect in their annual load forecast projections: (i) demand response resources, including but not limited, to any activities by load-serving entities to reduce, interrupt, or otherwise manage end-use customer load through the use of centralized control and/or by supplying load signal information, real-time pricing signals, or specific instruction; (ii) energy efficiency; and (iii) distributed energy resources, which is a kW/MW resource that nets with customer demand if behind the meter and must be specified separately.

4.2.2.2 Eligible Customers and Transmission Customers (a) providing information about current and potential needs for Point-to-Point Transmission Service and (b) when submitting their request for Point-to-Point Transmission Service are expected to accurately reflect: (i) demand response resources, including but not limited, to any activities by load-serving entities to reduce, interrupt, or otherwise manage end-use customer load through the use of centralized control and/or by supplying load signal information, real-time pricing signals, or specific instruction; (ii) energy efficiency; and (iii) distributed energy resources, which is a kW/MW resource that nets with customer demand if behind the meter and must be specified separately.

4.2.2.3 To the extent a TAG participant has a demand response resource, a generation resource, and/or any other reasonable combination of alternative resources and/or technology solutions ("Alternate Proposal") that the TAG participant desires the CTPC to specifically consider as an alternative to transmission expansion, or otherwise in conjunction with the CTPC Process, such TAG participant sponsoring such Alternate Proposal shall provide within 14 calendar days of the Needs Meeting the necessary information (cost, performance, lead time to install, etc.) in order for the CTPC to consider such Alternate Proposal comparably with other alternatives.

~~4.2~~4.3 Overview of Study Process for Local Economic ~~Study Process~~Projects

~~4.2.1~~4.3.1 The Local Economic Study Process is the process that allows the TAG participants to propose economic upgrades to be studied as part of the Local Planning Process. The Local Economic Study Process evaluates the means to increase transmission access to potential supply resources inside and outside the Control Areas of the Companies. This economic analysis provides the opportunity to study what transmission upgrades would be required to reliably integrate new resources.

4.3.2 The Local Economic Study Process begins with the TAG participants proposing scenarios and interfaces to be studied~~.~~ at least 30 calendar days prior to the Assumptions Meeting described in Section 5.1.3. 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 ~~N~~CTPC 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 a ~~R~~regional nature. The OSC will direct the TAG participants to submit ~~the Regional~~any regional study requests to the SERTP. Throughout the Local Economic Study Process, TAG participants (including TAG participants representing transmission solutions, generation solutions, and solutions utilizing demand resources) may participate.

~~4.2.2~~

~~4.2.2.1~~4.3.2.1 The OSC will review the PWG analysis, approve the compiled study list, and provide the study list, including study criteria, assumptions, and methodology to the TAG~~.~~ in accordance with the procedures set forth in Section 5.1.3 for the Assumptions Meeting(s) applicable to the Local Economic Project Study Process. For the study scenarios that impact the ~~N~~CTPC footprint, but are not ~~r~~Regional in nature, the TAG participants will select within 14 calendar days of the Assumptions Meeting a maximum of three scenarios that will be studied within ~~the current NCTPC~~a single CTPC planning cycle. If consensus cannot be reached as to which scenarios to study within 14 calendar days of the Assumptions Meeting, the choice will be resolved through the TAG Sector Voting Process. The TAG participants may request that the maximum of the three scenarios be combined or clustered.

~~4.2.2.2~~4.3.2.2 There will be no charge to the TAG participants for the three studies selected by the TAG participants. However, if a particular TAG participant wants the ~~N~~CTPC to evaluate a scenario that was not chosen by the TAG participants, then the TAG participant can request to have the ~~N~~CTPC conduct the study. The ~~NCTPC~~CTPC Participants 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.

~~4.2.2.3~~4.3.2.3 The final results of the Local Economic Study Process include the estimated costs and schedules to provide the increased transmission capabilities. The Local Economic Study Process results are reviewed and discussed with the TAG participants~~.~~ in accordance with the procedures set forth in Section 5.4.2 for the Solutions Meeting(s) applicable to the Local Economic Project Study Process.

4.3.2.4 Only Local Economic Projects approved pursuant to Section 5.6 are included in the Local Transmission Plan.

~~4.3~~4.4 Overview of Study Process ~~to Identify If Any~~for Public ~~Policies Exist that Drive Local Transmission Needs~~Policy Projects.

~~4.3.1~~4.4.1 Each year, the OSC will determine if there are any public policies driving the need for local transmission.

~~*4.3.1.1* The OSC will seek input (e.g. written comments) prior to the first TAG meeting of the Local Planning Process cycle (TAG Meeting 1) from TAG participants, asking that they identify any public policies that are driving the need for local transmission, pursuant to the criteria below.~~

~~The OSC may itself identify public policies that are driving the need for Local Projects.~~
~~*4.3.1.2* There will be a discussion at the TAG Meeting 1 as to whether there are public policies that are driving the need for Local Projects.~~

4.4.2 Criteria for determining if public policy drives local transmission need.

~~4.3.2~~

4.4.2.1 Public policy must be reflected in state, federal, or local law or regulation (including order of a state, federal, or local agency).

4.4.2.2 At least 30 calendar days prior to the Assumptions Meeting described in Section 5.1.3 the OSC will seek input (e.g. written comments) from TAG participants, asking that they (i) identify any public policies that are driving the need for local transmission, pursuant to the criteria below, and (ii) propose study criteria, assumptions, and methodology to evaluate the need for local transmission driven by the identified public policy ("Public Policy Study Proposal").

~~4.3.3~~

~~At least 30 calendar days prior to the Assumptions Meeting described in Section 5.1.3 the OSC will seek input (e.g. written comments) from TAG participants, asking that they (i) identify any public policies that are driving the need for local transmission, pursuant to the criteria below, and (ii) propose study criteria, assumptions, and methodology to evaluate the need for local transmission driven by the identified public policy ("Public Policy Study Proposal").~~

4.4.2.3 The OSC may itself identify a Public Policy Study Proposal.

4.4.2.4 Public Policy Study Proposals will be reviewed in accordance with Section 5.1.

~~4.3.4~~4.4.3 Within two weeks ~~of TAG~~following the Assumptions Meeting ~~1~~, the OSC will post on the ~~N~~CTPC website an explanation of (1) those local transmission needs driven by Public Policy Requirements that have been identified for evaluation for potential transmission projects in the then-current planning cycle; and (2) the reason(s) why other suggested, possible transmission needs driven by Public Policy

Requirements proposed by the TAG participants or the OSC were not selected for further evaluation. If one or more public policies are identified as driving local transmission needs, the ~~NCTPC will consider solutions to those needs~~Companies shall follow the procedures set forth in Section 5.3, and TAG participants may suggest projects to meet those needs in accordance with ~~the planning process.~~procedures set forth in Section 5.4. If no public policies are identified for the planning year, ~~public policy projects cannot~~ TAG participants will be ~~proposed as~~unable to propose Public Policy Project solutions.

4.4.4 Only Public Policy Projects approved pursuant to Section 5.6 are included in the Local Transmission Plan.

4.5 Overview of Study Process for Multi-Value Strategic Transmission Projects

4.5.1 On at least a triennial basis, the study process for Multi-Value Strategic Transmission Projects allows the OSC and TAG participants to propose different scenarios for evaluation of new resource supply options, changing load dynamics, transmission solutions requiring longer lead times, generator retirements, and/or economic development opportunities ("Strategic Planning Scenarios"). Strategic Planning Scenarios may consider, but are not limited to considering, (1) federal and state laws and regulations that affect the future resource mix and demand; (2) federal and state laws and regulations that affect decarbonization and electrification; (3) utility integrated resource plans approved pursuant to either N.C. G.S. § 62-110.1 or S.C. Code Ann. § 58-37-40 and long-term expected supply obligations for load serving entities; (4) trends in technology and fuel costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation; (5) resource retirements and replacements or expiration of power purchase agreements; (6) generator interconnection requests and withdrawals, and/or (7) the need for transmission during high-impact, low frequency events. At the beginning of each annual planning cycle, the PWG will recommend to the OSC and the OSC will decide whether or not to initiate a Multi-Value Strategic Transmission Project Study process more frequently than according to the minimum triennial basis.

4.5.2 At least 30 calendar days prior to the Assumptions Meeting described in Section 5.1.3, the OSC will seek input from TAG participants on Strategic Planning Scenarios to evaluate. The form to propose a Strategic Planning Scenario is posted on the CTPC Website. Proposed Strategic Planning Scenarios must specifically identify models, assumptions, and data proposed to be used in the study process. Proposed Strategic Planning Scenarios must also identify an appropriate planning horizon for the proposed scenario(s) to be studied.

4.5.3 The OSC may itself also identify Strategic Planning Scenarios to be presented at an Assumptions Meeting described in Section 5.1.3.

4.5.4 The PWG will determine if it would be efficient to combine and/or cluster any of the proposed Strategic Planning Scenarios and will also determine if any of the proposed Strategic Planning Scenarios are of a Regional nature. If the proposed Strategic Planning Scenario is regional in nature, the OSC will direct the TAG participants to submit the regional study requests to the SERTP.

4.5.5 The OSC will review the PWG analysis of the proposed Strategic Planning Scenarios to be studied, approve the compiled study list, and provide the study list, including study criteria, assumptions, and methodology to the TAG in accordance with the procedures set forth in Section 5.1.3 for the Assumptions Meeting(s) applicable to the Multi-Value Strategic Transmission Project Study Process. If there are more than three proposed Strategic Planning Scenarios proposed by TAG participants pursuant to Section 4.5.2 that impact the CTPC footprint, but are not Regional in nature presented at the Assumptions Meeting, the TAG participants will select within 14 calendar days of the Assumptions Meeting a maximum of three proposed Strategic Planning Scenarios that will be studied within a single CTPC planning cycle. If consensus cannot be reached as to which scenarios to study within 14 calendar days of the Assumptions Meeting, the choice will be resolved through the TAG Sector Voting Process. The TAG participants may request that the three scenarios be combined or clustered. A minimum of three Strategic Planning Scenarios will be evaluated for each Multi-Value Strategic Transmission Project study process.

4.5.5.1 There will be no charge to the TAG participants for the three proposed Strategic Planning Scenarios studies selected by the TAG participants. However, if a particular TAG participant wants the CTPC to evaluate a scenario that was not chosen by the TAG participants, then the TAG participant can request to have the CTPC conduct the study. The CTPC Participants 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.

4.5.6 The final results of the Multi-Value Strategic Transmission Project Study Process will include the estimated costs and schedules to provide the increased transmission capabilities. The Multi-Value Strategic Transmission Project Study results are reviewed and discussed with the TAG participants in accordance with the procedures set forth in Section 5.4 for the Solutions Meeting(s) applicable to the Local Economic Project Study Process.

4.5.7 Only Multi-Value Strategic Transmission Projects approved pursuant to Section 5.6 are included in the Local Transmission Plan.

5. CRITERIA, ASSUMPTIONS, AND DATA UNDERLYING THE LOCAL

TRANSMISSION PLAN AND METHOD OF DISCLOSURE OF LOCAL TRANSMISSION PLANS AND STUDIES

~~5.1 Study Assumptions~~

5.1 Identification of Study Criteria, Assumptions, and Methodology

~~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 Companies 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. TAG participants also may, upon request, review the base case models and provide input to the PWG with regard to whether the models represent the study assumptions approved by the OSC.~~

~~5.1.5 The Companies will also develop the necessary change case models as required to evaluate different resource supply scenarios and local economic project 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. TAG participants also may request to review the change case models and provide input to the PWG with regard to whether the models represent the study assumptions approved by the OSC.~~

~~5.2 Study Criteria~~

~~5.2.1~~5.1.1 The PWG establishes the reliability planning criteria by which the study results will be measured to identify Local Reliability Projects for inclusion in the Local Transmission Plan, in accordance with North American Electric Reliability Corporation (NERC) and SERC Reliability Standards and individual Company criteria. ~~TAG participants may review and comment on the planning criteria.~~

5.1.2 Study criteria, assumptions, and methodology for Local Economic Projects, Public Policy Projects, and Multi-Value Strategic Transmission Projects will be identified in accordance with the Sections 4.3, 4.4, and 4.5, respectively. -Inclusion of Local Economic Projects, Public Policy Projects, and Multi-Value Strategic Transmission Projects in the Local Transmission Plan is subject to the procedures and OSC approval required by Section 5.6.

5.1.3 The Companies shall schedule and facilitate a minimum of one TAG meeting to review the criteria, assumptions, and methodology the PWG plans to use to identify needs and transmission solutions to include in the Local Transmission Plan ("Assumptions Meeting"). The Assumptions Meeting shall take place prior to the OSC's approval of the final set of study assumptions. The Companies shall provide the criteria, assumptions, and methodology to the Administrator for posting on the CTPC website at least 20 calendar days in advance of the Assumptions Meeting to provide TAG participants sufficient time to review this information. TAG participants may provide comments on the criteria, assumptions, and methodology to the PWG for consideration either prior to or following the Assumptions Meeting. The Companies shall review and consider comments that are received within 14 calendar days of the Assumptions Meeting and may respond or provide feedback as appropriate.

5.1.4 The final criteria, assumptions, and methodology, including but not limited to the applicable planning horizon, for studying Local Economic Projects, Public Policy Projects, and Multi-Value Strategic Transmission Projects shall be set forth in a *Study Scope Document* to be reviewed by the TAG and approved by the OSC and posted to the CTPC website.

~~5.2.2~~5.1.5 Transmission System planning documents of ~~Duke~~DEC and ~~Progress~~DEP 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~~5.2 Data Collection and Case Development

~~5.3.1~~5.2.1 The Companies will prepare the Base Case models. 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~~DEC and ~~Progress~~DEP as a starting point for the ~~base case~~Base Case to be used by both ~~Progress~~DEP and ~~Duke~~DEC. The ~~base case~~Base Case will include the detailed internal models for ~~Progress~~DEP and ~~Duke~~DEC and will include current transmission additions planned to be in-service for given years.

5.2.2 The Companies will also develop the necessary Change Case models as required to evaluate scenarios directed by the *Study Scope Document* for Local Reliability Projects, Local Economic Projects, Public Policy Projects, and Multi-Value Strategic Transmission Projects. Such Change Case models will also be reviewed with the PWG to ensure that they represent the study criteria, assumptions, and methodology approved by the OSC in the *Study Scope Document*. Upon request, TAG participants will be provided the Change Case models, subject to CEII and confidentiality requirements. For Local Economic Projects, Public Policy Projects, and Multi-Value Strategic Transmission Projects, TAG participants may provide input to the PWG with regard to whether the models accurately represent the *Study Scope Document* approved by the OSC in accordance with the procedures set forth in Section 5.3.3 and during the Needs Meeting defined therein.

~~5.3.2~~5.2.3 The following data are relevant to the development of internal models for ~~Progress and Duke~~the Companies:

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

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

Generation real and reactive capacity data;

Generation dispatch priority data;

Dispatch assumptions for variable energy resources and energy storage;

Transmission facility impedance and rating data; ~~and~~

Interchange data adjusted to correctly model transfers associated with designated network resources from outside the Companies' Control Areas~~.~~;

Generation retirement;

Resource supply additions with locational information;

Import and export assumptions; ~~and~~

TRM and CRSG requirements; and

DER Aggregation modeling assumptions.

~~5.3.3~~5.2.4 The Companies 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, Eligible Customers, and Transmission 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~~ at the Assumptions Meeting, approved by the OSC, and documented in the *Study Scope Document*. To the extent data is required from TAG participants to conduct the study processes for Local Economic Projects, Public Policy Projects, and/or Multi-Value Strategic Transmission Projects, TAG participants are obligated to provide such data to the Companies in accordance with the timelines documented in the *Study Scope*

Document. Timelines for submission of data by TAG participants in the *Study Scope Document* set by the PWG shall be reasonable and may be amended if approved by the OSC. OSC approval of requests to extend timelines for submission of data shall not be unreasonably withheld. If required data is not provided in accordance with the timelines approved in the *Study Scope Document* or as amended by approval of the PWG, and the failure to provide the data is not cured within 30 days of the due date, the CTPC Participants shall have no obligation to continue with the study during the current planning cycle.

~~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~~5.2.5 Transmission Customers should provide the Companies with timely written notice of material changes in any information previously provided relating to load, resources, or other aspects of their facilities or operations affecting the Company's ability to provide service~~.~~ that affect the Base Case models. Network customers may provide revised versions of previously submitted annual data reporting forms.

~~*5.3.5.1* 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 local economic projects, such as predicted future point-to-point transmission uses, as submitted by the TAG participants.~~

~~5.3.6 The Case Development details will be identified in the annual *Study Scope Document*.~~

~~5.3.7 Sufficient information will be made available, subject to CEII and confidentiality restrictions, to enable TAG participants to replicate the results of planning studies. A TAG participant seeking data and information that would allow it to replicate the NCTPC planning studies should provide such request to the OSC Vice-Chair, who will verify that confidentiality requirements described in Section 9 have been met before providing such information.~~

~~5.3.8 Status Reports~~

~~The Companies will provide a written report on the status of the Local Projects presented in the previous Local Transmission Plans. A composite update will be posted on the NCTPC Website and will include the following information: the name of the project, the issue it resolves, the name of the relevant Company(s), the original planned in-service date and the current expected in-service date and an explanation of the reasons for any change. This report will be reviewed at the second TAG meeting of the planning cycle (TAG Meeting 2). Cost estimates for~~

~~Local Projects will also be updated at this time.~~

~~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~~5.3 Technical Analysis and ~~Study Results~~Identification of Transmission Needs

~~5.5.1~~5.3.1 The PWG performs the technical analysis in accordance with the OSC approved study criteria, assumptions, and methodology in the *Study Scope Document* and produces the study results.

~~5.5.2~~5.3.2 Results from the technical analysis are reported to identify transmission elements approaching their limits such that all ~~N~~CTPC 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.

5.3.3 The Companies shall schedule and facilitate a minimum of one TAG meeting per planning cycle to review the identified criteria violations, transmission elements approaching their limits, and resulting system needs, if any, that may drive the need for a Local Project (Needs Meeting). The Needs Meeting may be scheduled no fewer than 25 calendar days after the Assumptions Meeting. At the Needs Meeting, the Companies will review the identified system needs and the drivers of those needs, based on the application of its criteria, assumptions, and methodology in the *Study Scope Document*. The Companies shall share with the Administrator for posting to the CTPC website the identified criteria violations and drivers no fewer than 14 calendar days in advance of the Needs Meeting. TAG participants may provide comments on the criteria violations and drivers to the PWG for consideration prior to, at, or following the Needs Meeting. The Companies shall review and consider comments that are received within 14 calendar days of the Needs Meeting and may respond or provide feedback as appropriate.

~~5.5.3~~ Sufficient information will be made available, subject to CEII and confidentiality restrictions, to enable TAG participants to replicate the results of planning studies~~Study results are made available to the TAG participants for review and comment.~~

~~5.6 Assessment and Problem Identification~~

5.3.4 reviewed at the Needs Meeting. A TAG participant seeking data and information that would allow it to replicate the CTPC planning studies should provide such request to the Companies, who will verify that confidentiality requirements described in Section 9 have been met before providing such information.

~~5.6.1 The Companies 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 Companies 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~~5.4 Local Solution Development

~~5.7.1~~5.4.1 The PWG identifies potential solutions to the transmission ~~problems~~needs identified ~~(including public policy transmission needs)~~during the Needs Meeting 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 propose alternative transmission, generation and/or demand response solutions. The alternate transmission solutions may include potential solutions that could address reliability, economic and/or public policy transmission needs. TAG participants shall provide the necessary information (cost, performance, lead time to install, etc.) for proposed generation and/or demand response alternative solutions so that they may be compared with other alternatives.~~

5.4.2 No fewer than 25 calendar days after the Needs Meeting, the Companies shall schedule and facilitate a minimum of one TAG meeting per planning cycle to review potential solutions identified by the PWG pursuant to Section 5.4.1 (“Solutions Meeting”). The Companies shall share with the Administrator and post their potential solutions, as well as any alternatives, including non-wire alternatives, identified by the PWG or TAG participants, no fewer than 14 calendar days in advance of the Solutions Meeting. TAG participants may provide comments on the potential solutions to the PWG for consideration either prior to or following the Solutions Meeting, including but not limited to proposals for alternative transmission or non-wire alternative solutions to address the identified need, as well as other reliability, economic and/or public policy transmission needs. To the extent TAG participants propose alternative solutions, they shall provide to the PWG the necessary information (cost, performance, lead time to install, etc.) for the alternative solutions to be compared with other alternatives. The PWG shall review and consider comments and alternative solutions that are received within 14 calendar days of the Solutions Meeting and may respond or provide feedback as appropriate. To the extent a TAG participant proposes an alternative solution that is not selected by the PWG for the preferred Local Transmission Plan pursuant to Section 5.5, the draft "Local Transmission Plan Report" required by Section 5.6 will explain why the alternative was not selected.

~~5.7.3~~5.4.3 All solution options that satisfactorily resolve an identified transmission ~~problem~~need shall ~~would~~ be given consideration on a comparable basis.

~~5.7.4~~5.4.4 A solution that is seeking regional cost allocation must be submitted in accordance with the procedures set forth in Part II and will be evaluated through the SERTP Process.

~~5.7.5~~5.4.5 The Companies will estimate the costs for each of the proposed ~~local solutions~~Local Project (e.g., cost, cash flow, present value) and develop a rough schedule estimate to implement the solution. This information is reviewed and discussed by the PWG and during a Solutions Meeting.

~~5.8~~5.5 Selection of Preferred Local Transmission Plan

~~5.8.1~~5.5.1 The PWG compares all of the alternatives and selects the preferred solution by balancing the solutions' costs, benefits, and associated risks. Competing solutions will be evaluated against each other based on a comparison of their relative economics, timing, feasibility, and effectiveness of performance.

~~5.8.2~~5.5.2 The PWG selects a preferred set of solutions that provides the most reliable and cost effective solution while prudently managing the associated risks.

~~5.8.3~~5.5.3 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~~5.6 Local Transmission Plan Report

~~5.9.1~~5.6.1 ~~The~~After the Solutions Meeting, the PWG prepares a draft "Local Transmission Plan Report" based on the study results and the recommended solutions and provides the draft 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 solutions including estimates of costs and construction schedules and a summary of the PWG's selection evaluation required by Section 5.5.

~~5.9.2~~5.6.2 After review and approval by the OSC, ~~T~~the Administrator~~OSC~~ forwards the draft Local Transmission Plan Report to the TAG participants and posts the draft Local Transmission Plan Report on the CTPC website for their review~~ and discussion~~. The Companies shall schedule and facilitate a meeting to review the draft Local Transmission Plan Report. TAG participants may provide comments to the PWG on the draft Local Transmission Plan Report. TAG participants shall have at least 14 calendar days after it is posted on the CTPC website to comment on the draft Local Transmission Plan Report. 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~~ The PWG shall review and consider comments that are received on or before the 14th calendar day after the draft Local Transmission Plan Report is posted on the CTPC website.

~~5.9.3~~5.6.3 The OSC evaluates the ~~results and~~draft Local Transmission Plan Report, the PWG recommendations, and the TAG participants' input. ~~The~~ No fewer than 14 calendar days after the draft Local Transmission Plan Report is posted on the CTPC website, the OSC approves the final Local Transmission Plan for posting on the ~~N~~CTPC Website. The Plan also is posted on the Companies' OASIS and distributed to the TAG participants.

~~5.9.4~~5.6.4 The Local Transmission Plan allows the ~~N~~CTPC 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.

~~5.9.5~~5.6.5 The Local Transmission Plan, and the associated models, serve as the basis for the models that the Companies provide as input to the development of the SERC-wide model as described in Section 11.

~~5.9.6~~5.6.6 The Local Transmission Plan, which reflects the coordination described in Section 11, will be an input into the SERTP Process. Local Projects identified in a Local Transmission Plan may later be removed from a Local Transmission Plan due to, for example, the iterative nature of transmission planning in subsequent planning cycles, additional transmission planning coordination provided through the SERTP Process, or if a project seeking regional cost allocation has been selected in the regional transmission expansion plan to replace a Local Project.

5.7 ~~NCTPC~~No Limitation on Additional Meetings and Communications

5.7.1 Nothing in this Attachment N-1 precludes the Companies, the OSC, or the PWG from agreeing with an individual TAG participant or groups of TAG participants to have additional meetings or other communications regarding assumptions, needs, proposed solutions, or Local Projects.

6. CTPC DISPUTE RESOLUTION MECHANISM

6.1 ~~N~~CTPC Process Disputes

6.1.1 A Company has the right to reject an OSC decision if it believes that it would harm reliability. The Company rejecting the OSC decision on reliability grounds must provide data, studies, or other evidence to the OSC to support its rejection.

~~6.1.2 Any NCTPC Participant or TAG participant has the right to seek assistance from the North Carolina Utilities Commission (NCUC) Public Staff to mediate an issue and render a non-binding opinion on any disputed decision.~~

~~6.1.3 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 South Carolina Public Service Commission allows public participation in and may hold hearings regarding matters related to integrated resource planning.~~

~~6.4 Other Local Planning Process Disputes~~

~~6.4.1~~6.1.2 The dispute resolution process provisions included in this Tariff apply to disputes involving compliance with the Commission~~'~~'s local transmission planning obligations set forth in Order No. 890. Any TAG participant, not just a TAG participant that is a Transmission Customer, may avail itself of the dispute resolution provision of the Tariff, as that process is modified below.

~~6.4.2~~6.1.3 If a TAG participant has completed the negotiation step set forth in Section 12.1 of this Tariff, a TAG participant may ask to have the issue mediated on a non-binding basis before the next step (i.e., arbitration) commences. A request for mediation must be made within ~~thirty~~30 calendar days of the agreed-upon conclusion of the negotiation step. If the mediation step is concluded without resolution, the disputing party has ~~thirty~~30 calendar days to inform the Company(ies) that it seeks to commence the arbitration step set forth in Tariff Section 12.2. If this mediation option is selected, the parties to the dispute will use the Commission's Dispute Resolution Service as the forum for mediation.

~~6.4.3~~6.1.4 Matters over which the Commission does not have jurisdiction, including planning to meet retail native load of the Companies, shall not be within the scope of the dispute resolution process of this Tariff.

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 Public Service Commission authorization through the certificates of public convenience and necessity process.

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7. TRANSMISSION COST ALLOCATION FOR JOINT LOCAL PROJECTS

7.1 OATT Cost Allocation

With the exception of "Joint Local Reliability Projects" and "Joint Local Economic Projects" nothing in this Attachment is intended to alter the cost allocation policies of the Tariff.

7.2 Joint Local Reliability Project Cost Allocation

7.2.1 A Joint Local Reliability Project is defined as any reliability project that requires an upgrade to a Company's system that would not have otherwise been made based upon the reliability needs of the Company.

7.2.2 An "avoided cost" cost allocation methodology will apply to reliability projects where there is a demonstration that a Local Project meets the criteria for a Joint Local Reliability Project.

7.2.3 The ~~NCTPC Planning~~CTPC Process results in a set of projects that satisfy the reliability criteria of the Companies who are parties to the Participation Agreement (i.e., Local Reliability Projects). Through this process, a project may be identified that meets a reliability need in a more cost-effective manner than if each Company were only considering projects on its system to meet its reliability criteria. A Joint Local 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 Joint Local Reliability Project with a cost of less than $1 million would be borne by each Company based on the costs incurred on its system.

7.2.4 Unless a Joint Local Reliability Project is determined by the ~~NCTPC~~CTPC Participants to be the most cost-effective solution to a reliability need, it will not be selected to be included in the Local Transmission Plan. But, if a Joint Local Reliability Project is determined by the ~~NCTPC~~CTPC Participants to be the most cost effective solution, it will have its costs allocated based on an avoided cost approach, whereby each Company 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:

(Company ~~x~~X's Avoided Cost/Total Avoided Cost) * cost of Joint Local Reliability Project = Company ~~x~~X's Cost Allocation

(Company ~~y~~Y's Avoided Cost/Total Avoided Cost) * cost of Joint Local Reliability Project = Company ~~y~~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 Joint Local Reliability Projects. Examples of the application of the avoided-cost approach may be found in *~~N~~CTPC Transmission Cost Allocation*.

7.3 Joint Local Economic Project Cost Allocation

7.3.1 A Joint Local Economic Project is a project that permits energy to be transferred on a Point-to Point basis from an interface or a Point of Receipt on a Company's system to an interface or a Point of Delivery on another Company's system for a specified time period.

7.3.2 The costs of Joint Local Economic Projects are allocated on a "requestor pays" basis.

7.3.3 Transmission Customer(s) that are requesting a Joint Local Economic Project would provide the up-front funding of any transmission construction that was required to ensure that the transmission path capability that was created by the Joint Local Economic Project was available for the relevant time period. On the ~~Duke~~DEC and/or ~~Progress~~DEP systems, the Transmission Customer would receive a levelized repayment of this initial funding amount from ~~Duke~~DEC and/or ~~Progress~~DEP in the form of monthly transmission credits over a maximum 20-year period. The Companies will be permitted to work with the Transmission Customers to provide shorter or different crediting. As credits are paid, ~~Duke~~DEC and ~~Progress~~DEP would have the opportunity to include the costs of upgrades that were needed for the Joint Local Economic Project(s) in transmission rates, similar to the Generator Interconnection pricing/rate approach.

7.3.4 As part of the Joint Local Economic Project process, a network customer may ensure that power can be delivered from an interface on, or utilizing transmission capability created by, a Joint Local Economic Project 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.

7.3.5 No additional compensation is provided to the "requestors" of the Joint Local Economic Project for any "head-room" or excess transmission capability that would be created on the Transmission Systems. The total project cost for the transmission expansion required due to a Joint Local Economic Project will be reduced to provide compensation for the

7.3.6 positive transmission impacts that the Joint Local Economic Project would provide, compared to the existing Local Transmission Plan.

7.3.7 This Joint Local Economic Project concept and cost allocation methodology applies to the ~~N~~CTPC footprint, which consists of the ~~Duke~~DEC and ~~Progress~~DEP Control Areas.

8. COST ALLOCATION FOR PLANNING COSTS

8.1 ~~N~~CTPC-Related Planning Process Costs

8.1.1 Each ~~N~~CTPC Participant bears its own expenses.

8.1.2 TAG participants bear their own expenses.

8.1.3 The costs of the ~~N~~CTPC base reliability studies are borne by ~~Duke~~DEC and ~~Progress~~DEP.

8.1.4 Costs associated with ~~incremental reliability studies~~ the study process for Local Economic Projects, Public Policy Projects, and ~~local economic studies~~Multi-Value Strategic Transmission Projects are all allocated to ~~N~~CTPC Participants in the manner set forth in the *Participation Agreement*.

8.1.5 Pursuant to Section 4, costs associated with ~~local economic studies~~the Local Economic Project Study Process and Multi-Value Strategic Transmission Project Study Process that are outside the scope of Section 4, will be borne by the study requestor.

8.1.6 ~~N~~CTPC Participants may challenge the correctness of ~~NCTPC~~CTPC Process cost allocations.

8.1.7 For the Companies, 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-~~N~~CTPC-Related Planning Costs

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

9. CONFIDENTIALITY

9.1 The Companies 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 ~~N~~CTPC Participant 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 ~~N~~CTPC Participant or TAG participant providing Confidential Information acknowledges that such Confidential Information may be released to the representatives of TAG participants that have abided by the procedures in Section 9.4.3. If the information is Confidential Information only because it is CEII, the ~~N~~CTPC Participant or TAG participant should indicate that such information may be released to TAG participants eligible to receive CEII.

9.3 Availability of Confidential Information

9.3.1 The ~~N~~CTPC 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 ~~N~~CTPC Participants, as limited by the *Participation Agreement*. Each ~~N~~CTPC 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 market such that they do not receive preferential treatment or a competitive advantage.

9.3.3 TAG participants may be provided Confidential Information, in accordance with Section 9.4.3/9.4.4. In cases where the information is Confidential Information only because it is CEII, the TAG participants may be provided such information in accordance with Section 9.4.4.

9.4 Obtaining Confidential Information

9.4.1 ~~The OSC Vice-Chair~~Each Company 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.

9.4.2 ~~The OSC Vice-Chair~~Each Company ensures that the confidentiality of information principles reflected in Order No. 890 as well as any Standards of Conduct or Code of Conduct requirements are being adhered to within the TAG process, to the extent applicable and/or necessary.

9.4.3 If a TAG participant seeks non-CEII Confidential Information, s/he must formally request the data from the Company OSC representatives representing the non-CEII Confidential Information and the CTPC Administrator ~~OSC Vice-Chair~~ and demonstrate that s/he:

9.4.3.1 Is a representative of a TAG Sector Entity that has signed the ~~SERC~~CTPC Process Confidentiality Agreement or is an Individual that has signed the ~~SERC~~CTPC Process Confidentiality Agreement.

9.4.3.2 Is listed on Attachment A to a TAG Sector Entity's TAG Confidentiality Agreement as a representative of a TAG Sector Entity or is an Individual that has signed the ~~TAG~~CTPC Process Confidentiality Agreement.

9.4.4 If a TAG participant seeks CEII, s/he must formally request the data from the Company OSC representatives representing the CEII and the CTPC Administrator ~~OSC Vice-Chair~~ and demonstrate that s/he:

9.4.4.1 Is a representative of a TAG Sector Entity that has signed the ~~SERC~~CTPC Process Confidentiality Agreement or is an Individual that has signed the ~~SERC~~CTPC Process Confidentiality Agreement.

9.4.4.2 Is listed on Attachment A of a TAG Sector Entity's ~~TAG~~CTPC Process Confidentiality Agreement as a representative of a TAG Sector Entity or is an Individual that has signed the ~~TAG~~CTPC Process Confidentiality Agreement.

9.4.4.3 ~~The OSC Vice-Chair~~ Each Company will process the above requests, approve/deny the request, and if approved, provide the data to a TAG participant.

10. INTEGRATED RESOURCE AND SUB-LOCAL PLANNING

10.1 Integrated Resource Planning

In addition to the ~~N~~CTPC Process, the Companies must abide by state laws and regulations regarding Integrated Resource Planning (IRP~~). The information provided below is intended~~) pursuant to ~~assist persons who may want to participate in state IRP and siting proceedings.~~

~~10.1.1 North Carolina~~

~~The NCUC analyzes the probable growth in the use of electricity~~N.C. G.S. § 62-110.1 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 15-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 15-year forecast period. Such filings must include a section containing a comprehensive analysis of their Demand-Side Management (DSM) plans and activities.~~

~~10.1.2 South Carolina~~

~~Section~~S.C. Code Ann. § 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~~.

10.2 Sub-Local Planning

The Companies 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~~CTPC Process is planning higher-voltage facilities and transfers of bulk power and thus "sub-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 sub-local area plans developed by a Company are rolled into ~~NCTPC~~the CTPC transmission Base Case models. The same data and assumptions would be used in sub-local planning as are used in the ~~N~~CTPC Process.

11. ADDITIONAL COORDINATION

11.1 Coordination Activities Within SERC

~~Duke~~DEC and ~~Progress~~DEP are members of the SERC Reliability Corporation (SERC) and coordinate with other SERC members registered as Transmission Planners. SERC is the entity responsible for promoting and improving the reliability, adequacy, and critical infrastructure of the bulk power supply systems in the area served by its member systems. SERC membership is open to any entity that is a user, owner, or operator of the Bulk-Power System and is subject to the jurisdiction of FERC for the purpose of complying with Reliability Standards. SERC membership is comprised of investor-owned, municipal, cooperative, state and federal systems, RTOs/ISOs, merchant electricity generators, and power marketers. SERC has in place various committees and subcommittees that perform the identified SERC functions, including the promotion of the reliability and adequacy of the bulk power system as related to the planning and engineering of the electric systems. The SERC committees are identified on SERC's website. The particular activities that are coordinated among the Transmission Planners include the creation of a SERC-wide model and the preparation of a simultaneous feasibility assessment, which are discussed in further detail below.

11.1.1 Reliability Planning by Transmission Planners Located in SERC: A Transmission Planner's 10-year transmission expansion plan is the basis for models used for its own reliability planning process(es), such as the ~~NCTPC~~CTPC Process, as well as serving as a Transmission Planner's input into the development of the SERC-wide model.

Substantive transmission planning occurs as Transmission Planners develop reliability transmission expansions plans through their planning process(es), such as the ~~NCTPC~~CTPC Process. In this regard, the reliability plan for each planning process is generally 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 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. The transmission models also incorporate external models (at a minimum the current SERC models) that are developed using similar assumptions.

The transmission models created for use in developing the reliability 10-year transmission expansion plan are analyzed to determine if any planning criteria concerns are projected. In the event one or more planning criteria concerns are identified, the relevant Transmission Planners will develop solutions for these projected limitations in accordance with the planning process to which they belong. As a part of this study process, the Transmission Planners, in accordance with the process to which they belong, will reexamine the current reliability 10-year transmission expansion plan (determined through the previous year's 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 of any of the existing reliability transmission enhancements identified in the previous year's reliability planning process.

11.1.2 Coordination by Transmission Planners with Affected Systems: Once a planning criteria concern is identified and the optimization process identifies the potential solution, the Transmission Planner(s), here ~~Duke~~DEC and ~~Progress~~DEP, determine if any other Transmission Planner is potentially impacted by the projected solution. Potentially impacted Transmission Planners are then contacted to determine if there is a need for an *ad hoc* coordinated study. In the event one or more neighboring Transmission Planners agrees that they would be impacted by the projected limitation or identifies the potential for a superior reliability solution, based on transmission enhancements in their current reliability plan, an *ad hoc* coordinated study is initiated. In the event that no impacts are identified, or if once contacted the potentially impacted Transmission Planner(s) determine that they will not actually be impacted, the initiating Transmission Planner will move forward to conduct a reliability study to determine the solution for the projected planning criteria concern. In either case, once the study has been completed, the identified reliability transmission enhancements will then be incorporated into the 10-year transmission expansion plan as a reliability project.

11.1.3 SERC-Wide Reliability Assessment by Transmission Planners: After the transmission models are developed through the planning processes, the Transmission Planners 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 reliability transmission expansion plans are simultaneously feasible and to otherwise ensure that these processes are using consistent models and data. Additionally, the reliability assessment measures and reports the transfer capabilities within SERC. The SERC-wide assessment serves as a valuable tool for each of the Transmission Planners to reassess the need for additional reliability joint studies.

11.1.4 Other Coordination Activities Within SERC

11.1.4.1 Transmission Model Development: SERC transmission models are developed by the Transmission Planners in SERC through an annual model development process. Each Transmission Planner in SERC, incorporating input from their planning process(es), develops and submits their 10-year transmission models to a model development databank. The databank then joins the models to create SERC-wide models for use in reliability assessment. Additionally, the SERC-wide models are then used in each 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.

11.1.4.2 Additional Reliability Joint Studies: As mentioned above, the SERC-wide reliability assessment serves as a valuable tool for the Transmission Planners, in accordance with their planning process(es), to reassess the need for additional reliability joint studies. If the SERC-wide reliability model projects additional planning criteria concerns that were not identified in the reliability studies, then the impacted Transmission Planners may initiate one or more *ad hoc* coordinated study(ies) (in accordance with existing Reliability Coordination Agreements) to better identify the planning criteria concerns and determine the optimal reliability transmission enhancements to resolve the limitations. Once the study(ies) is completed, required reliability transmission enhancements will be incorporated into the 10-year expansion plan as a reliability project. Accordingly, planning criteria concerns identified at the SERC-wide level are "pushed down" to the Local Planning Process for detailed resolution.

11.1.5 Stakeholder Participation in Planning and Coordination Activities:

Since the bulk of the reliability transmission planning occurs at the local planning level as a "bottom up" process in the development of the various 10-year transmission expansion plans, stakeholders in the ~~N~~CTPC footprint may provide input into the coordination activities by participating in the ~~NCTPC process~~CTPC Process and any other planning processes that they choose to participate in. Specifically, the 10-year Local Transmission Plan developed in the ~~NCTPC process~~CTPC Process described in this Attachment is the basis for ~~Duke's~~DEC's and ~~Progress'~~DEP's input into the SERC model development. As discussed in Sections 4 and 5, the TAG participants are provided a number of opportunities to review and comment on and allowed to propose alternatives concerning the development of this transmission expansion plan. The results of coordination activities will be shared and discussed with TAG participants. ~~If the results of coordination activities are to be shared at a TAG participant meeting, the meeting notice will indicate that such results will be shared and discussed and will either provide the results or indicate how the results can be obtained if the results include Confidential Information.~~

11.2 ERAG & SERC-RFC East Coordination Activities

11.2.1 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 areas served by ERAG members.

11.2.2 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.

11.2.3 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.

~~11.3 VACAR Coordination Activities~~

~~11.3.1 DukeDEC and ProgressDEP both participate with Cube Hydro Carolinas, LLCAlcoa Power Generating, Inc., City of Fayetteville Public Works Commission, Dominion Energy South Carolina Electric & Gas Company, South Carolina Public Service Authority, and Dominion Virginia Power, in the VACAR Planning Task Force.~~

~~11.3.2 A VACAR contract agreement provides for coordination between the various entities within VACAR.~~

~~11.3.3~~

~~11.3.4 DukeDEC and ProgressDEP 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 VACAR, although VACAR coordinates with Southern and TVA under existing agreements.~~

~~11.4~~11.3 Bilateral Coordination Activities

Through bilateral agreements with neighboring transmission systems~~ of, Duke,~~ DEC and ~~Progress~~DEP will perform coordinated studies with such transmission systems on an as-needed basis.

PART II -- REGIONAL TRANSMISSION PLANNING

12. OVERVIEW OF REGIONAL TRANSMISSION PLANNING

Duke and Progress, referred to collectively for the purposes of regional transmission planning as the "Duke Transmission Provider" participate in the SERTP Process described herein and on the Regional Planning Website, a link to which is found on the Duke and Progress OASIS sites. The Duke Transmission Provider and the other transmission owners and transmission providers that participate in this SERTP Process are identified on the Regional Planning Website (Sponsors).[1]

[1] Duke and Progress are each separate "transmission providers" as that term is defined in this Tariff and under the Code of Federal Regulations. They are referred to here as the Duke Transmission Provider only for the purpose of Order No. 1000-mandated regional planning. The Duke Transmission Provider notes that the Duke Transmission Provider's participation in the SERTP is for purposes of regional planning only, since local planning is conducted in accordance with the Local Planning Process as described in Sections 1-11 of this Attachment N-1. While this Attachment N-1 discusses the Duke Transmission Provider largely effectuating the activities of the SERTP Process that are discussed herein, the Duke Transmission Provider expects that the other Sponsors will also sponsor those activities. For example, while this Attachment N-1 discusses the Duke Transmission Provider hosting the Annual Transmission Planning Meetings, the Duke Transmission Provider expects that it will be co-hosting such meetings with the other Sponsors. Accordingly, many of the duties described herein as being performed by the Duke Transmission Provider may be performed in conjunction with one or more other Sponsors or may be performed entirely by, or be applicable only to, one or more other Sponsors. Likewise, while this Attachment N-1 discusses the transmission expansion plan of the Duke Transmission Provider, the Duke Transmission Provider expects that transmission expansion plans of the other Sponsors shall also be discussed, particularly since the transmission expansion plans of the other Sponsors are expected to be included in the regional transmission plan that is to be developed in each planning cycle for purposes of Order No. 1000. To the extent that this Attachment N-1 makes statements that might be construed to imply establishing duties or obligations upon other Sponsors, no such duty or obligation is intended. Rather, such statements are intended to only mean that it is the Duke Transmission Provider's expectation that

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The Duke Transmission Provider participates in the SERTP through which transmission facilities and non-transmission alternatives may be proposed and evaluated. This regional transmission planning process develops a regional transmission plan that identifies the transmission facilities necessary to meet the needs of transmission providers and transmission customers in the transmission planning region for purposes of Order No. 1000. This regional transmission planning process is consistent with the provision of Commission-jurisdictional services at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential, as described in Order No. 1000.

This regional transmission planning process satisfies the following seven principles, as set out and explained in Order No. 1000: coordination, openness, transparency, information exchange, comparability,[2] dispute resolution, and economic planning studies. This transmission planning process includes at Sections 4.3 and 19 the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000. Transmission needs consist of the physical transmission system delivery capacity requirements necessary to reliably and economically satisfy the load projections; resource assumptions, including on-system and off-system supplies for current and future native load and network customer needs; public policy requirements; and transmission service commitments within the region. [3] This transmission planning process provides at Section 8 a mechanism for the recovery and allocation of planning costs consistent with Order Nos. 890 and 1000. This regional transmission planning process includes at Section 22 a clear enrollment process for public and non-public utility transmission providers that make the choice to become part of a transmission planning region for purposes of regional cost allocation. This regional transmission

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other Sponsors will engage in such activities. Accordingly, this Attachment N-1 only establishes the duties and obligations of the Duke Transmission Provider and the means by which Stakeholders may interact with the Duke Transmission Provider with respect to regional planning through the SERTP Process described herein. The term “Stakeholder” as used in this Attachment N-1 means any party interested in the Southeastern Regional Transmission Planning Process, including but not limited to transmission and interconnection customers, generation owners/development companies, developers of alternative resources, or state commissions.

[2] The Duke Transmission Provider is committed to providing comparable and non-discriminatory transmission service. As such, comparability is not separately addressed in a stand-alone Section of this Attachment N-1 but instead permeates the SERTP Process described in this Attachment N-1.

[3] As provided herein, Transmission Customers can provide input regarding updates to these needs assumptions consistent with Data Collection and Case Development provisions of Section 5.3 and the Information Exchange provisions of Section 16. Additionally, Stakeholder input is considered in the determination of transmission needs consistent with the Data Collection and Case Development provisions of Section 5.3 and through input regarding the transmission planning modeling assumptions consistent with the Coordination provisions of Section 13 and specifically related to transmission needs driven by public policy requirements consistent with Sections 4.3 and 19.2. Stakeholders can also provide input on Economic Planning Studies pursuant to Sections 4.2 and 18.

planning process subjects enrollees to cost allocation if they are found to be Beneficiaries of new transmission facilities selected in the regional transmission plan for purposes of cost allocation.[4]

Attachment N-3 contains a list of Enrollees as of the effective date of such tariff record. The relevant cost allocation method or methods that satisfy the six regional cost allocation principles set forth in Order No. 1000 are described in Sections 26-27 of this Attachment N-1. Nothing in this regional transmission planning process includes an unduly discriminatory or preferential process for transmission project submission and selection. As provided below, with respect to regional planning, the SERTP includes sufficient detail to enable Transmission Customers to understand:

12.1 The process for enrollment and terminating enrollment in the SERTP, which is set forth in Section 22 of this Attachment N-1;

12.2 The process for consulting with customers regarding regional transmission planning, which is set forth in Section 13 of this Attachment N-1;

12.3 The notice procedures and anticipated frequency of regional transmission planning meetings, which is set forth in Sections 13 and 14 of this Attachment N-1;

12.4 The Duke Transmission Provider's regional transmission planning methodology, criteria, and processes, which are set forth in Section 15 of this Attachment N-1;

12.5 The method of disclosure of regional transmission planning criteria, assumptions and underlying data, which is set forth in Sections 14 and 15 of this Attachment N-1;

12.6 The obligations of and methods for Transmission Customers to submit data if necessary to support the regional transmission planning process, which are set forth in Section 16 of this Attachment N-1;

12.7 The process for submission of data by nonincumbent developers of transmission projects that wish to participate in the regional transmission planning process and seek regional cost allocation for purposes of Order No. 1000, which is set forth in Sections 23-31 of this Attachment N-1;

12.8 The process for submission of data by merchant transmission developers that wish to participate in the regional transmission planning process, which is set forth in Section 21 of this Attachment N-1;

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[4] Enrollees that are identified pursuant to Section 26 to potentially receive cost savings (associated with the regional cost allocation components in Section 27) due to the transmission developer's proposed transmission project for possible selection in a regional transmission plan for regional cost allocation purposes ("RCAP") shall be referred to as "Beneficiaries."

12.9 The regional dispute resolution process, which is set forth in Section 17 of this Attachment N-1;

12.10 The study procedures for regional economic upgrades to address congestion or the integration of new resources, which is set forth in Section 18 of this Attachment N-1;

12.11 The procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000, which are set forth in Section 19 of this Attachment N-1; and

12.12 The relevant regional cost allocation method or methods satisfying the six regional cost allocation principles set forth in Order No. 1000, which is set forth at Section 26-27.

12.13 The process for interregional coordination as described in Attachment N-1 – FRCC, Attachment N-1 – MISO, Attachment N-1 – PJM, Attachment N-1 – SCRTP, and Attachment N-1 – SPP.

13. COORDINATION

13.1 General: The SERTP Process is designed to eliminate the potential for undue discrimination in planning by establishing appropriate lines of communication between the Duke Transmission Provider, its transmission-providing neighbors, affected state authorities, Transmission Customers, and other Stakeholders regarding transmission planning issues.

13.2 Meeting Structure: Each calendar year, the SERTP Process will generally conduct and facilitate four (4) meetings (Annual Transmission Planning Meetings) that are open to all Stakeholders. However, the number of Annual Transmission Planning Meetings, or duration of any particular meeting, may be adjusted by announcement upon the Regional Planning Website, provided that any decision to reduce the number of Annual Transmission Planning Meetings must first be approved by the Sponsors and by the Regional Planning Stakeholders' Group (RPSG). These meetings can be done in person, through phone conferences, or through other telecommunications or technical means that may be available. The details regarding any such meeting will be posted on the Regional Planning Website, with a projected meeting schedule for a calendar year being posted on the Regional Planning Website on or before December 31st of the prior calendar year, with firm dates for all Annual Transmission Planning Meetings being posted at least 60 calendar days prior to a particular meeting. The general structure and purpose of these four (4) meetings will be as follows:

13.2.1 First RPSG Meeting and Interactive Training Session: At this meeting, which will be held in the first quarter of each calendar year, the RPSG will be formed for purposes of that year. In addition, the Duke Transmission Provider will meet with the RPSG and any other interested Stakeholders for the purposes of allowing the RPSG to select up to five

(5) Stakeholder requested Economic Planning Studies[5] that they would like to have studied by the Duke Transmission Provider and the Sponsors. At this meeting, the Duke Transmission Provider will work with the RPSG to assist the RPSG in formulating these Economic Planning Study requests. The Duke Transmission Provider will also conduct an interactive training session regarding its transmission planning for all interested Stakeholders. This session will explain and discuss the underlying methodology and criteria that will be utilized to develop the transmission expansion plan[6] before that methodology and criteria are finalized for purposes of the development of that year's transmission expansion plan (*i.e.*, the expansion plan that is intended to be implemented the following calendar year).[7] Stakeholders may submit comments to the Duke Transmission Provider regarding the Duke Transmission Provider's criteria and methodology during the discussion at the meeting or within ten (10) business days after the meeting, and the Duke Transmission Provider will consider such comments. Depending upon the major transmission planning issues presented at that time, the Duke Transmission Provider will provide various technical experts that will lead the discussion of pertinent transmission planning topics, respond to Stakeholder questions, and provide technical guidance regarding transmission planning matters. It is foreseeable that it may prove appropriate to shorten the training sessions as Stakeholders become increasingly knowledgeable regarding the Duke Transmission Provider's transmission planning process and no longer need detailed training in this regard.

The Duke Transmission Provider will also address transmission planning issues that the Stakeholders may raise.

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[5] As indicated *infra* at footnote 1, the Economic Planning Studies discussed in the regional planning portion of this Attachment N-1 (Sections 12-31) refer to the regional Economic Planning Studies conducted through the SERTP Process.

[6] The expectation is that in any given planning cycle, the Duke Transmission Provider's ten year transmission expansion plan along with those of the other Sponsors, will be included in the regional transmission plan. Moreover, the iterative nature of transmission planning bears emphasis, with underlying assumptions, needs, and data inputs continually changing to reflect market decisions, load service requirements, and other developments. A transmission plan, thus, only represents the status of transmission planning when the plan was prepared.

[7] A regional transmission expansion plan completed during one calendar year (and presented to Stakeholders at that calendar year's Annual Transmission Planning Summit) is intended to be the starting point plan for the following calendar year. For example, the regional transmission expansion plan developed during 2014 and presented at the 2014 Annual Transmission Planning Summit is for the 2015 calendar year.

13.2.2 Preliminary Expansion Plan Meeting: During the second quarter of each calendar year, the Duke Transmission Provider will meet with all interested Stakeholders to explain and discuss: the Duke Transmission Provider's preliminary transmission expansion plan, which is also input into that year's SERC (or other applicable NERC region's) regional model; internal model updating and any other then-current coordination study activities with the transmission providers in the Florida Reliability Coordinating Council (FRCC); and any *ad hoc* coordination study activities that might be occurring. These preliminary transmission expansion plan, internal model updating, and coordination study activities will be described to the Stakeholders, with this meeting providing them an opportunity to supply their input and feedback, including the transmission plan/enhancement alternatives that the Stakeholders would like the Duke Transmission Provider and the Sponsors to consider. The Duke Transmission Provider will also provide an update as to the status of its regional planning analyses performed pursuant to Section 20. In addition, the Duke Transmission Provider will address transmission planning issues that the Stakeholders may raise and otherwise discuss with Stakeholders developments as part of the SERC (or other applicable NERC region's) reliability assessment process.

13.2.3 Second RPSG Meeting: During the third quarter of each calendar year, the Duke Transmission Provider will meet with the RPSG and any other interested Stakeholders to report the preliminary results for the Economic Planning Studies requested by the RPSG at the First RPSG Meeting and Interactive Training Session. This meeting will give the RPSG an opportunity to provide input and feedback regarding those preliminary results, including alternatives for possible transmission solutions that have been identified. At this meeting, the Duke Transmission Provider shall provide feedback to the Stakeholders regarding transmission expansion plan alternatives that the Stakeholders may have provided at the Preliminary Expansion Plan Meeting, or within a designated time following that meeting. The Duke Transmission Provider will also discuss with the Stakeholders the results of the SERC (or other applicable NERC region's) regional model development for that year (with the Duke Transmission Provider's input into that model being its ten (10) year transmission expansion plan); any on-going coordination study activities with the FRCC transmission providers; and any *ad hoc* coordination study activities. In addition, the Duke Transmission Provider will address transmission planning issues that the Stakeholders may raise.

13.2.4 Annual Transmission Planning Summit and Assumptions Input Meeting: During the fourth quarter of each calendar year, the Duke Transmission Provider will host the annual Transmission Planning Summit and Assumptions Input Meeting.

13.2.4.1 Annual Transmission Planning Summit: At the Annual Transmission Planning Summit aspect of the Annual Transmission Planning Summit and Assumptions Input Meeting, the Duke Transmission Provider will present the final results for the Economic Planning Studies. The Duke Transmission Provider will also provide an overview of the ten (10) year transmission expansion plan, which reflects the results of planning analyses performed in the then-current planning cycle, including analyses performed pursuant to Section 20. The Duke Transmission Provider will also provide an overview of the regional transmission plan for Order No. 1000 purposes, which should include the ten (10) year transmission expansion plan of the Duke Transmission Provider. In addition, the Duke Transmission Provider will address transmission planning issues that the Stakeholders may raise.

13.2.4.2 Assumptions Input Session: The Assumptions Input Session aspect of the Annual Transmission Planning Summit and Assumptions Input Meeting will take place following the annual Transmission Planning Summit and will provide an open forum for discussion with, and input from, the Stakeholders regarding: the data gathering and transmission model assumptions that will be used for the development of the Duke Transmission Provider's following year's ten (10) year transmission expansion plan, which includes the Duke Transmission Provider's input, to the extent applicable, into that year's SERC regional model development; internal model updating and any other then-current coordination study activities with the transmission providers in the FRCC; and any *ad hoc* coordination study activities that might be occurring. This meeting may also serve to address miscellaneous transmission planning issues, such as reviewing the previous year's regional planning process, and to address specific transmission planning issues that may be raised by Stakeholders.

13.3 Committee Structure - the RPSG: The RPSG has two primary purposes. First, the RPSG is charged with determining and proposing up to five (5) Economic Planning Studies on an annual basis and should consider clustering similar Economic Planning Study requests. Second, the RPSG serves as the representative in interactions with the Duke Transmission Provider and Sponsors for the eight (8) industry sectors identified below.

13.3.1 RPSG Sector Representation: The Stakeholders are organized into the following eight (8) sectors for voting purposes within the RPSG:

(1) Transmission Owners/Operators[8]

(2) Transmission Service Customers

(3) Cooperative Utilities

(4) Municipal Utilities

(5) Power Marketers

(6) Generation Owners/Developers

(7) ISO/RTOs

(8) Demand Side Management/Demand Side Response

13.3.2 Sector Representation Requirements: Representation within each sector is limited to two members, with the total membership within the RPSG being capped at 16 members (Sector Members). The Sector Members, each of whom must be a Stakeholder, are elected by Stakeholders, as discussed below. A single company, and all of its affiliates, subsidiaries, and parent company, is limited to participating in a single sector.

13.3.3 Annual Reformulation: The RPSG will be reformed annually at each First RPSG Meeting and Interactive Training Session discussed in Section 13.2.1. Specifically, the Sector Members will be elected for a term of approximately one year that will terminate upon the convening of the following year's First RPSG Meeting and Interactive Training Session. Sector Members shall be elected by the Stakeholders physically present at the First RPSG Meeting and Interactive Training Session (voting by sector for the respective Sector Members). If elected, Sector Members may serve consecutive, one-year terms, and there is no limit on the number of terms that a Sector Member may serve.

13.3.4 Simple Majority Voting: RPSG decision-making that will be recognized by the Duke Transmission Provider for purposes of this Attachment N-1 shall be those authorized by a simple majority vote by the then-current Sector Members, with voting by proxy being permitted for a Sector Member that is unable to attend a particular meeting. The Duke Transmission Provider will notify the RPSG of the matters upon which

[8] The Sponsors will not have a vote within the Transmission Owners/Operators sector, although they (or their affiliates, subsidiaries or parent company) shall have the right to participate in other sectors.

an RPSG vote is required and will use reasonable efforts to identify upon the Regional Planning Website the matters for which an RPSG decision by simple majority vote is required prior to the vote, recognizing that developments might occur at a particular Annual Transmission Planning Meeting for which an RPSG vote is required but that could not be reasonably foreseen in advance. If the RPSG is unable to achieve a majority vote, or should the RPSG miss any of the deadlines prescribed herein or clearly identified on the Regional Planning Website and/or at a particular meeting to take any action, then the Duke Transmission Provider will be relieved of any obligation that is associated with such RPSG action.

13.3.5 RPSG Guidelines/Protocols: The RPSG is a self-governing entity subject to the following requirements that may not be altered absent an appropriate filing with the Commission to amend this aspect of the Tariff: (i) the RPSG shall consist of the above-specified eight (8) sectors; (ii) each company, its affiliates, subsidiaries, and parent company, may only participate in a single sector; (iii) the RPSG shall be reformed annually, with the Sector Members serving terms of a single year; and (iv) RPSG decision-making shall be by a simple majority vote (*i.e.*, more than 50%) by the Sector Members, with voting by written proxy being recognized for a Sector Member unable to attend a particular meeting. There are no formal incorporating documents for the RPSG, nor are there formal agreements between the RPSG and the Duke Transmission Provider. As a self-governing entity, to the extent that the RPSG desires to adopt other internal rules and/or protocols, or establish subcommittees or other structures, it may do so provided that any such rule, protocol, etc., does not conflict with or otherwise impede the foregoing requirements or other aspects of the Tariff. Any such additional action by the RPSG shall not impose additional burdens upon the Duke Transmission Provider unless it agrees in advance to such in writing, and the costs of any such action shall not be borne or otherwise imposed upon the Duke Transmission Provider unless the Duke Transmission Provider agrees in advance to such in writing.

13.4 The Role of the Duke Transmission Provider in Coordinating the Activities of the SERTP Process Meetings and of the Functions of the RPSG: The Duke Transmission Provider will host and conduct the above-described Annual Transmission Planning Meetings with Stakeholders.[9]

13.5 Procedures Used to Notice Meetings and Other Planning-Related Communications: Meetings notices, data, stakeholder questions, reports, announcements, registration for inclusion in distribution lists, means for being

[9] As previously discussed, the Duke Transmission Provider expects that the other Sponsors will also be hosts and sponsors of these activities.

certified to receive Critical Energy Infrastructure Information (CEII), and other transmission planning-related information will be posted on the Regional Planning Website. Stakeholders will also be provided notice regarding the annual meetings by e-mail messages (if they have appropriately registered on the Regional Planning Website to be so notified). Accordingly, interested Stakeholders may register on the Regional Planning Website to be included in e-mail distribution lists (Registered Stakeholder). For purposes of clarification, a Stakeholder does not have to have received certification to access CEII in order to be a Registered Stakeholder.

13.6 Procedures to Obtain CEII Information: For access to information considered to be CEII, there will be a password protected area that contains such CEII information. Any Stakeholder may seek certification to have access to this CEII data area.

13.7 The Regional Planning Website: The Regional Planning Website will contain information regarding the SERTP Process, including:

13.7.1 Notice procedures and e-mail addresses for contacting the Sponsors and for questions;

13.7.2 A calendar of meetings and other significant events, such as release of draft reports, final reports, data, etc.;

13.7.3 A registration page that allows Stakeholders to register to be placed upon an e-mail distribution list to receive meetings notices and other announcements electronically; and

13.7.4 The form in which meetings will occur (*i.e.*, in person, teleconference, webinar, *etc*.).

14. OPENNESS

14.1 General: The Annual Transmission Planning Meetings, whether consisting of in-person meetings, conference calls, or other communicative mediums, will be open to all Stakeholders. The Regional Planning Website will provide announcements of upcoming events, with Stakeholders being notified regarding the Annual Transmission Planning Meetings by such postings. In addition, Registered Stakeholders will also be notified by e-mail messages. Should any of the Annual Transmission Planning Meetings become too large or otherwise become unmanageable for the intended purpose(s), smaller breakout meetings may be utilized.

14.2 Links to OASIS: In addition to open meetings, the publicly available information, CEII-secured information (the latter of which is available to any Stakeholder certified to receive CEII), and certain confidential non-CEII information (as set forth below) shall be made available on the Regional Planning Website, a link to which is found on the Duke Transmission Provider's OASIS website, so as to further facilitate the availability of this transmission planning information on an open and comparable basis.

14.3 CEII Information

14.3.1 Criteria and Description of CEII: The Commission has defined CEII as being specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure (physical or virtual) that:

14.3.1.1 Relates details about the production, generation, transmission, or distribution of energy;

14.3.1.2 Could be useful to a person planning an attack on critical infrastructure;

14.3.1.3 Is exempt from mandatory disclosure under the Freedom of Information Act; and

14.3.1.4 Does not simply give the general location of the critical infrastructure.

14.3.2 Secured Access to CEII Data: The Regional Planning Website will have a secured area containing the CEII data involved in the SERTP Process that will be password accessible to Stakeholders that have been certified to be eligible to receive CEII data. For CEII data involved in the SERTP Process that did not originate with the Duke Transmission Provider, the duty is incumbent upon the entity that submitted the CEII data to have clearly marked it as CEII.

14.3.3 CEII Certification: In order for a Stakeholder to be certified and be eligible for access to the CEII data involved in the SERTP Process, the Stakeholder must follow the CEII certification procedures posted on the Regional Planning Website (*e.g.*, authorize background checks and execute the SERTP CEII Confidentiality Agreement posted on the Regional Planning Website). The Duke Transmission Provider reserves the discretionary right to waive the certification process, in whole or in part, for anyone that the Duke Transmission Provider deems appropriate to receive CEII information. The Duke Transmission Provider also reserves the discretionary right to reject a request for CEII; upon such rejection, the requestor may pursue the dispute resolution procedures of Section 17.

14.3.4 Discussions of CEII Data at the Annual Transmission Planning Meetings: While the Annual Transmission Planning Meetings are open to all Stakeholders, if CEII information is to be discussed during a portion of such a meeting, those discussions will be limited to being only with those Stakeholders who have been certified eligible to have access to CEII information, with the Duke Transmission Provider reserving the discretionary right at such meeting to certify a Stakeholder as being eligible if the Duke Transmission Provider deems it appropriate to do so.

14.4 Other Sponsor- and Stakeholder- Submitted Confidential Information: The other Sponsors and Stakeholders that provide information to the Duke Transmission Provider that foreseeably could implicate transmission planning should expect that such information will be made publicly available on the Regional Planning Website or may otherwise be provided to Stakeholders in accordance with the terms of this Attachment N-1. Should another Sponsor or Stakeholder consider any such information to be CEII, it shall clearly mark that information as CEII and bring that classification to the Duke Transmission Provider's attention at, or prior to, submittal. Should another Sponsor or Stakeholder consider any information to be submitted to the Duke Transmission Provider to otherwise be confidential (*e.g.*, competitively sensitive), it shall clearly mark that information as such and notify the Duke Transmission Provider in writing at, or prior to, submittal, recognizing that any such designation shall not result in any material delay in the development of the transmission expansion plan or any other transmission plan that the Duke Transmission Provider (in whole or in part) is required to produce.

14.5 Procedures to Obtain Confidential Non-CEII Information

14.5.1 The Duke Transmission Provider shall make all reasonable efforts to preserve the confidentiality of information in accordance with the provisions of the Tariff, the requirements of (and/or agreements with) NERC, the requirements of (and/or agreements with) SERC or other applicable NERC region, the provisions of any agreements with the other Sponsors, and/or in accordance with any other contractual or legal confidentiality requirements.

14.5.2 Without limiting the applicability of Section 14.5.1, to the extent competitively sensitive and/or otherwise confidential information (other than information that is confidential solely due to its being CEII) is provided in the transmission planning process and is needed to participate in the transmission planning process and to replicate transmission planning studies, it will be made available to those Stakeholders who have executed the SERTP Non-CEII Confidentiality Agreement (which agreement is posted on the Regional Planning Website). Importantly, if information should prove to contain both competitively sensitive/otherwise confidential information and CEII, then the requirements of both Section 14.3 and Section 14.5 would apply.

14.5.3 Other transmission planning information shall be posted on the Regional Planning Website and may be password protected, as appropriate.

15. TRANSPARENCY

15.1 General**:** Through the Annual Transmission Planning Meetings and postings made on the Regional Planning Website, the Duke Transmission Provider will disclose to its Transmission Customers and other Stakeholders the basic criteria, assumptions, and data that underlie its transmission expansion plan, as well as information regarding the status of upgrades identified in the transmission plan. The process for notifying stakeholders of changes or updates in the data bases used for transmission planning shall be through the Annual Transmission Planning Meetings and/or by postings on the Regional Planning Website.

15.2 The Availability of the Basic Methodology, Criteria, and Process the Duke Transmission Provider Uses to Develop its Transmission Plan: In an effort to enable Stakeholders to replicate the results of the Duke Transmission Provider's transmission planning studies, and thereby reduce the incidences of after-the-fact disputes regarding whether transmission planning has been conducted in an unduly discriminatory fashion, the Duke Transmission Provider will provide the following information, or links thereto, on the Regional Planning Website:

15.2.1 The Electric Reliability Organization and Regional Entity reliability standards that the Duke Transmission Provider utilizes, and complies with, in performing transmission planning.

15.2.2 The Duke Transmission Provider's internal policies, criteria, and guidelines that it utilizes in performing transmission planning.

15.2.3 Software titles and version numbers that may be used to access and perform transmission analyses on the then-current posted data bases.

Any additional information necessary to replicate the results of the Duke Transmission Provider's planning studies will be provided in accordance with, and subject to, the CEII and confidentiality provisions specified in this Attachment N-1.

15.3 Additional Transmission Planning-Related Information: In an effort to facilitate the Stakeholders' understanding of the Transmission System, the Duke Transmission Provider will also post additional transmission planning-related information that it deems appropriate on the Regional Planning Website.

15.4 Additional Transmission Planning Business Practice Information: In an effort to facilitate the Stakeholders' understanding of the Business Practices related to Transmission Planning, the Duke Transmission Provider will also post the following information on the Regional Planning Website:

15.4.1 Means for contacting the Duke Transmission Provider.

15.4.2 Procedures for submittal of questions regarding transmission planning to the Duke Transmission Provider (in general, questions of a nonimmediate nature will be collected and addressed through the Annual Transmission Planning Meeting process).

15.4.3 Instructions for how Stakeholders may obtain transmission base cases and other underlying data used for transmission planning.

15.4.4 Means for Transmission Customers having Service Agreements for Network Integration Transmission Service to provide load and resource assumptions to the Duke Transmission Provider; provided that if there are specific means defined in a Transmission Customer's Service Agreement for Network Integration Transmission Service (NITSA), then the NITSA shall control.

15.4.5 Means for Transmission Customers having Long-Term Service Agreements for Point-To-Point Transmission Service to provide to the Duke Transmission Provider projections of their need for service over the planning horizon (including any potential rollover periods, if applicable), including transmission capacity, duration, receipt and delivery points, likely redirects, and resource assumptions; provided that if there are specific means defined in a Transmission Customer's Long-Term Transmission Service Agreement for Point-To-Point Transmission Service, then the Service Agreement shall control.

15.5 Transparency Provided Through the Annual Transmission Planning Meetings

15.5.1 The First RPSG Meeting and Interactive Training Session

15.5.1.1 An Interactive Training Session Regarding the Duke Transmission Provider's Transmission Planning Methodologies and Criteria: As discussed in (and subject to) Section 13.2.1, at the First RPSG Meeting and Interactive Training Session, the Duke Transmission Provider will, among other things, conduct an interactive, training and input session for the Stakeholders regarding the methodologies and criteria that the Duke Transmission Provider utilizes in conducting its transmission planning analyses. The purpose of these training and interactive sessions is to facilitate the Stakeholders' ability to replicate transmission planning study results to those of the Duke Transmission Provider.

15.5.1.2 Presentation and Explanation of Underlying Transmission Planning Study Methodologies: During the training session in the First RPSG Meeting and Interactive Training Session, the Duke Transmission Provider will present and explain its transmission study methodologies. While not all of the following methodologies may be addressed at any single meeting, these presentations may include explanations of the methodologies for the following types of studies:

(1) Steady state thermal analysis.

(2) Steady state voltage analysis.

(3) Stability analysis.

(4) Short-circuit analysis.

(5) Nuclear plant off-site power requirements.

(6) Interface analysis (*i.e.*, import and export capability).

15.5.2 Presentation of Preliminary Modeling Assumptions: At the Annual Transmission Planning Summit, the Duke Transmission Provider will also provide to the Stakeholders its preliminary modeling assumptions for the development of the Duke Transmission Provider's following year's ten (10) year transmission expansion plan. This information will be made available on the Regional Planning Website, with CEII information being secured by password access. The preliminary modeling assumptions that will be provided may include:

15.5.2.1 Study case definitions, including load levels studied and planning horizon information.

15.5.2.2 Resource assumptions, including on-system and off-system supplies for current and future native load and network customer needs.

15.5.2.3 Planned resource retirements.

15.5.2.4 Renewable resources under consideration.

15.5.2.5 Demand side options under consideration.

15.5.2.6 Long-term firm transmission service agreements.

15.5.2.7 Current TRM and CBM values.

15.5.3 The Transmission Expansion Review and Input Process: The Annual Transmission Planning Meetings will provide an interactive process over a calendar year for the Stakeholders to receive information and updates, as well as to provide input, regarding the Duke Transmission Provider's development of its transmission expansion plan. This dynamic process will generally be provided as follows:

15.5.3.1 At the Annual Transmission Planning Summit and Assumptions Input Meeting, the Duke Transmission Provider will describe and explain to the Stakeholders the database assumptions for the ten (10) year transmission expansion plan that will be developed during the upcoming year. The Stakeholders will be allowed to provide input regarding the ten (10) year transmission expansion plan assumptions.

15.5.3.2 At the First RPSG Meeting and Interactive Training Session, the Duke Transmission Provider will provide interactive training to the Stakeholders regarding the underlying criteria and methodologies utilized to develop the transmission expansion plan. The databases utilized by the Duke Transmission Provider will be posted on the secured area of the Regional Planning Website.

15.5.3.3 To the extent that Stakeholders have transmission expansion plan/enhancement alternatives that they would like for the Duke Transmission Provider and other Sponsors to consider, the Stakeholders shall perform analysis prior to, and provide any such analysis at, the Preliminary Expansion Plan Meeting. At the Preliminary Expansion Plan Meeting, the Duke Transmission Provider will present its preliminary transmission expansion plan for the current ten (10) year planning horizon, including updates on the status of regional assessments being performed pursuant to Section 20. The Duke Transmission Provider and Stakeholders will engage in interactive expansion plan discussions regarding this preliminary analysis. This preliminary transmission expansion plan will be posted on the secure/CEII area of the Regional Planning Website at least 10 calendar days prior to the Preliminary Expansion Plan meeting.

15.5.3.4 The transmission expansion plan/enhancement alternatives suggested by the Stakeholders will be considered by the Duke Transmission Provider for possible inclusion in the transmission expansion plan. When evaluating such proposed alternatives, the Duke Transmission Provider will, from a transmission planning perspective, take into account factors such as, but not limited to, the proposed alternatives' impacts on reliability, relative economics, effectiveness of performance, impact on transmission service (and/or cost of transmission service) to other customers and on third-party systems, project feasibility/viability and lead time to install.

15.5.3.5 At the Second RPSG Meeting, the Duke Transmission Provider will report to the Stakeholders regarding the suggestions/alternatives suggested by the Stakeholders at the

Preliminary Expansion Plan Meeting. The then-current version of the transmission expansion plan will be posted on the secure/CEII area of the regional planning website at least 10 calendar days prior to the Second RPSG Meeting.

15.5.3.6 At the Annual Transmission Planning Summit, the ten (10) year transmission expansion plan that is intended to be implemented the following year will be presented to the Stakeholders along with the regional transmission plan for purposes of Order No. 1000. The Transmission Planning Summit presentations and the regional transmission plan, which is expected to include the ten (10) year transmission expansion plan will be posted on the Regional Planning Website at least 10 calendar days prior to the Annual Transmission Planning Summit.

15.5.4 Flowchart Diagramming the Steps of the SERTP Process: A flowchart diagramming the SERTP Process, as well as providing the general timelines and milestones for the performance of the activities described herein, is provided in Appendix 2.

16. INFORMATION EXCHANGE

To the extent that the information described in this Section 16 has not already been exchanged pursuant to the Companies' Local Planning Process described in Sections 2-10 herein, the Duke Transmission Provider may request that Transmission Customers and/or other interested parties provide additional information pursuant to this Section 16 in support of regional transmission planning pursuant to Sections 12-31 herein.

16.1 General: Transmission Customers having Service Agreements for Network Integration Transmission Service are required to submit information on their projected loads and resources on a comparable basis (*e.g.*, planning horizon and format) as used by transmission providers in planning for their native load. Transmission Customers having Service Agreements for Point-To-Point Transmission Service are required to submit any projections they have a need for service over the planning horizon and at what receipt and delivery points. Interconnection Customers having Interconnection Agreements under the Tariff are required to submit projected changes to their generating facility that could impact the Duke Transmission Provider's performance of transmission planning studies. The purpose of this information that is provided by each class of customers is to facilitate the Duke Transmission Provider's transmission planning process, with the September 1 due date of these data submissions by customers being timed to facilitate the Duke Transmission Provider's development of its databases and model building for the following year's ten (10) year transmission expansion plan.

16.2 Network Integration Transmission Service Customers: By September 1 of each year, each Transmission Customer having Service Agreement[s] for Network Integration Transmission Service shall provide to the Duke Transmission Provider an annual update of that Transmission Customer's Network Load and Network Resource forecasts for the following ten (10) years consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff.

16.3 Point-to-Point Transmission Service Customers: By September 1 of each year, each Transmission Customers having Service Agreement[s] for long-term Firm Point-To-Point Transmission Service shall provide to the Duke Transmission Provider usage projections for the term of service. Those projections shall include any projected redirects of that transmission service, and any projected resells or reassignments of the underlying transmission capacity. In addition, should the Transmission Customer have rollover rights associated with any such service agreement, the Transmission Customer shall also provide non-binding usage projections of any such rollover rights.

16.4 Demand Resource Projects: The Duke Transmission Provider expects that Transmission Customers having Service Agreements for Network Integration Transmission Service that have demand resource assets will appropriately reflect those assets in those customers' load projections. Should a Stakeholder have a demand resource asset that is not associated with such load projections that the Stakeholder would like to have considered for purposes of the transmission expansion plan, then the Stakeholder shall provide the necessary information *(e.g.* technical and operational characteristics, affected loads, cost, performance, lead time to install) in order for the Duke Transmission Provider to consider such demand response resource comparably with other alternatives. The Stakeholder shall provide this information to the Duke Transmission Provider by the Annual Transmission Planning Summit and Assumptions Input Meeting of the year prior to the implementation of the pertinent ten (10) year transmission expansion plan, and the Stakeholder should then continue to participate in this SERTP Process. To the extent similarly situated, the Duke Transmission Provider shall treat such Stakeholder submitted demand resource projects on a comparable basis for transmission planning purposes.

16.5 Interconnection Customers: By September 1 of each year, each Interconnection Customer having an Interconnection Agreement[s] under the Tariff shall provide to the Duke Transmission Provider annual updates of that Interconnection Customer's planned addition or upgrades (including status and expected in-service date), planned retirements, and environmental restrictions.

16.6 Notice of Material Change: Transmission Customers and Interconnection Customers shall provide the Duke Transmission Provider with timely written notice of material changes in any information previously provided related to any such customer's load, resources, or other aspects of its facilities, operations, or conditions of service materially affecting the Duke Transmission Provider's ability to provide transmission service or materially affecting the Transmission

System.

17. DISPUTE RESOLUTION[10]

17.1 Negotiation: Any substantive or procedural dispute between the Duke Transmission Provider and one or more Stakeholders (collectively, the "Parties") that arises from the Attachment N-1 transmission planning process generally shall be referred to a designated senior representative of the Duke Transmission Provider and a senior representative of the pertinent Stakeholder(s) for resolution on an informal basis as promptly as practicable. Should the dispute also involve one or more other Sponsors of this SERTP Process, then such entity(ies) shall have the right to be included in "Parties" for purposes of this Section and for purposes of that dispute, and any such entity shall also include a designated senior representative in the above discussed negotiations in an effort to resolve the dispute on an informal basis as promptly as practicable. In the event that the designated representatives are unable to resolve the dispute within thirty (30) days, or such other period as the Parties may unanimously agree upon, by unanimous agreement among the Parties such dispute may be voluntarily submitted to the use of the Commission's Alternative Means of Dispute Resolution (18 C.F.R. § 385.604, as those regulations may be amended from time to time), the Commission's Arbitration process (18 C.F.R. § 385.605, as those regulations may be amended from time to time) (collectively, "Commission ADR"), or such other dispute resolution process that the Parties may unanimously agree to utilize.

17.2 Use of Dispute Resolution Processes: In the event that the Parties voluntarily and unanimously agree to the use of a Commission ADR process or other dispute resolution procedure, then the Duke Transmission Provider will have a notice posted to this effect on the Regional Planning Website, and an e-mail notice in that regard will be sent to Registered Stakeholders. In addition to the Parties, all Stakeholders and Sponsors shall be eligible to participate in any Commission ADR process as "participants", as that or its successor term in meaning is used in 18 C.F.R. §§ 385.604, 385.605 as may be amended from time to time, for purposes of the Commission ADR process; provided, however, any such Stakeholder or Sponsor must first have provided written notice to the Duke Transmission Provider within thirty (30) calendar days of the posting on the Regional Planning Website of the Parties' notice of their intent to utilize a Commission ADR Process.

17.3 Costs: Each Party involved in a dispute resolution process hereunder, and each

[10] Any dispute, claim or controversy amongst Duke or Progress and/or a stakeholder regarding application of, or results from the local transmission planning process contained in Sections 2-11 herein (each a "Dispute") shall be resolved in accordance with the procedures set forth in Section 6 herein. Any procedural or substantive dispute that arises from the SERTP will be addressed by the regional Dispute Resolution Measures contained in this Section 17.

"participant" in a Commission ADR Process utilized in accordance with Section 17.2, shall be responsible for its own costs incurred during the dispute resolution process. Should additional costs be incurred during the dispute resolution process that are not directly attributable to a single Party/participant, then the Parties/participants shall each bear an equal share of such cost.

17.4 Rights under the Federal Power Act: Nothing in this Section 17 shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

18. REGIONAL ECONOMIC PLANNING STUDIES[11]

18.1 General - Economic Planning Study Requests: Stakeholders will be allowed to request that the Duke Transmission Provider perform up to five (5) Stakeholder requested economic planning studies (Economic Planning Studies) on an annual basis.

18.2 Parameters for the Economic Planning Studies: These Economic Planning Studies shall be confined to sensitivity requests for bulk power transfers and/or to evaluate potential upgrades or other investments on the Transmission System that could reduce congestion or integrate new resources. Bulk power transfers from one area to another area with the region encompassed by this SERTP Process (the "Region") shall also constitute valid requests. The operative theory for the Economic Planning Studies is for them to identify meaningful information regarding the requirements for moving large amounts of power beyond that currently feasible, whether such transfers are internal to the Region or from this Region to interconnected regions.

18.3 Other Tariff Studies: The Economic Planning Studies are not intended to replace System Impact Studies, Facility Studies, or any of the studies that are performed for transmission delivery service or interconnection service under the Tariff.

18.4 Clustering: The RPSG should consider clustering similar Economic Planning Study requests. In this regard, if two or more of the RPSG requests are similar in nature and the Duke Transmission Provider concludes that clustering of such requests and studies is appropriate, the Duke Transmission Provider may, following communications with the RPSG, cluster those studies for purposes of the transmission evaluation.

18.5 Additional Economic Planning Studies: Should a Stakeholder(s) request the performance of an Economic Planning Study in addition to the above-described five (5) Economic Planning Studies that the RPSG may request during a calendar year, then any such additional Economic Planning Study will only be performed if

[11] The economic planning studies undertaken pursuant to this Section 18 are regional. Local economic studies are undertaken pursuant to Section 4.2 herein.

such Stakeholder(s) first agrees to bear the Duke Transmission Provider's actual costs for doing so and the costs incurred by any other Sponsor to perform such Economic Planning Study, recognizing that the Duke Transmission Provider may only conduct a reasonable number of transmission planning studies per year. If affected by the request for such an additional Economic Planning Study, the Duke Transmission Provider will provide to the requesting Stakeholder(s) a non-binding but good faith estimate of what the Duke Transmission Provider expects its costs to be to perform the study prior to the Stakeholder(s) having to agree to bear those costs. Should the Stakeholder(s) decide to proceed with the additional study, then it shall pay the Duke Transmission Provider's and other affected Sponsor[s]' estimated study costs up-front, with those costs being trued-up to the Duke Transmission Provider's and other affected Sponsor[s]' actual costs upon the completion of the additional Economic Planning Study.

18.6 Economic Planning Study Process

18.6.1 Stakeholders will be prompted at the Annual Transmission Planning Summit to provide requests for the performance of Economic Planning Studies. Corresponding announcements will also be posted on the Regional Planning Website, and Registered Stakeholders will also receive e-mail notifications to provide such requests. An Economic Planning Study Request Form will be made available on the Regional Planning Website, and interested Stakeholders may submit any such completed request form on the non-secure area of the Regional Planning Website (unless such study request contains CEII, in which case the study request shall be provided to the Duke Transmission Provider with the CEII identified, and the study request shall then be posted on the secure area of the Regional Planning Website).

18.6.2 Prior to each First RPSG Meeting, the RPSG shall compile the Economic Planning Study requests. At the First RPSG Meeting, the RPSG shall meet to discuss and select up to five (5) Economic Planning Studies to be requested to be performed. At the First RPSG Meeting, the Duke Transmission Provider will coordinate with the RPSG and any interested Stakeholders to facilitate the RPSG's efforts regarding its development and selection of the Economic Planning Study requests. Once the RPSG selects the Economic Planning Study(ies) (up to five annually), the RPSG will notify the Duke Transmission Provider, who will post the results on the Regional Planning Website.

18.6.3 The Duke Transmission Provider will post on the secure area of the Regional Planning Website the study assumptions for the five (5) Economic Planning Studies within thirty (30) days of the postings of the selected Economic Planning Studies on the Regional Planning Website. Registered Stakeholders will receive an e-mail notification of this posting, and an announcement will also be posted on the Regional Planning Website.

18.6.4 Stakeholders will have thirty (30) calendar days from the Duke Transmission Provider's posting of the assumptions for the RPSG to provide comments regarding those assumptions. Any such comments shall be posted on the secure area of the Regional Planning Website if the comments concern CEII.

18.6.5 The preliminary results of the Economic Planning Studies will be presented at the Second RPSG Meeting. These results and related data will be posted on the secure area of the Regional Planning Website a minimum of 10 calendar days prior to the Second RPSG Meeting. The Second RPSG Meeting will be an interactive session with the RPSG and other interested Stakeholders in which the Duke Transmission Provider will explain the results, alternatives, methodology, criteria, and related considerations pertaining to those preliminary results. At that meeting, the Stakeholders may submit alternatives to the enhancement solutions identified in those preliminary results. All such alternatives must be submitted by Stakeholders within thirty (30) calendar days from the close of the Second RPSG Meeting. The Duke Transmission Provider will consider the alternatives provided by the Stakeholders.

18.6.6 The final results of the Economic Planning Studies will be presented at the Annual Transmission Planning Summit, and the Duke Transmission Provider will report regarding its consideration of the alternatives provided by Stakeholders. These final results will be posted on the secure area of the Regional Planning Website a minimum of 10 calendar days prior to the Transmission Planning Summit.

18.6.7 The final results of the Economic Planning Studies will be non-binding upon the Duke Transmission Provider and will provide general non-binding estimations of the required transmission upgrades, timing for their construction, and costs for completion.

19. CONSIDERATION OF TRANSMISSION NEEDS DRIVEN BY PUBLIC POLICY REQUIREMENTS

19.1 Procedures for the Consideration of Transmission Needs Driven by Public Policy Requirements: The Duke Transmission Provider addresses transmission needs driven by enacted state, federal and local laws and/or regulations (Public Policy Requirements) in its routine planning, design, construction, operation, and maintenance of the Transmission System.

19.2 The Consideration of Transmission Needs Driven by Public Policy Requirements Identified Through Stakeholder Input and Proposals

19.2.1 Requisite Information: In order for the Duke Transmission Provider to consider possible transmission needs driven by Public Policy Requirements that are proposed by a Stakeholder, the Stakeholder must provide the following information in accordance with the submittal instructions provided on the Regional Planning Website:

19.2.1.1 The applicable Public Policy Requirement, which must be a requirement established by an enacted state, federal or local law(s) and/or regulation(s); and

19.2.1.2 An explanation of the possible transmission need(s) driven by the Public Policy Requirement identified in subsection (19.2.1.1) (*e.g.,* the situation or system condition for which possible solutions may be needed, as opposed to a specific transmission project).

19.2.2 Deadline for Providing Such Information: Stakeholders that propose a possible transmission need driven by a Public Policy Requirement for evaluation by the Duke Transmission Provider in the current transmission planning cycle must provide the requisite information identified in Section 19.2.1 to the Duke Transmission Provider no later than 60 calendar days after the SERTP Annual Transmission Planning Summit and Input Assumptions Meeting for the previous transmission planning cycle.

19.3 Duke Transmission Provider Evaluation of SERTP Stakeholder Input Regarding Possible Transmission Needs Driven by Public Policy Requirements

19.3.1 Identification of Public Policy-Driven Transmission Needs: In order to identify, out of the set of possible transmission needs driven by Public Policy Requirements proposed by Stakeholders, those transmission needs for which transmission solutions will be evaluated in the current planning cycle, the Duke Transmission Provider will assess:

19.3.1.1 Whether the Stakeholder-identified Public Policy Requirement is an enacted local, state, or federal law(s) and/or regulation(s);

19.3.1.2 Whether the Stakeholder-identified Public Policy Requirement drives a transmission need(s); and

19.3.1.3 If the answers to the foregoing questions 1) and 2) are affirmative, whether the transmission need(s) driven by the Public Policy Requirement is already addressed or otherwise being evaluated in the then-current planning cycle.

19.3.2 Identification and Evaluation of Possible Transmission Solutions for Public Policy-Driven Transmission Needs that Have Not Already Been Addressed: If a Public Policy-driven transmission need is identified that is not already addressed, or that is not already being evaluated in the transmission expansion planning process, the Duke Transmission Provider will identify a transmission solution(s) to address the aforementioned need in the planning processes. The potential transmission solutions will be evaluated consistent with Section 20.

19.4 Stakeholder Input During the Evaluation of Public Policy-Driven Transmission Needs and Possible Transmission Solutions

19.4.1 Typically at the First RPSG Meeting and Interactive Training Session, but not later than the Preliminary Expansion Plan Meeting, for the given transmission planning cycle, the Duke Transmission Provider will review the Stakeholder-proposed transmission needs driven by Public Policy Requirements to be evaluated in the then-current planning cycle. Prior to the meeting at which transmission needs driven by Public Policy Requirements will be reviewed, the Duke Transmission Provider will identify, on the Regional Planning Website, which possible transmission needs driven by Public Policy Requirements proposed by Stakeholders (if any) are transmission needs(s) that are not already addressed in the planning process and will, pursuant to Sections 19.3.1 and 19.3.2, be addressed in the current planning cycle.

19.4.2 Stakeholders, including those who are not Transmission Customers, may provide input regarding Stakeholder-proposed possible transmission need(s) and may provide input during the evaluation of potential transmission solutions to identified transmission needs driven by Public Policy Requirements. Specifically with regard to the evaluation of such potential transmission solutions, a Stakeholder may provide input at the Preliminary Expansion Plan Meeting. If a Stakeholder has performed analysis regarding such a potential transmission solution, the Stakeholder may provide any such analysis at that time.

19.4.3 Stakeholder input regarding possible transmission needs driven by Public Policy Requirements may be directed to the governing Tariff process as appropriate. For example, if the possible transmission need identified by the Stakeholder is essentially a request by a network customer to integrate a new network resource, the request would be directed to that existing Tariff process.

19.5 Posting Requirement: The Duke Transmission Provider will provide and post on the Regional Planning Website an explanation of (1) those transmission needs driven by Public Policy Requirements that have been identified for evaluation for potential transmission projects in the then-current planning cycle; and (2) why other suggested, possible transmission needs driven by Public Policy Requirements proposed by Stakeholders were not selected for further evaluation.

20. REGIONAL ANALYSES OF POTENTIALLY MORE EFFICIENT OR COST EFFECTIVE TRANSMISSION SOLUTIONS

20.1 Regional Planning Analyses

20.1.1 During the course of each transmission planning cycle, the Duke Transmission Provider will conduct regional transmission analyses to assess if the then-current regional transmission plan addresses the Duke Transmission Provider's transmission needs, including those of its Transmission Customers and those which may be driven, in whole or in part, by economic considerations or Public Policy Requirements. This regional analysis will include assessing whether there may be more efficient or cost effective transmission projects to address transmission needs than transmission projects included in the latest regional transmission plan (including projects selected in a regional transmission plan for RCAP pursuant to Section 26).

20.1.2 The Duke Transmission Provider will perform power flow, dynamic, and short circuit analyses, as necessary, to assess whether the then-current regional transmission plan would provide for the physical transmission capacity required to address the Duke Transmission Provider's transmission needs, including those transmission needs of its Transmission Customers and those driven by economic considerations and Public Policy Requirements. Such analysis will also evaluate those potential transmission needs driven by Public Policy Requirements identified by Stakeholders pursuant to Section 19.3.1. If the Duke Transmission Provider determines that the on-going planning being performed for the then-current cycle would not provide sufficient physical transmission capacity to address a transmission need(s), the Duke Transmission Provider will identify potential transmission projects to address the transmission need(s).

20.2 Identification and Evaluation of More Efficient or Cost Effective Transmission Project Alternatives

20.2.1 The Duke Transmission Provider will look for potential regional transmission projects that may be more efficient or cost effective solutions to address transmission needs than transmission projects included in the latest regional transmission plan or otherwise under consideration in the then-current transmission planning process for the ten (10) year planning horizon. Consistent with Section 20.1, through power flow, dynamic, and short circuit analyses, as necessary, the Duke Transmission Provider will evaluate regional transmission projects identified to be potentially more efficient or cost effective solutions to address transmission needs, including those transmission alternatives proposed by Stakeholders pursuant to Section 15.5.3.3 and transmission projects proposed for RCAP pursuant to Section 25. The evaluation of transmission projects in these regional assessments throughout the then-current planning cycle will be based upon their effectiveness in addressing transmission needs, including those driven by Public Policy Requirements, reliability and/or economic considerations. Such analysis will be in accordance with, and subject to (among other things), state law pertaining to transmission ownership, siting, and construction. In assessing whether transmission alternatives are more efficient and/or cost effective transmission solutions, the Duke Transmission Provider shall consider factors such as, but not limited to, a transmission project's:

20.2.1.1 Impact on reliability.

20.2.1.2 Feasibility, including the viability of constructing and tying in the proposed project by the required in-service date.

20.2.1.3 Relative transmission cost, as compared to other transmission project alternatives to reliably address transmission needs.

20.2.1.4 Ability to reduce real power transmission losses on the transmission system(s) within the SERTP region, as compared to other transmission project alternatives to reliably address transmission needs.

20.2.2 Stakeholder Input: Stakeholders may provide input on potential transmission alternatives for the Duke Transmission Provider to consider throughout the SERTP planning process for each planning cycle in accordance with Section 15.5.3.

21. MERCHANT TRANSMISSION DEVELOPERS PROPOSING TRANSMISSION FACILITIES IMPACTING THE SERTP:

Merchant transmission developers not seeking regional cost allocation pursuant to Sections 25-31 (Merchant Transmission Developers) who propose to develop a transmission project(s) potentially impacting the Transmission System and/or transmission system(s) within the SERTP region shall provide information and data necessary for the Duke Transmission Provider to assess the potential reliability and operational impacts of those proposed transmission facilities. That information should include:

- Transmission project timing, scope, network terminations, load flow data, stability data, HVDC data (as applicable), and other technical data necessary to assess potential impacts.

22. ENROLLMENT

22.1 General Eligibility for Enrollment: A public utility or non-public utility transmission service provider and/or transmission owner who is registered with NERC as a Transmission Owner or a Transmission Service Provider may enroll in the SERTP. Such Transmission Service Providers and Transmission Owners are thus potential Beneficiaries for cost allocation purposes on behalf of their transmission customers. Entities that do not enroll will nevertheless be permitted to participate as Stakeholders in the SERTP.

22.2 Enrollment Requirement In Order to Seek Regional Cost Allocation: While enrollment is not generally required in order for a transmission developer to be eligible to propose a transmission project for evaluation and potential selection in a regional transmission plan for RCAP pursuant to Sections 25-31, a potential transmission developer must enroll in the SERTP in order to be eligible to propose a transmission project for potential selection in a regional transmission plan for RCAP if it, an affiliate, subsidiary, member, owner or parent company has load in the SERTP.

22.3 Means to Enroll: Entities that satisfy the general eligibility requirements of Section 22.1 or are required to enroll in accordance with Section 22.2 may provide an application to enroll by submitting the form of enrollment posted on the Regional Planning Website.

22.4 List of Enrollees in the SERTP: Attachment N-3 provides the list of the entities who have enrolled in the SERTP in accordance with the foregoing provisions (Enrollees). Attachment N-3 is effective as of the effective date of the tariff record (and subject to Section 22.5, below) that contains Attachment N-3. In the event a non-public utility listed in Attachment N-3 provides the Duke Transmission Provider with notice that it chooses not to enroll in, or is withdrawing from, the SERTP pursuant to Section 22.5 or Section 22.6, as applicable, such action shall be effective as of the date prescribed in accordance with that respective Section. In such an event, the Duke Transmission Provider shall file revisions to the lists of Enrollees in Attachment N-3 within fifteen business days of such notice. The effective date of any such revised tariff record shall be the effective date of the non-public utility's election to not enroll or to withdraw as provided in Section 22.5 or 22.6, as applicable.

22.5 Enrollment, Conditions Precedent, Conditions Subsequent, and Cost Allocation Responsibility: Enrollment will subject Enrollees to cost allocation if, during the period in which they are enrolled, it is determined in accordance with this Attachment N-1 that the Enrollee is a Beneficiary of a transmission project(s) selected in the regional transmission plan for RCAP; subject to the following:

22.5.1 Upon Order on Compliance Filing: The initial non-public utilities that satisfy the general eligibility requirements of 22.1 and who have made the decision to enroll at the time of the Duke Transmission Provider's compliance filing in response to FERC's July 18, 2013 Order on Compliance Filings in Docket Nos. ER13-897, ER13-908, and ER13-913, 144 FERC ¶ 61,054, do so on the condition precedent that the Commission accepts: i) that compliance filing without modification and without setting it for hearing or suspension and ii) the Duke Transmission Provider's July 10, 2013 compliance filing made in Docket Nos. ER13-1928, ER13-1930, ER13-1940, and ER13-1941 without modification and without setting it for hearing or suspension. Should the Commission take any such action upon review of such compliance filings or in any way otherwise modify, alter, or impose amendments to this Attachment N-1, then each such non-public utility shall be under no obligation to enroll in the SERTP and shall have sixty (60) days following such an order or action to provide written notice to the Duke Transmission Provider of whether it will, in fact, enroll in the SERTP. If, in that event, such non-public utility gives notice to the Duke Transmission Provider that it will not enroll, such non-public utility shall not be subject to cost allocation under this Attachment N-1 (unless it enrolls at a later date).

22.5.2 Upon Future Regulatory Action: Notwithstanding anything herein to the contrary, should the Commission, a Court, or any other governmental entity having the requisite authority modify, alter, or impose amendments to this Attachment N-1, then an enrolled non-public utility may immediately withdraw from this Attachment N-1 by providing written notice within sixty (60) days of that order or action, with the non-public utility's termination being effective as of the close of business the prior business day before said modification, alteration, or amendment occurred (although if the Commission has not acted by that prior business day upon both of the compliance filings identified in Section 22.5.1, then the non-public utility shall never have been deemed to have enrolled in the SERTP). In the event of such a withdrawal due to such a future regulatory and/or judicial action, the withdrawing Enrollee will be subject to cost allocations, if any, that were determined in accordance with this Attachment N-1 during the period in which it was enrolled and that determined that the withdrawing Enrollee would be a Beneficiary of new transmission projects selected in the regional transmission plan for RCAP.

22.6 Notification of Withdrawal: An Enrollee choosing to withdraw its enrollment in the SERTP may do so by providing written notification of such intent to the Duke Transmission Provider. Except for non-public utilities electing to not enroll or withdraw pursuant to Section 22.5, a non-public utility Enrollee's withdrawal shall be effective as of the date the notice of withdrawal is provided to the Duke Transmission Provider pursuant to this Section 22.6. For public utility Enrollees, the withdrawal shall be effective at the end of the then-current transmission planning cycle provided that the notification of withdrawal is provided to the Duke Transmission Provider at least sixty (60) days prior to the Annual Transmission Planning Summit and Assumptions Input Meeting for that transmission planning cycle.

22.7 Cost Allocation After Withdrawal: Any withdrawing Enrollee will not be allocated costs for transmission projects selected in a regional transmission plan for RCAP after its termination of enrollment becomes effective in accordance with the provisions of Section 22.5 or Section 22.6. However, the withdrawing Enrollee will be subject to cost allocations determined in accordance with this Attachment N-1 during the period it was enrolled, if any, for which the Enrollee was identified as a Beneficiary of new transmission projects selected in the regional transmission plan for RCAP.

23. PRE-QUALIFICATION CRITERIA FOR A TRANSMISSION DEVELOPER TO BE ELIGIBLE TO SUBMIT A REGIONAL TRANSMISSION PROJECT PROPOSAL FOR POTENTIAL SELECTION IN A REGIONAL TRANSMISSION PLAN FOR RCAP

23.1 Transmission Developer Pre-Qualification Criteria: In order to be eligible to propose a transmission project (that the transmission developer intends to develop) for consideration for selection in a regional transmission plan for RCAP in the upcoming planning cycle, a transmission developer (including the Duke Transmission Provider and nonincumbents) or a parent company (as defined in Section 23.1.2.2 below), as applicable, must submit a pre-qualification application by August 1st of the then-current planning cycle. To demonstrate that the transmission developer will be able to satisfy the minimum financial capability and technical expertise requirements, the pre-qualification application must provide the following:

23.1.1 A non-refundable administrative fee of $25,000 to off-set the cost to review, process, and evaluate the transmission developer's pre-qualification application;

23.1.2 Demonstration that at least one of the following criteria is satisfied:

23.1.2.1 The transmission developer must have and maintain a Credit Rating (defined below) of BBB- or better from Standard & Poor's Financial Services LLC, a part of McGraw Hill Financial (S&P), a Credit Rating of Baa3 or better from Moody's Investors Service, Inc. (Moody's) and/or a Credit Rating of BBB- or better from Fitch Ratings, Inc. (Fitch, collectively with S&P and Moody's and/or their successors, the "Rating Agencies") and not have or obtain less than any such Credit Rating by S&P, Moody's or Fitch. The senior unsecured debt (or similar) rating for the relevant entity from the Rating Agencies will be considered the "Credit Rating". In the event of multiple Credit Ratings from one Rating Agency or Credit Ratings from more than one Rating Agency, the lowest of those Credit Ratings will be used by the Duke Transmission Provider for its evaluation. However, if such a senior unsecured debt (or similar) rating is unavailable, the Duke Transmission Provider will consider Rating Agencies' issuer (or similar) ratings as the Credit Rating.

23.1.2.2 If a transmission developer does not have a Credit Rating from S&P, Moody's or Fitch, it shall be considered "Unrated", and an Unrated transmission developer's parent company or the entity that plans to create a new subsidiary that will be the transmission developer (both hereinafter "parent company") must have and maintain a Credit Rating of BBB- or better from

S&P, Baa3 or better from Moody's and/or BBB- or better from Fitch, not have or obtain less than any such Credit Rating by S&P, Moody's or Fitch, and the parent company must commit in writing to provide an acceptable guaranty to the Duke Transmission Provider meeting the requirements of Section 31 for the transmission developer if a proposed transmission project is selected in a regional transmission plan for RCAP. If there is more than one parent company, the parent company(ies) committing to provide the guaranty must meet the requirements set forth herein.

23.1.2.3 For an Unrated transmission developer, unless its parent company satisfies the requirements under B. above, such transmission developer must have and maintain a Rating Equivalent (defined below) of BBB- or better. Upon an Unrated transmission developer's request, a credit rating will be determined for such Unrated transmission developer comparable to a Rating Agency credit rating (Rating Equivalent) based upon the process outlined below:

(1) Each Unrated transmission developer will be required to pay a non-refundable annual fee of $15,000.00 for its credit to be evaluated/reevaluated on an annual basis.

(2) Upon request by the Duke Transmission Provider, an Unrated transmission developer must submit to the Duke Transmission Provider for the determination of a Rating Equivalent, and not less than annually thereafter, the following information with respect to the transmission developer, as applicable:

(A) financial statements (audited if available) for each completed fiscal quarter of the then current fiscal year including the most recent fiscal quarter, as well as the most recent three (3) fiscal years;

(i) For Unrated transmission developers with publicly-traded stock, this information must include:

(a) Annual reports on Form 10-K (or successor form) for the three (3) fiscal years most recently ended, and quarterly reports on Form 10-Q (or successor form) for each completed quarter of the then current fiscal year, together with any amendments thereto, and

(b) Form 8-K (or successor form) reports disclosing material changes, if any, that have been filed since the most recent Form 10-K (or successor form), if applicable;

(ii) For Unrated transmission developers that are privately held, this information must include:

(a) Financial Statements, including balance sheets, income statements, statement of cash flows, and statement of stockholder's equity,

(b) Report of Independent Accountants,

(c) Management's Discussion and Analysis, and

(d) Notes to financial statements;

(B) its Standard Industrial Classification and North American Industry Classification System codes;

(C) at least one (1) bank and three (3) acceptable trade references;

(D) information as to any material litigation, commitments or contingencies as well as any prior bankruptcy declarations or material defaults or defalcations by, against or involving the transmission developer or its predecessors, subsidiaries or affiliates, if any;

(E) information as to the ability to recover investment in and return on its projects;

(F) information as to the financial protections afforded to unsecured creditors contained in its contracts and other legal documents related to its formation and governance;

(G) information as to the number and composition of its members or customers;

(H) its exposure to price and market risk;

(I) information as to the scope and nature of its business; and

(J) any additional information, materials and documentation which such Unrated transmission developer deems relevant evidencing such Unrated transmission developer's financial capability to develop, construct, operate and maintain transmission developer's projects for the life of the projects.

(3) The Duke Transmission Provider will notify an Unrated transmission developer after the determination of its Rating Equivalent. Upon request, the Duke Transmission Provider will provide the Unrated transmission developer with information regarding the procedures, products and/or tools used to determine such Rating Equivalent (*e.g.*, Moody's RiskCalc™ or other product or tool, if used).

(4) An Unrated transmission developer desiring an explanation of its Rating Equivalent must request such an explanation in writing within five (5) business days of receiving its Rating Equivalent. The Duke Transmission Provider will respond within fifteen (15) business days of receipt of such request with a summary of the analysis supporting the Rating Equivalent decision.

23.1.3 Evidence that the transmission developer has the capability to develop, construct, operate, and maintain significant U.S. electric transmission projects. The transmission developer should provide, at a minimum, the following information about the transmission developer. If the transmission developer is relying on the experience or technical expertise of its parent company or affiliate(s) to meet the requirements of this subsection 3, the following information should be provided about the transmission developer's parent company and its affiliates, as applicable:

23.1.3.1 Information regarding the transmission developer's or other relevant experience regarding transmission projects in-service, under construction, and/or abandoned or otherwise not completed including locations, operating voltages, mileages, development schedules, and approximate installed costs; whether delays in project completion were encountered; and how these facilities are owned, operated and maintained;

23.1.3.2 Evidence demonstrating the ability to address and timely remedy failure of transmission facilities;

23.1.3.3 Violations of NERC and/or Regional Entity reliability standard(s) and/or violations of regulatory requirement(s) that have been made public pertaining to the development, construction, ownership, operation, and/or maintenance of electric transmission infrastructure facilities (provided that violations of CIP standards are not required to be identified), and, if so, an explanation of such violations; and

23.1.3.4 A description of the experience of the transmission developer in acquiring rights of way.

23.1.4 Evidence of how long the transmission developer and its parent company, if relevant, have been in existence.

23.2 Review of Pre-Qualification Applications: No later than November 1st of the then-current planning cycle, the Duke Transmission Provider will notify transmission developers that submitted pre-qualification applications or updated information by August 1st, whether they have pre-qualified as eligible to propose a transmission project for consideration for selection in a regional transmission plan for RCAP in the upcoming planning cycle. A list of transmission developers that have pre-qualified for the upcoming planning cycle will be posted on the Regional Planning Website.

23.3 Opportunity for Cure for Pre-Qualification Applications: If a transmission developer does not meet the pre-qualification criteria or provides an incomplete application, then following notification by the Duke Transmission Provider, the transmission developer will have 15 calendar days to resubmit the necessary supporting documentation to remedy the identified deficiency. The Duke Transmission Provider will notify the transmission developer, whether they are, or will continue to be, pre-qualified within 30 calendar days of the resubmittal, provided that the Duke Transmission Provider shall not be required to provide such a response prior to November 1st of the then-current planning cycle.

23.4 Pre-Qualification Renewal: If a transmission developer is pre-qualified as eligible to propose a transmission project for consideration for selection in a regional transmission plan for RCAP in the then-current planning cycle, such transmission developer may not be required to re-submit information to pre-qualify with respect to the upcoming planning cycle. In the event any information on which the entity's pre-qualification is based has changed, such entity must submit all updated information by the August 1st deadline. In addition, all transmission developers must submit a full pre-qualification application once every 3 years.

23.5 Enrollment Requirement to Pre-Qualify as Eligible to Propose a Transmission Project for Potential Selection in a Regional Transmission Plan for RCAP: If a transmission developer or its parent company or owner or any affiliate, member or subsidiary has load in the SERTP region, the transmission developer must have enrolled in the SERTP in accordance with Section 22.2 to be eligible to pre-qualify to propose a transmission project for potential selection in a regional transmission plan for RCAP.

24. TRANSMISSION PROJECTS POTENTIALLY ELIGIBLE FOR SELECTION IN A REGIONAL TRANSMISSION PLAN FOR RCAP:

24.1 In order for a transmission project proposed by a transmission developer, whether incumbent or non-incumbent, to be considered for evaluation and potential selection in a regional transmission plan for RCAP, the project must be regional in nature in that it must be a transmission project effectuating significant bulk electric transfers across the SERTP region and addressing significant electrical needs in that it:

24.1.1 operates at a voltage of 300 kV or greater;

24.1.2 is a transmission line located in the SERTP region; and

24.1.3 spans at least 50 miles.

24.2 In addition to satisfying the requirements of Section 24.1, the proposed regional transmission project must not contravene state or local laws with regard to rights-of-way or construction of transmission facilities. The proposed transmission project also cannot be an upgrade to an existing facility. A transmission upgrade includes any expansion, partial replacement, or modification, for any purpose, made to existing transmission facilities, including, but not limited to:

24.2.1 transmission line reconductors;

24.2.2 the addition, modification, and/or replacement of transmission line structures and equipment;

24.2.3 increasing the nominal operating voltage of a transmission line;

24.2.4 the addition, replacement, and/or reconfiguration of facilities within an existing substation site;

24.2.5 the interconnection/addition of new terminal equipment onto existing transmission lines.

For purposes of clarification, a transmission project proposed for potential selection in a regional transmission plan for RCAP may rely on the implementation of one or more transmission upgrades (as defined above) by the Impacted Utilities in order to reliably implement the proposed transmission project.

24.3 In order for the proposed transmission project to be a more efficient or cost effective alternative to the transmission projects identified by the transmission providers through their planning processes, it should be materially different than projects already under consideration in the expansion planning process. A project will be deemed materially different, as compared to another transmission alternative(s) under consideration, if the proposal consists of significant geographical or electrical differences in the alternative's proposed interconnection point(s) or transmission line routing. Should the proposed transmission project be deemed not materially different than projects already under consideration in the transmission expansion planning process, the Duke Transmission Provider will provide a sufficiently detailed explanation on the Regional Planning Website for Stakeholders to understand why such determination was made.

25. SUBMISSION OF PROPOSALS FOR POTENTIAL SELECTION IN A REGIONAL TRANSMISSION PLAN FOR RCAP

Any entity may propose a transmission project for consideration by the Duke Transmission Provider for potential selection in a regional transmission plan for RCAP.[12] An entity that wants to propose a transmission project for potential selection in a regional transmission plan for RCAP but does not intend to develop the transmission project may propose such transmission project in accordance with Section 25.6.

25.1 Materials to be Submitted: In order for a transmission project to be considered for RCAP, a pre-qualified transmission developer proposing the transmission project (including an incumbent or nonincumbent transmission developer) must provide to the Duke Transmission Provider the following information:

25.1.1 Sufficient information for the Duke Transmission Provider to determine that the potential transmission project satisfies the regional eligibility requirements of Section 24;

25.1.2 A description of the proposed transmission project that details the intended scope (including the various stages of the project development such as engineering, ROW acquisition, construction, recommended in-service date, etc.);

25.1.3 A capital cost estimate of the proposed transmission project. If the cost estimate differs greatly from generally accepted estimates of projects of comparable scope, the transmission developer may be asked to support such differences with supplemental information;

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[12] The regional cost allocation process provided hereunder in accordance with Sections 25-31 does not limit the ability of the Duke Transmission Provider and other entities to negotiate alternative cost sharing arrangements voluntarily and separately from this regional cost allocation method.

25.1.4 Data and/or files necessary to appropriately model the proposed transmission project;

25.1.5 Documentation of the specific transmission need(s) that the proposed transmission project is intended to address. This documentation should include a description of the transmission need(s), timing of the transmission need(s), and may include, the technical analysis performed to support that the proposed transmission project addresses the specified transmission need(s);

25.1.6 A description of why the proposed transmission project is expected to be more efficient or cost effective than other transmission projects included in the then-current regional transmission plan. If available, and to facilitate the evaluation of the proposal and to mitigate the potential for disputes, the entity proposing the project for potential selection in a regional transmission plan for RCAP may submit documentation of detailed technical analyses performed that supports the position that the proposed transmission project addresses the specified transmission needs more efficiently or cost-effectively. Such optional documentation could include the following:

25.1.6.1 Transmission projects in the latest transmission expansion plan or regional transmission plan that would be displaced by the proposed project,

25.1.6.2 Any additional projects that may be required in order to implement the proposed project, or

25.1.6.3 Any reduction/increase in real-power transmission system losses;

25.1.7 The transmission developer must provide a reasonable explanation of, as it pertains to its proposed project, its planned approach to satisfy applicable regulatory requirements and its planned approach to obtain requisite authorizations necessary to acquire rights of way and to construct, operate, and maintain the proposed facility in the relevant jurisdictions;

25.1.7.1 The transmission developer should not expect to use the Duke Transmission Provider's right of eminent domain for ROW acquisition;

25.1.8 How the transmission developer intends to comply with all applicable standards and obtain the appropriate NERC certifications,

25.1.8.1 If it or a parent, owner, affiliate, or member who will be performing work in connection with the potential transmission project is registered with NERC or other industry organizations pertaining to electric reliability and/or the development, construction, ownership, or operation, and/or maintenance of electric infrastructure facilities, a list of those registrations;

25.1.9 The experience of the transmission developer specific to developing, constructing, maintaining, and operating the type of transmission facilities contained in the transmission project proposed for potential selection in a regional transmission plan for RCAP,

25.1.9.1 Including verifiable past achievements of containing costs and adhering to construction schedules for transmission projects of similar size and scope as the proposed transmission project, and

25.1.9.2 Including a description of emergency response and restoration of damaged equipment capability

25.1.10 The planned or proposed project implementation management teams and the types of resources, including relevant capability and experience, contemplated for use in the development and construction of the proposed project;

25.1.11 A written commitment to comply with all applicable standards, including Good Utility Practices, governing the engineering, design, construction, operation, and maintenance of transmission projects in the SERTP region; and

25.1.12 Evidence of the ability of the transmission developer, its affiliate, partner or parent company to secure a financial commitment from an approved financial institution(s) agreeing to finance the construction, operation, and maintenance of the transmission project if selected in a regional transmission plan for RCAP.

25.2 Administrative Fee: An administrative fee of $25,000 to off-set the costs to review, process and evaluate each transmission project proposal. A refund of $15,000 will be provided to the transmission developer if:

25.2.1 The proposal is determined to not satisfy the qualification criteria in Section 25.1; or

25.2.2 The transmission developer withdraws its proposal by providing written notification of its intention to do so to the Duke Transmission Provider prior to the First RPSG Meeting and Interactive Training Session for that transmission planning cycle.

25.3 Deadline for Transmission Developer Submittals: In order for its transmission project to be considered for RCAP in the current transmission planning cycle, a transmission developer must provide the requisite information and payment identified in Sections 25.1-25.2 to the Duke Transmission Provider in accordance with the submittal instructions provided on the Regional Planning Website no later than 60 calendar days after the SERTP Annual Transmission Planning Summit and Input Assumptions Meeting for the previous transmission planning cycle.

25.4 Initial Review of Submittal and Opportunity for Cure: The Duke Transmission Provider will notify transmission developers who propose a transmission project for potential selection in a regional transmission plan for RCAP whose submittals do not meet the requirements specified in Sections 25.1-25.2, or who provide an incomplete submittal, within 45 calendar days of the submittal deadline to allow the transmission developer an opportunity to remedy any identified deficiency(ies). Transmission developers, so notified, will have 15 calendar days to resubmit the necessary supporting documentation to remedy the identified deficiency. The Duke Transmission Provider will notify the transmission developer, whether they have adequately remedied the deficiency within 30 calendar days of the resubmittal. Should the deficiency(ies) remain unremedied, then the transmission project will not be considered for RCAP.

25.5 Change in the Qualification Information or Circumstances:

25.5.1 The transmission developer proposing a transmission project for potential selection in a regional transmission plan for RCAP has an obligation to update and report in writing to the Duke Transmission Provider any change to its or its parent company's information that was provided as the basis for its satisfying the requirements of Sections 23 through 31, except that the transmission developer is not expected to update its technical analysis performed for purposes of Section 25.1.6 to reflect updated transmission planning data as the transmission planning cycle(s) progresses.

25.5.2 The transmission developer must inform the Duke Transmission Provider of the occurrence of any of the developments described in (1) or (2) below should the following apply (and within the prescribed time period): (i) within five (5) business days of the occurrence if the transmission developer has a pre-qualification application pending as of the date of the occurrence; (ii) upon the submission of a renewal request for pre-qualification should the development have occurred since the transmission developer was pre-qualified; (iii) prior to, or as part of, proposing a transmission project for potential selection in a regional transmission plan for RCAP pursuant to Section 25.1 should the development have occurred since the transmission developer was pre-qualified; and (iv) within five (5) business days of the occurrence if the transmission developer has a transmission project either selected or under consideration for selection in a regional transmission plan for RCAP. These notification requirements are applicable upon the occurrence of any of the following:

25.5.2.1 the existence of any material new or ongoing investigations against the transmission developer by the Commission, the Securities and Exchange Commission, or any other governing, regulatory, or standards body that has been or was required to be made public; if its parent company has been relied upon to meet the requirements of Section 23.1.2 or Section 31, such information must be provided for the parent company and, in any event, with respect to any affiliate that is a transmitting utility; and

25.5.2.2 any event or occurrence which could constitute a material adverse change in the transmission developer's (and, if the parent company has been relied upon to meet the requirements of Section 23.1.2 or Section 31, the parent company's) financial condition (Material Adverse Change) such as:

(1) A downgrade or suspension of any debt or issuer rating by any Rating Agency,

(2) Being placed on a credit watch with negative implications (or similar) by any Rating Agency,

(3) A bankruptcy filing or material default or defalcation,

(4) Insolvency,

(5) A quarterly or annual loss or a decline in earnings of twenty-five percent (25%) or more compared to the comparable year-ago period,

(6) Restatement of any prior financial statements, or

(7) Any government investigation or the filing of a lawsuit that reasonably would be expected to adversely impact any current or future financial results by twenty-five percent (25%) or more.

25.5.3 If at any time the Duke Transmission Provider concludes that a transmission developer or a potential transmission project proposed for possible selection in a regional transmission plan for RCAP no longer satisfies such requirements specified in Sections 23-25, then the Duke Transmission Provider will so notify the transmission developer or entity who will have fifteen (15) calendar days to cure. If the transmission developer does not meet the fifteen (15) day deadline to cure, or if the Duke Transmission Provider determines that the transmission developer continues to no longer satisfy the requirements specified in Sections 23-25 despite the transmission developer's efforts to cure, then the Duke Transmission Provider may, without limiting its other rights and remedies, immediately remove the transmission developer's potential transmission project(s) from consideration for potential selection in a regional transmission plan for RCAP and, if previously selected, from being selected in a regional transmission plan for RCAP, as applicable.

25.6 Projects Proposed for RCAP Where the Entity Making the Proposal Does Not Intend to be the Developer of the Project: Any Stakeholder may propose a potentially more cost effective or efficient transmission project for consideration in the transmission planning process in accordance with Section 15.5.3, and nothing herein limits the ability of a Stakeholder and other entities to negotiate alternative transmission development arrangements voluntarily and separately from the processes provided in this Attachment N-1. Should an entity propose a transmission project for potential selection in a regional transmission plan for RCAP but not intend to develop the project, then the following applies. Such an entity must submit the information required by Sections 25.1.1, 25.1.5, and 25.1.6 for a regional transmission project eligible for potential selection in a regional transmission plan for RCAP within the sixty (60) day window established in 25.3. Provided that the proposal complies with those requirements, the Duke Transmission Provider will make information describing the proposal available on the Regional Planning Website. The entity proposing the transmission project should coordinate with a transmission developer (either incumbent or nonincumbent) to have the developer submit the remaining information and materials required by Section 25. A pre-qualified transmission developer, should it decide to proceed, must submit the materials required by Section 25 within the sixty (60) day window established in Section 25.3 in order for the proposed transmission project to be considered for selection in a regional transmission plan for RCAP. If such a transmission project has not been so submitted within the sixty (60) day window established in Section 25.3, then the Duke Transmission Provider may treat the project as a Stakeholder-proposed transmission project alternative pursuant to Section 15.5.3. Furthermore, should the Duke Transmission Provider identify in the regional transmission planning process a regional transmission project that is selected in the regional transmission plan for RCAP that does not have a transmission developer that intends or is able to develop the project, the Duke Transmission Provider will identify such project on the Regional Planning Website. A prequalified transmission developer that desires to develop the project, whether incumbent or non-incumbent, may then propose the transmission project, pursuant to Sections 24 and 25, as the intended transmission developer for the project's on-going consideration in a regional transmission plan for RCAP.

26. EVALUATION AND POTENTIAL SELECTION OF PROPOSALS FOR SELECTION IN A REGIONAL TRANSMISSION PLAN FOR RCAP

26.1 Potential Transmission Projects Seeking RCAP Will be Evaluated in the Normal Course of the Transmission Planning Process: During the course of the then-current transmission expansion planning cycle (and thereby in conjunction with other system enhancements under consideration in the transmission planning process), the Duke Transmission Provider will evaluate current transmission needs and assess alternatives to address current needs including the potential transmission projects proposed for possible selection in a regional transmission plan for RCAP by transmission developers consistent with the regional evaluation process described in Section 20. Such evaluation will be in accordance with, and subject to (among other things), state law pertaining to transmission ownership, siting, and construction. Utilizing coordinated models and assumptions, the Duke Transmission Provider will perform analyses, including power flow, dynamic, and short circuit analyses, as necessary and, applying its planning guidelines and criteria to evaluate submittals, determine whether, throughout the ten (10) year planning horizon:

26.1.1 The proposed transmission project addresses an underlying transmission need(s);

26.1.2 The proposed transmission project addresses transmission needs that are currently being addressed with projects in the transmission planning process and if so, which projects could be displaced (consistent with the reevaluation of the projects included in a regional transmission plan as described in Section 28) by the proposed transmission project, including;

26.1.2.1 transmission projects in the Duke Transmission Provider's ten year transmission expansion plan,

26.1.2.2 transmission projects in the regional transmission plan, including those currently under consideration and/or selected for RCAP;

26.1.3 The proposed transmission project addresses a transmission need(s) for which no transmission project is currently included in the latest ten (10) year expansion plans and/or regional transmission plan. If so, the Duke Transmission Provider will identify an alternative transmission project(s) which would be required to fully and appropriately address the same transmission need(s) (*e.g.*, otherwise considered to be the more efficient or cost effective transmission alternative). The Duke Transmission Provider will identify and evaluate such an alternative transmission project(s) consistent with the processes described in Sections 1 to 11 and 20;

26.1.4 Any additional projects that would be required to implement the proposed transmission project;

26.1.5 The proposed transmission project reduces and/or increases real power transmission losses on the transmission system within the SERTP region.

Previous analysis may be used, either in part or in whole, if applicable to the evaluation of the proposed regional transmission project. Stakeholders may provide input into the evaluation of RCAP proposals throughout the SERTP process consistent with Section 15.5.3

26.2 Transmission Benefit-to-Cost Analysis Based Upon Planning Level Cost Estimates

26.2.1 Based upon the evaluation outlined in Section 26.1, the Duke Transmission Provider will assess whether the transmission developer's transmission project proposed for potential selection in a regional transmission plan for RCAP is considered at that point in time to yield meaningful, net regional benefits. Specifically, the proposed transmission project should yield a regional transmission benefit-to-cost ratio of at least 1.25 and no individual Impacted Utility should incur increased, unmitigated transmission costs.[13]

26.2.1.1 The benefit used in this calculation for purposes of assessing the transmission developer's proposed transmission project will be quantified by the Beneficiaries' total cost savings in the SERTP region associated with:

(1) All transmission projects in the ten (10) year transmission expansion plan which would be displaced, as identified pursuant to Section 26.1;

(2) All regional transmission projects included in the regional transmission plan which would be displaced, as identified pursuant to Section 26.1 and to the extent no overlap exists with those transmission projects identified as displaceable in the Duke Transmission Provider's ten (10) year transmission expansion plan. This includes transmission projects currently selected in the regional transmission plan for RCAP; and

(3) All alternative transmission project(s), as determined pursuant to Section 26.1 that would be required in lieu of the proposed regional transmission project, if the proposed regional transmission project addresses a

[13] An entity would incur increased, unmitigated transmission costs should it incur more costs than displaced benefits and not be compensated/made whole for those additional costs. For purposes of this Attachment N-1, the terms "Impacted Utilities" shall mean: i) the Beneficiaries identified in the evaluation of the proposed transmission project and ii) any entity identified in this Section 26.2.1 to potentially have increased costs on its transmission system located in the SERTP region in order to implement the proposal.

transmission need for which no transmission project is included in the latest ten (10) year expansion plan and/or regional transmission plan.

26.2.1.2 The cost used in this calculation will be quantified by the transmission cost within the SERTP region associated with:

(1) The project proposed for selection in a regional transmission plan for RCAP; and

(2) Any additional projects within the SERTP region on Impacted Utility transmission systems required to implement the proposal as identified pursuant to Section 26.1.

(3) For interregional transmission projects proposed for purposes of cost allocation between the SERTP and a neighboring region(s), the cost used in this calculation will be quantified by the transmission cost of the project multiplied by the allocation of the transmission project's costs (expressed as a fraction) to the SERTP region as specified in the applicable interregional cost allocation procedures, plus the transmission costs of any additional project within the SERTP region on Impacted Utility transmission systems required to implement the proposal as identified pursuant to Section 26.1.

26.2.1.3 If the initial BTC calculation results in a ratio equal to or greater than 1.0, then the Duke Transmission Provider will calculate the estimated change in real power transmission losses on the transmission system(s) of Impacted Utilities located in the SERTP. In that circumstance, an updated BTC ratio will be calculated consistent with Section 26.2. in which:

26.2.1.4 The cost savings associated with a calculated reduction of real power energy losses on the transmission system(s) will be added to the benefit; and

26.2.1.5 The cost increase associated with a calculated increase of real power energy losses on the transmission system(s) will be added to the cost.

26.2.2 The Duke Transmission Provider will develop planning level cost estimates for use in determining the regional benefit-to-cost ratio. Detailed engineering estimates may be used if available. If the Duke Transmission Provider uses a cost estimate different than a detailed cost estimate(s) provided by the transmission developer for use in performing the regional benefit-to-cost ratio, the Duke Transmission Provider will provide a detailed explanation of such difference to the transmission developer.

26.2.3 The cost savings and/or increase associated with real power losses on the transmission system(s) within the SERTP region with the implementation of the proposed regional transmission project will be estimated for each Impacted Utility throughout the ten (10) year transmission planning horizon as follows:

26.2.3.1 The Duke Transmission Provider will utilize power flow models to determine the change in real power losses on the transmission system at estimated average load levels.

(a) If the estimated change in real power transmission losses is less than 1 MW on a given transmission system of an Impacted Utility, no cost savings and/or cost increase for change in real power transmission losses on such system will be assigned to the proposal.

26.2.3.2 The Duke Transmission Provider will estimate the energy savings associated with the change in real power losses utilizing historical or forecasted data that is publicly available (*e.g.*, FERC Form 714).

26.2.4 Within 30 days of the Duke Transmission Provider completing the foregoing regional benefit-to-cost analysis, the Duke Transmission Provider will notify the transmission developer of the results of that analysis. For potential transmission projects found to satisfy the foregoing benefit-to-cost analysis, the Impacted Utilities will then consult with the transmission developer of that project to establish a schedule for the following activities specified below, with the schedule to be developed within 90 days of the notification: 1) the transmission developer providing detailed financial terms for its proposed project and 2) the proposed transmission project to be reviewed by the jurisdictional and/or governance authorities of the Impacted Utilities pursuant to Section 26.4 for potential selection in a regional transmission plan for RCAP.[14]

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[14] The schedule established in accordance with Section 26.2.4 will reflect considerations such as the timing of those transmission needs the regional project may address as well as the lead-times of the regional project, transmission projects that must be implemented in support of the regional project, and projects that may be displaced by the regional project. This schedule may be revised by the Duke Transmission Provider and the Impacted Utilities, in consultation with the

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26.3 The Transmission Developer to Provide More Detailed Financial Terms and the Performance of a Detailed Transmission Benefit-to-Cost Analysis:

26.3.1 By the date specified in the schedule established in Section 26.2.4, the transmission developer shall identify the detailed financial terms for its proposed project, establishing in detail: (1) the total cost to be allocated to the Beneficiaries if the proposal were to be selected in a regional transmission plan for RCAP, and (2) the components that comprise that cost, such as the costs of:

26.3.1.1 Engineering, procurement, and construction consistent with Good Utility Practice and standards and specifications acceptable to the Duke Transmission Provider,

26.3.1.2 Financing costs, required rates of return, and any and all incentive-based (including performance based) rate treatments,

26.3.1.3 Ongoing operations and maintenance of the proposed transmission project,

26.3.1.4 Provisions for restoration, spare equipment and materials, and emergency repairs, and

26.3.1.5 Any applicable local, state, or federal taxes.

26.3.2 To determine whether the proposed project is considered at that time to remain a more efficient or cost effective alternative, the Duke Transmission Provider will then perform a more detailed 1.25 transmission benefit-to-cost analysis consistent with that performed pursuant to Section 26.2.1. This more detailed transmission benefit-to-cost analysis will be based upon the detailed financial terms[15] provided by the transmission developer, as may be modified by agreement of the transmission developer and Beneficiary(ies), and any additional, updated, and/or more detailed transmission planning, cost or benefit information/component(s) as provided by the Impacted Utilities that are applicable to/available for the proposed transmission project, the projects that would be displaced, any additional projects required to

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transmission developer, as appropriate to address, for example, changes in circumstances and/or underlying assumptions.

[15] The detailed financial terms are to be provided by the date specified in the schedule to be developed by the Impacted Utilities and the transmission developer in accordance with Section 26.2.4.

implement the proposal and real power transmission loss impacts.[16] Once the Duke Transmission Provider has determined the outcome of the aforementioned regional benefit-to-cost analysis, the Transmission Provider will notify the transmission developer within 30 days of the outcome.

26.3.3 To provide for an equitable comparison, the costs of the transmission projects that would be displaced and/or required to be implemented in such a detailed benefit-to-cost analysis will include comparable cost components as provided in the proposed project's detailed financial terms (and vice-versa), as applicable. The cost components of the transmission projects that would be displaced will be provided by the Duke Transmission Provider and/or other Impacted Utilities who would own the displaced transmission project. The cost components of the proposed transmission project and of the transmission projects that would be displaced will be reviewed and scrutinized in a comparable manner in performing the detailed benefit to cost analysis.

26.4 Jurisdictional and/or Governance Authority Review : Should the proposed transmission project be found to satisfy the more detailed benefit-to-cost analysis specified in Section 26.3, the state jurisdictional and/or governance authorities of the Impacted Utilities will be provided an opportunity to review the transmission project proposal and otherwise consult, collaborate, inform, and/or provide recommendations to the Duke Transmission Provider. The recommendations will inform the Duke Transmission Provider's selection decision for purposes of Section 26.5, and such a recommendation and/or selection of a project for inclusion in a regional transmission plan for RCAP shall not prejudice the state jurisdictional and/or governance authority's (authorities') exercise of any and all rights granted to them pursuant to state or Federal law with regard to any project evaluated and/or selected for RCAP that falls within such authority's (authorities') jurisdiction(s).

26.5 Selection of a Proposed Transmission Project for RCAP:

26.5.1 The Duke Transmission Provider will select a transmission project (proposed for RCAP) for inclusion in the regional transmission plan for RCAP for the then-current planning cycle if the Duke Transmission Provider determines that the project is a more efficient or cost effective

[16] The performance of this updated, detailed benefit-to-cost analysis might identify different Beneficiaries and/or Impacted Utilities than that identified in the initial benefit-to-cost analysis performed in accordance with Section 26.2.1.

transmission project as compared to other alternatives to reliably address transmission need(s).[17] Factors considered in this determination include:

26.5.1.1 Whether the project meets or exceeds the detailed benefit-to-cost analysis performed pursuant to Section 26.3. Such detailed benefit-to-cost analysis may be reassessed, as appropriate, based upon the then-current Beneficiaries and to otherwise reflect additional, updated, and/or more detailed transmission planning, cost or benefit information/component(s) that are applicable to/available for the proposed transmission project, the projects that would be displaced, any additional projects required to implement the proposal and real power transmission loss impacts;

26.5.1.2 Any recommendation provided by state jurisdictional and/or governance authorities in accordance with Section 26.4 including whether the transmission developer is considered reasonably able to construct the transmission project in the proposed jurisdiction(s);

26.5.1.3 Whether, based on the timing for the identified transmission need(s) and the stages of project development provided by the transmission developer in accordance with Section 25.1 and as otherwise may be updated, the transmission developer is considered to be reasonably able to construct and tie the proposed transmission project into the transmission system by the required in-service date;

26.5.1.4 Whether it is reasonably expected that the Impacted Utilities will be able to construct and tie-in any additional facilities on their systems located within the SERTP region that are necessary to reliably implement the proposed transmission project; and

26.5.1.5 Any updated qualification information regarding the transmission developer's finances or technical expertise, as detailed in Section 23.

[17] Being selected for RCAP in the then-current iteration of a regional transmission plan only provides how the costs of the transmission project may be allocated in Commission-approved rates should the project be built. Being selected in a regional transmission plan for RCAP provides no rights with regard to siting, construction, or ownership. The transmission developer must obtain all requisite approvals to site and build its transmission project. A transmission project may be removed from being selected in a regional transmission plan for RCAP in accordance with the provisions of Sections 25.4, 28, 29, 30 and 31.

The Duke Transmission Provider will post on the Regional Planning Website its determination regarding whether a proposed project will be selected for inclusion in the regional transmission plan for RCAP for that transmission planning cycle. The Duke Transmission Provider will document its determination in sufficient detail for Stakeholders to understand why a particular project was selected or not selected for RCAP and will make this supporting documentation available to the transmission developer or Stakeholders, subject to any applicable confidentiality requirements. For projects selected in the regional transmission plan for purposes of RCAP, the documentation will also include sufficient information regarding the application of the regional cost allocation method to determine the benefits and identify the Beneficiaries of the proposed regional transmission project.

26.5.2 If a regional transmission project is selected in the regional transmission plan for purposes of RCAP, the Duke Transmission Provider will perform analyses to determine whether, throughout the ten (10) year planning horizon, the proposed transmission project could potentially result in reliability impacts to the transmission system(s) of an adjacent neighboring transmission planning region(s). If a potential reliability impact is identified, the Duke Transmission Provider will coordinate with the neighboring planning region on any further evaluation. The costs associated with any required upgrades identified in neighboring planning regions will not be included for RCAP within the SERTP.

27. COST ALLOCATION TO THE BENEFICIARIES:

If a regional transmission project is selected in a regional transmission plan for RCAP in accordance with Section 26.5 and then constructed and placed into service, the Beneficiaries will be allocated the regional transmission project's costs based upon their cost savings calculated in accordance with Section 26.3 and associated with:

27.1 The displacement of one or more of the transmission projects previously included in their ten (10) year transmission expansion plan.

27.2 The displacement of one or more regional transmission projects previously included in the regional transmission plan. More specifically, if a regional transmission project addresses the same transmission need(s) as a transmission project selected in a regional transmission plan for RCAP and displaces the original RCAP project as a more efficient or cost effective alternative, this cost allocation component will be based upon the costs of the original RCAP project that were to be allocated to the Beneficiaries in accordance with the application of the regional cost allocation method to the transmission project being displaced.

27.3 Any alternative transmission project(s) that would be required in lieu of the regional transmission project, if the proposed regional transmission project addresses a transmission need for which no transmission project is included in the latest ten (10) year expansion plan and/or regional transmission plan.

27.4 The reduction of real power transmission losses on their transmission system.

28. ON-GOING EVALUATIONS OF PROPOSED PROJECTS:

28.1 In order to ensure that the Duke Transmission Provider can efficiently and cost effectively meet its respective reliability, duty to serve, and cost of service obligations, and to ensure that the proposed transmission project remains the more efficient or cost effective alternative, the Duke Transmission Provider will continue to reevaluate the regional transmission plan throughout the then-current planning cycle and in subsequent cycles. This continued reevaluation will assess, in subsequent expansion planning processes that reflect ongoing changes in actual and forecasted conditions, the then-current transmission needs and determine whether transmission projects included in the regional transmission plan (i) continue to be needed and (ii) are more efficient or cost effective as compared to alternatives.

28.1.1 These on-going assessments will include reassessing transmission projects that have been selected in the regional transmission plan for RCAP and any projects that are being considered for potential selection in a regional transmission plan for RCAP.

28.2 Even though a transmission project may have been selected in a regional transmission plan for RCAP in an earlier regional transmission plan, if it is determined that the transmission project is no longer needed and/or it is no longer more efficient or cost effective than alternatives, then the Duke Transmission Provider may notify the transmission developer and remove the proposed project from being selected in a regional transmission plan for RCAP.

28.3 The cost allocation of a regional transmission project selected in a regional transmission plan for RCAP that remains selected in the regional transmission plan for RCAP may be modified in subsequent planning cycles based upon:

28.3.1 The then-current determination of benefits (calculated consistent with Section 26.3),

28.3.2 Cost allocation modifications as mutually agreed by the Beneficiaries, or

28.3.3 Cost modifications, as found acceptable by both the transmission developer and the Beneficiary(ies).

All prudently incurred costs of the regional transmission project will be allocated if the project remains selected in the regional plan for RCAP.

28.4 The reevaluation of the regional transmission plan will include the reevaluation of a particular transmission project included in the regional transmission plan until it is no longer reasonably feasible to replace the proposed transmission project as a result of the proposed transmission project being in a material stage of construction and/or if it is no longer considered reasonably feasible for an alternative transmission project to be placed in service in time to address the underlying transmission need(s) the proposed project is intended to address.

29. DELAY OR ABANDONMENT:

29.1 The transmission developer shall promptly notify the Duke Transmission Provider should any material changes or delays be encountered in the development of a potential transmission project selected in a regional transmission plan for RCAP. As part of the Duke Transmission Provider's on-going transmission planning efforts, the Duke Transmission Provider will assess whether alternative transmission solutions may be required in addition to, or in place of, a potential transmission project selected in a regional transmission plan for RCAP due to the delay in its development or abandonment of the project. The identification and evaluation of potential transmission project alternative solutions may include transmission project alternatives identified by the Duke Transmission Provider to include in the ten year transmission expansion plan. Furthermore, nothing precludes the Duke Transmission Provider from proposing such alternatives for potential selection in a regional transmission plan for RCAP pursuant to Section 25.

29.2 Based upon the alternative transmission projects identified in such on-going transmission planning efforts, the Duke Transmission Provider will evaluate the transmission project alternatives consistent with the regional planning process. The Duke Transmission Provider will remove a delayed project from being selected in a regional transmission plan for RCAP if the project no longer:

29.2.1 Adequately addresses underlying transmission needs by the required transmission need dates; and/or

29.2.2 Remains more efficient or cost effective based upon a reevaluation of the detailed benefit-to-cost calculation. The BTC calculation will factor in any additional transmission solutions required to implement the proposal (*e.g.*, temporary fixes) and will also compare the project to identified transmission project alternatives.

30. MILESTONES OF REQUIRED STEPS NECESSARY TO MAINTAIN STATUS AS BEING SELECTED FOR RCAP:

30.1 Once a regional transmission project is selected in a regional transmission plan for RCAP, the transmission developer must submit a development schedule to the Duke Transmission Provider and the Impacted Utilities that establishes the milestones by which the necessary steps to develop and construct the transmission project must occur. These milestones include (to the extent not already accomplished) obtaining all necessary ROWs and requisite environmental, state, and other governmental approvals. A development schedule will also need to be established for any additional projects by Impacted Utilities that are determined necessary to integrate the transmission projects selected in a regional transmission plan for RCAP. The schedule and milestones must be satisfactory to the Duke Transmission Provider and the Impacted Utilities.

30.2 In addition, the Beneficiaries will also determine and establish the deadline(s) by which the transmission developer must provide security/collateral for the proposed project that has been selected in a regional transmission plan for RCAP to the Beneficiaries or otherwise satisfy requisite creditworthiness requirements. The security/collateral/creditworthiness requirements shall be as described or referenced in Section 31.

30.3 If such critical steps are not met by the specified milestones and then afterwards maintained, then the Duke Transmission Provider may remove the project from being selected in a regional transmission plan for RCAP.

31. CREDIT AND SECURITY REQUIREMENTS TO PROTECT THE BENEFICARIES AGAINST DELAY OR ABANDONMENT OF A TRANSMISSION PROJECT SELECTED IN A REGIONAL TRANSMISSION PLAN FOR RCAP

31.1 Demonstration of Financial Strength**:** In order for a project to be selected and remain selected in a regional transmission plan for RCAP, the transmission developer must satisfy the following:

31.1.1 Consistent with Sections 23.1 and 25.5.3, the transmission developer for such project or its parent company providing the Beneficiaries with a parent guaranty ("Parent Guarantor") must have and maintain a Credit Rating of BBB- (or equivalent) or better from one or more of the Rating Agencies and not have or obtain less than any such Credit Rating by any of the Rating Agencies, or the transmission developer must be Unrated and have and maintain a Rating Equivalent of BBB- or better.

31.1.2 In addition to the requirements of Section 31.1.1, the transmission developer must satisfy one of the following by and at all times after the deadline established pursuant to Section 30.2:

31.1.2.1 The transmission developer must (i) have and maintain a Credit Rating of BBB+ (or equivalent) or better from one or more of the Rating Agencies and not have or obtain less than any such Credit Rating by any of the Rating Agencies or (ii) be Unrated and have and maintain a Rating Equivalent of BBB+ or better; or

31.1.2.2 The transmission developer must provide to and maintain with the Beneficiaries Eligible Developer Collateral (as defined in Section 31.4 below) in an amount equal to twenty-five percent

(25%) of the total costs of the transmission developer's projects selected in a regional transmission plan for RCAP.

31.2 Limitation of Exposure

31.2.1 Notwithstanding the foregoing, the Beneficiaries may limit their exposure with respect to transmission projects selected in a regional transmission plan being developed by a transmission developer satisfying the requirements of Section 31.1.2.1 above if the aggregate costs of such projects are at any time in excess of the lesser of (a) 10% of the transmission developer's Tangible Net Worth if the transmission developer has a Tangible Net Worth of less than one billion dollars or (b) two hundred fifty million dollars (the "Cap"). In such event, the transmission developer must provide to and maintain with the Beneficiaries Eligible Developer Collateral in a dollar amount not less than the amount by which the aggregate costs of such projects exceed the Cap. Each transmission developer will provide and update the Beneficiaries with such information as is necessary to establish and confirm the transmission developer's Tangible Net Worth. For purposes hereof, "Tangible Net Worth" shall be equal to the relevant entity's total equity minus its intangible assets and also minus its goodwill.

31.2.2 Notwithstanding the foregoing, the Beneficiaries may limit their exposure with respect to transmission projects selected in a regional transmission plan being developed by a transmission developer or its affiliates who are satisfying the requirements of Section 31.1.2.2 or 31.2.1 above by providing and maintaining a Developer Parent Guaranty (as defined in Section 31.4 below) if the aggregate costs of such projects are at any time in excess of the lesser of (a) 10% of the Parent Guarantor's Tangible Net Worth if such Parent Guarantor has a Tangible Net Worth of less than one billion dollars or (b) two hundred fifty million dollars (the "Guarantor Cap"). In such event, the transmission developer must provide to and maintain with the Beneficiaries an acceptable Irrevocable Letter of Credit in a dollar amount not less than the amount by which the aggregate costs of such projects exceed the Guarantor Cap. Each transmission developer will provide and update the Beneficiaries with such information as is necessary to establish and confirm the Parent Guarantor's Tangible Net Worth.

31.3 Credit Evaluation/Updates

31.3.1 On at least an annual basis, a transmission developer with a transmission project selected in a regional transmission plan for RCAP will provide the Beneficiaries with an updated, completed application and the updated information described in Section 23.1.

31.3.2 On at least an annual basis, or more often if there is a Material Adverse Change in the financial condition and/or a relevant change in the Tangible Net Worth of the transmission developer or its Parent Guarantor or if there are issues or changes regarding a transmission project, the Beneficiaries may review the Credit Rating and review and update the Rating Equivalent, Cap, Guarantor Cap and Eligible Developer Collateral requirements for said transmission developer. In the event said transmission developer is required to provide additional Eligible Developer Collateral as a result of the Beneficiaries' review/update, the Beneficiaries will notify the transmission developer and such additional Eligible Developer Collateral must be provided within five (5) business days of such notice, all in amount and form approved by the Beneficiaries.

31.4 Eligible Developer Collateral: Acceptable forms of eligible collateral meeting the requirements referenced below and the Beneficiaries' approval (the "Eligible Developer Collateral") may be either in the form of an irrevocable letter of credit ("Irrevocable Letter of Credit") or parent guaranty issued by a Parent Guarantor who has and maintains a Credit Rating of BBB+ (or equivalent) or better from one or more of the Rating Agencies and does not have or obtain less than any such Credit Rating by any of the Rating Agencies ("Developer Parent Guaranty"). Acceptable forms of Eligible Developer Collateral and related requirements and practices will be posted and updated on the Regional Planning Website and/or provided to the relevant transmission developer directly.

31.4.1 Each Beneficiary shall require an Irrevocable Letter of Credit to be issued to it in a dollar amount equal to the percentage of the costs of a transmission developer's transmission projects allocated or proposed to be allocated to it ("Percentage") multiplied by the aggregate dollar amount of all Irrevocable Letters of Credit constituting or to constitute Eligible Developer Collateral for such transmission projects.

31.4.2 Each Beneficiary shall require a Developer Parent Guaranty to be issued to it in a dollar amount equal to its Percentage multiplied by the aggregate dollar amount of all Developer Parent Guaranties constituting or to constitute Eligible Developer Collateral for such transmission projects.

31.4.2.1 A transmission developer supplying a Developer Parent Guaranty must provide and continue to provide the same information regarding the Parent Guarantor as is required of a transmission developer, including rating information, financial statements and related information, references, litigation information and other disclosures, as applicable.

31.4.2.2 All costs associated with obtaining and maintaining Irrevocable Letters of Credit and/or Developer Parent

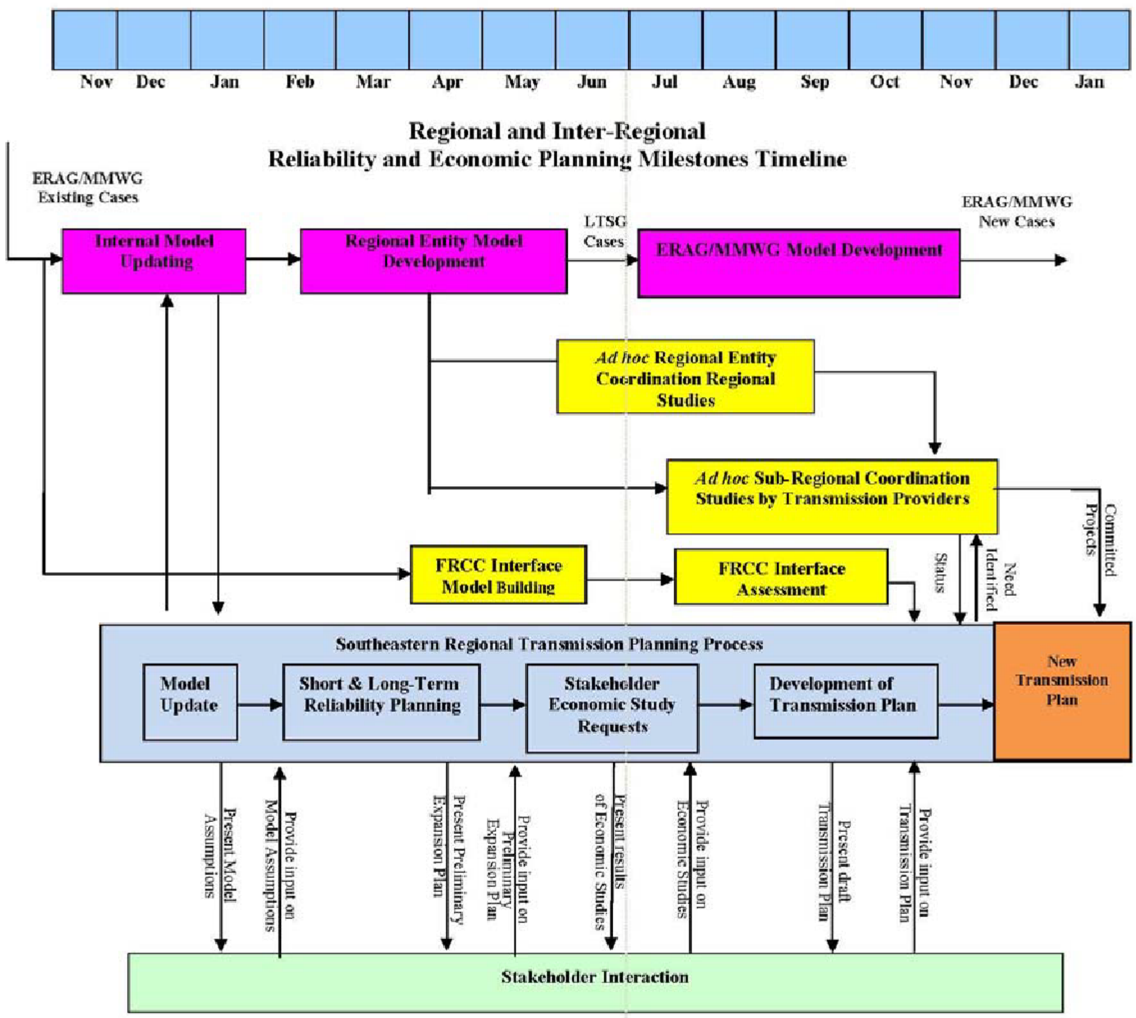
Guaranties and meeting the requirements of this Section 31 are the responsibility of the transmission developer.

31.4.2.3 The Beneficiaries reserve the right to deny, reject, or terminate acceptance and acceptability of any Irrevocable Letter of Credit or any Developer Parent Guaranty as Eligible Developer Collateral at any time for reasonable cause, including the occurrence of a Material Adverse Change or other change in circumstances.

31.5 Cure Periods/Default: If a transmission developer fails to comply with the requirements of this Section 31 and such failure is not cured within ten (10) business days after its initial occurrence, the Beneficiaries may declare such transmission developer to be in default hereunder and/or the Beneficiaries may, without limiting their other rights and remedies, revise the Cap, Guarantor Cap and Eligible Developer Collateral requirements; further, if such failure is not cured within an additional ten (10) business days, the Beneficiaries may, without limiting their other rights and remedies, immediately remove any or all of the transmission developer's projects from consideration for potential selection in the regional transmission plan for RCAP and, if previously selected, from being selected in a regional transmission plan for RCAP, as applicable.

Appendix 1
[Reserved]

Appendix 2



Nov
Dec
Jan
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Regional and Inter-Regional
Reliability and Economic Planning Milestones Timeline
ERAG/MMWG Existing Cases
Internal Model Updating
Regional Entity Model Development
LTSG Cases
ERAG/MMWG Model Development
ERAG/MMWG New Cases
Ad hoc Regional Entity Coordination Regional Studies
Ad hoc Sub-Regional Coordination Studies by Transmission Providers
Committed Projects
Status
Need Identified
FRCC Interface Model Building
FRCC Interface Assessment
Southeastern Regional Transmission Planning Process
Model Update
Short & Long-Term Reliability Planning
Stakeholder Economic Study Requests
Development of Transmission Plan
New Transmission Plan
Present Model Assumptions
Provide input on Model Assumptions
Present Preliminary Expansion Plan
Provide input on Preliminary Expansion Plan
Present results of Economic Studies
Provide input on Economic Studies
Present draft Transmission Plan
Provide input on Transmission Plan
Stakeholder Interaction

Appendix 3

Sector Voting Example

The example below illustrates the TAG Sector Voting Process. For purposes of explaining the example, we assume that the General Public (GP) Sector has 10 Individuals present. In addition to the 10 Individuals, there are 17 other TAG Sector Entities present, spread across four TAG Sectors (Cooperative LSEs (Coop LSE); Municipal LSEs (Muni LSE); Investor-Owned LSEs (IOU LSE); and Transmission Customers (TC)). These 17 TAG Sector Entities may each have several TAG participants present but only one may vote in one sector. Each Individual and TAG Sector Entity casts their vote, which vote is then weighted based on the number of persons/entities voting in the TAG Sector of which they are a member. E.g., since there are six Coop ~~LSEs is~~LSE voters present, each Coop LSE's vote is worth 1.00/6 or .166 (*see* Columns 4 and 5 for weighted vote). As the final step, the votes are weighted again, based on the number of TAG Sectors present. With five TAG Sectors present, each Sector Yes Vote and Sector No Vote is multiplied by 1.00/5 = .20. The weighted total is reported in columns 6 and 7. In the example, the No votes have won .53 to .47.

Column	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Sector	**No. of Voters**	**Yes Votes**	**No Votes**	**Sector Yes Vote**	**Sector No Vote**	**Weighted Sector Yes**	**Weighted Sector No Vote**
Coop LSE	6	6	0	1.00	0	.20	0
Muni LSE	8	2	6	.25	.75	.05	.15
IOU LSE	2	1	1	.50	.50	.10	.10
TP/TO	0	0	0	0	0	0	0
TCs	1	0	1	0	1.00	0	.20
GICs	0	0	0	0	0	0	0
ECs	0	0	0	0	0	0	0
GP	10	6	4	.60	.40	.12	.08
Total Vote						0.47	0.53