UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through Electric	)	
Regional Transmission Planning and Cost	)	Docket No. RM21-17-000
Allocation and Generator Interconnection	)	

COMMENTS OF THE SOUTHEAST PUBLIC INTEREST GROUPS

August 17, 2022

TABLE OF CONTENTS

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Southern Environmental Law Center, Energy Alabama, North Carolina Sustainable Energy Association, South Carolina Coastal Conservation League, Southface Energy Institute, and Southern Alliance for Clean Energy (together, Southeast Public Interest Groups) submit these initial comments in response to the Federal Energy Regulatory Commission's (FERC or Commission) Notice of Proposed Rulemaking, published on May 4, 2022 in the above-captioned proceeding (NOPR).[1] Southeast Public Interest Groups take this opportunity to show the Commission the degree to which its transmission planning policies have failed to materialize in the Southeast, leaving the region ill-equipped to adapt to an energy transformation that is already underway and rapidly intensifying.[2] The NOPR's proposed reforms provide an essential starting point, but a firm application of these expanded procedural mandates is imperative if the Southeast is to effectively meet the challenges before it in a cost-effective manner. Failure to do so will only deepen the financial strain on a region that already faces the highest energy burden in the country.[3]

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1 *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 87 Fed. Reg. 26504, 179 FERC ¶ 61,028 (2022) (NOPR).

2 *See, e.g.*, *Annual Energy Outlook 2022*, U.S. Energy Information Administration, at 6-7 (Mar. 2022), AEO2022 Narrative (eia.gov); Heather Prohnan & Maggie Shober, *Tracking Decarbonization in the Southeast: Generation + CO_2 Emissions Fourth Annual Report*, Southern Alliance for Clean Energy, at 6 (June 2022), Tracking Decarbonization in the Southeast Fourth Annual Report (cleanenergy.org).

3 *See, e.g.*, *Low-Income Household Energy Burden Varies Among States – Efficiency Can Help In All of Them*, U.S. Department of Energy (Dec. 2018), https://www.energy.gov/sites/prod/files/2019/01/f58/WIP-Energy-Burden_final.pdf (identifying Mississippi, South Carolina, Alabama, Georgia, and Arkansas as the five states with the

I. INTRODUCTION

The energy landscape is undergoing a rapid transformation. Driven by economic, technological, and political trends, the generation mix is evolving in both character and location. Centrally-located coal plants are retiring and far-flung renewable resources are connecting to the grid in their stead. Commercial and residential ratepayers are seeking cheaper and cleaner energy from their utilities, while overall demand is becoming more flexible and dynamic. Meanwhile, global temperatures continue their sustained upward march, presenting a constant threat to the grid as the weather careens between extremes of increasing severity.[4]

The Southeast is not immune to these shifts and, in many ways, is actively addressing them. In North Carolina, the General Assembly has established carbon-reduction targets for the power sector and directed the North Carolina Utilities Commission (NCUC) to create a roadmap for the state's largest utility to meet them (Carbon Plan).[5] In South Carolina, where ratepayers have shouldered the ballooning costs of a failed nuclear project,[6] the General Assembly has mandated a study of market alternatives, including joining or creating a Regional Transmission Organization

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highest low-income energy burden); Ariel Drehobl et al., *How High Are Household Energy Burdens? An Assessment of National and Metropolitan Energy Burden Across the U.S.,* American Council for an Energy-Efficient Economy (Sept. 10, 2020), https://www.aceee.org/sites/default/files/pdfs/u2006.pdf; *Low-Income Energy Affordability Data (LEAD) Tool*, U.S. Department of Energy, https://www.energy.gov/eere/slsc/low-income-energy-affordability-data-lead-tool (last visited Jul. 27, 2022).

4 *See, e.g.*, *2022 Summer Reliability Assessment*, North American Electric Reliability Corporation, at 7-8 (May 2022), 2022 SRA Draft (nerc.com) ("Peak electricity demand in most areas is directly influenced by temperature. Weather officials are expecting above normal temperatures for much of North America this summer. . . . In addition, drought exists or threatens wide areas of North America, resulting in unique challenges to area electricity supplies and potential impacts on demand."); *2021-2022 Winter Reliability Assessment*, North American Electric Reliability Corporation, at 4 (Nov. 2021), 2021-2022 WRA Draft (nerc.com) ("Extreme weather events, including extended durations of colder than normal weather, pose a risk to the uninterrupted delivery of power to electricity consumers").

5 2021 N.C. Sess. Laws 165 (H.B. 951).

6 Specifically, abandonment of the V.C. Summer facility caused customers to cover $9 billion for a generation facility that will never generate electricity. *See* Brad Plumer, "U.S. Nuclear Comeback Stalls as Two Reactors Are Abandoned," N.Y. Times (July 31, 2017), U.S. Nuclear Comeback Stalls as Two Reactors Are Abandoned - The New York Times (nytimes.com).

(RTO).[7] Across the region, utilities are retiring coal-fired plants while scrambling to replace their generation capacity with more economic alternatives. But despite these efforts, the region remains perilously unprepared to meet the challenges created by convulsions in resource mix, demand, and severe weather.[8] The oncoming wave of generation and transmission investments is poised to unfold in siloed, utility-by-utility planning processes, without the benefit of economies made possible by regional markets or coordinated transmission planning. Regulatory approval timelines, technology change, and increasingly severe weather will add both economic and reliability risk to this transition. So long as it remains burdened by a balkanized grid with minimal coordination among its utilities, the Southeast risks falling ever farther behind, with ratepayers once again bearing the burden. For the region to avoid this fate, the Commission must once again curb utility behavior with firm direction.

More than any other region of the country, the Southeast's energy landscape continues to resemble that which caused the Commission to overhaul transmission service requirements in Order Nos. 888,[9] 890,[10] and 1000.[11] Vertically integrated utilities preside over partitioned retail

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[7] 2020 S.C. Acts 187 (H.4940).

[8] For example, on multiple occasions this summer, the Tennessee Valley Authority (TVA) has asked customers to limit their electric consumption to ease strain on the grid during prolonged stretches of intense heat. *See, e.g.*, Paige Hill, "TVA Asks Customers to Reduce Electric Usage Due to Increased Temperatures," WVLT 8 (June 13, 2022), TVA asks customers to reduce electric usage due to increased temperatures (wvlt.tv).

[9] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. & Transmitting Utils.*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996) (cross-referenced at 75 FERC ¶ 61,080), *order on reh'g*, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (cross-referenced at 78 FERC ¶ 61,220), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. N. Y. v. FERC*, 535 U.S. 1 (2002).

[10] *Preventing Undue Discrimination and Preference in Transmission Serv.*, Order No. 890, 118 FERC ¶ 61,119, 51, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[11] *Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and*

service territories pursuant to state-granted monopolies. They have largely insulated themselves from competition, having consistently resisted joining or developing an organized wholesale energy market. This isolation extends to transmission planning, as the utilities "collaborate" by submitting their individual transmission expansion plans to the regional transmission planning processes, which the utilities themselves conduct. Without the independent oversight found in an RTO or Independent System Operator's (ISO) centralized planning process, the utilities approach the "regional" aspects of these processes—consideration of regional alternatives, economic studies, and Public Policy Requirements—as unserious boxes to be checked. Far from optimizing the region's transmission investment, the planning processes have yielded patchwork local transmission facilities addressing minimum reliability needs. The utilities routinely ignore or overlook the common transmission needs of their neighbors, leading to an overdevelopment of small-scale solutions instead of more cost-effective and efficient regional solutions that could produce systemwide savings. Ultimately, ratepayers bear the difference.

The impotence of the region's transmission planning processes owes in large part to the flexibility the Commission afforded utilities in establishing regional planning procedures.[12] Although well-intentioned, this experiment in regional deference has produced paltry results in the Southeast. Without firm Commission parameters for engaging in coordinated and meaningful regional transmission planning, the Southeast must rely on the initiative of the utilities themselves to do so. But, as the Commission found in first establishing transmission planning requirements, such reliance ignores the utilities' incentives: "[V]ertically-integrated utilities do not have an

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).

[12] *See, e.g.*, Order No. 1000 at P 61 ("[T]his Final Rule accords transmission planning regions significant flexibility to tailor regional transmission planning and cost allocation processes to accommodate these regional differences.").

incentive to expand the grid to accommodate new entries or to facilitate the dispatch of more efficient competitors."[13] They have no incentive to either (1) "relieve local congestion that restricts the output of a competing merchant generator if doing so will make the transmission provider's own generation less competitive,"[14] or (2) "increase the import or export capacity of [their] transmission system[s] if doing so would allow cheaper power to displace [their] higher cost generation or otherwise make new entry more profitable by facilitating exports."[15] Courts have agreed that "[u]tilities that own or control transmission facilities naturally wish to maximize profit,"[16] which dictates that they will "act in their own interest to maintain their monopoly and to use that position to retain or expand the market share for their own generated electricity, even if they do so at the expense of lower-cost generation companies and consumers."[17] Acting on these incentives, utilities in the Southeast have systematically exploited gaps in the Commission's transmission planning requirements, rendering them largely ineffective:

> IOUs are at the heart of the problem. They are driven to maintain the status quo, in part by capitalizing on FERC's rules that allow them to build projects within their state-granted territories without competitive pressures and on the backs of their captive retail ratepayers. This local focus is at odds with FERC's decades-long push for regionalization, and the IOUs' defensive approach to transmission development has no place in a technologically dynamic industry.[18]

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13 Order No. 890 at P 57.

14 *Id*. P 422.

15 *Id*.

16 *Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d at 683-84. *See N. Y. v. FERC*, 535 U.S. at 8 ("[P]ublic utilities retain ownership of the transmission lines that must be used by their competitors to deliver electric energy to wholesale and retail customers. The utilities' control of transmission facilities gives them the power either to refuse to deliver energy produced by competitors or to deliver competitors' power on terms and conditions less favorable than those they apply to their own transmissions.").

17 *Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d at 683-84.

18 Ari Peskoe, *Is the Utility Transmission Syndicate Forever?,* 42 Energy L.J. 1, 2 (2021).

By identifying these vulnerabilities in the Commission's rules and taking advantage of its flexibility, utilities are acting rationally; the established framework is simply insufficient to achieve the Commission's stated goals.

Foremost among these is ensuring that transmission planning processes do not result in unjust, unreasonable, or unduly discriminatory rates for transmission service.[19] In Order No. 1000, the Commission sought to achieve this goal in part by "enhanc[ing] the ability of the transmission grid to support wholesale power markets."[20] That concern is particularly acute in the Southeast, where there is no organized wholesale power market.[21] Instead, the region's utilities engage exclusively in bilateral wholesale transactions driven by their and other load-serving entities' (LSE) changing needs. This spot market lacks consistent independent oversight or any type of economic dispatch. As such, independent power producers in the region depend entirely on the utilities to provide an outlet for their output. This includes ensuring access to transmission capacity, particularly where that generation is located far from load centers. But as the Commission has recognized, one "cannot rely on the self-interest of transmission providers to expand the grid in a nondiscriminatory manner."[22]

Multiple studies have demonstrated the tremendous savings the Southeast could realize from greater regional coordination, most often in the form of creating a Southeast RTO.[23] For

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19 *See, e.g.*, Order No. 1000 at P 42.

20 *Id*. P 12.

21 The utilities in the Southeast have proposed to create the Southeast Energy Exchange Market (SEEM), a loose coalition of utilities engaging in an automated bilateral market construct. As proposed, SEEM would differ significantly from the organized wholesale energy markets that cover most of the country, with glaring deficiencies in terms of transparency, independence, and market access. SEEM's authorization is currently pending before the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit).

22 Order No. 890 at P 422.

23 *See, e.g.*, Eric Gimon et al., *Summary Report: Economic and Clean Energy Benefits of Establishing a Southeast U.S. Competitive Wholesale Electricity Market*, Energy Innovation Policy & Technology LLC (Aug. 2020), Economic-And-Clean-Energy-Benefits-Of-Establishing-A-Southeast-U.S.-Competitive-Wholesale-Electricity-Market_AUG_2020.pdf (energyinnovation.org) (Energy Innovation Report); Jennifer Chen, *Evaluating Options for*

example, Energy Innovation: Policy & Technology LLC concluded in 2020 that a Southeastern RTO would result in cumulative economic savings of approximately $384 billion by 2040, compared to the balkanized status quo.[24] The report explained that "[r]egional transmission planning through an RTO rationalizes transmission planning to reduce congestion and expose more expensive plants in load pockets to competition."[25] While the study did not isolate the savings created by coordinated regional planning, it compared a true RTO model—yielding the $384 billion savings figure—with an Economic IRP that did not optimize the generation and transmission buildout across the region, resulting in $298 billion in savings by 2040.[26] It stands to reason that a significant portion of the $86 billion delta owes to the optimized regional transmission investment. A regional transmission planning regime that ignores savings of this magnitude patently fails to "enhance the ability of the transmission grid to support wholesale power markets"[27] and results in unjust, unreasonable, and unduly discriminatory rates.

These ingrained inefficiencies stand to worsen in the coming years. The Commission overhauled its transmission planning policies in Order No. 1000 due to an impending transmission investment boom "driven, in large part, by changes in the generation mix," in which "existing and potential environmental regulation and state renewable portfolio standards [were] driving significant changes in the mix of generation resources, resulting in early retirements of coal-fired generation, an increasing reliance on natural gas, and large-scale integration of renewable

Enhancing Wholesale Competition and Implications for the Southeastern United States, Duke, Nicholas Institute for Environmental Policy Solutions (Mar. 2020), Evaluating Options for Enhancing-Wholesale-Competition-and-Implications-for-the-Southeastern-United-States-Final.pdf (duke.edu).

[24] Energy Innovation Report at 1.

[25] *Id*. at 10.

[26] *Id*. at 19-20.

[27] Order No. 1000 at P 42.

generation."[28] Those trends have only intensified in the decade since, as have increasingly common extreme weather and high-intensity, low-frequency events, both of which tax the grid's resilience. Once again, bold action is required to adapt regional transmission planning processes to these changes. This time, however, the Commission must impose firm requirements upon public utilities to overcome their natural incentives to avoid coordinated regional transmission planning, especially in non-RTO/ISO regions.

These comments will demonstrate the structural inability of the Southeast's regional transmission planning processes to proactively address these trends. First, they will discuss the region's planning processes, the Southeastern Regional Transmission Planning (SERTP) process, the South Carolina Regional Transmission Planning (SCRTP) process, and the Florida Reliability Coordinating Council, Inc. (FRCC) regional planning process, all of which have failed to prepare the regional grid for the substantial changes in motion. Second, they will survey the states in this region and showcase examples of the emerging transmission needs that, in the words of the utilities themselves, are shaping generation decisions. Finally, they will examine the NOPR proposals that can best address the existing deficiencies, including certain necessary tweaks.

Taken together, these comments will create a record that will allow the Commission to ensure that a non-RTO/ISO region like the Southeast has the tools it needs to provide just, reasonable, and reliable transmission service in an era of fundamental change. By their recommendations, the Southeast Public Interest Groups do not seek to disrupt the Commission's traditional planning paradigm of mandating a reasonable and transparent planning process rather dictating specific investment outcomes. Instead, the Southeast Public Interest Groups support a prescriptive and comprehensive regional planning process capable of identifying and evaluating

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28 *Id*. P 45.

regional transmission alternatives that could more efficiently and cost-effectively meet the region's collective needs. The transmission planning process must create a robust array of fully-considered, publicly-accessible transmission options that will allow state regulators and stakeholders to assess and scrutinize the utilities' ultimate choices. Ratepayers can only benefit from a fully transparent and exhaustive planning process that fundamentally prioritizes their interests.

II. BACKGROUND

The Southeast's energy landscape is segmented, with investor-owned utilities, TVA, and cooperative and municipal utilities occupying defined service territories and operating largely independently of one another. Southern Company's affiliates Georgia Power Company (Georgia Power), Alabama Power Company (Alabama Power), and Mississippi Power Company tend to their respective states.[29] Duke Energy Corporation's subsidiaries Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Duke Energy Florida, LLC (collectively, Duke) provide service throughout most of North Carolina and parts of South Carolina and Florida.[30] The remainder of South Carolina largely receives power from either Dominion Energy South Carolina (Dominion) or the South Carolina Public Service Authority (Santee Cooper). NextEra Energy is the parent company of Florida Power & Light (FPL), the largest utility in Florida. In Tennessee and parts of six surrounding states, TVA provides wholesale power and transmission services, while cooperative and municipal utilities known as Local Power Companies provide distribution services to end users.

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[29] The generation and transmission assets of Southern Company's vertically integrated utility subsidiaries are operated as a single, integrated electric system. *See* Southern Company, Annual Report (Form 10-K), at I-2 (Feb. 16, 2022), 0000092122-22-000003 (d18rn0p25nwr6d.cloudfront.net).

[30] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC jointly dispatch their generation resources subject to a Joint Dispatch Agreement.

State regulatory authorities oversee the investor-owned utilities and in some cases assess and approve the utilities' broad generation—and occasionally transmission—investment plans through an Integrated Resource Plan (IRP) or similar process. The IRP processes throughout the region differ substantially in their scope, frequency, and opportunities for public engagement. For instance, the North Carolina, South Carolina, and Georgia state commissions hold public proceedings to assess the investor-owned utilities' IRPs, although North Carolina's occurs every two years, while Georgia's occur every three. In Alabama, neither the state commission nor stakeholders formally assess Alabama Power's IRP, but the state commission reviews each of the utility's generation and transmission investments on a case-by-case basis. In Tennessee, TVA's Board of Directors approves TVA's IRP with no state review or approval.

Regarding procurement, the utilities in the Southeast do not participate in any organized wholesale energy market[31] and instead obtain their power supply from their own generation resources, through long-term arrangements with third-party generation, or on the bilateral spot market.[32] There is minimal coordination among the utilities, as exemplified by their perfunctory participation in the regional transmission planning processes. Insular planning persists even though each utility has encountered significant transmission needs caused by changes to the resource mix and demand. At the heart of the issue lies the utilities' disinterest in using the current planning framework to address these trends and explore appropriate solutions.

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31 As mentioned above, the utilities' authorization to create SEEM is pending before the D.C. Circuit. *See supra* note 21.

32 However, the investor-owned utilities' unregulated affiliates—such as Duke Energy Renewables and Southern Power—have robust portfolios of renewable resources operating in RTO/ISO markets.

A. Transmission Planning in the Southeast

1. SERTP

Most of the region's utilities participate in SERTP. In addition to Southern Company, Duke, and TVA, participants include Associated Electric Cooperative, Inc., Dalton Utilities, Georgia Transmission Corporation (GTC), Louisville Gas & Electric Company and Kentucky Utilities Company (LG&E/KU), Municipal Electric Authority of Georgia (MEAG), and PowerSouth Energy Cooperative. While SERTP sponsors often tout the combined line-miles of the transmission network SERTP covers,[33] not one of those miles originated from regional collaboration in SERTP. In reality, SERTP presents "a forum merely to confirm the simultaneous feasibility of transmission facilities contained in [the utilities'] local transmission plans," an outcome the Commission expressly sought to avoid in Order No. 1000.[34] As required by that final rule, SERTP culminates in a regional transmission plan, but it does so by simply compiling the local transmission plans of each member utility and presenting the compilation as a "regional plan." In the process, it provides minimal opportunity for stakeholders to influence outcomes and performs the bare minimum of the utilities' responsibilities to assess regional alternatives, consider Public Policy Requirements, and conduct economic studies. As currently constituted, SERTP is woefully insufficient—by design—to address the transmission needs emerging in the states. SERTP's status as one of the largest transmission planning regions in the country only amplifies the significance of that structural deficiency.[35]

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[33] SERTP Sponsors Oct. 12, 2021 Comments at 10 (SERTP Sponsors ANOPR Comments).

[34] Order No. 1000 at P 147.

[35] The eight balancing authority areas in the SERTP region "serve combined peak loads totaling more than 121,404 MWs." *2021 Regional Transmission Plan & Input Assumptions Overview*, SERTP, at 6 (2021), [2021-Regional-Transmission-Plan-and-Input-Assumptions-Non-CEII.pdf (southeasternrtp.com)](2021-Regional-Transmission-Plan-and-Input-Assumptions-Non-CEII.pdf).

Each year, SERTP rolls up the local transmission plans of its member utilities in order to create a regional powerflow model. This powerflow model provides "representations of the existing transmission topology plus forecasted topology changes" over a "ten-year planning horizon."[36] The "independent reliability planning studies . . . start with the combined local transmission plans of participating utilities,"[37] and the results comprise the ten-year regional expansion plan. In other words, the utilities individually conduct their own local reliability planning processes and submit the final local plans for inclusion in the regional plan, which SERTP sponsors first present during the Second Quarter meeting each year. Barring minor tweaks by the utilities to their own plans during the planning cycle, the regional expansion plan is substantially complete when the local plans are compiled and first unveiled to stakeholders. During the Third Quarter meeting, the SERTP sponsors reveal the results of the Economic Planning Studies, which have no bearing on the regional expansion plan. The process concludes during the Fourth Quarter meeting, when the SERTP sponsors present the largely unchanged regional expansion plan. There is no formal adoption process—largely because no regional projects that would require multi-utility concurrence ever emerge—so the utilities simply proceed to carry out their individual plans. As such, neither stakeholders nor state regulators has any actual influence over the ultimate facility selection in SERTP.[38]

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36 *Id*. at 14.

37 Joseph H. Eto & Giulia Gallo, *Regional Transmission Planning: A Review of Practices Following FERC Order Nos. 890 and 1000*, Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory, at 13 (Nov. 2017), Regional Transmission Planning: A Review of Practices Following FERC Order Nos. 890 and 1000 | Electricity Markets and Policy Group (lbl.gov).

38 *See* Joseph H. Eto, *Planning Electric Transmission Lines: A Review of Recent Regional Transmission Plans*, Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory, at 7 (Sept. 2016), Planning Electric Transmission Lines--A Review of Recent Regional Transmission Plans.pdf (energy.gov) (Berkeley Lab Transmission Planning).

This theme of limited stakeholder influence runs throughout the entire SERTP process. Stakeholders may participate in the process through the Regional Planning Stakeholder Group (RPSG).[39] The RPSG exists primarily to select and provide feedback on the Economic Planning Studies to be conducted by the SERTP sponsors, up to a maximum of five voluntary studies.[40] These Economic Planning Studies evaluate hypothetical bulk power flows that are not resource-specific and need not have any relevance or connection to the regional expansion plan. Because the Economic Planning Studies do not affect the regional plan, the RPSG's role is limited by design, and this overall impotence has borne out in lackluster membership. For 2022, the RPSG consists of two members: a representative from Santee Cooper in the Power Marketers sector and a representative from the Southern Renewable Energy Association in the Generation Owners/Developers sector.[41] There are no members in the Transmission Owners/Operators, Transmission Service Customers, Cooperative Utilities, Municipal Utilities, or ISO/RTOs sectors.[42] The RPSG has had only two members in three of the last five years, and three and four members in the other two years.[43] Given minimal opportunities to provide meaningful input, certain stakeholders—including some of the Southeast Public Interest Groups—have made the calculation that RPSG participation is not worth their time.

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39 Alabama Power, Open Access Transmission Tariff, Att. K, The Southeastern Regional Transmission Planning Process, § 1.2.1 (5.0.0) (Southern Company Transmission Planning Tariff).

40 *See id.*

41 *See 2022 SERTP RPSG Sector Members*, SERTP (2022), 2022-RPSG-Sector-Members.pdf (southeasternrtp.com).

42 *See id.*

43 *See id; 2021 SERTP RPSG Sector Members*, SERTP (2021), 2021-RPSG-Sector-Members.pdf (southeasternrtp.com); *2020 SERTP RPSG Sector Members*, SERTP (2020), 2020-RPSG-Sector-Members.pdf (southeasternrtp.com); *2019 SERTP RPSG Sector Members*, SERTP (2019), 2019 RPSG Sector Members.pdf (southeasternrtp.com); *2018 SERTP RPSG Sector Members*, SERTP (2018), 2018-RPSG-Sector-Representatives.pdf (southeasternrtp.com).

Similarly, stakeholders have had no success in proposing studies for transmission needs driven by Public Policy Requirements. Although SERTP includes a process whereby stakeholders may submit such requests once a year, the SERTP sponsors have rejected every request to study Public Policy Requirements-driven transmission needs. In 2015, 2016, and 2017, certain non-utility stakeholders submitted requests to evaluate transmission needs driven by various state and federal requirements, including North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard and EPA requirements applicable to coal-fired generation.[44] Regarding the latter, stakeholders asserted in 2017 that they

> internalize costs at coal-fired generation resources. The transmission need that would result from these decisions should be identified and evaluated to ensure that the 2017 SERTP transmission expansion plan incorporates the most cost-effective local and regional solutions.
>
> Without transparently addressing the impact of these PPRs as they may relate to the potential retirement(s) and/or replacement(s) of generation resources, such as a large coal-fired unit(s), it cannot be said that the SERTP process is cost-effectively and efficiently planning for situation(s) and/or system condition(s) for which a solution(s) is needed may arise.[45]

The SERTP sponsors denied the request, claiming that the Public Policy Requirements "have been factored into the resource assumptions for the 2017 transmission planning cycle" and do not "indicate that there is a transmission need."[46] Recent experience has contradicted this claim, as utilities across the region have struggled to replace coal-fired generation due to insufficient

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44 *See 2017 Planning Cycle, Transmission Needs Driven By Public Policy Requirements*, SERTP (2017), [2017 Planning Cycle Transmission Needs Driven by Public Policy Requirements.pdf (southeasternrtp.com)](southeasternrtp.com) (2017 Public Policy Requirements); *2016 Planning Cycle, Transmission Needs Driven By Public Policy Requirements*, SERTP (2016), [2016 SERTP PPR Results.pdf (southeasternrtp.com)](southeasternrtp.com) (2016 Public Policy Requirements); *2015 Planning Cycle, Transmission Needs Driven By Public Policy Requirements*, SERTP (2015), [2015 SERTP PPR Results.pdf (southeasternrtp.com)](southeasternrtp.com) (2015 Public Policy Requirements).

45 2017 Public Policy Requirements at 2.

46 *Id*. at 2-3.

transmission capacity.[47] The proactive planning proposed by stakeholders at SERTP for three straight years could have averted this issue.

The SERTP sponsors have also rejected Public Policy Requirements study requests (1) on the assumption that the LSE in question would have already considered them, or (2) on the basis that there can be no transmission need until resource decisions have been made at the state level.[48] Again, experience in the states shows that this is not always the case, as utilities are routinely making resource decisions *based* on available transmission capacity.[49] Unsurprisingly, in light of the SERTP sponsors' consistent and unfounded refusal to study Public Policy Requirements, no stakeholder submitted a Public Policy Requirement study request between 2017 and 2021.[50] When a stakeholder made a verbal request to study the effects of North Carolina's H.B. 951 earlier this year, the SERTP sponsors summarily rejected it. Surely, the Commission could not have intended the utilities to carry out this important function with such casual indifference.[51]

In theory, the other opportunity for stakeholder involvement consists of proposing alternatives to transmission facilities identified in the regional plan. However, this task is

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[47] *See infra* section II.B.

[48] *See* 2017 Public Policy Requirements at 1.

[49] *See infra* section II.B.

[50] *See 2021 Planning Cycle, Transmission Needs Driven By Public Policy Requirements*, SERTP (2021), 2021-SERTP-PPR-Results.pdf (southeasternrtp.com); *2019 Planning Cycle, Transmission Needs Driven By Public Policy Requirements*, SERTP (2019), 2019 SERTP PPR Results.pdf (southeasternrtp.com); *2018 Planning Cycle, Transmission Needs Driven By Public Policy Requirements*, SERTP (2018), 2018-SERTP-PPR-Results.pdf (southeasternrtp.com). The SERTP website does not contain a document related to transmission needs driven by Public Policy Requirements for the 2020 Planning Cycle.

[51] "When conducting transmission planning to serve native load customers, a prudent transmission provider will not only plan to maintain reliability and consider whether transmission upgrades or other investments can reduce the overall costs of serving native load, but also consider how to plan for transmission needs driven by Public Policy Requirements. Therefore, we conclude that, to avoid acting in an unduly discriminatory manner against transmission customers that serve other loads, a public utility transmission provider must consider these same transmission needs for all of its transmission customers. Moreover, given that consideration of transmission needs driven by Public Policy Requirements could facilitate the more efficient and cost-effective achievement of those requirements, we conclude the reforms adopted herein are necessary to ensure that rates for Commission-jurisdictional services are just and reasonable." Order No. 1000 at P 83.

complicated by SERTP's information sharing policies. In order to access the regional powerflow models, interested stakeholders must undergo a background check and receive pre-clearance for Critical Energy Infrastructure Information (CEII).[52] They must also pay a $180 application fee, a $100 background investigation fee, and execute a restrictive non-disclosure agreement.[53] Once completed, this process only facilitates access to the materials necessary to replicate the powerflow studies, assuming the requester has the necessary software and expertise. Missing from the materials is any cost estimate for the identified transmission facilities[54] or a specific explanation of the transmission need giving rise to them. This information deficit makes proposing alternatives to the SERTP sponsors, including viable Non-Transmission Alternatives, extremely difficult. Further, even if a stakeholder could develop and suggest an alternative with the limited information made available, their only recourse is to confer directly with the utility proposing the new facility and attempt to persuade the utility to pursue the alternative. The SERTP sponsors do not conduct a public study of these suggested alternatives within the broader context of the local or regional transmission plans.

This fundamentally flawed planning process that the SERTP sponsors implemented in response to Order No. 1000 has yielded correspondingly meager results. Since its inception, SERTP has *never* resulted in a regional facility displacing a local facility and being included in the regional transmission plan for cost allocation.[55] This owes primarily to the narrow evaluation

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52 *See* Secure Area, SERTP, SRTP - Secure Area | Secure Area | Southeastern Regional Tranmission Planning (southeasternrtp.com) (last visited Aug. 9, 2022).

53 *See id*.

54 *See Georgia Power Company*, Docket No. 44160, Tr. 246:11-17 (Ga. Pub. Serv. Comm'n June 21, 2022) ("Q. Are you aware that the SERTP regional transmission plan does not currently provide estimates of the cost of transmission projects proposed and ultimately included in the plan? A. (Witness Robinson) . . . Subject to check, those costs are not included.").

55 Additionally, no independent transmission developer has ever pre-qualified for a SERTP planning cycle. *See 2022 Planning Cycle, Pre-Qualified Transmission Developers*, SERTP (2021), 2021-October-Pre-qualified-Transmission-Developers-for-the-Upcoming-2022-Planning-Cycle.pdf (southeasternrtp.com); *2021 Planning Cycle,*

criteria applied to such regional alternatives. In each SERTP transmission planning cycle, the SERTP sponsors will "assess[] 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."[56] In practice, this involves consideration of a handful of regional projects each year. First, the SERTP sponsors consider whether the regional project would address identified transmission needs and could therefore displace projects currently identified in the regional plan. If not, the inquiry ends there, as the proposed alternative cannot be "a more efficient or cost effective project to address transmission needs" if there is no underlying local upgrade.[57] Of the 47 regional projects considered since 2014, only nine were found to address a transmission need identified in the regional plan and moved to the second step of the analysis.[58] *Not one* has been found to address a transmission need since 2017.

Pre-Qualified Transmission Developers, SERTP (2020), 2020-October-Pre-qualified-Transmission-Developers-for-the-Upcoming-2021-Planning-Cycle.pdf (southeasternrtp.com); *2020 Planning Cycle, Pre-Qualified Transmission Developers*, SERTP (2019), 2019-October-Pre-qualified-Transmission-Developers-for-the-Upcoming-2020-Planning-Cycle.pdf (southeasternrtp.com); *2019 Planning Cycle, Pre-Qualified Transmission Developers*, SERTP (2018), 2018-October-Pre-qualified-Transmission-Developers-for-the-Upcoming-2019-Planning-Cycle.pdf (southeasternrtp.com); *2018 Planning Cycle, Pre-Qualified Transmission Developers*, SERTP (2017), 2017-October-Pre-qualified-Transmission-Developers-for-the-Upcoming-2018-Planning-Cycle.pdf (southeasternrtp.com); *2017 Planning Cycle, Pre-Qualified Transmission Developers*, SERTP (2016), 2016 October - Pre-qualified Transmission Developers for the Upcoming 2017 Planning Cycle.pdf (southeasternrtp.com); *2016 Planning Cycle, Pre-Qualified Transmission Developers*, SERTP (2015), 2015October-PrequalifiedTransmissionDevelopersfortheUpcoming2016PlanningCycle.pdf (southeasternrtp.com); *2015 Planning Cycle, Pre-Qualified Transmission Developers*, SERTP (2014), 2014-11-01_SERTPPre-QualifiedTransmissionDevelopersList.pdf (southeasternrtp.com).

56 Southern Company Transmission Planning Tariff at § 11.1.1.

57 *E.g.*, *2014 Regional Transmission Planning Analyses*, SERTP, at 10 (2014), SERTP Regional Transmission Planning Analyses Summary.pdf (southeasternrtp.com) (2014 Analyses).

58 *See 2021 Regional Transmission Planning Analyses*, SERTP (2021), 2021-SERTP-Regional-Transmission-Planning-Analyses-Summary-Final.pdf (southeasternrtp.com); *2020 Regional Transmission Planning Analyses*, SERTP (2020), 2020-SERTP-Regional-Transmission-Planning-Analyses-Summary-FINAL.pdf (southeasternrtp.com); *2019 Regional Transmission Planning Analyses*, SERTP (2019), 2019-SERTP-Regional-Transmission-Planning-Analyses-Summary.pdf (southeasternrtp.com); *2018 Regional Transmission Planning Analyses*, SERTP (2018), 2018-SERTP-Regional-Transmission-Planning-Analyses-Summary.pdf (southeasternrtp.com); *2017 Regional Transmission Planning Analyses*, SERTP (2017), 2017-Regional-Transmission-Planning-Analyses-Summary.pdf (southeasternrtp.com) (2017 Analyses); *2016 Regional Transmission Planning Analyses*, SERTP (2016), 2016 SERTP Regional Transmission Planning Analyses Summary.pdf

When the rare regional project progresses to the second stage of the analysis, the SERTP sponsors compare its costs to the identified project(s) it would displace. In all nine cases, the larger regional project's costs far exceeded the small local project's costs and none of the regional projects has been selected.[59] The entirety of a representative analysis appears as follows:

> The planning level estimate for the South Hall – Oconee 500 kV transmission line is approximately **$227,000,000**. The total cost of all the potentially displaced transmission projects within the SERTP region is approximately **$26,000,000** and therefore, this transmission project alternative is not currently a more efficient or cost-effective project to address transmission needs in the SERTP region. A calculation of real power transmission loss impacts was not performed as it would be unlikely to measurably change the results of the 2017 regional assessment.[60]

This identical analysis, with the project names and costs swapped out, accompanies each of the nine rejected regional transmission projects.[61] This cut-and-paste cost comparison is the extent of the "consideration" given to regional facilities.

The jurisdictional utilities' tariffs establish this hollow exercise. Per Southern Company's tariff, a "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."[62] The "benefit" in this calculation is "quantified by the Beneficiaries' total cost savings" associated with displaced transmission projects and any alternative projects not identified in the regional plans whose needs the regional project would address.[63] The "cost" is the transmission

(southeasternrtp.com) (2016 Analyses); *2015 Regional Transmission Planning Analyses*, SERTP (2015) (2015 Analyses), 2015 Regional Transmission Planning Analyses Summary.pdf (southeasternrtp.com); 2014 Analyses.

59 *See* 2017 Analyses at 19; 2016 Analyses at 11, 15, 17, 19; 2015 Planning Analyses at 11; 2014 Analyses at 12, 18.

60 2017 Analyses at 19.

61 *See supra* note 59.

62 Southern Company Transmission Planning Tariff at § 17.2.1.

63 *Id*. § 17.2.1(1).

cost of the regional project and any additional projects needed to implement it.[64] If the benefit-to-cost calculation of these values equals or exceeds 1, changes in real power transmission losses will be considered as well.[65] Rather than a comprehensive benefits analysis, this process amounts to a straight cost comparison of the regional project versus the displaced local projects, with reductions in losses only potentially warranting consideration. By that measure, a large regional project's costs will always exceed its "benefits," i.e., the cost of the much smaller, immediate local project(s) it displaces. Further, SERTP's ten-year planning horizon fails to account for the benefits regional projects could provide over a much longer duration, which could dwarf the costs of many immediate-need local projects. Without considering a more comprehensive suite of benefits provided by the regional project over a longer period, this rubric will never result in selection of a regional project for cost allocation.

In a vacuum, SERTP's historical failure to produce any such regional transmission facilities is not necessarily a problem if the utilities' existing transmission systems can ably connect all generation to all load. It becomes problematic when utilities across the region have identified nearly identical, unaddressed transmission needs caused by the same resource trends. In the Southeast, coal retirements have become a particular flashpoint. In some cases, utilities have affirmatively sought to replace the retiring units with offsite renewable generation.[66] In others, utilities have sought to replace the coal units with new onsite gas units and have parried stakeholder protests by claiming that transmission deficits prevent them from installing renewable replacements.[67] In all cases, faced with actual transmission needs, utilities must seek the most

[64] *Id*. § 17.2.1(2).

[65] *Id*. § 17.2.3.

[66] *See infra* sections II.B.1-2.

[67] *See infra* sections II.B.3-5.

efficient and cost-effective manner of meeting them, particularly when all other costs of providing electricity costs are rapidly increasing. They can realize significant cost efficiencies through optimized regional transmission expansion,[68] but due to the superficial planning criteria they have implemented in SERTP, the widespread benefits of regional transmission facilities are simply not considered. Instead, SERTP's planning process ensures that utilities will select piecemeal local solutions to address increasing transmission needs, resulting in larger aggregate costs covered by captive ratepayers.

2. SCRTP

In South Carolina, Dominion and Santee Cooper conduct "regional" transmission planning through SCRTP. SCRTP is even less suited to assess regional solutions than SERTP. First and foremost, it operates on a much smaller scale, involving two utilities as opposed to twelve, meaning that the universe of regional transmission facilities that could create measurable efficiencies amongst the participants is severely limited. Missing from the process entirely are the two transmission systems with the largest actual interchange with Dominion and Santee Cooper: Southern Company and Duke. By planning on such a confined scale, Dominion and Santee Cooper necessarily overlook significant transmission optimization benefits they could realize by planning on the regional scale of SERTP. Second, SCRTP's regional planning process takes place over a two-year planning cycle,[69] which produces a regional plan that is less up-to-date and dynamic than SERTP's. Finally, SCRTP represents both the local and regional planning processes for its

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[68] *See* Johannes Pfeifenberger et al., *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, The Brattle Group, at iii-iv (Oct. 2021), [Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs (brattle.com)] (Brattle Report).

[69] Dominion, Open Access Transmission Tariff, Att. K, Transmission Planning Process, § III.E.2 (0.0.0) (Dominion Transmission Planning Tariff).

utilities.[70] Although certain utilities like Southern Company use SERTP for both their local and regional planning processes, most of the SERTP utilities have distinct local processes from which they derive their inputs to the regional plan.

In most other respects, SCRTP is identical to SERTP. It has similar stakeholder sectors and participation processes.[71] Like SERTP, state regulators and stakeholders have no influence over the ultimate facility selection.[72] It also considers regional alternatives to local transmission projects in a similar manner. Proposed regional transmission projects "must yield a regional benefit to cost ratio equal to or greater than 1.25 and must not have an unmitigated adverse impact on reliability."[73] The "benefit" is based on the total regional benefits associated with cancelled or postponed projects, the cost reductions of other existing projects, the alternative projects that would otherwise be required, and the reduction of real power losses.[74] The "costs" are calculated based on the cost of the regional project, the costs of any additional projects, and the increase of real power losses.[75] Although marginally more expansive than SERTP's benefits evaluation, this process effectively amounts to a straight cost comparison, which, like SERTP, has not resulted in regional transmission projects selected for regional cost allocation. Accordingly, many of the fundamental changes needed to reform SERTP apply with equal force to SCRTP.

3. <u>FRCC</u>

Similar to SERTP and SCRTP, though falling somewhere between the two in scope, the FRCC transmission planning process discourages stakeholder participation and has failed to yield

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70 *Id*. § I.

71 *See id*. § III.B.

72 Berkeley Lab Transmission Planning at 7.

73 Dominion Transmission Planning Tariff at § VII.G.1.

74 *Id*. § VII.G.1.

75 *Id*. § VII.G.2.

regional transmission investment. FRCC conducts two parallel transmission planning processes: (1) an Annual Transmission Planning Process (ATPP), which FRCC defines as "the result of coordinating each of the FRCC members' local plans to develop the overall Regional Plan,"[76] and (2) a Biennial Transmission Planning Process (BTPP), held in odd-numbered years, which allows FRCC members to propose cost-effective or efficient transmission solutions (CEERTS) and studies of transmission needs driven by Public Policy Requirements.[77] The ATPP begins when Florida's utilities submit their Ten Year Site Plans (TYSP) on April 1 of each year.[78] The TYSP is essentially a slimmed-down version of an IRP, in which each utility provides its load forecast, existing and planned generation, and a list of any planned transmission over the next ten years.[79] These planned transmission projects form the basis for the ATPP. Because the TYSP process begins anew each year, a utility's TYSP can change drastically from one year to the next.

Like SERTP and SCRTP, FRCC utilizes a simplistic cost-benefit calculation to determine whether CEERTS projects can be considered for inclusion in the BTPP. To merit consideration, the CEERTS project's costs must not exceed the sum of the costs of the local projects it would replace, with resulting changes to line losses considered as well.[80] Any CEERTS or Public Policy Requirements-driven projects that result in a benefits-to-cost ratio greater than 1.0 can be presented for potential approval to the FRCC Board of Directors,[81] which is dominated by the incumbent utilities. This rarely occurs, however. In the last three cycles of the BTPP—starting in 2017—no

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76 *FRCC Regional Transmission Planning Process FRCC-MS-PL-018*, FRCC, at 5 (Jul. 1, 2022), https://www.frcc.com/order1000/Shared%20Documents/Procedures-Public/FRCC/FRCC-MS-PL-018_FRCC_Regional_Transmission_Planning_Process.pdf.

77 *See id*.

78 *See id*. at 7.

79 *See id*. at 15.

80 *See id*. at 22-29.

81 *See id*. at 23.

potential CEERTS projects have been submitted.[82] Similarly, since at least 2019,[83] there have been no requests for studies of transmission needs driven by Public Policy Requirements.[84]

The development of the ATPP and BTPP by FRCC members takes place largely behind closed doors. After FRCC compiles the proposed transmission facilities from utility TYSPs and lists them in its annual "Load and Resources" report to the Florida Public Service Commission, the process becomes significantly more opaque. Information such as who represents the members on the FRCC standing committees and when meetings are held is not available to the public. All pertinent information and documents are housed on a password-protected website that is available only to members. Given the lack of meaningful stakeholder influence and ineffective consideration of both regional facilities and transmission needs driven by Public Policy Requirements, FRCC's failure to yield viable regional projects is not surprising. Nevertheless, significant transmission needs continue to surface in Florida. Recently, FPL completed a 176-mile transmission line, but limited the line's voltage to 161 kV in order to avoid meaningful regulatory

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[82] *FRCC 2021-2022 BTPP Potential CEERTS Project Submittals 2017/2018*, FRCC (Jul. 13, 2021), https://www.frcc.com/order1000/Lists/Announcements/DispForm.aspx?ID=43&ContentTypeId=0x01040068DF21F4B5757A4A9484377CD0C16F8A; *FRCC 2019-2020 BTPP Potential CEERTS Project Submissions*, FRCC (June 11, 2019), https://www.frcc.com/order1000/Lists/Announcements/DispForm.aspx?ID=32&ContentTypeId=0x01040068DF21F4B5757A4A9484377CD0C16F8A; *2017 - 2018 FRCC Regional Projects Subcommittee Proactive Planning Result Notice*, FRCC (Apr. 5, 2017), https://www.frcc.com/order1000/Lists/Announcements/DispForm.aspx?ID=9&ContentTypeId=0x01040068DF21F4B5757A4A9484377CD0C16F8A.

[83] A record of the 2017/2018 BTPP Public Policy Requirements submissions, if any, is not available on the FRCC website.

[84] *Results of FRCC 2021-2022 BTPP Public Policy Planning Submissions*, FRCC (Feb. 8, 2021), https://www.frcc.com/order1000/Lists/Announcements/DispForm.aspx?ID=38&ContentTypeId=0x01040068DF21F4B5757A4A9484377CD0C16F8A; *Results of FRCC 2019-2020 BTPP Public Policy Planning Submissions*, FRCC (Feb. 8, 2019), https://www.frcc.com/order1000/Lists/Announcements/DispForm.aspx?ID=28&ContentTypeId=0x01040068DF21F4B5757A4A9484377CD0C16F8A.

oversight.[85] As a result, FPL's ratepayers must bear the costs of a long line with limited transfer capability, as well as any other subsequent local facilities needed to pick up the slack, whereas a higher-voltage regional facility could have provided demonstrable benefits to ratepayers across the state. Like SERTP and SCRTP, FRCC's regional planning process ensures such efficient alternatives do not see the light of day.

B. Developments in the States

Throughout the Southeast, states have experienced significant upheaval in the generation resource mix.[86] Featured below are snapshots of various states in the region and their individual encounters with these changes. In their own words, the states' prominent utilities describe the significant transmission needs they face, which are overwhelmingly driven by these generation shifts. Yet none of these utilities identifies its regional planning process as a suitable venue to addressing the shared needs.

1. Georgia

Georgia Power recently completed its triennial IRP process, as the Georgia Public Service Commission (Georgia PSC) approved Georgia Power's IRP on July 21, 2022.[87] Throughout the proceeding, the issue of coal retirements in the northern part of the state and the utility's failure to proactively plan for them received substantial attention. The terrain of north Georgia—where the retiring coal plants and corresponding load centers are located—is not well suited to large-scale solar resources, which Georgia Power considers an ideal resource to replace the retiring coal units.

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85 *See* Ivan Penn, "How a Florida Power Project Flew Under the Regulatory Radar," N.Y. Times, (May 31, 2022), [How a Florida Power Project Flew Under the Regulatory Radar - The New York Times (nytimes.com)].

86 *See supra* note 2.

87 *See Georgia Power Company*, Docket No. 44160 (Ga. Pub. Serv. Comm'n July 21, 2022) (GPC IRP Order).

The southern part of the state has significantly more potential for solar capacity, but there is insufficient transmission capacity to transport south Georgia solar to north Georgia load.

Georgia Power attempted to address this issue in the IRP through its proposed North Georgia Reliability & Resilience Action Plan, "a multi-faceted plan to address future reliability needs associated with the retirement of Plant Bowen."[88] Because north Georgia "relies on the transmission system to import power from south Georgia,"[89] generation retirements in the north create a need for significant transmission expansion to avoid outages:

> The current projected transmission and generation infrastructure cannot sufficiently support reliable electric service to north Georgia following the retirement of Plant Bowen Units 1-4. However, the combination of renewable generation expansion, low load growth, forecasted low gas prices, and substantial environmental pressures will continue to place a significant burden on coal unit economics, including Plant Bowen.[90]

This "significant gap between generation and load forecasted in north Georgia" will (1) "be further increased by future coal retirements" and (2) "require the transmission system to transport large amounts of energy from south to north Georgia and place additional strain on the existing transmission system."[91] To overcome these issues, Georgia Power proposed an action plan that included: (1) controls on certain coal units to allow continued operation; (2) a request for proposals (RFP) for solar facilities sited in north Georgia, which is unlikely to succeed given the area's physical constraints; (3) a "strategic portfolio of projects to address the long-term transmission

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88 *See Georgia Power Company*, Docket No. 44160, Georgia Power, 2022 Integrated Resource Plan, Main Document, at 12-87 (Ga. Pub. Serv. Comm'n Jan. 31, 2022).

89 *Id*.

90 *Id*.

91 *Id*. at 12-88

planning operation needs" of the area; and (4) a consolidated expansion plan for the area's generation needs.[92]

Beyond the quixotic attempt to site solar resources in the unsuitable terrain of north Georgia, attention shifted to transmission planning. Concern over the lack of adequate transmission capacity on Georgia Power's system was also driven by its parallel plan to integrate 6,000 MW of new renewable energy by 2035.[93] For these transmission needs as well as the North Georgia Reliability & Resilience Plan, Georgia Power committed only to conducting planning activities among the Integrated Transmission System (ITS) participants.[94] The ITS is comprised of the aggregate of transmission facilities in the state owned by Georgia Power, GTC, MEAG, and Dalton.[95] It is jointly planned, and its expansion is funded by the ITS members.[96] Although the ITS joint planning process represents the first step for any transmission expansion in the state, it is not open to the public and features no stakeholder involvement beyond the ITS members.[97] Georgia Power officially conducts its Order No. 890 local transmission planning process through SERTP (along with Southern Company's other affiliates),[98] but practically speaking, local transmission planning in Georgia occurs on the ITS level. As such, the transmission portion of the North Georgia Reliability & Resilience Plan would depend entirely upon the ITS coordination process.

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92 *Id*.

93 *Id*. at 11-72.

94 *Id*. at 12-88.

95 *See, e.g.*, Georgia Power, Dalton ITS Agreement, § 1.04 (0.0.0).

96 *See id*. at art. III.

97 *See Georgia Power Company*, Docket No. 44160, Georgia Power, 2022 Integrated Resources Plan, Vol. 3 at 12-14 (Ga. Pub. Serv. Comm'n Jan. 31, 2022).

98 Southern Company Transmission Planning Tariff at preamble (Local Transmission Planning).

Throughout the IRP proceeding, the Georgia PSC Public Interest Advocacy Staff (Public Staff) questioned the usefulness of this closed-door process, especially given the scale of transmission investment required to facilitate both the North Georgia Reliability & Resilience Plan and the planned integration of 6,000 MW of renewable resources:

> I recommend that the [Georgia PSC] develop a collaborative transmission planning process which has [Georgia PSC] oversight, and includes all of the ITS Participants, the Staff and the Company to wrestle with this issue and come up with a comprehensive plan that considers the regional needs for a reliable, resilient and economic grid to support the Company's transition to a clean energy future.[99]

Looking back, the Public Staff asked how Georgia Power arrived in this position, scrambling to address coal retirements it should have anticipated long ago:

> Not already having a transmission expansion plan that is designed to facilitate new generation to feed North Georgia is a serious problem that requires rapid decisions. The failure of the Company to have a long-term strategic plan in place for the loss of Bowen generation is a flaw in [Georgia Power]'s planning process and something that should have been addressed in a [Georgia PSC]-directed, transparent process long before the 2022 Integrated Resource Plan. Many organizations conduct long-term planning assessments beyond the ten-year horizon, and [Georgia Power] and [the Georgia PSC] would benefit from such a collaborative long-term transmission planning process which includes Staff, consultants, and ITS Participants.[100]

Of course, stakeholders in SERTP had asked the SERTP sponsors to study certain Public Policy Requirements that would result in coal retirements every year from 2015 to 2017.[101] Yet, as noted

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[99] *See Georgia Power Company*, Docket No. 44160, Public Staff, Direct Testimony and Exhibits of John W. Chiles, at 9-10 (Ga. Pub. Serv. Comm'n May 6, 2022) (Chiles Test.).

[100] *Id*. at 11-12.

[101] 2017 Public Policy Requirements at 2-3; 2016 Public Policy Requirements 2-3; 2015 Public Policy Requirements at 2-3.

above, the SERTP sponsors rejected these requests on the basis that they did not demonstrate a transmission need.[102]

Part of the problem, as identified by the Public Staff, is the truncated transmission planning horizon used by Georgia Power in both the ITS and SERTP. Seemingly echoing this Commission, Public Staff asserted that "[t]he significant changes in [Georgia Power]'s generation mix and retirement/siting strategy requires a long-term view and will likely require much analysis."[103] Georgia Power representatives acknowledged during the hearing that SERTP's ten-year planning horizon limits the company's ability to proactively plan transmission expansion.[104] When asked how, then, Georgia Power intended to plan for the North Georgia Reliability & Resilience Plan and 6,000 MW of renewable resources by 2035, the company's representative identified this NOPR proceeding and the Commission's proposal to expand the planning horizon to 20 years.[105] SERTP's existing planning constraints—in addition to the SERTP sponsors' reluctance to conduct Public Policy Requirements studies—directly limited its ability to facilitate long-term proactive planning.

Between the North Georgia Reliability & Resilience Plan and Georgia Power's 6,000 MW renewable energy goal, the need for expanded transmission infrastructure in Georgia is apparent. Unfortunately, each of the systems in place for planning those enhancements is wholly insufficient to do so in an efficient, least-cost manner. Put another way, there is a fundamental disconnect

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102 *Id*.

103 Chiles Test. at 13.

104 *See Georgia Power Company*, Docket No. 44160, Tr. 280:11-281:9 (Ga. Pub. Serv. Comm'n June 21, 2022) ("Q. Does SERTP have a planning horizon further than ten years out? A. (Witness Robinson) Not at the moment.").

105 *Id*. ("Q. So how are you going to be able to take a longer than ten-year planning horizon with the North Georgia reliability projects and insert them into SERTP if SERTP can't even accept them? A. (Witness Robinson) Well, I think there's ways you can talk beyond the horizon. I think the current NOPR that's out there that FERC let a couple weeks ago, it proposes to address that horizon issue. Q. How so? A. (Witness Robinson) They propose a 20-year horizon.").

between the three forums relevant to transmission planning in the state, contributing to Georgia Power's transmission planning paralysis. The ITS operates without regulatory oversight or stakeholder input, insulating its utilities from any outside influence, yet forms the basis for Georgia Power's local transmission plans. The Georgia PSC reviews Georgia Power's IRP, but only does so every three years, and it is unclear—even to Georgia Power—whether the Georgia PSC must affirmatively approve the portfolio of transmission facilities contained in the ten-year transmission plan or examine the process that created it.[106] And SERTP has failed to avert the situation in which Georgia Power now finds itself, due to—among other failings—its limited planning horizon and failure to consider the resource trends driving transmission needs, even where stakeholders had previously identified those very needs.

The Georgia PSC ultimately approved Georgia Power's IRP, but directed no changes to its transmission planning process aside from a minor reporting requirement.[107] The Georgia PSC also deferred a decision on the retirement of some of the coal units that created the need for the North Georgia Reliability & Resilience Plan.[108] These units are still expected to retire and will still cause the need for additional transmission capacity, but if anything, Georgia Power earned a short reprieve and another chance to proactively plan for this eventuality. To do so, Georgia Power

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106 *Compare Georgia Power Company*, Docket No. 44160, Tr. 546:19-547:8 (Ga. Pub. Serv. Comm'n Apr. 4 21, 2022) (Q. Are you seeking approval of . . . the ten-year transmission plan in this IRP? A. (Witness Robinson) No. This is a transmission plan that we developed with the ITS participants as part of the SERTP process as well. We bring this to show our prudency as it relates to planning the system and meeting the transmission plan associated with the resource plan to make sure that we deliver the megawatts from the generation to the load. Q. So the Commission is not going to approve this ten-year transmission plan in this IRP? A. (Witness Robinson) It's part of the IRP. We're not asking for explicit approval of the transmission plan. This is a work product of the ITS that also feeds into the SERTP process on an annual basis.") *with Georgia Power Company*, Docket No. 44160, Tr. 264:1-8 (Ga. Pub. Serv. Comm'n June 21, 2022) (Q. If the IRP and stipulation are approved by the Commission, is the Commission also approving the ten-year transmission plan? A. (Witness Grubb) Yes. I believe that's one of the items in there, yes. Q. Okay. A. (Witness Robinson) That is explicitly in? A. (Witness Grubb) That is correct.").

107 *See* GPC IRP Order at 18.

108 *See id*. at 46.

must overcome a transmission deficit that spans the entire state. Neighboring states are experiencing similar needs, presenting a golden opportunity for regional coordination, but given the current processes in place, that option has not been seriously considered.

2. North Carolina

In North Carolina, the NCUC is conducting a proceeding to establish a Carbon Plan for Duke to comply with the state's carbon reduction mandate, H.B. 951. The law requires a 70 percent reduction in power sector carbon emissions from 2005 levels by 2030 and carbon neutrality by 2050.[109] It also directs the NCUC to develop a plan by December 31, 2022 that "may, at a minimum, consider power generation, transmission and distribution, grid modernization, storage, energy efficiency measures, demand-side management, and the latest technological breakthroughs to achieve the least cost path" to meet the required reductions.[110] On May 16, 2022, Duke submitted its Carbon Plan proposal, which contained four discrete portfolios, each of which "outlines near-term development and procurement needed in 2022-2024 to bring projects into service in the period of 2026-2029, along with development activities necessary for longer lead-time resources to remain on track to come online between 2030-2034."[111] Each of the four portfolios would require greater integration of wind and solar resources, electric storage, energy efficiency, demand response, as well as newer resources like nuclear small modular reactors and

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109 H.B. 951 at § 1.

110 *Id*. § 1(1).

111 *See Duke Energy Progress, LLC and Duke Energy Carolinas, LLC*, Docket No. E-100, Sub 179, Duke, Carolinas Carbon Plan, Executive Summary, at 3 (N.C. Utils. Comm'n May 16, 2022). On July 15, 2022, parties to the proceeding filed comments in response to Duke's proposed Carbon Plan, including alternative plans. Although many of these submissions made compelling cases that Duke has not presented the best way forward to meeting H.B. 951's milestones, it is a virtual certainty that the final Carbon Plan will require significant transmission upgrades, which will necessitate forward-looking transmission planning.

hydrogen solutions.[112] Three of the four portfolios involve significant offshore wind additions.[113] All four depend on the retirement of Duke's remaining coal-fired units, but "the timing of actual retirements will ultimately be driven by the ability to place in service the necessary replacement resources and access to fuel supply."[114] Importantly, given H.B. 951's directive that the Carbon Plan "achieve the least cost path" to its carbon reduction goals, cost containment will be a key consideration throughout this process.

Not surprisingly, this overhaul of the generation fleet "requires transformation of the [Duke] transmission system in the near-term and long-term to interconnect the unprecedented amounts of new supply-side resources that will be needed to retire significant amounts of coal-fired generation and achieve the carbon emission reduction targets."[115] Interconnecting the tremendous number of new renewable resources while retiring all remaining coal units necessitates "significant investment in the transmission system on an aggressive timeline."[116] These include certain "Red Zone" transmission upgrades that have arisen in many generator interconnection studies but which have uniformly caused the interconnection customers to withdraw due to their cost.[117] Further, even though Duke has proposed an expedited generator replacement process for new generation that can repurpose the interconnection facilities vacated by retiring coal facilities, new transmission will be needed if the replacement generation cannot interconnect to the same switchyard.[118] Finally, given most of the portfolios' reliance on substantial offshore wind

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112 *Id*. at 12.

113 *Id*. at 12-13.

114 *Id*. at 17.

115 *See Duke Energy Progress, LLC and Duke Energy Carolinas, LLC*, Docket No. E-100, Sub 179, Duke, Carolinas Carbon Plan, App. P, at 1 (N.C. Utils. Comm'n May 16, 2022) (Carbon Plan App. P).

116 *Id*.

117 *Id*. at 11-12.

118 *Id*. at 15.

facilities, the ultimate Carbon Plan will likely require significant new transmission facilities to unlock their output.[119]

Duke estimates that injecting between 800 and 1,600 MW from offshore wind facilities will require $1.3 to $2.39 billion in transmission upgrades.[120] Estimates for all the transmission upgrades necessary to implement Duke's proposed Carbon Plan range from $3.76 to $4.76 billion by 2035.[121] As interconnection of incremental resources and coal retirements progress, "more extensive transmission network upgrades will be required to ensure more remote interconnected resources can safely and reliably deliver energy to load centers under various stressed grid conditions."[122] This will require new greenfield transmission infrastructure as Duke seeks to achieve carbon neutrality by 2050, which could cost as much as $7 billion.[123] To the extent these facilities require new rights-of-way, development would take ten to 15 years.[124] In light of this significant investment of time and money, Duke acknowledges that "a more proactive approach to transmission planning and expansion is needed to meet the Carbon Plan objectives."[125]

The proactive transmission planning process Duke intends to utilize to implement the Carbon Plan is not SERTP, but the North Carolina Transmission Planning Collaborative (NCTPC).[126] The NCTPC is Duke's local planning process under Order No. 890 and involves North Carolina Electric Membership Corporation and ElectriCities of North Carolina, Inc., the

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119 *See id*. at 16-17.

120 *See id*. at 17.

121 *See id*. at 19-20.

122 *Id*. at 20.

123 *Id*. at 20-21.

124 *Id*. at 21.

125 *Id*. at 13.

126 *See id*. at 13-14.

organizations representing cooperative and municipal power suppliers in the state, respectively.[127] The NCTPC creates a Local Transmission Plan focused on cost-effective, reliability-focused transmission upgrades.[128] Non-LSE stakeholders generally cannot serve on the Planning Working Group that develops the local transmission plan or the Oversight/Steering Committee that approves it, but they may participate on the Transmission Advisory Group that provides input on the transmission plan, including recommendations regarding Public Policy Requirements.[129]

Throughout its Carbon Plan proposal, Duke proposes to rely upon the NCTPC to plan the transformative transmission investment needed to implement the final Carbon Plan. In fact, Duke has already presented the "Red Zone" transmission upgrades to the NCTPC for assessment.[130] Rather than proactively study and plan for these facilities, however, the NCTPC has deferred doing so until the NCUC approves a final Carbon Plan,[131] even though Duke has known about these necessary upgrades since at least 2016.[132] Duke also intends to submit a comprehensive 2022 Public Policy Requirements study request in the NCTPC for the long-term transmission facilities needed to meet the Carbon Plan targets.[133] Acknowledging the likelihood that substantial greenfield transmission facilities will be required, Duke states that the NCTPC "will help Duke

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[127] Duke Energy Carolinas, LLC, Open Access Transmission Tariff, Att. N-1, Transmission Planning Process, § 1 (10.0.0).

[128] *See id*. § 4.

[129] *See id*. § 2.4.

[130] *See* Carbon Plan App. P at 12.

[131] *See Status of NCTPC's Review of Red Zone Expansion Plan Projects and Release of Final 2021 Mid-Year Update to the NCTPC Transmission Plan*, NCTPC, at 4 (Aug. 15, 2022) ("The NCTPC will likely wait on the NCUC Order in the current open Carbon Plan Docket prior to considering approval of a Local Transmission Plan that includes the RZEP Projects.").

[132] *See TAG Meeting: Webinar Final*, North Carolina Transmission Planning Collaborative, at 40 (June 27, 2022), TAG_Meeting_Presentation_for_06-27_2022_FINAL.pdf (nctpc.org).

[133] *See* Carbon Plan App. P at 13.

Energy work through how to achieve the Carbon Plan targets of 70% CO_2 emissions reductions and carbon neutrality by 2050."[134]

Aside from a brief descriptor,[135] Duke barely mentions SERTP and evinces no intention to utilize the regional process to implement its proposed Carbon Plan, even though it will require billions of dollars in transmission investment and Duke must adhere to least-cost planning principles. Despite the clear efficiencies and cost savings to be realized from optimized regional transmission and despite the common regionwide transmission needs caused by coal retirements and renewable integration, Duke intends to avoid the only applicable regional planning forum. This omission is a damning indictment of SERTP's ability to create efficient regional solutions to inherently regional transmission needs. It is also entirely understandable, given the demonstrated apathy with which its utility sponsors—including Duke—approach coordinated planning. Without significant overhaul, it is unlikely SERTP will play any facilitative role in North Carolina's transformational generation shift.

3. Alabama

Another Southern Company affiliate, Alabama Power, serves the vast majority of customers in Alabama.[136] Unlike in Georgia and North Carolina, the Alabama Public Service Commission (Alabama PSC) does not approve Alabama Power's IRP; there is no formal assessment of the company's broad facility investment plans in which interested parties and the public may participate. As a result, the Alabama PSC and the public are limited to assessing—

[134] *Id*. at 21.

[135] *See id*. at 10.

[136] *See Electricity in Alabama*, Find Energy, Alabama Electricity in Facts, Statistics, Companies (findenergy.com) (last visited Aug. 9, 2022).

and if necessary, contesting—the utility's resource decisions and the transmission facilities that may be required to facilitate them on a case-by-case basis.

Earlier this year, Alabama Power proposed to acquire a generation facility comprised of four simple cycle combustion turbine units (Calhoun Power Facility)[137] in order to replace retiring coal capacity.[138] In seeking the Alabama PSC's approval, the company disclosed the alternatives it considered to acquiring the Calhoun Power Facility. These included a portfolio of 17 solar facilities and energy storage proposed in response to a previous renewable resource solicitation.[139] Alabama Power compared the estimated costs of this alternative, which came to $1,067/kW, to the costs of acquiring the Calhoun Power Facility, which came to $497/kW, and summarily ruled out the solar/storage alternative.[140] The company asserted that transmission costs largely accounted for the difference: "The costs to integrate these facilities into our transmission system is a significant cost, both for delivery of the power and for charging of the batteries."[141]

In calculating these comparative costs, the company made no effort to assess the potential benefits the transmission expansion would bring:

> Q. [W]ould those transmission costs in the facilities that are associated with them, would those only be associated with those projects, or would that be available for any sort of electron to use those transmission?

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137 *See Alabama Power Company*, Docket No. 33182, Alabama Power, Petition for Certificate of Convenience and Necessity, at 1-2 (Ala. Pub. Serv. Comm'n Oct. 28, 2021).

138 *See Alabama Power Company*, Docket No. 33182, Alabama Power, Petition for Certificate of Convenience and Necessity, Direct Testimony of John B. Kelley, at 6:119-9:195 (Ala. Pub. Serv. Comm'n Oct. 28, 2021).

139 *See id*. at 14:294-15:301.

140 *See id*. at 15:320-16:335.

141 *Alabama Power Company*, Docket No. 33182, Deposition of John B. Kelley, at 145:10-20 (Ala. Pub. Serv. Comm'n May 4, 2022) (Kelley Depo.). When the company allocated these transmission costs across all projects in the portfolio, a subset of 15 solar projects were competitive with the Calhoun Power Facility, at $545/kW, but still exceeded the costs associated with the acquisition. *See Alabama Power Company*, Docket No. 33182, Alabama Power, Brief, at 26 (Ala. Pub. Serv. Comm'n May 10, 2022).

> A. Well, the way we evaluated it was if these projects were undertaken, they created, they gave rise to these transmission dollars, these interconnection delivery and charging dollars. So once they were put in place, you know, we're looking at cost causation caused by the projects. Once they were put in place, our transmission system would be there to transmit and deliver those, the electricity from those projects.
>
> Q. So would there be benefits to those transmission facilities?
>
> A. Could be, maybe. I mean, it might help future projects or it might not.
>
> Q. And those benefits were not considered in this analysis, correct?
>
> A. No. We were looking at what costs did they cause in the transmission system, that's how we look at every transmission. Whenever we site a resource. . . . the transmission cost is a key consideration, especially given our ever-changing system today. We try to minimize that cost.
>
> Q. So I guess on the flipside of that, that investment creates benefits down the line when you do invest in that transmission apparatus?
>
> A. In the form of a more robust transmission system or something, conceivably, but we don't look at what additional transmission benefits it would provide.[142]

Despite acknowledging the likelihood that transmission expansion could bring benefits to the greater Alabama Power system, the company did not attempt to quantify these benefits within the context of assessing alternatives to the Calhoun Power Facility. To be sure, integration of the solar and storage facilities would have required significant additional investment, but the transmission improvements had the potential to both strengthen the utility's transmission system and facilitate the integration of future projects.

Although this Alabama PSC proceeding is distinct from SERTP, there are clear parallels between the two processes. First, Alabama Power and its parent, Southern Company, are

142 Kelley Depo. at 194:9-195:17.

prominent SERTP sponsors. Second, the company's approach to assessing transmission benefits within its own resource planning process mirrors SERTP's approach, where cost is the only relevant metric and broader, quantifiable benefits are ignored. In order to plan for resource changes that are affecting the entire region—like the coal retirements that precipitated the Calhoun Power Facility proceeding—in an efficient and cost-conscious manner, a more holistic consideration of benefits is necessary. The Calhoun Power Facility example calls into question whether the state level is the most appropriate forum for that assessment, as the SERTP sponsors have long asserted.[143] The lack of any regular, formal proceeding to consider Alabama Power's comprehensive facility investment plan is troubling and ensures that both generation and transmission are considered on a project-by-project basis. This piecemeal approach to addressing transmission needs for individual generation resource decisions will cause sticker-shock every time and an institutional aversion to broader transmission investment, especially when transmission benefits are expressly ignored. Instead, transmission system upgrades will occur primarily through the generator interconnection process, despite its many inefficiencies.

Because no forward-looking, portfolio-based consideration of Alabama Power's transmission facilities exists at the state level, SERTP provides the only alternative forum for such planning. As these comments have shown, however, SERTP's focus on local transmission facilities and emphasis on cost present the same problem and fail to adequately account for the efficiencies inherent to broad-based planning.

143 SERTP Sponsors ANOPR Comments at 4 ("[T]he Commission must avoid unlawfully intruding into resource/IRP planning reserved to the states or inappropriately seeking to force 'substantive outcomes' rather than merely regulating the transmission planning process.").

4. Tennessee

Whereas most states in the Southeast are predominantly served by one or two investor-owned utilities, the federal utility TVA dominates the energy landscape in Tennessee. TVA controls the generation and transmission facilities in the state, providing mostly wholesale service to cooperative and municipal distribution utilities in Tennessee and parts of six surrounding states. Although broadly subject to Congressional oversight, TVA is governed by its Board of Directors[144] and its activities are largely unregulated. TVA participates in SERTP as part of its "voluntary response" to Order Nos. 890 and 1000,[145] but its transmission planning activities outside of SERTP, like much of TVA's processes, are a black box.

In recent years, TVA has publicized a goal to reduce its greenhouse gas emissions by 80 percent by 2035, compared to 2005 levels, and to reach net zero emissions by 2050.[146] In July 2022, TVA announced an RFP for 5,000 MW of carbon-free energy before 2029, from resources both internal and external to TVA.[147] Without assessing the likelihood that TVA follows through on either its aspirational carbon reduction goals or this latest clean energy procurement push, any integration of renewable resources at this scale will require significant transmission planning and investment. In practice, when TVA has sought to replace retiring coal-fired generation, it has shied away from procuring renewable capacity, asserting in part that it would require significant transmission investments. For example, TVA recently proposed to retire the two coal-fired units at its Cumberland Fossil Plant (Cumberland) and replace them with either new gas generation or

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144 *Our Leadership*, TVA, Our Leadership (tva.com) (last visited Aug. 6, 2022).

145 *Southeastern Regional Transmission Planning Group: TVA Membership Background and History – Note to OASIS*, TVA (Aug. 10, 2015), Microsoft Word - Note for OASIS on SERTP Aug10-15.doc (oati.com).

146 Jonathan Mattise & Adrian Sainz, "Federal Utility Seeks Proposals for Big Carbon-Free Push," Associated Press (Jul 12, 2022), Federal utility seeks proposals for big carbon-free push | AP News.

147 *See id*.

a portfolio of solar and storage resources.[148] TVA has shown a clear preference for the new gas option, having estimated that the solar/storage alternative would cost $2.3 billion more and would require "extensive regional transmission upgrades."[149] TVA also rejected replacing Cumberland's capacity with wind generation external to TVA due to transmission costs, despite its ability to "provide dependable capacity in both summer and winter."[150] Putting aside the fact that TVA has not shared the detailed assumptions underlying its renewables and storage alternative (including related to project siting), or even the projected costs of its claimed transmission needs, it is apparent that TVA has not considered the benefits of regional transmission investment. As commenters have explained, such investment would "provide operational benefits to the TVA system as a whole, such as improved reliability and resilience, and will facilitate the utility's plans to install 10,000 MW of solar by 2035. . . .Those projects will benefit directly from any transmission upgrades required . . . because they can be sited to maximize the value of the prior transmission investment."[151]

Like its utility neighbors, TVA asserts that it plans to integrate significant renewable capacity, primarily to serve large corporate customers with renewable energy goals, over the next decade and beyond. Also like its utility neighbors, it has claimed that the required transmission facilities make it cost-prohibitive to replace retiring coal facilities with renewable capacity. Yet it has also neglected to collaboratively plan for these eventualities alongside those neighbors who share the same stated transmission needs. Like Southern Company, which also has internal carbon

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[148] *Cumberland Fossil Plant Retirement: Draft Environmental Impact Statement*, TVA, at i (2022), Cumberland Retirement Draft Environmental Impact Statement Report (azureedge.net) (Draft EIS).

[149] *Cumberland Retirement EIS: Alternatives Evaluation*, TVA, at 17 (Apr. 2022), TVA Public Meeting (azureedge.net).

[150] Draft EIS at 43.

[151] Southern Environmental Law Center et al., Conservation Groups' Comments on TVA's Draft Environmental Impact Statement for the Cumberland Fossil Plant Retirement, at 23 (June 13, 2022).

reduction goals, TVA has not attempted to incorporate these goals into the regional transmission planning process. Although the Commission does not have jurisdiction over TVA's participation in regional transmission planning, it may shape SERTP in a manner that convinces TVA that SERTP can provide a forum to seek solutions to regionwide problems. Otherwise, the Southeast utilities will continue to plan for themselves in parallel, disregarding their shared issues and the cost-savings that could be realized from optimized planning.

5. South Carolina

As discussed above, South Carolina differs from the other states in the region due to its two separate regional transmission planning processes. Duke, which serves a significant portion of the state, participates in SERTP. Dominion, the other major investor-owned utility in the state, participates in SCRTP with Santee Cooper. Just like the other states in the region, however, South Carolina has seen accelerated retirement of coal units, necessitating replacement capacity. It has similarly struggled with the questions of whether and to what degree its utilities should upgrade its transmission facilities to adapt.

In its 2020 IRP, Dominion modeled the 2028 retirements of the Wateree and Williams coal units.[152] Dominion's Electric Transmission Planning Department performed a Transmission Impact Analysis (TIA) to assess the transmission impacts of these retirements. The TIA concluded that, while retirement of Wateree by the end of 2028 was feasible, retiring Williams before 2030 was not due to "the complexity of selecting and siting replacement resources including electric transmission and fuel supply."[153] Under each of the cases modelled, Dominion found that

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[152] *See Dominion Energy South Carolina, Inc.*, Docket No. 2021-418, Dominion, 2022 Coal Plants Retirement Study Report, at 3 (S.C. Pub. Serv. Comm'n May 16, 2022).

[153] *Id*. at 5.

"maintaining reliable service after Williams and Wateree are retired will require significant upgrades to the DESC transmission system."[154]

Putting aside the prudence of investing in significant transmission upgrades in this instance, as intervenors to the proceeding persuasively argued that Dominion did not adequately consider non-wires alternatives or siting generation nearby,[155] Dominion's predicament is common to other utilities across the region, as these comments have shown. By virtue of its commitment to SCRTP's confined planning sphere, however, Dominion is isolated from its regional peers. It cannot then assess whether regional transmission facilities could alleviate its current constraints on a lower-cost basis than if it made such investments alone. Taking those options off the table entirely creates costs for Dominion's ratepayers that they might otherwise avoid, but neither state regulators nor stakeholders will ever know their extent.

The reforms included in the NOPR and supported in these comments are not designed to lead to specific outcomes; they are meant to create an array of fully vetted options and to allow state regulators and stakeholders to assess whether the transmission provider selected the option that would provide the most reliable service at the lowest cost. This is especially important as overwhelming changes confront the energy industry, requiring an accurate assessment of the role transmission can play in providing just and reasonable solutions. SCRTP's limited scope and SERTP's structural myopia fail primarily because they do not present sufficient optionality to ensure that ratepayers are receiving the best outcome available to them.

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[154] *Id*. at 17.

[155] *See Dominion Energy South Carolina, Inc.*, Docket No. 2021-418, Sierra Club et al., Comments on Coal Retirements Study, at 19-25 (S.C. Pub. Serv. Comm'n June 27, 2022).

III. REFORMS

These developments demonstrate the glaring need for an overhaul to the Southeast's regional transmission planning processes. Each of the region's prominent utilities has recognized that keeping pace will require substantial transmission investment, yet each has neutered and then effectively ignored the one forum that would allow them to proactively plan that investment on the scale required. Given the ubiquity of the transmission needs throughout the region and the efficiencies to be realized from optimally planning transmission on a regional basis, no moment could better justify SERTP, SCRTP, and FRCC's existence. The sheer scale of the transmission investment needed to meet this moment presents both a golden opportunity for efficient growth and a looming threat of exorbitant overbuilds. If the Commission cannot ensure the former, it will have to better police the latter, perhaps by revoking the presumption of prudence for facilities planned in the local processes. Otherwise, the region's ratepayers will see their already immense energy burdens become unbearable. Recognizing the significance of this moment, the Commission should use this proceeding to ensure that the regional planning processes avoid that outcome by comprehensively and genuinely assessing regional transmission facilities.

The NOPR's proposals to implement forward-looking, scenario-based planning are essential to shaping SERTP, SCRTP, and FRCC into processes that meaningfully assess efficient, regional transmission facilities. This in turn would allow state regulatory bodies and stakeholders to scrutinize the utilities' choices in a well-informed manner. As things stand, these cost-effective regional alternatives are either not presented or not seriously considered, leaving both state decisionmakers and ratepayers in the dark, and causing the latter to foot the bill. The NOPR's proposals could go a long way toward alleviating these flaws, but if the Commission allows the utilities too much leeway in establishing the ground rules, regional transmission planning in the Southeast will continue to be an empty, box-checking exercise. Firm direction is required, especially with respect to the process and criteria with which regional projects are assessed and selected. Below, Southeast Public Interest Groups discuss the most important reforms the Commission can implement to address the concerns expressed above.[156]

A. Long-Term Regional Transmission Planning

Southeast Public Interest Groups acknowledge the Commission's reluctance to dictate outcomes through the transmission planning process. They recognize that the regional transmission planning process exists instead to involve stakeholders, ensure transparency, and assess whether any regional transmission facilities or upgrades might provide a more efficient or cost-effective alternative to local transmission investment. Each of these principles has eluded the region's regional transmission planning processes. The ultimate intent remains selecting transmission facilities that will be approved by state regulatory authorities, but the process requires significant changes to ensure that multiple options are adequately vetted at the regional level before they reach the approval stage. Through a firm application of the NOPR's proposed reforms, including a defined set of minimum benefits, the reformed regional transmission planning process could live up to its promise as a collaborative venue for consideration of regional alternatives.

1. Long-Term Scenario Planning

Southeast Public Interest Groups strongly support the NOPR's proposal to require public utility transmission providers to engage in Long-Term Regional Transmission Planning (LTRTP) by developing and incorporating multiple Long-Term Scenarios that cover different assumptions about the changing electric power system over a 20-year planning horizon.[157] Comprehensive and proactive LTRTP in this vein is necessary to avoid the fate of Order No. 1000's Public Policy

156 The discussion of NOPR reforms herein takes a higher-level view of the proposed reforms. Southeast Public Interest Groups largely support the more granular proposals contained in the Public Interest Organizations' initial comments.

157 *See* NOPR at PP 84, 97

Requirements obligations, which the SERTP sponsors do not seriously observe. Whereas the SERTP sponsors can currently reject stakeholder requests for Public Policy Requirements studies, LTRTP would become a regular obligation they cannot skirt. For LTRTP to provide any value, however, the Commission must establish a robust set of minimum requirements; as experience in the Southeast shows, the bare minimum expected of utilities will become the norm.

First and foremost, expanding the breadth of the compulsory study factors beyond minimum legal requirements would prevent utilities from discounting resource trends simply because they do not reflect state legislation, like the wave of coal retirements affecting the region. To this end, Southeast Public Interest Groups support the NOPR's proposed mandatory factors for incorporation in LTRTP:

> (1) federal, state, and local laws and regulations that affect the future resource mix and demand; (2) federal, state, and local laws and regulations on decarbonization and electrification; (3) state-approved utility integrated resource plans and 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; (6) generator interconnection requests and withdrawals; and (7) utility and corporate commitments and federal, state, and local goals that affect future resource mix and demand.[158]

Factors 1-3 largely cover the existing Public Policy Requirements definition but provide additional specificity. Factor 4 requires consideration of resource trends that have had a much larger effect on the region's resource mix and demand than legislation. Most of the Southeastern states do not have decarbonization mandates or renewable portfolio standards, but all of them are susceptible to fuel price volatility given their reliance on gas and coal. And each has made at least halting progress in integrating renewables due to improved technology and economics. On the demand

158 *Id*. P 104.

side, an influx of electric vehicles—which are and will continue to be manufactured in the region in substantial numbers[159]—could also have a material effect. Factor 5, resource retirements, incorporates a development that has affected each state in the region and created transmission needs throughout, as discussed at length above. Factor 6's focus on needs created by interconnection requests and withdrawals has specifically arisen in North Carolina's Red Zone transmission upgrades.[160] And corporate renewable goals among both utilities—including Southern Company[161] and TVA[162]—and customers—such as Google[163]—have driven resource procurement decisions without the force of law.

These factors establish a strong foundation to drive LTRTP, and the Commission should require that each Long-Term Scenario explicitly account for each factor. However, allowing for their evolution as additional developments emerge is crucial. For this reason, Southeast Public Interest Groups support the NOPR's proposal to provide "stakeholders, including states, with a meaningful opportunity to propose potential factors that public utility transmission providers must incorporate."[164] As the ultimate arbiter of facility investment, the states have a substantial interest in guaranteeing that the factors they consider when approving utilities' plans inform the utilities'

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159 *See, e.g.*, *The State of the Green Mobility Industry in the Southeast: Market Trends and Policies Driving Transportation Electrification*, N.C. Clean Energy Technology Center (Nov. 29, 2021), The State of the Green Mobility Industry in the Southeast: Market Trends and Policies Driving Transportation Electrification - NC Clean Energy Technology Center (ncsu.edu) ("'Most of the states in the Southeast are home to either vehicle assembly plants or automotive supply chain manufacturers,' said Heather Brutz, . . . Finance & Operations Manager for NCCETC's Clean Transportation program. Additionally, several Southeast states like Tennessee, Georgia and South Carolina had a higher prevalence of manufacturing specifically related to battery electric or fuel cell vehicles.").

160 *See supra* section II.B.2.

161 *See Southern Company Releases Plan on Net Zero Carbon Emissions Goal*, Southern Company (Sept. 21, 2020), Southern Company releases plan on net zero carbon emissions goal (discussing Southern Company's goal of achieving net zero greenhouse gas emissions by 2050).

162 *See supra* section II.B.4.

163 *See 24/7 Carbon-Free Energy by 2030*, Google Data Centers, 24/7 Clean Energy – Data Centers – Google (last visited Aug. 7, 2022).

164 NOPR at P 109.

planning processes. They do not currently engage in the regional planning processes to any meaningful degree. Accordingly, the Commission should not only permit but encourage their participation in shaping and conducting LTRTP. And states should take the initiative to actively participate at this stage of the process to create better continuity between the planning and approval processes. LTRTP would better enable this synergy compared to the current framework.

Second, the Commission must establish the baseline format by which public utilities must conduct LTRTP to ensure they will actually engage in transparent and proactive transmission planning. Otherwise, they will seize on any opportunity to avoid additional process. SERTP sponsors have summarily rejected stakeholder requests to study transmission needs driven by Public Policy Requirements, yet they can arguably claim compliance with the Commission's loose standard for "consideration" under the current planning regime. Similarly, the utilities conduct a half-hearted consideration of regional alternatives, which corresponds with the narrow cost-benefit analysis contained in their tariffs and approved by the Commission. Accordingly, Southeast Public Interest Groups support the NOPR's proposal to require utilities to develop a minimum of four distinct Long-Term Scenarios.[165]

The Southeast Public Interest Groups further urge the Commission to require utilities to affirmatively incorporate all of the factors listed above into the Long-Term Scenarios, rather than merely "consider" them. While flexibility in distinguishing between the four Long-Term Scenarios is warranted, the baseline requirement that utilities develop four plausible, diverse, and comprehensive scenarios should prevent LTRTP from devolving into a box-checking exercise on par with the current Public Policy Requirements studies. Likewise, the requirement that one of the Long-Term Scenarios account for a high-impact, low-frequency event ensures that reliability

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165 *See id*. P 121.

remains critical to the planning process.[166] Crucially, the Commission must ensure that stakeholders have the opportunity to provide timely and meaningful input into the Long-Term Scenarios' development.[167] Stakeholder participation has suffered in SERTP due to the minimal opportunities for input and a general lack of transparency. A clear opportunity for stakeholders to actively engage from the beginning of the Long-Term Scenarios' development—as opposed to commenting on a fully-baked transmission expansion plan—would address many of these issues.

Third, Southeast Public Interest Groups support the NOPR's proposal to set the minimum LTRTP planning horizon at 20 years.[168] SERTP's current ten-year planning horizon has contributed to utilities' reticence to utilize the process to account for longer-term projects, such as the North Georgia Reliability & Resilience Plan in Georgia[169] and certain greenfield transmission investment likely to be included in the NCUC's ultimate Carbon Plan.[170] A 20-year planning horizon would better account for long-term transmission needs that are nevertheless relatively certain.

Fourth, Southeast Public Interest Groups support the NOPR's proposal to require "best available data inputs" in developing the Long-Term Scenarios.[171] Southeast Public Interest Groups ask the Commission to specify and regularly update sources that meet this standard to ensure that public utilities select their inputs from a respected, nonbiased data source. Whichever data inputs public utility transmission providers ultimately use, it is crucial that they do so transparently and that such inputs be available to stakeholders. Information asymmetries have devalued stakeholder

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166 *See id*. P 122

167 *See id*.

168 *See id*. PP 97-98.

169 *See supra* section II.B.1.

170 *See supra* section II.B.2.

171 NOPR at P 130.

participation in SERTP, as the SERTP sponsors do not share all relevant information utilized in the planning process, such as the estimated costs of proposed transmission facilities. Stakeholders must have access to all relevant information in order to meaningfully participate. Further, the same data inputs must be utilized across the entire planning region. The Southeast is comprised of multiple balancing authority areas, each of which operates independently of the others. Uniformity of planning data inputs would help to bridge existing informational gaps that contribute to the balkanized planning processes.

Finally, although the NOPR proposes not to change the current reliability and economic planning processes,[172] Southeast Public Interest Groups recommend that LTRTP encompass these planning priorities as well. Currently, SERTP focuses entirely on reliability planning, while treating economic planning and Public Policy Requirements as afterthoughts. Even if the Commission mandates a fairly comprehensive LTRTP process, the SERTP sponsors will continue to prioritize reliability planning, likely at LTRTP's expense. However, multi-value planning that does not silo these three overlapping aspects would allow them to complement each other. The factors that necessitate LTRTP—changing resource mix, demand, and weather—substantially affect system reliability and economics as well. A comprehensive planning process should reflect all of these values to avoid marginalizing any one of them.[173]

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[172] *Id*. P 3.

[173] *See Duke Energy Progress, LLC and Duke Energy Carolinas, LLC*, Docket No. E-100, Sub 179, North Carolina Sustainable Energy Association et al., Joint Comments, Ex. 2, Report of Jay Caspary, at 4-8 (N.C. Utils. Comm'n July 15, 2022) ("Reliability and economics are inseparable when it comes to the value proposition of prudent transmission expansion planning. Today's transmission expansion project to address a reliability need, based on existing reliability standards, provides economic benefits to support grid operations. Conversely, economic upgrades in the near term will also provide reliability benefits that are difficult to quantify since operating conditions rarely mirror planned scenarios. The benefits associated with the flexibility and optionality provided by a strong electric transmission network are significant and will not be realized if incremental least cost planning is performed with limited planning horizons, particularly if those do not align with corporate, institutional, state and municipal commitments to decarbonize their electric power supply resources by a date certain, as is the case following enactment of HB 951.").

LTRTP is not the silver bullet that will solve the region's increasing transmission needs or the utilities' aversion to collaboratively planning for them. Nor will it dictate which transmission facilities will ultimately be built. But LTRTP would build upon Order Nos. 890 and 1000's focus on process to ensure that public utility transmission providers engage in comprehensive and proactive transmission planning, while closing the loopholes that have allowed them to escape this responsibility to this point. Ideally, LTRTP will present a menu of well-considered potential transmission facilities that address the region's rapidly changing needs in the most efficient and cost-effective manner possible. Once these alternatives see the light of day, it will be incumbent upon the utilities to choose the options that best serve their customers' needs and defend those choices before the regulators that will ultimately approve them.

2. Benefits/Selection Criteria

Ultimately, stakeholders, state regulators, and ratepayers cannot meaningfully scrutinize the utility's decisions if the alternative transmission facilities' benefits are not quantified, presented, and evaluated in a manner that reflects their true value. If the assessment of regional alternatives amounts to a cost comparison between a small local facility and a multi-state transmission line, the utilities will choose the local facilities every time. Worse, when presented in this manner, the choice will always appear reasonable. True transparency in transmission planning requires that alternatives be presented accurately, with costs and benefits accurately calculated. Conducting a true cost-benefit analysis—which SERTP, SCRTP, and FRCC purport to do—requires a complete consideration of benefits: "Quantifying a broader range of transmission benefits . . . will yield a more accurate benefit-cost analysis, provide more insightful comparisons, and would avoid rejected beneficial investments that would reduce system-wide costs."[174]

[174] Brattle Report at 32.

Southeastern utilities *could* do this under the Commission's planning policies, but they chose not to when establishing their current processes, and the Commission validated that choice. The Commission afforded utilities flexibility in establishing and assessing benefits in Order No. 1000, and utilities in the Southeast exploited that flexibility to implement a straight cost comparison. If the Commission takes that path again and allows utilities to flexibly assess transmission benefits, they will select benefits that amount to avoided transmission costs, all under the guise of regional variation. This time, to ensure regional facilities are accurately represented in the planning processes, the Commission must establish a minimum set of benefits for the utilities to incorporate in their assessment of regional transmission facilities.

Southeast Public Interest Groups urge the Commission to prescribe a set of benefits for use in the utilities' cost-benefit analyses, starting with the entire list of benefits the NOPR offered as optional:

> (1) avoided or deferred reliability transmission projects and aging infrastructure replacement; (2) either reduced loss of load probability or reduced planning reserve margin; (3) production cost savings; (4) reduced transmission energy losses; (5) reduced congestion due to transmission outages; (6) mitigation of extreme events and system contingencies; (7) mitigation of weather and load uncertainty; (8) capacity cost benefits from reduced peak energy losses; (9) deferred generation capacity investments; (10) access to lower-cost generation; (11) increased competition; and (12) increased market liquidity.[175]

Proposed benefits 1 and 4 are factored into SERTP, SCRTP, and FRCC's cost-benefit analyses to some degree today, but the remainder are not considered in any appreciable form. The reliability benefits captured by proposed benefits 2, 6, and 7 are particularly relevant to the region. The geographical area covered by SERTP is immense, which provides significant load diversity due to

[175] NOPR at P 185.

the regional differences in weather and climate across so large an expanse: "Climate diversity benefits . . . are particularly pronounced in . . . the Southeast" because it "contain[s] both winter-peaking and summer-peaking power systems."[176] Yet the ability of regional transmission facilities to better connect the various systems and capitalize on these benefits is not currently captured by SERTP's processes and therefore not reflected in the cost-benefit analysis.

Granted, some of these benefits may not apply in the same manner to RTO/ISO regions as they do to the Southeast, whose utilities are neither in an RTO/ISO nor an organized energy market, but that should not allow Southeastern utilities to evade quantifying these benefits in some form. For example, the NOPR notes that RTO/ISO regions typically quantify production cost savings using security-constrained production cost models that simulate electric system operation and the wholesale electricity market.[177] Because the Southeastern utilities do not participate in RTO/ISO markets, they do not regularly calculate security-constrained production costs or locational marginal prices.[178] However, just like utilities in RTO/ISO regions, Southeastern utilities would realize "savings in fuel and other variable operating costs of power generation"[179] from the expansion of regional transmission facilities. They have the means and the system knowledge to quantify those savings and must be made to do so. Indeed, the NOPR acknowledges that non-RTO/ISO regions often utilize alternative methods of quantifying production costs.[180] It highlights WestConnect's process of "modeling the potential of the transmission facilities to support more

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[176] Brattle Report at 40-41.

[177] *See* NOPR at P 199.

[178] To the extent wholesale market-related metrics are required to quantify some of the proposed benefits, such as increased competition or increased market liquidity, the Southeast could have a quasi-organized wholesale market in SEEM, pending the outcome of ongoing litigation. *See supra* note 21. If SEEM commences operations, the participating utilities cannot claim that they are wholly isolated from wholesale electricity markets in order to escape assessment of these market-related benefits.

[179] NOPR at P 198.

[180] *See id*. P 201.

economic bilateral transactions between generators and loads in the region" by "consider[ing] the transactions between loads and lower-cost generation that [] proposed regional transmission facilities could support and, accounting for the costs associated with transmission service, identif[ying] the transactions that are likely to occur."[181] As a similarly bilateral market, the Southeast could implement an analogous production cost model to capture the savings regional facilities could bring to the region. To this end, the Commission should fashion equivalent, standardized metrics for both RTO/ISO regions and non-RTO/ISO regions that ultimately capture the same concepts.

As the above descriptions of emerging transmission needs in the Southeast show, there are tremendous benefits to be realized from regional transmission facilities. For instance, Georgia Power's insistence on replacing retiring coal capacity with solar facilities in a topographically unsuitable area could be addressed by proposed benefits 9 and 10: deferred generation capacity investments and access to lower-cost generation. Couple that transmission need with the low-cost, plentiful solar in south Georgia and TVA's claimed intent to import renewable capacity, and a regional transmission facility connecting south Georgia to north Georgia and tapping into TVA's north Georgia system would provide measurable benefits. Similarly, both Georgia Power and Dominion must accommodate coal retirements with replacement generation. Georgia Power prefers solar in north Georgia while Dominion prefers gas due to transmission constraints. A regional facility that links these neighboring systems with east-west load diversity could address their respective needs much more efficiently than local solutions. But because SERTP and SCRTP operate independently and limit their cost-benefit assessments to straight cost comparisons, none of these benefits is considered. Without a firm Commission directive that a full suite of benefits

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181 *Id*.

be incorporated into the calculation, utilities will continue to focus solely on costs and in the process, deprive states and stakeholders of a full picture of the utilities' transmission options.

Ultimately, a transparent regional transmission planning process that assures state regulators and stakeholders that viable alternatives were comprehensively evaluated—and allows them to scrutinize that evaluation in an informed manner—should be the goal of this proceeding. In the Southeast, where IRP or other state regulatory processes solidify resource decisions, states and regulators need certainty that the utilities have identified the most efficient, lowest-cost alternatives for investment. A regional transmission planning process that quantifies and fully accounts for the benefits of regional alternatives would provide some measure of assurance. Contrary to the SERTP sponsors' assertions that prescriptive regional planning is incompatible with the region's bottom-up, IRP-driven process,[182] a fulsome regional transmission planning process would facilitate a better-informed state regulatory process that ensures the most cost-effective alternatives are considered. As the Commission has previously found, open and transparent regional transmission planning allows for "the identification and evaluation of transmission solutions that may be more efficient or cost-effective than those identified and evaluated in the local transmission plans of individual public utility transmission providers" and therefore "provide[s] more information and more options for consideration by public utility transmission providers and state regulators."[183] If the planning process does not accurately account for and evaluate the benefits of these options while selecting the facilities that comprise the ultimate expansion plan, it will not have the same facilitating effect.

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182 *See supra* note 143.

183 Order No. 1000 at P 190.

Certain aspects of regional transmission planning lend themselves to regional flexibility while still advancing the Commission's broader goal of improving the process. Evaluation criteria do not fall within that category. Giving public utility transmission providers free rein to define the metrics that underlie the cost-benefit analysis—when they have built-in incentives to avoid regional transmission investment[184]—will undermine the entire process. It has already done so in the Southeast, where consideration of regional alternatives is designed to fail. To avoid this, the Commission must impose a set of minimum benefits for quantification and implementation into the cost-benefit analysis.

B. Local/Regional Coordination

Southeast Public Interest Groups support the NOPR's proposal to increase coordination between the local and regional planning processes by enhancing the transparency of the local processes and establishing an iterative process that would allow stakeholders opportunities to participate in local planning through the regional process.[185] Closer coordination between the planning processes would better ensure that the local process does not operate to nullify the effectiveness of the regional process. That has already occurred in the Southeast, where utilities invest exclusively in local transmission facilities and the local transmission plans arrive at SERTP fully baked and immune to change. True consideration of regional alternatives will require that the local and regional planning processes mesh at an earlier stage so that local facilities do not become entrenched before they appear in the regional plan.

Southeastern utilities have taken wildly divergent approaches to their local processes. North Carolina's NCTPC is wholly removed from SERTP until its local plan rolls up into the

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[184] *See supra* section I.

[185] *See* NOPR at P 400.

SERTP regional plan. Southern Company utilizes SERTP for both its local and regional processes, meaning that SERTP's structural deficiencies taint both. Additionally, Southern Company's subsidiary, Georgia Power, substantially conducts its local planning through the ITS process, which does not permit non-utility stakeholder participation. Accordingly, requiring an iterative process in which stakeholders provide input into (1) the criteria, models, and assumptions used, (2) the transmission needs identified, and (3) the transmission facilities evaluated to address those local needs, will better integrate separate local processes like the NCTPC while building out the local planning aspects already inherent to SERTP. The former will be of significant use as North Carolina implements its ultimate Carbon Plan through the NCTPC, which, as discussed above, will require significant transmission investment.[186]

In any event, drawing the local and regional processes into closer coordination will ideally allow stakeholders to influence the local plans before they calcify into unchangeable components of the regional plan.

C. Cost Allocation

Southeast Public Interest Groups support the NOPR's proposal to require public utilities to seek the agreement of relevant state entities regarding a cost allocation method for the region.[187] Because SERTP has not produced a regional transmission project for cost allocation, the region has not had occasion to encounter state opposition to development. This provides a unique opportunity for states in the region to agree ahead of time on a cost allocation methodology they can support. The states' role in transmission facility approval is fiercely protected in the Southeast, where the IRP process predominantly drives generation investment. As discussed above, regional

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186 *See supra* section II.B.2.

187 *See* NOPR at P 303.

transmission planning is eminently compatible with that process. Accordingly, state involvement in this important aspect of the process would ideally smooth the approval of any regional transmission facilities that emerge from the regional planning process if cost allocation is already established. The significant role that states play in transmission expansion suggests that their participation in developing a cost allocation methodology on the front end will avoid potentially insurmountable issues on the back end.

In terms of the mechanics of assessing state approval, Southeast Public Interest Groups propose that "state agreement" entail unanimous acceptance by the states in the region. However, if the utilities are unable to achieve unanimity, the Commission could presumptively impose the cost allocation mechanism approved by a plurality of the region's states.

D. Oversight

Although proposed in the Advanced Notice of Proposed Rulemaking, the NOPR declined to "establish an independent entity to monitor the planning and cost of transmission facilities in the region."[188] Southeast Public Interest Groups urge the Commission to revisit the concept of an independent transmission monitor, which could have significant value in the Southeast. As transmission planning processes outside of RTOs/ISOs, SERTP, SCRTP, and FRCC are overseen and conducted by the utilities that participate in the process, despite the Commission's acknowledgment that public utility transmission providers do not have an incentive to "expand the grid to accommodate new entries or to facilitate the dispatch of more efficient competitors."[189] As discussed at length above, this has led to an intentionally ineffectual process and predictably poor results. For this reason, introducing a form of independent oversight into the region's transmission

[188] *Building for the Future Through Electric Regional Transmission Planning & Cost Allocation & Generator Interconnection*, 86 FR 40266 (July 15, 2021), 176 FERC ¶ 61,024, at P 163 (2021).

[189] Order No. 890 at P 57.

planning process would go a long way toward ensuring that the Commission's transmission planning directives are followed. There is a clear need for cost-effective regional projects in the Southeast given the widespread transmission needs in each state. Planning for and assessing options to address these needs is a mandatory process, and utilities in the region have not shown that they warrant trust in conducting the process seriously and comprehensively.

E. Planning Regions

As discussed above, while most of the public utilities in the SERC Reliability region participate in SERTP, Dominion conducts its regional transmission planning in SCRTP with Santee Cooper.[190] Given the broader benefits that regionally optimized transmission investment can bring, South Carolina ratepayers would be better served if their utilities planned transmission expansion on a truly regional basis, alongside the utilities in SERTP. SCRTP's capacity to conduct proactive regional planning that adapts to changes in the resource mix and demand is severely limited by the size of its planning region, which contains one other utility with one other set of transmission needs. This prevents Dominion from facilitating its multiple coal retirements through regular coordination with the neighboring systems of Duke and Southern Company—both of which have similar needs with similar causes—short of resorting to the cumbersome interregional process. Accordingly, Southeast Public Interest Groups urge the Commission to revise its criteria for transmission planning regions to require at least two public utility transmission providers within each region.

IV. CONCLUSION

The Southeast is experiencing the same seismic shifts in generation mix, demand, and weather as the rest of the country. However, by virtue of its independence from any RTO/ISO or

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[190] *See supra* sections II.A.II, II.B.5.

organized wholesale energy market, it lacks an effective mechanism for regional coordination. This extends to its mandatory regional transmission planning process, which has manifestly failed to assess regional alternatives to its widespread transmission needs, thereby resulting in unjust and unreasonable rates for transmission service. Recognizing the failure of its transmission planning policies to take hold in the region, the Commission must take a firmer stand in requiring Southeast utilities to engage in a robust planning process with substantial minimum responsibilities. Otherwise, they will continue to plan their own systems, ignoring efficiencies and overbuilding local transmission whose excessive costs will burden their customers. This insular investment will only further entrench itself as the generation and demand changes accelerate, ensuring that the burden to ratepayers will grow insurmountable. Accordingly, Southeast Public Interest Groups respectfully request that the Commission craft a final rule that addresses the concerns raised in these comments and adopts the suggested reforms.

Respectfully submitted,

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August 17, 2022