UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Industrial Energy Consumers of America,
American Forest & Paper Association, R Street
Institute, Glass Packaging Institute, Public Citizen,
PJM Industrial Customer Coalition, Coalition of
MISO Transmission Customers, Association of
Businesses Advocating for Tariff Equity, Carolina
Utility Customers Association, Inc., Pennsylvania
Energy Consumer Alliance, Resale Power Group
of Iowa, Wisconsin Industrial Energy Group,
Multiple Intervenors (NY), Arkansas Electric
Energy Consumers, Inc., Public Power
Association of New Jersey, Oklahoma Industrial
Energy Consumers, Large Energy Group of Iowa,
Industrial Energy Consumers of Pennsylvania,
Maryland Office of People's Counsel,
Pennsylvania Office of Consumer Advocate,
Consumer Advocate Division of the Public
Service Commission of West Virginia, and
Missouri Industrial Energy Consumers,

Complainants

Docket No. EL25-________

v.

Avista Corporation; Idaho Power Company
MATL LLP; NorthWestern Corporation;
PacifiCorp; Portland General
Electric Company; Puget Sound Energy, Inc.;
Duke Energy Florida, LLC; Florida Power &
Light Company; Tampa Electric Company;
Dominion Energy South Carolina, Inc.;
Duke Energy Carolinas, LLC and Duke Energy
Progress, Inc.; Louisville Gas and Electric
Company and Kentucky Utilities Company;
Southern Company Services Inc., as agent
For Alabama Power Company, Georgia Power
Company, Georgia Power Company and
Mississippi Power Company; Arizona Public
Service Company; Black Hills Power, Inc.;
Black Hills Colorado Electric Utility Company,

LP; Cheyenne Light, Fuel & Power Company;)
El Paso Electric Company, NV Energy, Inc.;)
Public Service Company of Colorado; Public)
Service Company of New Mexico; Tucson)
Electric Power Company; UNS Electric, Inc.;)
California Independent System Operator, Inc.;)
Southwest Power Pool, Inc.; PJM Interconnection,)
L.L.C.; Midcontinent Independent System Operator)
Inc.; New York Independent System Operator, Inc.;)
and Independent System Operator of New England)
Inc.,)
Respondents)

COMPLAINT
OF
CONSUMERS FOR INDEPENDENT REGIONAL TRANSMISSION PLANNING FOR ALL FERC-JURISDICTIONAL TRANSMISSION FACILITIES AT 100 KV AND ABOVE

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Industrial Energy Consumers of America, American Forest & Paper Association, R Street Institute, Glass Packaging Institute, Public Citizen, PJM Industrial Customer Coalition, Coalition of MISO Transmission Customers, Association of Businesses Advocating for Tariff Equity, Carolina Utility Customers Association, Inc., Pennsylvania Energy Consumer Alliance, Resale Power Group of Iowa, Wisconsin Industrial Energy Group, Multiple Intervenors (NY), Arkansas Electric Energy Consumers, Inc., Public Power Association of New Jersey, Oklahoma Industrial Energy Consumers, Large Energy Group of Iowa, Industrial Energy Consumers of Pennsylvania, Maryland Office of People's Counsel, Pennsylvania Office of Consumer Advocate, Consumer Advocate Division of the Public Service Commission of West Virginia, and Missouri Industrial Energy Consumers,	)	
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Black Hills Colorado Electric Utility Company,)
LP; Cheyenne Light, Fuel & Power Company;)
El Paso Electric Company, NV Energy, Inc.;)
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COMPLAINT
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CONSUMERS FOR INDEPENDENT REGIONAL TRANSMISSION PLANNING FOR ALL FERC-JURISDICTIONAL TRANSMISSION FACILITIES AT 100 KV AND ABOVE

Pursuant to Sections 206, 306, and 309 of the Federal Power Act ("FPA")[1] and Rule 206 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or the "Commission"),[2] Industrial Energy Consumers of America, American Forest & Paper Association, R Street Institute, Glass Packaging Institute, Public Citizen, PJM Industrial Customer Coalition, Coalition of MISO Transmission Customers, Association of Businesses Advocating for Tariff Equity, Carolina Utility Customers Association, Inc., Pennsylvania Energy Consumer Alliance, Resale Power Group of Iowa, Wisconsin Industrial Energy Group, Multiple Intervenors (NY), Arkansas Electric Energy Consumers, Inc., Public Power Association of New Jersey, Oklahoma Industrial Energy Consumers, Large Energy Group of Iowa, Industrial Energy Consumers of Pennsylvania, Maryland Office of People's Counsel, Pennsylvania Office of

[1] 16 U.S.C. §§ 824e, 825e, and 825h.
[2] 18 C.F.R. § 385.206.

Consumer Advocate, Consumer Advocate Division of the Public Service Commission of West Virginia, and Missouri Industrial Energy Consumers (collectively, "Complainants")[3], submit this Complaint against all FERC-jurisdictional public utility transmission providers with local planning tariffs – regional transmission organizations and independent system operators ("RTOs/ISOs") and FERC-jurisdictional public utility transmission owners that are not members of a FERC-jurisdictional RTO/ISO.[4] Complainants demonstrate that provisions in the tariffs of the named public utilities and the RTOs/ISOs inappropriately authorize individual transmission owners to plan FERC-jurisdictional transmission facilities at 100 kilovolts ("kV") and above ("Local Planning"[5]) without regard to whether such Local Planning approach is the more efficient or cost-effective transmission project for the interconnected transmission grid and cost-effective for electric consumers.

Local Planning, coupled with the absence of an independent transmission system planner, has produced inefficient planning and projects that are not cost-effective, resulting in unjust and unreasonable rates for both individual projects and cumulative regional transmission plans and portfolios.[6] The Federal Power Act requires that the Commission address the tariff provisions

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[3] As to Communications for this Complaint, Complainants request that the persons listed in signature blocks on behalf of each of the parties be included on the Commission's official service list for this proceeding. Per 18 C.F.R. § 385.203(b)(3), Complainants request that Mr. Kenneth R. Stark (kstark@mcneeslaw.com) and Ms. Susan E. Bruce (sbruce@mcneeslaw.com) as the primary two persons "upon whom service is to be made and to whom communications are to be addressed in the proceeding."

[4] The respondents listed above and the FERC-jurisdictional transmission owners served (see **Attachment D**) represent, to the best of Complainants' knowledge, all of the FERC-jurisdictional public utilities with local planning tariffs. Complainants are also serving this complaint on FERC-jurisdictional transmission owners within RTOs and ISOs, given that existing RTO/ISO tariffs empower self-interested Local Planning by those transmission owners.

[5] When referring to individual transmission owner planning, the Complaint will refer to Local Planning or state that a project was Locally Planned. This Complaint refers to the resulting transmission project is "Self-Planned Transmission."

[6] In a critical analysis issued in November 2024, RMI (formerly, the Rocky Mountain Institute) reviewed the lack of oversight of local project planning and spending. "Mind the Regulatory Gap: How to Enhance Local Transmission Oversight," RMI (Nov. 2024), *available at* https://rmi.org/insight/mind-the-regulatory-gap (hereinafter "RMI Report") (last accessed Dec. 17, 2024). RMI concluded that that local planning is "inherently inefficient" as "uncoordinated local projects will generally be more costly than larger, well-planned regional projects, and they will also tend to have greater land use and environmental impacts and fewer economic and operational benefits." RMI Report at 48.

causing unjust and unreasonable transmission rates. Given the upcoming holidays and the breadth of this Complaint, Complainants do not have any objection to extending the comment period to 45 days or whatever comment period the Commission deems reasonable.

I. SUMMARY OF COMPLAINT

The Commission embraces the following mission:

> FERC's Mission: Assist **consumers** in obtaining reliable, safe, secure, and economically efficient energy services at a **reasonable cost** through appropriate regulatory and market means, and collaborative efforts.[7]

Assisting consumers in securing energy at a reasonable cost is not simply a lofty mission-statement objective to be placed on the Commission's website; it is the Commission's statutory obligation to protect consumers from excessive rates and charges.[8] As the Commission itself has said:

> The electric transmission grid is the backbone of the American economy and essential to the national security of our country. The mission of this agency is to ensure reliable, safe, secure, and economically efficient energy for consumers at a reasonable cost. Ensuring we have a robust, well-planned electric transmission grid is the single most important step that this Commission can take to fulfill that statutory mandate.[9]

The role of Section 206 of the FPA has been stated thusly: "[T]he purpose of the power given the Commission by s. 206(a) is the protection of the public interest, as distinguished from the private interests of the utilities."[10] To meet its mission to consumers regarding the fastest growing part

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[7] About FERC, https://www.ferc.gov/what-ferc (emphasis added) (last accessed Dec. 17, 2024).
[8] *NextEra Energy Res. v. FERC*, 898 F.3d 14, 21 (D.C. Cir. 2018).
[9] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, 187 FERC ¶ 61,068 (May 13, 2024)("Order No. 1920"), Phillips, Chairman, Clements, Commissioner, *concurring* ("Joint Order No. 1920 Concurrence") at P 1; see also, Order No. 1920, Christie, Commissioner, *dissenting*, ("Christie Order No. 1920 Dissent") at P 1 ("The Federal Power Act (FPA) is, at its core, a consumer protection statute.")
[10] *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348, 355 (1956).

of consumer electricity bills,[11] transmission rates, the Commission must ensure two things: (1) that the appropriate transmission projects are planned; and (2) that those planned transmission projects are implemented in an economically efficient manner.

As described in this Complaint, existing tariffs allowing individual transmission owner "Local"[12] planning do not meet the Commission's obligation to consumers because those tariffs fail to ensure that the most appropriate transmission projects for the interconnected grid are planned.[13] The Commission has not fulfilled its statutory obligation to ensure just and reasonable, non-discriminatory transmission rates and practices affecting those rates because existing local planning tariffs allow individual transmission owners to plan FERC-jurisdictional transmission facilities at 100 kV and above without regard to whether it is the right project for the interconnected grid, resulting in unjust and unreasonable rates.[14] The Commission recognized in Order No. 1920:

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[11] *See* "US electricity prices outpace annual inflation," Utility Dive (Mar. 13, 2024), *available at* https://www.utilitydive.com/news/us-electricity-prices-rise-customer-eia-outlook/710113/ (last accessed Dec. 18, 2024); *see also* "Understanding Transmission Costs in Your Power Bill," Constellation, *available at* https://blogs.constellation.com/energy-management/understanding-transmission-costs-in-your-power-bill-2/ (last accessed Dec. 18, 2024). *See* Order No. 1920 at P 92 (recognizing the substantial increases in transmission prices and the that "transmission investment is likely to substantially increase in coming years" through at least 2050).

[12] For purposes of this Complaint, "local" is used to refer to Commission jurisdictional transmission facilities planned by individual transmission owners based on criteria set by the transmission owner. The term "local" is not used to refer to the cost allocation for the project, as the Commission defined "local" in Order No. 1000. *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000 at P 63, 136 FERC ¶ 61,051 (2011) ("Order No. 1000"), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 at PP 43, 430 ("Order No. 1000A"), *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012) ("Order No. 1000-B"), *aff'd sub nom. S. C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014). Please see the discussion of the Local Planning on pages 67-180 of this Complaint.

[13] *See* **Attachment B**, Declaration and Direct Testimony of Michael A. Giberson at 3:19-4:10 (hereinafter "Giberson Testimony") (explaining the importance of protecting consumers from unjust and unreasonable rates and inefficient planning by "removing today's ineffective tariff framework that allows individual transmission owners to plan Commission-jurisdictional transmission regardless of voltage or regional impact").

[14] Transmission planning is a practice that directly affects FERC-jurisdictional rates. *See South Carolina v. FERC*, 762 F.3d 41, 55-56 (D.C. Cir. 2014) (citing FERC's determination in Order No. 1000 at P 112). In Order No. 1000, FERC explained that the transmission planning activities being reviewed by FERC "have a direct and discernable affect [sic] on rates" as it is "through the transmission planning process that public utility transmission providers determine which transmission facilities will more efficiently or cost-effectively meet the needs of the region, the development of which directly impacts the rates, terms and conditions of jurisdictional service." Order No. 1000 at P 112.

> [i]n light of these changing demands on the transmission system, the record also affirms *what the Commission has long recognized*: regional transmission planning that identifies more efficient or cost-effective transmission solutions to needs helps to ensure cost-effective transmission development for customers and can yield better returns for every dollar spent than localized or piecemeal transmission solutions. Conversely, *inadequate or poorly designed transmission planning processes can lead to relatively inefficient or less cost-effective transmission investment, with customers footing the bill for piecemeal, inefficient, and less cost-effective transmission solutions designed to meet short-term or small-scale transmission needs*.[15]

The Commission also found:

> the record demonstrates that a substantial amount of new transmission investment is occurring outside of regional transmission planning processes. Because these other processes—specifically, generator interconnection processes and local transmission planning processes—are generally designed to address discrete, shorter-term needs, and do not comprehensively assess either broader transmission needs or solutions to those needs, overreliance on those processes can result in relatively inefficient or less cost-effective transmission development for customers, which contributes to rates for transmission that are unjust and unreasonable.[16]

The Commission concluded: "[t]his dynamic results in, among other things, transmission *customers paying more than is necessary or appropriate* to meet their transmission needs, customers forgoing benefits that outweigh their costs, or some combination thereof, *which results in less efficient or cost-effective transmission investments and, in turn, renders Commission-*

[15] Order No. 1920 at P 100 (emphasis added); *see also* Joint Order No. 1920 Concurrence at P 4 ("[U]nder the status quo, with its de facto emphasis on the piecemeal, just-in-time development of the grid to meet near-term reliability and economic needs, customers are being forced to fund investments that could have been more beneficial, less costly, or both had they been better planned from the start. That result undermines our economy and leaves customers less safe and secure, with enormous costs for both our grid and our country.").

[16] Order No. 1920 at P 103; *see also*, *Id*. at P 110 ("local transmission planning, with its focus on the needs of individual utility footprints, does not necessarily provide sufficient, comprehensive analysis of broader regional transmission needs.)

jurisdictional regional transmission planning and cost allocation processes unjust and unreasonable."[17]

Notwithstanding that Local Planning produces unjust and unreasonable transmission planning, and therefore unjust and unreasonable transmission rates, the Commission chose not to address the deficiencies in Local Planning in Order No. 1920 or in response to rehearing requests in Order No. 1920-A.[18] Notably, the Commission did not retract its findings that Local Planning, through its failure to account for all needs of the broader region, contributes to "Commission-jurisdictional regional transmission planning and cost allocation processes [that are] unjust and unreasonable."[19] Instead, the Commission merely responded that because "the Commission in the [Notice of Proposed Rulemaking ("NOPR")] did not propose other changes to local transmission planning processes," other requests for the Commission to address Local Planning "are beyond the scope of this final rule."[20] This Complaint addresses the tariff provisions allowing individual transmission owner Local Planning for FERC-jurisdictional transmission facilities at 100 kV and above and the resulting unjust and unreasonable transmission rates.

The rates for a transmission project that is not needed cannot be just and reasonable. The rates for a transmission project that does not provide "economically efficient energy services"[21] to consumers because it fails to address the combined needs of multiple interconnected parties serving those consumers, are unjust and unreasonable. In PJM, for example, there are **1,584 Locally Planned transmission projects valued at $18.1 billion with expected in service dates between January 1, 2024 and December 31, 2028**.[22] As discussed below, those projects, like

[17] *Id*. at P 112 (emphasis added).
[18] *See* Order No. 1920-A, 189 FERC ¶ 61,126 (issued Nov. 21, 2024).
[19] Order No. 1920 at P 112.
[20] *Id*. at P 247.
[21] *Supra* note 6.
[22] Monitoring Analytics, LLC, State of the Market Report for PJM 2023 at 721 (Mar. 14, 2024) ("IMM Report"). The IMM reports that "[t]he average number of supplemental projects in each expected in service year increased by

Locally Planned projects across the country, receive only a superficial, if any, independent review and thus there is no assurance that they represent efficient or cost-effective projects for consumers. Importantly, this Complaint does not challenge the rates for any *specific* Locally Planned project as unjust and unreasonable; instead, this Complaint alleges that the *cumulative* effect of tariff provisions allowing Local Planning of transmission projects 100 kV and above results in unjust and unreasonable transmission rates.

Although the overuse of individual transmission owner planning cuts across all transmission voltages, the Electricity Customer Alliance ("ECA") specifically called out projects between 100 kV and 230 kV, in all planning categories, as being overbuilt. As a result of the lack of competition or economic discipline for such projects "when paired with the overcapitalization incentive of cost-of-service rates, [ ] incumbent utilities have an incentive to overspend on less efficient transmission outside the scope of regionally-planned projects, which then subverts investment in efficient regional transmission."[23] Section 206 of the FPA[24] obligates the Commission to act. As the Commission observed in 2010:

> The Commission's responsibility to ensure that transmission rates are just and reasonable and not unduly discriminatory or preferential is not new; however, *the circumstances in which the Commission must fulfill its statutory responsibilities change with developments in the electric industry*, such as changes with respect to the demands placed on and the corresponding operation of the transmission grid.[25]

925.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 205 for years 2008 through 2023 (post Order No. 890). The average cost of supplemental projects in each expected in service year increased by 2,531.6 percent, from $64.6 million for years 1998 through 2007 (pre Order No. 890) to $1.7 billion for years 2008 through 2023 (post Order No. 890)." *Id*. at pp 721-22.

[23] Post-technical Conference Comments of Joint Customers, filed March 23, 2023 in Docket No. AD22-8-000 at 2. ECA was joined by on the Comments by The Citizens Utility Board of Illinois, Electricity Consumers Resource Council, Maryland Office of People's Counsel, New Jersey Division of Rate Counsel, Office of the People's Counsel for the District of Columbia, Greg Poulos-Executive Director of Consumer Advocates of PJM States, acting in his individual capacity, Public Citizen, Inc., and R Street Institute.

[24] 16 U.S.C. § 824e.

[25] *Southwest Power Pool, Inc.*, 131 FERC ¶ 61,252 (2010) at P 63 (emphasis added).

Although the electric industry has changed rapidly over the last several decades,[26] in most important respects transmission planning has not, largely continuing to be planned in the same manner it was decades ago by individual utilities planning exclusively to the utility's self-interest. The interconnected transmission grid is not the same grid it was in 1920. Today, an issue on the transmission system in the South can reach the Northeast or even Canada.[27] Allowing individual transmission owners to engage in Local Planning as if the grid were the same as it was in 1920 ignores the fact that today's interconnected "transmission grid is the backbone of the American economy and essential to the national security of our country."[28] The Commission's efforts to ensure that transmission rates remain just and reasonable have been unable to keep pace with incumbent transmission owners' self-interested planning, notwithstanding multiple Commission attempts to encourage regional planning. As such, the Commission has been unable to meet its statutory duty to consumers to ensure just and reasonable transmission rates. The Commission recognized the shortcomings of Local Planning in Order No. 1920 but did not address Local Planning in that Order, necessitating this Complaint.

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[26] *See e.g.*, Lauren Bauer et al., *Ten Economic Facts About Electricity and the Clean Energy Transition* (Apr. 27, 2023) *available at* https://www.brookings.edu/articles/ten-economic-facts-about-electricity-and-the-clean-energy-transition/ (noting that "The relationships between new ways of generating energy, the current and future pace of change, and legacy infrastructure create conflict and challenges. . . . Fully realizing the promise of the clean energy transition for U.S. economic growth, jobs, and prosperity will require developing solutions that remove the choke points created by the existing infrastructure and regulatory systems and deploying both new clean energy generation and the systems required to connect these new energy sources to electricity consumers.). https://infrastructurereportcard.org/wp-content/uploads/2021/03/Failure-to-Act-Energy-2020-Final.pdf ("Since ASCE last issued its Failure to Act electricity report in 2011, the energy sector has vastly transformed. A combination of technology, markets, more severe storms, and policy changes at the state and federal level are driving this transformation.); https://www.eei.org/issues-and-policy/clean-energy (Changing Energy Mix, noting "Over the past decade, our nation's energy mix has changed dramatically.")

[27] *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott*, FERC, NERC and Regional Entity Staff Report, October 2023 ("The Eastern Interconnection is electrically connected to the Western, ERCOT and Quebec Interconnections by means of Direct Current (DC) asynchronous transmission tie lines. Within each interconnection, power generally flows without barriers (subject to operational limits) from one utility's system to another across the entire grid via alternating current (AC) tie lines. A significant enough imbalance of generation and demand can cause instability of one utility's system to affect the stability of all utility systems operating in that interconnection.")

[28] Joint Order No. 1920 Concurrence at P 1.

This Complaint focuses on planning the right projects. Although existing Commission requirements neither plan for nor implement Local transmission projects as is needed to ensure just and reasonable and nondiscriminatory transmission rates, this Complaint proactively focuses only on the planning of the appropriate transmission projects for all interconnected consumers in the existing planning regions to ensure that consumers are afforded "economically efficient energy services at a reasonable cost."[29] It is only when the proper projects are planned that the subsequent development, operation, and maintenance of that project can produce rates that are just and reasonable. In the Order No. 1000 context, the Commission has asserted that the selection of the more efficient or cost-effective developer is less important because the planning process appropriately determines the more efficient or cost effective transmission project.[30] While Complainants believe that competitive transmission development has a significant role in achieving just and reasonable rates,[31] for this Complaint, that issue is secondary because the **existing planning processes are not identifying or selecting the more efficient or cost-effective transmission projects because regionally impactful transmission is being planned in a fragmented, piecemeal manner by individual transmission owners under their local planning tariffs with limited, to no, regional independent review**. No developer can produce just and reasonable rates for a transmission project that is the wrong project from the start!

So long as the public utility transmission tariffs and RTO/ISO tariffs continue to permit individual transmission owners to Locally Plan and build transmission at the "local" level for

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[29] Supra note 6.

[30] *Midwest Independent Transmission System Operator, Inc.*, 147 FERC ¶61,127 (2014) at P 157 (finding "We recognize that, even if a transmission project is subject to a state right of first refusal, the regional transmission planning process still results in the selection for planning and cost allocation purposes of transmission projects that are more efficient or cost-effective than would have been developed but for such processes") *rehearing*, 150 FERC ¶ 61,037 (2015) at P 32.

[31] *See e.g.*, Comments of LS Power Grid, LLC In Response To The Commission's Advance Notice Of Proposed Rulemaking, Appendix II at 11 (comparing costs of competed and non-competed projects in MISO), filed October 12, 2021 in Docket No. RM 21-17-000.

transmission facilities at 100 kV and above, the Commission cannot ensure that the appropriate transmission projects to meet the needs of today's interconnected regional grid are planned and built.[32] Order No. 1920, which did not address Local Planning deficiencies, does not change the fact that existing tariffs allowing Local Planning for 100 kV and above are unjust and unreasonable under Section 206 of the FPA. This Complaint demonstrates that Local Planning provisions of individual or regional Open Access Transmission Tariffs ("OATTs") are practices affecting rates pursuant to Section 206 and 306 of the Federal Power Act,[33] and that those practices are unjust and unreasonable or unduly discriminatory or preferential and result in unjust and unreasonable transmission rates.[34] The Complaint also establishes an appropriate replacement rate, revising local planning tariffs to prohibit local transmission planning for FERC-jurisdictional transmission facilities at 100 kV or above, and a reciprocal change to regional tariffs to require exclusively regional planning of include 100 kV and above transmission facilities in the already required regional planning based on existing Order No. 1000 planning regions.[35] The proposed replacement rate also requires that regional planning be conducted by an independent transmission system planner to ensure that consumers benefit from the determination of the appropriate project and are not again stymied by the self-interest and undue influence of existing transmission providers and transmission-owning entities.

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[32] Because there is widespread and longstanding recognition from Congress, FERC, and NERC that facilities at a level of 100 kV and above have regional impacts, this Complaint calls for drawing a clear line for exclusive regional planning at 100 kV.

[33] 16 U.S.C. § 824e & 825e.

[34] Local Planning makes it nearly impossible for consumers or the Commission to determine whether the rates for specific Locally Planned transmission additions are just and reasonable, as the individual planning is often not brought into Commission jurisdictional rates until years later upon project completion, leaving limited ability to recreate the planning that should have occurred.

[35] Although the Complaint proposes an appropriate just and reasonable replacement rate, because the Complaint establishes that the existing tariffs are unjust and unreasonable, the Commission is obligated to determine the appropriate just and reasonable rate. *FirstEnergy Serv. Co. v. FERC*, 758 F.3d 346, 353 (D.C. Cir. 2014) *quoting Md. Pub. Serv. Comm'n v. FERC*, 632 F.3d 1283, 1285 n. 1 (D.C. Cir.2011) (holding "It is 'the Commission's job—not the petitioner's—to find a just and reasonable rate.'")

The Commission has repeatedly recognized that allowing individual transmission owners to plan Commission-jurisdictional transmission facilities at the local level leads to inefficient transmission outcomes that hamper the Commission's ability to ensure just and reasonable rates.[36] The Commission made the finding again in Order No. 1920 but did nothing to address the root problem – the continued use of Local Planning by self-interested transmission owners. The Commission has made several revisions to the *pro forma* OATT in an effort to address the lack of regional planning without directly addressing the core deficiency – the existence of Local Planning. The Commission has also recognized that the self-interested nature of transmission owners inherently interferes with FERC's statutory objectives.[37] Notwithstanding those findings, the Commission has spent nearly two decades, without success, merely trying to *incentivize* individual transmission owners to plan at the regional level, and has thus far failed to require true regional planning by allowing local planning exceptions to run roughshod over regional planning rules.

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[36] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, Recovery of Stranded Costs by Public Utilities*, 61 Fed. Reg. 21,540, at 21,546 (May 10, 1996)("Order No. 888"), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 62 Fed. Reg. 64688, 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 Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002)(Order No. 888); *Regional Transmission Organizations*, Order No. 2000, 89 FERC ¶ 61,285, 65 Fed. Reg. 809, Stats. & Regs. ¶ 31,089 (Jan. 6, 2000), *order on reh'g*, Order No. 2000-A, FERC 65 Fed. Reg. 12088 (Mar. 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom*. *Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001) ("Order No. 2000"); *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 at P 422, *order on reh'g*, Order No. 890-A, 73 Fed. Reg. 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g and clarification*, Order No. 890-B, 73 Fed. Reg. 39092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 74 Fed. Reg. 12540 (Mar. 25, 2009), 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 74 Fed. Reg. 61511 (Nov. 25, 2009), 129 FERC ¶ 61,126 (2009) ("Order No. 890"); *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 76 Fed. Reg. 49842 (Aug. 11, 2011), FERC Stats. & Regs. ¶ 31,323 at P 268, fn 244, *order on reh'g*, Order No. 1000-A, 77 Fed. Reg. 31134 (May 31, 2012), 139 FERC ¶ 61,132 ("Order No. 1000-A"), *order on reh'g*, Order No. 1000-B, 77 Fed. Reg. 64390 (oct. 24, 2012), 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S. C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) ("Order No. 1000").

[37] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,682; Order No. 2000, Stats. & Regs. ¶ 31,089 at pp 152, 466; Order No. 1000 at P 268, fn 244 *quoting Carolina Power and Light Co.*, 94 FERC ¶ 61,273 at 62,010, *order on reh'g*, 95 FERC ¶ 61,282 at 61,995 (2001).

As early as Order No. 888 the Commission recognized that it was adopting "the less intrusive and less costly remedy" to transmission owner's discriminatory and self-interested behavior and that its approach risked a continuation of that behavior.[38] The concern expressed was well placed. While the Commission's approach may have been least costly to transmission owners, it has proven immensely costly to consumers with transmission rates skyrocketing. But "less intrusive" regulation has not worked. And now, that less intrusive policy has led the Commission to assert that "the transmission provider *holds the leverage* as to whether to build a [regional] transmission facility or a less efficient in-kind replacement transmission facility . . .."[39] Congress, however, gave FERC the leverage through the authority granted in the Federal Power Act and **mandated** that FERC act when unjust and unreasonable tariff provisions are present, as demonstrated by this Complaint. Further, the D.C. Circuit Court of Appeals has granted the Commission "great deference" in fashioning remedies, where the Commission's "discretion is often at its zenith."[40]

The Federal Power Act's requirement that the Commission **ensure** just and reasonable transmission rates, and practices and tariff provisions that impact those rates, requires that the Commission mandate revision of local and regional planning tariffs to: (1) prohibit individual transmission owner planning of FERC-jurisdictional transmission facilities 100 kV and above; and (2) require exclusive regional planning of all transmission facilities 100 kV and above,

[38] Order No. 2000 Stats. & Regs. ¶ 31,089 at pp 35-36, fn 68, noting that "in Order No. 888, the Commission received and considered numerous comments that functional unbundling was unlikely to work, and that more drastic restructuring, such as corporate unbundling, was needed. For example, the Federal Trade Commission advised the Commission that a functional unbundling approach 'would leave in place the incentive and opportunity for some utilities to exercise market power in the regulated system. Preventing them from doing so by enforcing regulations to control their behavior may prove difficult.' However, the Commission decided at the time to adopt the less intrusive and less costly remedy of functional unbundling."
[39] Order No. 1920 at P 1706 (emphasis added).
[40] *Sacramento Mun. Util. Dist. v. FERC*, 616 F.3d 520, 541 (D.C. Cir. 2010); *see Shetek Wind, Inc. et al.*, 138 FERC ¶ 61,250, at P 124 (2012).

utilizing existing Order No. 1000 regions. Further, to prevent continuation of self-interested decisions at the regional level, all regional planning must be conducted through an Independent Transmission Planner ("ITP") as described herein to ensure the best project for the interconnected grid is the project that flows from the regional plan.[41]

II. DESCRIPTION OF PARTIES

A. Complainants

The Complainants are comprised of several consumer-oriented parties and advocates that have expressed longstanding concerns about transmission planning, transmission rates, transmission affordability, and economic efficiency over the past several years in several different RTO/ISO regions and non-RTO/ISO regions in the United States.

1. ***Industrial Consumers of America ("IECA").*** IECA is a nonpartisan association of leading manufacturing companies with $1.3 trillion in annual sales, over 12,000 facilities nationwide, and with more than 1.9 million employees. IECA was founded on the belief that a robust, diverse and affordable supply of energy is required to sustain economic growth, quality of life for our citizens, and the competitiveness of industry. IECA promotes the interests of manufacturing companies through advocacy and collaboration for which the availability, use and cost of energy, power or feedstock play a significant role in their ability to compete in domestic and world markets. IECA membership represents a diverse set of industries including: chemicals, plastics, steel, iron ore, aluminum, paper, food processing, fertilizer, insulation, glass, industrial gases, pharmaceutical, consumer goods, building products, automotive, independent oil refining, and cement all of which use tremendous amounts of electricity in their industrial processes. IECA

[41] To be clear, the Complaint does not seek elimination of individual transmission owner identified planning criteria. Those criteria, as reported to the Commission and available to stakeholders, would be incorporated into the regional planning criteria.

has members throughout the United States. The U.S. manufacturing sector consumes approximately 34% of U.S. electricity production. The vast majority of IECA member companies are energy intensive trade exposed, which means that relatively small increases in the price of electricity can have relatively high negative impacts to their global competitiveness – directly impacting jobs and investment.

2. ***American Forest & Paper Association*** **("AF&PA").** AF&PA serves to advance a sustainable U.S. pulp, paper, packaging, tissue, and wood products manufacturing industry through fact-based public policy and marketplace advocacy. AF&PA member companies make products essential for everyday life from renewable and recyclable resources and are committed to continuous improvement through the industry's sustainability initiative – *Better Practices, Better Planet 2020*. The forest products industry accounts for approximately 4% of the total U.S. manufacturing GDP, manufactures over $200 billion in products annually, and employs approximately 900,000 men and women. The industry meets a payroll of approximately $50 billion annually and is among the top 10 manufacturing sector employers in 45 states. AF&PA member companies purchase a significant amount of electricity in Commission-regulated markets, and have observed transmission charges as a growing portion of their total charges for electricity.

3. ***PJM Industrial Customer Coalition*****.** PJMICC is a continuing *ad hoc* association of large industrial and commercial end-users of electricity in the PJM Interconnection, L.L.C. ("PJM") region operated for the purposes of representing the interests of large energy consumers. PJMICC member companies pay transmission rates that are assessed by PJM transmission owners, and have observed transmission charges as a growing portion of their total charges for electricity. PJMICC's members include manufacturers and other energy-intensive consumers. Increased energy costs impair CMTC members' competitiveness and have directly contributed to elevated risks of facility closures and job losses

4. ***Coalition of MISO Transmission Customers.*** CMTC is a continuing *ad hoc* association of large industrial and commercial end-users of electricity in the Midwest operated to represent the interests of industrial energy consumers before regulatory and legislative bodies. CMTC has participated in the Midcontinent Independent System Operator, Inc. ("MISO") market/transmission issues since the inception of CMTC more than 20 years ago. CMTC member companies pay transmission rates that are assessed by MISO transmission owners. Some CMTC member facilities are assessed transmission charges as a separate, stand-alone charge on invoices assessed by market suppliers. Other CMTC facilities pay for transmission charges on a bundled basis, as a component of retail electricity charges that also included charges for generation and distribution service. CMTC's members include manufacturers and other energy-intensive consumers. Increased energy costs impair CMTC members' competitiveness and have directly contributed to elevated risks of facility closures and job losses.

5. ***Resale Power Group of Iowa.*** RPGI is a special-purpose governmental entity organized in 1986 pursuant to Iowa law to purchase electric supply, transmission, and related services as agent for its members. RPGI's members are 24 Iowa municipal utilities, one cooperative, and one privately-owned utility that (with one exception)[42] are exempt from the Commission's jurisdiction under Section 201(f) of the Federal Power Act.[43] RPGI is legally separate and fiscally independent from other state and local governmental entities.

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[42] The Amana Society Service Company is a small transmission-dependent electric utility that is privately owned by the Amana Society and provides service only to retail customers within the service territory of the Amana Society in Iowa. Its current annual sales are 71,000 MWh and its peak load is 13 MW. Because of its size, it is not subject to rate regulatory authority of the Iowa Utilities Commission.

[43] 16 U.S.C § 824f.

The electric transmission rates paid by most RPGI members are determined primarily according to the Network Integration Transmission Service ("NITS") Schedule 9 formula rate for ITC Midwest set forth in MISO's transmission tariff.[44] RPGI's members that do not receive NITS from ITC Midwest purchase that service from MidAmerican Energy Transmission Company. Other RPGI members located outside MISO are pseudo-tied into MISO where they purchase MISO Schedule 7 Point to Point ("PTP") transmission service. Over the past 15 years, RPGI's members have experienced staggering increases in transmission rates, especially the rates of ITC Midwest, that have eliminated any benefit of reduced purchased power costs or congestion relief from new infrastructure projects and have created such significant rate disparities among Iowa transmission providers that some members have bypassed ITC Midwest's system, choosing to incur significant new interconnection facility costs rather than continuing to pay ITC Midwest's higher rates.

6. ***R Street Institute.*** The R Street Institute is a Washington, DC-based think tank engaged in policy research in support of free markets and limited, effective government. The energy and environmental policy program at R Street has long advocated for competition in wholesale and retail energy marketplaces and effective regulation of industry in cases in which competition cannot be made effective in meeting industry and consumer needs. The program's work on transmission policy has been extensive, spanning legal and economic research to regulatory interventions to convenings of national transmission consumer groups.

7. ***Pennsylvania Energy Consumer Alliance ("PECA").*** The Pennsylvania Energy Consumer Alliance (PECA) consists of businesses, manufacturers, colleges and other

[44] These members pay ITC Midwest's Joint-load Zonal rate, which is slightly lower than the ITC Midwest-only NITS rate. The zonal rate is an average rate that is calculated based on a weighted average of the NITS rates of ITC Midwest and seven small transmission utilities that are in the ITCM Transmission Joint-load Rate Zone. The ITC Midwest-only rate represents approximately 95% of the Joint-load Rate Zone.

organizations that support pro-growth energy policies in Pennsylvania to keep energy costs at competitive levels in the national and international markets and support our members' successes. PECA focuses its efforts on working with legislative, regulatory and executive leadership so that Pennsylvania state government: 1) understands the impact that energy and energy policy has on business, 2) prioritizes the importance of energy to Pennsylvania's economy, and 3) balances various legislative and regulatory initiatives with the goal to enhance the business growth opportunities in the Commonwealth.

8. ***Association of Businesses Advocating for Tariff Equity ("ABATE").*** ABATE is an interest group of large energy users representing its members before regulatory and governmental bodies and other organizations that affect Michigan's energy pricing, reliability, and terms and conditions of service. Since 1981, ABATE's purpose has been to represent the large energy user viewpoint on energy and utility issues before all appropriate governmental bodies and other pertinent organizations which affect energy pricing, reliability, sustainability and terms and conditions of service in Michigan. ABATE continues its mission to be vigilant in securing reasonable rates in the face of predicted substantial cost increases.

9. ***Wisconsin Industrial Energy Group***. WIEG is a voluntary member association consisting of large industrial and commercial customers in the State of Wisconsin. WIEG is concerned about affordability and the impact the rising trend in transmission costs will have on customers. Wisconsin's advocacy groups, including WIEG, have worked hard to remove barriers to competitive bidding in Wisconsin. Cost effective transmission is crucially important now more than given MISO's costly four-tranche long-range regional transmission planning initiative. Wisconsin manufacturers cannot afford rate hikes due to unnecessary or wasteful spending caused by inefficient and uncompetitive transmission planning.

10. ***Glass Packaging Institute.*** Founded in 1919 as the Glass Container Association of America, the Glass Packaging Institute ("GPI") is the trade association representing the North American glass container industry. On behalf of glass container manufacturers and their supply chain partners, GPI promotes glass as the optimal packaging choice, advances environmental and recycling policies, advocates industry standards, and educates packaging professionals. GPI members consist of companies that make up the vast majority of North America's leading glass container manufacturing companies.

11. ***Multiple Intervenors (New York).*** Multiple Intervenors, an unincorporated association of large industrial, commercial and institutional energy consumers with manufacturing and other facilities located throughout New York State, advances the interests of its members in ensuring access to reliable energy supplies at the lowest reasonable cost.

12. ***Carolina Utility Customers Association, Inc. ("CUCA").*** CUCA is a 501 C(6) non-profit trade association serving North Carolina industries and manufacturers. Since CUCA's inception, our primary focus has been to secure reliable energy at the lowest possible rate for our members. For the past 37 years, we have had a seat at the table where utility issues have been negotiated. We have successfully prevailed in keeping energy cost-effective through amicable working relationships with regulators, legislators, utilities, and stakeholders in the energy arena.

13. ***Arkansas Electric Energy Consumers ("AEEC").*** Arkansas Electric Energy Consumers promotes and represents the interests of industrial electric energy consumers by providing joint resources for effective representation before various state and federal regulatory agencies to ensure their interests are effectively represented.

14. ***Public Citizen, Inc***. Established in 1971, Public Citizen is a national, not-for-profit, non-partisan, research and advocacy organization representing the interests of household consumers. Public Citizen is active before FERC promoting just and reasonable rates, and supporting efforts for utilities to be accountable to the public interest. Financial details about the organization are on the web site: www.citizen.org/about/annual-report/.

15. ***Public Power Association of New Jersey ("PPANJ").*** PPANJ is a non-profit association of New Jersey public power and rural electric cooperative systems comprised of the municipal electric utilities of the Boroughs of Butler, Lavallette, Madison, Milltown, Park Ridge, Pemberton, Seaside Heights, South River, the Vineland Municipal Electric Utility, and Sussex Rural Electric Cooperative, Inc. Nine of the ten PPANJ members are members of PJM Interconnection, L.L.C. ("PJM"). Every PPANJ member system depends upon PJM for transmission services.

16. ***Oklahoma Industrial Energy Consumers ("OIEC").*** OIEC's mission is to achieve the most reliable and lowest, reasonably priced energy supply for Oklahoma industrial consumers by influencing energy policy development and decision making. Since 1995, OIEC has acted on behalf of industrial and other large consumers of energy. OIEC has successfully secured utility energy cost reductions and opposed significant utility rate increases for its members. OIEC seeks to ensure that Oklahoma companies have a voice in energy policies that impact the cost of doing business in our state.

17. ***Large Energy Group ("LEG") of Iowa***. Large Energy Group of Iowa is a group consisting of industrial, hospital and city utility customers of Interstate Power and Light Company ("IPL").The primary focus of the LEG is to ensure approval of rates in the IPL electric system that are based on costs that reflect market-determined capacity and energy cost components, load factors, delivery voltage levels, customer-related costs, levels of interruptibility, and time of usage, without subsidies among customer classes.

18. ***Industrial Energy Consumers of Pennsylvania ("IECPA").*** The Industrial Energy Consumers of Pennsylvania ("IECPA") is an association of large, energy-intensive, trade-exposed industrial entities taking electricity service from a variety of regulated utilities and competitive suppliers in Pennsylvania. As a voice for large energy consumers in Pennsylvania, IECPA has played a critical role in the restructuring of the electric industry and supports and promotes competitive energy markets, including transmission markets, and regulatory structures that facilitate consumers' use of those markets.

19. ***Maryland Office of People's Counsel ("MD OPC").*** The Maryland Office of People's Counsel is an agency of the State of Maryland established under Maryland law.[45] By statute, OPC is authorized and charged, among other matters, to represent and "protect the interests of" Maryland's residential and non-commercial customers of electric service before state and federal regulatory agencies, including the Commission.[46]

20. ***Pennsylvania Office of Consumer Advocate ("PA OCA").*** The Pennsylvania Office of Consumer Advocate (PA OCA) is statutorily authorized to represent the interests of Pennsylvania retail utility consumers in matters before the Pennsylvania Public Utility Commission, federal and state courts, and federal regulatory agencies. 71 P.S. § 309-1 et seq. The PA OCA is led by the Consumer Advocate, Patrick Cicero.

21. ***Consumer Advocate Division of the Public Service Commission of West Virginia.*** The Consumer Advocate Division's ("CAD") primary responsibility is to represent the interests of West Virginia residential users of utility service. CAD's attorneys advocate for rates,

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[45] Md. Code, Public Utilities Art., §§2-201 et seq.
[46] Id., § 205(b).

services and practices to benefit residential customers in regulatory and court proceedings. Most of our work takes place in proceedings before the West Virginia Public Service Commission (WV PSC), the state agency that regulates utility companies. These proceedings include cases, rulemakings, public conferences and work groups set up by the WV PSC. CAD also intervenes in cases before the FERC, the federal agency that oversees wholesale electricity markets, interstate electricity transmission and interstate gas transportation. As a result of the deregulation of the retail electric industry in West Virginia in 1999, the importance of FERC policies and decisions for West Virginia consumers has increased dramatically. CAD has been an advocate for West Virginia consumers in numerous FERC cases involving wholesale market issues and interstate transmission line costs to be allocated to West Virginia consumers. At the same time, CAD is an active consumer representative in the PJM stakeholder groups concerning the operation of the regional transmission organization. We sometimes participate in these cases as part of a coalition of consumer offices and other agencies.

22. ***Missouri Industrial Energy Consumers (*"MIEC").** The Missouri Industrial Energy Consumers represent the interests of industrial electric energy consumers in the State of Missouri before various state and federal regulatory agencies to ensure their interests are effectively represented.

B. Respondents

This Complaint has sought relief against the local planning tariffs of all FERC-jurisdictional *public utilities* in the United States and the RTO/ISOs to which some are members which RTO/ISO tariffs facilitate Local Planning. To the best of Complainants' knowledge, the FERC-jurisdictional *public utilities* in non-RTO/ISO regions include the following:

- Avista Corporation;
- Idaho Power Company;

- MATL LLP;
- NorthWestern Corporation;
- PacifiCorp;
- Portland General Electric Company;
- Puget Sound Energy, Inc.;
- Duke Energy Florida, LLC;
- Florida Power & Light Company;
- Tampa Electric Company;
- Dominion Energy South Carolina, Inc.;
- Duke Energy Carolinas, LLC;
- Duke Energy Progress, Inc.;
- Louisville Gas and Electric Company and Kentucky Utilities Company;
- Southern Company Services Inc., as agent for Alabama Power Company, Georgia Power Company, Georgia Power Company, and Mississippi Power Company;
- Arizona Public Service Company;
- Black Hills Power, Inc.;
- Black Hills Colorado Electric Utility Company, LP;
- Cheyenne Light; Fuel & Power Company;
- El Paso Electric Company;
- NV Energy, Inc.;
- Public Service Company of Colorado;
- Public Service Company of New Mexico;
- Tucson Electric Power Company; and
- UNS Electric, Inc.

As to the Respondent RTOs/ISOs, PJM Interconnection, L.L.C. ("PJM") is a "public utility" as that term is defined in Section 201(b)(2)(e) of the FPA.[47] PJM is a duly authorized RTO approved by the Commission pursuant to 18 C.F.R. § 35.34. Similarly, Southwest Power Pool, Inc. ("SPP") is a "public utility" as that term is defined in Section 201(b)(2)(e) of the FPA. SPP is a duly authorized RTO approved by the Commission pursuant to 18 C.F.R. § 35.34. The Midcontinent Independent System Operator, Inc. ("MISO") is a "public utility" as that term is defined in Section 201(b)(2)(e) of the FPA. MISO is a duly authorized ISO approved by the Commission pursuant to 18 C.F.R. § 35.34. The California Independent System Operator, Inc ("CAISO") is a "public utility" as that term is defined in Section 201(b)(2)(e) of the FPA.

[47] 16 U.S.C. § 824(b)(2)(e).

CAISO is a duly authorized ISO approved by the Commission pursuant to 18 C.F.R. § 35.34. New York Independent System Operator, Inc. ("NYISO") is a "public utility" as that term is defined in Section 201(b)(2)(e) of the FPA. NYISO is a duly authorized ISO approved by the Commission pursuant to 18 C.F.R. § 35.34. The Independent System Operator of New England, Inc. ("ISO-NE") is a "public utility" as that term is defined in Section 201(b)(2)(e) of the FPA. ISO-NE is a duly authorized ISO approved by the Commission pursuant to 18 C.F.R. § 35.34. All of the aforementioned RTOs/ISOs provide transmission and other FERC-jurisdictional market services under their FERC-approved tariffs. Complainants are also serving this Complaint on FERC-jurisdictional, incumbent transmission-owning public utilities within the FERC-jurisdictional RTOs/ISOs.[48]

III. SUMMARY OF THE PROBLEM AND REQUIRED SOLUTION

A. Individual Transmission Owner Self-Planned Transmission Has Exploded

In the last 15 years, hundreds of billions of dollars have been invested in electric transmission, with nearly half of the investments based on "local" utility criteria that does not subject the project to regional planning[49] ("Self-Planned Transmission"). Because the projects are "Locally Planned," the projects are also cost allocated exclusively to the customers in the pricing zone of the planning transmission owner, regardless of beneficiaries.[50] These

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[48] For a list of those FERC-jurisdictional, incumbent transmission-owning public utilities, please see the attached service list (**Attachment D**). Complainants have endeavored to serve this Complaint on all incumbent transmission owners within the FERC-jurisdictional RTOs/ISOs. The service list reflects Complainants' best understanding of the incumbent transmission owners within the FERC-jurisdictional RTOs/ISOs. Any omission of an interested, FERC-jurisdictional transmission-owning entity is inadvertent.

[49] The total was approximately $25 billion invested, with about half "solely based on 'local' utility criteria." Brattle Group, *Annual U.S. Transmission Investments, 1996-2023*, (2023), available at https://www.brattle.com/wp-content/uploads/2023/07/Annual-US-Transmission-Investments-1996%E2%80%932023.pdf (last accessed Dec. 18, 2024).

[50] In *Consolidated Edison Company of New York, Inc.*, *et al.*, 180 FERC ¶ 61,106 (2022), the Commission accepted an agreement among New York transmission owners with captive load to create "a statewide cost allocation on a volumetric load-ratio basis for local transmission upgrades selected by the New York Public Service Commission (NYPSC) to meet New York State public policy goals." *Id*. at P 1. The New York Transmission Owners supporting the filing argued that "because of the statewide environmental, public health, and other benefits of a free-flowing

Commission-jurisdictional, Self-Planned Transmission additions have been planned and implemented by individual transmission owners based on planning criteria the individual transmission owner created, and without regard to the needs of their interconnected transmission neighbors or the broader planning region, and often without proof of an electrical need even for their own system.[51] A significant percentage of these Self-Planned Transmission additions have been new transmission facilities built to replace existing transmission facilities that have reached the end of operational life, without any analysis of whether the transmission facilities from the grid of yesterday are actually needed for the grid of today, or more importantly the right projects for the grid of tomorrow where "the differing characteristics of [new] resources are creating new demands on the transmission system."[52]

The Commission has commented that "evidence suggests that sufficiently long-term, forward-looking regional transmission planning and cost allocation to meet transmission needs driven by changes in resource mix and demand **is not occurring** in most transmission planning regions on a regular or consistent basis."[53] The Commission made it clear in Order No. 1920 that its focus in the final rule was on regional planning, and other than a transparency requirement around aging transmission assets, was making no changes to Local Planning and that any requested changes or limitation on Local Planning were outside the scope of the NOPR in RM21-17-000.[54] As demonstrated herein, existing individual transmission planning fails to

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decarbonized electric system, a cost allocation for Approved Local Transmission Upgrades confined to local customers would present a free-ridership problem that is unfair to consumers in local areas where upgrades are needed." *Id*. at 17.

[51] *The Office of the Ohio Consumers' Counsel v PJM Interconnection, L.L.C. et al*, filed September 28, 2023 in Docket No. EL23-105-000 ("OCC Complaint") at 3 (asserting that "Ohio consumers are paying billions of dollars for new, locally-planned Supplemental Projects whose need, prudence, and cost-effectiveness are evading all regulatory review."

[52] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Advance Notice of Proposed Rulemaking, RM21-17-000 at P 3 ("2021 Transmission ANOPR").

[53] NOPR, Docket No. RM21-17 at PP 34, 36 (emphasis added).

[54] Order No. 1920 at P 247.

ensure just and reasonable rates because the existing individual public utility OATT or local planning parts of regional OATTs continue to permit individual transmission owners to plan regionally interconnected transmission as if they are exclusively a "local" resource.

B. The Commission Has Recognized The Problem But Has Failed To Protect Consumers From Unjust And Unreasonable, Discriminatory Or Preferential Transmission Rates Resulting From Local Planning Abuses

In Order No. 890, the Commission reaffirmed its findings from Order Nos. 2000 and 2003 that "that opportunities for undue discrimination continue to exist *in areas where the pro forma OATT leaves transmission providers with substantial discretion*."[55] Local Planning is precisely one of those areas.[56] Therefore, the Commission declared: "[w]e cannot rely on the self-interest of transmission providers to expand the grid in a non-discriminatory manner."[57] Yet, that is exactly what existing Local Planning tariffs do and have done for decades.

The Commission's State of the Markets Report acknowledged the need for new transmission, noting that the "drivers of these evolving infrastructure needs are diverse and include the changing resource mix, increases in actual and forecasted demand for energy, and evolving reliability concerns that prompt the need for new and upgraded infrastructure to ensure reliable and cost-effective system operations."[58] But that same report recognizes that Self-Planning Transmission projects account for a large percentage of transmission rate base and that many of those projects are rebuilding the grid of yesteryear,[59] which is "a network of

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[55] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 26 (emphasis added), *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (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).
[56] Order No. 1920 at P 1706 asserting the Commission's belief that individual transmission owners "hold the leverage" as to whether to move forward with less efficient projects.
[57] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 422.
[58] 2023 State of the Markets Report at 18, available at https://www.ferc.gov/news-events/news/presentation-report-2023-state-markets.
[59] *Id*. at 20, noting that 382 of MISO's 572 projects were Self-Planned Transmission "Other Projects" in MISO, that the 572 new projects include 742 miles of new or upgraded lines, 87% of which are 161 kV or below, and that the

transmission infrastructure that was overwhelmingly built in the last century and in the face of a very different reality."[60] Allowing Local Planning to rebuild such facilities at the whim of individual transmission owners "undermines our economy and leaves customers less safe and secure, with enormous costs for both our grid and our country."[61] The Commission's summary of the State of the Market Report indicated that "[t]he United States saw more than 500 new transmission projects entering service in 2023, according to data from C3 Group LLC. These projects produced more than 4,000 miles of new transmission lines and upgrades, *mostly at the 138-kilovolt level*."[62] Data center demand, driven in part due to recent advances in artificial intelligence, continues to drive the need for new, cost-effective transmission.[63]

Commissioner Christie recently remarked that:

> Congress enacted a suite of **consumer protection statutes**, including the FPA almost 100 years ago. Congress's subsequent revisions to the FPA over the years, such as by the Energy Policy Act of 2005, signal **the ongoing importance of consumer protection in the Commission's regulatory responsibilities** …[64]

Commissioner Christie further opined that "it is absolutely essential for regulators to make sure that the interests of investors do not conflict with the public service obligations that a utility has."[65] While Commissioner Christie's comments focused on the impact of investor interests on the utilities in meeting their retail service obligation, the impact of transmission rates, whether

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$8.98 billion estimated cost was second highest total ever in MISO and that transmission owners in PJM put forward 277 Self-Planned Transmission projects totaling $2.4 billion in 2023.

[60] Joint Order No. 1920 Concurrence at P 34.

[61] Joint Order No. 1920 Concurrence at P 4. So called "right-sizing" of transmission owner declared rebuilds does not solve the problem that Local Planning of facilities 100 kV and over is unjust and unreasonable as the individual transmission owners are preventing holistic regional planning for all needs by the continued availability or individual planning authority.

[62] https://ferc.gov/news-events/news/ferc-state-market-report-need-transmission.

[63] *See, e.g.,* "Can regulators protect small customers form rising transmission costs for big data centers?" Utility Dive (Dec. 11, 2024), *available at* https://www.utilitydive.com/news/regulators-protect-small-customers-rising-transmission-costs-data-centers/735155/ (last accessed Dec. 18, 2024).

[64] *Federal Power Act Section 203 Blanket Authorizations for Investment Companies, Notice of Inquiry*, AD24-6-000, Christie, Commissioner, *concurring* at P 4.

[65] *Id*. at P 1.

collected at retail or wholesale, is exclusively within the Commission's jurisdiction and its duty to balance consumer and utility/investor needs.[66] In this regard, a utility's Self-Planned Transmission additions have a direct impact on its retail consumers as Commission rules currently *require* that such projects be paid for by consumers exclusively in the pricing zone of the transmission owner building the Self-Planned Transmission.[67] Further, while Commissioner Christie notes the existence of a "a state-granted monopoly franchise" that carries service obligations at the retail level, transmission planning for electric transmission in interstate commerce is subject to exclusively FERC jurisdiction (with the exception of siting of any planned facilities). The notion that there is Commission-jurisdictional "local transmission" at 100 kV and above is a mistaken concept that the Commission must cease permitting existing transmission owners to perpetuate.

The usual refrain that individual transmission owner planning is a necessary extension of retail service obligation,[68] is likewise misplaced. The former Chairman of the Kentucky Public Service Commission explained to the Commission that a significant volume of PJM related Self-Planned Transmission is planned by entities with no retail service obligation.[69] Indeed, the

[66] *New York v. FERC*, 535 U.S. 1 (2002); *NextEra Energy*, 898 F.3d at 21, *quoting Wis. Pub. Power v. FERC*, 483 F.3d 239, 262 (D.C. Cir. 2007) (*quoting Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) "[S]etting a just and reasonable rate necessarily 'involves a balancing of the investor and consumer interests'").
[67] *See Municipal Energy Agency of Nebraska, at al., v Public Service Company of Colorado*, filed February 16, 2024 in Docket No. EL24-74-000 ("Colorado Cities Complaint") (asserting, among other things, that local ratepayers are being improperly forced to pay for a regionally beneficial 560-mile double circuit 345 kV transmission addition because Public Service of Colorado improperly forced the project through as a locally planned transmission addition, notwithstanding violating its local planning tariff.)
[68] *See*, *e.g.*, Christie Order No. 1920 Dissent, at fn 6, referencing retail service obligations and inferring that the Commission's exclusive jurisdiction regarding transmission in interstate commerce should take a back seat to state level retail jurisdiction.
[69] Initial Comments of Kentucky Public Service Commission Chairman and Commissioner Kent A. Chandler at 23, filed in Docket No. RM21-17-000 on Aug. 17, 2022 (noting that: "The Commission needs to look no further than to PJM to see this is the case, where entities without a retail service obligation have built billions of dollars of rate base, primarily through the "local" transmission planning process, during the time Order No. 1000 has been in effect. See generally FERC rate filings for AEP Appalachian Transmission Co., AEP Indiana Michigan Transmission Co., AEP Kentucky Transmission Co., AEP Ohio Transmission Co., AEP West Virginia Transmission Co. The presumption that the local transmission system needs to be left alone so that incumbent utilities can maintain their retail service obligations has been proven to be demonstrably false. Across PJM, billions of dollars' worth of local

Federal Power Act's requirement that the Commission ensure that transmission rates are just and reasonable requires the Commission to reject efforts to expand retail distribution franchise territories into federally sanctioned transmission franchises[70] by allowing the perpetual rebuilding of FERC-jurisdictional transmission facilities at 100 kV and above, built decades ago, for a different grid and a different purpose without appropriate regional review.[71] The generation mix, load distribution, consumer preferences, technologies, and large load data centers are all vastly different today than half a century ago when facilities were placed into service. Rebuilding twentieth century infrastructure may be a viable solution for keeping the lights on, but it neglects the innovative potential of twenty-first century technologies and will not be the most cost-effective solution for decarbonizing the nation's power networks."[72]

The Commission has concluded that over reliance on Self-Planned Transmission "results in, among other things, transmission ***customers paying more than is necessary or appropriate*** to meet their transmission needs, customers forgoing benefits that outweigh their costs, or some combination thereof, ***which results in less efficient or cost-effective transmission investments and, in turn, renders Commission-jurisdictional regional transmission planning and cost allocation processes unjust and unreasonable***."[73] Ensuring the justness and reasonableness of transmission rates, whether paid through bundled retail rates or standalone transmission rates, is

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transmission is owned by entities that do not have retail service obligations or legal obligations under state law to maintain reliability."

[70] *West Virginia v. Environmental Protection Agency*, 597 U.S. 697 (2022).

[71] *See, e.g.*, Ari Peskoe, *Is The Utility Syndicate Forever*, 2021 Energy Law Journal Vol. 42 at 35, observing that "For more than a century, IOUs have enjoyed transmission monopolies within their state-granted service territories. A fundamental pillar of the IOU business model is to build more transmission in their exclusive retail footprints. As their local networks age, IOUs may find that the simplest paths forward for maintaining reliability, as well as the easiest for supporting their financial returns, are in replacing aging infrastructure or supplementing it with new or reconductored local lines."

[72] *Id*.

[73] Order No. 1920 at P 112 (emphasis added).

the exclusive obligation of the Federal Energy Regulatory Commission[74] and based on the facts set forth herein, the Commission is obligated to act to restrict individual transmission owner planning that renders jurisdictional rates unjust and unreasonable.[75]

C. Investor Self-Interest Leads To Self-Planned Transmission

Several factors impact the spending pattern that has burdened consumers. The massive spike in consumer expenditures for Locally Planned transmission is that incumbent utility self-interest responds to shareholder directives. The investor-owned utilities do not hide this fact, repeatedly telling Wall Street analysts the amount of Commission-jurisdictional capital expenditure ("CapEx") expected over the coming years in order to bolster stock prices.[76] The investor-owned utilities could only know the level of FERC-jurisdictional transmission CapEx if they also know that the jurisdictional transmission planned will inure to their rate base because they will not be subject to any competition to garner those projects, and thus exists the incentive for Self-Planned Transmission.[77]

For more than two decades, despite well-meaning efforts, the Commission has not protected electric consumers from the impact of Locally Planned transmission on transmission

[74] *New York v. FERC*, 535 U.S. 1 (2002).
[75] 16 U.S. Code § 824e.
[76] *See* "May 2024 Investor Meetings," PPL Corporation, at Slide 5, *available at* https://investors.pplweb.com/download/PPL+Investor+Meetings_May+2024_Website_Final.pdf (last accessed Dec. 19, 2024); "2024 Investor Update," Pacific Gas and Electric, Slide 11-14, *available at* https://s1.q4cdn.com/880135780/files/doc_presentations/2024/June/2024-Investor-Update-Presentation_Final.pdf (last accessed Dec. 19, 2024).; "2024 Earnings Presentation," Duke Energy, at Slide 20, *available at* https://s201.q4cdn.com/583395453/files/doc_financials/2024/q3/Q3-2024-Earnings-Presentation_vF-w-Reg-G.pdf (last accessed Dec. 19, 2024).; "Mid-Atlantic Investor Meeting," Ameren, at Slide 9, *available at* https://s21.q4cdn.com/448935352/files/doc_events/2024/Sep/18/mid-atlantic-investor-meetings-2024-vfinal.pdf. (last accessed Dec. 19, 2024).
[77] Certain transmission owners have also used state level lobbying muscle to have state incumbent preference laws, colloquially known as Right-of-First-Refusal laws or ROFRs, passed to prohibit consumers from benefitting from transmission competition in their state even when projects are planned regionally, thus also allowing those entities to predict future CapEx even if regionally planned. *See Industrial Energy Consumers of America, et al v. Midcontinent Independent System Operator, Inc.* EL22-78-000, at pp. 55-64 (filed July 22, 2024) (identifying the impact of such laws on consumers in the MISO footprint).

rates. Despite the Commission's emphasis on the importance of regional planning to achieve the Commission's statutory obligation to ensure just and reasonable transmission rates and despite multiple consumer focused filings requesting action on excessive Local Planning, the Commission has allowed individual transmission owners to thwart regional planning by both determining their individual transmission needs and fulfilling those needs virtually unchecked through Self-Planned Transmission.[78] At the same time, through the adoption of wide-spread formula rates, the Commission has shifted to consumers the burden of proving that those self-serving planning decisions were imprudent.[79] That burden – and overcoming that presumption of prudence – is nearly impossible to meet with planning hindsight, particularly when the **only** planning analysis available was done by the transmission owner implementing the project in

[78] *See, e.g.*, 2021 Transmission ANOPR at P 17 noting that "Generally, the transmission facilities that transmission providers include in their individual local transmission plans are incorporated into regional transmission plans as inputs, with minimal opportunity for stakeholder review in the regional transmission planning process." *See also* Post-Technical Conference Comments of the National Association of State Utility Consumer Advocates, filed March 23, 2023 in AD22-8-000 (noting "it is important to not lose sight of the need for reforms to address policies that are contributing to ongoing and escalating levels of local transmission investment and the regulatory gap that enables such unchecked investment and contributes to ongoing transmission rate pressure for electric consumers."); Initial Comments of the New England States Committee on Electricity, Docket No. RM21-17-000 (filed Aug. 17, 2022) at 79-80.

[79] *See*, *e.g.*, Pre-Conference Comments Of Maine Public Utilities Commission Chair Philip L. Bartlett II, filed in Docket No. AD22-8-000, October 4, 2022 by New England States Committee on Electricity (noting that "the use of formula rates has effectively shifted the burden from transmission owners to demonstrate just and reasonable rates, as would happen in a state rate case, to states and consumer advocates to rebut the proposed rate through challenges."

question.[80] Commissioner Christie has highlighted the lack of a realistic formula rate challenge process, given the burden and information deficit for consumers.[81]

As the Commission has recognized, transmission owners have largely resorted to self-interested local planning to avoid even the specter of competition.[82] Although the Commission inferred that the shift to local planning was a result of "perverse investment incentives"[83] created by the Commission, that assertion is misguided and fails to take into account the Commission's multiple prior findings that transmission owners will act in their economic self-interest in making transmission investment decisions.[84] The Supreme Court of the United States upheld the Commission's actions in Order No. 888 *et seq.* taken specifically to address the economic reality that transmission owners will act in their self-interest.[85] Interestingly, Justice Thomas concurred in part and dissented in part,[86] not because the Commission went too far in exercising its

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[80] Pre-Conference Comments Of Maine Public Utilities Commission Chair Philip L. Bartlett II, filed in Docket No. AD22-8-000, October 4, 2022 by New England States Committee on Electricity (noting "While it is true that states can review transmission costs when certificates of public convenience and necessity are required for transmission siting purposes, that is an isolated evaluation of a single project rather than a more comprehensive assessment of transmission investments by the utility or for the region as a whole. Moreover, asset condition projects—basically in-kind replacements due to age or deteriorating conditions—typically do not require any local siting review in Maine, and the costs are regionalized. This regulatory gap that exists where transmission project costs do not undergo any state-level review and only limited FERC review in a formula rate annual update proceeding is not insignificant. We have approximately $2.5 billion of installed asset condition projects in New England and another $3 billion of such projects in planning or construction.")

[81] *See* "FERC Commissioner urges reform of federal transmission planning and financial incentives," Blue Ridge Leader & Loudon Today (Jan. 3, 2024), *available at* https://blueridgeleader.com/ferc-commissioner-urges-reform-of-federal-transmission-planning-and-financial-incentives/ (last accessed Dec. 18, 2024).

[82] NOPR, Docket No. RM21-17 at PP 40, 344.

[83] NOPR, Docket No. RM21-17 at P 350.

[84] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, Recovery of Stranded Costs by Public Utilities*, 61 Fed. Reg. 21,540, at 21,546 (May 10, 1996)("Order No. 888"), FERC Stats. & Regs. ¶ 31,036 (1996); *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (Jan. 6, 2000), Stats. & Regs. ¶ 31,089 at pp 152, 466; *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 at P 422; *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 76 Fed. Reg. 49842 (Aug. 11, 2011), FERC Stats. & Regs. ¶ 31,323 at P 268, fn 244 *quoting Carolina Power and Light Co.*, 94 FERC ¶ 61,273 at 62,010, *order on reh'g*, 95 FERC ¶ 61,282 at 61,995 (2001).

[85] *New York v. FERC*, 535 U.S. 1 (2002).

[86] Joined by Justices Scalia and Kennedy.

exclusive federal jurisdiction, but **because it did not go far enough to protect retail consumers** as it relates to Commission-jurisdictional transmission.

> FERC failed to explain why regulating such transmission [bundled retail] is not "necessary," and FERC's inconclusive jurisdictional analysis does not provide a sound basis for our deference. . . . FERC's decision to exclude transmission because it is associated with a particular type of transaction appears to make little sense. And this decision may conflict with **FERC's statutory mandate to regulate when it finds unjust, unreasonable, unduly discriminatory, or preferential treatment with respect to any transmission subject to its jurisdiction**. . . . To be sure, I would not prejudge whether FERC must require that transmission used for bundled retail sales be subject to FERC's open access tariff. At a minimum, however, FERC should have determined whether regulating transmission used in connection with bundled retail sales was in fact 'necessary to eliminate undue discrimination and protect electricity customers.'[87]

As the Southeast Public Interest Groups informed the Commission, "[f]or Southern Company, this bundled retail service accounts for roughly 90 percent of its transmission investment [while for] Duke Energy (Duke) in North Carolina, that figure is closer to 70-75 percent."[88] As such, the problem of Local Planning and unjust, unreasonable, unduly discriminatory, or preferential transmission rates is not an issue restricted to unbundled transmission service because in the bundled regions "the various Certificate of Public Convenience and Necessity (CPCN) and rate recovery processes in the region either do not capture all transmission facilities or do not assess transmission on a portfolio-wide basis to ensure a cost-effective mix of facilities."[89] The problem is a national problem that only the Commission can remedy.

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[87] *New York v. FERC*, 535 U.S. 1, 30-35, Thomas, Justice concurring in part and dissenting in part (emphasis added).
[88] Post-Technical Conference Comments of Southeast Public Interest Groups, filed March 23, 2023 in Docket No. AD22-8-000 at 4.
[89] *Id*. at 5 (noting that transmission planning "decisions are largely made during the planning stage such that proposed transmission investments arrive at the state commissions fully baked."

As part of its mandate that transmission providers participate in regional planning that results in a regional plan, the Commission unfortunately left transmission owners the ability to render that requirement meaningless by allowing the continued opportunity to develop Self-Planned Transmission facilities in their individual retail distribution service territory, if they have one, or footprint outside the regional planning requirement. Because the regionally planned projects could, depending on cost allocation and other exemptions, result in a project being subject to required competitive solicitation to determine the more efficient or cost-effective transmission developer, the level of Self-Planned Transmission skyrocketed. In addition, the age of the existing transmission facilities presented an opportunity to legitimize the increase as necessary to the rebuild of yesterday's grid without ever addressing whether yesterday's grid is the appropriate electric grid for America's tomorrow.

This increase in Locally Planned transmission additions was not because individual transmission owner planning was the best approach for consumers, or even the Commission's preferred approach, but because of the transmission owner's individual obligations to investors, *i.e.*, its self-interest. In this regard, Xcel Energy provides a perfect demonstration that economic self-interest geared toward investors, rather than consumers, will always prevail, demonstrating three different investor focused approaches to FERC-jurisdictional transmission in three different retail service territories: (1) reacting to Order No. 1000's regional competition requirement by successfully lobbying for a state incumbent preference when its lobbying power made that feasible in Minnesota;[90] (2) planning regionally impactful projects at the local level when it

[90] *See*, Testimony of Rick Evans, Xcel Energy, Minnesota Senate Energy, Utilities and Telecommunication Committee on Senate File 1815, Mar. 20, 2012, unofficial transcript submitted in EL22-78-000 Comments of LSP Transmission Holdings II, LLC and LS Power Midcontinent, LLC in Support of Complaint, at 13-15 & Exhibit 2, in support of a Minnesota incumbent transmission owner preference. As noted in that submission, Xcel also supported additional preference laws: Advertisement in support of Texas preference law, listing Xcel as a Sponsor, submitted in Docket No. EL22-78-000 Comments of LSP Transmission Holdings II, LLC and LS Power Midcontinent, LLC in Support of Complaint as Exhibit 8, pdf page 76; Testimony of Tony Clark, at 20:20-25 indicating that his testimony

could in WestConnect;[91] (3) when required to compete for a project in its footprint, because its efforts at a state preference law failed twice, asserting that its shareholder obligation prohibited it from agreeing to binding cost caps on its competitive transmission proposal under consideration.[92] While claiming in Colorado that it is not a transmission developer, Xcel is developing a $2 billion, 560 mile double circuit 345 kV Self-Planned Transmission project as a "local" transmission addition.

Of course, if transmission providers are unable or unwilling to effectively compete on design and cost and the Commission has provided them with an opportunity to avoid that requirement, not only will they seize that opportunity but they would have an obligation to shareholders to take it.[93] There is no effective regulatory check on the investor incentive to plan locally as long as Local Planning remains available. Yet, in requiring participation in regional

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in support of the bill was on behalf of Xcel, among other FERC jurisdictional utilities. *Id*. Exhibit 8 at pdf page 56; Testimony of Lino Mendiola, at 23:15-18 indicating that his testimony in support of the bill was on behalf of Xcel, among other FERC jurisdictional utilities. *Id*. Exhibit 8 at pdf page 57; s*ee also*, Xcel support for unsuccessful legislation in New Mexico. *Id*. at 47-50 & Exhibit 11 at pdf pages 5-7, 26-28, 40-41; 46-69.

[91] *See Municipal Energy Agency of Nebraska, at al., v Public Service Company of Colorado*, filed February 16, 2024 in Docket No. EL24-74-000 (asserting that Xcel affiliate Public Service Company of Colorado submitted the 560 mile double circuit 345 kV Pathway Project to the Colorado Commission as a "local" project.)

[92] SPP's Independent Expert Panel ("IEP") provided additional insight to the SPP Board on its evaluation of various proposals. Xcel affiliate Southwest Public Service Company submitted a proposal for the project but was not the recommended project developer. In answering why the Xcel proposal did not receive a higher score on cost containment, the Independent Expert Panel noted that: "Proposal C explained in Section 4.8 on Cost Guarantees that the company believes its various responsibilities '**prevents it from being able to provide a capped cost**.' The IEP awarded Proposal C 11.25 points in the Other Attachment Y Factors category of the Rates Analysis section; the minimum allowed for an acceptable response. Since Proposal C did not offer any cost cap/guarantee the IEP had no basis to award any additional points to Proposal C in this category." (emphasis added); *see also* Colorado Commission Proceeding No. 21A-0096E, Hearing Transcript (Nov. 15, 2021) at 89:5-8, 200:1-8, 201:15, and 255:2-7 (Public Service witness Ms. Trammell emphasized that while competitive transmission developers are "in the business of developing transmission projects, [t]hat's not the business model of Public Service," (at 89:5-8) and because Public Service is "not a developer," (at 201:15) it cannot generally subject itself to binding cost caps. Ms. Trammel also recognized (at 255:2-7) that cost uncertainty "adds a lot of risk to this project, for those components, which we do believe are generally beyond the control of the company.").

[93] *See* Affidavit of Paul Thessen, President LS Power Development, filed as Attachment 1 to the Comments of LS Power Grid, LLC To The Commission's Notice Of Proposed Rulemaking in RM21-17-000, at 26:3-30:2 (discussing that regulation cannot be as effective as competition in establishing just and reasonable rates because investor owned utilities will always have an incentive to obtain the highest available rate.)

planning that leads to a regional plan, the Commission also *required* that the regional planning process evaluate displacement of locally planned projects. The Commission held:

> These reforms work together to ensure that public utility transmission providers in every transmission planning region, in consultation with stakeholders, evaluate proposed alternative solutions at the regional level that may resolve the region's needs more efficiently or cost-effectively than solutions identified in the local transmission plans of individual public utility transmission providers. This, in turn, will provide assurance that rates for transmission services on these systems will reflect more efficient or cost-effective solutions for the region.[94]

Despite this clear directive, the interaction of local and regional planning processes has prohibited meaningful regional displacement efforts.[95]

Finally, while transmission owner self-interest is a primary driver of Locally Planned rate-base additions, the Commission has also played a part in perpetuating Self-Planned Transmission. The Commission issued a series of orders in CAISO and PJM allowing, over consumer interest objections, allowing transmission owners to rebuild, virtually unimpeded, the grid of yesterday regardless of whether the grid of yesterday is the appropriate grid of tomorrow.[96] Consumer-focused interests sought to ensure that the grid of tomorrow was planned at the regional level, rather than allowing yesterday's transmission owners to solidify a perpetual transmission monopoly to simply rebuild what they built decades ago for a different reason and a different grid. When presented with the opportunity to address the over-reliance on Local

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[94] Order No. 1000 at P 68.

[95] Parties to the Commission's Advanced Notice of Proposed Rulemaking, Docket RM21-17-000 identified this deficiency in the Commission's enforcement of prior transmission planning orders. *See e.g.*, Comments Of LS Power Grid, LLC In Response To The Commission's Advanced Notice Of Proposed Rulemaking, filed October 12, 2021 at pp 130-132, 134-135 (noting the lack of displacement despite the Commission directive and seeking a Commission show cause order).

[96] *See S. Cal. Edison Co.*, 164 FERC ¶ 61,160, (2018); *Cal. Pub. Utils. Comm'n v. Pac. Gas & Elec. Co.*, 164 FERC ¶ 61,161, at P 68 (2018); *PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,136, at PP 12, 89, *order on reh'g*, 173 FERC ¶ 61,225 (2020); *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,242, at P 54 (2020), *order on reh'g*, 176 FERC ¶ 61,053 (2021).

Planning, the Commission undertook a narrow reading of its precedent to find that existing transmission owners could rebuild the grid of yesterday without meeting even the minimum required consumer engagement set in Order No. 890.[97] Likewise, in partial reliance on its narrow ruling regarding Order No. 890, the Commission narrowly read contractual provisions among transmission owners and PJM to prohibit planning for the grid of tomorrow at the regional level, notwithstanding overwhelming stakeholder support.[98] But the Commission itself acknowledges: "**Our country cannot meet the challenges of today, let alone tomorrow, with yesterday's transmission system**.[99]

As supported in this Complaint, the transmission grid of today is an interconnected machine that operates as three distinct units: Eastern Interconnect, Western Interconnect, and the Electric Reliability Council of Texas ("ERCOT").[100] While most of the pieces of these three machines were put in place more than a half-century ago by individual utilities, they have built upon the original purpose of the Federal Power Act by increasing the interconnection of individual utilities and enhancing reliability through transfers of power between utility zones. The "electric transmission grid is the backbone of the American economy and essential to the

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[97] *S. Cal. Edison Co.*, 164 FERC ¶ 61,160, at P 31 (2018) ("While Order No. 890 does not explicitly define the scope of 'transmission planning,' the Commission adopted the transmission planning requirements in Order No. 890 to remedy opportunities for undue discrimination in *expansion* of the transmission grid." (citing Order No. 890, 118 FERC ¶ 61,119 at PP 57-58, 421-422)).

[98] *PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,136, at PP 12, 89, *order on reh'g*, 173 FERC ¶ 61,225 (2020); *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,242, at P 54 (2020), *order on reh'g*, 176 FERC ¶ 61,053 (2021). The D.C Circuit Court of Appeals dismissed consumer-oriented parties' petition for review challenging the Commission's orders pertaining to End-of-Life projects in the PJM region. *Am. Mun. Power, Inc. v. FERC*, 86 F.4th 922 (D.C. Cir. 2023). The D.C. Circuit found that the consumer-side stakeholders did not demonstrate that FERC's findings regarding language provisions in the PJM Tariff and the PJM Consolidated Transmission Owners Agreement were arbitrary and capricious or that FERC's conclusions were not supported by reasoned decision-making. 86 F.4th 922, 931-937. This Complaint presents an opportunity for the Commission to direct revisions to RTO governance procedures and governing documents, such as the PJM Tariff and PJM Consolidated Transmission Owners Agreement, that impede regional planning and regional cost allocation for all FERC-jurisdictional transmission facilities at 100 kV and above.

[99] Joint Order No. 1920 Concurrence at P 4 (emphasis added).

[100] "The North American Power Grid Is One Large, Interconnected Machine." Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, U.S.-Canada Power System Outage Task Force (Apr. 2004) at 5; *see also Id.*, Figure 2.2 at 6.

national security of our country."[101] At Congress' direction, the Commission has recognized the interconnected nature of today's grid by establishing reliability standards for Bulk Power System facilities 100 kV and above.[102] Despite recognizing the interconnected nature of the grid for reliability purposes at 100 kV and above, the Commission nevertheless continues to allow individual transmission owners to plan at the 'local' level without regard to voltage or whether the planned project is the right project for the regional grid, or even for the supposed local area. These Local Planning tariff rules are unjust and unreasonable and unduly discriminatory.

The authorization of Local Planning for facilities that are 100 kV and above is a practice that directly affects transmission rates. Allowing individual planning decisions notwithstanding the interconnected nature of the transmission grid and the regional impacts of facilities 100 kV and above are unjust and unreasonable practices, whether or not it can be established that the rates for a particular project are unjust and unreasonable.[103] Rules that allow individual transmission owners to address needs they create through self-determined planning criteria, and which allow them to fulfil those self-proclaimed transmission needs without regard to the needs of neighboring systems or the region are unduly discriminatory. Simply creating planning criteria that suggests when a transmission facility has reached the end of operational life does nothing to address whether the facility remains necessary in an integrated grid.

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[101] "Chairman Phillips' and Commissioner Clements' Joint Concurrence on FERC Order No. 1920," (May 14, 2024), *available at* https://www.ferc.gov/news-events/news/chairman-phillips-and-commissioner-clements-joint-concurrence-ferc-order-no-1920 (last accessed Dec. 18, 2024).

[102] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594, Section 1211 (2005); Mandatory Reliability Standards for the Bulk-Power System, Order No. 693, 72 FR 16,416 (April 4, 2007), FERC Stats & Regs. ¶ 31,242 (2007) (Order No. 693).

[103] As described herein, a review of transmission investments **after** those transmission investments are already built and placed into rates leave consumers and the Commission effectively unable to determine whether the project was appropriate or not or produces just and reasonable transmission rates. Further, although some of those locally planned projects may be reviewed at the state level to determine whether siting of the project is appropriate, those proceedings cannot determine whether the resulting transmission rates are just and reasonable as the Commission has exclusive jurisdiction to make that determination.

As a Massachusetts Institute of Technology ("MIT") study noted in 2011, the load picture has changed significantly during the life of transmission assets that are currently being replaced.

> On average during 1950 to 1959, industrial customers accounted for half of retail sales of electricity. Industrial plants often run around the clock all year, so the more important industrial load is, the flatter the load duration curve tends to be. The relative importance of industrial customers has declined steadily since the 1950s, however, and on average in the 2000 to 2009 period, they accounted for only 28% of retail sales.[104]

MIT concluded that "Ongoing changes in the character of electricity demand and the future penetration of electric vehicles will, in the absence of other changes, tend to accelerate the decline in capacity utilization in the electric power system."[105] The changes noted in 2011 have only expanded. Now, artificial intelligence and the data centers serving those needs will transform electricity usage again.[106] Simply rebuilding the grid of yesterday, because the Commission allowed self-interested transmission owners to do so will not provide consumers the cost-effective resources they need, or the economically efficient transmission that the FPA mandates. The Commission has already conceded that ample evidence shows the failure of regional planning initiatives as a direct result of the availability of these Local Planning rules. To address Local Planning tariffs head-on and to remedy the unjust and unreasonable practices affecting and causing unjust and unreasonable transmission rates, the Commission must:

A. For every Commission-jurisdictional public utility transmission owner, require tariff revisions to remove FERC-jurisdictional transmission facilities[107] at 100 kV and above from Local Planning tariffs, and relevant RTO/ISO tariffs;

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[104] The Future of the Electric Grid, An Interdisciplinary MIT Study, 2011, at 16, available at https://energy.mit.edu/wp-content/uploads/2011/12/MITEI-The-Future-of-the-Electric-Grid.pdf. (last accessed Dec. 18, 2024).

[105] *Id*.

[106] See, e.g., https://www.scientificamerican.com/article/the-ai-boom-could-use-a-shocking-amount-of-electricity/ (last accessed Dec. 18, 2024).

[107] The Commission has existing processes in place to determine those electric facilities above 100 kV are not part of the interconnected transmission system and thus, non-jurisdictional to the Commission because they constitute distribution facilities.

B. For every Commission-jurisdictional transmission owner, require the amendment of regional planning tariffs to require that all planning for transmission facilities 100 kV and above be done at the regional or interregional level;

C. For every Commission-jurisdictional transmission owner, require that planning for transmission facilities at 100 kV or above reaching the end of operational life be planned at the regional or interregional level;

D. For every Commission-jurisdictional transmission owner, require that regional planning tariffs be amended to require that the regional planning within the existing Order No. 1000 regions be conducted by an independent transmission system planner as described below.

IV. THE COMMISSION HAS RECOGNIZED THE IMPORTANCE OF REGIONAL PLANNING AND AN INTERCONNECTED GRID

A common refrain regarding individual transmission owner planning is that the Self-Planned Transmission relates to a "local" issue. With respect to transmission facilities 100 kV and above, that assertion misrepresents the nature of today's interconnected transmission grid. As it relates to transmission 100 kV and above, the transmission planning rules allowing Local Planning reflect transmission planning from a century ago and have not kept pace with the regulatory requirements of the grid that exists today.

A. History Of The U.S. Grid

As the United States electrified, the early power distribution systems were localized in nature. They used direct current to transmit power over copper lines.[108] Because this transmission method was very inefficient, power plants needed to be located within one mile of load.[109] However, by the end of the 19th century, high-voltage power transmission lines using alternating current, which could transmit power over longer distances, began to be developed.[110] As a result, electric companies began building larger generators to serve larger loads.[111] This

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[108] *See* Electricity Transmission, A Primer, National Council on Electricity Policy, 2004, p. 2.
[109] *See id*.
[110] *See id*. "In 1896, George Westinghouse built an 11,000 volt AC line to connect a hydroelectric generating station at Niagara Falls to Buffalo, 20 miles away."
[111] *See id*.

development favored larger companies over the existing multiple small generators and local distribution systems.[112]

The first quarter of the 20th century saw the acquisition and consolidation of many of these smaller companies.[113] The consolidation of these smaller companies was accomplished through the use of various holding company structures.[114] By 1932, eight large holding companies controlled about three-quarters of the investor-owned utility business.[115] Although these holding companies resulted in the consolidated ownership of electric companies, **that joint ownership led to little consolidation or interconnectedness of the actual electric systems**. The structure (particularly the super holding companies) also gave rise to numerous abuses, such as the write-up of securities and inflation of capital assets, abusive intercompany financial practices and transactions (including charging operating company subsidiaries excessive fees).[116]

During their early formation, regulation of electric utilities was left primarily to the states. By 1927, however, because of the physics of electricity and the interconnection of utility lines across state borders, the United States Supreme Court in *Public Utility Commission of R. I. vs. Attleboro Steam & Elec. Co.*,[117] declared that electricity was not an intrastate but an interstate commodity that therefore was subject to federal regulation. At the time the only federal

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[112] *See id*. at 2-3.
[113] *See id*. at 3; *see* Giberson Testimony at 6:8-8:15.
[114] The holding company structures took one of four forms:

(1) Diversified investment (owned utilities which generated and distributed electricity over a wide geographic area but did not have contiguous territories and were not interconnected);
(2) Large connected (owned utilities which were widespread geographically but were interconnected with each other and served small to medium-sized communities);
(3) Large city (formed to serve large cities and consolidated service areas within a large city); and
(4) Super holding company (formed to hold other holding companies which could have been any one of the other three types).

See Public Utility Holding Company Act of 1935: 1935-1992, Energy Information Administration (January 1993) at Chapter 2, pp. 3-4.
[115] *See* Electricity Transmission, A Primer, National Council on Electricity Policy, 2004, p. 3.
[116] *See* Public Utility Holding Company Act of 1935: 1935-1992, Energy Information Administration (January 1993) at Chapter 3, pp. 2-5.
[117] 273 U. S. 83, 89 (1927).

regulation of electric utilities was the Federal Power Act of 1920, which dealt with licensing of hydropower projects,[118] thus identifying what became known as the *Attleboro* gap.[119] The growth of holding companies during the late 1920s and early 1930s, which led to the increased level of consolidation of control of the operating companies, and the operating companies' poor performance during the Great Depression, gave rise to calls for federal regulation of the holding companies to address the interstate nature of electricity and to close the *Attleboro* gap.[120] So, in 1935, Congress passed the Public Utility Holding Company Act ("PUHCA 1935")[121] and the Federal Power Act.[122]

Two key components of PUCHA 1935 required holding companies with interstate assets to (1) eliminate unnecessary complexity by either selling off their multistate holdings *or operating their utility assets as a single integrated utility*,[123] and (2) register with and submit to the financial scrutiny of the U.S. Securities and Exchange Commission.[124] As they do today, the electric utility operating companies and their holding companies strongly objected to federal regulation. Over 50 cases were brought challenging the law.[125] One of the more significant cases was *Electric Bond & Share Co. v. SEC*[126] in which the U.S. Supreme Court affirmed the constitutionality of the registration provisions of the act, finding that utility operations had a "*highly important relation to interstate commerce and the national economy*."[127] In *North*

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[118] *See* 16 U.S.C. §§ 791a, et seq.
[119] *See New York v. FERC*, 535 U.S. 1, 6 (2002)
[120] *See* Public Utility Holding Company Act of 1935: 1935-1992, Energy Information Administration (January 1993) at Chapter 2, p. 7.
[121] 15 U.S.C. § 79, et seq.
[122] *See* 16 U.S.C. §§ 201, et seq.
[123] *See, e.g.,* 15 U.S.C. § 79k (emphasis added).
[124] *See, e.g.* 15 U.S.C. §§ 79e – 79g, 79i & 79l.
[125] *See* Public Utility Holding Company Act of 1935: 1935-1992, Energy Information Administration (January 1993) at Chapter 3, p. 11.
[126] 303 U.S. 419 (1938).
[127] *Id*. at 441 (emphasis added).

American Co. v. SEC,[128] the Supreme Court upheld the provisions of PUHCA requiring operation of multistate facilities as a single integrated utility.[129]

The Federal Power Act meanwhile directly addressed the *Attleboro* gap by providing for exclusive federal regulation of interstate transmission service (including the rates and terms and conditions of such service) and interconnections between utilities because interconnection of electrical systems was in the national interest.[130] With respect to transmission, the Federal Power Act reserved to the states only the siting of transmission facilities.

In the post-World War II era the electric industry continued to grow and change.[131] Larger generation facilities were constructed to capture economies of scale and transmission facilities expanded.[132] During the 1950s and 1960s the number of higher voltage transmission lines tripled (to more than 60,000 circuit miles) providing utilities with access to more distant power sources.[133] The Commission recognized this history in Order No. 890, finding:

> In the first few decades after enactment of the Federal Power Act (FPA) in 1935, the industry was characterized mostly by self-sufficient, vertically integrated electric utilities, in which generation, transmission, and distribution facilities were owned by a single entity and sold as part of a bundled service to wholesale and retail customers. Most electric utilities built their own power plants and transmission systems, entered into interconnection and coordination arrangements with neighboring utilities, and entered into long-term contracts to make wholesale requirements sales (bundled sales of generation and transmission) to municipal, cooperative, and investor-owned utilities connected to each utility's transmission system. Each system covered a limited service area, which was defined by the retail franchise decisions of state regulatory agencies. This structure of separate systems arose

[128] 327 U.S. 686, 695-696 (1946).
[129] *See also, North American Co. v. SEC,* 327 U.S. 686, 695-696 (1946) (upholding provisions of PUHCA requiring operation as a single integrated utility).
[130] *See* 16 U.S.C. §§ 201, et seq.
[131] *See* Electricity Transmission, A Primer, National Council on Electricity Policy, 2004, p. 4.
[132] *See id*.
[133] *See id*.

> naturally primarily due to cost and the technological limitations on the distance over which electricity could be transmitted.[134]

In the late 1970's, Congress passed a federal statute which contributed to the increasingly interstate nature of the industry and brought about additional growth in both the transmission system and its use., the Public Utility Regulatory Policies Act of 1978 ("PURPA").[135] PURPA initiated the rise of a class of competitive, independent, non-utility generators, and further required that such non-utility generators be given access to the transmission grid to deliver their power.[136]

Because PURPA led to the advancement of non-utility generation, Congress included in the Energy Policy Act of 1992 a requirement that competitive generators be given access to the transmission system on comparable terms to what the transmission owner would charge itself. As discussed below, this mandate led to a number of Commission orders recognizing the importance of regional planning to an interconnected grid.

B. Interconnected Nature Of Today's Transmission Grid And Importance To Interstate Commerce And The Reliable Provision Of Electricity

The interconnected nature of the transmission grid and its importance to interstate commerce can be demonstrated by the impact of some of the more recent disruptions to the grid, which led to a recognition of the need to designate an Electric Reliability Organization and to develop standard reliability criteria. Those disruptions demonstrate the highly interconnected nature of today's electricity grid as well as the impact on the national economy from that grid. In fact, a robust national transmission grid is essential to not only a strong economy but also for national security. The Macro Grid Initiative argues that National Security Depends on a Robust

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[134] Order No. 890 at P 10.
[135] *See* 16 U.S.C. §§ 2601, et seq.
[136] *See* Electricity Transmission, A Primer, National Council on Electricity Policy, 2004, pp. 4-5.

Transmission Grid: "Transmission buildout is critical to resilience as it can relieve line overloading—or 'congestion' in industry jargon—on the existing system, lessening the compounding risks that come with a strained grid that could then be tested by an extreme weather event or an attack incident."[137] Today's individual transmission owner-centric planning tariffs place that National Security grid determination in the hands of 100s of self-interested transmission owners, planning for their individual rate-base needs.

1. 1965 Northeast Blackout

On November 9, 1965, a 230-kv transmission line near Ontario, Canada tripped causing 2 key 345-kv lines in New York and several lower voltage lines to open, 5 of 16 generating units to trip, and 10 generating units to shut down.[138] This sequence of events resulted in the loss of over 20,000 MW of load and left over 30 million people in 8 states and 1 Canadian province without power for up to 13 hours.[139] The affected area included parts or all of Connecticut, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Pennsylvania, Vermont, and Ontario.[140]

2. Western North America Blackout 1996

There were two major blackouts about 6 weeks apart in the summer of 1996 that impacted the same areas of Western Canada, Western United States and Northwest Mexico – i.e., Idaho, Colorado, Montana, Nebraska, Nevada, Oregon, South Dakota, Texas, Utah, Washington,

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[137] *See, e.g.,* MGI_National_Security_Transmission_Factsheet.pdf (acore.org) (last accessed Dec. 18, 2024) (citing Oak Ridge National Laboratory EIS Response.pdf (energy.gov)).
[138] *See* Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, U.S.-Canada Power System Outage Task Force (Apr. 2004) at p. 104.
[139] *Id.; see also* 9 of the Worst Power Outages in United States History (electricchoice.com) (last accessed Dec. 18, 2024).
[140] *Id.*

Wyoming, New Mexico, California and Arizona in the United States and Alberta and British Columbia in Canada, and Baja California Norte in Mexico.[141]

The first outage occurred on July 2-3, 1996 when a 345-kv transmission line in Idaho sagged into a tree and tripped out. A protective relay on a parallel line incorrectly tripped the second line, which in turn tripped two units at a nearby generation plant. With the loss of the generation units, *the frequency in the entire Western Interconnection declined* and voltage began to collapse in the Boise, Idaho area affecting the California-Oregon Intertie transfer limit.[142] Approximately 2 million people lost power for anywhere from a few minutes to several hours.[143]

The second outage occurred on August 10, 1996.[144] It was caused by several major transmission line outages, the loss of the McNary Dam generation, and resulting system oscillations.[145] The Western Interconnection separated into four electrical islands with significant loss of load (over 28,000 MW) and generation.[146] Approximately 7.5 million people lost power from a few minutes to 9 hours.[147]

3. Western Energy Crisis 2000

In 2000, drought conditions caused a shortage of hydropower.[148] During 2000, "approximately 10 gigawatts of generation capability was out of operation during some of the high demand times."[149] There was also insufficient transmission infrastructure in place, serving

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141 *See* Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, U.S.-Canada Power System Outage Task Force (Apr. 2004) at pp. 105-106.
142 *Id.* at 106.
143 *Id.* at 105.
144 *Id.* at 106.
145 *Id.*
146 *Id.*
147 *See* Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, U.S.-Canada Power System Outage Task Force (Apr. 2004) at p. 106.
148 FERC, "Addressing the 2000–2001 Western Energy Crisis: Chronology at a Glance," (Apr. 28, 2005), retrieved from https://www.ferc.gov/sites/default/files/2020-05/chronology-glance.pdf (last accessed Dec. 18, 2024).
149 US Energy Information Administration, "Subsequent Events – California's Energy Crisis," retrieved from https://www.eia.gov/electricity/policies/legislation/california/subsequentevents.html (last accessed December 18, 2024).

as a bottleneck in the electricity market.[150] Spot market prices were low during the years leading up to the crisis, which induced generation developers not to invest in developing more generation resources.[151] With retail electricity market restructuring at the state level, utilities were concerned about creating stranded assets that would not be able to recover costs.[152] Retail price caps with the high wholesale prices placed utilities in a weak financial position, so independent power producers "were reluctant to sell power to PG&E, [*sic*] and SCE."[153] The retail price caps also discouraged consumers from employing strategies to reduce their loads.[154] In addition, restructuring the natural gas market without sufficient oversight led to Enron and El Paso "churning" natural gas and manipulating natural gas markets to artificially inflate the price of power produced from the commodity.[155] Enron also manipulated the electricity market by scheduling power deliveries over congested lines and at times of peak demand.[156] As a result, grid planners "failed to fully appreciate and factor into decisions the risks facing the industry."[157]

4. Northeast Blackout 2003

A cascading series of events beginning in the afternoon on August 14, 2003 created a power outage that resulted in a loss of 61,800 MW of load and impacted about 50 million people throughout the United States and Canada.[158] The loss of both 345 kV and 138 kV transmission

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[150] *See Id.* "Path 15, the high voltage transmission line connecting southern California to northern California, became congested at times, reducing the flow of surplus electricity capacity in southern California to meet shortages in northern California."
[151] Northwest Power and Conservation Council, "Energy Crisis of 2000/2001," retrieved from https://www.nwcouncil.org/reports/columbia-river-history/energycrisis/ (last accessed Dec. 18, 2024).
[152] *Id.*
[153] *Id.*
[154] Congressional Budget Office, "Causes and Lessons of the California Electricity Crisis," (Sept. 2001), retrieved from https://www.cbo.gov/sites/default/files/107th-congress-2001-2002/reports/californiaenergy.pdf (last accessed Dec. 18, 2024).
[155] *See* Joel B. Eisen et al., Energy, Economics, and the Environment, 610-12 (5th ed. 2019).
[156] Joel B. Eisen et al., Energy, Economics, and the Environment, 741 (5th ed. 2019).
[157] Northwest Power and Conservation Council, "Energy Crisis of 2000/2001," retrieved from https://www.nwcouncil.org/reports/columbia-river-history/energycrisis/ (last visited Dec. 18, 2024).
[158] *See* Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, U.S.-Canada Power System Outage Task Force (Apr. 2004) at p. 1.

in the First Energy transmission footprint in Ohio led to impacts in an area including Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, and New Jersey in the United States and Ontario in Canada.[159] People were without power for a period that lasted for anywhere from a few hours to up to four days in some areas of the United States, while Ontario experienced rolling blackouts for more than a week before full power was restored.[160] Total costs associated with the 2003 blackout in the United States are estimated between $4 billion and $10 billion.[161]

5. Winter Storm Uri

Winter Storm Uri, occurred in February 2021 as a result of a weather event primarily impacting the Electric Reliability Council of Texas ("ERCOT"), and the South-Central United States, including SPP and MISO regions. Although the event resulted in more than 65,000 MW of unplanned generation outages and more than 23,000 MW of manual firm load shed,[162] the availability of an interconnected grid and interregional transfer capability in the Eastern Interconnection resulted in far less impacts than in the electrically isolated ERCOT region. Within Texas, the impact was devastating. More than 4.5 million people lost power and at least 210 people died.[163] The Federal Reserve Bank of Dallas estimated that the outages caused direct and indirect losses to the Texas economy of between $80 to $130 billion. ERCOT has limited import capability.[164]

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[159] *See id.* at 68 ("Starting at 15:39EDT, the first of an eventual sixteen138-kV lines began to fail(Figure 5.13). Relay data indicate that each of these lines eventually ground faulted, which indicates that it sagged low enough to contact something below the line.)
[160] *See id.* at 1.
[161] *See id.*
[162] The February 2021 Cold Weather Outages In Texas And The South Central United States | FERC, NERC And Regional Entity Staff Report, issued November 16, 2021, at 8.
[163] *Id*. at 9-10.
[164] *Id*. at 24-25 identifying the very limited HVDC import capability into ERCOT.

While SPP and MISO South also saw significant generation unavailability above expectations,[165] they were able to mute the impact of those generation loses with imports from other parts of the Eastern interconnect through interregional transfers. "Specifically, MISO was able to import large amounts of power from neighbors to the east (e.g. PJM Interconnection, LLC), and SPP was able to transfer some of that power through MISO. Those east-to-west transfers into MISO peaked at nearly 13,000 MW on February 15."[166] MISO and SPP have 193 tie-lines between them, with more than 100 of those being at 100 kV or more.[167]

6. Winter Storm Elliott

From December 23-25, 2022, Winter Storm Elliott hit the eastern United States and greatly tested the reliability of the Eastern Interconnection.[168] While natural gas pipeline disruptions and generation outages greatly attributed to the emergency situation in PJM arising from Winter Storm Elliott (and while the PJM transmission overall performed fairly well), PJM in its report on the storm explained the importance of certain interregional planning/coordination procedures, including the Shared Reserve Activation to help "provide faster relief of the initial stress on the interconnected transmission system."[169] PJM is typically a net exporter of energy but became a net importer for several hours on December 24.[170] PJM was unable to provide assistance to Tennessee Valley Authority ("TVA") and Duke (which were both in EEA-3 and shedding load), and instead PJM was receiving assistance primarily from NYISO.[171] In

[165] *Id*. at 14, noting that SPP averaged 20,000 MW of generation unavailable (based on expected capacity) for over four consecutive days, from February 15 to 19, and MISO South averaged 14,500 MW of generation unavailable for two consecutive days, from February 16 to 18.
[166] *Id*.
[167] *Id*. at 27, Figure 9. Notwithstanding the significant interregional transfer capability, because of its configuration MISO's intra-region north-south or south-north transfer capability is limited. *Id*. at 27-28, Figure 10.
[168] *See* Winter Storm Elliott: Event Analysis and Recommendation Report, *PJM Interconnection, L.L.C.*, at 1 (published July 17, 2023), *available at* 20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx (pjm.com) (last accessed Dec. 18, 2024) (hereinafter "PJM Winter Storm Elliott Report").
[169] PJM Winter Storm Elliott Report at 30.
[170] PJM Winter Storm Elliott Report at 44.
[171] PJM Winter Storm Elliott Report at 33.

coordinating with its neighboring RTOs, PJM explained that transmission constraints "limited PJM's ability to support export transactions across the southern interfaces."[172] PJM further explained that there was "a significant number of hours in which the assistance requested by other regions was not supplied."[173] Accordingly, Winter Storm Elliott illuminates the importance of the interconnectedness of the grid from an interregional perspective.

C. Commission Efforts To Incent Regional Planning Have Failed Because The Commission Allowed Retention Of Individual Transmission Owner Local Planning

1. Although Order No. 890 Recognized The Importance To Consumers Of Regional Transmission Planning Its Participation Requirement Has Not Ensured Cost-Effective, Efficient Regional Planning

In Order No. 888, the Commission encouraged joint planning between transmission providers and their customers and between transmission providers in a given region, but did not mandate such coordination.[174] Nearly a decade after issuing Order No. 888, the Commission found itself "compelled" to act through Order No. 890 to strengthen its transmission planning requirements with an emphasis on regional coordination because self-interested transmission owners were not planning the grid that was needed by all customers.[175] In determining the need to act, the Commission held that a nationally applicable rule was necessary to "promote efficient utilization of transmission **by requiring an open, transparent, and coordinated transmission planning process**."[176] The Commission declared that "Transmission planning is a critical function under the pro forma OATT because it is the means by which **customers** consider and

[172] PJM Winter Storm Elliott Report at 45.
[173] PJM Winter Storm Elliott Report at 45-46.
[174] Order No. 888-A at 30,311.
[175] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (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 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).
[176] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 3 (emphasis added).

access new sources of energy and have an opportunity to explore the feasibility of non-transmission alternatives."[177] Importantly, for purposes of this Complaint, the Commission made it clear that the Final Rule was necessary to protect transmission customers.

The Commission described the then-current transmission system in the United States as plagued by transmission constraints leading to "limited amounts of [available transmission capacity] in many regions, increased frequency of denied transmission requests, increasingly common transmission service interruptions or curtailments and rising congestion costs in organized markets."[178] This is because the lack of needed transmission inhibited customer access to generation resources outside the transmission provider's area even though Order No. 888 required open access and "power markets ha[d] become regional in almost every area of the country."[179] That is the same system that is being rebuilt today through Self-Planned Transmission by rate base focused individual transmission owners with no regard for whether rebuilding the grid of yesterday is right for tomorrow. Part of the problem was that "legacy systems constructed by vertically-integrated utilities prior to the adoption of Order No. 888 support 'only limited amounts of inter-regional power flows and transactions. Thus, existing systems [could not] fully support all of society's goals for a modern electric-power system.'"[180] Billions of dollars in these "legacy systems" are being rebuilt on an annual basis with little or no independent oversight as to whether they are the right project for the interconnected grid or consumers. The Commission is obligated to provide that oversight and ensure that planning practices are just and reasonable.

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[177] *Id*. (emphasis added).
[178] Order No. 890 at P 421; *see also id.* at P 58 (detailing evidence showing the "compelling need" for new transmission infrastructure but lack of transmission investment in new transmission infrastructure).
[179] *Id.* at P 523.
[180] *Id*. at P 58 (*quoting* Eric Hirst, U.S. Transmission Capacity: Present Status and Future Prospects at v (Aug. 2004).

In Order No. 890 the Commission noted that the planning requirements adopted in Order No. 888, which did not require transmission providers to engage in any sort of planning with neighboring systems, were insufficient to address the needs of the changing industry.[181] While there had been some efforts among transmission providers to plan with neighboring, interconnected systems, the Commission found that it could not rely on voluntary efforts.[182] Planning coordination among interconnected systems was too important to remain entirely voluntary.

To remedy this deficiency, the Commission included a "regional participation principle" as one of the principles that a transmission provider's planning process must satisfy.[183] The regional participation principle required transmission providers to include, in their planning processes, an opportunity to coordinate with interconnected systems. Specifically, as transmission providers developed their local plans, they were required to share plans with interconnected systems to ensure that the plans were simultaneously feasible and identify system enhancements that could relieve congestion or integrate new resources.[184]

The Commission *expected* regional coordination to "increase efficiency through the coordination of transmission upgrades that have region-wide benefits, as opposed to pursuing transmission expansion on a piecemeal basis."[185] The Commission hoped the requirement would spur investment in transmission facilities that a self-interested transmission provider planning alone was unlikely to plan.[186] The Commission found additional support for its regional planning requirement in the new provisions of EPAct 2005. EPAct 2005 added Section 219,

[181] Order No. 890 at P 524.
[182] *Id*. at P 525.
[183] *Id*. at P 523.
[184] *Id*.
[185] *Id*. at P 524.
[186] *Id*.

which required the Commission to "promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities . . .."[187] As this Compliant demonstrates, despite the Commission's efforts to implement Section 219, transmission owner self-interest has prevented the planning of "economically efficient transmission . . . by promoting capital investment . . . regardless of ownership." Instead, the Complaint demonstrates, existing transmission owners plan in a manner to ensure their continued ownership of the existing grid, even if those facilities have reached the end of operational life, and the ownership of all future facilities. The ability of individual transmission owners to Locally Plan through existing local planning tariffs allows circumvention of Section 219 and the Commission's implementation of that provision.

2. Longstanding Recognition by the Department of Energy For More Coordinated, Regional Grid Planning

As the Commission was implementing new transmission planning requirements in Order No. 890, the Department of Energy ("DOE") in July 2008 released a report ("DOE 2030 Report") highlighting the importance of building "a new transmission superhighway system" that includes a mix of shorter and longer distance transmission lines to ensure new generation resources can be connected to load centers.[188] The DOE 2030 Report provided some analysis of the cost-effective mix of needed new transmission and found that transmission planning itself needed to change.

> **Numerous parties across a wide geographic area would need to collaborate on developing a common plan, instead of individual**

[187] *Id*. at P 79 (*quoting* 16 U.S.C. 824s).
[188] DOE Office of Energy Efficiency and Renewable Energy, "20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply Report" at 95 (July 2008).

> **entities planning in isolation.** This approach yields major economics of scale in that all users would benefit by pooling solutions to their needs into a single plan that would be more productive (in regional terms) than simply summing the needs of individual organization.[189]

Following the DOE 2030 Report, DOE's Office of Electricity Delivery and Energy Reliability began a significant push for interconnection-wide planning.[190] Using funds made available through the American Recovery and Reinvestment Act of 2009,[191] the Office of Electricity Delivery and Energy Reliability funded (1) transmission planners who analyzed options for alternative electricity supplies and the associated transmission requirements at the interconnection-wide level and (2) state agencies' participation in the development of interconnection-level analyses and plans.[192] The stated goal was to facilitate the development of a robust transmission system in the three interconnections.[193] As a later memorandum described the electricity industry, the restructuring of the electricity sector prompted widespread support for "an evolution in how transmission planning is conducted" – away from the individual, vertically-integrated utility level to a regional and interregional level.[194] Despite the widespread support for increased regional planning and regional planning requirements, the trend has instead revealed a focus on Local Planning, leading the Electricity Advisory Committee a decade later to assert, "Planning processes at the local, regional and inter-regional levels are not adequately

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189 *Id*. at 98 (emphasis added).
190 *See* https://www.energy.gov/oe/recovery-act-interconnection-transmission-planning (last accessed Dec. 18, 2024).
191 American Recovery and Reinvestment Act of 2009, Pub. L. No. 111-5.
192 *See* https://www.energy.gov/oe/recovery-act-interconnection-transmission-planning (last accessed Dec. 18, 2024).
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193 DOE, Research Call to DOE/Federal Laboratories: Technical Support for Interconnection-Level Electric Infrastructure Planning RC-BM-2010 at 4 (April 1, 2010) *available at* https://www.energy.gov/oe/articles/research-call-doefederal-laboratories-technical-support-interconnection-level-electric (last accessed Dec. 18, 2024).
194 Memorandum from Electricity Advisory Committee to Honorable Patricia Hoffman, Assistant Secretary for Electricity Delivery and Energy Reliability, U.S. Department of Energy (June 6, 2013), *available at* https://www.energy.gov/oe/articles/eac-recommendations-doe-action-regarding-interconnection-wide-planning-june-6-2013. (hereinafter "2013 DOE Electric Infrastructure Planning Memo") (last accessed Dec. 18, 2024).

coordinated to process and in some cases, accelerate needed new transmission and interconnection projects."[195] Of course, the Commission reached this conclusion in 2007 in Order No. 890, finding "[w]e cannot rely on the self-interest of transmission providers to expand the grid in a non-discriminatory manner."[196]

The Office of Electricity Delivery and Energy Reliability awarded approximately $60 million in grants to support interconnection wide planning.[197] The funding facilitated the creation of the Eastern Interconnection Planning Collaborative, the first Eastern Interconnection-wide process.[198] It also strengthened the existing interconnection in the Western Interconnection and the Texas Interconnection.[199] Nevertheless, as discussed *infra*, we continue to rebuild the grid of yesterday because self-interested transmission providers are not required to do otherwise.

3. Order No. 1000 Regional Planning Requirements

After it issued Order No. 890, the Commission began collecting information through stakeholder meetings[200] and a notice of inquiry[201] about the effectiveness of transmission

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[195] Urgent Need To Reliably Facilitate The Energy Transition, Recommendations to the Department of Energy, October 18, 2023, available at https://www.energy.gov/sites/default/files/2023-10/EAC%20Recommendations%20-%20Urgent%20Needs%20to%20Reliably%20Facilitate%20the%20Energy%20Transition%20October%202023.pdf (last accessed Dec. 18, 2024).
[196] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 422.
[197] 2013 DOE Electric Infrastructure Planning Memo at 4.
[198] *Id*. at 4-5.
[199] *Id*.
[200] *Transmission Planning Processes Under Order No. 890*, Notice of Technical Conferences, Docket No. AD09-8-000 (June 30, 2009). The focus of the conferences was:

> (1) to determine the progress and benefits realized by each transmission provider's transmission planning process, obtain customer and other stakeholder input, and discuss any areas that may need improvement; (2) to examine whether existing transmission planning processes adequately consider needs and solutions on a regional or interconnection-wide basis to ensure adequate and reliable supplies at just and reasonable rates; and (3) to explore whether existing processes are sufficient to meet emerging challenges to the transmission system, such as the development of interregional transmission facilities, the integration of large amounts of location-constrained generation, and the interconnection of distributed energy resources.

[201] *Transmission Planning Processes Under Order No. 890*, Notice of Request for Comments, Docket No. AD09-8-000 (October 8, 2009) ("Post Order No. 890 Request for Comments"). The Post Order No. 890 Request for Comments asked stakeholders to address two categories of issues – "Enhancing Regional Transmission Planning Processes" and "Allocating the Cost of Transmission"). *Id.* at 2-8.

planning, particularly regional transmission planning, around the United States. The evidence showed that the electricity sector was continuing to change and, as DOE and others had predicted, a significant increase in new transmission was needed to accommodate a changing industry.[202] Yet, notwithstanding Order No. 890, transmission planning was not changing in a manner sufficient to meet future transmission needs. The Commission noted that there was "no comprehensive structure in place to identify the optimal set of facilities that address needs that affect multiple systems," which "could be needlessly increasing costs for customers of individual transmission providers or resulting in discrimination among potential users of the grid."[203]

Under the planning rules established in Order No. 890, individual transmission providers continued to dictate investment in new transmission and failed to coordinate, which led the Commission to conclude that **the lack of regional planning** "may be **impeding the development of beneficial transmission lines or resulting in inefficient and overlapping transmission development** due to a lack of coordination, all of which contributes to unnecessary congestion and difficulties in obtaining more efficient or cost-effective transmission service."[204] Hence further planning reforms were needed "to ensure just and reasonable rates and to prevent undue discrimination by public utility transmission providers [because] . . . the existing requirements of Order No. 890 do not necessarily result in the development of a regional transmission plan that reflects the identification by the transmission planning region of the set of

[202] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 at P 45 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014); *see id.* at P 44 ("the recent increase in transmission investment supports issuance of this Final Rule to ensure that the Commission's transmission planning and cost allocation requirements are adequate to support more efficient and cost-effective transmission investment decisions moving forward.").

[203] Post Order No. 890 Request for Comments at 2.

[204] Order No. 1000 at P 43 (emphasis added); *see also id*. at P 51 ("the narrow focus of [then] current planning requirements and shortcomings of current cost allocation practices create[d] an environment that fail[ed] to promote the more efficient and cost-effective development of new transmission facilities, and that addressing these issues [was] necessary to ensure just and reasonable rates.").

transmission facilities that are more efficient or cost-effective solutions for the transmission planning region."[205] **When the less efficient or cost effective Locally Planned transmission facility is advanced without an effective determination of the more efficient or cost effective transmission project, the rates for the less efficient or cost effective transmission facilities are unjust and unreasonable.** Stated differently, the Commission cannot economically regulate just and reasonable rates out of a transmission addition that was either entirely unnecessary or while "necessary" for an individual transmission owner's self-imposed criteria, would be more efficiently or cost effectively served by a transmission addition planned at the regional level.

The inadequacies of existing processes and anticipated changes meant that to fulfill its rate obligations the Commission could not wait to see whether regional planning processes encouraged under Order No. 890 developed and improved on their own.[206] The Commission determined that it was necessary to require transmission providers to participate in a regional planning process that "create[s] a regional transmission plan that identifies transmission facilities needed to meet reliability, economic and Public Policy Requirements, including fair consideration of lines proposed by nonincumbents, with cost allocation mechanisms in place to facilitate lines moving from planning to development."[207] Transmission providers had to do more than compare their local plans because local planning was inadequate. They must conduct

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[205] Order No. 1000 at P 78; *see also id.* at P 42 ("[The Commission's review of the record, as well as the recent studies discussed above, indicates that the transmission planning and cost allocation requirements established in Order No. 890 provide an inadequate foundation for public utility transmission providers to address the challenges they are currently facing or will face in the near future.")
[206] Order No. 1000 at P 84 ("[W]hile transmission planning processes have improved since the issuance of Order No. 890, we are concerned that the existing Order No. 890 requirements regarding transmission planning, as well as cost allocation, are insufficient to ensure that the evolution of transmission planning processes will occur in a manner that ensures that the rate and conditions of jurisdictional services are just and reasonable and not unduly discriminatory or preferential.").
[207] Order No. 1000 at P 47.

a regional analysis to identify regional needs and potential solutions to those needs.[208] The Commission explained that:

> [i]n the absence of the reforms implemented below, we are concerned that public utility transmission providers may not adequately assess the **potential benefits of alternative transmission solutions at the regional level that may meet the needs of a transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process**. For example, proactive cooperation among public utility transmission providers within a transmission planning region could better identify transmission solutions to more efficiently or cost-effectively meet the reliability needs of public utility transmission providers in the region. Further, regional transmission planning could better identify transmission solutions for reliably and cost-effectively integrating location-constrained renewable energy resources needed to fulfill Public Policy Requirements such as the renewable portfolio standards adopted by many states. **Similarly, the development of transmission facilities that span the service territories of multiple public utility transmission providers may obviate the need for transmission facilities identified in multiple local transmission plans while simultaneously reducing congestion across the region.** Under the existing requirements of Order No. 890, however, there is no affirmative obligation placed on public utility transmission providers to explore such alternatives in the absence of a stakeholder request to do so.[209]

The Commission reiterated this point when it rejected compliance filings that proposed to rely on "rolled up" local plans.[210] The Commission explained that "i[t] is not sufficient for a transmission planning region to merely 'roll-up' local transmission plans without analyzing whether the region's transmission needs, when taken together, can be met more efficiently or

[208] Order No. 1000 at P 80 (recounting that Order No. 1000 imposed "an affirmative obligation in these transmission planning regions to evaluate alternatives that may meet the *needs of the region* more efficiently or cost-effectively." (emphasis added)).
[209] Order No. 1000 at P 81 (emphasis added).
[210] *Tampa Elec. Co.*, 143 FERC ¶ 61,254 at P 54 (2013) ("Florida Compliance Order"); *see also Louisville Gas & Elec. Co.*, 144 FERC ¶ 61,054 at P 69 (2013) ("SERTP Compliance Order"); *So. Carolina Elec. & Gas Co.*, 143 FERC ¶ 61,058 at P 67 (2013) ("South Carolina Compliance Order").

cost-effectively by a regional transmission solution."[211] The region must conduct a regional analysis that uses, for example, power flow studies, production cost analyses, and/or other methods.[212]

The Commission also rejected proposed regional cost allocation methods that proposed to allocate the costs of a regional project based on what local project(s) were avoided by the regional project, the so-called avoided cost methodology.[213] The avoided cost methodology values a project based on the benefits identified at the local level.[214] The Commission found that the local analysis was insufficient to identify regional benefits. Only a regional analysis can identify the regional benefits of a project.[215] This regional analysis is still not occurring because of the continued ability of individual transmission owners to plan locally for transmission additions above 100 kV.

Notwithstanding these findings that local transmission plans could not be simply rolled up into the regional plan without a legitimate regional look, Self-Planned Transmission in local transmission plans is effectively being rolled into the regional plan throughout the country, whether in non-RTO/ISO regions or within regions under an RTO/ISO. Further, transmission owners have made it clear that they will plan locally, notwithstanding regional planning **requirements,** if given the choice between Self-Planned Transmission additions planned locally

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[211] Florida Compliance Order at P 54; *see also* SERTP Compliance Order at P 59; South Carolina Compliance Order at P 67.
[212] Florida Compliance Order at PP 54, 56; *see also* SERTP Compliance Order at P 61; South Carolina Compliance Order at P 69.
[213] Florida Compliance Order at PP 248-49; *see also* SERTP Compliance Order at PP 249-50; South Carolina Compliance Order at PP 226-27.
[214] Florida Compliance Order at PP 248-49; *see also* SERTP Compliance Order at PP 249-50; South Carolina Compliance Order at PP 226-27.
[215] Florida Compliance Order at P 249 ("The proposed avoided cost method fails to account for benefits that were not identified in the local transmission planning processes but that could be recognized at the regional level through a regional analysis of more efficient or cost-effective solutions to regional needs."); *see also* SERTP Compliance Order at PP 250; South Carolina Compliance Order at PP 227.

and potential competition (and greater scrutiny over proposed project costs and rates). Unfortunately, when provided the opportunity to address the excess in Self-Planned Transmission the Commission has denied consumer focused Complaints, protests, and tariff filings through narrowly focused rulings that leave electric consumers paying the bill for Self-Planned Transmission included in rates notwithstanding that the Commission itself recognized that excess local planning would result in unjust and unreasonable rates. Those narrowly focused rulings ignored the fundamental point of the filings, locally planned Self-Planned Transmission additions result in unjust and unreasonable transmission rates. When unjust and unreasonable rates are present, however, the Commission is required to act. That time is now.

4. Order No. 1920 Did Not Address The Issue Of Excess Local Planning Addressed In This Complaint

In its Advanced Notice of Proposed Rulemaking ("ANOPR") in Docket No. RM21-17-000, the Commission raised a number of issues for comment, including noting that

> the transmission facilities that transmission providers include in their individual local transmission plans are incorporated into regional transmission plans as inputs, with minimal opportunity for stakeholder review in the regional transmission planning process. This is because the analysis of the local transmission plan in the regional transmission planning process is limited mainly to a reliability analysis to ensure that local transmission plans do not negatively affect the reliability of the regional transmission system.[216]

The Commission also noted that in Order No. 1000 it "did not require that the transmission facilities in a transmission provider's local transmission plan be subject to approval at the regional or interregional level, unless that transmission provider seeks to have any of those facilities selected in the regional plan for purposes of cost allocation.[217]

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[216] ANOPR, Docket No. RM21-17, at P 17.
[217] *Id*. at P 26 (citing Order No. 1000 at P 190).

Sticking with its prior approach of seeking to incent proper transmission owner behavior rather that to regulate that behavior, in the ANOPR the Commission stated: "we seek comment on whether and, if so, how to *expand or improve any incentives to incent the development of regional transmission facilities* that demonstrably may offer a more efficient or cost-effective solution to an identified need than local alternatives."[218] Recognizing the inefficiency of Local Planning versus regional planning, the Commission also sought comments on whether an "independent transmission monitor could review transmission provider spending on transmission facilities and identify instances of potentially excessive transmission facility costs, including through inefficiencies between local and regional transmission planning processes."[219]

Although through the ANOPR process the Commission received extensive comments on the excessive Local Planning,[220] the Commission did not make any substantive proposals to reform local planning in its RM21-17-000 NOPR. As noted *supra*, in Order No. 1920 that Commission specifically held that "the Commission in the NOPR did not propose other changes to local transmission planning processes" and thus requests that the Commission address Local Planning "are beyond the scope of this final rule."[221] The Commission chose to do nothing in Order No. 1920 notwithstanding that the Commission found

> the record demonstrates that a substantial amount of new transmission investment is occurring outside of regional transmission planning processes. Because these other processes—specifically, generator interconnection processes and **local transmission planning processes**—are generally designed to address discrete, shorter-term needs, and do not comprehensively assess either broader transmission needs or solutions to those needs, **overreliance on those processes can result in relatively**

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[218] ANOPR at P 61 (emphasis added).
[219] *Id*. at P 164.
[220] *See, e.g.,* "Comment of the Harvard Electricity Law Initiative, filed March 1, 2024 in Docket No. RM21-17-000; Comments of the Edison Electric Institute, filed February 21, 2024 in Docket No. RM21-17-000; and Comments of American Municipal Power, Inc. filed August 17, 2022 in Docket RM-21-17-000.
[221] ANOPR at P 247.

> **inefficient or less cost-effective transmission development for customers, which contributes to rates for transmission that are unjust and unreasonable**.[222]

The Commission also found that "local transmission planning, *with its focus on the needs of individual utility footprints*, does not necessarily provide sufficient, comprehensive analysis of broader regional transmission needs."[223] The Commission concluded that:

> [t]his dynamic results in, among other things, transmission ***customers paying more than is necessary or appropriate*** to meet their transmission needs, customers forgoing benefits that outweigh their costs, or some combination thereof, ***which results in less efficient or cost-effective transmission investments and, in turn, renders Commission-jurisdictional regional transmission planning and cost allocation processes unjust and unreasonable***.[224]

The Commission is obligated by Section 206 of the Federal Power Act to address "rates for transmission that are unjust and unreasonable" yet Order No. 1920 did not mandate any changes to the unjust and unreasonable local planning tariffs because the NOPR "did not propose other changes to local transmission planning processes."[225] In Order No. 1920, the Commission expressly found that a commenter's "suggestion for implementing a voltage threshold level above which a transmission facility would receive regional cost allocation" is "beyond the scope of this proceeding" because FERC "did not make such proposals in the NOPR."[226] In response to several requests for rehearing to Order No. 1920, the Commission in Order No. 1920-A did not finalize any changes to local planning processes.[227] The Commission also found that

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[222] *Id*. at P 103 (emphasis added).
[223] *Id*. at P 110 (emphasis added).
[224] *Id*. at P 112 (emphasis added).
[225] *Id*. at P 247.
[226] Order No. 1920 a P 1307.
[227] On rehearing, the Commission rejected several requests seeking more transparency into local planning requirements. The Commission also rejected arguments by Industrial Customers, including four of the named complainants, that the Commission must take some action, such as through an independent transmission monitor, to ensure transmission planning yields just and reasonable rates. *See* Order No. 1920-A at PP 851-858.

requests for Commission review of in-kind replacement facilities or local transmission facilities were outside the scope of the NOPR (and thus the rulemaking).[228] As has been evident for nearly three decades, the Commission cannot address regional transmission planning processes without addressing the currently permitted individual planning of transmission facilities in interstate commerce, which planning directly impacts the existence of and quality of regional planning. This Complaint addresses those unjust and unreasonable local planning tariff provisions leading to "customers . . . being forced to fund investments that could have been more beneficial, less costly, or both had they been better planned from the start."[229]

In Order No. 1920-A, the Commission explained its determination that "local transmission planning processes lack adequate provisions for transparency and meaningful input from stakeholders."[230] The Commission recognized the importance of stakeholder understanding of local transmission needs to help those stakeholders to ensure "the more efficient or cost-effective regional transmission solutions are identified, evaluated, and selected."[231] The Commission emphasized the importance of coordination between local and regional transmission planning processes regarding the replacement of aging infrastructure.[232] To address local planning issues, the Commission in Order No. 1920 (as affirmed in Order No. 1920-A) attempted to enhance the transparency of local transmission planning processes by requiring transmission providers to evaluate whether transmission facilities that need replacing can be "right-sized" to more efficiently or cost-effectively address Long-Term Transmission Needs identified in Long-Term Regional Transmission Planning.[233] However, the Commission fell

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[228] Order No. 1920 at P 1735.
[229] *Id*. at Joint Order No. 1920 Concurrence at P 4.
[230] Order No. 1920-A at P 806.
[231] Order No. 1920-A at P 806.
[232] Order No. 1920-A at P 807.
[233] Order No. 1920-A at P 811. The Commission emphasized its belief that "a federal right of first refusal will remove a disincentive for transmission providers to consider right-sizing in Long-Term Transmission Planning." *Id.*

short of addressing and tackling the core problem: the federal tariff provisions that insulate and allow for incumbent transmission owner control over local transmission planning.[234] Increased efforts at transparency and coordination, while important, will not fix the core problem identified in the RMI Report: "Continuing the status quo approach to transmission planning, which separates local and regional planning…is an inherently inefficient way to expand the grid."[235] Therefore, RMI concluded: **"More remains to be done to reform local planning, even after Order No. 1920."[236]** Importantly, the Commission in Order No. 1920-A committed to "continue to consider potential additional local transmission planning reforms, such as independent transmission monitors, along with other transmission reforms in the future."[237] This Complaint presents a clear pathway toward such reform.

V. PRIOR COMMISSION EFFORTS INTENDED TO ENSURE JUST AND REASONABLE RATES THROUGH REQUIRED REGIONAL PLANNING HAVE BEEN THWARTED BY TARIFFS ALLOWING CONTINUED LOCAL PLANNING RESULTING IN UNJUST AND UNREASONABLE TRANSMISSION RATES

The Commission has acknowledged both that more regional planning is necessary for it to ensure just and reasonable rates and that existing regulations have not produced such planning.[238] As just noted, the Commission in Order No. 1920 confirmed the NOPR preliminary

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at P 822. Setting aside Complainants' concerns about further empowering existing monopolies to maintain project control without sufficient independent oversight, Order No. 1920 does not address or solve the core issue: the unjustness and unreasonableness of local planning tariff provisions. Unlike in Order No. 1920 or 1920-A, this Complaint provides the Commission with a clear and simple solution to ensuring that more projects will be regionally planned and planned in a such a manner (*i.e.,* independently and holistically) that provides greater assurances to consumers and state regulators that the resulting rates will be just and reasonable: 1) all projects at or above 100 kV should be subject to regional planning (with very few exceptions); and 2) independent transmission planner standards should guide regional transmission planning.

[234] RMI highlighted the potential benefits of right-sizing as a general practice but emphasized that Order No. 1920's determination to apply right-sizing "only to long-term regional planning processes and not to short-term ones…will limit its impact." RMI Report at 21.

[235] RMI Report at 48.

[236] RMI Report at 22.

[237] Order No. 1920-A at P 858; *see id.* at fn. 2195.

[238] NOPR, Docket No. RM21-17 at P 40, 344.

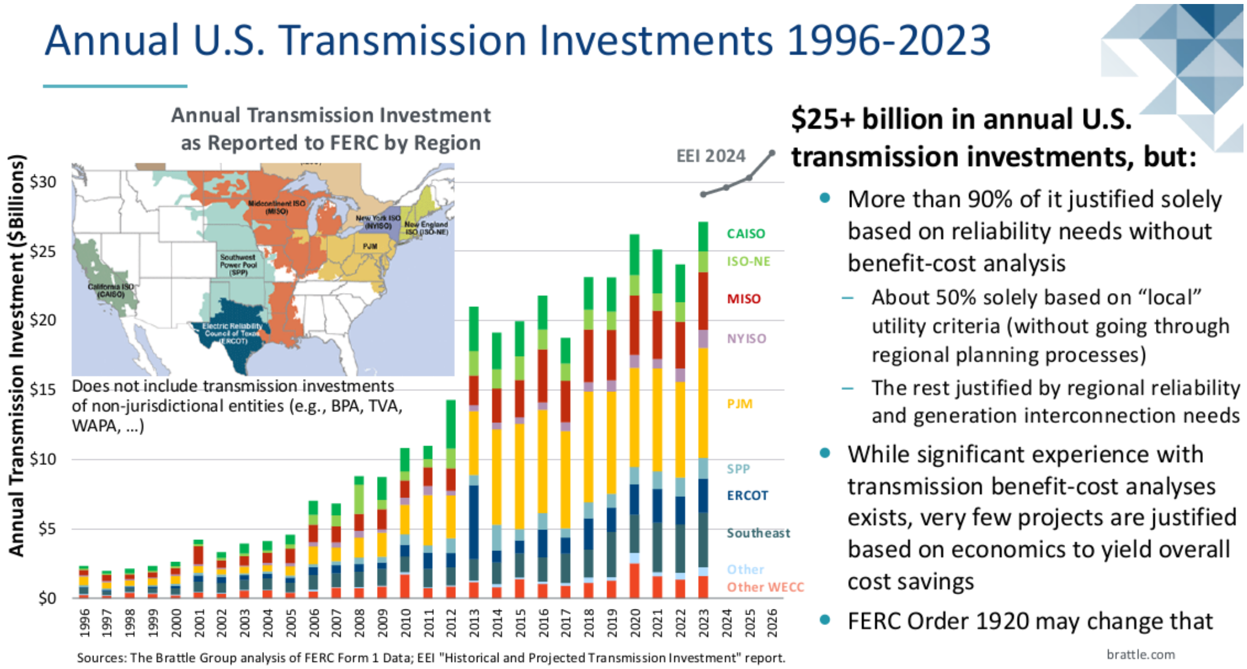
finding and went further to find that individual transmission owner planning was in fact resulting in unjust and unreasonable Commission-jurisdictional rates. Although Order No. 1920 addressed perceived deficiencies in **regional planning**, because it made no changes in the ability of individual transmission owners use of local planning tariffs to plan outside of regional oversight, the ability to plan locally is unchanged and thus its interference with regional planning unchanged. While the Commission in Order No. 1920 generically recounted excess reliance on Local Planning, the Commission did not offer specifics regarding the depth of the problem. In the sections below, Complainants identify individual transmission owner Self-Planned projects in various Order No. 1000 planning regions. The identified projects do not account for all the Self-Planned Transmission. Further, as identified below, for a vast majority of projects there is limited information regarding the real cost of the Self-Planned transmission additions.

A. Individual Transmission Owner Self-Planned Transmission Projects Explode

In 2023, there was over $25 billion in transmission investment, with about $12.5 billion in individual transmission owner planned transmission projects.[239] The projects are in all areas of the country, not just in regions with RTO/ISOs where the likelihood of a competitive process

[239] The total was approximately $25 billion invested, with about half "solely based on 'local' utility criteria." Brattle Group, *Annual U.S. Transmission Investments, 1996-2023*, (2023), available at https://www.brattle.com/wp-content/uploads/2023/07/Annual-US-Transmission-Investments-1996%E2%80%932023.pdf (last accessed Dec. 18, 2024) (hereinafter "Brattle 2023 Transmission Investment Analysis").

for selection of the developer for a regionally planned project is, slightly,[240] greater. The Brattle Group's summary analysis is captured below[241]



1. California Transmission Owner Self-Planned Transmission Projects

California regulators, as the protector of California retail consumers, have long been dissatisfied that California transmission owners retain the authority to plan transmission projects without regional oversight so long as those projects were merely replacing existing transmission facilities. As the affidavit of the California Public Utilities Commission ("CPUC") in RM21-17-000 presented, between 2019 and 2021 alone three California utilities had added over $4 billion

[240] As recounted in various consumer complaints, protests and other filings before the Commission, incumbent transmission owners, often with the support of supposedly independent regional planners, have undertaken a number of actions to diminish the number of regionally planned projects subject to competition, even when Commission regulations would otherwise call for such competition. *See*, *e.g.*, *Industrial Energy Consumers of America, et al v. Midcontinent Independent System Operator, Inc.,* EL22-78-000 challenging MISO tariff provisions that allow MISO to circumvent required competition if a state incumbent preference law is in place and noting that MISO excluded more than $5 Billion in transmission additions from competitive solicitation based on such laws; *see also*, Appendix I to Comments Of LS Power Grid, LLC In Response To The Commission's Advanced Notice Of Proposed Rulemaking, filed October 12, 2021 in Docket No. RM21-17-000 (describing Cost Allocation and Planning Manipulation geared to avoiding competition).
[241] Brattle 2023 Transmission Investment Analysis at 1.

to their transmission rate base in Self-Planned Transmission.[242] The CPUC pointed out that the total represented 63.3% of transmission spend collectively and for one utility, Pacific Gas & Electric, 76.3%.[243] The CPUC further noted that PG&E projected another $13 billion in transmission additions between 2022 and 2027, with 54.3% for Self-Planned Transmission 200 kV and below and $3.9 billion for Self-Planned Transmission above 200 kV, which would be allocated across California as part of the CAISO transmission access charge.

2. PJM Transmission Owner Self-Planned Transmission Projects

The Commission is well versed in the explosion in PJM Supplemental Project spending in the last decade. Between 2014 and 2022, incumbent transmission owners in PJM have planned $38.3 billion in locally planned transmission projects[244] that went in the PJM Regional Transmission Expansion Plan without PJM Board approval.[245] During that same period only $6.4 billion in regional projects were approved.[246] The transmission component of consumer rates in PJM has increased 117% during that period.[247]

Contrary to the clear directive of Order No. 1000, PJM does not thoroughly review those projects for displacement, notwithstanding inclusion of a provision of its Operating Agreement requiring that it post **all** transmission needs.[248] Indeed, in August 2016 the Commission itself

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[242] Affidavit of Simon Hurd, CPUC Program & Project Supervisor of FERC Cost Recovery Section, filed Aug. 17, 2022 in Docket No. RM21-17-000, at ¶¶ 3-5, Table 1.
[243] *Id*.
[244] Regulation of Access, Pricing, and Planning of High Voltage Transmission in the U.S., DeLosa III, Pfeienberger, Joskow, MIT CEEPR February 2024, at 13 "MIT Planning Paper"). While the report refers to the projects collectively as Supplemental Projects, in 2020 the local planning tariff was changed to include additional projects that were alleged to outside the original scope of Supplemental Projects, referred to as Attachment M-3 Projects.
[245] PJM Operating Agreement, Schedule 1 (definition of Supplemental Project), Schedule 6, Sec. 1.6; *see also* PJM Tariff Attachment M-3.
[246] MIT Planning Paper at 13.
[247] Motion for Leave to Submit Supplemental Comments and Supplemental Comments of American Municipal Power, Inc., filed in Docket No. RM21-17-000 on Mar. 6, 2024 (noting that the wholesale transmission rate was $5.75 in 2014, more than doubling to $12.50 in 2022).
[248] OA, Schedule 6, Section 1.4(a), 1.5.6(b) ("Following identification of transmission needs and prior to evaluating potential enhancements and expansions to the Transmission System the Office of the Interconnection shall publicly post all transmission need information…").

identified that there was a problem with the intersection of the PJM regional transmission planning process and the PJM transmission owners individual planning that was sufficient to warrant the Commission initiating a Show Cause proceeding.[249] However, rather than reinforce regional planning obligations, the Commission allowed individual transmission owners to strengthen their hold on local planning, to the exclusion of PJM review.[250] The Commission noted that "the planning for Supplemental Projects is done almost entirely by the PJM Transmission Owners, with PJM playing a relatively minor role in which it reviews the proposed Supplemental Projects only to ensure that they do not have adverse reliability impacts."[251] Although the Commission required addition process for local planning, with PJM merely acting as a facilitator, the additional process did not require coordination of the local planning with PJM's regional planning or create a hierarchy for planning.[252] As discussed *infra*, the PJM transmission owners have taken a number of additional steps to insulate their local planning from PJM interference to further insure that local planning takes precedence in PJM.[253]

In its most recent Independent Market Monitor ("IMM") Report, the PJM IMM reported that "[a]s of December 31, 2023, there are **1,584 supplemental projects with expected in service dates between January 1, 2024 and December 31, 2028**."[254] The IMM's Report reflects what PJM transmission owners tell Wall Street analysists. The reflected PJM

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[249] *Monongahela Power Company, et al.*, 156 FERC ¶ 61,134 (2016) ("Order to Show Cause").
[250] *Monongahela Power Company, et al.*, 162 FERC ¶ 61,129 (2018), *order on rehearing and compliance,* 164 FERC ¶ 61,217 (2018).
[251] *Id*. at P 97.
[252] *Id*. at PP 106-116.
[253] *Infra* at __.
[254] Monitoring Analytics, LLC, State of the Market Report for PJM 2023 at 721 (Mar. 14, 2024)("IMM Report"). The IMM further notes that "As of December 31, 2023, the 1,584 supplemental projects with expected in service dates between January 1, 2024 and December 31, 2027, have a total cost estimate of $18.1 billion." *Id*. at 722. The IMM reports that "[t]he average number of supplemental projects in each expected in service year increased by 925.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 205 for years 2008 through 2023 (post Order No. 890). . . . The average cost of supplemental projects in each expected in service year increased by 2,531.6 percent, from $64.6 million for years 1998 through 2007 (pre Order No. 890) to $1.7 billion for years 2008 through 2023 (post Order No. 890)." *Id*. at pp 721-22.

transmission owners report that they will add more than $50 billion in new transmission over the next several years.

AEP	$16 Billion 2024-2028[255]
Exelon	$3.6 Billion 2023-2026[256]
Duke Energy	$13 Billion 2024-2028[257]
PSEG	$5 Billion 2019-2023[258]
First Energy	$11.7 Billion 2024-2028[259]
Dominion	$6 Billion 20221-2025[260]

To the extent this $50 billion is presented through the PJM transmission owners M-3 process, PJM will conduct only a "do no harm study."[261]

In a recent analysis, the Rocky Mountain Institute reported that 71 percent of the PJM transmission investment since 2014 has been directed toward low-voltage lines operating below 230 kilovolt (kV) as opposed to 26 percent before 2014.[262] In addition, transmission owner planned project spending increased dramatically.

[255] AEP has transmission facilities in both PJM and SPP. AEP's capital forecast includes $6.2 Billion for AEP Transmission Holdco and $9.8 Billion of other Transmission https://www.aep.com/Assets/docs/investors/fixedincome/2024-2028CapitalForecast.pdf (last accessed Dec. 18, 2024).

[256] Expects rate base to grow $18 Billion between 2023-2026, with 20% recovered through transmission formula rates, https://investors.exeloncorp.com/static-files/1ce013d3-79a4-4379-ad12-d81c28aa33c1 (last accessed Dec. 18, 2024), slide 11.

[257] https://s201.q4cdn.com/583395453/files/doc_financials/2023/q4/Q4-2023-Earnings-Presentation_vF-w-Reg-G.pdf, (last accessed Dec. 18, 2024); slide 27.

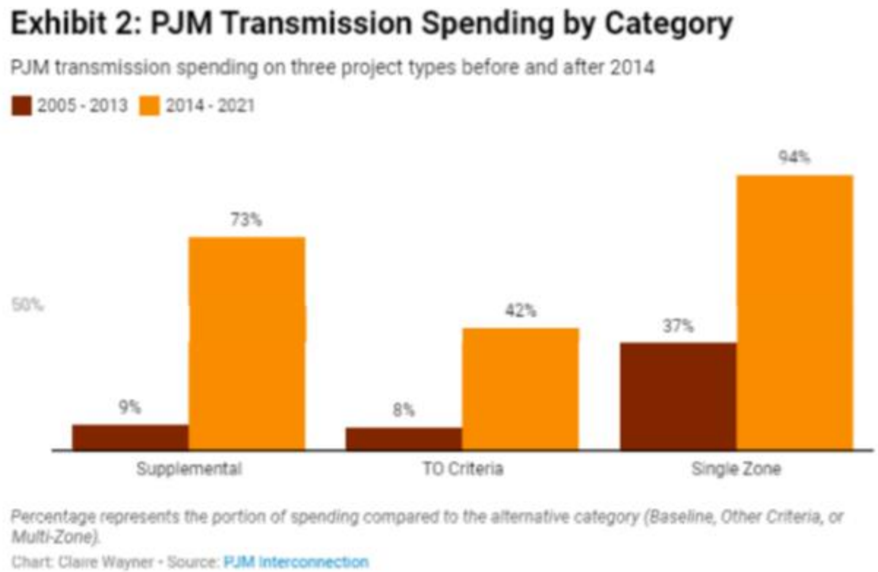
[258] https://investor.pseg.com/investor-news-and-events/financial-news/financial-news-details/2024/PSEG-ANNOUNCES-2023-RESULTS/default.aspx (last accessed Dec. 18, 2024).

[259] https://www.utilitydive.com/news/firstenergy-capex-investment-plan-transmission-earnings/707223/

[260] https://s2.q4cdn.com/510812146/files/doc_financials/2020/q4/2021-02-12-DE-IR-4Q-2020-earnings-call-slides-vTC1.pdf at slide 9 (last accessed Dec. 18, 2024).

[261] *See* PJM, Manual 14b, PJM Region Transmission Planning Process, *available at* https://pjm.com/directory/manuals/m14b/index.html#Sections/11%20Planning%20Process%20Work%20Flow.html (last accessed Dec. 18, 2024); *see* RMI Report at 27(explaining that RTOs only do a "no-harm analysis" for Local Projects).

[262] Claire Wayner, *Increase Spending on Transmission in PJM – Is It the Right Type of Line?* (Rocky Mountain Institute, Mar. 20, 2023), https://rmi.org/increased-spending-on-transmission-in-pjm-is-it-the-right-type-of-line/ (last accessed Dec. 18, 2024) (hereinafter "RMI March 2023 PJM Transmission Analysis")



[263]

Rocky Mountain Institute further concludes that these transmission owner planned project result in "16 to 24 percent higher utility earnings than their alternatives (Baseline, Other Criteria, Multi-Zone) on a net present value (NPV) basis . . .."[264]

Below is a partial list of PJM transmission owner Self-Planned Transmission submissions to the PJM *Regional* Transmission Expansion Plan. The list provides numerous examples of Self-Planned Transmission projects 100 kV or greater.

American Electric Power ("AEP")[265]

[263] *See* RMI March 2023 PJM Transmission Analysis, Exhibit 2
[264] *See id.*; RMI March 2023 PJM Transmission Analysis, Exhibit 3.
[265] Although the listed projects are identified as "local," the AEP transmission pricing zone in PJM encompasses portions of six states: Virginia, West Virginia, Kentucky, Ohio, Indiana, and Michigan. As such, AEP "local" projects are all cost allocated across portions of six states. Because these projects do not, generally, cross state borders, they are only reviewed, if at all, by the state in which the project is located, with no ability for the regulatory agencies in the other states to review the need or cost-effectiveness of the project, notwithstanding that consumers in those states pay for a portion of the project. The six state AEP transmission zone was precisely the type of interstate regulatory gap that led Congress to pass the Federal Power Act as a consumer protection mechanism nearly a century ago.

- Southern Muncie – Rebuild an existing line, build a new 138 kV transmission line, and retire a tap line.[266] In 2019, AEP estimated that the selected solution would cost $68.7 Million.[267]
- Wapakoneta – Build a new 345/138 kV station, a new 138 kV station, two new 138 kV transmission lines, and remove an existing 138 kV transmission line.[268] The estimated cost of the project in 2019 was $66.2 Million.[269]
- Jay-Allen – Rebuild a 138 kV line, rebuild a 69 kV station, and retire a tap line.[270] The estimated selected solution cost is $71 Million.[271]
- Allen -Robison Park – Rebuild 12 miles of a 138 kV double circuit line.[272] The estimated cost of the selected solution was $34.9 Million.[273]
- Anguin Station – Selected solution combines several projects, including expanding an existing station by constructing a new 345 kV/138 kV station yard.[274] The selected solution was estimated to cost $91.3 Million in 2020.[275]
- Amos Hopkins – Rebuild 19.6 miles of 138 kV line.[276] AEP estimated that the selected solution would cost $61.4 Million in 2020.[277]
- Hillcrest-Adams – Selected solution combines several projects, including rebuilding/replacing 69 kV transmission lines with 138 kV transmission lines.[278] The estimated cost of the selected solution was $116.2 Million in 2020.[279]
- Stuart Area – Selected solution combines several projects, including constructing over 90 miles of 138 kV transmission lines and removing 69 kV transmission lines.[280] AEP estimated that the selected solution would cost $326.9 Million in 2020.[281] In 2023, AEP

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[266] AEP, Submission of Supplemental Projects for Inclusion in the Local Plan at slide 19 (2019), https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/aep-local-plan-submission-of-the-supplemental-projects-for-2019-rtep.ashx ("AEP 2019 Local Plan Presentation") (last accessed Dec. 18 2024).
[267] *Id*.
[268] *Id*. at slide 23.
[269] *Id*.
[270] *Id*. at slide 112.
[271] *Id*.
[272] *Id*. at slide 122.
[273] *Id*.
[274] AEP, Submission of Supplemental Projects for Inclusion in the Local Plan at slide 3 (2020), https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/aep-local-plan-submission-of-the-supplemental-projects-for-2020-rtep.ashx ("AEP 2020 Local Plan") (last accessed Dec. 18, 2024.
[275] *Id*.
[276] *Id*. at slide 31.
[277] *Id*.
[278] *Id*. at slide 59.
[279] *Id*.
[280] *Id*. at slides 90-92.
[281] *Id*. at slide 92.

updated the selected solution to include additional 138 kV transmission lines.[282] The cost of the selected solution increased to $379.37 Million.[283]

- Kenna Station – The selected solution involved constructing 138 kV lines and circuit breakers and other work.[284] The estimated cost of the selected solution was $61.7 million in 2020.[285]
- Fieldale-Dan River – Rebuild approximately 15 miles of a 138 kV transmission line.[286] The estimated cost was $32.2 million in 2020.[287]
- Athens Area – Selected solution combines several projects, including replacing and installing 138 kV transmission infrastructure.[288] Its estimated cost was $55.5 Million in 2020.[289]
- Crooksville-Philo – Rebuild 12 miles of existing 138 kV transmission line and other work.[290] AEP estimated that the selected solution would cost $30.9 Million in 2020.[291]
- Saltville-Kingsport – Rebuild 26 miles of 138 kV double circuit transmission line.[292] The estimated cost was $107.1 Million in 2020.[293]
- Cameron– Selected solution combines several projects, including constructing a new 500-138 kV station and various 138 kV transmission facilities.[294] In 2020 the full selected solution was estimated to cost $68.7 Million.[295]
- Millbrook Park-South Point – Rebuild 35 miles of a double circuit 138 kV line and other work.[296] AEP estimated that the selected solution would cost $148.7 Million in 2020.[297]
- Shannon Station – Rebuild approximately 9 miles of 138 kV transmission lines, construct approximately 4.6 miles of greenfield 138 kV transmission line, and other work.[298] The estimated cost of the entire selected solution was $60.8 Million in 2020.[299]

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[282] AEP, Submission of Supplemental Projects for Inclusion in the Local Plan at slide 167-70 (2023), https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/2023/aep-local-plan-submission-of-the-supplemental-projects-for-2023-rtep.ashx (last accessed Dec. 18, 2024).
[283] *Id*. at slide 170.
[284] AEP 2020 Local Plan at slide 100.
[285] *Id*.
[286] *Id*. at slide 122.
[287] *Id*.
[288] *Id*. at slides 170-171.
[289] *Id*. at slide 171.
[290] *Id*. at slide at 185.
[291] *Id*.
[292] *Id*. at slide at 192.
[293] *Id*.
[294] *Id*. at slides 200-201.
[295] *Id*.
[296] *Id*. at slide 206.
[297] *Id*.
[298] *Id*. at slide 222.
[299] *Id*.

- Sorenson-Desoto – Rebuild an approximately 51.1-mile transmission line using double circuit 345 kV and other work.[300] The estimated cost of the solution was $202.4 Million in 2024.[301]
- South Coshocton-Wooster – Rebuild 37.7-mile 138 kV transmission line and other work at an estimated $97.54 Million.[302]
- Haviland-VanWert – Rebuild 69 kV transmission line using 138 kV double circuit design and other work at an estimated cost of $32.57 Million.[303]
- Apple Grove – Install a new 345 kV station (phase one) and construct a new 345 kV transmission line (phase two).[304] The combined cost of the phase one and phase two work was $215.8 Million.[305]
- Fostoria-East Lima – Rebuild 41.3-miles of existing transmission line with double circuit 138 kV line and other work at an estimated cost of $95.98 Million.[306]
- Apple Grove – Among other work, replace a 69 kV line with a 138 kV line and replace an existing 138 kV transmission line.[307] The total cost of the selected solution is $57 Million.[308]
- Dover to South Canton – Rebuild two 138 kV transmission lines at an estimated cost of $89.58 Million.[309]
- Albion Area – Conducted in two phases, AEP planned to rebuild an existing approximately 8.7-mile line using double circuit 138 kV, rebuild approximately 8.5 miles of an existing 138 kV transmission line, rebuild a 69 kV transmission line as double circuit 138 kV (but will energize as 69 kV), and build a new approximately 11.7 mile double circuit 138/69 kV transmission line, and other work.[310] The total estimated cost of the two phase solution was $124.8 Million in 2023.[311]
- Conesville-Bixby – Rebuild approximately 46.1 miles of 345 kV transmission line at an estimated cost of $154.53 Million in 2023.[312]

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[300] AEP, Submission of Supplemental Projects for Inclusion in the Local Plan at slide 26 (2024), https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/2024/aep-local-plan-submission-of-the-supplemental-projects-for-2024-rtep.ashx (last accessed Dec. 18, 2024).
[301] *Id.*
[302] *Id.* at slide 28.
[303] *Id.* at slide 34.
[304] *Id.* at slides 36-37.
[305] *Id.*
[306] AEP, Submission of Supplemental Projects for Inclusion in the Local Plan at slide 12 (2023), https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/2023/aep-local-plan-submission-of-the-supplemental-projects-for-2023-rtep.ashx (last accessed Dec. 18, 2024).
[307] *Id.* at 36.
[308] *Id.*
[309] *Id.* at slide 39.
[310] *Id.* at slides 62-64.
[311] *Id.*
[312] *Id.* at slide 139.

- Central Ohio – Rebuild approximately 19 miles of double circuit 345 kV with an estimated cost of $116.7 Million in 2023.[313]
- Robison Park-Sowers – Rebuild 13.6 of existing transmission line with double circuit 138 kV capable transmission line and other work.[314] In 2022, AEP estimated that the selected solution would cost $43.3 Million.[315]
- Belva-Clendenin – Rebuild existing 46 kV transmission line to 138 kV standard (approximately 27 miles) and other work at an estimated cost of $89.2 Million.[316]
- Seneca County, Ohio – Rebuild approximately 33 miles of 138 kV transmission lines at an estimated cost of $82.12 Million in 2022.[317]
- New Albany, Ohio – Among other work, build a new substation at an estimated cost of $21.08 Million in 2022.[318]
- Pendleton-Makahoy – Rebuild approximately 15 miles of 138 kV transmission line and replace a 138/34.5 kV transformer.[319] The total estimated cost of the selected solution was $38.5 Million in 2022.[320]
- Philo-Newcomerstown – Selected solution combines various work, including rebuilding 138 kV transmission lines and new 138 kV transmission lines at an estimated cost $117.42 Million in 2021.[321]
- Reusens-Roanoke – Selected solution involves several components, including rebuilding approximately 43 miles of double circuit 138 kV transmission.[322] The selected solution was estimated to cost $177.6 Million in 2021.[323]
- Philo-Howard – Rebuild an existing line as 138 kV double circuit for approximately 64 miles, rebuild another segment as 138 kV single circuit for approximately 19 miles, and perform other work.[324] The estimated cost of the selected solution was $187.84 Million in 2021.[325]

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[313] *Id*. at slide 181.
[314] AEP, Submission of Supplemental Projects for Inclusion in the Local Plan at slide 70 (2022), https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/2022/aep-local-plan-submission-of-the-supplemental-projects-for-2022-rtep.ashx (last accessed Dec. 18, 2024).
[315] *Id*.
[316] *Id*. at slide 111.
[317] *Id*. at slide 121.
[318] *Id*. at slide 123.
[319] *Id*. at slide 159.
[320] *Id*.
[321] AEP, Submission of Supplemental Projects for Inclusion in the Local Plan at slides 105-06 (2021), https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/2021/aep-local-plan-submission-of-the-supplemental-projects-for-2021-rtep.ashx (last accessed Dec. 18, 2024).
[322] *Id*. at slides 117-18.
[323] *Id*. at slide 118.
[324] *Id*. at slide 136.
[325] *Id*.

- Hartford Area – Rebuild approximately 14.7 miles of existing 138 kV transmission line, rebuild approximately 18.7 miles of 69 kV transmission, and other work at an estimated cost of $65.4 Million in 2021.[326]

<u>Public Service Electric and Gas Company ("PSE&G")</u>

- Mansfield – Install a 230 kV bus with two 230/13 kV transformers and cut and loop a line into the 230 kV bus.[327] In 2019, the solution was estimated to cost $43 Million.[328]
- Voorhees Area—Install a 230 kV station and perform other work. The estimated cost in 2019 was $39 Million.[329]
- Northern Burlington County Area – Install a 230 kV station and perform other work.[330] In 2020, the selected solution was estimated to cost $39 Million.[331]
- New Livingston 230-13 kV Station - Install a 230 kV station and perform other work.[332] In 2020, the solution was estimated to cost $29.8 Million.[333]
- Pennsauken 230-13 kV Station - Install a 230 kV station and perform other work.[334] In 2020, the solution was estimated to cost $48.6 Million.[335]
- South Edison Area – Construct a 230 kV substation and perform other work.[336] In 2024, PSEG estimated that the selected solution would cost $56.1 Million.[337]
- Harlingen Area – Construct a new 69-13 kV substation, a 230-69 kV transfer at substation, and perform other work.[338] The estimated cost of the selected solution was $105.1 Million.[339]

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[326] *Id*. at 158.
[327] PSEG, PSEG 2019 Submission of Supplemental Projects for Inclusion in the Local Plan at slide 13 (2019), https://www.pjm.com/-/media/committees-groups/committees/srrtep-ma/postings/2019/pseg-local-plan-submission-for-2019-rtep.ashx (last accessed Dec. 18, 2024).
[328] *Id*.
[329] *Id*. at 15.
[330] PSEG, PSEG 2020 Submission of Supplemental Projects for Inclusion in the Local Plan at slide 3 (2020), https://www.pjm.com/-/media/committees-groups/committees/srrtep-ma/postings/2020/pseg-local-plan-submission-for-2020-rtep.ashx (last accessed Dec. 18, 2024).
[331] *Id*.
[332] *Id*. at 5.
[333] *Id*.
[334] *Id*. at 13.
[335] *Id*.
[336] PSE&G, PSEG 2024 Submission of Supplemental Projects for Inclusion in the Local Plan at slide 7 (2024), https://www.pjm.com/-/media/committees-groups/committees/srrtep-ma/postings/2024/pseg-local-plan-submission-for-2024-rtep.ashx ("PSEG 2024 Local Plan Presentation") (last accessed Dec. 18, 2024).
[337] *Id*.
[338] PSEG 2024 Local Plan Presentation at 11.
[339] *Id*.

- Northern Camden County Area – Construct a new 230-13 kV station and perform other work.[340] The estimated cost of the selected solution in 2021 was $48.6 Million.[341]

FirstEnergy

- Armstrong-Horner City – Rebuild and reconductor approximately 33 miles of existing wood pole transmission line.[342] In 2019, the 345 kV transmission line was estimated to cost $138 Million.[343]
- Saxton-Shade Gap – Construct 8.64 miles of 115 kV transmission line and install various infrastructure.[344] The estimated cost of the selected solution in 2023 was $23.96 Million.[345]
- Piney-Erie South – Rebuild existing 115 kV transmission line with a double circuit 115 kV transmission line for approximately 82 miles and perform other work.[346] The total estimated cost of the selected solution was $443 Million in 2022.[347]
- Windsor-Charleroi – Build a new 138 kV substation and new 138 kV transmission lines, and perform other work.[348] The estimated cost of the selected solution was $31.5 Million in 2023.[349]

ATSI

- Cuyahoga Falls – Build three new 138 kV transmission lines and perform other work at an estimated cost of $36.3 Million in 2023.[350]

[340] PSE&G, PSEG 2021 Submission of Supplemental Projects for Inclusion in the Local Plan at slide 21, https://www.pjm.com/-/media/committees-groups/committees/srrtep-ma/postings/2021/pseg-local-plan-submission-for-2021-rtep.ashx (last accessed Dec. 18, 2024).
[341] *Id*.
[342] First Energy, First Energy MAAC Local Plan Submission for the 2019 RTEP at slide 112 (2019), https://www.pjm.com/-/media/committees-groups/committees/srrtep-ma/postings/2019/first-energy-east-local-plan-submission-for-2019-rtep.ashx (last accessed Dec. 18, 2024).
[343] *Id*.
[344] FirstEnergy, Submission of Supplemental Projects for Inclusion in the Local Plan at slide 3 (2023), https://www.pjm.com/-/media/committees-groups/committees/srrtep-ma/postings/2023/penelec-local-plan-submission-for-2023-rtep.ashx (last accessed Dec. 18, 2024).
[345] *Id*.
[346] FirstEnergy, First Energy (Penelec) Local Plan Submission for the 2022 RTEP at slide 3 (2022), https://www.pjm.com/-/media/committees-groups/committees/srrtep-ma/postings/2022/penelec-local-plan-submission-for-2022-rtep.ashx (last accessed Dec. 18, 2024).
[347] *Id*. at slide 4.
[348] FirstEnergy, Subregional RTEP Committee FirstEnergy Supplemental Projects at slides 19-20 (2023), https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/2023/aps-local-plan-submission-of-the-supplemental-projects-for-2023-rtep.ashx (last accessed Dec. 18, 2024).
[349]*Id*. at slide 20.
[350] ATSI, Subregional RTEP Committee-Western FirstEnergy Supplemental Projects at slide 10 (2023), https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/2023/atsi-local-plan-submission-of-the-supplemental-projects-for-2023-rtep.ashx (last accessed Dec. 18, 2024).

- Carol – Construct a new 138-69 kV switching station, build new transmission lines, including 138 kV transmission lines, and perform other work.[351] The estimated cost of the selected solution was $45 Million in 2023.[352]
- Black River-Astor – Build approximately 10 miles of new 138 kV transmission lines and complete other work at an estimated cost of $24.5 Million in 2023.[353]
- Lincoln Park-Riverbend – Build a new 138 kV transmission line, approximately 5.7 miles, and complete other work at an estimated cost of $25.9 Million in 2021.[354]
- Cuyahoga Falls – Build a new 138 kV ring bus, 10 miles of 138 kV transmission lines, and complete other work at an estimated cost of $44 Million in 2021.[355]

Duquesne

- Pittsburgh, PA – Establish a new 138 kV substation and complete other work at an estimated cost of $34 Million in 2022.[356]

NextEra Energy

- Rebuild approximately 20 miles of aging 345 kV transmission line at an estimated cost of $51.9 Million in 2021.[357]

Baltimore Gas and Electric Company ("BG&E")

- Port Covington – Build a new Port Covington 115/13 kV station, expand an existing station, and build four 115 kV transmission stations.[358] In 2019, the project was estimated to cost $105 Million.[359]

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351 *Id*. at slides 48-52.
352 *Id*. at slide 52.
353 *Id*. at slides 60-61.
354 ATSI, Submission of Supplemental Projects for Inclusion in the Local Plan at slide 53 (2021), https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/atsi-local-plan-submission-of-the-supplemental-projects-for-2019-rtep.ashx (last accessed Dec. 18, 2024)..
355 ATSI, Submission of Supplemental Projects for Inclusion in the Local Plan at slide 4 (2021), https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/2021/atsi-local-plan-submission-of-the-supplemental-projects-for-2021.ashx (last accessed Dec. 18, 2024) (supplemental submission on June 18, 2021).
356 Duquesne, Subregional RTEP Committee – Western FirstEnergy Supplemental Projects at slide 3 (2022), https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/2022/dlco-local-plan-submission-of-the-supplemental-projects-for-2022-rtep.ashx (last accessed Dec. 18, 2024).
357 NextEra Energy, Submission of Supplemental Projects for Inclusion in the Local Plan at slide 3 (2021), https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/2021/neet-local-plan-submission-of-the-supplemental-projects.ashx (last accessed Dec. 18, 2024).
358 BG&E, BGE 2019 Submission of Supplemental Projects for Inclusion in the Local Plan at slide 3 (2019), https://www.pjm.com/-/media/committees-groups/committees/srrtep-ma/postings/2019/bge-local-plan-submission-for-2019-rtep.ashx (last accessed Dec. 18, 2024).
359 *Id*.

PECO

- Navy Yard – Construct a new 230 kV break and half configuration.[360] In 2019, the estimated cost of the selected solution was $71 Million.[361]

Allegheny Power Systems ("APS")

- Doubs-Goose Creek – Rebuild and reconductor portion of 500 kV transmission line and other equipment replacements.[362] In 2020, APS estimated that the selected will cost $60 Million.[363]

PPL

- South Akron – Rebuild approximately 22.5 miles of two 138 kV transmission lines.[364] The estimated cost of the proposed solutions in 2023 was $67.5 Million.[365]
- Updated a 2016 supplemental project that included a 500 kV substation to establish 22 miles of a second circuit on existing 230 kV transmission lines.[366] PPL estimated that additional work would cost $63 Million in 2020 (in addition to the $95 Million estimated cost of the 500 kV substation and associated work).[367]

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[360] PECO, PECO 2019 Submission of Supplemental Projects for Inclusion in the Local Plan at slide 7 (2019), https://www.pjm.com/-/media/committees-groups/committees/srrtep-ma/postings/2019/peco-local-plan-submission-for-2019-rtep.ashx (last accessed Dec. 18, 2024).
[361] *Id*.
[362] Allegheny Power Systems, Submission of Supplemental Projects for Inclusion in the Local Plan at slide 22 (2020), https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/aps-local-plan-submission-of-the-supplemental-projects-for-2020-rtep.ashx (last accessed Dec. 18, 2024).
[363] *Id*.
[364] PPL, Submission of PPL Supplemental Projects for Inclusion in the 2023 Local Plan at slides 9, 11 (2023), https://www.pjm.com/-/media/committees-groups/committees/srrtep-ma/postings/2023/ppl-local-plan-submission-for-2023-rtep.ashx (last accessed Dec. 18, 2024) ("PPL 2023 Local Plan Presentation"). Solutions were described as "Proposed Solutions."
[365] *Id*.
[366] PPL, Submission of PPL Supplemental Projects for Inclusion in the Local Plan at slide 5 (2020), https://www.pjm.com/-/media/committees-groups/committees/srrtep-ma/postings/2020/ppl-local-plan-submission-for-2020-rtep.ashx (last accessed Dec. 18, 2024).
[367] *Id*.

Dominion

- Rebuild portions of 230 kV transmission lines (almost 20 miles) with an estimated cost of $43 Million.[368]
- Evans Creek – Construct a 230 kV substation and two new 230 kV transmission lines (roughly 8 miles total).[369] The estimated cost of the selected solution in 2024 was $30 Million.[370]
- Tunstall – Build a new 500/230 kV station, construct a 230 kV substation, construct two new 230 kV single circuit transmission lines for approximately 11 miles, and other work.[371] The total estimated cost of the selected solution was $140 Million in 2024.[372]
- Raines – Construct a 230 kV substation and one new 230 kV transmission line for approximately 8 miles.[373] The estimated cost of the project was $20 Million in 2024.[374]
- Mountain Run – Selected solution combines several projects, including a new switching stations and a wreck and rebuild of approximately five miles of existing double-circuit 115 kV lines using 230 kV construction.[375] The selected solution is estimated to cost $60 Million.[376]
- Hornbaker – Construct one new 230 kV transmission line for approximately 7.5 miles and other work.[377] The total estimated cost of the selected solution was $139 Million in 2024.[378]
- Jeffress – Selected solution includes construction of two 230 kV single circuits to new 230 kV substation and other work.[379] The estimated cost of the selected solution was $120 Million in 2024.[380]
- Hornertown to Hathaway – Rebuild approximately 28.9 miles of an existing 230 kV transmission line.[381] The selected solution has an estimated cost of $49.1 Million.[382]

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368 Dominion, Submission of Supplemental Projects for Inclusion in the Local Plan at slide 13 (2024), https://www.pjm.com/-/media/committees-groups/committees/srrtep-s/postings/dominion-local-plan-submission-of-the-supplemental-projects-for-2024.ashx. (last accessed Dec. 18, 2024) The rebuild project was initially posted in 2023 and revised in 2024.
369 *Id*. at slide 31.
370 *Id*.
371 *Id*. at slide 33.
372 *Id*.
373 *Id*. at slide 35.
374 *Id*.
375 *Id*. at slide 37.
376 *Id*.
377 *Id*. at slide 57.
378 *Id*.
379 *Id*. at slide 71.
380 *Id*.
381 Dominion, Dominion Local Plan – 2023 at slide 2, https://www.pjm.com/-/media/committees-groups/committees/srrtep-s/postings/dominion-local-plan-submission-of-the-supplemental-projects-for-2023-rtep.ashx (last accessed Dec. 18, 2024).
382 *Id*.

- Rebuild approximately 20 miles of portions of 230 kV transmission lines.[383] The estimated cost was $43 Million.[384]
- Rebuild 15.7 miles of existing 115 kV transmission line and other work.[385] The estimated cost was $24.5 Million in 2022.[386]
- Rebuild approximately 12 miles of 230 kV double circuit transmission lines and other work.[387] The estimated cost was $38 Million in 2022.[388]
- Replace 11 miles of a 115 kV transmission line and other work.[389] In 2022, the estimated cost was $29.6 Million.[390]
- Butler Farm – Build a new 500/230 kV switching station, construct a 230 kV substation, build a new 10-mile 230 kV transmission line, and conduct other work.[391] The estimated cost was $180 Million in 2022.[392]
- Replace approximately 17.8 miles of existing 230 kV single-circuit, 3.5 miles of double-circuit transmission lines, and other work.[393] The estimated cost of the selected solution was $44.8 Million in 2021.[394]
- Rebuild approximately 14.94 miles of existing 138 kV transmission line and other work.[395] The estimated cost of the selected solution in 2021 was $30 Million.[396]
- Rebuild transmission line to current115 kV standards at an estimated cost of $14 Million in 2021.[397]
- Rebuild approximately 5.21 miles of transmission line to current 115 kV standards at an estimated cost of $8 Million in 2021.[398]
- Build a new 230/115 kV switching station and other work.[399] The estimated cost of the selected solution was $16.3 Million in 2021.[400]

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[383] *Id*. at slide 4.
[384] *Id*.
[385] Dominion, Dominion Local Plan – 2022 at slide 2 (2022), https://www.pjm.com/-/media/committees-groups/committees/srrtep-s/postings/dominion-local-plan-submission-of-the-supplemental-projects-for-2022-rtep.ashx (last accessed Dec. 18, 2024).
[386] *Id*.
[387] *Id*. at slide 10.
[388] *Id*.
[389] *Id*. at slide 30.
[390] *Id*.
[391] *Id*. at slide 48.
[392] *Id*.
[393] Dominion, Dominion Local Plan – 2021 at slide 8 (2021), https://www.pjm.com/-/media/committees-groups/committees/srrtep-s/postings/dominion-local-plan-submission-of-the-supplemental-projects-for-2021-rtep.ashx (last accessed Dec. 18, 2024).
[394] *Id*.
[395] *Id*. at slide 10.
[396] *Id*.
[397] *Id*. at slide 12.
[398] *Id*. at slide 16.
[399] *Id*. at slide 71.
[400] *Id*.

- Construct two single circuit 230 kV transmission lines for approximately 15 miles, 230 kV substation work, and other work.[401] The estimated cost of the selected solution was $81 Million in 2021.[402]
- Rebuild approximately 16 miles of a 230 kV transmission line.[403] The estimated cost of the selected solution was $34 Million.[404]
- Install a 500 kV ring bus at the Occoquan substation, rebuild a 230 kV transmission line, and do other work at an estimated cost of $84.5 Million.[405]
- Build a new substation and extend a new 230 kV double-circuit 230 kV transmission line for approximately 3 miles and other work.[406] The estimated cost of the selected solution in 2020 was $74.9 million.[407]
- Extend a new double-circuit 230 kV transmission line for 3.5 miles and do other work at an estimated cost of $44 million.[408]

<u>ComEd</u>

- Rebuild 23 miles of an existing 138 kV transmission line at an estimated cost of $94 Million in 2023.[409]
- Rebuild a 138 kV bus with 138 kV breaker and a half GIS at an estimated cost of $68 Million in 2022.[410] The solution was driven by the existing 138 kV bus "not comply[ing] with internal design guidelines."[411]
- Install two new autotransformers, reconductor two miles of 138 kV line, and perform other work, estimated to cost $36 million in 2022.[412]

<u>Dayton</u>

[401] *Id*. at slide 93.
[402] *Id*.
[403] *Id*. at slide 97.
[404] *Id*.
[405] *Id*. at slide 103.
[406] Dominion, Submission of Supplemental Projects for Inclusion in the Local Plan at slide 83 (2020), https://www.pjm.com/-/media/committees-groups/committees/srrtep-s/postings/dominion-local-plan-submission-of-the-supplemental-projects-for-2020-rtep.ashx (last accessed Dec. 18, 2024).
[407] *Id*.
[408] *Id*. at slide 85.
[409] ComEd, Submission of Supplemental Projects for Inclusion in the Local Plan at slide 3 (2023), https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/2023/comed-local-plan-submission-of-the-supplemental-projects-for-2023-rtep.ashx (last accessed Dec. 18, 2024).
[410] ComEd, Submission of Supplemental Projects for Inclusion in the Local Plan at slide 3 (2022), https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/2022/comed-local-plan-submission-of-the-supplemental-projects-for-2022-rtep.ashx (last accessed Dec. 18, 2024).
[411] *Id*. at slide 2.
[412] *Id*. at slide 5.

- Build a new 345 kV/138 kV/69 kV substation, 13 miles of greenfield double circuit 345 kV transmission lines, a new 345 kV substation, and perform other work at an estimated cost of $145.10 Million.[413]
- Replace 20 miles of existing 69 kV transmission with double circuit 138 kV facilities, build a new 138 kV substation, expand an existing substation, and perform other work at an estimated cost of $65.35 Million in 2021.[414]
- Phase one of a proposed solution included replacing a 138 kV substation, constructing new 138 kV transmission lines, and performing other work at an estimated cost of $36.1 Million in 2022.[415]

Duke

- Retire 69 kV substation and build a new ring bus substation on the 138 kV system in its place at an estimated cost of $19.5 Million.[416]
- Install a new 138 kV ring bus substation, construct new 138 kV transmission lines, and complete other work at an estimated cost of $30,159,604 Million in 2021.[417]

In November 2020, a PJM stakeholder had PTerra, LLC ("PTerra") perform a solution-based distribution factor ("DFAX") analysis of nineteen then-proposed Self-Planned Transmission projects presented through the PJM Attachment M-3 process. PTerra's analysis showed that the projects benefit, under the PJM benefit test, multiple zones.[418] Yet under PJM's cost allocation rules, each project was allocated solely to the zone where the project was

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[413] Dayton, Submission of Supplemental Projects for Inclusion in the Local Plan at slide 7 (2023), https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/2023/dayton-local-plan-submission-of-the-supplemental-projects-for-2023-rtep.ashx (last accessed Dec. 18, 2024).
[414] Dayon, Submission of Supplemental Projects for Inclusion in the Local Plan at slide 3 (2021), https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/2021/dayton-local-plan-submission-of-the-supplemental-projects-for-2021-rtep.ashx (last accessed Dec. 18, 2024).
[415] Dayton, Submission of Supplemental Projects for Inclusion in the Local Plan at slide 8 (2022), https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/2022/dayton-local-plan-submission-of-the-supplemental-projects-for-2022-rtep.ashx (last accessed Dec. 18, 2024).
[416] Duke, Submission of Supplemental Projects for Inclusion in the Local Plan at slide 9 (2023), https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/2023/deok-local-plan-submission-of-the-supplemental-projects-for-2023-rtep.ashx (last accessed Dec. 18, 2024).
[417] Duke, Submission of Supplemental Projects for Inclusion in the Local Plan at slide 3 (2021), https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/deok-local-plan-submission-of-the-supplemental-projects-for-2019-rtep.ashx(last accessed Dec. 18, 2024).
[418] *See*, Supplemental Comments of LSP Transmission Holdings, LLC and Central Transmission, LLC Regarding PJM Members Committee Approved Section 205 Filing on Transmission End of Life Planning, filed November 23, 2020 in Docket No. ER20-2308-000 at Exhibit A.

located.[419] Below are the PTerra analyzed benefits of just two of the projects, showing that costs are inappropriately allocated to PPL, the project sponsor.

Self-Planned Sponsor	Self-Planned Transmission Project Name And Cost Estimate	Dfax Analysis Of Project Benefits As Reflected By Flows	Cost Allocation Because Self-Planned
PPL-2020-0012	Montour-Susquehanna and Montour-Susquehanna T10 230kV $69.6 million	AEC (1.39%) / AEP (0.17%) / APS (0.98%) / ATSI (0.64%) / BGE (1.66%) / COMED (0.09%) / DAYTON (0.06%) / DEOK (0.12%) / DL (0.21%) / DPL (11.40%) / DVP (0.80%) / EKPC (0.06%) / JCPL (11.71%) / ME (1.88%) / NEPTUNE (1.24%) / OVEC (0.00%) / PECO (1.69%) / PENELEC (24.24%) / PEPCO_SMECO (0.47%) / PPL (19.64%) / PSEG_RECO (21.56%)	PPL – 100%
PPL-2020-0013	Siegfried-Harwood and Harwood-East Palmerton/Siegfried-East Palmerton 230 kV $136.8 million	AEC (0.35%) / AEP (0.12%) / APS (0.20%) / ATSI (22.29%) / BGE (1.31%) / COMED (0.42%) / DAYTON (0.12%) / DEOK (0.34%) / DL (5.11%) / DPL (2.57%) / DVP (2.16%) / EKPC (0.22%) / JCPL (17.80%) / ME (5.71%) / NEPTUNE (0.86%) / OVEC (0.00%) / PECO (0.58%) / PENELEC (0.21%) / PEPCO_SMECO (0.46%) / PPL (23.28%) / PSEG_RECO (15.88%)	PPL – 100%

[420]

PTerra's analysis of another twenty projects that were Self-Planned by individual PJM transmission owners to address transmission facilities reaching the end of their useful life yielded

[419] *Id*. Although this points to a deficiency in existing cost-allocation rules for Locally Planned projects, more importantly the benefits test results demonstrate that these Self-Planned transmission projects in no way reflect "local" transmission but instead have broad regional impact.
[420] *Id*. (emphasis added).

a similar result.[421] Eight of the analyzed projects showed that zones other than the local zone benefited by more than 70%.[422]

In a state proceeding regarding a similar project, a proposed $38 million rebuild of double circuit 230 kV facilities owned by PPL, an expert retained by the Pennsylvania Office of Consumer Advocate noted that PJM conducts what he refers to as a "minimalistic do no harm assessment" of Self-Planned Transmission.[423] In his testimony, Mr. Konidena noted that while the project under review was a single $38.8 million rebuild,[424] "PPL has 15 scheduled transmission line rebuilds within the next 8 years (2023-2030) with a combined cost of ($555-971 [million].[425] Mr. Konidena also testified that PPLs cost estimate for the single project under review "increased by 75% in the 27 months from when it was initially mentioned at the PJM [Transmission Expansion Advisory Committee] 'Solutions' meeting in October 2020 to when [ ] filed at the [Pennsylvania Public Utility Commission] ("PUC") in December 2022."[426] As Mr. Konidena concluded "PJM's processes may work well for PJM TOs but are not designed to protect the best interests of Pennsylvania ratepayers."[427] In this regard, Mr. Konidena outlined the review undertaken by the PUC which makes it clear that just and reasonable transmission rates are not part of its evaluation.[428] He further address a number of regional project alternatives that could have been, but were not, explored by PPL nor permitted to be explored by

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[421] LSP Transmission Holdings II, LLC and Central Transmission LLC Comments in Support of Stakeholder Approved Section 205 Filing at Attachment 3, Docket No. ER20-2308-000, filed on July 23, 2020.
[422] *Id*.
[423] Direct Testimony of Rao Konidena on behalf of Pennsylvania Office of Consumer Advocate, filed July 7, 2023 in Pennsylvania Public Utility Commission Docket No. A-2022-3037374 ("Konidena PA PUC Testimony") at 14 & fn 20.
[424] *Id*. at 8.
[425] *Id*. at 19-20, fns 30-31, Table 1.
[426] *Id*. at 21.
[427] *Id*.
[428] *Id*. at 6-7.

PJM.[429] In April 2024, PPL proposed another Self-Planned Transmission project at 500 kV at the cost of $244 million.[430] Although the project is identified to address a claimed customer request, the need and the solution will receive little or no review.

3. MISO Other Projects

Over the last decade, transmission owners in MISO have heavily invested in transmission facilities that they have planned largely outside of the MISO regional transmission planning process using the MISO Transmission Owner planning criteria.[431] MISO's tariff categorizes these transmission owner-planned projects as "Other Projects."[432] The Other Projects category is essentially a catch-all category for projects that are included in MISO's annual regional transmission expansion plan (even though they are not planned by MISO[433]) but are not one of the other defined categories of projects.[434] Other Projects typically address an individual transmission owner's reliability planning criteria (that do not rise to the level of NERC reliability issues) and aging infrastructure.[435]

Transmission owner investment in Other Projects has dwarfed investment in transmission facilities regionally planned by MISO. The 2023 MISO Transmission Expansion Plan

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[429] Compare *Id*. at 28-30 (regional alternatives) with *Id*. at 10 (PPL alternatives reviewed) and *Id*. at 17-18 (PJM lack of alternative review).

[430] https://pjm.com/-/media/committees-groups/committees/teac/2024/20240402/20240402-item-08---ppl-supplemental-projects.ashx (last accessed Dec. 18, 2024).

[431] MISO Tariff, Schedule 1, Appendix B.VI.

[432] *See* MISO Tariff, Att. FF, § III.A.2.k. MISO's Tariff requires MISO to plan and operate all facilities of the MISO Transmission Owners above 100 kV. *See id.*, Schedule 1, Appendix B.I. Other Projects become part of the MISO Regional Transmission Expansion Plan, but the Other Projects are not independently planned by MISO.

[433] In the 2023 MTEP, MISO stated that, for Other Projects and Baseline Reliability Projects (another category of locally cost allocated projects), it conducted a "no harm" analysis on 54% of the projects, verified the need for 17% of the projects, and simply posted the remaining 29% with no analysis. 2023 MTEP Report at 26, *available at* https://cdn.misoenergy.org/MTEP23%20Full%20Report630587.pdf. (last accessed Dec. 18, 2024). *See* RMI Report at 27 (explaining that RTOs only do a "no-harm analysis" for Local Projects).

[434] MISO Tariff, Att. FF, § III.A.2.k. Baseline Reliability Projects are also locally planned by individual transmission providers.

[435] *See* 2023 MTEP Report at 24-25.

("MTEP") included $9 billion in investment in 572 new transmission facilities and two-thirds of that investment, $6 billion, will be spent on 382 Other Projects,[436] as the chart below shows:

MTEP Year	Number of Other Projects	Cost of Other Projects	Total Number of Projects in MTEP[437]	Total Cost of Projects in MTEP[438]	Self-Planned Cost As Percentage Of Total Costs
2024	310	$4.054 billion	459	$6.727 billion	60%
2023	382	$6.023 billion	572	$9 billion	67%
2022	270	$3.169 billion	382	$4.3 billion	74%
2021	255	$2.491 billion	335	$3 billion[439]	83%
2020	340	$2.8 billion	515	$4.159 billion	67%
2019	320	$2.8 billion	480	$4 billion	70%
2018	341	$2.3 billion	442	$3.3 billion	70%
2017	248	$1.4 billion	354	$2.7 billion	52%
2016	243	$1.75 billion	383	$2.69 billion	65%
2015	242	$1.38 billion	345	$2.75 billion	50%
2014	312	$1.5 billion	369	$2.5 billion	60%

Perhaps the most egregious recent example of local planning is the Amite South Reliability Project Phase 1 ("AS Phase 1").[440] In 2023, Entergy Louisiana proposed 29 new

[436] The 2023 MTEP Report includes 382 Other Projects, 45 Baseline Reliability Projects, 2 Market Participant Funded Projects, 142 Generator Interconnection Projects, and 1 Multi-Value Project.
[437] The total number of projects includes other projects, baseline reliability projects, generator interconnection projects, market efficiency projects, multi-value projects, and transmission delivery service projects.
[438] The total costs of projects include other projects, baseline reliability projects, generator interconnection projects, market efficiency projects, multi-value projects, and transmission delivery service projects.
[439] Excludes projects approved through MISO's Long Range Transmission Planning process, which includes 18 transmission projects representing approximately $10 billion of investment, of which approximately only 10% was subject to competition.
[440] *See* 2023 MTEP, Appendix A – New Project Recommended for Approval (2023), https://cdn.misoenergy.org/MTEP23%20Appendix%20A%20-%20New%20Projects%20recommended%20for%20approval629964.xlsx (last accessed Dec. 18, 2024) ("2023 MTEP Appendix A"). The Amite South Reliability Project – Phase 1's Project ID number is, 25242. Given that

projects, including 10 Other Projects, with an estimated cost of $2.7 billion.[441] AS Phase 1 made up more than half of Entergy's proposed $2.7 billion with an estimated price tag of $1.4 billion. MISO reviewed the AS Phase 1 and, after working with Entergy Louisiana, MISO proposed an even more expensive alternative project that would replace Entergy Louisiana's proposed version of the AS Phase 1 and the Gypsy reliability project, which had an estimated cost of $164 Million.[442] The alternative AS Phase 1 is estimated to cost $1.7 Billion and will consist of a new 500/230 kV substation; a new 85-mile, 500 kV transmission line; a new 60-mile, 230 kV transmission line; an upgraded substation; and a 230 kV transmission line modified to 500 kV.[443] Notwithstanding that MISO reviewed Entergy's proposed AS Phase 1, and developed a more expensive and expansive alternative project (which includes replacing the need for another project), and the AS Phase 1 includes a new 500 kV substation and new 500 kV transmission line, the AS Phase 1 remained categorized as an Other Project, and its costs will be allocated entirely to the local Entergy Louisiana pricing zone, and thus will not be subject to MISO's successful competitive solicitation process.

Another higher voltage, expensive Entergy Louisiana Other Project included in 2023 MTEP is Amite South Reliability Project Phase 2 ("AS Phase 2").[444] This Other Project includes

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MISO plans Baseline Reliability Projects, projects needed to meet mandatory reliability criteria, adding "Reliability" to the project name was an effort to sanitize the need for $1.4 billion in localized spending.

[441] MISO, 2023 MTEP Project Information, City of Alexandria, Cleco, Entergy Louisiana, Entergy New Orleans, Lafayette Utilities System, 1st South Subregional Planning Meeting at slides 15, 30 (Feb. 3, 2023), https://cdn.misoenergy.org/20230203%20SSPM1%20Item%2003b%20Review%20of%20Proposed%20Reliability%20Projects%20LA627753.pdf (last accessed Dec. 18, 2024).

[442] Amanda Durish Cook, *MTEP 23 Catapults to $9.4B; MISO Replaces South Reliability Projects*, RTO INSIDER (Sept. 10, 2023), https://www.rtoinsider.com/54929-mtep-23-miso-replaces-south-reliability-projects/(last accessed Dec. 18, 2024).

[443] MISO, 2023 MTEP Project Selection, City of Alexandria, Cleco, Entergy Louisiana, Entergy New Orleans, Lafayette Utilities System, 3rd South Subregional Planning Meeting at slide 26 (Sept. 6, 2023), https://cdn.misoenergy.org/20230906%20SSPM3%20Item%2003c-2%20Louisiana%20Proposed%20Projects630081.pdf ("Sept. 2023 South Subregional Meeting") (last accessed Dec. 18, 2024).

[444] *See id.* at slide 29; *see also* 2023 MTEP.

a new 500 kV substation, a new 5-mile, 500 kV transmission line, a new 14-mile, 230 kV transmission line, and other associated facilities.[445] The cost of this "Other Project" is $290 million.[446] MISO also reviewed and developed an alternative, but ultimately MISO and Entergy Louisiana moved forward with Entergy Louisiana's proposed version of the project.[447]

Several transmission owners, including the Entergy companies,[448] ATC,[449] ITC,[450] ITC Midwest,[451] METC,[452] and NIPSCO[453] have variations on "asset renewal programs" included in Appendix A of recent MTEPs. The project descriptions tell stakeholders in general terms that the transmission owner is going to complete projects to address aging and failing transmission infrastructure, but do not identify any particular transmission facilities that will be replaced. For instance, the Entergy companies each have an "Asset Renewal Program" that involves "replac[ing] aged and/or degraded transmission line and transmission substation assets" with a

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[445] Sept. 2023 South Subregional Meeting at slide 29.
[446] *Id*.
[447] *See* Sept. 2023 South Subregional Meeting at slides 29-31.
[448] 2023 MTEP Appendix A – Entergy Mississippi's 2024 Asset Renewal Program, Project ID 23932; Entergy Louisiana's 2024 Asset Renewal Program, Project ID 23924; Entergy Texas's 2024 Asset Renewal Program, Project ID 23870; Entergy Arkansas's 2024 Asset Renewal Program, Project ID 23899. 2023 MTEP is available at, https://cdn.misoenergy.org/MTEP23%20Full%20Report630587.pdf. 2022 MTEP Appendix A – Entergy Mississippi's 2023 Asset Renewal Program, Project ID 21815; Entergy Louisiana's 2023 Asset Renewal Program, Project ID 21809; Entergy Texas's 2023 Asset Renewal Program, Project ID 15649. 2022 MTEP is available at, https://cdn.misoenergy.org/MTEP22629955.zip; 2021 MTEP Appendix A – Entergy Arkansas 2021 and 2022 Asset Renewal Programs, Project IDs 19909, 19910; Entergy Louisiana 2021 and 2022 Asset Renewal Programs, Project IDs 20039, 20040; Entergy Mississippi 2021 and 2022Asset Renewal Programs, Project IDs 20060, 20061; Entergy Texas 2021 and 2022 Asset Renewal Programs, Project IDs 20041, 20242. 2021 MTEP is available at, https://cdn.misoenergy.org/MTEP21626044.zip.
[449] 2023 MTEP Appendix A – ATC's Small Capital Project and Asset Renewal Program 2024, Project ID 20201; 2022 MTEP Appendix A – Small Capital Project and Asset Renewal Program 2023, Project ID 16766; 2021 MTEP Appendix A – ATC's Small Capital Project and Asset Renewal Program 2022, Project ID 14964.
[450] 2023 MTEP Appendix A – ITC Transmission's 2025 Transmission Asset Replacement Program, Project ID 23884; 2022 MTEP Appendix A – ITC Transmission's 2024 ITC Transmission Asset Replacement Program, Project ID 22017; 2021 MTEP Appendix A – ITC Transmission 2023 Asset Replacement Program, Project ID 18237.
[451] 2023 MTEP Appendix A – ITC Midwest's Asset Replacement Program 2025, Project ID 23677; 2022 MTEP Appendix A – ITC Midwest's Asset Replacement Program 2024, Project ID 21980.
[452] 2023 MTEP Appendix A – METC 2025 Asset Replacement Program, Project ID 23948; 2022 MTEP Appendix A – METC 2024 Asset Replacement Program, Project ID 22000; 2021 MTEP Appendix A – METC's Asset Replacement Program, Project ID 18239.
[453] 2022 MTEP Appendix A – NIPSCO Upgrade Transmission Substation and Upgrade Transmission line programs 2022-2026, Project IDs 21876, 21878, 21879, 21880, 21881, 21882, 21883, 21884, 21885, 21886. The projects collectively cost an estimated $368.9 Million.

maximum voltage of 500 kV.[454] Even though the "Asset Renewal Programs" are essentially "approved" because they were included in Appendix A of 2023 MTEP, the description of the Entergy companies' programs makes it clear that "the specifics for the 2024 asset renewal plans have not yet been finalized."[455] The estimated cost of these programs in 2023 MTEP ranges from $24.6 Million up to $50.4 Million.

Additional examples of Other Projects in Appendix A of 2021-2023 MTEPs that are 100 kV and above include the following.

Submitting Company	Project Name and Description	In-Service Date	Individual Project Cost	Project ID
Appendix A MTEP 2023[456]				
Ameren Illinois	Rebuild double-circuit towers on a 345 kV transmission line	12/1/2024	$34.3 million	22266
Ameren Missouri	Rebuild of a 138 kV transmission line and other work	12/1/2026	$77.7 million	22801
Ameren Illinois	Rebuild of a 37-mile, 345 kV transmission line	12/1/2026	$51 million	22817
Ameren Illinois	Rebuild of a 36-mile, 345 kV transmission line	6/1/2025	$48 million	22851
Ameren Illinois	Construct a new 138 kV substation and an approximately 3.5-mile, 138 kV transmission line to a new substation and other related work	6/1/2028	$167.85 million	23026
Ameren Illinois	Rebuild of a 345 kV transmission line	12/1/2026	$29 million	23072
METC	Construct a new, 3-row, 138 kV substation, rebuild of an	3/1/2025	$56 million	23865

[454] 2023 MTEP Appendix A.
[455] *Id.*
[456] *Id.*

Submitting Company	Project Name and Description	In-Service Date	Individual Project Cost	Project ID
	entire 138 kV transmission line (approximately 17.6 miles), and rebuild of a 7.8-mile segment of a 138 kV transmission line			
MidAmerican	Expand an existing 345 kV bus and construction of a new 345 kV transmission line	6/3/2027	$58 million	24999
DEI	Construct a new 230/69 kV substation	6/1/2025	$92 million	23964
Ameren Services Company	Construct a new 138 kV line from; rebuild 138 kV substation as a 4-position initial, 6-position ultimate 138 kV ring bus; rebuild 138 kV substation as 5-position initial, 6-position ultimate 138 kV ring bus; and other work	12/1/2025	$26.7 million	22946
Ameren Services Company	Add 4 138 kV dynamic reactive 250 Mvar each located at four locations	6/1/2027	$170 million	22966
Ameren Services Company	Reconductor a 51 mile 345 kV line with conductor capable of carrying 3,000 amps during Summer Emergency conditions	12/1/2025	$25 million	22813
Ameren Services Company	Construct a new 138 kV substation in ring bus configuration on the existing 138 kV line and other work	12/1/2025	$8.5 million	22667
Entergy Mississippi	Construct a new 115 kV substation and other work	12/1/2024	$32.6 million	23348
Ameren Services Company	Replace the 134 original vintage wood structures on the Louisville-Newton-1 138 kV line due to age and condition. Replace the existing conductor with ones capable of carrying 2,000 amps under Summer Emergency conditions.	12/1/2024	$32 million	22816

Submitting Company	Project Name and Description	In-Service Date	Individual Project Cost	Project ID
	Replace both shield wires with 72-fiber OPGW.			
Gridliance	Rebuild the portion of 161 kV three terminal line	12/31/2026	$21.9 million	23765
Duke Energy Corporation	Construct 138kV system followed by 345/138kV transformation as large new customer load projections increase.	12/31/2029	$123.5 million	23925
Great River Energy	Rebuild a substation, upgrade a substation, and other work	5/21/2027	$29.57 million	23921
Cleco Power LLC	Tap an existing 138 kV line, build a new 138 kV substation, build a new 6.1 mile 138 kV line to a new substation Ragley, and other work	7/17/2024	$40 million	24415
Entergy	Construct a new 138 kV transmission station and other work	10/31/2024	$29.6 million	24920
METC	Construct a new 138 kV, 3-row, breaker and a half substation to be fed by looping an existing 138 kV line approximately 0.2 miles into the new substation	5/31/2024	$16.6 million	24673
ITC Midwest	To meet new load, build a new 3 row 161 kV breaker and ½ substation with 4 line positions and 2 transformer positions and other work.	12/31/2024	$56.5 million	24449
Otter Tail Power Company	Construct a new 115 kV line to connect to a new 115/12.5 kV substation; construct an additional 115 kV line that will connect to a new 115 kV switching station; and other work.	12/31/2026	$32.3 million	23936

Submitting Company	Project Name and Description	In-Service Date	Individual Project Cost	Project ID
Indianapolis Power & Light Company	New 138 kV, two 22.4 MVA transformers, 3 breaker, straight bus substation to serve load	12/31/2025	$10 million	24293
Indianapolis Power & Light Company	New 138 kV, two 20 MVA transformer, three-breaker substation	12/31/2026	$10.7 million	24273
Ameren Services Company	Rebuild a138 kV line with conductors capable of 2000 amps at Summer Emergency and OPGW.	6/1/2025	$12.5 million	22848
Ameren Services Company	Rebuild a 11.4 mile 138 kV Transmission Line with T2 conductor rated at 2,000 amps Summer Emergency Conditions and 2 EA 72-Fiber OPGW shield wires	12/1/2024	$13 million	23504
Entergy	Construct a new 138 kV substation to serve industrial customer	10/30/20214	$28 million	24134
Entergy	Construct a new 138 kV transmission station to service industrial load customer	10/31/2024	$29.6 million	24920
METC	Rebuild approximately 19.3 miles of a 138 kV circuit to 1431 ACSR conductor utilizing 138 kV double- circuit structures with OPGW and other work	12/31/2026	$35.395 million	23847
Montana-Dakota Utilities	Rebuild current substation 230/115/41.6 kV	10/31/2025	$23.5 million	23596
Minnesota Power (Allete, etc.)	New 230 kV switching station	6/1/2026	$25 million	23877
Appendix A in MTEP22[457]				

[457] 2022 MTEP, Appendix A – New Project Recommended for Approval (2022), https://cdn.misoenergy.org/MTEP22629955.zip (last accessed Dec. 18, 2024).

Submitting Company	Project Name and Description	In-Service Date	Individual Project Cost	Project ID
Entergy Arkansas	Construct a new 500/230 kV substation and related work	3/1/2024	$122 million	22530
Ameren Illinois	Rebuild of a 345 kV transmission line	12/1/2023	$36.1 million	21646
Ameren Illinois	Rebuild of a 345 kV transmission line	12/1/2024	$25.2 million	21647
Northern States Power	Construction of two 345 kV circuits to connect existing substations	9/1/2025	$48.7 million	23452
NIPSCO	New 138/69 kV substation	12/31/2025	$42.37 million	21167
NIPSCO	New 138 kV transmission line	12/31/2024	$27.53 million	21168
NIPSCO	Rebuild of a 138 kV substation	12/31/2024	$30.19	21867
METC	Rebuild of approximately 21 miles of a 138 kV transmission line	12/31/2025	$39 million	22021
METC	Rebuild of approximately 19 miles of a 138 kV transmission line	12/31/2025	$32.63 million	22020
METC	Rebuild 18.76 miles of 138 kV circuit using 954 ACSR conductor with double-circuit steel structures	12/31/2025	$27.6 million	15910
METC	Rebuild approximately 12 miles and approximately 28.6 miles on 138kV future double circuit steel poles with 1431 ACSR conductor with OPGW (coordinating with J875 Generator Interconnection project)	5/15/2025	$53.58 million	21945
ATC	138 kV underground line replacement	12/31/2025	$37 million	21926
Duke Energy	New substation (138-345 kV)	Between 12/27/2024 to 1/1/2025	$100 million	22425

Submitting Company	Project Name and Description	In-Service Date	Individual Project Cost	Project ID
Entergy Mississippi	Build new 500 kV line	12/15/2025	$7.1 million	20064
Ameren Service Company	Rebuild existing 345 kV line	12/15/2022	$9.1 million	21428
Northern State Power (Xcel Energy)	Install second 345/115 kV transformer	6/1/2023	$9.75 million	21285
ITC Midwest	Construct a new 161/69 kV substation and other work	12/31/2025	$19.3 million	21982
Duke Energy Corporation	138 kV substation rebuild and reconfigure and other work	7/19/2024	$28.444 million	22211
Cleco Power	Tap existing 230 kV line 2.4 miles and build a new substation	3/27/2023	$18.76 million	22205
MISO 2021 MTEP[458]				
ATC	Rebuild of a 138 kV transmission line	12/31/2024	$35.8 million	18048
Ameren Illinois	Rebuild of a 138 kV transmission line	6/1/2025	$12.8 million	21325
Ameren Illinois	Rebuild of a 138 kV transmission line	12/1/2022	$4.2 million	21585
Entergy Louisiana	Rebuild of a 115 kV transmission line for approximately seven miles	2/28/2022	$86.3 Million	18228
Entergy Louisiana	New 230 kV substation	12/31/2022	$20.1 million	21085
Entergy Louisiana	New 230 kV substation	6/1/2025	$32.2 million	13995
ITC Midwest	New approximately 29-mile 161 kV transmission line	5/1/2026	$71.2 million	20029
ITC Transmission	New 345 kV substation	6/1/2024	$32.5 million	20036
MidAmerican Energy Company	Rebuild of a 161 kV transmission line	10/1/2020	$6.75 million	18885

458 2021 MTEP Appendix A.

Submitting Company	Project Name and Description	In-Service Date	Individual Project Cost	Project ID
MidAmerican Energy Company	New 161 kV substation	12/1/2024	$6 million	20003
MidAmerican Energy Company	New 161-69 kV substation	12/31/2022	$5 million	20013
METC	138 kV substation rebuild	12/31/2025	$24.2 million	20162
METC	138 kV substation rebuild	12/31/2023	$24 million	20164
MidAmerican Energy Company	New 161 kV transmission line	6/1/2023	$17 million	20173
NIPSCO	Rebuild of a 138 kV substation	12/31/2022	$16.57 million	20605
METC	Replace 345/138 kV transformer	12/31/2023	$7.1 million	20147
METC	Replace 345/138 kV transformer	12/31/2023	$6.2 million	20146
METC	Replace 345/138 kV transformer	12/31/2025	$6.1 million	20145
METC	Replace 345/138 kV transformer	12/31/2025	$5.3 million	20144
ITC Transmission	Replace 345/120 kV transformer	12/31/2025	$4.8 million	20132
ITC Transmission	Replace 345/120 kV transformer	12/31/2023	$4.8 million	20138
ITC Transmission	Replace 345/120 kV transformer	12/31/2023	$4.8 million	20144
American Transmission Co. LLC	345 kV asset renewal substation project	12/1/2024	$28.95 million	16490
Ameren Services Company	Add second 345/138 kV transformer	12/1/2023	$10.2 million	19988
American Transmission Co. LLC	Replace 128/345 kV power transformer (asset renewal – substation)	12/1/2024	$7.938 million	19706
MidAmerican Energy Company	Replace 345/161 kV transformer	Between 7/31/2021 and 9/30/2022	$3.85 million	21430

Submitting Company	Project Name and Description	In-Service Date	Individual Project Cost	Project ID
Otter Tail Power Company	Like-for-like replacement of transformer	2/4/2022	$2.6 million	20606
Minnesota Power (Allete, Inc.)	Replace aging 230 kV bank and 230 kV circuit	12/31/2025	$7.35 million	20075
ITC Transmission	Replace 230/120 kV transformer	12/31/2025	$4.8 million	20133
ITC Transmission	Install two 230 kV lines	12/31/2023	$2.7 million	19185
GridLiance	Rebuild portion of 161 kV line (Ckt 1)	6/1/2023	$14.7 million	20005
GridLiance	Rebuild portion of 161 kV line (Ckt 4)	6/1/2023	$11.7 million	20004
GridLiance	Rebuild portion of 161 kV line (Ckt 3)	6/1/2023	$11.7 million	20001
GridLiance	Rebuild portion of 161 kV line (Ckt 2)	3/1/2022	$11 million	19746
ITC Midwest	Construct a 161/69 kV substation	5/31/2023	$7.888 million	17968
Ameren Services Company	Rebuild 138 kV substation	12/1/2022	$16.2 million	17979
ITC Transmission	Build approximately .85 miles of 120 kV underground cable	12/31/2024	$40 million	20167
Northern States Power (Xcel Energy)	Construct new 115 kV substation and other work	10/15/2022	$10.6 million	19893
ITC Transmission	Construct a new in-and-out 120 kV station and other work	5/28/2023	$17.147 million	21105
American Transmission Co. LLC	Asset renewal at 138 kV substation	12/31/2024	$9.9 million	16489

Among MISO transmission owners, the following transmission additions were projected to Wall Street analysts:

Xcel $11.7 Billion*[459]

[459] https://investors.xcelenergy.com/files/doc_financials/2023/q4/Xcel-Energy-Earnings-Presentation-2023-Q4.pdf

ITC	$5 Billion*[460]
Entergy	$3.8 Billion*[461]

* Each of the referenced entities operates in a state with a state incumbent preference law (often referred to as a right-of-first refusal law), so the referenced transmission may include regional transmission additions that the incumbent is currently assured of being assigned, subject to ongoing litigation.

The cost of Other Projects is allocated solely to the transmission owner's local transmission pricing zone. Neither the transmission owner nor MISO evaluates whether an Other Project will have benefits outside the transmission owner's local zone, although the Commission, and DC Circuit have found that extra-high voltage transmission additions, such as Entergy's Amite South 500 kV projects, have regional benefits.[462] In the Southwest Power Pool region the Commission has found that 100 kV facilities and above have region-wide benefits.[463]

On December 12, 2024, MISO Board approved MTEP24, which includes $6.7 billion in local reliability projects, [464] including $4 billion characterized as Other Projects, as reflected below.[465]

(last accessed Dec. 18, 2024). slide 11

[460] ITC expects to invest in $3.6 Billion in infrastructure investments, $800 Million in new interconnections, $200 Million in grid security, and $400 Million in major capital projects. https://www.fortisinc.com/docs/default-source/investor-presentations/august-2022-marketing-presentation---final.pdf?sfvrsn=cbb47598_2, slide 2, (last accessed Dec. 18, 2024).

[461] https://s201.q4cdn.com/714390239/files/doc_presentations/2023/Nov/10/EEI-2023-Financial-Conference-handout.pdf, slide 21, (last accessed Dec. 18, 2024).

[462] *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254 (D.C. Cir. 2018), *reh'g denied*, 905 F.3d 671 (D.C. Cir. 2018); Southwest Power Pool, Inc. 131 FERC ¶ 61,252 (2010) at P 73, P 75 ("We find this evidence compelling that the high voltage 345 kV and EHV facilities provided significantly greater support to regional power flows relative to the lower voltage facilities. . . . We also find that SPP has demonstrated that the benefits of the EHV facilities accrue to all members of its system.")

[463] *Southwest Power Pool, Inc.*, 131 FERC ¶ 61,252 (2010) at P 4 accepting that transmission facilities 100 kV to 300 kV were important "transmission facilities to integrate the eastern and western portion of the SPP grid, reduce congestion, efficiently integrate new resources, and accommodate new or growing loads."

[464] *See* MTEP24 Preview: Local Reliability, JTIQ, and Regional Projects, System Planning Committee of the Board of Directors (Oct. 30, 2024), *available at* https://cdn.misoenergy.org/20241030 System Planning Committee of the BOD Item 03b MTEP24 Preview655620.pdf (last accessed Dec. 18, 2024). MTEP24 is available here. https://cdn.misoenergy.org/MTEP24 Full Report658025.pdf (hereinafter "MTEP24 Full Report").

[465] *See* MTEP24 Full Report at p. 180.

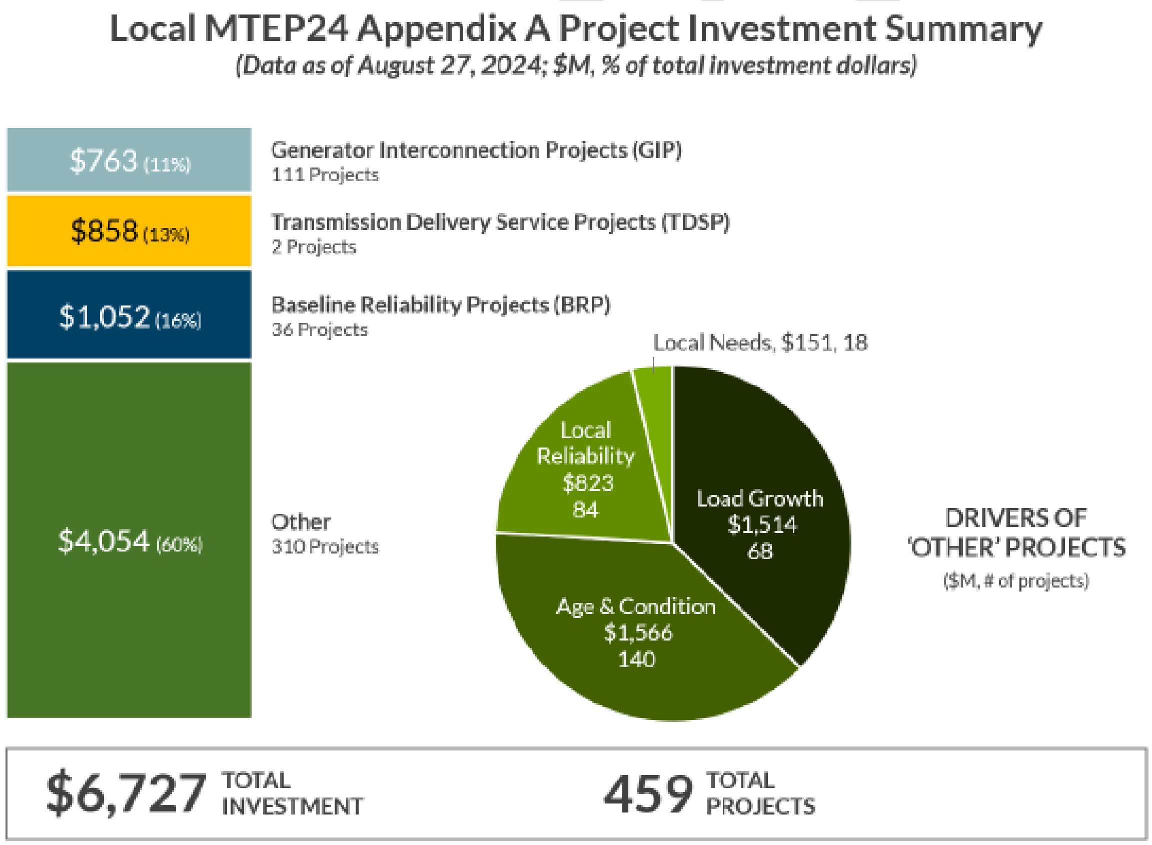


Figure 4.1-1: Local Appendix A project investment summary (data as of 8-27-2024).

4. ISO-NE

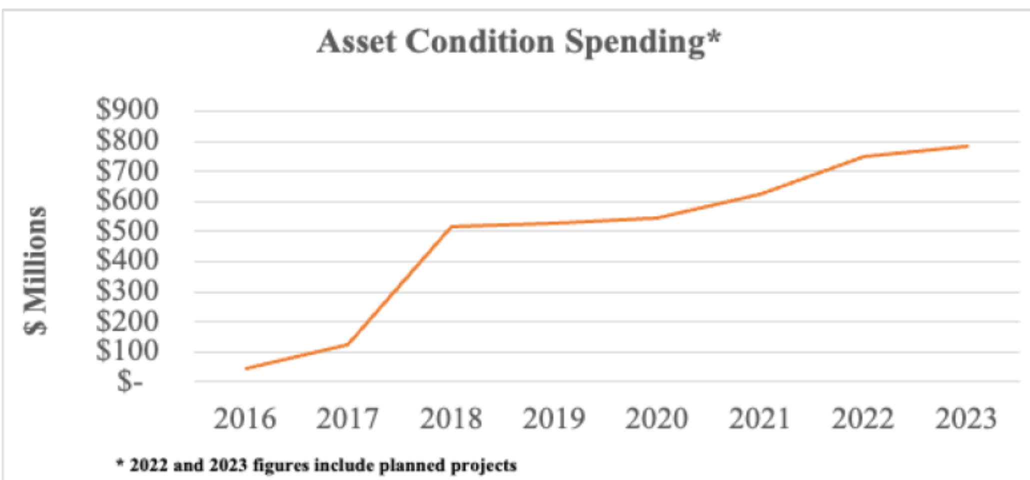
As New Hampshire's consumer advocate noted "[i]n New England overall, there are nearly $5 billion in these Asset Condition projects that are proposed, planned, or already under construction . . . which means half a billion dollars charged to our state's struggling ratepayers."[466] New Hampshire Consumer Advocate Kreis asserted, "[u]nlike entirely new transmission projects – which are commissioned according to a rigorous planning process overseen by the regional grid operator ISO New England – Asset Condition projects essentially receive no scrutiny at present."[467] The New England States Committee on Electricity

[466] The $500,000,000 Question: "Asset Condition" Transmission Projects, Office of the Consumer Advocate Donald Kreis, New Hampshire, https://www.oca.nh.gov/news-and-media/500000000-question-asset-condition-transmission-projects (last accessed Dec. 18, 2024).
[467] *Id.*

("NESCOE") raised the issue also, directly with the New England Transmission Owners and ISO-NE. As NESCOE noted "[s]ince NESCOE asked the [transmission owners] for process changes in early 2023, the [transmission owners] have presented to the PAC forty-two (42) asset condition projects totaling over $1.6 billion."[468] NESCOE stated "New England states, stakeholders, and electricity customers deserve continuing visibility into the scope, scale, and pace of asset condition project planning and spending. Moreover, such information is a prerequisite to a prudent right-sizing approach."[469]

As NESCOE laid out, "[c]urrent processes do not result in a uniform approach to asset condition project development across the region, as each transmission owner appears to have different standards and to apply different judgment to their asset condition projects."[470]

Chart from New England States Committee ("NESCOE") on Electricity February 8, 2023 Letter to the ISO-NE Planning Advisory Committee.



[471]

468 https://nescoe.com/resource-center/asset-condition-process-improvements-next-steps/ (last accessed Dec. 18, 2024).
469 *Id.*
470 *Id.*
471 Letter from New England States Committee on Electricity, to ISO-NE Planning Advisory Committee at 2 (Feb. 8, 2023), https://www.iso-ne.com/static-assets/documents/2023/02/2023_02_08_nescoe_asset_conditions_letter.pdf ("NESCOE February 2023 Letter") (last accessed Dec. 18, 2024).

New Hampshire's and NESCOE's concerns were echoed in a formal challenge raised by the Maine Office of Public Advocate to asset condition projects included in formula rates.[472] The Maine Consumer Advocate argued:

> But Maine's concern is that at least some New England utilities may be taking advantage of this lax review process to the benefit of their shareholders. Are they building replacement projects prematurely? If so, such practices can contribute to significant and unnecessary rate increases. Could the projects be more targeted and smaller? Are there less expensive alternatives to large transmission replacement projects? Do the NETOs adequately keep track of the condition of their current transmission assets? Do they have processes for maximizing the timing of replacements or the evaluation of non-transmission or hybrid alternatives?

While the Maine Advocate may get the answers to some of its questions through the after-the-fact formal challenge process included in formula rate protocols, it will not get answers to the ultimate underlying question: what, was the appropriate transmission project, if any, to move forward when existing assets have reached the end of operational life.

In the New England transmission owners' most recent Asset Condition Project update, there is an estimated $3,714,549,672 in Asset Condition Projects that are planned or under construction and another $1,392,672,710 in Asset Condition Projects that are proposed or under consideration.[473] Stakeholders are given little information, notice, and meaningful opportunity to provide comments.[474] ISO-NE posts transmission owner-prepared presentations on their Asset

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[472] Formal Challenge Of The Maine Office Of Public Advocate To Violations Of ISO New England's Information Exchange Protocols By The Identified New England Transmission Owners, filed January 31, 2024 in Docket No. ER20-2054-000.

[473] March 2024 ISO-NE Asset Condition Update – ISO-NE Public posted on March 14, 2024 in the meeting materials for the ISO-NE Planning Advisory Committee, https://www.iso-ne.com/static-assets/documents/100009/a04_2024_03_20_pac_draft_acl_march_update_2024.xlsx ("March 2024 Asset Condition Project List") (last accessed Dec. 18, 2024).

[474] *See* NESCOE February 2023 Letter; Letter from New England States Committee on Electricity, to ISO-NE Planning Advisory Committee (July 14, 2023), https://www.iso-ne.com/static-assets/documents/2023/07/2023_07_17_nescoe_asset_condition_request_netos.pdf ("NESCOE July 2023 Letter") (last accessed Dec. 18, 2024).

Condition Projects a week before Planning Advisory Committee meetings[475] making it difficult for stakeholders to prepare meaningful feedback and questions. Even if a stakeholder comments during a Planning Advisory Committee meeting, New England transmission owners do not have an obligation to modify an Asset Condition Project based on stakeholder feedback.[476]

ISO-NE also maintains a spreadsheet of Asset Condition Projects that are in-service, under construction, or being proposed.[477] However, like the presentations, the information available in the spreadsheet is limited and may not include information such as voltage and approximate miles. Yet many of the Asset Condition Projects are costly and extensive. For instance, Eversource is rebuilding an approximately 22.9-mile, 115 kV transmission line at an estimated cost of $105,432,000 as part of its "Northern New Hampshire 115 kV Line Rebuilds."[478] National Grid is building a 115 kV substation at an estimated cost of $59,953,000.[479] United Illuminating Company has a grouping of thirteen Asset Condition

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[475] For instance, ISO-NE posted the "RSP Project List and Asset Condition List" for ISO-NE's March 20, 2024 Planning Advisory Committee meeting on March 14, 2024, https://www.iso-ne.com/static-assets/documents/100009/a04_2024_03_20_pac_draft_project_list_update_presentation.pdf (last accessed Dec. 18, 2024).

[476] In its February 8, 2023 Letter, NESCOE stated that it is "not aware of any Asset Condition Projects . . . that have ever been withdrawn or materially modified based on PAC feedback." NESCOE February 2023 Letter at 2.

[477] *See* ISO-NE, *RSP Project List and the Asset Condition* List, March 2024 Asset Condition Project List, available at https://www.iso-ne.com/system-planning/system-plans-studies/rsp/rsp-project-list-and-the-asset-condition-list (Last accessed Dec. 18, 2024).

[478] March 2024 Asset Condition Project List, Asset Condition Id 386; https://www.eversource.com/content/residential/about/transmission-distribution/projects/new-hampshire-projects/beebe-river-to-white-lake-line-rebuild-project (last accessed Dec. 18, 2024). There are two more Asset Condition Projects being planned as part of the "Northern New Hampshire 115 kV Line Rebuilds" at an estimated cost of $151,180,000. *Id*. at Asset Condition Ids 387, 388.

[479] March 2024 Asset Condition Project List, Asset Condition Id 333; National Grid Local System Plan – 2023 PAC Presentation at 22 (Nov. 15, 2023), https://www9.nationalgridus.com/oasis/non_html/pdf/National%20Grid%20Local%20System%20Plan%202021.pdf (last accessed Dec. 18, 2024).

Projects, "Railroad Corridor Transmission Line Asset Condition Upgrades," that appear to be rebuilds of 115 kV transmission lines at a total estimated cost of $525,092,798.[480]

As New England transmission owners make significant investments in rebuilding the existing transmission system, there appears to be no consideration of whether the investment is the right one from the perspective of the future needs of the ISO-NE transmission system or neighboring systems. Recognizing this very problem, in February 2023, the New England States Committee on Electricity ("NESCOE") sent a letter to the ISO-NE Planning Advisory Committee calling the planning process for "Asset Condition Projects . . . antiquated and ultimately, inadequate."[481] NESCOE noted the lack of warning to "states, stakeholders, and the paying public as to which of these costs will be presented and how significant they will be."[482] NESCOE sent a follow-up letter in July 2023 setting out specific recommended changes to when and how Asset Condition Projects are presented to stakeholders and how the Asset Condition Projects are tracked, in the hopes that it will create more opportunities to "right-size" transmission projects.[483] However, even if the recommendations are implemented, it is unclear whether additional information will result in the kind of holistic planning that is needed to ensure that ratepayer funds are invested in transmission that will be needed in the future.[484] ISO-NE's

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[480] March 2024 Asset Condition Project List, Asset Condition Ids 91, 151-162; *UI Railroad Transmission Lines Upgrade Project*, United Illuminating Company https://www.uirailroadtlineupgrades.com/index.htm (last accessed Dec. 18, 2024).
[481] NESCOE February 2023 Letter at 1.
[482] *Id*. at 3.
[483] NESCOE July 2023 at 2, 4-7.
[484] *Id*. at 1 ("Consumers face these cost increases [from Asset Condition Projects] at the same that New England transforms the electric grid to accommodate the anticipated rapid increases in both electrification and renewable resource integration.").

October 2024 Asset Condition List Update reveals substantial cost estimate changes that occurred since June 2024.[485]

Despite Order No. 1920's efforts, state utility regulators in New England continue to push for more oversight into local transmission spending in light of efforts by Eversource and National Grid to advance two local projects that exceed $724 million collectively.[486] RMI recently highlighted the issues with Eversource's X-178 Project, a $385 million planned full rebuild of a 115 kv line, even though only 43 of the 594 structures of the line have been identified has high priorities for replacement and many of the structures are younger than their estimated useful lives.[487] Annual spending on local projects in New England increased eight-fold from 2016 to nearly $800 million in 2023.[488] Six billion dollars in asset condition projects is expected in New England in the next several years.[489] While NESCO and RMI were able to highlight issues with Eversource's X-178 Project, RMI aptly observes that most local projects are not receiving enhanced scrutiny by regulators and interested stakeholders.[490]

5. SERTP

The Southeastern Regional Transmission Planning ("SERTP") region includes most of the Southeastern and Gulf Coast States, other than Florida, the Tennessee Valley Authority, Louisville Gas & Electric, and Kentucky Utilities.[491] SERTP now includes more than 83,000

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485 *See* "RSP Project List and Asset Condition List October 2024 Update," ISO-NE Planning Advisory Committee, *available at* https://www.iso-ne.com/static-assets/documents/100017/final_project_list_presentation_oct_2024.pdf (last accessed Dec. 18, 2024).

486 *See* "Local transmission spending soars nationwide amid 'serious absence of cost containment," Utility Dive (Nov. 20, 2024), *available at* https://www.utilitydive.com/news/local-transmission-asset-condition-spending-regulatory-gap-rmi/733430/ (last accessed Dec. 18, 2024) (hereinafter "Nov. 2024 Utility Dive Article"). Utility Dive cited the ISO-NE October 23, 2024 presentation, which is available at https://www.iso-ne.com/static-assets/documents/100017/final_project_list_presentation_oct_2024.pdf (last accessed Dec. 18, 2024).

487 RMI Report at 33.

488 Nov. 2024 Utility Dive Article (citing RMI Report).

489 Nov. 2024 Utility Dive Article.

490 RMI Report at 33.

491 Southern Company, Dalton Utilities, Georgia Transmission Corporation, the Municipal Electric Authority of Georgia, PowerSouth, Louisville Gas & Electric Company and Kentucky Utilities Company, Associated Electric

linear miles of transmission,[492] making it "one of the largest regional transmission planning processes in the United States."[493] Yet SERTP's Order No. 1000 required regional planning process is not really a regional process at all but is merely a roll-up of SERTP Members Self-Planned Transmission from individual transmission owner local plans. SERTP members then analyze those Self-Planned Transmission projects against regional alternatives, with the caveat that regardless of the voltage of the Self-Planned Transmission the regional alternative must be greater than 300 kV. As a result, SEPTP has not planned a single regional project since the requirement to participate in a regional planning process that develops a regional plan. Thus, when Commissioner Pridemore of the Georgia Public Service Commission reports that SERTP has built more than 3000 miles of new transmission between 2015 and 2020, upgraded almost 7000 miles more, and in the 10-year period between 2012 and 2021 added $20 billion in new transmission investment, those projects are all Self-Planned Transmission.[494] Notwithstanding the Commission's exclusive jurisdiction over the rates for transmission in interstate commerce, Complainants are not aware that any of the transmission rates for these Self-Planned Transmission projects have been addressed through FERC proceedings, as Complainants understand that the costs incurred for such projects are rolled into bundled rates.

Circuit Miles Above 100 kV Planned Locally	**Total Miles**	**100-121 kV**	**121-150 kV**	**151-199 kV**	**200-299 kV**	**300-399 kV**	**400-550 kV**
2023 SERTP Local Projects - New Transmission (in Circuit Miles)	640.80	97.9	0	139	281.1	0	

Cooperative Inc., the Tennessee Valley Authority, and Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, http://www.southeasternrtp.com/ (last accessed Dec. 18, 2024).

492 Transcript, Eighth Meeting of the Joint Federal-State Task Force on Electric Transmission (Feb. 28, 2024), Docket No. AD21-15-000, Commissioner Tricia Pridemore, Georgia Public Service Commission at 27:23-28:5.

493 http://www.southeasternrtp.com/ (last accessed Dec. 18, 2024).

494 *Id*. at 28:5-16.

							122.8[495]
2022 SERTP Local Projects – New Transmission (in Circuit Miles)	688.80	124	0	139	323	0	102.8[496]
2021 SERTP Local Projects – New Transmission (in Circuit Miles)	374.10	79.7	0	104.9	189.5	0	0[497]
2020 SERTP Local Projects – New Transmission (in Circuit Miles)	741.10	242.8	1	329.3	168	0	0[498]
2019 SERTP Local Projects – New Transmission (in Circuit Miles)	605.20	138.1	1.1	315	151	0	0[499]
2018 SERTP Local Projects – New Transmission (in Circuit Miles)	358.30	100.2	1.1	89.5	167.5	0	0[500]
2017 SERTP Local Projects – New Transmission (in Circuit Miles)	336.00	133.6	0	129	73.4	0	0[501]
2016 SERTP Local Projects – New Transmission (in Circuit Miles)	521.80	180.2	1.3	199	86.3	0	55[502]

495 http://www.southeasternrtp.com/docs/general/2023/2023_SERTP_Regional_Transmission_Plan_and_Input_Assumptions.pdf at p 14 ("2023 SERTP Report") (last accessed Dec. 18, 2024).

496 http://www.southeasternrtp.com/docs/general/2022/2022_Regional_Transmission_Plan_and_Input_Assumptions_Final_Non-CEII.pdf at p 13 ("2022 SERTP Report") (last accessed Dec. 18, 2024).

497 http://www.southeasternrtp.com/docs/general/2021/2021-Regional-Transmission-Plan-and-Input-Assumptions-Non-CEII.pdf at p 13 ("2021 SERTP Report") (last accessed Dec. 18, 2024).

498 http://www.southeasternrtp.com/docs/general/2020/2020-Regional-Transmission-Plan-and-Input-Assumptions.pdf at p 13 ("2020 SERTP Report") (last accessed Dec. 18, 2024).

499 http://www.southeasternrtp.com/docs/general/2019/2019-SERTP-Regional-Transmission-Plan-and-Input-Assumptions.pdf at p 13 ("2019 SERTP Report") (last accessed Dec. 18, 2024).

500 http://www.southeasternrtp.com/docs/general/2018/2018-SERTP-Regional-Transmission-Plan-and-Input-Assumptions.pdf at p 14 ("2018 SERTP Report") (last accessed Dec. 18, 2024).

501 http://www.southeasternrtp.com/docs/general/2017/2017-Regional-Transmission-Plan-and-Input-Assumptions.pdf at p 14 ("2017 SERTP Report") (last accessed Dec. 18, 2024).

502 http://www.southeasternrtp.com/docs/general/2016/2016%20SERTP%20Regional%20Transmission%20Plan%20Input%20Assumptions.pdf at p 14 ("2016 SERTP Report") (last accessed Dec. 18, 2024).

2015 SERTP Local Projects – New Transmission (in Circuit Miles)	596.20	209.3	1.3	191.1	89.5	0	105[503]
2014 SERTP Local Projects – New Transmission (in Circuit Miles)	771.00	213	1	172	385	0	0[504]
Total SERTP Sponsors Local Projects (2014-2023) - New Transmission (In Circuit Miles)	**5,633.30**	**1,518.80**	**6.80**	**1,807.80**	**1,914.30**	**0**	**385.60**

In addition to more than 5600 miles of new transmission since 2014, SERTP sponsoring transmission owners planned more than 13,000 miles of uprates or reconductoring.

SERTP Sponsors Locally Planned Uprates, Reconductoring, etc.	**Total**	**100-121 kV**	**121-150 kV**	**151-199 kV**	**200-299 kV**	**300-399 kV**	**400-550 kV**
2023 SERTP Local Projects – Uprates (in Circuit Miles)	1,631.80	1138	0	129.8	349.7	14.3	0[505]
2022 SERTP Local Projects – Uprates (in Circuit Miles)	1,649.40	1230	9.5	100.3	295.3	14.3	0[506]
2021 SERTP Local Projects – Uprates (in Circuit Miles)	1,645.40	1262.1	1.8	76.6	290.6	14.3	0[507]
2020 SERTP Local Projects – Uprates (in Circuit Miles)	1,212.50	680.7	0	229.3	302.5	0	0[508]

503 http://www.southeasternrtp.com/docs/general/2015/2015%20SERTP%20Regional%20Transmission%20Plan%20-%20Input%20Assumptions.pdf at p 14 (“2015 SERTP Report”) (last accessed Dec. 18, 2024).

504 http://www.southeasternrtp.com/docs/general/2014/2014RegionalTransmissionPlanInputAssumptionsOverview.pdf at p 14 (“2014 SERTP Report”) (last accessed Dec. 18, 2024).

505 2023 SERTP Report at p 14.

506 2022 SERTP Report at p 13.

507 2021 SERTP Report at p 13.

508 2020 SERTP Report at p 13.

2019 SERTP Local Projects – Uprates (in Circuit Miles)	1,215.60	720.4	45.9	194.3	255	0	0[509]
2018 SERTP Local Projects – Uprates (in Circuit Miles)	1,365.10	950.4	59.6	187.9	167.2	0	0[510]
2017 SERTP Local Projects – Uprates (in Circuit Miles)	942.20	674.9	1.6	183.2	82.5	0	0[511]
2016 SERTP Local Projects – Uprates (in Circuit Miles)	1,123.00	762.1	14.1	247	99.8	0	0[512]
2015 SERTP Local Projects – Uprates (in Circuit Miles)	1,163.30	694.9	15.8	227.8	224.8	0	0[513]
2014 SERTP Local Projects – Uprates (in Circuit Miles)	1,127.00	701	16	228	176	0	6[514]
Total SERTP Local Projects (2014-2023) - Uprates (In Circuit Miles)	**13,075.30**	**8,814.50**	**164.30**	**1,804.20**	**2,243.40**	**42.90**	**6.00**

[509] 2019 SERTP Report at p 13.
[510] 2018 SERTP Report at p 14.
[511] 2017 SERTP Report at p 14.
[512] 2016 SERTP Report at p 14.
[513] 2015 SERTP Report at p 14.
[514] 2014 SERTP Report at p 14.

If the SERTP sponsors do not identify any areas for potential regional alternatives and stakeholders do not submit any regional alternatives, then the SERTP process ends, as it did in 2023.[515] If there are potential regional alternatives, then SERTP considers whether the regional alternative would potentially displace projects currently identified in the regional plan.[516] If the regional project cannot displace a local project, then it is eliminated from further consideration.[517] Not one regional project has been found to address a transmission need, *i.e.*, displace a local project, since 2017 with thousands of miles of locally planned additions.

For the regional alternatives that move forward to the second step of SERTP's process, SERTP adds up the estimated cost of the displaced projects and compares the total to the estimated cost of the regional alternative. Since 2014 SERTP has considered 49 regional projects, mostly between 2014 and 2017, and found that only 9 of those regional alternatives would potentially displace a local project and could move forward to the second step of SERTP's analysis.[518]

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[515] SERTP, 2023 Regional Transmission Planning Analyses at 8 (Nov. 27, 2023), http://southeasternrtp.com/docs/general/2023/2023_SERTP_Regional_Transmission_Planning_Analyses_Summary.pdf (last accessed Dec. 18, 2024).

[516] *See, e.g.*, SERTP, 2022 Regional Transmission Planning Analyses at 7 (Nov. 17, 2022), http://southeasternrtp.com/docs/general/2022/2022_SERTP_Regional_Transmission_Planning_Analyses_Summary_Final.pdf (last accessed Dec. 18, 2024).

[517] *See, e.g.*, *id*. at 11. When a regional alternative does not displace any local projects, SERTP uses the same cut-and-paste "analysis" to eliminate the regional project from further consideration – "There were no potentially displaced transmission projects in the SERTP region identified in this evaluation and therefore, this transmission project alternative is not currently a more efficient or cost-effective project to address transmission needs in the SERTP region." *Id.*

[518] *See* SERTP, 2023 Regional Transmission Planning Analyses (Nov. 27, 2023), http://southeasternrtp.com/docs/general/2023/2023_SERTP_Regional_Transmission_Planning_Analyses_Summary.pdf (last accessed Dec. 18, 2024) (identifying zero regional alternatives); SERTP, 2022 Regional Transmission Planning Analyses (Nov. 17, 2022), http://southeasternrtp.com/docs/general/2022/2022_SERTP_Regional_Transmission_Planning_Analyses_Summary_Final.pdf (last accessed Dec. 18, 2024) (identifying two regional alternatives, zero would potentially displace other transmission projects); SERTP, 2021 Regional Transmission Planning Analyses (Nov. 17, 2021), http://southeasternrtp.com/docs/general/2021/2021-SERTP-Regional-Transmission-Planning-Analyses-Summary-Final.pdf (identifying three regional alternatives, zero would potentially displace other transmission projects); SERTP, 2020 Regional Transmission Planning Analyses (Nov. 16, 2020), http://southeasternrtp.com/docs/general/2020/2020-SERTP-Regional-Transmission-Planning-Analyses-Summary-FINAL.pdf (identifying three regional alternatives, zero would potentially displace other transmission projects);

SERTP uses this same analysis for every rejected regional alternative that makes it to step two. Because SERTP's analysis requires regional projects above 300 kV, regardless of the projects being displaced, and looks only at the cost estimate for the potentially displaced projects as determined by the self-interested SERTP members, the process is unlikely to ever find that a regional alternative is more efficient or cost-effective than local projects.[519]

In the 2023 SERTP Plan,[520] the following Self-Planned Transmission projects were listed:

Balancing Authority	**Project Name**	**Description and In-Service Date**	**Individual Project Cost**	**Page in 2023 SERTP Regional Plan and Input Assumptions Overview**
Duke Carolinas	Lancaster Main – Monroe 100 kV	Rebuild 23.8 miles with double circuit 100 kV – 2027	Not Provided in Regional Plan	32
Duke Carolinas	Newport Tie – Morning Star 230 kV line	New 230 kV line – 2029	Not Provided in	36

SERTP, 2019 Regional Transmission Planning Analyses (Dec. 2, 2019), http://southeasternrtp.com/docs/general/2019/2019-SERTP-Regional-Transmission-Planning-Analyses-Summary.pdf (identifying five regional alternatives, zero would potentially displace other projects); SERTP, 2018 Regional Transmission Planning Analyses (Nov. 29, 2018), http://southeasternrtp.com/docs/general/2018/2018-SERTP-Regional-Transmission-Planning-Analyses-Summary.pdf (identifying three regional alternatives, zero would potentially displace other transmission projects); SERTP, 2017 Regional Transmission Planning Analyses (Nov. 30, 2017), http://southeasternrtp.com/docs/general/2017/2017-Regional-Transmission-Planning-Analyses-Summary.pdf (identifying seven regional alternatives, one would potentially displace other projects, zero determined to be "cost-effective"); SERTP, 2016 Regional Transmission Planning Analyses (Dec. 2016), http://southeasternrtp.com/docs/general/2016/2016%20SERTP%20Regional%20Transmission%20Planning%20Analyses%20Summary.pdf (identifying nine regional alternatives, four would potentially displace other transmission projects, zero determined to be "cost-effective"); SERTP, 2015 Regional Transmission Planning Analyses (Dec. 2015), http://southeasternrtp.com/docs/general/2015/2015%20Regional%20Transmission%20Planning%20Analyses%20Summary.pdf (identifying nine regional alternatives, one would potentially displace other transmission projects, zero determined to be "cost-effective"); SERTP, 2014 Regional Transmission Planning Analyses (Dec. 2014), http://southeasternrtp.com/docs/general/2014/SERTP%20Regional%20Transmission%20Planning%20Analyses%20Summary.pdf (identifying eight regional alternatives, three would potentially displace other transmission projects, zero determined to be "cost-effective").

[519] The Southeast Public Interest Groups raised these same concerns in their comments responding to the Commission's Notice of Proposed Rulemaking on transmission planning. Comments of the Southeast Public Interest Groups, filed in Docket No. RM21-17-000 on Aug. 17, 2022.

[520] http://www.southeasternrtp.com/docs/general/2023/2023_SERTP_Regional_Transmission_Plan_and_Input_Assumptions.pdf (last accessed Dec. 18, 2024).

			Regional Plan	
Duke Carolinas	Dan River Steam – Greensboro 100 kV line	Rebuild entire 26 miles of 100 kV lines – 2030	Not Provided in Regional Plan	38
Duke Carolinas	McGuire Nuclear Station – Marshall Steam Station	Rebuild entire 230 kV lines - 2031	Not Provided in Regional Plan	39
Duke Carolinas	Dan River Steam – Sadler 100 kV	Rebuild entire line (Reidsville and Wolf Creek Circuits) – 2033	Not Provided in Regional Plan	40
Duke Progress	Robinson – Rockingham 115 / 230 kV lines	Reconductor 58 miles as part of NCUC Carolina Carbon Plan	Not Provided in Regional Plan	44
Duke Progress West	Craggy-Enka 230 kV Transmission Line	New 230 kV transmission line – 2026	Not Provided in Regional Plan	46
Power South	EREC 115 kV conversion	Convert 46 kV line to 115 kV transmission (20 miles) - 2025	Not Provided in Regional Plan	48
Southern	Pell City Area Solution	New Pell City 115 kV substation and 12 miles 115 kV transmission line – 2032	Not Provided in Regional Plan	101
Southern	Greenville Area Solution	New 230 kV ring bus – 2031	Not Provided in Regional Plan	100
Southern	Goshen – Vogtle 230 kV Rebuild	Rebuild 18.7 miles of 230 kV transmission lines - 2031	Not Provided in Regional Plan	100
Southern	Alex City Area Solution	New Alex City substation and upgrade 35 miles 115 kV transmission lines- 2031	Not Provided in Regional Plan	99
Southern	Union Springs – Pickard 115 kV	Rebuild/ reconductor 60 miles 115 kV transmission – 2030	Not Provided in Regional Plan	98

Southern	Tallulah Lodge – Toccoa 115 kV	Rebuild entire 10 mile 115 kV line – 2030	Not Provided in Regional Plan	98
Southern	Ray Place – Warrenton 115 kV	Rebuild 10 miles Ray Place – Warrenton 115 kV transmission line- 2030	Not Provided in Regional Plan	97
Southern	Gordon – Sandersville 115 kV	Rebuild 11 miles Gordon Sandersville 115 kV transmission line – 2030	Not Provided in Regional Plan	96
Southern	Bostick – East Social Circle 230 kV Reconductor	Reconductor 10.8 miles of Bostick-East Social Circle 230 kV transmission line– 2030	Not Provided in Regional Plan	95
Southern	Westlake Road SS	New 230 kV switching station and New 20 miles 230 kV Big Grocery Creek – Westlake line – 2029	Not Provided in Regional Plan	94
Southern	Thurlow Dam – Union Springs 115 kV	Rebuild 25 miles 115 kV transmission line– 2029	Not Provided in Regional Plan	93
Southern	Miller – Gorgas 230 kV Upgrade	Upgrade 16 miles 230 kV transmission line – 2029	Not Provided in Regional Plan	91
Southern	Kettle Creek Parkway – Pine Grove Primary 115 kV Rebuild	Rebuild 15.3 miles of 115 kV transmission line – 2029	Not Provided in Regional Plan	90
Southern	Lawrenceville – Winder 230 kV Rebuild	Rebuild 230 kV transmission lines (20 miles) – 2029	Not Provided in Regional Plan	90
Southern	Dresden – Talbot 500 kV line	New 500 kV / 230 substation and 75 miles of 500 kV - 2029	Not Provided in Regional Plan	89
Southern	Banks Crossing – Center Primary 230 kV line	New 230 kV transmission line 14.6 miles – 2029	Not Provided in Regional Plan	88

Southern	Augusta Park – Vogtle 230 kV line	Rebuild 230 kV transmission line (30 miles) – 2029	Not Provided in Regional Plan	88
Southern	Arlington Primary – Highway 45/234 115 kV line	Reconductor 42.61 miles 115 kV transmission lines– 2029	Not Provided in Regional Plan	87
Southern	Union City – Yates (Black line) Rebuild	Rebuild entire 23.4 mile 230 kV line – 2028	Not Provided in Regional Plan	87
Southern	Barneysville – East Moultrie 115 kV New Line	New 20 mile 115 kV transmission line – 2028	Not Provided in Regional Plan	84
Southern	Anniston – Crooked Creek 115 kV	Reconductor 28 miles 115 kV transmission line – 2028	Not Provided in Regional Plan	84
Southern	Sandersville #1 – Wadley Primary 115 kV rebuild	Rebuild 24 miles 115 kV transmission lines – 2027	Not Provided in Regional Plan	83
Southern	New South Hazelhurst- New Lacy 230 kV	New 25 mile 230 kV transmission line – 2027	Not Provided in Regional Plan	82
Southern	North Selma – Selma #2 115 kV Transmission Line	Rebuild 27 miles 115 kV transmission lines – 2027	Not Provided in Regional Plan	82
Southern	Highway 112 – East Moultrie 230 kV line	New 27 mile 230 kV transmission line – 2027	Not Provided in Regional Plan	81
Southern	Jesup -Offerman 115 kV line	Reconductor 16 miles of 115 kV transmission line – 2027	Not Provided in Regional Plan	81

Southern	East Walton 500/ 230 kV Project[521]	GTC: Construct the East Walton 500/230 kV substation - Construct the Bostwick 230 kV switching station - Construct the East Walton - Rockville 500 kV line (40 miles)- Construct the Bethabara - East Walton 230 kV line (8 miles) - Construct the Bostwick - East Walton 230 kV line (4 miles) - Construct the East Walton - Jack's Creek 230 kV line (9 miles) - East Watkinsville 230 kV line into Bostwick GPC: Construct the Rockville 500 kV switching station - Loop the Scherer - Warthen 500 kV line into Rockville - Loop the Doyle - LG&E Monroe 230 kV line into Jack's Creek MEAG: Construct the Jack's Creek 230 kV switching station	Not Provided in Regional Plan	78
Southern	Autaugaville- East Pelham New 230 kV	New 75 mile 230 kV line from Autaugaville to East Pelham – 2027	Not Provided in Regional Plan	79
Southern	Arkwright -Lloyd Shoals 115 kV	Rebuild the entire 36 mile 115 kV line – 2027	Not Provided in Regional Plan	78
Southern	Ray Place – Washington 115 KV	Rebuild the entire 17 mile 115 kV line -2026	Not Provided in Regional Plan	76
Southern	Mitchell- North Tifton 230 kV	Reconductor 35 miles of 230 kV line – 2026	Not Provided in Plan	76
Southern	Lagrange – North Opelika TS New 230 kV line	New 14 miles 230 kV transmission line and New 230 kV station – 2026	Not Provided in Plan	74
Southern	LaGrange – North Opelika 230 kV New Line	New 15 mile 230 kV transmission line – 2026	Not Provided in Plan	73
Southern	Hill View and Grassy Hollow Switching Station	Build two new 230 kV substations and 15 miles of new 230 kV lines – 2023	Not Provided in Plan	72

[521] *See* previous Rural Development Environmental Assessment from 2010 on the general location and scale of project area https://www.rd.usda.gov/resources/environmental-studies/assessment/east-walton-500kv-transmission-line-project-georgia (last accessed Dec. 19, 2024).

Southern	Fayetteville Area Transmission Network Upgrade	Build new 500/230 kV station with two new 230 kV lines – 2026	Not Provided in Plan	69
Southern	Boulevard – Deptford 115 kV Rebuild	Rebuild 8 mile 115 kV line – 2026	Not Provided in Plan	68
Southern	Big Ogeechee 500/230 kV substation	New 500 /230 kV substation- 2026	Not Provided in Plan	67
Southern	Union City – Yates 230 kV Rebuild	Rebuild the entire Union City – Yates 230 kV line 23 miles – 2025	Not Provided in Plan	66
Southern	Savannah Area Transmission Network Upgrade	New 230 kV substation and 21 miles of new 230 kV transmission – 2025	Not Provided in Plan	65
Southern	Lizard Lope-Westover 115 kV	Two New 115 kV substation and 20 miles of new 115 kV transmission lines– 2025	Not Provided in Plan	62
Southern	Garrett Road Switching Station – Trae Lane Network Upgrades	New 230 kV substation and 8 miles of 230 kV – 2025	Not Provided in Plan	61
Southern	Bremen – Crooked Creek 115 kV Project	Rebuild 14 miles of 115 kV lines – 2025	Not Provided in Plan	59
Southern	Anthony Shoals – Washington 115 kV Rebuild	Rebuild 21 miles of 115 kV lines – 2025	Not Provided in Plan	58
TVA	Anderson 500 kV Substation	New 500 kV Substation – 2024	Not Provided in Plan	103
TVA	Dickson 161 kV area improvement	24 miles of new 161 kV transmission lines and new 161 kV substation – 2025	Not Provided in Plan	104
TVA	Alcoa – Dixon Road 161 kV	16 miles of 161 kV lines – 2025	Not Provided in Plan	104
TVA	Midway – S Macon – Dekalb 161 kV line	51.3 miles of new 161 kV lines – 2027	Not Provided for in Plan	107
TVA	Apalachia Area Improvement Plan	New 161 kV substation and 25 miles of new 161 kV lines – 2027	Not Provided in Plan	107

TVA	North Oakland – Coffeville 161 kV line	18 miles of new 161 kV lines – 2026	Not Provided in Plan	106
TVA	Loving, KY Substation	New 161 kV Substation and Reconductoring 161 kV lines – 2026	Not Provided in Plan	105
TVA	Island Road 138 kV Capacitor Bank	New 138 kV substation with 138kV capacitor bank – 2026	Not Provided in Plan	105
TVA	North Dayton 161 kV line	27 miles of new 161 kV lines and new 161 kV substation	Not Provided in Plan	104

The 2023 SERTP roll up of individual transmission owner Self-Planned Transmission was not an anomaly. For example, in 2019 SERTP roll-up of Self-Planned Transmission which became the "regional plan" noted that the local plans "consist[ ] of over 140 transmission projects, totaling an estimated $2.9 billion dollars, including: over 600 miles of new transmission lines, over 1200 miles of transmission line uprates (including upgrades, reconductors, and rebuilds), and 38 transformer additions and/or replacements."[522] Likewise, the 2015 SERTP local planning roll-up which became the 2015 regional plan reflected " over 200 transmission projects, totaling an estimated $2.5 billion dollars, including: over 550 miles of new transmission lines, over 1,100 miles of transmission line uprates (including upgrades, reconductors, and rebuilds), and over 35 transformer additions and/or replacements."[523]

The impact on consumers from the lack of regional planning in the Southeast has been analyzed by independent analysts as reported to the Commission by the Southeast Public Interest Groups:

[522] http://www.southeasternrtp.com/docs/general/2019/2019-SERTP-Regional-Transmission-Plan-and-Input-Assumptions.pdf at 20. Prior SERTP plans are available in SERTP's reference library here: http://www.southeasternrtp.com/reference_library.cshtml (last accessed Dec.18, 2024).

[523] http://www.southeasternrtp.com/docs/general/2015/2015%20SERTP%20Regional%20Transmission%20Plan%20-%20Input%20Assumptions.pdf at 20 (last accessed Dec. 18, 2024).

> 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. *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), https://energyinnovation.org/wp-content/uploads/2020/08/Economic-And-Clean-Energy-Benefits-Of-Establishing-A-Southeast-U.S.-Competitive-Wholesale-Electricity-Market_AUG_2020.pdf (Energy Innovation Report); Jennifer Chen, E*valuating Options for Enhancing Wholesale Competition and Implications for the Southeastern United States*, Duke, Nicholas Institute for Environmental Policy Solutions (Mar. 2020), https://nicholasinstitute.duke.edu/sites/default/files/publications/Evaluating%20Options%20for%20Enhancing-Wholesale-Competition-and-Implications-for-the-Southeastern-United-States-Final_0.pdf. 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. Energy Innovation Report at 1. 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." *Id*. at 10. 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. *Id*. at 19-20. 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," Order No. 1000 at P 42, and results in unjust, unreasonable, and unduly discriminatory rates.[524]

Retained information within the local planning process that is not integrated into the regional planning, which itself is not independent anyway, prevents the regional stakeholders from fully analyzing the potential for regional alternatives compared to the local plans. For

[524] Comments of the Southeast Public Interest Groups at 6-7, filed in Docket No. RM21-17-000 on Aug. 17, 2022.

example, although Louisville Gas and Electric/Kentucky Utilities ("LGEKU") received approval to retire 600 MW of coal generation and build 640 MW of natural gas generation plus 800 MW of solar and additional battery storage, LGEKU reported no changes to its ten-year planning horizon to SERTP.[525] Similarly, TVA told SERTP it expects no changes even though it planned to sign contracts for 6,000 MW of clean energy.[526]

The response to concerns about transmission planning in the Southeast is often that such concerns should be raised in state integrated resource planning processes ("IRP"). The various State petitioners raised this argument in response to Order No. 1000.[527] The United States Court of Appeals for the D.C. Circuit rejected the assertion, finding that "relevant precedent suggests that Section 201(a) does not stand in the way of the orders' [regional] planning mandate.[528] More importantly for purposes of this Complaint, the state IRP's are not an effective substitute for mandated regional planning 100 kV and above, with a corresponding prohibition on local planning. For example, it came to light in Georgia Power's recent triennial integrated resource planning ("IRP") process that Georgia Power had failed to prepare for the retirement of Plant

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[525] Simon Mahan, *Gridlocked: Planning Failure with the Southeastern Regional Transmission Planning Process*, Southern Renewable Energy Association blog (Dec. 20, 2023), https://www.southernrenewable.org/blog ("Failure of SERTP Process"), *citing* SERTP, Economic Planning Studies Final Results (Nov. 27, 2023), http://www.southeasternrtp.com/docs/general/2023/2023_SERTP_Final_Economic_Study_Results.pdf, *citing* Ethan Howland, *Kentucky PSC partly approves PPL's $2.1B plan to retire coal, add gas, solar and storage*, Utility Dive (Nov. 8, 2023), https://www.utilitydive.com/news/kentucky-psc-ppl-LGE-KU-retire-coal-gas-solar-storage/699092/ and SERTP, SERTP – 4th Quarter Meeting: Annual Transmission Planning Summit & Assumptions Input Meeting at slide 188 (Dec. 7, 2023), http://www.southeasternrtp.com/docs/general/2023/2023_SERTP_4th_Qtr_Presentation.pdf ("SERTP Annual Planning Summit") (last accessed Dec. 18, 2024).
[526] Failure of SERTP Process, citing Dave Flessner, *TVA to buy power from 40 more solar farms*, Chattanooga Times Free Press (May 10, 2023), https://www.timesfreepress.com/news/2023/may/10/tva-to-buy-power-from-40-more-solar-farms/#:~:text=TVA%20President%20Jeff%20Lyash%20told,free%20power%20grid%20by%202050 and SERTP Annual Planning Summit at 261 (last accessed Dec. 18, 2024).
[527] *South Carolina Public Service Authority v. FERC*, 762 F.3d 41, 62-63 (2014)(noting that Petitioners argue that "because state regulators were already substantially involved in regulating that [transmission planning] process, the orders encroach on their authority in violation of Section 201(a)'s statement that the Commission's authority 'extend[s] only to those matters which are not subject to regulation by the States.' 16 U.S.C. § 824(a).")[footnote omitted].
[528] *Id.*

Bowen, a 3,450 MW coal-fired power plant in Northern Georgia. The Georgia Commission Staff testified:

> 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.[529]

SERTP Stakeholders had requested that SERTP consider the retirement of coal as a Public Policy Requirement in 2015, 2016, and 2017 Regional Transmission Plan, but the SERTP sponsors rejected those requests, finding that the Stakeholders the did not demonstrate a need.[530]

6. SPP

SPP conducts local transmission planning for most of the participating transmission owners in its footprint.[531] In performing such planning, SPP originally used each individual transmission owner's planning criteria, even in those zones with multiple transmission owners.[532] In 2022, SPP submitted revisions to its tariff to require that a single set of uniform planning

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[529] *See* Georgia Power Company, Docket No. 44160, Public Staff, Direct Testimony and Exhibits of John W. Chiles, at 11-12 (Ga. Pub. Serv. Comm'n May 6, 2022).
[530] SERTP, 2017 Planning Cycle, Transmission Needs Driven By Public Policy Requirements at 2-3, http://www.southeasternrtp.com/docs/general/2017/2017%20Planning%20Cycle%20Transmission%20Needs%20Driven%20by%20Public%20Policy%20Requirements.pdf; SERTP, 2016 Planning Cycle, Transmission Needs Driven By Public Policy Requirements at 3, http://www.southeasternrtp.com/docs/general/2016/2016%20SERTP%20PPR%20Results.pdf; SERTP, 2015 Planning Cycle, Transmission Needs Driven By Public Policy Requirements at 3, http://www.southeasternrtp.com/docs/general/2015/2015%20SERTP%20PPR%20Results.pdf (last accessed Dec. 18, 2024).
[531] Order Addressing Arguments Raised on Rehearing and Granting Clarification, In Part, *Southwest Power Pool, Inc.*, 181 FERC ¶ 61,053 (2022) at P 4, *affirmed*, *Evergy Kansas Central, Inc., et al., v. FERC*, 77 F.4th 1050 (D.C. Cir. 2023).
[532] *Id*. at P 5.

criteria, called Zonal Planning Criteria."[533] Regardless, under both approaches, SPP as the regional planner plans facilities under transmission owner specific planning criteria, with projects 100 kV to 300 kV having a component of project costs (one-third) allocated across the full SPP region to reflect the regional benefit derived from such facilities.[534] As a result of SPP's approach, limited individual transmission owner planned facilities exist in the SPP region. Indeed, SPP's regional approach is consistent with the relief requested nationally through this Complaint.

Nevertheless, some transmission owners maintain a local planning tariff. For example, at its 2023 customer meeting, Xcel Energy presented its transmission projects added between September 2022 and September 2023. Five of the eighteen additions were rebuilds of 115 kV transmission lines (approximately 72 miles of rebuilt transmission lines) ostensibly needed for "asset renewal."[535]

7. WestConnect

a) Public Service Colorado's 560-mile Double Circuit 345 kV 'Local' Project

On February 16, 2024 the Municipal Energy Agency of Nebraska, the City of Aspen, Colorado, the City of Glenwood Springs, Colorado, and the Town of Center, Colorado, filed a complaint under Sections 206 and 306 of the Federal Power Act against Public Service Company

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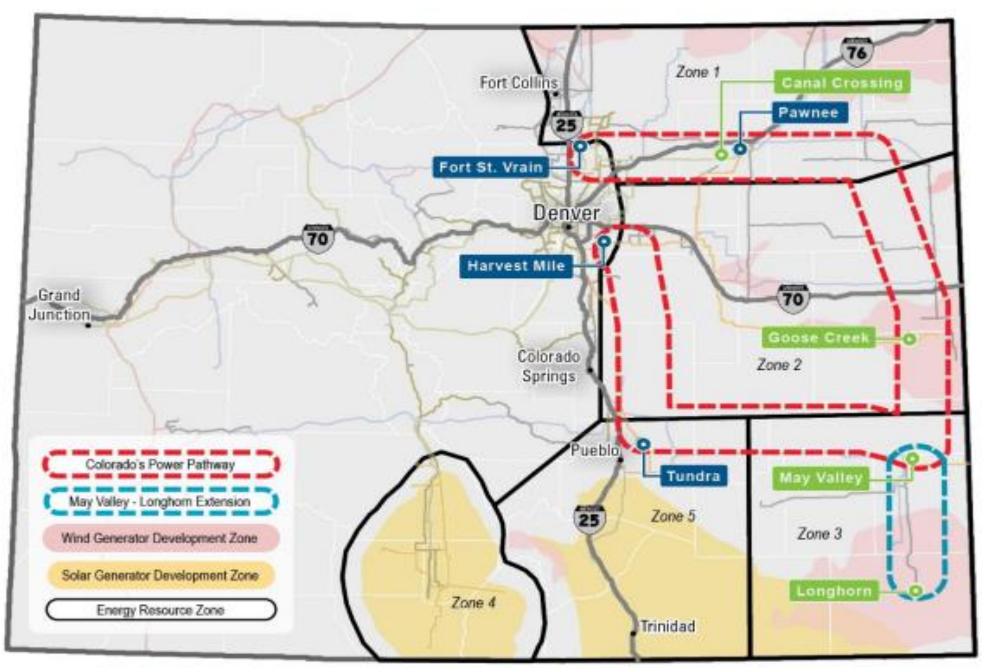
[533] *Id*. at P 1, *citing Sw. Power Pool, Inc.*, 179 FERC ¶ 61,229 (2022).
[534] Transmission facilities 345 kV and above are allocated 100% to the region reflecting their "Highway" nature. *Sw. Power Pool, Inc.*, 131 FERC ¶ 61,252 (2010) at P 73 ("We find this evidence compelling that the high voltage 345 kV and EHV facilities provided *significantly greater* support to regional power flows relative to the lower voltage facilities.") (emphasis added). As discussed above, while focusing on the "significantly greater" support to regional flows of transmission facilities 345 kV and above, the Commission recognized that all transmission facilities 100 kV and above provided regional benefits.
[535] Xcel, Xcel Energy-Texas and New Mexico Sub-Regional Transmission Planning Meeting at slides 9, 10, 12, 13, & 15 (Oct. 12, 2023), https://www.ieca-us.org/wp-content/uploads/Xcel-Energy-Texas-and-New-Mexico-Sub-Regional-Transmission-Planning-Meeting-October-2023-Presentation.pdf. *See also*, slide 78 for future projects, (last accessed Dec. 18, 2024).

of Colorado ("Public Service Colorado" or "PSCo").[536] The Colorado Cities Complaint raised a host of issues with Public Service Colorado's planning of a proposed $2 billion 560-mile, double circuit 345 kV "local" project. The Complaint asserts that Public Service Colorado violated both its local planning tariff and its regional tariff in the manner in which it planned the project.[537]

The Power Pathway is a 560-mile, 345 kV double circuit network transmission system between four existing substations and three new substations submitted for state approval as a "locally" planned project.[538] The proposal included a potential 90-mile extension, also double-circuit 345kV, between new substations.[539] The initial project cost estimates for the Power Pathway and the extension were $1.7 billion and $250 million respectively.[540]



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[536] Complaint of Municipal Energy Agency of Nebraska, the City of Aspen, Colorado, the City of Glenwood Springs, Colorado, and the Town of Center, Colorado, v. Public Service Company of Colorado, filed February 16, 2024 in Docket No. EL24-74-000 ("Colorado Cities Complaint").
[537] Colorado Cities Complaint at 21-40.
[538] Colorado Cities Complaint at 9-10.
[539] *Id.* at 10.
[540] *Id*. at 9.
[541] *Colorado Cities Complaint* at 10, *citing* Colorado Commission Proceeding No. 21A-0096E, Direct Testimony and Attachment of Alice K. Jackson (Mar. 2, 2021) at p. 27, Figure AKJ-D-3:

While the Power Pathway was not initially exclusively locally planned, Public Service Colorado removed the Power Pathway from consideration in the WestConnect sub-regional transmission planning process and on March 2, 2021 filed an application for a CPCN for the Power Pathway and the potential extension with the Colorado Public Utilities Commission ("Colorado Commission") as a locally planned project.[542] According to the Colorado Cities Complaint, "Public Service asserted in its Application that the Power Pathway will provide a 'backbone network transmission system' in eastern Colorado for an area that does 'not currently have a backbone transmission system that can integrate new renewable energy resources needed to meet Colorado's clean energy goals.'"[543]

Even though the Power Pathway Project was submitted as a local project, it was not actually planned pursuant to Public Service's local planning tariff, nor did Public Service actually believe it was local in nature. Regarding local planning, the Colorado Cities Complaint asserted that:

> without any advance notice, Public Service updated its local transmission plan on March 2, 2021 to include the Power Pathway, the same day it submitted its Application to the Colorado Public Utilities Commission. Public Service did not reveal the $2 billion project to stakeholders in the Order No. 890 required coordination meeting until a week later.[544]

Public Service admitted that it did not include the Power Pathway Project in its local plan and submit it to stakeholders until 8 days after it sought a Certificate of Convenience and Necessity

[542] *Colorado Cities Complaint* at 9.
[543] *Id*.
[544] *Id*. at 20. Pursuant to Public Service Colorado's OATT, the first meeting of the year is to discuss the study parameters for transmission additions. OATT Attachment R – PSCo, Transmission Planning Process of Public Service Company of Colorado, Section II, C. 4. available at http://www.oasis.oati.com/woa/docs/PSCO/PSCOdocs/PSCo_Attachment_R_5-5-2020.pdf (last accessed Dec. 18, 2024).

from the Colorado Public Utility Commission.[545] While it used the pretext of its local planning tariff to make its filing at the Colorado Commission, Public Service Colorado recognized that the project was not a localized project. Public Service acknowledged that the only public discussion of Power Pathway was at the WestConnect level, under its subregional planning.[546] Further, Public Service testified before the Colorado Commission that "[t]he Company has been in *continuous discussions with the other utilities* through … the development of this CPCN application filing about their possible participation in the Project because of the likelihood that the Pathway Project can support the clean energy goals of more than just Public Service."[547]

On November 7 2024, the Commission denied the Complaint, finding that the Colorado Cities had not met their burden to show that the assignment of a portion of the costs of the Project was inconsistent with the cost causation principle or otherwise unjust and unreasonable or unduly discriminatory or preferential.[548] The Commission also found that the Colorado Cities did not demonstrate that Public Service violated the local transmission planning or regional transmission planning requirements in its Tariff or Order Nos. 890 and 1000.[549]

b) Other Examples of Local Transmission Planning in the WestConnect Region

In addition to parts of Colorado, the WestConnect region includes parts of Arizona, California, Colorado, New Mexico, Nebraska, Nevada, South Dakota, Texas, and Wyoming. It has ten "enrolled" public utility members and several non-public "non-enrolled" members.[550]

[545] Motion to Dismiss and Answer of Public Service Company of Colorado, filed March 21, 2024 in Docket No. EL24-74-000 ("PSCo Answer") at Appendix A-17.55.
[546] *Id*.
[547] Colorado Cities Complaint at 13.
[548] "Order Denying Complaint," *Municipal Energy Agency of Nebraska and the Colorado Cities et al. v. Public Service Co. of Colorado*, 189 FERC ¶ 61,099 at P 40 (2024) (hereinafter "Order Denying Colorado Cities Complaint").
[549] Order Denying Colorado Cities Complaint at PP 76-88.
[550] The list of enrolled entities is included in the individual member open access transmission tariffs. *See* El Paso Electric Open Access Transmission Tariff at Attachment K, Section III.C.3.c.

Transmission owner members participate in one of three subregional planning groups. The base of WestConnect's regional plan includes projects that each transmission owner planned and submitted to WestConnect. To date, WestConnect has not identified a single regional need.[551]

Below is a list of 100 kV and above projects submitted by transmission owners to their respective subregional planning group.

Regional Study Plan for the Planning Cycle 2022-2023[552]

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
Arizona Public Service	Avery 230/69kV Substation	2024	Not Provided	30
Arizona Public Service	Jojoba-Rudd or TS21 500 kV Line	2028	Not Provided	30
Arizona Public Service	Relocation of the Morgan-Pinnacle Peak 230kV and 500 kV Lines	2022	Not Provided	30
Arizona Public Service	Runway 230 kV Lines	2022	Not Provided	30
Arizona Public Service	Runway Additional 230 kV Lines	2024	Not Provided	30
Arizona Public Service	TS22 500 and 230kV Lines	2030	Not Provided	31

[551] WestConnect Regional Transmission Planning 2016-17 Cycle, Regional Transmission Plan at 39 (Approved Dec. 20, 2017, updated July 28, 2021), https://doc.westconnect.com/Documents.aspx?NID=18010; WestConnect Regional Transmission Planning 2018-19 Cycle, Regional Transmission Plan Report at 7 (Approved Dec. 18, 2019, Updated July 27, 2021), https://doc.westconnect.com/Documents.aspx?NID=18530; WestConnect 2020-21 Regional Transmission Planning Cycle, Regional Transmission Plan Report at 7 (approved Dec. 15, 2021), https://doc.westconnect.com/Documents.aspx?NID=20390; WestConnect Regional Transmission Plan Report, WestConnect 2022-23 Regional Transmission Planning Cycle at 6 (Approved Dec. 13, 2023), https://doc.westconnect.com/Documents.aspx?NID=21047 (last accessed Dec. 18, 2024).
[552] WestConnect Regional Transmission Planning, 2022-23 Planning Cycle, Final Regional Study Plan (Approved Mar. 16, 2022), https://doc.westconnect.com/Documents.aspx?NID=20810 (last accessed Dec. 18, 2024).

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
El Paso Electric Company	Add 345 kV ring bus to VADO substation. Split Newman 345 kV to Afton_N 345 kV line tapping inand-out to VADO 345 kV bus	2030	Not Provided	31
El Paso Electric Company	Afton North (Two) 224 MVA 345/115 kV Autotransformers (New)	2025	Not Provided	31
El Paso Electric Company	Afton North-Airport 115 kV Line (New)	2025	Not Provided	31
El Paso Electric Company	Afton North-Vado 115 kV Double Bundled Line (New)	2026	Not Provided	31
El Paso Electric Company	Afton-Afton North 345 kV Double Bundled Line (New)	2025	Not Provided	31
El Paso Electric Company	Apollo-Cox Line 69 kV to 115 kV (Moongate-Apollo Portion - Rebuild)	2024	Not Provided	31
El Paso Electric Company	Arroyo-Cox 69 kV to 115 kV (Arroyo-Moongate Portion - Reconductor)	2023	Not Provided	31
El Paso Electric Company	Caliente-MPS 16700 115 kV Line (Reconductor)	2027	Not Provided	31
El Paso Electric Company	CE2 Capacitor Banks (New), 115 kV	2025	Not Provided	31
El Paso Electric Company	CE-2 Substation (New) and Related 115 kV West Loop Line Reconfiguration	2025	Not Provided	31
El Paso Electric Company	CE-3 Substation (New) and Related 115 kV West Loop Line Reconfiguration	2027	Not Provided	31
El Paso Electric Company	CE4 Capacitor Banks (New), 115 kV	2027	Not Provided	31

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
El Paso Electric Company	CE-4 Substation (New) and Related 115 kV West Loop Line Reconfiguration	2027	Not Provided	31
El Paso Electric Company	Coyote-Pine 115 kV Line (Reconductor)	2026	Not Provided	31
El Paso Electric Company	In-and-Out into Otero 345 kV and In-and-Out into Picante 345 kV Substation from Caliente-Amrad 345 kV Line (Amrad to Otero)	2023	Not Provided	31
El Paso Electric Company	In-and-Out into Otero 345 kV and In-and-Out into Picante 345 kV Substation from Caliente-Amrad 345 kV Line (Otero to Picante)	2023	Not Provided	32
El Paso Electric Company	In-and-Out into Otero 345 kV and In-and-Out into Picante 345 kV Substation from Caliente-Amrad 345 kV Line (Picante to Caliente)	2023	Not Provided	32
El Paso Electric Company	In-and-Out into Vado 345 kV Substation from Afton North-Newman 345 kV Line	2026	Not Provided	32
El Paso Electric Company	Jornada-Arroyo 115 kV Line (Reconductor/Rebuild)	2024	Not Provided	32
El Paso Electric Company	Leasburg Capacitor Banks (New), 115 kV	2026	Not Provided	32
El Paso Electric Company	Leasburg Substation, 115 kV	2026	Not Provided	32
El Paso Electric Company	McCombs Substation (New) and Related 115 kV Line Reconfiguration	2023	Not Provided	32

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
El Paso Electric Company	New Amrad SVC/STATCOM device connecting on high-voltage side to Amrad 345 kV side using its own dedicated step-up step up transformer.	2026	Not Provided	32
El Paso Electric Company	Pine Switching Station 115 kV (New)	2026	Not Provided	32
El Paso Electric Company	Pine-Seabeck 115 kV Line (New)	2026	Not Provided	32
El Paso Electric Company	San Felipe Capacitor Banks (New), 115 kV	2025	Not Provided	32
El Paso Electric Company	San Felipe Substation 115/69 kV (New)	2025	Not Provided	32
El Paso Electric Company	Seabeck Switching Station 115 kV (New)	2025	Not Provided	32
El Paso Electric Company	Seabeck-Horizon 115 kV Line (New)	2025	Not Provided	33
El Paso Electric Company	Seabeck-San Felipe 115 kV Line (New)	2024	Not Provided	33
El Paso Electric Company	Sparks-San Felipe Line (Conversion/Reconductor) 69 kV to 115 kV	2026	Not Provided	33
El Paso Electric Company	Vado 224 MVA Vado 345/115 kV Autotransformer (New)	2026	Not Provided	33
El Paso Electric Company	Vado Substation 115 kV (New)	2026	Not Provided	33
El Paso Electric Company	Vado-Anthony 115 kV Line Double Bundled (Reconductor)	2027	Not Provided	33

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
El Paso Electric Company	Vado-Salopek 115 kV Double Bundled Line (Reconductor)	2027	Not Provided	33
Public Service Company of New Mexico	Belen Phase Shifting Transformer, 115 kV	2023	Not Provided	34
Public Service Company of New Mexico	Dagger Point Switching Station, 345 kV	2023	Not Provided	34
Tucson Electric Power	500/345kV Transformer addition at Pinal West	2022	Not Provided	35
Tucson Electric Power	500/345kV Transformer addition at Westwing	2022	Not Provided	36
Tucson Electric Power	Bopp-Donald 138/13.8kV Substation	2026	Not Provided	36
Tucson Electric Power	Bopp-Donald to Midvale 138kV line	2027	Not Provided	36
Tucson Electric Power	Cottonwood to Bopp-Donald 138kV line	2026	Not Provided	36
Tucson Electric Power	DMP 230/138kV Transformers	2025	Not Provided	36
Tucson Electric Power	DMP to Vail 230kV line	2027	Not Provided	36
Tucson Electric Power	East Loop 138kV Conversion to breaker-and-a-half substation	2027	Not Provided	36
Tucson Electric Power	Golden Valley 230kV Transmission Line	2027	Not Provided	36
Tucson Electric Power	Kantor Capacitor Bank Addition for Hermosa, 138 kV	2023	Not Provided	36

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
Tucson Electric Power	New 230kV Yard at DMP Substation	2025	Not Provided	37
Tucson Electric Power	New 230kV Yard at Tortolita Substation	2025	Not Provided	37
Tucson Electric Power	New 230kV Yard at Vail Substation	2027	Not Provided	37
Tucson Electric Power	Orange Grove Capacitor Bank Addition, 138 kV	2025	Not Provided	37
Tucson Electric Power	Rillito 138kV Conversion to breaker-and-a-half substation	2025	Not Provided	37
Tucson Electric Power	TEPTDA 138kV Substation	2027	Not Provided	37
Tucson Electric Power	Tortolita 500/230kV Transformers	2025	Not Provided	37
Tucson Electric Power	Tortolita to DMP 230kV line	2025	Not Provided	37
Tucson Electric Power	Vail 345/230kV Transformers	2027	Not Provided	37
Tucson Electric Power	Whetstone 138kV Substation	2022	Not Provided	37
Cheyenne Light Fuel and Power	Allison Draw - Campstool 115 kV Line	TBD prior to 2026	Not Provided	39
Cheyenne Light Fuel and Power	Allison Draw - CPGS 115 kV Line	TBD prior to 2026	Not Provided	39
Cheyenne Light Fuel and Power	Allison Draw 115 kV Substation	TBD prior to 2026	Not Provided	39

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
Cheyenne Light Fuel and Power	Bison - Orchard Valley 115 kV Line	TBD prior to 2026	Not Provided	39
Cheyenne Light Fuel and Power	Bison - West Cheyenne 115 kV Line	TBD prior to 2026	Not Provided	39
Cheyenne Light Fuel and Power	Bluffs 230 kV Substation	TBD prior to 2026	Not Provided	39
Cheyenne Light Fuel and Power	Orchard Valley - King Ranch 115 kV Line	TBD prior to 2026	Not Provided	39
Cheyenne Light Fuel and Power	Orchard Valley 115 kV Substation	TBD prior to 2026	Not Provided	39
Cheyenne Light Fuel and Power	Sweetgrass - Bluffs 230 kV Line	TBD prior to 2026	Not Provided	39
Cheyenne Light Fuel and Power	Sweetgrass - South Cheyenne kV 115 kV Line	2023	Not Provided	39
Cheyenne Light Fuel and Power	Sweetgrass 115 kV Substation	2023	Not Provided	40
Cheyenne Light Fuel and Power	Sweetgrass 230 kV Substation	TBD prior to 2026	Not Provided	40
Cheyenne Light Fuel and Power	West Cheyenne - Sweetgrass 230 kV Line	TBD prior to 2026	Not Provided	40
Cheyenne Light Fuel and Power	West Cheyenne - Windstar 230 kV Line	TBD prior to 2026	Not Provided	40

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
Cheyenne Light Fuel and Power	West Cheyenne 230 kV Substation	TBD prior to 2026	Not Provided	40
Public Service Company of Colorado/Xcel Energy	Daniels Park to Prairie Reconductor 230kV	2023	Not Provided	41
Public Service Company of Colorado/Xcel Energy	Midway Transformer Upgrade, 230 kV	2023	Not Provided	41
Public Service Company of Colorado/Xcel Energy	Stagecoach Switching Station, 230 kV	2024	Not Provided	41

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Arizona Public Service	Broadway 230kV Lines	2024	Not Provided	27
Arizona Public Service	Contrail 230kV Lines	2023	Not Provided	27
Arizona Public Service	Stratus 230kV Lines	2022	Not Provided	27
Arizona Public Service	Three Rivers 230kV Lines	2023	Not Provided	27
Arizona Public Service	TS17 230kV Lines	2025	Not Provided	27

553 WestConnect Regional Transmission Planning, 2020-21 Planning Cycle, Final Regioanl Study Plan (Approved Mar. 18, 2020) https://doc.westconnect.com/Documents.aspx?NID=18668 (last accessed Dec. 19, 2024).

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
Arizona Public Service	TS2 230kV Lines	2023	Not Provided	27
El Paso Electric Company	Wrangler - Sparks Transmission Line Reconductor, 115kV	2021	Not Provided	29
NV Energy[554]	Arden - Mead 230kV line upgrade	2020	Not Provided	30
NV Energy	Magnolia second 230/138kV Transformer bank	2020	Not Provided	30
NV Energy	Reid Gardner - Tortoise #2, 230 kV	2022	Not Provided	30
NV Energy	SE2-West Henderson substation, 138 kV	2021	Not Provided	31
NV Energy	Westside 230kV Switch replacement	2020	Not Provided	31
Tucson Electric Power	Catron 345/34.5 kV Substation	2021	Not Provided	31
Tucson Electric Power	Catron Loop-in to Springerville-Greenlee 345 kV line	2023	Not Provided	31
Tucson Electric Power	Del Cerro capacitor Banks, 138 kV	2020	Not Provided	31
Tucson Electric Power	DMP 138 kV, Conversion to breaker-and-a-half substation	2021	Not Provided	32
Tucson Electric Power	Greenlee Capacitor Additions, 345 kV	2021	Not Provided	32
Tucson Electric Power	Greenlee Loop-in to Springerville-Vail 345 kV line	2023	Not Provided	32

[554] NV Energy transitioned to NorthernGrid in 2021. NV Energy filed tariff changes on August 25, 2021. *See Nevada Power Co.*, Docket No. ER21-2768 (Aug. 25, 2021). No parties protested. The Commission issued a letter order accepting the revised tariff provisions on October 22, 2021.

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
Tucson Electric Power	Hedrick 138/13.8 kV Substation	2024	Not Provided	32
Tucson Electric Power	Hermosa 138kV Switchyard	2023	Not Provided	32
Tucson Electric Power	Hermosa Capacitor Bank Addition, 138 kV	2023	Not Provided	32
Tucson Electric Power	Irvington - East Loop 138 kV Transmission Line	2023	Not Provided	32
Tucson Electric Power	Kino Capacitor Addition, 138 kV	2020	Not Provided	32
Tucson Electric Power	Lago Del Oro 138/13.8 kV Substation	2027	Not Provided	32
Tucson Electric Power	Re-Conductor Canez to Soniota 138-kV Transmission Line	2023	Not Provided	33
Tucson Electric Power	Re-Conductor Nogales to Kantor 138-kV Transmission Line	2023	Not Provided	33
Tucson Electric Power	Sears Wilmot 138/13.8 kV Substation	2025	Not Provided	33
Tucson Electric Power	Springerville-Catron 345 kV Circuits 1 and 2 Uprate	2023	Not Provided	34
Tucson Electric Power	UofA North 138/13.8 kV Substation (was UA Med)	2023	Not Provided	34
Tucson Electric Power	Winchester to Vail 345kV line uprate	2023	Not Provided	34
NV Energy	Bannok capacitor, 115 kV	2020	Not Provided	38
NV Energy	Bell Creek Capacitor, 115 kV	2020	Not Provided	38
NV Energy	Replace Wave Traps on Valmy - Coyote - Humboldt 345kV	2020	Not Provided	38

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
NV Energy	West Tracy - Patrick Line, 115 kV	2020	Not Provided	38
NV Energy	West Tracy 345/120kV 280 MVA Transformer	2020	Not Provided	38
Black Hills Energy	Boone - South Fowler 115 kV line.	2021	Not Provided	35
Black Hills Energy	Desert Cove-Fountain Valley-MidwayBR 115kV line rebuild	2020	Not Provided	35
Black Hills Energy	Hogback 115/69 kVSubstation	2021	Not Provided	35
Black Hills Energy	North Penrose 115/13.2 kV Distribution Substation	2021	Not Provided	35
Black Hills Energy	Nyberg - Airport Memorial 115 kV rebuild.	2022	Not Provided	35
Black Hills Energy	Salt Creek 115/13.2 kV Distribution Substation	2021	Not Provided	35
Black Hills Energy	West Station - Green Horn 115 kV rebuild.	2022	Not Provided	35
Black Hills Power	Lange - Lookout 230 kV rebuild.	2021	Not Provided	35
Black Hills Power	Lange - South Rapid City 230 kV.	2020	Not Provided	35
Black Hills Power	Lookout - Wyodak 230 kV rebuild.	2022	Not Provided	35
Cheyenne Light Fuel and Power	East Business Park - Skyline 115 kV Rebuild.	2021	Not Provided	35
Cheyenne Light Fuel and Power	Loop King Ranch - South Cheyenne into West Cheyenne, 115 kV.	2020	Not Provided	35

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
Cheyenne Light Fuel and Power	Loop North Range - Corlett into West Cheyenne, 115 kV.	2020	Not Provided	35
Public Service Company of Colorado/Xcel Energy	Greenwood - Denver Terminal 230kV transmission line	2022	Not Provided[555]	36
Public Service Company of Colorado/Xcel Energy	NREL Substation, 115 kV	2020	Not Provided	36
Public Service Company of Colorado/Xcel Energy	Shortgrass - Cheyenne Ridge 345 kV transmission line	2020	Not Provided	36

Regional Study Plan for the Planning Cycle 2018-2019[556]

Arizona Public Service	TS4 230/69kV Substation	2020	Not Provided	24
El Paso Electric Company	Add 345 kV ring bus to VADO substation. Split Newman 345 kV to Afton_N 345 kV line tapping in-and-out to VADO 345 kV bus.	2025	Not Provided	24

555 The 2022 10-Year Transmission Plan for the State of Coloardo describes the project as approximately 15 miles of new 230 kV transmission, with an estimated cost of $74.7 millon. 10-Year Transmission Plan for the State of Colorado to comply with Rule 3627 of the Colorado Public Utilities Commission Rules Regulating Electric Utilities at 72-73 (Feb. 22, 2022), https://www.transmission.xcelenergy.com/staticfiles/microsites/Transmission/Files/2022%2010-Year%20Report,%20Rev%202.pdf ("Colorado 10 Year Plan") (last accessed Dec. 18, 2024).
556 WestConnect Regional Transmission Planning, 2018-19 Planning Cycle, Final Regional Study Plan (Approved Mar. 14, 2018), https://doc.westconnect.com/Documents.aspx?NID=18068 (last accessed Dec. 18, 2024).

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
El Paso Electric Company	Anthony to VADO 115 kV transmission line ckt 3. Created from existing Anthony to Arroyo 115 kV transmission line being tapped in and out of new VADO 115 kV substation.	2023	Not Provided	24
El Paso Electric Company	MOONGATE - Jornada Transmission Line, 115 kV	2020	Not Provided	24
El Paso Electric Company	MOONGATE Substation, 115 kV	2020	Not Provided	24
El Paso Electric Company	New Afton_N to VADO 115 kV transmission line.	2022	Not Provided	24
El Paso Electric Company	New Anthony to VADO 115 kV transmission line ckt 2	2024	Not Provided	25
El Paso Electric Company	New transmission line from VADO 115 kV to Salopek 115 kV ckt 2	2023	Not Provided	25
El Paso Electric Company	New VADO 115 kV switching station.	2022	Not Provided	25
El Paso Electric Company	VADO 115 kV to Arroyo 115 kV transmission line ckt 1. Created from existing Anthony to Arroyo 115 kV transmission line being tapped in and out of new VADO 115 kV substation.	2023	Not Provided	25
NV Energy	Arden - McDonald 230 kV Line upgrade	2019	Not Provided	26
NV Energy	Avera - Tomsik 138 kV Reconductor	2027	Not Provided	26
NV Energy	Burnham - Fold 138 kV fold into Pebble	2018	Not Provided	26

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
NV Energy	Craig - LV Cogen 138 kV line upgrade	2018	Not Provided	26
NV Energy	East Tracy 345/120kV XFMR #2	2020	Not Provided	27
NV Energy	Faulkner - Wilson 138 kV Reconductor	2027	Not Provided	27
NV Energy	McDonald 230/138 kV Transformer Addition	2019	Not Provided	27
NV Energy	Replace Wave-Traps on Humboldt-Midpoint 345kV	2018	Not Provided	27
NV Energy	Wild Horse 120kV	2020	Not Provided	27
Public Service Company of New Mexico	Albuquerque-Clines Corners 345 kV Line	2020	Not Provided	27
Public Service Company of New Mexico	Blackwater Synchronous Condenser, 345 kV	2019	Not Provided	27
Tucson Electric Power	DeMoss Petrie (DMP) Capacitor Bank Addition, 138 kV	2022	Not Provided	27
Tucson Electric Power	Drexel Capacitor Bank Addition, 138 kV	2021	Not Provided	28
Tucson Electric Power	Harrison Capacitor Bank Addition, 138 kV	2028	Not Provided	28
Tucson Electric Power	Irvington - Kino 138kV Transmission Line	2021	Not Provided	28
Tucson Electric Power	Irvington Capacitor Bank Addition, 138 kV	2020	Not Provided	28
Tucson Electric Power	Irvington to 22nd Street 138-kV Line ReConductor	2019	Not Provided	28

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
Tucson Electric Power	Irvington to South 138-kV Line Re-Conductor	2020	Not Provided	28
Tucson Electric Power	Irvington to Vail 138-kV Line Re-Conductor	2020	Not Provided	28
Tucson Electric Power	Kantor Capacitor Bank Addition, 138 kV	2019	Not Provided	28
Tucson Electric Power	La Canada to Orange Grove 138-kV Line ReConductor	2020	Not Provided	28
Tucson Electric Power	Line 125 Re-conductor & Conversion to Double Circuit	2022	Not Provided	28
Tucson Electric Power	Loop-in of Hassayampa to Pinal West 500-kV Line with with existing Jojoba Substation	2019	Not Provided	28
Tucson Electric Power	Loop-in of Irvington to Robert Bills 138-kV line with new Sonoran substation	2021	Not Provided	29
Tucson Electric Power	Loop-in of Irvington to Sount 138-kV Line to Sonoran Substation	2020	Not Provided	29
Tucson Electric Power	Loop-in of Irvington to Vail 138-kV Line to Sonoran Substation	2021	Not Provided	29
Tucson Electric Power	Naranja Capacitor Bank Addition, 138 kV	2025	Not Provided	29
Tucson Electric Power	North Loop Capacitor Bank Addition (#3), 138 kV	2022	Not Provided	29
Tucson Electric Power	North Loop Capacitor Bank Addition (#4), 138 kV	2024	Not Provided	29

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
Tucson Electric Power	Orange Grove Capacitor Bank Addition, 138 kV	2019	Not Provided	29
Tucson Electric Power	Orange Grove to Rilito 138-kV Line Re-Conductor	2020	Not Provided	29
Tucson Electric Power	Pantano Capacitor Bank Addition, 138 kV	2020	Not Provided	29
Tucson Electric Power	Q59 138/13.8 kV Substation	2022	Not Provided	29
Tucson Electric Power	Rancho Vistoso to La Canada 138-kV Line ReConductor	2020	Not Provided	29
Tucson Electric Power	Re-Conductor Nogales to Kantor 138-kV Transmission Line	2019	Not Provided	29
Tucson Electric Power	Sonoran 138/46/13.8 kV Substation	2020	Not Provided	29
Tucson Electric Power	Sonoran to NextEra 138-kV Line	2022	Not Provided	29
Tucson Electric Power	South to NextEra 138-kV Line	2022	Not Provided	30
Tucson Electric Power	Tortolita Capacitor Bank Addition (#2), 138 kV	2019	Not Provided	30
Tucson Electric Power	Tortolita Capacitor Bank Addition (#3), 138 kV	2021	Not Provided	30
Tucson Electric Power	Tortolita Capacitor Bank Addition (#4), 138 kV	2022	Not Provided	30
Tucson Electric Power	Tucson to El Camino del Cerro 138-kV Line ReConductor	2020	Not Provided	30
Tucson Electric Power	West Ina Capacitor Bank Addition, 2021	2021	Not Provided	30

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
NV Energy	Brunswick Rebuild, 115 kV	2018	Not Provided	33
NV Energy	California Substation upgrade, 115 kV	2018	Not Provided	33
NV Energy	Carson - Emerson Line Rebuild, 115 kV	2019	Not Provided	33
NV Energy	Cortez South Pipeline Capacitor Bank, 115 kV	2018	Not Provided	33
NV Energy	Dove - East Tracy 120 kV Line Reconductor	2019	Not Provided	33
NV Energy	Dove Capacitor Bank, 115 kV	2019	Not Provided	33
NV Energy	North Valley Road - Penny's Tap 120 kV line Uprate	2018	Not Provided	34
NV Energy	Silver Lake 120 kV Capacitor Bank	2021	Not Provided	34
NV Energy	Tracy - Patrick 120 kV Line Uprate	2018	Not Provided	34
Black Hills Energy	Boone-La Junta 115 kV Rebuild	2020	Not Provided	30
Black Hills Energy	West Station - West Cañon 115kV	2021	Not Provided	30
Black Hills Power	Sagebrush 230/69 kV Substation	2019	Not Provided	30
Black Hills Power	Westhill-Stegall 230 kV Line Rebuild	2019	Not Provided	31
Cheyenne Light Fuel and Power	Happy Jack-North Range 115 kV Rebuild	2018	Not Provided	31
Public Service Company of Colorado/Xcel Energy	Monument 115 kV Phase Shifter	2020	Not Provided	31

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
Public Service Company of Colorado/Xcel Energy	Badgers Hills 345 kV Substation	2020	Not Provided	31

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NV Energy	California – Bordertown 120kV Line	Not Provided	Not Provided	31
Arizona Public Service	North Gila – Orchard 230kV Line	Not Provided	Not Provided	31
Arizona Public Service	Morgan – Sun Valley 230kV Line	Not Provided	Not Provided	31
Arizona Public Service	Morgan – Sun Valley 500kV Line	Not Provided	Not Provided	32
El Paso Electric Company	Wrangler – Sparks Transmission Line Reconductor	Not Provided	Not Provided	32
El Paso Electric Company	Leo Substation Upgrade from 69 kV to 115 kV	Not Provided	Not Provided	32
El Paso Electric Company	LE1 (Organ) Substation, 115 kV	Not Provided	Not Provided	32
El Paso Electric Company	LE1 (Organ) – Jornada Transmission Line, 115 kV	Not Provided	Not Provided	32
El Paso Electric Company	Leo – Dyer (6500) Transmission Line Upgrade to 115 kV	Not Provided	Not Provided	32

[557] WestConnect Regional Transmission Planning, 2016-17Planning Cycle, Regional Study Plan (Approved Mar. 16, 2016) https://doc.westconnect.com/Documents.aspx?NID=17180 (last accessed Dec. 18, 2024).

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
El Paso Electric Company	Leo – Milagro (7800) Transmission Line Upgrade to 115 kV	Not Provided	Not Provided	32
El Paso Electric Company	NW2 (Verde) Substation 30 MVA Transformer, 115 kV	Not Provided	Not Provided	32
El Paso Electric Company	Global Reach Substation Transformer (T2), 115 kV	Not Provided	Not Provided	32
El Paso Electric Company	Patriot Substation Transformer (T2), 115 kV	Not Provided	Not Provided	32
El Paso Electric Company	Afton North Autotransformer, 345 kV	Not Provided	Not Provided	32
El Paso Electric Company	NW3 (Transmountain) Substation Transformer, 115 kV	Not Provided	Not Provided	32
El Paso Electric Company	Afton North – Airport Transmission Line, 115 kV	Not Provided	Not Provided	32
El Paso Electric Company	Airport – Jornada Transmission Line, 115 kV	Not Provided	Not Provided	32
El Paso Electric Company	Global Reach Substation Capacitor Bank, 115 kV	Not Provided	Not Provided	32
El Paso Electric Company	Picante Substation Capacitor Bank, 115 kV	Not Provided	Not Provided	32
El Paso Electric Company	Uvas Substation 12 MVA Transformer, 115 kV	Not Provided	Not Provided	32
El Paso Electric Company	Pipeline Substation 33.6 MVA Transformer, 115 kV	Not Provided	Not Provided	32
El Paso Electric Company	Leasburg Substation 33.6 MVA Transformer, 115 kV	Not Provided	Not Provided	32
El Paso Electric Company	Sol – Vista Transmission Line Upgrade, 115 kV	Not Provided	Not Provided	32

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
El Paso Electric Company	East-side Loop Expansion Phase I, 115 kV	Not Provided	Not Provided	33
El Paso Electric Company	East-side Loop Expansion Phase 2, 115 kV	Not Provided	Not Provided	33
El Paso Electric Company	Move Sparks 115/69 kV Autotransformer to Felipe Substation	Not Provided	Not Provided	33
El Paso Electric Company	Sparks to Felipe 69 kV to 115 kV Line Upgrade	Not Provided	Not Provided	33
Public Service Company of New Mexico	Alamogordo Voltage Support Phase II, 115 kV	Not Provided	Not Provided	34
Public Service Company of New Mexico	Second Yah-Ta-Hey 345/115 kV Transformer	Not Provided	Not Provided	34
Public Service Company of New Mexico	Guadalupe SVC, 345 kV	Not Provided	Not Provided	34
Public Service Company of New Mexico	Cabezon Switching Station, 345 kV	Not Provided	Not Provided	34
Tucson Electric Power	Kino 138/13.8 kV Substation	Not Provided	Not Provided	34
Tucson Electric Power	Marana 138/13.8 kV Substation	Not Provided	Not Provided	34
Tucson Electric Power	Corona 138/13.8 kV Substation	Not Provided	Not Provided	34
Tucson Electric Power	Craycroft Barril 138/13.8 kV Substation	Not Provided	Not Provided	34
Tucson Electric Power	Irvington – Tucson 138 kV Transmission Line Circuit 2	Not Provided	Not Provided	34

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
Tucson Electric Power	Harrison 138/13.8 kV Substation	Not Provided	Not Provided	34
Tucson Electric Power	Hartt 138/13.8 kV Substation	Not Provided	Not Provided	34
Tucson Electric Power	Marana 138kV Transmission Line	Not Provided	Not Provided	34
Tucson Electric Power	Orange Grove 138/13.8 kV Substation	Not Provided	Not Provided	35
Tucson Electric Power	Rosemont 138kV Line	Not Provided	Not Provided	35
Tucson Electric Power	Tortolita 500 kV Switchyard	Not Provided	Not Provided	35
Tucson Electric Power	Naranja 138/13.8 kV Substation	Not Provided	Not Provided	35
Tucson Electric Power	Rancho Vistoso to La Canada 138kV Line Uprate	Not Provided	Not Provided	35
Tucson Electric Power	Irvington – Drexel 138 kV Line Uprate	Not Provided	Not Provided	35
Tucson Electric Power	NL - NARANJA 138 kV Project	Not Provided	Not Provided	35
Tucson Electric Power	Tortolita – Rancho Vistoso 138kV Line Re-configuration: Tortolita – NL EXP / NL EXP – Rancho Vistoso	Not Provided	Not Provided	35
Tucson Electric Power	NL EXP – Rancho Vistoso 138kV Line Uprate	Not Provided	Not Provided	35
Tucson Electric Power	NL Expansion 138kV Capacitor Bank Upgrades, Banks 1&2	Not Provided	Not Provided	35
Tucson Electric Power	Del Cerro - Tucson 138 kV Line Uprate/Reconductor	Not Provided	Not Provided	35

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
Tucson Electric Power	Irvington 138 kV Breaker-and-a-half Substation	Not Provided	Not Provided	35
Tucson Electric Power	South Loop 345 kV, Conversion to Breaker-and-a-half Substation	Not Provided	Not Provided	35
Tucson Electric Power	Greenlee 345 kV, Conversion to Breaker-and-a-half Substation	Not Provided	Not Provided	35
Tucson Electric Power	East Loop Bus Tie Breaker, 138 kV	Not Provided	Not Provided	35
Tucson Electric Power	La-Canada Line Switch, 138 KV	Not Provided	Not Provided	35
Tucson Electric Power	NorthEast Bus Tie Breaker, 138 kV	Not Provided	Not Provided	35
Tucson Electric Power	North Loop – Naranja Line Uprate, 138 kV	Not Provided	Not Provided	35
Tucson Electric Power	Naranja – Rancho Vistoso Line Uprate, 138 kV	Not Provided	Not Provided	35
Tucson Electric Power	Roberts Capacitor Bank Addition, 138 kV	Not Provided	Not Provided	35
Black Hills Energy	Overton 115 kV Substation	Not Provided	Not Provided	28
Black Hills Energy	LaJunta 115kV Substation	Not Provided	Not Provided	28
Black Hills Energy	Baculite Mesa – Overton 115 kV Line Rebuild	Not Provided	Not Provided	28
Black Hills Energy	Portland 115/69kV Transformer Replacement	Not Provided	Not Provided	28
Black Hills Power	Second 230/69kV Yellow Creek Transformer	Not Provided	Not Provided	28

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
Black Hills Power	South Rapid City – Westhill 230kV Rebuild	Not Provided	Not Provided	28
Cheyenne Light Fuel and Power	Swan Ranch 115 kV Substation	Not Provided	Not Provided	28
Cheyenne Light Fuel and Power	King Ranch 115kV Substation	Not Provided	Not Provided	28
Cheyenne Light Fuel and Power	East Business Park – Cheyenne Prairie 115kV Line Reconductor	Not Provided	Not Provided	28
Cheyenne Light Fuel and Power	Archer – Cheyenne Prairie 115kV Reconductor	Not Provided	Not Provided	28
Cheyenne Light Fuel and Power	North Range – Swan Ranch 115kV Reconductor	Not Provided	Not Provided	28
Public Service Company of Colorado/Xcel Energy	Pawnee – Daniels Park 345 kV Transmission Project	Not Provided	Not Provided	28
Public Service Company of Colorado/Xcel Energy	Rifle – Parachute 230 kV Line #2	Not Provided	Not Provided	28
Public Service Company of Colorado/Xcel Energy	Happy Canyon Substation, 115 kV	Not Provided	Not Provided	29
Public Service Company of Colorado/Xcel Energy	Thornton Substation, 115 kV	Not Provided	Not Provided	29

Sponsor	Project Name and Description	In-Service Date	Individual Project Cost	Page No.
Public Service Company of Colorado/Xcel Energy	Avery Substation, 230 kV	Not Provided	Not Provided[558]	29
Public Service Company of Colorado/Xcel Energy	Gilman – Avon 115 kV Transmission Line and Cap Bank	Not Provided	Not Provided[559]	29
Public Service Company of Colorado/Xcel Energy	Weld to Rosedale 230 kV Line	Not Provided	Not Provided	29
Public Service Company of Colorado/Xcel Energy	Ault – Cloverly 115 kV Transmission Project	Not Provided	Not Provided[560]	29
Public Service Company of Colorado/Xcel Energy	Milton – Rosedale 230 kV Transmission Line	Not Provided	Not Provided	29

8. FRCC- FPL North Florida Project

Starting in 2019 various Florida Power & Light affiliated entities began planning development of a 176-mile 161 kV transmission line, known as the North Florida Resiliency Project ("FPL 'Local' Project"). Although substations on either end of the 176-mile line were 230 kV, the FPL 'Local' Project was planned at 161 kV "to be below the 230 kV statutory

[558] The Colorado 10 Year Plan describes the project as a new 230/13.8 kV, 28 MVA transformer needed for future load growth with an estimated cost of $12.1 million. Colorado 10 Year Plan at 4, 75-76.
[559] The Colorado 10 Year Plan describes the project as a new 10-mile 115 kV line with an estimated cost of $11.4 million. Colorado 10 Year Plan at 75.
[560] The Colorado 10 Year Plan describes the project as approximately 25 miles of new 230 kV and 115 kV transmission lines with an estimated cost of $84.7 million. Colorado 10 Year Plan at 5, 74-75.

threshold" for State of Florida review or regional planning in the Florida Reliability Coordinating Council, Inc. ("FRCC region.")[561] Testimony submitted in a complaint regarding the project, discussed below, asserted that "[a]t 161 kV, the same conductor, or wire, will present a relative electrical resistance to the power system that is more than twice the resistance at an operating voltage of 230 kV."[562] By planning the project at 161 kV instead of 230 kV, or higher, FPL clearly planned a less efficient or cost effective solution to the identified transmission transfer needs, avoiding both substantive state review or a trigger of required regional planning alternative.

The FPL 'Local' Project is a perfect example of the issues which arise when self-interested transmission owners have local planning control and financial incentives to inefficiently plan, develop, and construct within the local planning regime. In this instance, the regional planning entity FRCC has a 230 kV threshold to be a regional project.[563] To avoid this voltage threshold FPL planned the project at 161 kV notwithstanding that "the choice of stepping down voltage to transmit power over a 176-mile distance is unusual."[564] Duke notes that "[a] transmission system is typically designed to step up voltage near the source of power, the power is then transmitted at a higher voltage before voltage is stepped back down to ultimately distribute and deliver the power to customers at a lower voltage. . . . At 161 kV, the same

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[561] Duke Energy Florida, LLC v. Florida Power & Light, Co., et al. Docket No. EL21-93-000, filed August 06, 2021 ("Duke Complaint") at 3.
[562] *Id*. at ¶¶ 34-35.
[563] Florida Power & Light, *Order No. 1000 Compliance Filing*, Section 1.2.3, available at https://www.oasis.oati.com/woa/docs/FPL/FPLdocs/Order_1000_-_FPL_Transmittal_Letter_-_10-11-12_Final_with_Appendices.pdf (last accessed Dec. 18, 2024) ("To be eligible for approval by the FRCC Board for inclusion in the regional plan, a proposed . . . project must meet these threshold criteria: A. Be a transmission line subject to the requirements of the Florida Transmission Line Siting Act."); Fla. Stat. Ann. § 403.522(22) ("'Transmission line' or 'electric transmission line' means structures, maintenance and access roads, and all other facilities that need to be constructed, operated, or maintained for the purpose of conveying electric power extending from, but not including, an existing or proposed substation or power plant to, but not including, an existing or proposed transmission network or rights-of-way or substation to which the applicant intends to connect which defines the end of the proposed project and which is designed to operate at 230 kilovolts or more.").
[564] Duke Complaint Exhibit B at ¶ 34.

conductor, or wire, will present a relative electrical resistance to the power system that is more than twice the resistance at an operating voltage of 230 kV."[565] These facts demonstrate that the FPL 'Local' Project is not the more efficient or cost effective transmission project to address the requested transfers of power.

9. New York Self-Planned Transmission

The New York region has not escaped the proliferation of local projects, but as a single state region its local planning has received less scrutiny. In 2023, transmission owners in New York pushed through sixty-two locally planned projects, ostensibly in support of the Climate Leadership and Community Protection Act.[566] The sixty-two projects included rebuilding existing 115 kV transmission lines, rebuilding and upgrading 69 kV lines to 115 kV transmission lines, upgrading existing substations, and building one 345/115 kV substation and two new 115 kV substations, among other work.[567] The total estimated cost of the projects is $4.4 Billion.[568] The projects will undoubtedly have a regional impact by reducing congestion in certain regions of New York,[569] yet they were planned by individual transmission owners.[570] The below table provides an overview of the 62 Areas of Concern ("AOC") projects proposed by the sponsoring utilities in New York:

[565] *Id*. at ¶¶ 34-35.
[566] New York Public Service Commission, Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act Case 20-E-0197, *Order Approving Phase 2 Areas of Concern Transmission Upgrades* at 11 (Feb. 16, 2023), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={0C1FE2AF-2922-4BF5-809C-5C93F4F73121}. (last accessed Dec. 18, 2024), S.Res. 6599, 2019 Leg., 242nd Sess. (N.Y. 2019) (codified as Ch. 106, L. 2019).
[567] *Id*. at 11-12.
[568] *Id*. at 12.
[569] *Id*. at 45.
[570] *Id*. at 10-11 (describing the transmission owners' process for planning the sixty-two projects).

Table 2: Summary of Proposed AOC Projects

Region/ Company	Zone	Pro-jects	Project Descriptions	In Service Dates	Proposed Cost ($millions)
Northern NY - National Grid & NYSEG	X2&3	28	Rebuild/Upgrade 115 kV Lines (402 mi.); Upgrade 13-115 kV Substations; Construct 2 new greenfield 115 kV Substations; Install 4 Synchronous Condensers, 2-PARs and Dynamic Line Ratings.	2024 - 2029	$2,071.7
Capital Porter Rotterdam - National Grid	Y1	1	Construct new Marshville 345/115 kV greenfield Substation interconnecting 4-115 kV lines to Bulk System via Edic-Princetown AC Transmission Segment A 345 kV line.	2028	$81.3
Capital North Catskill - Coxsackie - Central Hudson	Y2	1	Rebuild/Upgrade 69 kV Line (9 mi.) to 115 kV Standards; initially operate at 69 kV.	2029	$15.7
Southern Tier - NYSEG & RG&E	Z1	32	Line Rebuilds: 230 kV (63 mi.); 115 kV (197 mi.); 34.5 kV (27 mi.). Substation Upgrades: new 345/115 kV and 230/115 kV transformers; 1-345 kV, 2-230 kV and 6-115 kV Substation Rebuilds/Upgrades (2 relocations out of flood plain), 7-115 kV voltage support installations; 1-115 kV power flow control device, minor 115 kV Substation upgrades.	2024 - 2030	$2,245.7
TOTAL CLCPA AOC		62		2024 - 2030	$4,414.4

Another example of a locally planned project with regional impacts is the Brooklyn Clean Energy Hub. Consolidated Edison Company of New York, Inc. ("ConEd") planned a new 345 kV substation estimated to cost $1 Billion that it claimed would allow the injection of up to 6,000 MW of offshore wind energy at the substation.[571] Parties raised concerns about the cost of the new substation and whether it would be physically feasible to inject 6,000 MW. A group of industrial, commercial, and institutional energy consumers also expressed concern about "the

[571] New York Public Service Commission, Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act, Case 20-E-0197, *Order Approving Cost Recovery for Clean Energy Hub* at 1 (Apr. 20, 2023), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={70E99F87-0000-C112-92F7-F4F713A55987} ("NYPSC Apr 2023 Order") (last accessed Dec. 18, 2024).

lack of coordination between [ConEd's] Petition and any ongoing transmission planning process" and that the project had "yet to be reviewed rigorously by any entity independent from [ConEd]."[572] The New York Public Service Commission ultimately approved an alternative version of the project with a lower but still expensive price tag, an estimated $773 million. The NYPSC also determined that the alternative project would not support the injection of 6,000 MW of offshore wind at the substation.[573]

The end result is that customers may be on the hook for a new 345 kV substation and additional transmission improvements to integrate offshore wind. Had the project been regionally planned by NYISO as a public policy project, it is likely that competitive sponsors would have allowed NYISO and the NYPSC to select a more efficient or cost-effective solution to address the reliability need or a project that would address the reliability need and enable offshore wind. The City of New York said it well when it commented that "addressing local and bulk transmission system needs via the same projects will be critical to enabling federal, state, and local governments to achieve their respective climate policy objectives at reasonable costs."[574]

10. Northern Grid

Northern Grid is a single transmission planning association comprised of FERC-jurisdictional and non-jurisdictional entities across the Pacific Northwest and Intermountain West.[575] Northern Grid's 2022-2023 Regional Transmission Plan explains that the regional

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[572] Multiple Intervenors, Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act Case 20-E-0197, Comments at 2, 3 (Sept. 21, 2022).
[573] NYPSC Apr 2023 Order at 2.
[574] Comments of the City of New York, filed in Docket No. RM21-17-000 on October 12, 2021. The City of New York also supports a "more holistic" approach to regional planning that integrates NYISO's separate regional planning processes for reliability, economic, and public policy needs. *Id*. at 9-11.
[575] *See* https://www.northerngrid.net/northerngrid/purpose/; *see also* https://www.northerngrid.net/private-media/documents/NothernGrid_AICM_2024.pdf (last accessed Dec. 18, 2024).

planning process is "a 'bottom up' approach that begins with a compilation of the Members' loads, generation resources, local area plans, and regional transmission projects."[576] Northern Grid explains that projects identified in the local area planning process "are assumed to be in service for the regional planning effort."[577]

The NorthernGrid Order No. 1000 planning region is an expansive area covering the upper Pacific Northwest and Intermountain West area of the United States and launched January 1 2020 with the combined Columbia Grid and Northern Tier Transmission Group ("NTTG") planning region utilities.[578] In 2021 NV Energy transitioned into NorthernGrid from WestConnect.[579] Unlike many areas, the projected cost of the substantial majority of the locally planned projects within the NorthernGrid region are not reflects in the local plan.

Like the other non-RTO regions, NorthernGrid, including its predecessors Columbia Grid and NTTG have not approved a single "regional" project despite numerous 345 kV, 500 kV, and 525 kV projects spanning hundreds of miles.

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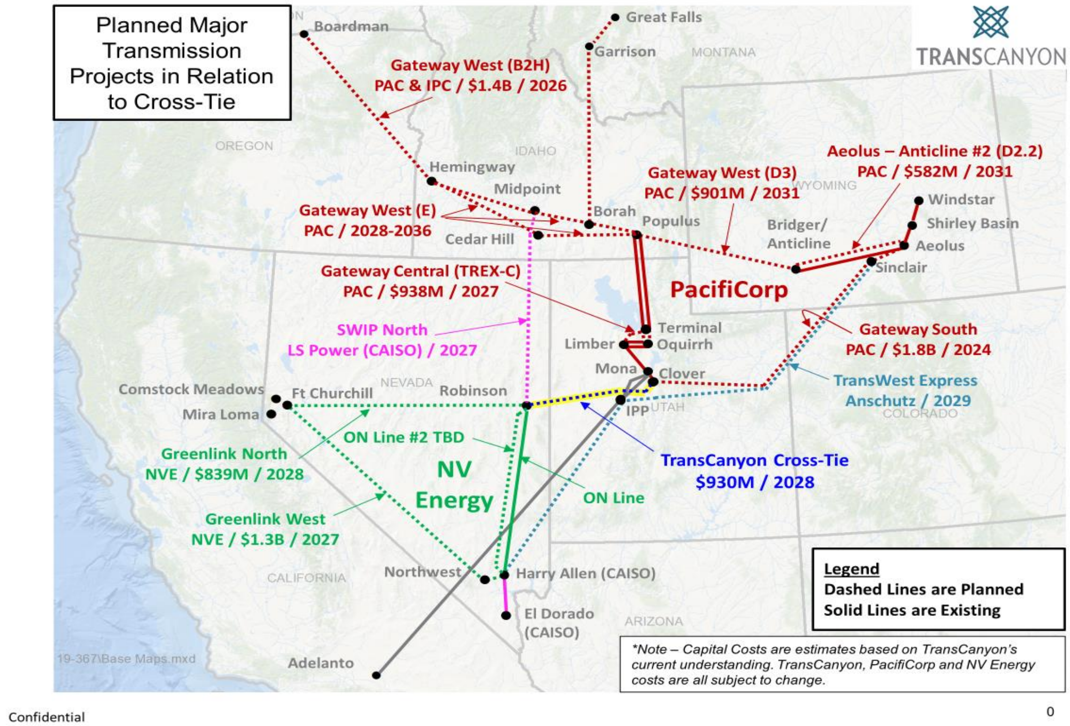
[576] *See* "Regional Transmission Plan for the 2022-2023 NorthernGrid Planning Cycle," at p. 11 (approved Dec. 14, 2023), *available at* https://www.northerngrid.net/private-media/documents/2022-23_Regional_Transmission_Plan.pdf (last accessed Dec. 18, 2024) (hereinafter "2023-2023 Northern Grid Regional Plan").

[577] 2023-2023 Northern Grid Regional Plan at p. 11.

[578] https://www.northerngrid.net/northerngrid/purpose/ (last accessed Dec. 18, 2024).

[579] On October 22, 2021, in Docket No. ER21-2768-000, by Letter Order the Commission approved the move of NV Energy Companies, Nevada Power and Sierra Pacific Power Company from the WestConnect Order No. 1000 planning region to the NorthernGrid. As such, NV Energy Local Planning is reflected in this Complaint both in the WestConnect and NorthernGrid sections.



Based on voltage, NorthernGrid includes some of these locally planned projects in its "regional plan" while noting that "A cost allocation analysis was not required because no Qualified Developers' projects were selected into the Regional Transmission Plan."[580] NorthernGrid asserts that the projects reflect the "most efficient and cost-effective combination for the NorthernGrid region **given the analysis performed** as described in this report."[581]

A list of just some of the locally planned projects is reflected below.

Sponsor	**Project Name and Description**	**Local Plan Year**	**Proposed In-Service or Requirement Date**	**Individual Project Cost**
Puget Sound	Bellingham 115 kV Substation Rebuild	2017[582]	2019	Not Provided

[580] https://www.northerngrid.net/private-media/documents/2022-23_Regional_Transmission_Plan.pdf at 20 (last accessed Dec. 18, 2024).
[581] *Id.*
[582] http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2017_Final.pdf at 1 (last accessed Dec. 18, 2024).

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
Puget Sound	Sedro Woolley – Bellingham #4 115 kV Rebuild and Reconductor	2017[583]	2021[584]	Not Provided
Puget Sound	Lake Hills – Phantom Lake New 115 kV Line	2017[585]	2018[586]	Not Provided
Puget Sound	Sammamish – Juanita New 115 kV Line	2017[587]	2018+[588]	Not Provided
Puget Sound	Eastside 230 kV Transformer Addition and Sammamish – Lakeside – Talbot 115 kV Rebuilds	2017[589]	2018+[590]	Not Provided
Puget Sound	Electron Heights – Enumclaw 55-115 kV Conversion	2017[591]	2019[592]	Not Provided

583 *Id*.

584 Changed to 2024 in the 2020 Puget Sound Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2020_Final.pdf at 2; changed to 2025 in the 2021 Puget Sound Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2021_Final.pdf at 2 (last accessed Dec. 18, 2024).

585 *Id*. at 2.

586 Changed to 2019 in the 2018 Puget Sound Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2018_Final.pdf; changed to 2020 in the 2019 Puget Sound Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2019_Final.pdf (last accessed Dec. 18, 2024).

587 *Id*.

588 Changed to 2020 in 2018 Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2018_Final.pdf; changed to 2021 in the 2019 Puget Sound Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2019_Final.pdf; changed to 2023 in the 2020 Puget Sound Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2020_Final.pdf at 2 (last accessed Dec. 18, 2024).

589 *Id*.

590 Changed to 2020 in 2018 Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2018_Final.pdf; changed to 2022 in the 2019 Puget Sound Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2019_Final.pdf, changed to 2023 in the 2021 Puget Sound Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2021_Final.pdf at 2; changed to 2024 in the 2022 Puget Sound Plan, although the "Need Date" was reflected as "Existing", http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2022_Final_-_Updated.pdf at 7 (last accessed Dec. 18, 2024).

591 *Id*. at 3.

592 Changed to 2020 in 2018 Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2018_Final.pdf; changed to 2022 in the 2019 Puget Sound Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2019_Final.pdf; changed to 2024 in the 2020 Puget Sound Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2020_Final.pdf at 2; changed to 2025 in the 2022 Puget Sound Plan, although the "Need Date" was reflected as "Existing", http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2022_Final_-_Updated.pdf at 8 (last accessed Dec. 18, 2024).

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
Puget Sound	Brisco Park Substation and O'Brien – Brisco New 115 kV Transmission Line and Substation	2017[593]	2019+	Not Provided
Puget Sound	Spurgeon Creek Transmission Substation Development (Phase 2)	2017[594]	2020[595]	Not Provided
Puget Sound	White River – Electron Heights 115 kV Line Re-route to Alderton (Phase 2)	2017[596]	2018	Not Provided
Puget Sound	Woodland – St. Clair 115 kV (Phase 2)	2017[597]	2022+	Not Provided
Puget Sound	West Kitsap Transmission Project	2017[598]	2021+[599]	Not Provided
Puget Sound	Lynden Substation Rebuild and Install Circuit Breaker	2018[600]	2022-23[601]	Not Provided
Puget Sound	Kent / Tukwila New Substation	2018[602]	2023	Not Provided
Puget Sound	Black Diamond Area New Substation	2018[603]	2023	Not Provided
Puget Sound	Issaquah Area New Substation	2018[604]	2023	Not Provided
Puget Sound	Bellevue Area New Substation	2018[605]	2023	Not Provided

593 *Id.*
594 *Id.*
595 Changed to 2024 in 2018 Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2018_Final.pdf (last accessed Dec. 18, 2024).
596 *Id.*
597 *Id.* at 4.
598 *Id.*
599 Changed to 2023 in 2018 Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2018_Final.pdf.
600 http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2018_Final.pdf (last accessed Dec. 18, 2024).
601 Changed to 2024 in the 2020 Puget Sound Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2020_Final.pdf at 2; changed to 2025 in the 2023 Puget Sound Plan, although the "Need Date" remained 2021, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2023_Final.pdf at 4 (last accessed Dec. 18, 2024).
602 *Id.* at 3.
603 *Id.*
604 *Id.* at 4.
605 *Id.*

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
Puget Sound	Electron Heights - Yelm 115 kV Rebuild Transmission Project	2018[606]	2024[607]	Not Provided
Puget Sound	Bainbridge Island New 115 kV Transmission Project	2018[608]	2021+[609]	Not Provided
Puget Sound	Kent / Tukwila Area[610]	2019[611]	2029[612]	Not Provided
Puget Sound	Inglewood – Juanita[613]	2019[614]	2029[615]	Not Provided

606 *Id*.
607 Changed to 2029 in the 2019 Puget Sound Plan http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2019_Final.pdf at 5 (last accessed Dec. 18, 2024).
608 *Id*. at 5.
609 Changed to 2024 in the 2019 Puget Sound Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2019_Final.pdf; changed to 2026 in the 2021 Puget Sound Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2021_Final.pdf at 4; changed in the 2022 Puget Sound Plan to 2027despite adding an "existing" under the newly added "Need Date", http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2022_Final_-_Updated.pdf at 16(last accessed Dec. 18, 2024).
610 The "project" is generically described as "[a] project is in the planning phase and will be developed to provide needed capacity and improve the reliability of transmission service to support existing and expected load growth in this commercial/industrial area. The interim operating plan to mitigate identified issues is to shed load." http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2019_Final.pdf at 4; the identical description was used in the 2020 Puget Sound Plan http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2020_Final.pdf at 5 (last accessed Dec. 18, 2024).
611
612 In the 2021 Puget Sound Plan, Puget Sound changed the in-service date as 2031 and moved the project to a section titled "Identified Needs", http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2021_Final.pdf at 6; changed to 2032 in the 2022 Puget Sound Plan, although the "Need Date" reflected "Existing", http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2022_Final_-_Updated.pdf at 10; changed to 2033 in the 2023 Puget Sound Plan although the "Need Date" remained "Existing", http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2023_Final.pdf at 10 (last accessed Dec. 18, 2024).
613 The "project" is generically described as "[a] project is in the planning phase and will be developed to increase capacity of existing Sammamish – Moorlands #1 115 kV line between Inglewood to Juanita substation. The interim operating plan to mitigate identified issues is to shed load." http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2019_Final.pdf at 4; the identical description was used in the 2020 Puget Sound Plan http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2020_Final.pdf at 5 (last accessed Dec. 18, 2024).
614 http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2019_Final.pdf at 4.
615 In the Puget Sound 2021 Plan, Puget Sound changed the in-service date as 2031 and moved the project to a section titled "Identified Needs", http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2021_Final.pdf at 5 (last accessed Dec. 18, 2024).

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
Puget Sound	South Thurston County[616]	2019[617]	2029[618]	Not Provided
Puget Sound	Electron Heights – Yelm Transmission project	2019[619]	2029[620]	Not Provided
Puget Sound	West Kitsap[621]	2019[622]	2029[623]	Not Provided
Puget Sound	Yelm Area Project[624]	2021	2031[625]	Not Provided
Puget Sound	Whidbey Island Transmission Improvements	2022[626]	2030	Not Provided

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616 The "project" is generically described as "[a] project is in the planning phase and will be developed to improve the reliability of transmission service to the cities of Lacey, Olympia and Tumwater. The interim operating plan to mitigate identified issues is to open the bus section breaker between the south and middle buses at PSE's Olympia Substation under certain system conditions. For issues that arise from high path flows, it is anticipated that BPA will curtail Puget Sound area schedules." *Id*. at 5; the identical description was used in the 2020 Puget Sound Plan http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2020_Final.pdf at 6 (last accessed Dec. 18, 2024).
617 *Id*. at 5.
618 In the Puget Sound 2021 Plan, Puget Sound changed the in-service date as 2031 and moved the project to a section titled "Identified Needs", http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2021_Final.pdf at 7 changed to 2032 in the 2022 Puget Sound Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2022_Final_-_Updated.pdf at 14; changed to 2033 in the 2023 Puget Sound Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2023_Final.pdf at 15 (last accessed Dec. 18, 2024).
619 *Id*.
620 In the Puget Sound 2021 Plan, Puget Sound changed the in-service date as 2031 and moved the project to a section titled "Identified Needs", http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2021_Final.pdf at 7; changed to 2032 in the 2022 Puget Sound Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2022_Final_-_Updated.pdf at 14 (last accessed Dec. 18, 2024).
621 The "project" is generically described as "[a] project is in the planning phase and will be developed to provide additional capacity to serve the projected load growth in Kitsap County and improve transmission reliability for customers in central and north Kitsap County. The project is planned to be staged in phases over time and may involve addition of a new 230-115 kV bulk transformer. The interim operating plan to mitigate identified issues is shift load to the South King County transmission system or to shed load in North Kitsap or Bainbridge Island." *Id*.; ; the identical description was used in the 2020 Puget Sound Plan http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2020_Final.pdf at 6 (last accessed Dec. 18, 2024).
622 *Id*.
623 In the Puget Sound 2021 Plan, Puget Sound changed the in-service date as 2031 and moved the project to a section titled "Identified Needs", http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2021_Final.pdf at 8 (last accessed Dec. 18, 2024).
624 The "project" is described as "[a] need has been identified to improve transmission reliability and capacity to support PSE's growing customer base in the city of Yelm and surrounding areas. This project will propose to add a 3rd 115 kV transmission line into the Yelm area for increased reliability." http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2021_Final.pdf at 7 (last accessed Dec. 18, 2024).
625 Changed to 2032 in the 2022 Puget Sound Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2022_Final_-_Updated.pdf at 14-15; changed to 2033 in the 2023 Puget Sound Plan, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2023_Final.pdf at 15 (last accessed Dec. 18, 2024).
626 With the Puget Sound 2022 Plan Puget Sound changed the format to more fully identify the transmission elements in the respective Puget Sound internal planning regions.

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
Puget Sound	Juanita – Moorlands Transmission Capacity	2022[627]	2031[628]	Not Provided
Puget Sound	Alderton – White River Transmission Project	2023[629]	2028	Not Provided
Puget Sound	White River – Krain Corner 55 kV to 115 kV conversion Transmission Project	2023[630]	2033[631]	Not Provided
Puget Sound	White River – Cascade Reach 230 kV Line	2023[632]	2033[633]	Not Provided
Puget Sound	Cross-Cascades Transmission Capacity	2023[634]	2033[635]	Not Provided
Avista	Benton – Othello SS 115 kV Transmission Line Rebuild	2017[636]	2018[637]	$7.1 Million[638]
Avista	Saddle Mountain Integration Phase 1	2017[639]	2020	$16 Million[640]
Avista	Addy – Devil's Gap 115 kV Transmission Line	2017[641]	2019	$3.025 Million[642]

[627] http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2022_Final_-_Updated.pdf at 8 (last accessed Dec. 18, 2024).
[628] Although the Plan lists a 2031 estimated date of operation, the Plan identifies a "Need Date" of 2027; changed to 2033 in the 2023 Puget Sound Plan with the Need Date moved up to 2025, http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2023_Final.pdf at 9 (last accessed Dec. 18, 2024).
[629] http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2023_Final.pdf at 16 (last accessed Dec. 18, 2024).
[630] http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2023_Final.pdf at 16 (last accessed Dec. 18, 2024).
[631] The "Need Date" is reflected as 2025, *Id*.
[632] http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2023_Final.pdf at 22-23 (last accessed Dec. 18, 2024).
[633] The "Need Date" is reflected as "Existing", *Id*.
[634] *Id*. at 23.
[635] The "Need Date" is reflected as "Existing", *Id*.
[636] http://www.oasis.oati.com/woa/docs/AVAT/AVATdocs/2017_Avista_System_Planning_Assessment_-_Final.pdf at 20 (last accessed Dec. 18, 2024).
[637] Avista does not identify an in-service date but lists its "completion date based on company budget", *Id*.
[638] *Id*. at 5.
[639] http://www.oasis.oati.com/woa/docs/AVAT/AVATdocs/2017_Avista_System_Planning_Assessment_-_Final.pdf at 20 (last accessed Dec. 18, 2024).
[640] http://www.oasis.oati.com/woa/docs/AVAT/AVATdocs/2017_Avista_System_Planning_Assessment_-_Final.pdf at 5; at p 56 -57 an estimated cost for Phase 1 of $35 Million is reflected, and repeated in 2018 Avista Plan at 62, http://www.oasis.oati.com/woa/docs/AVAT/AVATdocs/2018_Avista_System_Planning_Assessment_-_Final.pdf (last accessed Dec. 18, 2024).
[641] *Id*. at 20.
[642] *Id*.

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
Avista	Saddle Mountain Integration Phase 2	2017[643]	2022	$10.5 Million[644]
Avista	Chelan - Stratford 115 kV Transmission Line Rebuild	2017[645]	2026	$19.4 Million[646]
Avista	Sandpoint Reinforcement Project	2018[647]	2027	$20 Million[648]
Avista	Cabinet – Noxon 230 kV Transmission Line Rebuild	2018[649]	2020	$15 Million[650]
Avista	New Noxon – Pinecreek No. 2 230 kV Line	2018[651]	2022	Not Provided[652]
Avista	Noxon – Pinecreek 230 kV Line Rebuild	2018[653]	2022	Not Provided[654]
Avista	Hatwai – Lolo #2 230 kV Transmission Line	2018[655]	2026	$8 Million[656]
Avista	Ninth and Central 230 kV Substation Addition	2018[657]	2023	Not Provided
Avista	Indian Trail – Waikiki 115 kV Line	2018[658]	2025	$8.5 Million[659]

[643] *Id*. at 20-21.
[644] *Id*. at 5; in the 2018 Avista Plan at 62-63 the Phase 2 projects are reflected at $40 million, http://www.oasis.oati.com/woa/docs/AVAT/AVATdocs/2018_Avista_System_Planning_Assessment_-_Final.pdf (last accessed Dec. 18, 2024).
[645] http://www.oasis.oati.com/woa/docs/AVAT/AVATdocs/2017_Avista_System_Planning_Assessment_-_Final.pdf at 20 (last accessed Dec. 18, 2024).
[646] *Id*. at 63.
[647] http://www.oasis.oati.com/woa/docs/AVAT/AVATdocs/2018_Avista_System_Planning_Assessment_-_Final.pdf at 6 (last accessed Dec. 18, 2024).
[648] *Id*. at 10.
[649] *Id*. at 6.
[650] *Id*. at 121.
[651] *Id*. at 6.
[652] *Id*. at 122.
[653] *Id*. at 6.
[654] *Id*. at 123.
[655] *Id*. at 6.
[656] *Id*. at 155.
[657] *Id*. at 7.
[658] *Id*.
[659] *Id*. at 278.

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
Avista[660]	Big Bend System Reinforcement[661]	2019	2020-2022[662]	Not Provided
Avista	Cabinet Gorge GSU Isolation[663]	2019	2021	Not Provided
Avista	Coeur d'Alene System Reinforcement[664]	2019	2019-2024[665]	Not Provided
Avista	East Coeur d'Alene Lake System Reinforcement[666]	2019	2023[667]	Not Provided
Avista	Lewiston/Clarkston System Reinforcement[668]	2019	2021-2025[669]	Not Provided
Avista	Metro Station Rebuild[670]	2019	2020-2023	Not Provided
Avista	North Spokane System Reinforcement[671]	2019	2021-2024	Not Provided

660 Beginning in the 2019-20 Avista's Planning Assessment provided substantially less information, only general information about "Single System Projects . . . necessary to meet performance requirements categorized as Corrective Action Plans . . .." http://www.oasis.oati.com/woa/docs/AVAT/AVATdocs/2019_Avista_System_Assessment_-_V1-1.pdf. at 10. Avista notes that "All Single System Projects are subject to change or modification as necessary to accommodate changes in load, generation, or other unforeseen system conditions." *Id*. Avista also notes that "The cost estimate and schedule of each project is subject to change." *Id*. Finally, it is difficult to determine which of the projects that Avista includes in its Local Transmission Planning that it considers distribution related versus Commission jurisdictional transmission, but Complainants have not reflected every project in the 2019 Avista Local Plan.

661 The Big Bend System Reinforcement represents 7 separate projects, 5 of which list the "issue mitigated" as "Age and Condition, 1 references the issue mitigated as "Sand Dune 115 kV bus outage" and 1 which lists the issue mitigated as "to be determined." *Id*. at 10.

662 Only 3 of the proposed projects reflect a Date of Operation. *Id*. In the 2022 Updated Avista Plan, two of those projects were changed from Date of Operation of 2021 and 2022 to Nov. 2023 and December 2025 respectively. http://www.oasis.oati.com/woa/docs/AVAT/AVATdocs/2022_Avista_System_Plan_-_V0_(final).pdf at 5 (last accessed Dec. 18, 2024).

663 *Id*.

664 The Coeur d'Alene System Reinforcement references 7 separate projects, 5 of which list "Distribution Capacity" as the issue mitigated, 1 "Contingency," and 1 "Contingency and capacity." *Id*.

665 Only the projects addressing "Contingency" and "Contingency and capacity" reflect Date of operation, with 2024 and 2019 listed respectively. *Id*.

666 East Coeur d'Alene Lake System Reinforcement included 5 projects, (*Id*. at 11) one of which is to "Construct new Carlin Bay Station with a 13 mile radial 115kV transmission line to a rebuilt O'Gara Station" and another the Benewah-Pine Creek 230kV. *Id*. at 11, 16-17.

667 3 of 5 projects reflected a Date of Operation of 2023. *Id*. at 11.

668 The Lewiston/Clarkston System Reinforcement references 9 separate projects, including the Hatwai-Lolo #2 230kV Line identified first in the 2018 Avista Plan (although with a 2024 operation date rather that 2026 as reflected in 2018), as well as the Lolo-Oxbow 230kV Line and two new stations. *Id*. at 11, 18-19.

669 *Id*. at 11.

670 *Id*.

671 The North Spokane System Reinforcement reflects 13 separate projects. *Id*.

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
Avista	Silver Valley System Reinforcement[672]	2019	2022	Not Provided
Avista	South Spokane System Reinforcement[673]	2019	2019-2025	Not Provided
Avista	Spokane Valley Transmission Reinforcement[674]	2019	2021	Not Provided
Avista	West Plains System Reinforcement[675]	2021-22	2022-2024[676]	Not Provided
Portland General	Horizon Phase II 230 kV Project	2014[677]	2018[678]	Not Provided
Portland General	Blue Lake/Gresham 230kV Project	2014[679]	2018[680]	Not Provided
Portland General	Blue Lake/Gresham 115 kV Project	2015[681]	None Given	Not Provided
Portland General	Carver-McLoughlin Phase II Project[682]	2015	None Given	Not Provided

[672] The Silver Valley System Reinforcement reflects 3 projects, including the previously identified Noxon-Pine Creek 230kV identified in 2018. *Id*.
[673] The South Spokane System Reinforcement reflects 9 separate projects. *Id*.
[674] The Spokane Valley Transmission Reinforcement reflects 6 separate projects. *Id*. at 12-13.
[675] The West Plains System Reinforcement reflects 3 separate projects having a status of "budgeted." http://www.oasis.oati.com/woa/docs/AVAT/AVATdocs/2021-2022_Avista_System_Assessment_-_Rev_A.pdf at 10-11.
[676] Garden Springs Project changed from 2023 to 2027 in 2022 Avista Plan, http://www.oasis.oati.com/woa/docs/AVAT/AVATdocs/2022_Avista_System_Plan_-_V0_(final).pdf at 9 (last accessed Dec. 18, 2024).
[677] https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Final_Near_Term_LTP_2014.pdf at 13-14 (last accessed Dec. 18, 2024). The 2014 Plan is referred to as the Short Term Plan.
[678] Moved to 2017 in the 2016 Portland General Short Term Plan, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Near_Term_LTP_2016_FINAL.pdf at 15 but to 2019 in the 2018 Portland General near Term Plan, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_DRAFT_Near_Term_LTP_2018.pdf at 15 (last accessed Dec. 18, 2024).
[679] https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Final_Near_Term_LTP_2014.pdf at 15-16. The project was included among Portland General's longer term planning as early as 2008, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/LTP_Projects,_2008.pdf at 9-10 (last accessed Dec. 18, 2024).
[680] Moved to 2017 in the 2016 Portland General Near Term Plan, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Near_Term_LTP_2016_FINAL.pdf at 14, but back to 2018 in the 2018 Portland General Near Term Plan, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_DRAFT_Near_Term_LTP_2018.pdf (last accessed Dec. 18, 2024).
[681] https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Long_Term_LTP_2015_FINAL.pdf at 15. The 2015 plan is referred to as the Long Term Plan (last accessed Dec. 18, 2024).
[682] *Id*. at 16.

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
Portland General	Harborton Reliability Project[683]	2015	2021[684]	Not Provided
Portland General	Pearl-Sherwood 230kV Project[685]	2015	None Given[686]	Not Provided
Portland General	Marquam Substation	2016[687]	2018	Not Provided
Portland General	Lower Columbia Resiliency Project New 230 kV Transmission Line[688]	2017	None Given	Not Provided
Portland General	North Hillsboro Capacity Project[689]	2017	None Given	Not Provided
Portland General	Orenco-Sunset 115 kV Reconductor Project[690]	2017	None Given	Not Provided
Portland General	Northern Substation 115 kV Conversion Project[691]	2017	None Given[692]	Not Provided

683 *Id*. at 17.
684 Moved to 2020 in the 2016 Portland General Near Term Plan, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Near_Term_LTP_2016_FINAL.pdf at 16. In the 2020 Portland General Near Term Plan Project expanded to include Phase 2 with an in-service date of 2025, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Near_Term_LTP_2020_Final.pdf at 14, which was changed to Q3 2026 in the 2022 Portland General Near Term Plan, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/Final_Near_Term_LTP_2022_12-28-22.pdf at 16, and listed as November 2026 in the 2023 Plan, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/2023_Local_Transmission_Plan.pdf at (unnumbered) p 19 (last accessed Dec. 18, 2024).
685 Id. at 19. This project appeared as early as the 2008 Portland General Plan, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/LTP_Projects,_2008.pdf (last accessed Dec. 18, 2024).
686 Estimated for requirement 4/ 2027 in the 2021 Portland General Longer Term Plan, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Longer_Term_LTP_2021_FINAL.pdf at 18, changed to Q 2 2026 in the 2022 Plan, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/Final_Near_Term_LTP_2022_12-28-22.pdf at 24, and May 2025 in the 2023 Plan, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/2023_Local_Transmission_Plan.pdf at (unnumbered) 20 (last accessed Dec. 18, 2024).
687 Revealed in the 2016 Portland General Near Term Plan as "under construction", https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Near_Term_LTP_2016_FINAL.pdf at 17 (last accessed Dec. 18, 2024).
688 https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Long_Term_LTP_2017_FINAL.pdf at 14 (last accessed Dec. 18, 2024).
689 The project involves the construction of a new 230 kV substation, looping several lines into the new substation, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Long_Term_LTP_2017_FINAL.pdf at 15 (last accessed Dec. 18, 2024).
690 *Id*. at 16.
691 *Id*. at 17.
692 A projected completion of Q2 2022 reflected in 2020 Portland General Near Term Plan, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Near_Term_LTP_2020_Final.pdf at 19 (last accessed Dec. 18, 2024).

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
Portland General	Dayton-Grand Ronde Conversion Project[693]	2019	12/2027	Not Provided
Portland General	Southeast Portland Conversion Project[694]	2019	2025[695]	Not Provided
Portland General	Horizon-Keeler BPA #2 230kV Project[696]	2019	None Given[697]	Not Provided
Portland General	Horizon VWR3 115 kV Project[698]	2020	Q2 2021	Not Provided
Portland General	Helvetia Substation Project[699]	2020	Q2 2021	Not Provided
Portland General	Kelley Point Reconfiguration Project[700]	2020	Q3 2021	Not Provided
Portland General	Butler Substation Project[701]	2020	Q4 2020 and Q2 2022	Not Provided
Portland General	Murrayhill-St Marys 230 kV Reconductor[702]	2020	Q2 2022	Not Provided
Portland General	Tonquin Substation Project[703]	2020	Q4 2023 and Q4 2024[704]	Not Provided

693 https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Longer_Term_LTP_2019_FINAL.pdf at 15 (last accessed Dec. 18, 2024).
694 *Id*. at 16. Project contains both near term and longer term components. In 2022 the Holgate Substation (Q2 2026) was included in the 2022 Plan, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/Final_Near_Term_LTP_2022_12-28-22.pdf at 31 (last accessed Dec. 18, 2024).
695 Changed to 2029 in the 2021 Portland General Longer Term Plan, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Longer_Term_LTP_2021_FINAL.pdf at 16.
696 https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Longer_Term_LTP_2019_FINAL.pdf at 19 (last accessed Dec. 18, 2024).
697 Q2 2025 indicated in the 2020 Portland General Near Term Plan, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Near_Term_LTP_2020_Final.pdf at 27, and changed to Q2 2024 in the 2022 Plan, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/Final_Near_Term_LTP_2022_12-28-22.pdf at 17 (last accessed Dec. 18, 2024).
698 https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Near_Term_LTP_2020_Final.pdf at 15, listed as under construction (last accessed Dec. 18, 2024).
699 *Id*. at 16.
700 *Id*. at 17.
701 *Id*. at 20.
702 *Id*. at 21.
703 *Id*. at 26.
704 Changed to April 2025 in the 2023 Plan, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/2023_Local_Transmission_Plan.pdf at (unnumbered) 20 (last accessed Dec. 18, 2024).

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
Portland General	Arrowhead Substation Project[705]	2020	Q2 2025	Not Provided
Portland General	Hillsboro Reliability Project[706]	2021	2020-2027[707]	Not Provided
Portland General	Willamette Valley Resiliency Project[708]	2021	6/2027[709]	Not Provided
Portland General	Murrayhill-Sherwood #1 & #2 230 kV Reconductor Project[710]	2021	6/2027[711]	Not Provided
Portland General	Beaverton-Tektronix and Murrayhill-Reedville 115kV Reconductor Project[712]	2021	11/2027	Not Provided
Portland General	Horizon-Keeler BPA #1 230 kV Reconductor Project[713]	2021	6/2028[714]	Not Provided

[705] https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Near_Term_LTP_2020_Final.pdf at 28 (last accessed Dec. 18, 2024).

[706] The Project consists of 8 identified "Near Term" projects and 1 "longer Term" https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Longer_Term_LTP_2021_FINAL.pdf at 19-20 (last accessed Dec. 18, 2024)..

[707] Although it is unclear that Portland General had identified 7 of the 8 near term component projects, the new 115 kV substation and transmission lines are reported as "under construction" and two additional project components are reported as "in design and permitting," https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Longer_Term_LTP_2021_FINAL.pdf at 20 (last accessed Dec. 18, 2024).

[708] The Willamette Valley Resiliency Project has 11 component parts, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Longer_Term_LTP_2021_FINAL.pdf at 21. Project was expanded in the 2022 Plan to add Monitor 115 kV and 230 kV substation project (Q4 2025), St. Louis 115 kV project (Q4 2025), North Marion 115 kV project (Q4 2027), and Woodburn 115 kV project (Q4 2027), https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/Final_Near_Term_LTP_2022_12-28-22.pdf at 27-30 (last accessed Dec. 18, 2024).

[709] All 4 parts listed as May 2029 in the 2023 Plan, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/2023_Local_Transmission_Plan.pdf at (unnumbered) 20.

[710] https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Longer_Term_LTP_2021_FINAL.pdf at 22 (last accessed Dec. 18, 2024).

[711] In the 2022 Plan changed to "Targeting 2026," https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Longer_Term_LTP_2021_FINAL.pdf at 35 (last accessed Dec. 18, 2024).

[712] https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Longer_Term_LTP_2021_FINAL.pdf at 23 (last accessed Dec. 18, 2024).

[713] https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Longer_Term_LTP_2021_FINAL.pdf at 24. Appears to be a companion to the Horizon-Keeler BPA #2 230 kV addition reflected in the 2019 Plan (last accessed Dec. 18, 2024).

[714] Changed to Q2 2026 in the 2022 Plan, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/Final_Near_Term_LTP_2022_12-28-22.pdf at 34, and changed to December 2026 in the 2023 Plan,

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
Portland General	Dayton Reliability Project[715]	2021	11/2028	Not Provided
Portland General	Evergreen-Harborton 230 kV Reconductor Project[716]	2021	6/2029	Not Provided
Portland General	Evergreen-Sherwood New 230 kV Line Project[717]	2021	None Given	Not Provided
Portland General	Reedville Substation Rebuild[718]	2022	Q3 2024	Not Provided
Portland General	Memorial Substation Project[719]	2022	Q4 2024	Not Provided
Portland General	Kaster Substation Project[720]	2022	None Given	Not Provided
Portland General	Groveland Substation Project[721]	2022	Q2 2025[722]	Not Provided
Portland General	Glencullen Rebuild & Cedar Hills Breakers[723]	2022	Q4 2026	Not Provided
Portland General	Mt Pleasant Substation Project[724]	2022	Q4 2027	Not Provided
Portland General	Murrayhill-St. Marys #2[725]	2022	Targeting 2027	Not Provided
Portland General	North of Sherwood[726]	2023	May 2026	Not Provided
Portland General	Scholls Ferry Substation Project[727]	2023	Nov. 2025	Not Provided
Portland General	Linneman 115 kV Project[728]	2023	June 2026	Not Provided

https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/2023_Local_Transmission_Plan.pdf at (unnumbered) 20 (last accessed Dec. 18, 2024).
[715] https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Longer_Term_LTP_2021_FINAL.pdf at 25 (last accessed Dec. 18, 2024).
[716] *Id*. at 26.
[717] *Id*. at 28.
[718] https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/Final_Near_Term_LTP_2022_12-28-22.pdf at 18 (last accessed Dec. 18, 2024).
[719] *Id*. at 19.
[720] *Id*. at 21.
[721] *Id*. at 25.
[722] Date is only for Phase 1. No date given for Phase 2. *Id*.
[723] *Id*. at 26.
[724] *Id*. at 33.
[725] *Id*. at 36.
[726] https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/2023_Local_Transmission_Plan.pdf at (unnumbered) 32 (last accessed Dec. 18, 2024).
[727] *Id*. at (unnumbered) 36.
[728] *Id*. at (unnumbered) 29.

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
Idaho Power	New Lowell Junction 138 kV Line[729]	2014-15[730]	5 Year[731]	Not Provided
Idaho Power	Boardman to Hemingway 500 kV Line[732]	2014-15	10 Year[733]	$1.4 Billion[734]
Idaho Power	Hemingway-Bowmont 230 kV Lines[735]	2014-15	10 Year[736]	Not Provided
Idaho Power	Hubbard-Bowmont 230 kV Line[737]	2014-15	10 Year[738]	Not Provided
Idaho Power	Kuna-Bowmont Build 138 kV line[739]	2014-15	10 Year	Not Provided

729 Idaho Power lists regions rather than specific project names. The "Project Title" is not a project name, but a shorthand description. See, e.g., https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_Final_2015_Local_Transmission_Plan.pdf at Appendix B-1 (last accessed Dec. 18, 2024).

730 In total Idaho Power listed 36 distinct projects in the 2014-15 Local Plan. Appendix B.

731 Idaho Power lists projects in time horizons: 1-5 year horizon; 5-10 year horizon; 10-20 year horizon. Notwithstanding the range in the time horizons, the Time Frames listed for specific projects are either 5 year, 10 year, or 20 year. *Id*. at Appendix B-1 – B-3. Project changed to 10 Year in the 2016-17 Idaho Power Plan, https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_2017_Final_Local_Transmission_Plan.pdf at Appendix B-2 (last accessed Dec. 18, 2024).

732 https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_Final_2015_Local_Transmission_Plan.pdf at Appendix B-2. Boardman to Hemingway is a 290 mile 500 kV addition that Idaho Power first identified in 2006. https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/current-projects/boardman-to-hemingway/purpose-and-need/ Despite the expectation that construction is imminent, the cost impact to consumers of Boardman to Hemingway is difficult to ascertain from information available from Idaho Power's planning documents, with Idaho Power telling consumers that "It's too soon to tell how B2H would affect energy rates. Typically, the money utilities spend to build and operate transmission lines are included in future rates after the new lines go into service. Regulators review these investments to ensure they benefit customers." *Id*. News sources report "the project is estimated to cost between $1.1 billion and $1.3 billion, according to Idaho Power." https://www.newsdata.com/clearing_up/courts_and_commissions/b2h-line-secures-regulatory-approval-from-oregon-puc/article_9be82fca-1cd9-11ee-b541-0f00c4f84371.html (last accessed Dec. 18, 2024).

733 Moved to 5 Year in the 2022-23 Idaho Power draft plan, https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_2023_Draft_Local_Transmission_Plan.pdf at Appendix B-1 (last accessed Dec. 18, 2024).

734 https://www.northerngrid.net/resources/ Western Transmission Projects download.

735 https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_Final_2015_Local_Transmission_Plan.pdf at Appendix B-2. Project includes both a new 230 kV and to uprate an existing 138 kV to 230 kV. (last accessed Dec. 18, 2024).

736 Moved to 5 Year horizon https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_2023_Draft_Local_Transmission_Plan.pdf at Appendix B-1 (last accessed Dec. 18, 2024).

737 https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_Final_2015_Local_Transmission_Plan.pdf at Appendix B-2 (last accessed Dec. 18, 2024).

738 https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_2023_Draft_Local_Transmission_Plan.pdf at Appendix B-1 (last accessed Dec. 18, 2024).

739 https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_Final_2015_Local_Transmission_Plan.pdf at Appendix B-2 (last accessed Dec. 18, 2024).

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
Idaho Power	Willis-Star Build 138 kV line[740]	2014-15	10 Year[741]	Not Provided
Idaho Power	Gateway West 500 kV Line[742]	2014-15	10 Year[743]	Not Provided
Idaho Power	Dry Creek 230/138kV Substation[744]	2014-15	10 Year	Not Provided
Idaho Power	Beacon Light Substation[745]	2014-15	20 Year[746]	Not Provided
Idaho Power	Star-Beacon Light – Build New 138 kV Line[747]	2014-15	20 Year[748]	Not Provided
Idaho Power	Build 138 kV line from Zilog Substation to Blackcat Station Substation[749]	2014-15	20 Year	Not Provided
Idaho Power	Build 138 kV Line from Happy Valley to New Amity Substation[750]	2014-15	20 Year	Not Provided
Idaho Power	Twin Falls-Filer-Buhl Build New 138 kV Line[751]	2014-15	20 Year	Not Provided

740 *Id*.
741 Moved to 5 Year horizon in the 2016-17 Idaho Power Plan, https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_2017_Final_Local_Transmission_Plan.pdf at Appendix B-1 (last accessed Dec. 18, 2024).
742 Project includes 6 distinct parts. https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_Final_2015_Local_Transmission_Plan.pdf at Appendix B-1. Although the Gateway projects remain in the Idaho Power local plan, Idaho Power now identifies PacifiCorp as the majority developer. https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/current-projects/gateway-west/ (last accessed Dec. 18, 2024).
743 As of the 2022-23 Idaho Power plan the Gateway Projects remained on the 10 year list although portions of the project owned by PacifiCorp are under construction. https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/current-projects/gateway-west/ (last accessed Dec. 18, 2024).
744 https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_Final_2015_Local_Transmission_Plan.pdf at Appendix B-1 (last accessed Dec. 18, 2024).
745 *Id*. at Appendix B-3.
746 Moved to 5 Year Horizon in the 2016-17 Idaho Power Plan, https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_2017_Final_Local_Transmission_Plan.pdf at Appendix B-1 (last accessed Dec. 18, 2024).
747 https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_Final_2015_Local_Transmission_Plan.pdf at Appendix B-3 (last accessed Dec. 18, 2024).
748 Moved to 5 Year Horizon in the 2016-17 Idaho Power Plan, https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_2017_Final_Local_Transmission_Plan.pdf at Appendix B-1 (last accessed Dec. 18, 2024).
749 https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_Final_2015_Local_Transmission_Plan.pdf at Appendix B-3 (last accessed Dec. 18, 2024).
750 *Id*.
751 *Id*. The 2014-15 Plan includes multiple conversions of facilities from 46 kV to 138 kV.

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
Idaho Power	Kramer and Pingree New 138 kV Line[752]	2014-15	20 Year	Not Provided
Idaho Power	New Canada - Blackcat 138kV line[753]	2016-17	20 Year[754]	Not Provided
Idaho Power	Gateway West 500kV Line – Midpoint to Hemingway #2[755]	2016-17	10 Year	Not Provided
Idaho Power	Langley to Garnet 230kV line[756]	2016-17	20 Year	Not Provided
Idaho Power	Garnet 230/138kV station[757]	2016-17	20 Year	Not Provided
Idaho Power	Hubbard-Cloverdale 230kV line[758]	2018-19	5 Year	Not Provided
Idaho Power	Star-Beacon Light – Build 138 kV line[759]	2018-19	5 Year	Not Provided
Idaho Power	Wood River to Ketchum 138kV line[760]	2018-19	5 Year	Not Provided
Idaho Power	Midpoint to Shoshone 138kV[761]	2018-19	5 Year	Not Provided
Idaho Power	Haven to Goshen 161 kV Line and 161/138 kV transformer[762]	2018-19	5 Year	Not Provided
Idaho Power	Shoshone Station 138 kV conversion[763]	2018-19	10 Year	Not Provided

[752] *Id*.
[753] https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_2017_Final_Local_Transmission_Plan.pdf at Appendix B-2 (last accessed Dec. 18, 2024).
[754] Moved to 5 Year horizon in 2018-19 Idaho Power Plan, https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_Final_2019_Local_Transmission_Plan.pdf at Appendix B-1 (last accessed Dec. 18, 2024).
[755] https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_2017_Final_Local_Transmission_Plan.pdf at Appendix B-2.
[756] *Id*. at Appendix B-3.
[757] *Id*.
[758] https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_Final_2019_Local_Transmission_Plan.pdf at Appendix B-1 (last accessed Dec. 18, 2024).
[759] *Id*.
[760] *Id*.
[761] *Id*.
[762] *Id*.
[763] *Id*.

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
Idaho Power	Multiple 138 kV Line Uprates or Rebuilds[764]	2018-19	20 Year	Not Provided
Idaho Power	Ontario to Cairo 69 kV to 138 kV Conversion[765]	2020-21	5 Year	Not Provided
Idaho Power	Blackfoot to American Potato 138 kV Conversion[766]	2020-21	5 Year	Not Provided
Idaho Power	Pingree to Kramer 138 kV line[767]	2020-21	5 Year	Not Provided
Idaho Power	Bannock Creek 138 kV conversion[768]	2020-21	5 Year	Not Provided
Idaho Power	Langley Gulch to Fruitland New 138 kV Line[769]	2020-21	10 Year	Not Provided
Idaho Power	Aiken 138 kV Conversion[770]	2020-21	10 Year	Not Provided
Idaho Power	New Karcher to Northside 138 kV line[771]	2020-21	20 Year	Not Provided
Idaho Power	King – Upper Salmon 138 kV Rebuild[772]	2020-21	20 Year	Not Provided
Idaho Power	Heyburn – Unity 138 kV Upgrade[773]	2020-21	20 Year	Not Provided
Idaho Power	Multiple 5 Year Rebuilds or Uprates[774]	2022-23[775]	5 Year	Not Provided

[764] *Id*. at Appendix B-3, adding Burley Rural substation 69 kV to 138kV conversion, Heyburn Junction to Heyburn 138 kV rebuild, Midpoint to Jerome 138kV rebuild, Twin Falls Jct. to Pole Line 138kV rebuild, Tyhe Substation 138 kV conversion, and 138kV Garnet Tap Line.
[765] https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_2021_Final_Local_Transmission_Plan.pdf at Appendix B-1 (last accessed Dec. 18, 2024).
[766] *Id*.
[767] *Id*.
[768] *Id*.
[769] *Id*. at Appendix B-2.
[770] *Id*.
[771] *Id*. at Appendix B-3
[772] *Id*.
[773] *Id*.
[774] https://www.oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_2023_Draft_Local_Transmission_Plan.pdf at B-1, listing DRAM – Rattlesnake 230kV line rebuild, Rattlesnake – Mountain Air Wind Tap 230kV line rebuild, Huntington Wind – Quartz 138kV line rebuild, Boise Bench – Emmett 138kV line rebuild, Boise Bench – DRAM 230kV line rebuild, Lucky Peak – Mountain Home Junction #1 138kV line rebuild, Convert Cairo – Ontario line from 69kV to 138kV, and Convert Orchard substation from 69kV to 138kV. (last accessed Dec. 18, 2024).
[775] The 2022-23 plan on Idaho Power's OASIS is shown as "Draft".

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
Idaho Power	Nampa to new Northside substation 138 kV Line[776]	2022-23	5 Year	Not Provided
Idaho Power	Wood River – Ketchum 138kV line[777]	2022-23	5 Year	Not Provided
Idaho Power	Pingree to Kramer 138kV line[778]	2022-23	5 Year	Not Provided
Idaho Power	Multiple 10 Year Rebuilds or Uprates[779]	2022-23	10 Year	Not Provided
Idaho Power	Multiple 20 Year Rebuilds or Uprates[780]	2022-23	20 Year	Not Provided
PacifiCorp	Energy Gateway[781]	2014-15	None Given	Not Provided
PacifiCorp	St. George Substation Install 345 kV[782]	2014-15	May 2021[783]	Not Provided
PacifiCorp	Southwest Wyoming - Silver Creek New 138 kV Line[784]	2014-15	Various[785]	Not Provided
PacifiCorp	Pinto 345 kV Transformer[786]	2014-15	December 2015	Not Provided
PacifiCorp	Cameron – Milford 138 kV Line[787]	2014-15	December 2015	Not Provided

[776] *Id*. at Appendix B-1. Project includes multiple parts.
[777] *Id*.
[778] *Id*.
[779] *Id* at Appendix B-2, including: DRAM – Lucky Peak 138 kV line rebuild, Black Mesa – Mountain Home Junction #1 138 kV line rebuild, GEMM substation 69 kV to 138 kV conversion, Weiser substation 69 kV to 138 kV conversion, Midpoint – Justice – Mountain Air Wind Tap 230kV line rebuild, and Aiken 46 kV to 138 kV conversion/build.
[780] *Id*. at B-3, including: Kimberly – Rimview 138 kV line rebuild, Midpoint – Jerome 138 kV line rebuild, Twin Falls Jct – Poleline Tap 138 kV line rebuild, and Burley Rural substation 69 kV to 138kV conversion.
[781] https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2014-2015_Report.pdf at 27 (last accessed Dec. 18, 2024).
[782] *Id*. at 27.
[783] Changed to May 2026 in the 2018-19 PacifiCorp Local Plan, https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2018-2019_Report.pdf at 36 (last accessed Dec. 18, 2024).
[784] https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2014-2015_Report.pdf at 28. Five separate projects: Segment 1: Devils Slide to Moss Junction transmission line, Railroad substation and Silver Creek Substation; Segment 2: Moss Junction- Railroad; Segment 3: Croydon Substation; Segment 4: Coalville substation- December 31, 2018; Devil's Slide-Silver Creek (last accessed Dec. 18, 2024).
[785] Segments 1-3 were listed as "Complete" while Segments 4 and 5 were listed with in-service dates of December 31, 2018. *Id*. at 28
[786] *Id*. at 29-30.
[787] *Id*. at 30.

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
PacifiCorp	Goshen – Jefferson 161 kV Reconductor[788]	2014-15	May 2018	Not Provided
PacifiCorp	Union Gap 230 kV Substation Rebuild[789]	2014-15	2016-17.	Not Provided
PacifiCorp	Vantage – Pomona 230 kV Line[790]	2014-15	Jan. 2018[791]	Not Provided
PacifiCorp	Snow Goose 500 kV – 230 kV Substation[792]	2014-15	Nov. 2017[793]	Not Provided
PacifiCorp	Troutman 230 kV Substation[794]	2014-15	April 2017	Not Provided
PacifiCorp	St. Johns – Knott 115 kV Line Conversion Project[795]	2014-15	Dec. 2018	Not Provided
PacifiCorp	Sams Valley 500 kV – 230 kV Substation[796]	2014-15	Nov. 2019[797]	Not Provided

788 *Id*. at 31.
789 *Id*. at 32.
790 *Id*. at 32.
791 Changed to May 2019 in the 2016-17 PacifiCorp Local Plan, https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2016-2017_Report.pdf at 45; changed to May 2020 in the 2018-19 PacifiCorp Local Plan, https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2018-2019_Report.pdf at 43 (last accessed Dec. 18, 2024).
792 https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2014-2015_Report.pdf at 33 (last accessed Dec. 18, 2024).
793 Changed to December 2017 in the 2016-17 PacifiCorp Local Plan, https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2016-2017_Report.pdf at 45 (last accessed Dec. 18, 2024).
794 https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2014-2015_Report.pdf at 34 (last accessed Dec. 18, 2024).
795 *Id*. at 35.
796 *Id*. at 36. Project includes new Substation as well as new and reconductored 230 kV transmission lines.
797 Changed to November 2020 in the 2016-17 PacifiCorp Local Plan, https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2016-2017_Report.pdf at 44; changed to May 2023 in the 2018-19 PacifiCorp Local Plan, https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2018-2019_Report.pdf at 42-43; changed to May 2024 in the 2020-21 PacifiCorp Local Plan, https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2020-2021_Report.pdf at 40; changed to Dec. 2028 in the 2022-23 PacifiCorp Local Plan, https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp__Local_Transmission_System_Plan_2022-2023_Report_Dec_31.pdf at 42 (last accessed Dec. 18, 2024).

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
PacifiCorp	Wallula – McNary 230 kV Line[798]	2014-15	Nov. 2017[799]	Not Provided
PacifiCorp	Ben Lomond – Syracuse – Parrish 138 kV Three Terminal Line[800]	2016-17	Complete	Not Provided
PacifiCorp	Bull River – Carter Substation 138 kV Conversion[801]	2016-17	May 2019[802]	Not Provided
PacifiCorp	Camp Williams – Oquirrh 345 kV # 3 and 4[803]	2016-17	May 2022	Not Provided
PacifiCorp	Goshen – Sugarmill – Rigby 161 kV Line[804]	2016-17	Oct. 2020[805]	Not Provided
PacifiCorp	Goshen – Westwood – Rigby 161 kV reconductor[806]	2016-17	May 2019	Not Provided

798 https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2014-2015_Report.pdf at 37 (last accessed Dec. 18, 2024)..

799 Changed to November 2018 in the 2016-17 PacifiCorp Local Plan, https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2016-2017_Report.pdf at 46(last accessed Dec. 18, 2024).

800 https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2016-2017_Report.pdf at 28 (last accessed Dec. 18, 2024).

801 *Id.*

802 Changed to November 2018 in the 2018-19 PacifiCorp Local Plan, https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2018-2019_Report.pdf at 30 (last accessed Dec. 18, 2024)..

803 https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2016-2017_Report.pdf at 29. PacifiCorp notes that the Project is “part of three dependent projects: Project #1 (Gateway): Build new double circuit between Oquirrh - Terminal 345 kV #3 and #4 lines. In-service date is May 15, 2021 (changed to May 2022 in the 2018-19 PacifiCorp plan; changed to May 2026 in the 2020-21 Plan; changed to May 2024 in the 2022-23 Plan); Project #2: Rebuild the double circuit between Camp Williams – Oquirrh 345 kV #1 and #2 lines with high temperature conductor. In-service date is May 15, 2022 (changed to May 2025 in the 2018-19 Plan); Project #3: Loop 90th South – Terminal 345 kV into MidValley 345 kV. In-service date May 15, 2023 (changed to May 2026 in the 2018-19 Plan; changed to May 2024 in the 2020-21 Plan; changed to January 2025 in the 2022-23 Plan). The costs for these projects was not provided (last accessed Dec. 18, 2024).

804 *Id.* at 32-33.

805 Changed to November 2022 in the 2018-19 PacifiCorp Local Plan, https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2018-2019_Report.pdf at 32; changed to January 2022 in the 2020-21 PacifiCorp Local Plan, https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2020-2021_Report.pdf at 31 (last accessed Dec. 18, 2024).

806 https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2016-2017_Report.pdf at 33 (last accessed Dec. 18, 2024).

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
PacifiCorp	Red Butte/Central – St. George 4th 138 kV Circuit[807]	2016-17	May 2018[808]	Not Provided
PacifiCorp	Terminal – Grow Parrish 138 kV Line Rebuild[809]	2016-17	Nov. 2021	Not Provided
PacifiCorp	Railroad – Silver Creek 138 kV Line[810]	2016-17	Complete	Not Provided
PacifiCorp	Bridgerland Substation Expansion[811]	2016-17	May 2024	Not Provided
PacifiCorp	Lone Pine – Whetstone 230 kV Line[812]	2016-17	May 2020[813]	Not Provided
PacifiCorp	Camp Williams – Oquirrh 345 kV Rebuild[814]	2018-19	May 2025	Not Provided
PacifiCorp	Harvest 138 kV Substation[815]	2018-19	May 2025[816]	Not Provided
PacifiCorp	Path C System Improvements[817]	2018-19	May 2024[818]	Not Provided

[807] *Id*. at 37-38. The Project is dependent on energizing an "already constructed by not energized Red Butte – St. George 345 kV Circuit (20.088 miles) and energize at 138 kV in Washington County, Utah." The project has multiple components.
[808] *Id*. Status is referenced as "In Progress."
[809] *Id*. at 39.
[810] *Id*. at 40. Constructed 70 miles of 138 kV transmission and substation.
[811] *Id*. at 41.
[812] *Id*. at 43.
[813] Changed to May 2024 in the 2018-19 PacifiCorp Local Plan, https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2018-2019_Report.pdf at 41; changed to November 2024 in the 2020-21 PacifiCorp Local Plan, https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2020-2021_Report.pdf at 39; changed to July 2025 in the 2022-23 PacifiCorp Local Plan, https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp__Local_Transmission_System_Plan_2022-2023_Report_Dec_31.pdf at 40 (last accessed Dec. 18, 2024).
[814] https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2018-2019_Report.pdf at 30-31(last accessed Dec. 18, 2024).
[815] *Id*. at 37-38.
[816] Changed to May 2027 in the 2020-21 PacifiCorp Local Plan, https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2020-2021_Report.pdf at 35 (last accessed Dec. 18, 2024).
[817] https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2018-2019_Report.pdf at 38 (last accessed Dec. 18, 2024).
[818] Changed to November 2023 in the 2020-21 PacifiCorp Local Plan, https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2020-2021_Report.pdf at 36 (last accessed Dec. 18, 2024).

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
PacifiCorp	Outlook – Punkin Center 115 kV Line No. 2[819]	2018-19	April 2021	Not Provided
PacifiCorp	Klamath Falls – Snow Goose #2 230 kV Line[820]	2020-21	Nov. 2022[821]	Not Provided
PacifiCorp	Sigurd – Clover 69 mile 345 kV Line[822]	2022-23	Nov. 2028	Not Provided
PacifiCorp	Spanish Fork – Mercer 50 mile 345 kV Line[823]	2022-23	Nov. 2027	Not Provided
PacifiCorp	Three Peaks – Purgatory Flats 60 mile 345 kV Line[824]	2022-23	July 2019	Not Provided
PacifiCorp	Burns 500 kV Reactor Station Replacement[825]	2022-23	Oct. 2026	Not Provided
PacifiCorp	Corral – Snow Goose 167 mile 500 kV Line[826]	2022-23	Oct. 2030	Not Provided
PacifiCorp	Grasslands Annex – B2H Tap Substation 16 mile 500 kV Line and Substation[827]	2022-23	Oct. 2026	Not Provided
NV Energy	Greenlink - 585 miles of 500 kV Lines and 235 miles of345 kV Lines[828]	2023	2026-2028[829]	$2.9 Billion[830]

[819] https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2018-2019_Report.pdf at 44 (last accessed Dec. 18, 2024).
[820] https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2020-2021_Report.pdf at 39 (last accessed Dec. 18, 2024).
[821] Changed to July 2023 in the 2022-23 PacifiCorp Local Plan, https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp__Local_Transmission_System_Plan_2022-2023_Report_Dec_31.pdf at 40 (last accessed Dec. 18, 2024).
[822] https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp__Local_Transmission_System_Plan_2022-2023_Report_Dec_31.pdf at 36-37 (last accessed Dec. 18, 2024).
[823] *Id*. at 37.
[824] *Id*.
[825] *Id*. at 38.
[826] *Id*. at 39.
[827] *Id*.
[828] http://www.oasis.oati.com/woa/docs/NEVP/NEVPdocs/TPL-001-5_2023_corrective_action_plan_-_Intermediate_Transmission_Plan.pdf at A123. While the referenced Transmission Plan reflects 357 miles of 500 kV transmission and 162 miles of 345 kV transmission, NV Energy's website for the Projects reflects a total of 585 miles of 500 kV and 235 miles of 345 kV, https://www.nvenergy.com/cleanenergy/greenlink (last accessed Dec. 18, 2024).
[829] https://www.nvenergy.com/cleanenergy/greenlink. News reports suggest that the Projects are substantially behind schedule. https://www.ktnv.com/news/nv-energy-greenlink-nevada-project-is-about-11-months-behind (last accessed Dec. 18, 2024).
[830] https://www.reviewjournal.com/business/energy/consumers-to-foot-bill-for-nv-energys-over-budget-2-9b-transmission-project-3007850/ (last accessed Dec. 18, 2024).

Sponsor	Project Name and Description	Local Plan Year	Proposed In-Service or Requirement Date	Individual Project Cost
NV Energy	TRIC Master Plan[831]	2023	2025-2028	Not Provided
NV Energy	Various "NERC Required" Projects[832]	2023	Various	Not Provided

NV Energy's planned transmission lines across Nevada for a $2.9 billion project is expected to be at least $443 million over budget.[833]

B. The Commission Has Recognized The Transmission Owners Are Thwarting Regional Planning Through Self-Planned Transmission

The Commission has recognized that individual transmission owner planning through authorized local planning tariffs is thwarting the Commission requirement to ensure just and reasonable transmission rates. In its Notice of Proposed Rulemaking[834], the Commission declared:

> a) NOPR at P 24: "It has now been more than a decade since Order No. 1000—the Commission's last significant regional transmission planning and cost allocation rule—and there is mounting evidence that the Commission's regional transmission planning and cost allocation requirements may be inadequate to ensure Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential."
>
> b) NOPR at P 25 "the regional transmission planning and cost allocation processes that public utility transmission providers adopted to comply with Order No. 1000 may not be identifying the more efficient or cost-effective transmission facilities. We are concerned that the absence of sufficiently long-term,

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[831] The Project includes 4 new 345 kV transmission lines and 4 new 120 kV transmission lines, as well as multiple additional components, http://www.oasis.oati.com/woa/docs/NEVP/NEVPdocs/TPL-001-5_2023_corrective_action_plan_-_Intermediate_Transmission_Plan.pdf at A22-A26(last accessed Dec. 18, 2024).
[832] NV Energy's Plan included 64 pages of "NERC Required projects (inclusive of TRIC Master Plan) that ranged from uprates, new lines, generation must run, and generation limitations. *Id*. at A15-A79.
[833] *See* "Consumers to foot bill for NV Energy's over-budget $2.9B transmission project," Las-Vegas Review-Journal (Feb. 27, 2024), *available at* https://www.reviewjournal.com/business/energy/consumers-to-foot-bill-for-nv-energys-over-budget-2-9b-transmission-project-3007850/ (last accessed Dec. 18, 2024).
[834] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Notice of Proposed Rulemaking, issued April 21, 2022 in Docket No. RM21-17-000.

comprehensive transmission planning processes appears to be resulting in piecemeal transmission expansion to address relatively near-term transmission needs. We are concerned that continuing with the status quo approach may cause public utility transmission providers to undertake relatively inefficient investments in transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates."

c) NOPR at P 32: "the Commission has long recognized, 'vertically-integrated utilities do not have an incentive to expand the grid to accommodate new entries or to facilitate the dispatch of more efficient competitors.'"[835]

d) NOPR at P 34: "consumers may not be seeing the benefits such as enhanced reliability, improved resource adequacy, access to lower cost and diverse resources, and other benefits that result from regional transmission planning and cost allocation processes that identify, select, and allocate the costs of the more efficient or cost-effective transmission solutions to transmission needs driven by changes in the resource mix and demand."

e) NOPR at P 36: "the status quo appears to be resulting in a disproportionate share of transmission facilities to meet transmission needs driven by changes in the resource mix and demand being developed outside regional transmission planning and cost allocation processes, resulting in less efficient and cost-effective transmission development."

f) NOPR at P 40: "The vast majority of investment in transmission facilities since the issuance of Order No. 1000 has been in local transmission facilities."

g) NOPR at P 43: "…consumers may ultimately bear the costs of inefficient piecemeal transmission expansion."

h) NOPR at P 47: "we preliminarily find that the Commission's regional transmission planning and cost allocation requirements fail to require public utility transmission providers to: (1) perform a sufficiently long-term assessment of transmission needs; (2) adequately account on a forward-looking basis for known determinants of transmission needs driven by changes in the resource mix and demand; and (3) consider the broader set of benefits and beneficiaries of regional transmission facilities planned to meet those transmission needs."

In Order No. 1920 the Commission confirmed the concerns it raised in the NOPR:

[835] Order No. 890, 118 FERC ¶ 61,119 at P 57.

> [i]n light of these changing demands on the transmission system, the record also affirms *what the Commission has long recognized*: regional transmission planning that identifies more efficient or cost-effective transmission solutions to needs helps to ensure cost-effective transmission development for customers and *can yield better returns for every dollar spent than localized or piecemeal transmission solutions*. Conversely, *inadequate or poorly designed transmission planning processes can lead to relatively inefficient or less cost-effective transmission investment, with customers footing the bill for piecemeal, inefficient, and less cost-effective transmission solutions designed to meet short-term or small-scale transmission needs*.[836]

The Commission also found:

> the record demonstrates that a substantial amount of new transmission investment is occurring outside of regional transmission planning processes. Because these other processes—specifically, generator interconnection processes and local transmission planning processes—are generally designed to address discrete, shorter-term needs, and do not comprehensively assess either broader transmission needs or solutions to those needs, overreliance on those processes can result in relatively inefficient or less cost-effective transmission development for customers, which contributes to rates for transmission that are unjust and unreasonable.[837]

The Commission went on to find that "local transmission planning, with its focus on the needs of individual utility footprints, does not necessarily provide sufficient, comprehensive analysis of broader regional transmission needs."

In their Concurrence to Order No. 1920, Chair Phillips and Commissioner Clements argued that

> "under the status quo, with its de facto emphasis on the piecemeal, just-in-time development of the grid to meet near-term reliability and economic needs, customers are being forced to fund investments that could have been more beneficial, less costly, or both had they been better planned from the start. That result

[836] *Id*. at P 100 (emphasis added)
[837] *Id*. at 103; *see also*, *Id*. at P 110 ("local transmission planning, with its focus on the needs of individual utility footprints, does not necessarily provide sufficient, comprehensive analysis of broader regional transmission needs.")

> undermines our economy and leaves customers less safe and secure, with enormous costs for both our grid and our country."[838]

The Commission concluded that: "[t]his dynamic results in, among other things, transmission ***customers paying more than is necessary or appropriate*** to meet their transmission needs, customers forgoing benefits that outweigh their costs, or some combination thereof, which results in less efficient or cost-effective transmission investments and, in turn, renders Commission-jurisdictional regional transmission planning and cost allocation processes unjust and unreasonable."[839] Notwithstanding these declarations, in Order No. 1920 the Commission focused on regional planning while failing to rein in or restrict local planning tariffs in any regard, and in fact erroneously suggests that existing transmission owners have some inherent right to rebuild yesterday's grid.[840]

VI. SECTION 206

A. Local Planning Tariff Provisions Are Unjust, Unreasonable Or Unduly Discriminatory (Section 206, Step 1)

The "transmission grid is the backbone of the American economy and essential to the national security of our country."[841] Notwithstanding nearly two decades of Commission 1) pronouncements that regional planning is an essential component of the Commission's ability to determine just and reasonable transmission rates and 2) findings that individual transmission owner planning is inefficient and leads to consumers paying more for transmission than they should, Local Planning continues to overwhelm and circumvent regional planning, producing

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[838] *Id*. at Joint Order No. 1920 Concurrence at P 4.
[839] *Id*. at P 112 (emphasis added).
[840] The Commission in Order No. 1920 at P 1706 stated that "the transmission provider *holds the leverage* as to whether to build a [regional] transmission facility or a less efficient in-kind replacement transmission facility . . .."; *see also* NOPR at P 408 and Order No. 1920-A at P 876. This Complaint presents the Commission with a means to remove the leverage of the transmission provider in order to protect consumers and ensure the most efficient, cost-effective grid of tomorrow.
[841] Joint Order No. 1920 Concurrence at P 1.

transmission rates that are unjust, unreasonable, and unduly discriminatory. Because Order No. 1920 found that "the Commission in the NOPR did not propose other changes to local transmission planning processes" and that requests for the Commission to address Local Planning "are beyond the scope of this final rule,"[842] Complainants file this Complaint to urge the Commission to confront Local Planning issues now.

As the Commission knows, "opportunities for undue discrimination continue to exist in areas where the *pro forma* OATT leaves transmission providers with substantial discretion."[843] The individual Commission-jurisdictional public utility transmission owners and RTOs/ISOs listed as respondents to this Complaint have tariff provisions, allowing the individual transmission owner to plan transmission facilities at 100 kV or above that it alone declares necessary, on criteria it alone sets, notwithstanding the regional impact of the planned transmission.[844] As described above, those tariff provisions are unjust and unreasonable to the extent that the provisions apply to transmission at 100 kV and above which the Commission has recognized is regionally impactful. As a result of those tariff provisions allowing individual transmission owner planning, the Commission itself asserts that "the transmission provider holds the leverage as to whether to build a [regional] transmission facility or a less efficient in-kind replacement transmission facility . . .."[845] Consumers bear the cost of this "leverage," which has been exercised to prop up shareholder interests at the expense of electric consumers like the Complainants.

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[842] *Id*. at P 247.
[843] Order No. 890 at P 26. *See also Municipal Energy Agency of Nebraska, et al., v. Public Service Company of Colorado*, 189 FERC ¶ 61,099 (2024) at P 87 (accepting that WestConnect found no regional public policy needs despite considering region impacting public policy laws because "the Tariff provides public utility transmission providers in the WestConnect transmission planning region with discretion in identifying regional transmission needs driven by public policy requirements, as well as solutions to address those needs."
[844] *See* Attachment C.
[845] Order No. 1920 at P 1706 (emphasis added).

The evidence presented throughout this Complaint to support step 1 under Section 206 includes prior Commission declarations and findings in Order No. 1920 that excess local planning results in transmission rates that are unjust and unreasonable. This Complaint establishes that individual transmission owner Local Planning of transmission 100 kV and above results in unjust and unreasonable transmission rates, or the Commission's inability to determine a just and reasonable rate because there is no review to determine the appropriate project to address all needs of the region, including the individual transmission owner's claimed needs. An after-the-fact review of an implemented project provides no ability to determine whether there was a more efficient or cost-effective project from the outset. The Commission is thus obligated by Section 206 to act.

In multiple RTO OATTs, locally planned projects are rolled up into the regional plan with limited regional planner review. This is routinely true in non-RTO regions. Further, even when limited review is available, disparate planning timelines allow individual transmission owners to circumvent a regional review of holistic alternatives because the locally planned project is permitted to advance on timelines inconsistent with more rigid regional planning timelines. As such, the transmission owner/regional OATTs identified in Attachment B are unjust and unreasonable to the extent that they permit individual transmission owners to plan FERC-jurisdictional transmission facilities at 100 kV and above.

The issues with Local Planning extend to planning for existing transmission facilities that have reached the end of operational life. To date the Commission has excluded so-called "replacement" projects from its transmission planning requirements, even the minimal requirements of Order No. 890.[846] But as early as Order No. 888 the Commission exercised its

[846] For a discussion of those proceedings, which have mainly occurred in PJM and CAISO, *see* Complaint at 251-262.

jurisdiction "to remedy undue discrimination in *access* to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce."[847] Allowing the near automatic rebuilding of "a network of transmission infrastructure that was overwhelmingly built in the last century and in the face of a very different reality"[848] without even the barest of transmission planning protection means that consumers continue to suffer from "undue discrimination in access" to transmission as the grid of yesterday is not configured for the needs of today or tomorrow, nor is it planned based on the fully interconnected nature of today's transmission grid. Indeed, in Order No. 2003, the Commission recognized as much when it applied Order No. 888's open access requirements to the generator interconnection process in recognition of the fact that interconnection is a "critical component of open access transmission service."[849]

1. Transmission Planning Provisions are Practices Affecting Rates

First, it is beyond dispute that tariff provisions addressing transmission planning, whether so-called "local" planning or regional planning are practices affecting rates and are within the Commission's jurisdiction under Section 206.[850] The Commission made that initial finding in Order No. 888 when it established a *pro forma* OATT.[851] Over the objection of the State of New York and others the United States Supreme Court upheld the Commission's exercise of complete jurisdiction over transmission sufficient to require open access of transmission facilities.[852] In upholding Order No. 888, Justices Thomas, Scalia and Kennedy, *concurring* in part, *dissenting* in part found that not only did the Commission have the authority to require open access for

[847] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,634 (emphasis added).
[848] Joint Order No. 1920 Concurrence at P 34.
[849] Order No. 2003, *Standardization of Generator Interconnection Agreements and Procedures*, 104 FERC ¶ 61,103 at PP. 8-9, 11-12 (Jul. 24, 2003).
[850] *See FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 264, 266, 277 (2016).
[851] Order No. 888, FERC Stats. & Regs. ¶ 31,036.
[852] *New York v. FERC*, 535 U.S. 1 (2001).

transmission, the Commission may not have gone far enough in exercising that jurisdiction because it left untouched established discrimination in retail transactions.[853]

This Complaint demonstrates that the undue discrimination continues through local transmission planning of regionally impactful transmission resulting in unjust and unreasonable rates because individual transmission owners are permitted by their tariffs to plan 100 kV and above transmission facilities. In *New York v. FERC*, the Supreme Court recognized FERC's fundamental obligation to address discriminatory practices "over interstate transmission of energy (whether for wholesale or retail sales.)"[854] While Order No. 888 addressed discriminatory practices in the provision of transmission service, that discrimination continues today as individual transmission owners use the existence of local planning tariffs to plan regionally impactful transmission in a manner that fails to address all regional needs, and which often limits their approach to simply rebuilding the grid of yesterday, "a network of transmission infrastructure that was overwhelmingly built in the last century and in the face of a very different reality."[855] In upholding issuance of Order No. 888, the Supreme Court recognized the significant changes in the use of the electricity grid since passage of the Federal Power Act, noting that "[t]he interconnected nature of transmission grids, and their use in interstate commerce, have increased dramatically since 1935, when Congress enacted the relevant provisions of the FPA."[856] Changes in the interconnected nature of the grid and its use have changed even more dramatically since issuance of Order No. 888 and local planning tariff prevent the Commission's ability to ensure that rates electricity consumers pay for transmission

[853] *Id*. 535 U.S. 1, 30-35, Thomas, Justice *concurring in part and dissenting in part*.
[854] 535 U.S. at 20.
[855] Joint Order No. 1920 Concurrence at P 34.
[856] *Id*. at 5.

are just and reasonable. "The electric transmission grid is the backbone of the American economy and essential to the national security of our country."[857] As Chair Phillips recognized,

> The mission of this agency is to ensure reliable, safe, secure, and economically efficient energy for consumers at a reasonable cost. Ensuring we have a robust, well-planned electric transmission grid is the single most important step that this Commission can take to fulfill that statutory mandate.[858]

Section 206 **requires** that the Commission provide consumers with a remedy for the unjust and unreasonable transmission practices affecting those rates, namely Local Planning tariffs that continue to allow individual transmission owners to self-plan transmission facilities at 100 kV and above.

More recent judicial precedent has confirmed that the Commission not only has the jurisdiction to mandate regional planning, the Commission must do so to ensure just and reasonable rates. Multiple Petitioners challenged the Commission's regional planning mandate in Order No. 1000. The D.C. Circuit turned to *New York v. FERC*[859] to reaffirm that "there is no textual warrant for the suggestion that the Commission lacks jurisdiction over retail transmission."[860] In this regard, the argument that local planning remains a necessity in order to address retail service obligations[861] does not override the Commission's obligation to ensure just and reasonable rates for all transmission. The Court further recognized the importance of the Commission taking control of transmission planning "because the orders' planning mandate is directed at ensuring the proper functioning of the interconnected grid spanning state lines, cf. *Duke Power Co. v. FPC*, 401 F.2d 930, 935 (D.C.Cir.1968) (explaining that the "major

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[857] Joint Order No. 1920 Concurrence at P 1.
[858] *Id.*
[859] 535 U.S. 1 (2002).
[860] *South Carolina Public Service Authority v. FERC*, 762 F.3d 41, 63 (2014).
[861] Order No. 1920, Christie, Commissioner, *dissenting*, ("Christie Dissent") at P 6.

emphasis" of the FPA "is upon federal regulation of those aspects of the industry which—for reasons either legal or practical—are beyond the pale of effective state supervision"), the mandate fits comfortably within Section 201(b)'s grant of jurisdiction over "the transmission of electric energy in interstate commerce."[862] In this regard, the Court found that federal authority under the FPA extends to the "transmission of electric energy in interstate commerce" and that FPA Section 206 is among those provisions that grant "authority in connection with such interstate transmission operations."[863] In *El Paso Electric Company v. FERC*,[864] the United States Court of Appeals for the 5th Circuit confirmed again that "FERC has retained the authority **to review transmission planning** and cost allocations **pursuant to FPA Section 206**, through which FERC may review challenges on its own motion or through complaints about rates and practices."[865]

Having been unsuccessful in court in challenging regional planning requirements, the individual transmission owners have been successful in practice by using their local planning tariffs to circumvent effective regional planning. Transmission planning tariff provisions have a direct impact on jurisdictional transmission rates in that once planned and placed into service the costs for the Self-Planned transmission additions go directly into transmission rates as the vast majority of existing transmission owners have Commission approved formula rates.[866] Formula rates shift the burden to transmission customers to establish that the transmission addition was imprudent, often years after the decision was made to move forward with a locally planned project and with no information available to them other than the one-sided information prepared

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[862] *Id*. (concluding that "Given that fit, *New York v. FERC* teaches that there is no reason to think that the "prefatory" statement of federalism "policy" in Section 201(a) poses an obstacle to the Commission's assertion of authority. See 535 U.S. at 17, 22, 122 S.Ct. 1012).

[863] *Id*. *citing United States v. Pub. Utils. Comm'n of Cal.*, 345 U.S. 295, 299 (1953).

[864] 832 F.3d 495, 510 (5th Cir. 2016).

[865] *Id*. at 510.

[866] Even without formula rates, a local planning tariff would remain unjust and unreasonable.

by the transmission owner when planning the project initially. Those locally planned projects also are allocated, by Commission requirement, solely within the zone of the planning transmission owner, regardless of beneficiaries.[867]

Prudence challenges are not a viable option for containing local project spending or challenging local project spending due to the heavy burden placed on consumers to demonstrate impudence.[868] The presumption of prudence provided to transmission owners is highly deferential[869] and must be overcome by concrete evidence presented by consumers, who are operating from an information deficit, before the transmission owner takes on the burden of affirmatively demonstrating prudence.

To the extent that existing tariffs allow individual transmission owners to plan for transmission facilities at 100 kV and above on an individual basis, those tariffs are practices affecting rates and are unjust and unreasonable.

2. A Complaint Regarding Local Planning Tariffs Is Appropriate

In other instances where a complaint has been asserted under Section 206 as to tariff provisions that have implications to more than one transmission owner, or implications in more than one planning region, certain parties have argued that the complaint is improper as the complaint under review "Inappropriately Seeks to Revise a Rule of General Applicability."[870]

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[867] *See, e.g.*, *Municipal Energy Agency of Nebraska, et al., v. Public Service Company of Colorado*, 189 FERC ¶ 61,099, at PP 40-44 (2024).

[868] "A prudent expenditure is one 'reasonable utility management [] would have made, in good faith, under the same circumstances, and at the relevant point in time.' A prudence determination is based upon what the company knew or should have known at the time a decision was made." *Potomac-Appalachian Transmission Highline, LLC*, Opinion No. 554, 158 FERC ¶ 61,050 at P 99 (2017) (quoting *New England Power Co.* 31 FERC , 61,047, 61,084 (1985)).

[869] "[M]anagers of a utility have broad discretion to conduct business affairs and to incur costs necessary to provide service to utility customers. The Commission held that the appropriate test to be used in a prudence review is whether the costs incurred are the costs which a reasonable utility management would have made, in good faith, under the same circumstances, and at the relevant point in time." *New England Power Co.,* 42 FERC ¶ 61,016 (1988), *citing Re New England Power Co.,* 31 FERC ¶ 61,047 (1985).

[870] *See*, *e.g.*, Motion to Dismiss And Answer of Midcontinent Independent System Operator, Inc. filed in Docket No. EL22-78-000 at 10.

The assertion is that under such circumstances the Commission must act through a rulemaking if it to act all.[871] Those parties asserting such an argument charge that "[u]nder the FERC rules, 'a person must file a petition when seeking . . . a rule of general applicability.'"[872] The assertion that challenges to rules of general applicability can only be achieved by filing a petition for a rulemaking under Commission rules is wrong as the Commission is a "'creature of statute,' having 'no constitutional or common law existence or authority, but only those authorities conferred upon it by Congress.'"[873] The Court went on to note that Section 206 "authorizes FERC to investigate, on its own motion or upon complaint, rates and terms of service" and to thus "initiate changes to *existing* utility rates and practices."[874] Prohibiting a complaint challenging a tariff provision of general applicability would be a direct violation of Section 206, which unequivocally provides that

> **Whenever the Commission**, after a hearing held upon its own motion or **upon complaint**, **shall find** that **any rate**, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, **or that any rule, regulation, practice, or contract affecting such rate**, charge, or classification **is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order**.

While it may be appropriate for the Commission to permit interested parties to file a petition for a rulemaking if the party chooses to do so, Section 206 provides for the filing of a Complaint regarding *any* rate or *any* rule, regulation, practice, or contract affecting such rate, whether that

[871] To be clear, Complainants do not oppose any Commission-initiated rulemaking to initiate further transmission planning reforms, as the Commission recognized by the Commission in Order No. 1920. *See* Order No. 1920-A at P 858. Instead, Complainants present this Complaint to the Commission to enable the Commission to more expeditiously address the Local Planning practices that continue to cause rates to become unjust and unreasonable.
[872] *Id*. at 12, *citing* 18 C.F.R. § 385.207(a)(4) (emphasis added).
[873] *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 8 (D.C. Cir. 2002).
[874] *Id*. at 21.

rate or rule is generally applicable or not. Section 206 does not restrict the filing of a complaint to one practice of one particular public utility.[875] The Complaint herein is appropriate, notwithstanding that it challenges the justness or reasonableness of multiple tariffs.

In this regard, the cases cited by MISO in Docket No. EL22-78-000 do not stand for the proposition that a petition for a rulemaking is the only mechanism to address unjust and unreasonable tariff provisions as the cited cases did not address that issue at all. MISO cited *MidAmerican Energy Holdings Co.*, 113 FERC ¶ 61,298, P 57 (2005), *reh'g denied*, 118 FERC ¶ 61,003 (2007) which did not involve a complaint proceeding, but instead involved a filing under Section 203 of the FPA. A party protesting the Section 203 filing raised an issue unrelated to the Section 203 filing itself, but instead challenging pre-filing meetings and whether they were "*ex parte*" under the Administrative Procedure Act ("Administrative Procedure Act"). The Commission appropriately noted that the Section 203 filing of a third-party was an improper place to challenge prior Commission findings on what constitutes an *ex parte* contact under the APA.[876] Likewise, in *Colstrip Energy Ltd. P'ship*, 119 FERC ¶61,133 (2007), cited by MISO, the issue was not a complaint case regarding a specific tariff provision or multiple similar tariff provisions, but instead a challenge to a third-party's filing on the basis that application of another Federal Agency's regulations was improper. The Commission rightfully rejected that collateral challenge. Here, the challenge to the tariff provisions is direct under Section 206. Under Section

[875] For example, in Docket No. EL00-95, San Diego Electric filed a complaint against all of the Sellers of Energy & Ancillary Services in CAISO and the California Power Exchange, seeking an amendment to the market-based rate schedules of all those sellers of E&AS services. *See San Diego Gas & Electric v. Sellers of Energy and Ancillary Services,* Docket No. EL00-95 (Complaint filed Aug. 2, 2000). In Docket No. EL18-26, EDF Renewable Energy, Inc. ("EDF") filed a complaint against MISO, SPP, and PJM to reform the affected system coordination in the generator interconnection process. *EDF Renewable Energy v. MISO, SPP, and* PJM, Docket No. EL18-26 (complaint filed Oct. 30, 2017). EDF sought a FERC order directing MISO, SPP, and PJM to file tariff revisions to reform their interconnection coordination procedures.
[876] *Id*.

206, the Commission "may rely on 'generic' or 'general' findings of a systemic problem to support imposition of an industry-wide solution."[877]

The Commission has made clear in the past that a complaint is proper under Section 206 whether there is another mechanism available to challenge a particular action or not. In this regard, the Commission has noted that parties have "**a statutory right** to file [a] complaint under section 206 of the FPA."[878] Regardless of the fact that the unjust and unreasonable tariff issue may be one of general applicability, that statutory right remains.

It is also important to note, as was recounted above, that consumers have made multiple efforts to address excessive local planning through various Commission proceeding, to no avail, making a complaint on the underlying cause of the excessive planning appropriate. Each of the prior efforts recounted above sought to address the problem of excess local planning, or the ramifications of that planning, under the issues raised in the individual cases but none took on directly the underlying unjust and unreasonable tariff provisions: tariffs allowing existing transmission owners on an individual basis to plan transmission facilities at 100 kV and above, which is regional in nature. The multiple efforts of consumers and others to challenge prior efforts by existing transmission owners to benefit from excess Self-Planned Transmission, rebuilding the grid of yesterday, or limiting regional transmission were all addressed by the Commission on the narrow grounds of the proceedings involved and the precedent of those cases

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[877] *Public Utilities Com'n of State of Cal. v. F.E.R.C.*, 462 F.2d 1027, 1025 (9th Cir. 2006) (*citing Interstate Natural Gas Ass'n of Am. v. FERC*, 285 F.3d 18, 37 (D.C. Cir. 2002)).

[878] *See, e.g.*, *Midcontinent Independent System Operator, Inc. Otter Tail Power Company v. Midcontinent Independent System Operator, Inc. Midcontinent Independent System Operator, Inc.* 151 FERC P 61220, P 58 (2015)(holding "While we encourage parties to follow the MISO stakeholder process when requesting changes to MISO's Tariff, parties have a statutory right to file complaints under section 206 of the FPA")(emphasis added), *vacated and remanded on other grounds Ameren Services Company v. FERC*, 880 F.3d 571, (D.C.Cir. 2018); *EDF Renewable Energy*, 163 FERC ¶ 61,003 (2018) at P 46; *see also Central Hudson Gas & Elec. Corp. v. FERC*, 783 F.3d 92, 116 (2nd Cir. 2015) (finding "Petitioners are free to file a complaint under Section 206 of the Federal Power Act, 16 U.S.C. § 824e, challenging NYISO's tariff as unjust and unreasonable.")

offers no insight into the claims in this case that individual transmission owner planning of *FERC-jurisdictional transmission* facilities at 100 kV and above is unjust and unreasonable in all circumstances. As such, the Complainants neither seek to relitigate those prior orders nor does this Complaint constitute a collateral attack on those orders or any of the Commissions various general transmission orders such as Order No. 1000 or Order No. 1920. In *Massachusetts Municipal Wholesale Electric Company v. Northeast Utilities Service Company*,[879] the Commission reiterated that

> Section 206 of the FPA clearly permits challenges to the justness and reasonableness of existing rates. Because various circumstances may change over time, rates which have been accepted for filing under Section 205 of the FPA later may be shown to be unjust and unreasonable. In this regard, Section 206 operates to ensure that a utility's current rates are just and reasonable by permitting the Commission and others to challenge such current rates.[880]

Complainants make that showing here: tariffs allowing individual transmission owners to self-plan tens of billions of dollars in FERC-jurisdictional transmission facilities at 100 kV and above are unjust and unreasonable or unduly discriminatory and therefore improper under the Federal Power Act. The Commission has never ruled on that direct question.

What the Commission has said, over and over, is that regional planning is an essential component of the Commission mandate to consumers to ensure just and reasonable rates. The Commission **cannot** achieve regional planning or just and reasonable transmission rates that flow from independent regional planning with individual transmission owner Local Planning tariff provisions remaining in place. Further, it is impractical to challenge individual transmission projects, individual tariffs, or the cost allocation for individual projects when the issue is one for which the unjust and unreasonable nature of the tariff provision is not

[879] 57 FERC ¶ 61,306 (1991).
[880] *Id*. at ¶ 61,997.

individualized but instead the excessive retained rights are unjust and unreasonable across the country. Thus, this Complaint drives at the underlying core issue and provides more efficient reforms/relief than disparate, individual challenges of select RTO/ISO or individual transmission owner practices can provide.

3. Local Planning Tariffs Are Standing In the Way of Regional Planning

The Commission has found repeatedly that self-interested transmission owners are standing in the way of regional planning. The Commission made that finding in Order No. 890.[881] In Order No. 1000, the Commission found that Order No. 890 had been insufficient and that it was **required to act** as transmission owner self-interest had not resulted in the voluntary regional planning required to ensure just and reasonable rates.[882] The Commission made clear in Order No. 1000 that regional planning was essential to determining just and reasonable transmission rates.[883] Although the Commission mandated regional planning participation, the retention of tariff provisions allowing planning of transmission facilities by the individual transmission owner has thwarted the Order No. 1000 **requirement** for regional planning. In Order No. 1920 the Commission again found that regional planning was not occurring because "local transmission planning processes—are generally designed to address discrete, shorter-term needs, and do not comprehensively assess either broader transmission needs or solutions to those needs, overreliance on those processes can result in relatively inefficient or less cost-effective transmission development for customers, which contributes to rates for transmission that are unjust and unreasonable.[884]

[881] Order No. 890 72 FERC ¶ 12,266 (2007).
[882] Order No. 1000. 136 FERC ¶ 61,051 (2011).
[883] *Id*.
[884] Order No. 1920 at P 103; *see also*, *Id*. at P 110 ("local transmission planning, with its focus on the needs of individual utility footprints, does not necessarily provide sufficient, comprehensive analysis of broader regional transmission needs.)

As established in this Complaint, every region of the Country has seen significant "local" planning with little, or no, regional planning. Billions of dollars in planned spending for individually planned projects have been announced and built, or are under construction, across every region of the country. Overall, the explosion in local planning has resulted in a drop in regional planning comparatively.[885]

The Commission itself has recognized the excess local planning.[886] Ironically, the existing transmission owners, or their surrogates, have likewise recognized that local planning does not produce optimal transmission results. In a recent GridStrategies Report,[887] sponsored by incumbent transmission owner surrogate WIRES,[888] the study found that:

> collaboration provides multiple benefits, such as improving the quality and quantity of information used in transmission planning, enabling a more holistic view of system needs, allowing better use of existing assets and rights of way, driving more efficient technology choices, facilitating faster development of needed infrastructure, allowing for improved coordination of outages during and after construction, and facilitating needed stakeholder and policymaker consensus on need and thus, cost allocation and recovery.[889]

Collaboration does not occur with Self-Planned Transmission. The assertion as to the benefits of collaborative planning is not surprising as the Commission made all these findings in Order No. 890, encouraging regional collaboration, and Order No. 1000 *requiring* regional planning when

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[885] In 2022 and 2024, MISO facilitated two tranches of substantial long-range regional planning; however, a substantial portion of MISO's most recent MTEP24 concerned Other Projects ($4 billion) that were not subject to regional planning requirements. In years where MISO does not facilitate an LRTP Tranche, the Other Project category has dwarfed other project categories. *See supra*, Complaint, at 88-101.
[886]ANOPR 176 FERC ¶ 61,024 (2021). ,NOPR 179 FERC ¶ 61,028 (2022). NOPR at P 40: "The vast majority of investment in transmission facilities since the issuance of Order No. 1000 has been in local transmission facilities." *See also* Order No. 1920 at PP 100-112.
[887] Fostering Collaboration Would Help Build Needed Transmission, R. Gramlich, R. Doying, & Z. Zimmerman, GridStrategies, February 2024 ("GridStrategies Report").
[888] WIRES Leadership and Board of Directors are all employees of incumbent transmission owners who have opposed transmission competition and that have actively worked to thwart the Commission's transmission competition mandate, including by exercising Self-Planning Transmission through authorized local planning tariffs.
[889] GridStrategies Report at II-III.

the Commission's prior Order No. 890 *encouragement* was not effective. Given that "required" collaboration has not worked due to investor expectations/pressures placed on utilities that lead them to circumvent regional planning, the existing transmission owners' surrogates ask the Commission to once again trust them on voluntary collaboration.

But this essential part of transmission development is precisely what retained local planning tariffs prevent and will continue to prevent as an investor-owned utility's self-interest will always prevail. GridStrategies says as much when it notes that "[p]arties come together when they had common interest and objectives."[890] The Common interests and objects of existing transmission owners do not represent the common interest of consumers or getting the right regional project(s) built. Thus, where GridStrategies reports that a "factor common across all examples [of reported collaborative projects] was *a mutual agreement on who would build and own what portions of transmission projects*"[891] the clear inference is that without that "mutual agreement on who would build" collaboration among self-interest utilities will remain just as elusive. GridStrategies need not merely infer that self-interest will dominate, as the existing transmission owners have made clear that they will only "voluntarily" collaborate, *i.e.* fully participate in regional planning as mandated, if they are guaranteed the right to build.[892] The Commission is obligated to balance consumer and investor interests.[893] The Commission has favored investor interests over consumer interest for more than a decade, and unfortunately

[890] *Id*. at 32.
[891] *Id*. at 33 (emphasis added).
[892] *See* ANOPR 176 FERC ¶ 61,024 (2021) and NOPR 179 FERC ¶ 61,028 (2022). *See also*, GridStrategies Report at 42, noting that "Parties at both utilities and the RTO stated to this report's authors that there was much more collaboration between the various owners of the network and between owners and RTO planners prior to 2011 when FERC issued Order No. 1000." Of course, prior to 2011 the transmission owners had contractually guaranteed themselves the right to build any project in their footprint, regardless of whether they were more efficient or cost-effective developer of that project, through cartel like contractual agreements dividing the market. *MISO Transmission Owners v. FERC*, 819 F.3d 329, 334 (7th Cir. 2016).
[893] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944); *Permian Basin Area Rate Cases*, 390 U.S. 747, 792 (1968).

continued to do so in Order No. 1920 by empowering incumbent transmission owners through the issuance of the federal right of first refusal to incumbents for right-sized replacement transmission facilities.[894] In Order No 1920-A, the Commission posited that authorizing a monopolist right for incumbents to right-size was the only way to incent regional planning in comparison "to the alternative of piecemeal development of in-kind replacement facilities."[895] However, the Commission in 1920 did not address the Local Planning problem head-on. This Complaint allows Commission 1) to better balance consumer and investor interests and 2) to confront the piecemeal development issues with Local Planning via the removal local planning tariff provisions that impede appropriate regional planning.

Interestingly, GridStrategies makes the point of this complaint by referencing CAISO's 2022-2023 Transmission Plan asserting that "many of the 46 investments are labeled as investments such as 'reconductoring,' 'reinforcement,' 'reconfiguration,' 'bus voltage addition,' 'upgrade,' and 'replacement' . . .."[896] Although GridStrategies claims that the identified projects "are only possible through collaboration with existing transmission owners"[897] that assertion completely misses the point that these were CAISO regionally planned projects and the **"collaboration" was mandatory because CAISO had planning authority**. Although GridStrategies recreated Table 8.2-1 from the CAISO transmission plan, GridStrategies left out the lead in for the chart that recounts that:

> [i]n the 2022-2023 transmission planning process, **the ISO determined** that 24 transmission projects were needed to mitigate identified reliability concerns; 21 policy-driven projects were

[894] *See* Order No. 1920-A at P 875.
[895] Order No. 1920-A at P 875.
[896] GridStrategies Report at 37.
[897] *Id*.

> needed to meet the GHG reduction goals and no economic-driven projects were found to be needed.[898]

Because of the nature of the need identified, "the ISO determined" the project and the regional tariff determined whether the project would be assigned to the existing transmission owner or subject to competitive solicitation. This result is precisely what this Complaint seeks, through removal of the Local Planning tariffs that allow individual transmission owners to self-plan transmission facilities. Even in CAISO's footprint, where it was able to plan 45 regional projects, Self-Planned Transmission still has resulted in billions of dollars in individual transmission owner planned projects within the last several years, each of which impact the CAISO administered grid and prohibits CAISO's ability to determine that the individual transmission owner project is actually the correct investment for California.

The point that GridStrategies makes, that regional planning incorporates existing transmission owner facilities more efficiently when the regional entity has the authority to plan, is repeated across the county in RTOs, particularly when those planned projects are excluded from competition for the transmission developer.[899] In non-RTO regions, the lack of any effective regional planning means that even the bare minimum regional planning that GridStrategies highlights as the model, does not exist. Where individual transmission owners have the authority to circumvent regional planning, the efficiencies of regional planning are not obtained because an entity that must respond to investors will always default to its self-interest.

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[898] https://www.caiso.com/InitiativeDocuments/Revised-Draft-2022-2023-Transmission-Plan.pdf at 167. GridStrategies listed only the 24 reliability projects, ignoring the "21 policy-driven projects" apparently because they do not fit its results driven narrative (last accessed Dec. 18, 2024).

[899] For example, in the 2013-2018 transmission plans, CAISO identified 41 regional transmission projects, none of which qualified for competition. Competition for Electric Transmission Projects in the U.S.: FERC Order No. 1000, P. Joskow, available at https://ceepr.mit.edu/wp-content/uploads/2021/09/2019-004.pdf at 30; *see also* LS Power Grid LLC., Reply Comments on ANOPR Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection (Nov. 30, 2021) (last accessed Dec. 18, 2024).

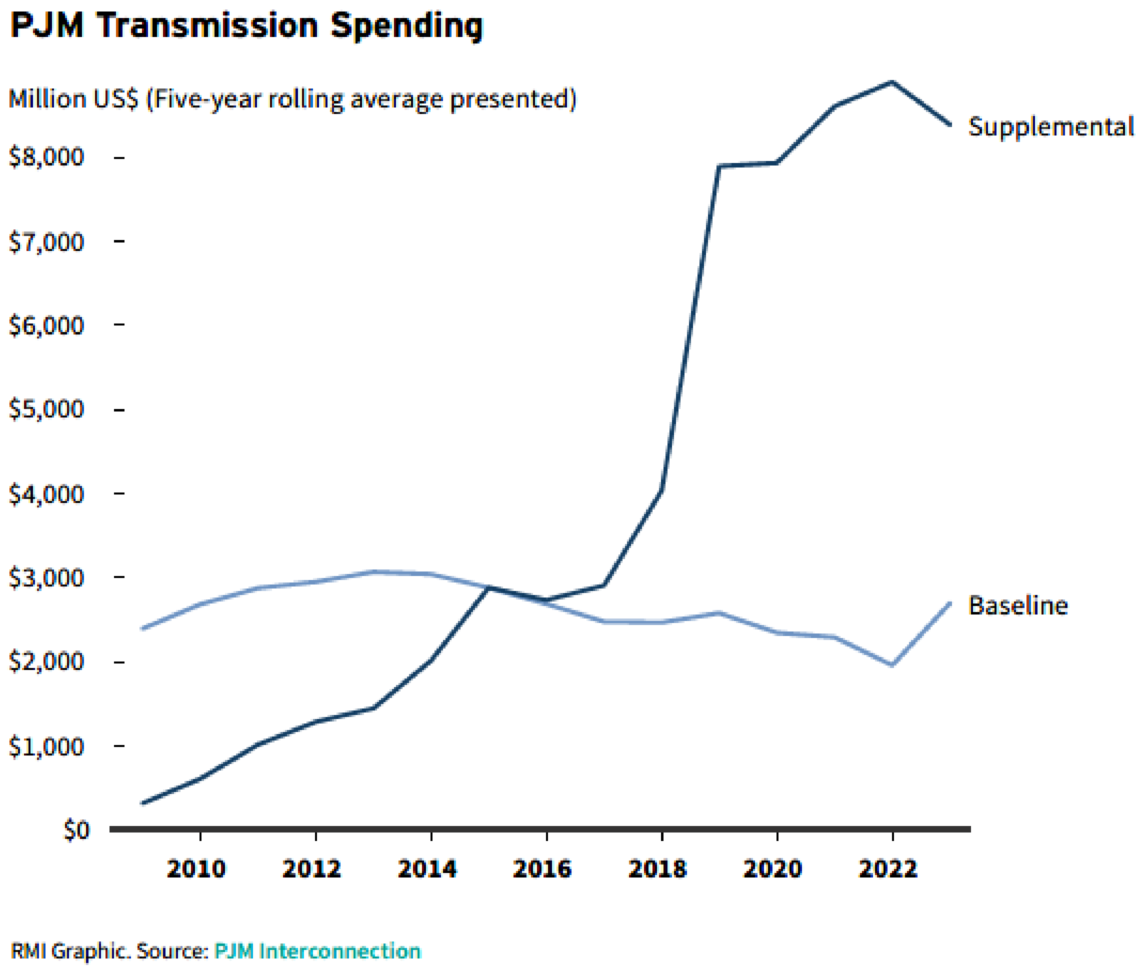
For these reasons, the local planning tariffs are unjust and unreasonable practices affecting rates.

4. Regional Planning as a Percentage of Total Planning Is Deficient

As set forth above, local planning has dwarfed regional planning, whether in RTOs or non-RTO regions. In the decade since the Commission required regional planning there has not been a single regional project identified in a non-RTO/ISO region. As RMI concluded, "local transmission spending has increasingly displaced regional investment in recent years."[900] RMI summarized the issue as follows in RTO/ISO regions:

- In ISO-NE, local projects (asset condition projects) increased eightfold from 2016 to 2023;
- In CAISO, local projects (self-approved projects) were 63% of all projects from 2018 to 2023 that were not eligible for state or CAISO review;
- In MISO, Other Projects (local projects) increased from 54% of total spend in 2017 to 78% in 2022; and
- PJM Supplemental Project spending increased 26-fold from 2009 to 2023 while regional baseline project spending remained flat (as reflected below).[901]

[900] *See* RMI Report at 48; *see id.* at
[901] RMI Report at 27-28.



5. The Grid of Yesterday is Not Sufficient for the Grid of Tomorrow

The grid of yesterday is "a network of transmission infrastructure that was overwhelmingly built in the last century and in the face of a very different reality."[902] Short-term, local planning needs to be replaced by more holistic, regional planning, of a short-term, medium-term and long-term duration.[903] Traditional baseload, dispatchable resources are being replaced by a mixture of intermittent and storage resources.[904] Electrification pushes and data

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[902] Joint Order No. 1920 Concurrence at P 34.
[903] *Grid of the Future: PJM's Regional Planning Perspective,* May 10, 2022, at 6, 45, https://www.pjm.com/-/media/library/reports-notices/special-reports/2022/20220510-grid-of-the-future-pjms-regional-planning-perspective.ashx (last accessed Dec. 18, 2024).
[904] *U.S. Department of Energy: Next-Generation Grid Technologies*, November 2021, at 11, 28, 47, https://www.energy.gov/oe/articles/next-generation-grid-technologies-report-download (last accessed Dec. 18, 2024).

center load growth are changing the load picture. This transition will require robust transmission expansions and reinforcements. Given the substantial investments associated with those expansions and reinforcements, such transmission planning must be conducted independently and in a coordinated manner to ensure that the most efficient and cost-effective solution is selected. With the onset of distributed generation and expected continued deployment of grid-enhancing technologies, the grid of tomorrow will be more complex than the grid of yesterday and today.[905] The grid of tomorrow will see more transmission automation, smart grid technologies, and digital and hardened substations.[906] Connecting distance renewable generation resources to more populous load centers will necessitate long-range, high-voltage transmission lines that provide net benefits to customers. The grid of tomorrow cannot be planned in a balkanized and piecemeal fashion, or by simply rebuilding the grid of yesterday, yet such an approach continues to be threatened by Local Planning tariff provisions that authorize and encourage such a piecemeal approach. As one state regulator interviewed by RMI concluded: "**I have a hard time believing that simply rebuilding the grid of 80 or 90 years will produce the right grid for 50 or 60 years from now, which is how long these facilities are going to last**."[907]

6. Individual Transmission Owner Planning Results In Inappropriate Cost Allocation For Voltages Above 100 kV

This Complaint is not a complaint regarding the cost allocation for any specific project. Nevertheless, the inappropriate cost allocation endemic in individual transmission owner planned projects is a consideration in showing that individual local planning tariffs are unjust and

[905] *Id*. at 9, 24, 43, 52.
[906] *U.S. Smart Grid Case Studies,* Prepared for the Energy Information Administration, Sept. 28, 2011 at 132, https://www.eia.gov/analysis/studies/electricity/pdf/smartggrid.pdf (last accessed Dec. 18, 2024).
[907] RMI Report at 32 (emphasis added).

unreasonable. The Commission has required that the costs for individual transmission owner projects must be allocated solely to the zone of the transmission owner planning the project, if the transmission owner wants to be exempted from competition. Of course, it is undisputed that the desire to be exempted from competition is the sole basis for the proliferation of locally planned projects. The mandated single zone cost allocation for those individual transmission owner planned projects, along with the sheer magnitude of those projects, demonstrates that continuing to allow individual transmission owner planning authority over high voltage transmission is unjust and unreasonable as that transmission serves the regional.

The Commission has recognized the regional value of transmission across all voltages. Between 100 kV and 300 kV the Commission found regional benefit sufficient that one-third of the cost of any such project is allocated across the vast SPP region.[908] For double circuit 345 kV and above, the Commission has found that half of the benefits can be attributed across the entire region and the remainder measured by DFAX analysis.[909] Nevertheless when planned through individual transmission owner planning tariffs the costs are allocated solely to the zone of the transmission developer, regardless of voltage.[910]

This is not a case where regional differences make a difference to consumers, as the law has long been that consumers are entitled to transmission cost allocation where the benefits are allocated to based on cost causation. FERC "generally may not single out a party for the full cost of a project, or even most of it, when the benefits of the project are diffuse."[911] The Courts have

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[908] *See supra*, Complaint at 121-122. The SPP region covers approximately 60,000 miles of high-voltage transmission lines spanning 14 states. https://en.wikipedia.org/wiki/Southwest_Power_Pool#:~:text=Southwest%20Power%20Pool%20and%20its,headquartered%20in%20Little%20Rock%2C%20Arkansas (last accessed Dec. 18, 2024).
[909] *PJM Interconnection, LLC*, 142 FERC ¶ 61,214, PP 412–26 (2013).
[910] *Municipal Energy Agency of Nebraska, et al., v. Public Service of Colorado*, 189 FERC ¶ 61,099 (2024) (approving the allocation of the entire $2 billion plus in costs for a a 560-mile double circuit 345 kV Self-Planned Transmission addition solely to the Public Service Co. Colorado service territory.)
[911] *BNP Paribas Energy Trading GP v. FERC*, 743 F.3d 264, 268 (D.C. Cir. 2014).

also confirmed that the cost causation principle, which predates Order No. 1000, "focuses on project benefits, not on how particular planning criteria were developed."[912] The *Old Dominion* Court went on to note that "compliance with Order No. 1000 does not necessarily ensure compliance with the cost-causation principle—a pre-existing, more general rule that, in order to ensure just and reasonable rates, FERC must make some reasonable effort to match costs to benefits."[913] For locally planned projects, matching costs and benefits does not occur as it would defeat the entire purpose of local planning, avoiding competition by avoiding submission of a project for regional cost allocation.

Correcting the cost allocation after-the-fact does not address the improper planning in the first instance. In fact, allowing improper planning on the front end, with corrected regional cost allocation on the back end but without the required competition would encourage even more improper planning, and thus this Complaint is the appropriate mechanism to prevent future similar actions.

AEP also has examples of inappropriate cost allocations for projects above 100 kV.[914] The Stuart-Area Project costs $379.37 million, and it includes constructing over 90 miles of 138 kV lines. With over 90 miles of line, it is impossible to define the impacts as being confined to a localized area. Similarly, AEP's Apple Grove Project involves the installation of a 345 kV station and the construction of a 345 kV line, at a combined cost of $215.8 million. 345 kV is a significantly-sized line, designed to transport electricity over large distances. And the Philo-Howard Project costs $187.84 million to, among other things, rebuild an existing line as 138 kV double circuit for approximately 64 miles, while rebuilding another segment as 138 kV single

[912] *Old Dominion Elec. Coop. v FERC*, 898 F.3d 1254, 1262 (2018).
[913] *Id*. at 1263, *citing BNP Paribas Energy*, 743 F.3d at 268.
[914] *See Supra* pages 68-72.

circuit for approximately 19 miles. The size of these lines are not insignificant, involving increased capacities and mileage. What all three of these projects have in common is the framing of large transmission projects as "local" so that there would be insufficient oversight for cost-recovery. But there is no showing of prudency, and it is akin to a kid whipping out his or her parents' credit card and purchasing items that are not necessary to satiate underlying needs. Except here, the kid at issue is the utility's investors that are overspending on capital to make bloated profits from the ballooning of rate base, at the expense of the consumers. But proper planning protocols would provide more oversight on the transmission spend to ensure that needs are efficiently met and that the sizes and actions involved in the projects can be adapted and responsive to changing circumstances.

7. Allowing Individual Transmission Owners to Plan the Bulk Electric System to only Their Needs, Including Rebuilding Transmission at the End of Operational Life, is Unduly Discriminatory

The Commission is obligated to prevent undue discrimination. A FERC-regulated public utility may not "grant any undue preference or advantage" "with respect to any transmission or sale subject to" FERC's jurisdiction.[915] The Federal Power Act only prohibits "undue" discrimination.[916] Undue discrimination arises when similar classes or groups that are similarly situated are treated differently without justification.[917] Order No. 888 was built on the premise that self-interested transmission owners were discriminating against other users of the transmission grid. That same undue discrimination is endemic in the retained authority to plan individual transmission owner projects above 100 kV notwithstanding the interconnected nature of the grid. As noted in the Colorado Cities complaint, Public Service Company of Colorado's

[915] 16 U.S.C. § 824d(b).
[916] *See N.J. Bd. of Public Utilities v. FERC*, 744 F.3d 74, 106 (3d Cir. 2014).
[917] *See Dynegy Midwest Generation v. FERC*, 633 F.3d 1122, 1125-1129 (D.C. Cir. 2011).

submission of the Pathway Project as a local solution left other regional transmission owners to scramble to find a mechanism to address the same public policies that Public Service claimed it was required to address. By usurping the project as a locally planned project, Public Service either guaranteed itself ownership of a regionally beneficial project that others needing to address the same laws are forced to use at terms Public Service sets, or they are forced to build their own potential duplicative facilities at significant expense. Planning for individual needs within an interconnected grid is the definition of undue discrimination, as tariff provisions authorizing a utility to plan locally to serve itself unduly discriminates against similarly situated transmission developers that could otherwise provide an efficient and cost-effective transmission solution to address an appropriate, identified regional need.

This point is equally made with reference to the 161 kV FPL "Local" Project. In addition to the fact that the 161 kV transmission line was an imprudent design for FPL's claimed needs, the fact that it was imprudent put additional pressure on neighboring systems resulting in additional costs to those systems as the imprudent design had those systems carrying more of the load.[918] Failure to regionally, or inter-regionally, plan in this instance resulted in undue discrimination as both Duke and Southern were required to operate their system to accommodate FPL's imprudent design without a seat at the table as required by regional planning.

The decisions referenced above in Colorado and Florida as well as proceedings in PJM and CAISO pertaining to end-of -life projects[919] and efforts to rebuild the grid of yesterday are provide evidence of undue discrimination. The grid of yesterday was designed for a different

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[918] *Duke Energy Florida, LLC v. Florida Power & Light, Co., et al*. Docket No. EL21-93-000, filed August 06, 2021.
[919] *See infra*, Complaint at pp. 251-262 (citing *California Public Utility Commission, at al., v. Pacific Gas & Electric Company*, 164 FERC ¶ 61,161 (2018) and *PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,136, at PP 12, 89, *order on reh'g*, 173 FERC ¶ 61,225 (2020); *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,242, at P 54 (2020), *order on reh'g*, 176 FERC ¶ 61,053 (2021), *pet. denied, Am. Mun. Power, Inc. v. FERC*, 86 F.4th 922 (D.C. Cir. 2023)).

purpose than the grid is used today, and also under vastly different circumstances. Allowing individual transmission owners to unilaterally decide to rebuild that grid without regard to whether the facilities are the appropriate facilities for the post-Order 888 uses of the grid is the same level of undue discrimination as if the transmission owner had prohibited third-party use in the first instance. Constraining the use of the grid of tomorrow to the topography of the grid of yesterday is precisely the type of undue discrimination the Commission is charged with preventing. The only way to do that in the context of transmission planning for transmission facilities above 100 kV is to remove the Local Planning opportunities currently embedded in Local Planning tariffs and require that all transmission planning above 100 kV be handled at the regional level. In addition, because of the inherent self-interest of existing transmission owners, the regional transmission planning necessary to achieve just and reasonable rates must be undertaken by an independent planner, inclusive of whether existing transmission facilities should be rebuilt when the owner of those facilities determines that the transmission facilities have reached the end of operational life.

8. Appellate Court Precedent Concerning FPA Section 205 Filing Rights of FERC-Jurisdictional Transmission Owners Does Not Constrain the Commission's Authority to Act on This Section 206 Complaint.

Opponents to this Complaint may contend that certain appellate court and Commission precedent concerning the Section 205 FPA filing rights of transmission owners in the PJM region may hamper or limit the Commission's ability to grant the fullest relief requested in this Complaint. Because that precedent addressed Section 205 filing rights, the precedent in no way constrains the Commission in granting relief under Section 206 upon the finding that existing local planning practices addressed in the complaint are unjust, unreasonable, preferential or unduly discriminatory.

The D.C. Circuit Court of Appeals in 2002 in *Atlantic City Electric v. FERC*[920] reviewed PJM's authority and Section 205 filing rights relative to those filing rights of the PJM Transmission Owners. On appeal, the PJM Transmission Owners contended that FERC exceeded its statutory authority by requiring the owners of existing transmission assets to cede their statutory right under Section 205 with respect to rate design for those assets as a condition to their voluntary participation in PJM.[921] The D.C. Circuit reversed FERC's determination that the joining transmission owners must abdicate Section 205 rights and held that the PJM Transmission Owners retain Section 205 filing rights related to rates and rate design for their assets.[922] The D.C. Circuit explained that the Consolidated Transmission Owners Agreement ("CTOA") voluntarily transferred "the administration of the tariff and *regional transmission planning* and operations to [PJM]."[923] While the Court in *Atlantic City* explained that "Section 205 . . . gives a utility the right to file rates and terms for service rendered with its assets,"[924] the Court held that "utilities may choose to voluntarily give up, by contract, some of their rate-filing freedom under section 205."[925] Notably, the D.C. Circuit reversed FERC because FERC required the PJM Transmission Owners to "give up *all authority* to make unilateral changes to rate design."[926] The Court in *Atlantic City* emphasized that "FERC has no power to force public utilities to file particular rates unless it first finds the existing filed rates unlawful, which is precisely what this Complaint demonstrates."[927] This Complaint asks the Commission to find that, under Section 206 of the FPA, the Local Planning tariff provisions – which hinder regional

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[920] 295 F. 3d 1, 3, 9 (D.C. Cir. 2002).
[921] 295 F. 3d 1, 3, 9 (D.C. Cir. 2002).
[922] *Id.* at 11.
[923] *Id.* at 6 (emphasis added). The Court explained that the CTOA "established procedures for changes to rate design and other tariff terms for transmission services." *Id.* The Court did not address Local Planning issues specifically.
[924] *Atlantic City*, 295 F. 3d at 9.
[925] *Id*.
[926] *Atlantic City*, 295 F. 3d at 9 (emphasis added).
[927] *Atlantic City*, 295 F. 3d at 10 (citing *Pub. Serv. Comm'n v. FERC*, 866 F.2d 487, 488-489 (D.C. Cir. 1989)).

planning and selection of the most cost-efficient project – are unjust, unreasonable, and unduly discriminatory or preferential.

Arguments concerning Section 205 filing rights and transmission owner contractual rights over Locally Planned projects arose more recently in the context of two dueling Section 205 filings in the PJM region concerning the authority of PJM Transmission Owners to engage in certain Local Planning activities when transmission facilities are reaching the end of their useful lives instead of ensuring transmission facility replacements, enhancements, and additions are subjected to a robust, holistic regional planning process.[928] The Commission rejected a PJM Members Committee Section 205 proposal that enjoyed wide stakeholder support, concluding that the Members Committee could not expand PJM regional planning authority when the transmission owners had not voluntarily expanded their grant of regional planning to include end-of-life planning. The D.C. Circuit found that the consumer-side stakeholders did not demonstrate that FERC's findings regarding provisions in the PJM Tariff and the PJM Consolidated Transmission Owners Agreement were arbitrary and capricious or that FERC's conclusions were not supported by reasoned decision-making.[929] The D.C. Circuit upheld FERC's determination that the projects at issue in *AMP v. FERC* were "non-regional" under the PJM governing documents and therefore could not apply to regional transmission plan requirements in Order No. 1000.[930] Importantly, neither the Commission's nor the D.C. Circuit's review of the various Section 205 filings address the core legal arguments raised in this Section 206 Complaint that local planning tariffs for Commission jurisdictional transmission 100 kV and above are unjust, unreasonable, unduly discriminatory or preferential.

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[928] *PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,136, at PP 12, 89, *order on reh'g*, 173 FERC ¶ 61,225 (2020); *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,242, at P 54 (2020), *order on reh'g*, 176 FERC ¶ 61,053 (2021).
[929] *AMP v. FERC*, 86 F.4th 922, 931-937.
[930] *AMP v. FERC*, 86 F.4th at 935.

This Complaint is national in scope because the problem is national in scope as demonstrated by the referenced projects in every region of the country. Local planning tariffs impede regional planning for all FERC-jurisdictional transmission facilities at 100 kV and above. Importantly, the cases in *Atlantic City* and *AMP v. FERC* arose out of Section 205 proceedings, not a Section 206 Complaint, which is now before the Commission. In Order No. 1920, the Commission recently reaffirmed its robust jurisdiction over regional transmission planning under Section 206 of the FPA.[931] The D.C. Circuit has granted the Commission "great deference" in fashioning remedies when existing rates are unjust, unreasonable, unduly discriminatory or preferential, where the Commission's "discretion is often at its zenith."[932] Under Section 206, once the Commission determines that the existing local planning tariffs are unjust, unreasonable, unduly discriminatory or preferential, the Commission must act. Complainants request the Commission to exercise its obligation under Section 206 to require removal of Local Planning provisions in federal tariffs for transmission 100 kV and above, as those provisions hamper the Commission's ability to ensure cost-effective and holistic regional planning and that resulting rates for transmission service that are just and reasonable rates.

B. Just And Reasonable Replacement Rate

1. Congress And The Commission Recognize That Transmission Above 100 kV Has Regional Impacts

Both Congress and the Commission recognize the integrated nature of the regional transmission grid and thus the need for uniform rules protecting that grid. While those rules, to date, have focused on reliability of the existing facilities, and thus incorporated into transmission

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[931] *See* Order No. 1920-A at PP 125-131 (explaining that transmission planning is a practice affecting rates that FERC can regulate under the Federal Power Act and U.S. Supreme Court and precedent in *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 55-59 (D.C. Cir. 2014); *Emera Me. v. FERC*, 854 F.3d 9, 22, 25 (D.C. Cir. 2017); and *FERC v. EPSA*, 577 U.S. 260, 281-82 (2016)).

[932] *Sacramento Mun. Util. Dist. v. FERC*, 616 F.3d 520, 541 (D.C. Cir. 2010); *see Shetek Wind, Inc. et al.*, 138 FERC ¶ 61,250, at P 124 (2012).

planning, the interconnected nature of transmission facilities at 100 kV and above warrants extending the rationale behind the reliability rules to the planning of all FERC-jurisdictional transmission facilities at 100 kV and above. In addition, applying the same inclusions and exclusions to the required regional planning related to transmission facilities 100 kV or above that the Commission uses to determine applicability of reliability rules to those facilities will allow the Commission, transmission owners, and consumers to understand the full set of transmission facilities to which the regional planning requirements apply.

In the Energy Policy Act of 2005, Congress mandated that the Commission secure the reliability of the Bulk-Power System, which Congress defined as the "facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)."[933] To achieve that goal Congress required the Commission to certify a national electric reliability organization ("ERO")[934] that would enforce reliability standards for the Bulk-Power System.[935] Congress also authorized the Commission's approval of nationally applicable reliability standards, developed by the ERO and approved by the Commission,[936] to

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[933] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594, Section 1211 (2005). https://www.congress.gov/109/plaws/publ58/PLAW-109publ58.pdf (last accessed Dec. 18, 2024).

[934] *Id.*, 16 U.S.C. § 824o(a)(1)(A). Congress defined an Electric Reliability Organization as an organization certified by the Commission the purpose of which is to establish and enforce reliability standards for the bulk-power system, subject to Commission review. 16 U.S.C. § 824o(a)(2).

[935] *Id.*, 16 U.S.C. § 824o(c). Congress gave the Commission authority to issue regulations authorizing the ERO to enter into an agreement to delegate authority to a regional entity for the purpose of proposing reliability standards to the ERO and enforcing reliability standards if: "(A) the regional entity is governed by (i) an independent board; (ii) a balanced stakeholder board; or (iii) a combination independent and balanced stakeholder board; (B) the regional entity otherwise satisfies the provisions of subsection (c)(1) [insert] and (2)[insert]; and (C) the agreement promotes effective and efficient administration of bulk-power system reliability." 16 U.S.C. § 824o(e)(4).

[936] *Id.*, 16 U.S.C. § 824o(d). Congress required the ERO to "file each reliability standard or modification to a reliability standard that it proposes to be made effective… with the Commission. Further Congress said the Commission could approve a proposed reliability standard or modification to a reliability standard if it determined that the "standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest." 16 U.S.C. § 824o(d)(2). Congress provided that a proposed standard or modification would only take effect "upon approval by the Commission." *Id*.

ensure the reliable operation of the Bulk-Power System.[937] Once approved, such standards would be mandatory, enforced by the ERO and subject to penalties for failure to comply.

The Commission took several initial steps to implement the Congressional mandate. On July 20, 2006, the Commission designated the North American Electric Reliability Corporation ("NERC") as the ERO and allowed NERC to enter into *pro forma* agreements with eight regional areas to monitor and enforce compliance with the reliability standards once those standards were approved.[938] On March 15, 2007,[939] to be effective June 18, 2007, the Commission issued Order No. 693[940] approving 83 reliability standards to be enforced by NERC and approved NERC's definition of "bulk electric system." That definition provides:

> As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated **at voltages of 100 kV or higher**. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.[941]

Notwithstanding its adoption of NERC's definition of bulk electric system, the Commission in Order No. 693 noted that "[it] remains concerned about the need to address the potential for gaps in coverage of facilities."[942] The approved reliability standards applied to the entire geographic

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[937] 16 U.S.C. § 824o(d)(2).
[938] The eight regional entities were: (1) Florida Reliability Coordinating Council, (2) Midwest Reliability Organization, (3) Northeast Power Coordinating Council, (4) ReliabilityFirst Corporation, (5) SERC Reliability Corporation, (6) Southwest Power Pool,(7) Texas Regional Entity, and Western Electricity Coordinating Council ("WECC").
[939] On May 18, 2007, the Commission applied the reliability standards to generation facilities classified as Qualifying Facilities under the Public Utilities Policy Act of 1978. Applicability of Federal Power Act Section 215 to Qualifying Small Power Production and Cogeneration Facilities, 119 FERC ¶ 61149 at P 24 (2007) ("When Congress enacted Section 215 [Section 1211 of the Energy Policy Act], it used broad language to ensure that all those entities that could affect the reliability of the bulk power system would be subject to mandatory reliability standards.")
[940] Mandatory Reliability Standards for the Bulk-Power System, Order No. 693, 72 FR 16,416 (April 4, 2007), FERC Stats & Regs. ¶ 31,242 (2007) (Order No. 693).
[941] Order No. 693 at P 75, fn 47 (emphasis added).
[942] Order No. 693 at P 77.

area of the ERO, *i.e.*, the continental United States and Canada and the northern portion of Mexico.

In March of 2010, the Commission issued a Notice of Proposed Rulemaking in which it directed NERC as the ERO to revise the definition of bulk electric system.[943] The Commission required the revision "to address the Commission's technical concerns, . . . and ensure that the definition encompasses *all facilities necessary for operating an interconnected electric transmission network*."[944] In implementing the authority Congress gave it to ensure grid reliability, the Commission has long been guided by the principle that "uniform Reliability Standards, and uniform implementation, should be the goal and the practice, the rule rather than the exception, absent a showing that a regional variation is superior or necessary due to regional differences."[945] The Commission explained that "[c]onsistency is important as it sets a common bar for transmission *planning*, operation, and maintenance necessary to achieve reliable operation."[946]

More specifically, the Commission has generally rejected the concept of region-specific reliability standards. The Commission said it would approve regional-specific standards only when they are either (i) "more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not," or (ii) "necessitated by a physical difference in the Bulk-Power System."[947] Yet with transmission planning, the Commission has permitted each utility to establish its own planning

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[943] *Revision to Electric Reliability Organization Definition of Bulk Electric System, Notice of Proposed Rulemaking*, 75 FR 14097 (Mar. 24, 2010), FERC Stats. & Regs. ¶ 32,654 (2010)("Order No. 743 NOPR").
[944] *Revisions to Electric Reliability Organization Definition of Bulk Electric System*, Order No. 743, 75 FR 72910 (November 26, 2010) 133 FERC ¶ 61,150 at P 1 (emphasis added) ("Order No. 743").
[945] Order No. 743 at P 82, *citing* Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 290.
[946] Order No. 743 at P 82 (emphasis added).
[947] Order No. 743 at P 141.

criteria, and then to build regionally impactful transmission based on those individualized planning criteria, so long as the individual facilities "do no harm."[948]

In the context of compliance with mandatory reliability standards to ensure reliability, the Commission started with a "general" 100 kV threshold but allowing leeway to address specific circumstances, before settling upon a bright line 100 kV or more threshold with limited exceptions.[949] But even with the general 100 kV threshold in Order No. 693 the Commission rejected assertions by transmission owners and others that the threshold captured facilities which are not part of the Bulk-Power System as intended by Congress. The National Association of Regulatory Utility Commissioners ("NARUC") and the New York Department of Public Service argued that a layer of transmission facilities existed – which they referred to as "area transmission facilities"[950] – which were below the "bulk-power system" and above distribution facilities. Each argued that such facilities were not part of the Bulk-Power System, *i.e.* facilities not necessary for operating an interconnected electric transmission network (or any portion thereof), because these facilities flow energy only within a service territory and toward load centers. They argued that only a "small subset of these area facilities assists in maintaining the reliability of the bulk system."[951] The Commission disagreed and clarified that the Bulk-Power System, as defined by Congress, should be defined broadly – and not limited by NERC's historic interpretations of the bulk electric system.[952]

In Order No. 743, the Commission adopted a bright-line threshold of 100 kV, with specific inclusions and exclusions, and significantly reduced the ability of the regional entities to

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[948] *See* RMI Report at 27 (explaining that RTOs only do a "no-harm analysis" for Local Projects).
[949] Order No. 693 at P 79.
[950] *Id*. at P 72.
[951] *Id*.
[952] *Id*. at P 76.

deviate from this threshold. The Commission found that the broad discretion given to the regional entities in Order No. 693 to deviate from the 100 kV threshold had "failed to ensure that all facilities necessary for operation of the interconnected transmission network are covered by the Reliability Standards."[953] In the Notice of Proposed Rulemaking to Order No. 743, the Commission explained why a 100 kV bright line threshold would be consistent with NERC practice and the practice of the regional entities. The Commission said "NERC has applied a definition of bulk electric system that includes a 100 kV 'general' threshold for decades."[954] The Commission found that seven of eight Regional Entities (excluding only Northeast Power Coordinating Council) have adopted NERC's definition, including the 100 kV threshold, either verbatim or with limited additional criteria. The Commission added:

> [s]ignificantly, ReliabilityFirst Regional Entity, which resulted from a merger of three historical reliability regions, successfully replaced three 'legacy' definitions with a 100 kV threshold for defining bulk electric system facilities. Moreover, the NERC Statement of Compliance Registry Criteria, which the ERO and Regional Entities use to determine which entities should be registered to comply with mandatory Reliability Standards, also utilizes a 100 kV threshold. In fact, the Registry Criteria provide that a load serving entity should be subject to registration if its peak load exceeds 25 MW 'and is directly connected to the bulk power (>100 kV) system . . ..' Likewise, the Registry Criteria provide that a transmission owner or transmission operator should be registered if it owns or operates "an integrated transmission element associated with the bulk power system 100 kV and above . . ..'[955]

The Commission explained the adverse impacts of allowing regional entities broad discretion to deviate from the 100 kV threshold because allowing:

> broad regional discretion without ERO or Commission oversight[] …has resulted in reliability issues such as the exclusion of transmission serving bulk electric generators (including nuclear

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[953] Order No. 743 at P 72.
[954] Order No. 743 NOPR at P 20.
[955] Order No. 743 NOPR at P 20.

> plants), inconsistency in classification at the seams that compromises the effectiveness of the Reliability Standards, routine TLR events on non-bulk electric system facilities, and the exclusion of elements necessary to operate the interconnected transmission network.[956]

To address its concerns, the Commission concluded that "it is necessary to direct the ERO to revise the definition of 'bulk electric system' to ensure that all facilities necessary to operate the interconnected transmission network are included and to address the concerns noted herein."[957] The Commission added "[w]e believe that the Commission's proposed approach of adopting a bright-line, 100 kV threshold, NERC-developed, Commission approved exemption process, as well as eliminating regional variations unless approved by the Commission as provided in Order No. 672, is an appropriate action to ensure bulk electric system reliability."[958] The Commission explained that facilities operated at 100 kV and above have a significant effect on the overall functioning of the grid.

> The majority of 100 kV and above facilities in the United States operate in parallel with other high voltage and extra high voltage facilities, interconnect significant amounts of generation sources and operate as part of a defined flow gate, which illustrates their parallel nature and therefore their necessity to the reliable operation of the interconnected transmission system. Parallel facilities operated at 100-200 kV will experience similar loading as higher voltage parallel facilities at any given time and the lower voltage facilities will be relied upon during contingency scenarios. Further, as illustrated by the Commission's examples and as Bay Area Municipal states, 115 kV and 138 kV facilities have either caused or contributed to significant bulk system disturbances and cascading outages. As noted above the Northeast blackout of 2003 demonstrated this as the failure of First Energy's 138 kV system contributed to the cascading blackout.[959]

[956] Order No. 743 at P 72.
[957] Order No. 743 at P 72.
[958] Order No. 743 at P 72. One of the purposes of the exemption was determining where "the line between 'transmission' and 'local distribution' lies."
[959] Order No 743 at P 73.

In the Notice of Proposed Rulemaking to Order No. 743, the Commission explained the "compelling technical reasons" for a 100 kV threshold. The Commission held that its:

> proposal to direct the ERO [NERC] to consistently maintain a 100 kV threshold for identifying bulk electric system facilities for reliability purposes, with exceptions allowed only with ERO and Commission oversight, is justified based on (1) the need to eliminate inappropriate inconsistencies among regions, (2) the historical and current application of a 100 kV threshold to identify the bulk electric system for reliability purposes, and (3) the technical justification for a 100 kV threshold provided above, including events on facilities rated at 115 kV and 138 kV that have caused or contributed to significant bulk electric system disturbances and cascading outages.[960]

These same factors identify why such facilities are not "local" for purposes of transmission planning. The Commission focused on and addressed the difficulties experienced in the Northeast Power Coordinating Council (NPCC) – the only regional entity not to use a 100 kV threshold – and why such facilities should be included. The Commission said:

> [t]here are other compelling technical reasons for proposing a 100 kV threshold. Certain transmission lines in the U.S. portion of NPCC region are not identified as bulk electric system although these transmission lines extend into the footprint of another Regional Entity where they are considered bulk electric system facilities. For example, NPCC [Northeast Power Coordinating Council] does not identify two 115 kV transmission lines-Falconer to Warren, and North Waverly to East Sayre-as part of the bulk electric system in its region even though the sections of these lines that connect to PJM's balancing authority area are considered bulk electric system within the Reliability First Corporation footprint.[961]

Finally, in Order No. 773, the Commission retained the "core" definition – 100 kV bright-line threshold – noting that it "merely clarifies the current NERC definition, which

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[960] Order No. 743 NOPR at P 26 (2010).
[961] Order No. 743 NOPR at P 24. The Commission went on to explain how the 115 kV transmission facilities in the NPCC were deemed critical by transmission operators in NPCC "even though NPCC does not identify the same transmission facilities as bulk electric system elements." *Id*.

classifies facilities operating at 100 kV or above as part of the bulk electric system."[962] The Commission adopted the "core" definition of the Bulk-Power System as including, unless modified by the inclusion and exclusion lists "all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher . . . ."[963] The Commission held "that the proposed 'core' definition, together with the more granular inclusions and exclusions, should produce consistency in identifying bulk electric system elements across the reliability regions . . . [and] transparency and uniformity to the determination of what constitutes the bulk electric system."[964]

The NYPSC once again opposed the 100 kV threshold, contending "the proposed definition will likely result in classifying certain facilities as part of the bulk electric system despite their being unnecessary for operating an interconnected transmission network"[965] and that there was "no technical justification for a 100 kV bright-line definition."[966] The Commission disagreed, citing its findings in Order No. 743.[967]

MISO's Tariff actually recognizes the importance of a threshold around 100 kV. MISO's Tariff requires MISO to plan and operate all facilities of the MISO Transmission Owners above 100 kV.[968] Notably, the shortcoming in MISO's tariff is that the MISO Transmission Owner retain control and use of their own criteria to develop local projects, referred to as Other Projects.

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[962] Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedures, Order No. 773, 141 FERC ¶ 61,236 at P 43 ("Order No. 773) citing Order No. 743-A, 134 FERC ¶ 61,210 at P 36; Order No. 773 at P 45.
[963] Order No. 773 at P 12.
[964] Order No. 773 at P 2.
[965] Order No. 773 at P 36.
[966] *Id.*
[967] The Commission disagreed that "the proposed definition will likely result in classifying certain facilities as part of the bulk electric system despite their being unnecessary for operating an interconnected transmission network." As to "NYPSC's claim that there is no technical justification for the 100 kV threshold," the Commission reiterated its findings in Order No. 743. Order No. 773 at P 41.
[968] *See* MISO Tariff, Schedule 1, Appendix B.I.

Those Other projects become part of the MISO Regional Transmission Expansion Plan, but the Other Projects are not independently planned by MISO.

2. Facilities Above 100 kV That Are Appropriately Characterized as Local Distribution Facilities Would Not Be Subject to Regional Planning

The Commission's jurisdiction is limited to transmission in interstate commerce. As a result, the Commission has, since Order No. 888, recognized in rulings that it lacks jurisdiction over distribution facilities, regardless of voltage and thus established a mechanism to distinguish between Commission-jurisdictional and non-jurisdictional electric facilities. The Commission likewise recognizes an exclusion to its bulk electric system reliability regulations for local networks, certain facilities between 100 and 300 kV which can be shown are not part of the integrated transmission grid and thus not part of the bulk electric system.[969] These exceptions for electric facilities that are truly local allow the Commission to expand its regional planning requirements without concern that it is interfering with true "local" planning or state level retail service obligations.

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[969] The Commission did exclude local networks (LN) – a group of contiguous transmission elements operated at or above 100 kV but less than 300 kV that distribute power to load rather than transfer bulk-power across the interconnected system – from the facilities of the bulk power system. The Commission said this local network exclusion (along with three other exclusions approved in Order No. 773) will exclude many facilities that are used in local distribution and thus should be excluded from the bulk electric system.

The Commission held, "LN's [Local Networks] emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk-power transfer across the interconnected system. The LN is characterized by all of the following:

> a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusion I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);
> b) Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and
> c) Not part of a Flowgate or transfer path: The LN does not contain a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

To establish the limits of its jurisdiction the Commission has employed a Seven Factor Test to determine whether specific facilities are excluded from Commission jurisdiction, regardless of voltage. In Order No. 888, the Commission said that section 201 of the FPA, gives the Commission jurisdiction over transmission in interstate commerce (by public utilities) **without qualification**, finding compelling the fact that section 201 of the FPA, on its face, gives the Commission such jurisdiction.[970] Once jurisdiction over transmission has been established, the Commission explained that sections 205 and 206 of Part 2 of the Federal Power Act mandate that "we ensure that, with respect to any transmission in interstate commerce or any sale of electric energy for resale in interstate commerce by a public utility, no person is subject to any undue prejudice or disadvantage."[971] The Commission added that "[u]nder these sections, we must determine whether any rule, regulation, practice, or contract affecting rates for such transmission or sale for resale is unduly discriminatory or preferential, and **we must disapprove those** contracts and **practices that do not meet this standard**."[972]

In Order No. 888, the Commission rejected assertions that its jurisdiction was limited, finding: "we have the authority—**indeed, a responsibility**—to require non-discriminatory open access transmission as a remedy for undue discrimination."[973] But "non-discriminatory open access" is meaningless if it is restricted to what self-interested transmission owners decide are the limits of the transmission grid for which such access is available, particularly if that means

[970] 16 U.S. Code § 824. Section 201(b)(1) states in part:

> The provisions of this Part [Part 2 of the Federal Power Act] shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but except as provided in paragraph (2) shall not apply to any other sale of electric energy or deprive a State or State commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line.

[971] Order No. 888 61 FR 21564.
[972] *Id*.
[973] *Id*. (emphasis added).

rebuilding the grid of yesterday instead of the grid needed for tomorrow. As discussed below, the Commission's orders on transmission planning recognized this very fact.

In Order No. 888, while recognizing the breadth of its jurisdiction, the Commission also recognized the limitations of that jurisdiction, which does not cover facilities used in local distribution. Section 201(b)(1) continues stating in part: "but shall not have jurisdiction, . . . over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter."[974] To differentiate between transmission facilities subject to the Commission's jurisdiction and local distribution facilities not subject to the Commission's jurisdiction, the Commission has set out a seven-factor test.

The seven factors are as follows:

> (1) local distribution facilities are normally in close proximity to retail customers;
>
> (2) local distribution facilities are primarily radial in character;
>
> (3) power flows into local distribution systems and it rarely, if ever, flows out;
>
> (4) when power enters a local distribution system, it is not re-consigned or transported on to some other market;
>
> (5) power entering a local distribution system is consumed in a comparatively restricted geographical area;
>
> (6) meters are based at the transmission/local distribution interface to measure flows into the local distribution system; and
>
> (7) local distribution systems are of reduced voltage.

[974] 16 U.S. Code § 824.

Under that test, the voltage of the facility is not the only factor,[975] or the key factor.[976] Rather, the seven-factor test enables the Commission to identify *the primary function of a facility*. The primary function determines whether the facility is under our jurisdiction, either transmission or local distribution.[977] In this regard, the Commission has recognized that even lower voltage facilities can, and do, operate as transmission in interstate commerce.[978] The Commission has also found facilities above 100 kV to be local distribution.[979] In the *Southwest Power Pool (Tri-*

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[975] Commission precedent under the seven-factor test also allows for additional factors to be taken into consideration, such as previous classifications in a joint pricing zone, and how the totality of the circumstances bears on each of the seven factors. S*ee, e.g., S. Calif. Edison Co.*, 153 FERC ¶ 61,384, at P 19 and PP33-34 (2015)(finding the bulk of SoCal Edison's 115 kV Facilities to be local distribution facilities but concluding the specific protection systems and associated lines to be transmission and subject to Commission jurisdiction.)

[976] In the context of 60 kV facilities, the Commission has clarified "the seven-factor test may be applied to determine whether any facility is transmission, regardless of whether it is operated at, above, or below 60 kV" concluding nothing "precludes the application of the seven-factor test to any facilities." *Southwest Power Pool, Inc., GridLiance High Plains LLC,* 172 FERC ¶ 61129 at P 23 (2020).

[977] *California Pacific Electric Company, LLC,* 133 FERC ¶ 61018 at P 45 (2010).

[978] The Commission has found facilities under 100 kv can be transmission. See *City of Pella, Iowa v. Midwest Independent Transmission System Operator, Inc. and MidAmerican Energy Company,* 134 FERC ¶ 61081 at P 73 (2011)(applying the seven factor test and finding 69 kV facilities to be transmission when (i) the 69 kV facilities are not in close proximity to retail customers, but are used to support service to communities across a wide region, (ii) the 69 kV facilities are not primarily radial in character, (iii) when the evidence indicates that an average of 30 percent of the energy flowing into Pella's interconnection points between 2007 and 2009 flowed out of Pella's facilities and power that enters Pella's 69 kV facilities is transported across its system to other markets (iv) power that enters Pella's system is not consumed in a comparatively restricted geographical area (v) the evidence indicates that Pella's meters are designed to measure bilateral flows and that Pella's 69 kV facilities operate at a higher voltage than those facilities that Pella uses to serve retail load.); *Public Service Electric and Gas Company*, 122 FERC ¶ 61,234 (2008)(finding seven specific 69kV circuits to be transmission when these to-be-constructed 69 kV facilities will connect with facilities that are already classified as transmission.)

[979] See *S. Calif. Edison Co*., 153 FERC ¶ 61,384, at P 19, PP 33-34 (2015) (the 115 kV facilities are generally in close proximity to the retail customers they serve, the 115 kV facilities are not planned or designed to form parallel paths between the systems and the bulk electric system, power flows into the 115 kV facilities from the integrated transmission network through a single point, power entering from the interconnected transmission network operated by the CAISO typically remains within the 115 kV facilities and the radial nature of those facilities otherwise prevents this power from being transported back to the integrated transmission network for consignment to another market during normal operating conditions, power entering into the 115 kV facilities is consumed in a comparatively restricted geographical area, as evidenced by the relative proximity of the 115 kV facilities to the retail customers, metering of the 115 kV facilities at or near the point of interconnection to the CAISO-controlled integrated transmission network is consistent with factor six, use of the 115 kV facilities is for ""reduced voltage," given the longer distances that must be traversed in serving retail load in these portions of SoCal Edison's service territory); see also, *DTE Electric Company v. Midcontinent Independent System Operator, Inc. and International Transmission Company, LLC,* 180 FERC ¶ 61,222 (2022)(finding new single-circuit radial line and associated equipment to serve load in the City of Croswell, Michigan (Croswell Interconnection) is local distribution facility despite the fact that facility 120 kv in part because the Croswell Interconnection distribution has a strong similarity to other distribution lines owned by DTE Electric at the same voltage, specifically the Croswell Interconnection is "most akin" to the 50 radial 120 kV lines running to end-use customers classified as local distribution by the Michigan Public Service Commission.); *see also Consumers Energy Co. v. MISO*, 171 FERC ¶ 61,020 at P 91 (2020) (finding a 138 kV radial line that will serve a

County),[980] the issue was whether Tri-County's Bourk 115/69 kV Transmission Interchange and the Cole 115/69 kV Transmission Interchange were transmission facilities. Applying the seven-factor test, the Administrative Law Judge (ALJ) found the facilities to be local distribution facilities. The Commission agreed. The facilities were local distribution under six of the seven factors, but the facilities were not of low voltage – the seventh factor. The Commission reiterated, however, that "the voltage levels at which the Bourke and Cole Transmission Interchanges operate (the seventh factor) does not by itself determine whether a facility is transmission or distribution." Rather the Commission said it would "evaluate upstream and downstream power segments and flows across the facilities against the primary function of the facility to form a conclusion," in that case that the facilities were local distribution facilities.[981]

Thus, the Commission's seven-factor test allows any transmission owner to establish that certain of its specific facilities, regardless of voltage, function as distribution, *i.e.*, "local" facilities, if they are indeed of a nature that only provides local service. But, as the Commission's adoption of NERC's bulk electric system definition and reliability regulations

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distribution substation is a distribution facility).

980 *Southwest Power Pool, Inc.,* 149 FERC ¶ 61,051 (2014) (finding 115/69 kV facilities to be local distribution and rejecting the claim that Tri-County's facilities were transmission facilities because of the vast size of its service territory and how far its customers are from each other, facilities are not in close proximity to its retail customers, agreeing with ALJ that the relevant consideration was not the sheer size of Tri-County's service territory, but the fact that the geographic territory in which its power was consumed is restricted by end-users and finding that the meters only measure power flows into Tri-County's local distribution system facilities serving Tri-County's retail customers and Tri-County did not show that the meters measure bilateral flows.

981 Later in the *Southwest Power Pool/Gridliance case*, after GridLiance acquired from Tri-County approximately 410 miles of 69 kV and 115 kV lines and substations, feeders, switches, transformers, and related assets located in the Oklahoma Panhandle region (Pre-Upgrade Oklahoma Assets), the Commission continued to find that the facilities were local distribution even after certain upgrades and extensions were constructed. After the purchase to improve system reliability, GridLiance constructed certain upgrades and extensions to a subset of the Pre-Upgrade Oklahoma Assets, which, GridLiance said and an ALJ agreed, resulted in a portion of the Pre-Upgrade Oklahoma Assets qualifying as transmission facilities under Attachment AI (i.e., the GridLiance Facilities). The Commission disagreed. While the facilities were transmission under factors 2 (the facilities were looped and not **primarily radial in character)** and 7 (the facilities were not of low voltage) the Commission found that the fact "that the GridLiance Facilities are looped and high voltage, without more, is insufficient in this case to establish that the **primary function** of the GridLiance Facilities under the seven-factor test is transmission." *Southwest Power Pool, Inc*, 180 FERC ¶ 61,192 at P 215 (2022).

establish, the vast majority of electric facilities operating at 100 kV or greater[982] are part of the interconnected transmission grid and should be planned as such. Owners of facilities above 100 kV have had, and would continue to have, the ability to demonstrate that particular facilities are not Commission-jurisdictional transmission, or represent a Local Area Network and should continue to be planned with other distribution functions.

3. The Commission Has Recognized That 100 kV And Above Transmission Facilities Have Region-wide Benefits

More than a decade ago the Commission recognized that transmission facilities between 100 kV and 300 kV were regionally important "transmission facilities to integrate the eastern and western portions of the SPP grid, reduce congestion, efficiently integrate new resources, and accommodate new or growing loads."[983] Although the Commission made the determination in the context of a cost-allocation proposal, the SPP Highway/Byway Methodology recognizes that transmission facilities at 100 kV and above have region-wide benefits, and should be planned as such. Indeed, the Commission found relevant that in making the filing,

> SPP states that due to the realities of an integrated network and Commission policies such as Order No. 890, **transmission system planning in SPP has evolved from a utility-by-utility approach focusing primarily on maintaining reliability at the local level to a region-wide approach.** SPP states that a region-wide approach focuses on the development of a robust transmission system that is required to take into account not only reliability issues, but economic opportunities to reduce congestion, as well as state and federal policy goals such as increased use of renewable energy resources, greater incorporation of demand response and energy efficiency technologies, and reduced carbon dioxide emissions.[984]

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[982] With the advent of new technology, certain facilities that were designed as 69 kV facilities are now operated at 115 kV and should be treated as such for both bulk electric system definitional purposes and for the transmission planning rules addressed in this complaint as the impact on the regional grid is established by the operating voltage, not the original design.
[983] *Southwest Power Pool, Inc.*, 131 FERC ¶ 61,252 (2010) at P 4.
[984] *Id*. at P 21. Not surprisingly, although widely supported within SPP, multiple parties outside SPP commented on the proposal to ensure that it would not be applicable outside of SPP.

Under the SPP Highway/Byway approach, for transmission between 100 kV and 300 kV, costs are allocated one-third on a regional postage stamp basis and two-thirds to the zone in which the facilities are located.[985] SPP's filing was supported by a power transfer analysis that demonstrated that 115 kV and 138 kV facilities played a significant role in power transfers among the SPP zones. In explaining its support for the proposal, the "Oklahoma Commission argues that without the Highway/Byway Methodology, 'individual companies within the SPP footprint would continue to build transmission that benefits themselves and their customers rather than the region.'"[986] That reality is precisely the basis for this Complaint.

In accepting the SPP Highway/Byway proposal, the Commission recognized that although "Commission's responsibility to ensure that transmission rates are just and reasonable and not unduly discriminatory or preferential is not new; however, **the circumstances in which the Commission must fulfill its statutory responsibilities change with developments in the electric industry, such as changes with respect to the demands placed on and the corresponding operation of the transmission grid.**"[987] The Commission identified the following as changes warranting a change in its approach:

> the continuing transition from relatively localized transmission system operation and markets trading to larger, centralized transmission system operations and regional power markets, and the increasing adoption of renewable portfolio standards, other state policies that promote increased reliance on renewable energy resources, and a focus by Congress and the Commission on promoting reliability and economically efficient transmission infrastructure development.[988]

These changes have only accelerated while the amount of regional planning has decreased.

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[985] *Id*. at P 10.
[986] *Id*. at P 32, citing Oklahoma Corporation Commission at 2.
[987] *Id*. at P 63 (emphasis added).
[988] *Id*. at P 65.

4. Existing Tariff Provisions That Are Unjust And Which Must Be Removed

Once the Commission determines that an existing rate/practice[989] is unjust and unreasonable, Section 206 requires the Commission to act.[990] While Section 206 requires that the complainant recommend a replacement rate, "[i]t is 'the Commission's job—not the petitioner's—to find a just and reasonable rate.'"[991] Here the Commission's job is made easier by the fact that for more than two decades the Commission has recognized that regional planning is essential to the Commission meeting its statutory mandate to ensure just and reasonable transmission rates.[992] If the Commission's core mission is "reliability and affordability,"[993] regional planning is essential to both parts of that mission.

Notwithstanding the regional planning requirements of Order No. 1000, the required regional transmission planning processes[994] have not appropriately evaluated "alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process."[995] As the Commission noted in Order

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[989] Local planning tariff provisions are practices that directly affect FERC-jurisdictional transmission rates.
[990] 16 U.S. Code § 824e.
[991] *FirstEnergy Serv. Co. v. FERC*, 758 F.3d 346, 353 (D.C. Cir. 2014) *quoting Md. Pub. Serv. Comm'n v. FERC*, 632 F.3d 1283, 1285 n. 1 (D.C. Cir.2011).
[992] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*, Order 888, 61 Fed. Reg. 21,540, 21,542 (May 10, 1996) ("888"); *Regional Transmission Organizations*, Order No. 2000, 89 FERC ¶ 61,285, FERC Stats. & Regs. ¶ 31,089 (1999)("Order No. 2000"); *order on reh'g*, Order No. 2000-A, 90 FERC 61,201 (2000) ("Order No. 2000-A); *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119, FERC Stats. & Regs. ¶ 31,241 (2007) ("Order No. 890"), *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297, FERC Stats. & Regs. ¶ 31,261 (2007) ("Order No. 890-A"); *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 (2009); Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, 76 FR 49842 (Aug. 11, 2011), 136 FERC ¶ 61,057, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 ("Order No. 100-A"); *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *affirmed sub. nom*. *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 68 (D.C. Cir. 2014).
[993] https://energycommerce.house.gov/posts/chair-rodgers-to-ferc-without-affordable-and-reliable-energy-our-economic-and-national-security-are-at-risk (last accessed Dec. 18, 2024).
[994] Order No. 1000 at P 146.
[995] Order No. 1000 at P 148.

No. 1000, the requirement to plan at a regional level "include[s] transmission facilities to meet reliability requirements, address economic considerations, and/or meet transmission needs driven by Public Policy Requirements . . ..."[996] This cannot happen efficiently and cost-effectively if individual transmission owners have planning authority for a range of projects that go into the regional plan but do not come through regional planning.

The lack of regional planning is a direct result of the ability of existing transmission owners to develop Self-Planned Transmission under currently effective "local" planning tariff provisions to the exclusion of regional planning. Because their own economic self-interest makes planning through local tariffs often the only mechanism to ensure that rate base additions inure to their shareholders,[997] Local Planning has supplanted the required regional planning. Those facilities above 100 kV planned by individual transmission owners are almost always Commission-jurisdictional transmission and the Commission has established practices for determining when above 100 kV is not jurisdictional transmission[998] or part of the Bulk Electric System.[999] For facilities above 100 kV that are jurisdictional transmission and part of the Bulk Electric System, they are by definition regional in nature and regionally impactful. Allowing continued individual transmission owner planning of regionally integrated jurisdictional transmission notwithstanding the integrated nature of the transmission grid will continue to lead to the circumvention of regional planning processes, cumulatively resulting in unjust and unreasonable rates, contrary to the Commission's core mission. In addition, through

[996] *Id*.
[997] As noted previously, state level incumbent preferences also provide a mechanism for transmission owners with strong state level lobbying to ensure that all new transmission inures to its benefit.
[998] *Southwest Power Pool, Inc.,* Order On Initial Decision, Opinion No. 579, 180 FERC ¶ 61,192 (2022) (finding that 115 kV facilities did not meet the Commission's Seven Factor Test).
[999] *So. Cal. Edison Co.*, 153 FERC 61,384 (2015) (determining that certain Southern California Edison 115 kV facilities are "facilities used in local distribution of electric energy" and thus exempt from mandatory reliability requirements of Order No. 773).

Commission Orders, the Commission has excluded the bulk of Self-Planned Transmission, those addressing transmission facilities reaching the end of operational life, from even the most basic requirements of Order No. 890.[1000] Because this Complaint has demonstrated that existing tariff provisions allowing individual transmission owners to plan regionally impactful jurisdictional transmission results in unjust and unreasonable rates, the Commission must determine the just and reasonable replacement tariff provisions.[1001]

Existing RTO/ISO tariffs and individual transmission owner tariffs in non-RTO/ISO regions with local planning provisions across the country have overlapping planning provisions applying to the same voltage level transmission facilities, allowing transmission above 100 kV to be planned both "locally" (*i.e.*, by an individual transmission owner) and regionally, notwithstanding that each of the three continental United States electric transmission interconnections (the Eastern, Western, and ERCOT) represent three singular machines.[1002] Other tariffs clearly segregate "high voltage (69 kV and above) transmission system"[1003] planning from planning for truly local facilities. To the extent that facilities under 100 kV and those over 100 kV are not segregated for planning purposes, several existing local planning tariff

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[1000] *S. Cal. Edison Co.*, 164 FERC ¶ 61,160, at P 31 (2018) *citing* Order No. 890, 118 FERC ¶ 61,119 at PP 57-58, 421-422)); *Cal. Pub. Utils. Comm'n v. Pac. Gas & Elec. Co.*, 164 FERC ¶ 61,161, at P 68 (2018); *PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,136, at PP 12, 89, *order on reh'g*, 173 FERC ¶ 61,225 (2020); *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,242, at P 54 (2020), *order on reh'g*, 176 FERC ¶ 61,053 (2021).
[1001] 16 U.S. Code § 824e.
[1002] *See* "U.S. electric system is made of interconnections and balancing authorities," EIA (July 2016, *available at* three continental United States electric transmission interconnections represent three singular machines (last accessed Dec. 18, 2024). The Commission has explained that "all of the individual facilities used to transmit electricity are treated as if they were part of a single machine. The Commission takes this approach on the ground that a transmission system performs as a whole; the availability of multiple paths for electricity to flow from one point to another contributes to the reliability of the system as a whole. This principle has a strong basis in the physics of electrical transmission for there is no way to determine what path electricity actually takes between two points or indeed whether the electricity at the point of delivery was ever at the point of origin." *Buckeye Power, Inc.*, 142 FERC ¶ 63,007, 66167 (2013).
[1003] *See*, *e.g.*, Order No. 1000 Compliance Filing of Public Service Company of Colorado, Southwestern Public Service Company, filed October 11, 2012 in Docket No. ER13-75 by Xcel Energy Operating Companies, reflecting that for the Southwest Power Pool region in which Southwest Public Service Company is a member, all planning above 69 kV is conducted on the regional level, while lower voltage is not, but for Public Service Colorado any voltage level can be planned either locally or regionally.

provisions allow individual transmission owners to plan projects with regional impact at any voltage level, regardless of regional implications.[1004] These same planning provisions[1005] allow those transmission owners to establish the criteria for which they will plan, effectively allowing them to create a planning "need" and then plan an individual transmission project having regional implications to address that self-created need. Since the regional planning requirements of Order No. 1000 were implemented, the investment of billions of dollars in Self-Planned Transmission investment has been undertaken. Transmission owners have identified Billions of dollars more in investment in Locally Planned projects in the next several years. Many of these locally planned projects, both historically and future ones, are the replacements of aging infrastructure that was built decades ago for purposes substantially different than the grid needed for tomorrow, whether that grid is driven by generation transition, electrification, data center load growth, or all of the above. As noted above, the Commission has determined that Order No.

[1004] PJM OA, § 1, Definitions S–T, *Supplemental Project*, available at: pjm.com/directory/merged-tariffs/oa.pdf (last visited Nov. 26, 2024); NYISO, OATT, § 31.2.2, Attachment Y, retrieved from https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOOATT.pdf (last accessed (Dec. 18, 2024); Pacificorp, Open Access Transmission Tariff FERC Electric Tariff Volume No. 11, updated Oct. 28, 2024, Attachment K retrieved from https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20241028_OATTMaster.pdf (last accessed Dec. 18, 2024); Dominion Energy South Carolina, Inc. Open Access Transmission Tariff, Attachment K, https://www.oasis.oati.com/woa/docs/SCEG/SCEGdocs/DOMINION_ENERGY_SOUTH_CAROLINA_OATT_07.18.24.pdf (last accessed Dec. 18, 2024); Joint Pro Forma Open Access Transmission Tariff, Louisville Gas and Electric Company and Kentucky Utilities Company, Attachment K (Jan. 24, 2015), retrieved from https://www.oasis.oati.com/woa/docs/LGEE/LGEEdocs/LGE_and_KU_Joint_Pro_Forma_OATT_as_filed_of_date_12_7_2021.pdf (last accessed Dec. 18, 2024); Open Access Transmission Tariff of Alabama Power Company, Georgia Power Company, Mississippi Power Company and Mississippi Power Company, Tariff Volume 5, Attachment K (May 1, 2024), Retrieved from https://www.oasis.oati.com/woa/docs/SOCO/SOCOdocs/Southern-OATT_current.pdf (last accessed Dec. 18, 2024); Arizona Public Service Company, Pro Forma Open Access Transmission Tariff, Attachment E, retrieved from https://www.oasis.oati.com/woa/docs/AZPS/AZPSdocs/APS_OATT_Volume_2_20240423.pdf (last accessed Dec. 18, 2024)
Duke Energy Florida and Florida Power & Light have a threshold of 230 kV before a project will be included in the regional plan. Joint Open Access Transmission Tariff of Duke Energy Carolinas, LLC, Duke Energy Carolinas LLC, and Duke Energy Progress, LLC, Attachment N-2, § 1.2.3, retrieved from https://www.ferc.duke-energy.com/Tariffs/Joint_OATT.pdf (last accessed Dec. 18, 2024); Florida Power & Light Company, FERC FPA Electric Tariff Open Access Transmission Tariff, Attachment K, § 1.2.3, retrieved from oasis.oati.com/woa/docs/FPL/FPLdocs/Amended_FPL_OATT_04-01-2024.pdf (last accessed Nov. 26, 2024).
[1005] **Attachment B** to the Complaint includes several provisions of transmission providers and transmission owners authorizing and related to Local Planning.

890's local planning requirements do not apply to the replacement of aging infrastructure unless the replacement will "expand" the grid, effectively incentivizing existing owners to rebuild the grid of yesterday to the exclusion of regional planning what is needed for today's integrated grid. This Complaint does not challenge the Commission's prior interpretation of Order No. 890. Instead, based on the extensive evidence referenced above regarding the interconnected nature of the transmission grid, the changes in that grid since existing facilities were built, and the demands for the future, demonstrate that planning of any Commission-jurisdictional transmission facilities at 100 kV or above at the individual transmission owner level is unjust and unreasonable and that regional planning is required for such facilities. As such, the Complaint is not reliant on the prior arguments as to the scope of Order No. 890 or the appropriate interpretation of contractual agreements addressing the planning turned over to an RTO/ISO as the Complaint addresses individual transmission owner and regional planning among all Commission-jurisdictional entities, whether in an RTO/ISO or not.

As noted in this Complaint, notwithstanding the requirement that regional planning determine alternatives to the locally planned projects, the required regional look or displacement of locally planned projects has not occurred. In regions not covered by an RTO/ISO, it has not occurred due to a lack of independence in regional planning, which is currently controlled exclusively by the individual transmission owners, together with an inference in Order No. 1000 that an existing transmission owner can build what it wants notwithstanding the required regional planning process. In Order 1920 the Commission went further than a mere inference and asserted that the individual transmission owner "hold the leverage"[1006] over regional planning. In Order No. 1920-A the Commission tied the "leverage" to unidentified state laws "providing an

[1006] Order No. 1920 at P 1706.

individual transmission provider's ability to proceed with an in-kind replacement transmission facility . . ..”[1007] despite the fact that the states address only retail distribution of electricity, and have no jurisdiction to dictate FERC-jurisdictional transmission planning. The gaming of “local” needs versus regional needs, results in projects with clear regional implications being planned by individual transmission owners, creating cost allocation issues, failing to address all regional needs, and resulting in a lack of holistic planning.[1008] These failures cumulatively result in unjust and unreasonable transmission rates.

In those regions covered by an RTO/ISO, while independence is a required component of the RTO/ISO, contractual limitations on regional planning in governing documents and ongoing local planning have limited the RTO/ISOs ability (and desire) to plan regionally beneficial projects as replacements for projects planned by individual transmission owners.[1009] In addition, even when feasible, timing challenges from separate planning processes prevent holistic planning in a manner that allows for the assurance of just and reasonable rates. For example, the MISO “Other” Projects category allows those transmission owners that have, in theory, turned over local planning to MISO to nevertheless plan projects not needed to meet MISO identified criteria.

Finally, reviewing a project for “prudence” after it is already constructed provides no real opportunity to address the fundamental problem of a lack of holistic planning in the first instance. An after-the-fact prudence analysis is unfit to determine the correct project to build in

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[1007] Order No. 1920-A at P 831.

[1008] By way of example, Public Service of Colorado discussed a regionally beneficial 560 mile, double circuit 345 kV project through the WestConnect subregional planning group, before submitting the project to the Colorado Public Service Commission as a project allegedly planned under its local tariff. *See Colorado Cities Complaint* at 5, 30-38.

[1009] *See e.g.*, Comments of PJM Interconnection, L.L.C to the PJM Stakeholder approved proposal in ER20-2308-000, filed July 2, 2020, in which PJM asserted under the PJM governing documents that it did not have authority to supplant locally planned projects.

the first instance. The totality of evidence provided establishes that the local planning tariffs of the respondents to this Complaint are unjust and unreasonable and must be stricken to the extent that they allow individual transmission owners to plan FERC-jurisdictional transmission at facilities 100 kV or above.

5. Specific Relief[1010]

a) 100 kV Threshold for Regional Planning

Although the Commission is required to determine the just and reasonable replacement rate,[1011] Section 206 requires that the Complainants identify what they believe to be the appropriate replacement rate. To address the unjust and unreasonable transmission rates arising from the over-reliance on individual transmission owner local planning to the exclusion of holistic regional planning, the Commission must require that all transmission providers and FERC-jurisdictional public utilities in non-RTO/ISO regions remove the ability to plan any Commission-jurisdictional transmission facilities 100 kV and above from their local planning tariffs.[1012] Further, the Commission must require that the regional planning processes required by Order No. 1000 be revised to implement exclusive regional planning of all transmission facilities 100 kV and above for all needs, including but not limited to: reliability, resilience, economic considerations, Public Policy, facilities addressing multiple needs, substations, generator interconnection, and planning for the end of operational life for existing transmission facilities above 100 kV. This Complaint seeks to keep all of Order No. 1000 in tact except for

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[1010] This Complaint requests two key elements of relief: 1) the 100 kV threshold for regional planning and 2) the Independent Transmission Planner. The 100 kV threshold is the primary relief sought by this Complaint. The ITP is important, and will help support more holistic, cost-effective planning; however, any concerns with implementation and administration of an ITP should not hold up the expeditious granting of the Complaint's requested 100 kV threshold and removal of the applicable local planning tariff provisions.

[1011] *FirstEnergy Serv. Co. v. FERC*, 758 F.3d 346, 353 (D.C. Cir. 2014) *quoting Md. Pub. Serv. Comm'n v. FERC*, 632 F.3d 1283, 1285 n. 1 (D.C. Cir. 2011).

[1012] As noted above, the Commission has processes to determine whether facilities above 100 kV are nevertheless "facilities used in local distribution of electric energy" and thus outside Commission jurisdiction. *So. Cal. Edison Co.*, 153 FERC 61,384 (2015).

the requested change pertaining to the 100 kV threshold for regional planning and the suggested modification to the definition of Regional Transmission Facility.[1013]

In Order No. 1000, although the Commission required a regional planning process and a regional plan, to determine whether the project was 'local' or 'regional' the Commission focused on the cost allocation of proposed projects rather than the regional nature of the transmission facility. For example, in Order No. 1000, the Commission held that "[a] local transmission facility is a transmission facility located solely within a public utility transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation."[1014] Similarly, while the Commission required the participation in a regional transmission planning process that results in a regional plan, the Commission distinguished between those transmission facilities in the regional plan and those "[t]ransmission facilities selected in a regional transmission plan for purposes of cost allocation..."[1015] The Commission held that "[t]ransmission facilities selected in a regional transmission plan for purposes of cost allocation have been selected pursuant to a transmission planning region's Commission-approved regional transmission planning process for inclusion in a regional transmission plan for purposes of cost allocation because they are more efficient or cost-effective solutions to regional transmission needs."[1016] The Commission noted however that the transmission facilities selected in a regional plan for purposes of cost allocation "often will not compromise all of the transmission facilities *in the regional plan* . . .."[1017]

[1013] *See* Section VI.B.5(d) of this Complaint.
[1014] Order No. 1000 at P 63.
[1015] *Id*.
[1016] *Id*.
[1017] *Id*. (emphasis added).

The Commission further made clear that "the presence of such transmission projects in the regional transmission plan does not necessarily indicate an evaluation of whether such transmission facilities are more efficient or cost-effective solutions to a regional transmission need, as is the case for transmission facilities selected in a regional transmission plan for purposes of cost allocation."[1018] Thus, for clarity, the Commission should declare that electrical facilities at or above 100 kV – unless specifically excluded by a seven-factor or BES analysis or an emergency/*force majeure* rebuild (as discussed below) – are Commission-jurisdictional regional transmission facilities and all planning for regional transmission facilities above 100 kV must be conducted exclusively under the regional planning processes required by Order No. 1000, as further identified herein. Importantly, this Complaint requests no change in the cost allocation for regional projects, or the implications, if any, raised by the cost allocation of regionally planning projects 100 kV and above. This Complaint requests no changes to the existing cost allocation methodologies for existing project categories except to the extent that certain qualifying local project categories would now be planned regionally and allocated across benefitting zones in a manner that is roughly commensurate with benefits.

To ensure that the regional planner has sufficient opportunity to plan for facilities reaching the end of operational life, regional planning tariffs must be amended to require regional planning of needs arising from transmission facilities reaching the end of operational life. To facilitate that regional planning, the regional planning tariff must require that each existing owner of covered transmission facilities above 100 kV will be required to identify, on a minimum 10 year forward looking basis, transmission facilities likely to reach the end of operational life, and to provide final notification to the regional planner that the end of

[1018] *Id*. at P 64.

operational life will occur seven (7) years in advance of that happening (other than in the case of an established emergency).[1019]

To ensure that the legitimate planning needs of individual transmission owners for meeting retail service obligations continue to be met, the regional planning tariffs must be amended to require individual transmission owners, by a date certain annually appropriate to the respective regional planning cycle, to submit any "local" planning criteria for transmission facilities 100 kV and above that the regional planning entity should incorporate into the regional planning.[1020]

b) Independent Transmission System Planner

In the ANPOR to Docket No. RM21-17, the Commission outlined extensive questions regarding the role of an independent transmission monitor, and sought comments expressly on the need for "appropriate oversight over how new regional transmission facilities are identified and paid for."[1021] The Commission recognized the need for more independence in both RTO/ISO and non-RTO/ISO regions to monitor the planning and costs of transmission facilities.[1022] The Commission envisioned that such an entity "could review transmission provider spending on transmission facilities and identify instances of potentially excessive transmission facility costs, **including through inefficiencies between local and regional transmission planning**

[1019] If the Commission grants this component of the Complaint, the Commission will need to square this requirement regarding the identification of end-of-life facilities with the Commission's determination in Order No. 1920 (and any court precedent developed in response to the petition for review of Order No. 1920).

[1020] To the extent than an individual transmission owner submits such local planning criteria to the regional planner it must also include those criteria on an individual transmission owner FERC Form No. 715 submission.

[1021] ANOPR, RM22-17, at P 163. The Commission previously considered the value of an Independent Transmission Monitor in Docket Nos. RM05-17-000 and RM05-25-000, which culminated in the issuance of Order No. 890, numerous parties proposed, and the Commission considered, whether to appoint an independent entity to monitor transmission processes. The Commission noted that "overall comments on the use of an independent third party to oversee or coordinate the planning process range from those who believe it is not needed to those who feel it should be required rather than merely encouraged." Order No. 890 at P 563.

[1022] ANOPR, RM22-17, at P 163.

processes."[1023] This Complaint is focused on the role of the Independent Transmission Planner ("ITP") and ensuring cost-effective, holistic, and efficient regional planning from the outset at the project development stage. Therefore, this Complaint's use of the term independent transmission planner incorporates elements of what the Commission initially sought comment on in the ANOPR, including the need for an independent review of the planning process and costs of transmission facilities before construction starts.[1024]

While the Complaint seeks regional planning for all transmission facilities 100 kV and above, that regional planning is effective only if the planning is conducted independent of incumbent transmission owner self-interest. This reality is made abundantly clear by the fact that in the decade since the Commission required the development of a regional plan there has not been a single regional transmission project in those Order No. 1000 regions where the incumbent transmission owners control both local and regional planning. The current regulatory regime incentivizes transmission owners to overinvest in local projects while potentially underinvesting in more efficient regional solutions.[1025] Further, the lack of regional planning in non-RTO/ISO regions leads to the constant threat by transmission owners in RTO/ISO regions to exit RTO/ISO regions, often leading the RTO/ISO to favor incumbent interests.[1026] The requested requirement for an Independent Transmission Planner addresses the appropriate replacement rate/practice for

[1023] ANOPR, RM22-17, at P 164 (emphasis added).
[1024] ANOPR, RM22-17, at P 165. The Complaint's request for an ITP also addresses the Commission's concerns "on whether individual transmission provider practices regarding retirement and replacement of transmission facilities sufficiently align with the directive to ensure evaluation of alternative transmission solutions and whether these practices sufficiently consider the more efficient or cost-effective ways to serve future needs," including whether "sufficient transparency exists in retirement decisions to allow for [a] regional assessment." *Id.* at P 171.
[1025] Giberson Testimony at 5:6-6:2, 17:9-11, 18:17-20 (further observing that transmission owners exploit exemptions from regional planning requirements to pursue projects that increase rate base without assuring stakeholders that the investments serve the public interest).
[1026] *See Pa.-NJ-Md. Interconnection*, 101 FERC ¶ 61,318 at P 54 (2002) (a transmission owner's exit or entrance to an RTO is voluntary).

the unjust, unreasonable, and unduly discriminatory or preferential local tariff provisions allowing self-interested transmission owners to dictate regional planning.

In Complainants' supporting testimony, Mr. Giberson explains that an ITP will address key inefficiencies and biases in current transmission planning processes that undermine efforts to achieve just and reasonable rates. Even where regional planning occurs today, existing transmission owners are capable of "exert[ing] undue influence over outcomes by selective disclosure of generation investments plans, customer load forecasts, and the life expectancy of existing assets."[1027] The ITP can ensure that alternatives are adequately considered and the cost-effectiveness of project, including benefits metrics, are strongly supported.[1028]

Ensuring a successful and capable ITP requires robust transparency and information sharing. This Complaint does not dictate complete standardization of practices by utility or at the local level. Regional planning criteria would be subject to FERC's determination and approval, as reflected in the governing tariffs. Transmission Owner-determined local criteria must be provided to and implemented by the ITP. Such an approach recognizes differences in utility practices and ensures that the ITP is conducting regional planning independently but not in a way that could undermines the transmission needed to meet the utility's load-serving obligations under Section 217 of the Federal Power Act, 16 U.S.C. § 824q.

To ensure that the required regional planning is undertaken in a manner that results in the identification of the more efficient or cost-effective project, each Order No. 1000 regional planning region must amend its tariff, if necessary, to establish that the regional planning is conducted by an entity meeting an independent planning standard complying with the following criteria for Commission certification as an Independent Transmission Planner:

[1027] Giberson Testimony at 35:1-4.
[1028] *See* Giberson Testimony at 35:18-36:9.

(1) The Independent Transmission Planner Tariff will be subject to a governance and voting process, including necessary changes in both the tariff and operating agreement regarding planning rules without undue transmission owner influence;[1029]

(2) No Common Interest Agreements or other agreements that are unknown to other regional stakeholders between the planning entity and the transmission owners;[1030]

(3) Independent Transmission Planner directly accountable to FERC;

(4) Planning Authority: The Independent Transmission Planner will have planning authority for all transmission facilities over 100 kV (regional can include lower voltage facilities under the Independent Transmission Planner at a region's discretion).

(5) The Independent Transmission Planner will plan to a minimum planning horizon.

(6) The Independent Transmission Planner will be able to review non-transmission solutions to identified needs including cost recovery.

(7) For those transmission additions that are regionally planned and for which a competitive window is required, the Independent Transmission Planner will conduct the competitive process, including qualification and selection of the more efficient or cost-effective solution.

In RTO/ISO regions, the above requirements for transmission planning are traditionally administered by the RTO/ISO, as it is assumed the RTO/ISO has met FERC's existing independence standards.[1031] It is expected that certain RTO/ISO regions will be able to establish that the required independence is in place once the local planning opportunities for 100 kV and above transmission facilities are removed from individual transmission owner tariffs. The

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[1029] Critically, the governance changes must not allow for any loopholes or undue influence by transmission-owning interests to the detriment of consumers and other stakeholders in the stakeholder process. Recently, the Commission rejected efforts by PJM and the PJM Transmission Owners to effectuate governance changes that would have curtailed the rights of other stakeholders. The Commission rejected proposed CTOA amendments by the PJM Transmission Owners because certain of those amendments "contravene[d] Order No. 2000's requirement that RTOs be independent of control by any market participant or class of participants in both reality and perception." *Duquesne Light Co. et al*, 189 FERC ¶ 61,181 at P 43 (2024) (citing Order No. 2000, FERC Stats & Regs. ¶ 31,089 at 31,061)). The Commission further emphasized that "it is not just and reasonable to include substantive transmission planning procedures in the CTOA." *Duquesne*, 189 FERC ¶ 61,181 at P 55.

[1030] Such provision does not prohibit an agreement, available to all qualified persons, for the sharing of Critical Energy Infrastructure Information.

[1031] *See generally* FERC Order Nos. 888, 889, and 2000. The minimum independence characteristics of an RTO are delineated in Order No. 2000. *See* 18 C.F.R. § 35.34(j) (RTO independence requirements).

existing RTOs/ISOs would maintain FPA Section 205 filing rights.[1032] Certain RTO/ISOs should be required to continue in their role as independent system planners[1033] and develop necessary tariff changes emphasizing their independence from all sectors and membership groups, as well as incorporating and facilitating competitive solicitation rules that will take into consideration all transmission projects 100 kV and above. Funding for the ITP in existing RTO/ISO regions could occur through Schedule 1 in the RTO/ISO tariff that is subject to Commission review.

For transmission owners in non-RTO regions who met Order No. 1000 regional planning requirements through the establishment of an Order No. 1000 region, the transmission owners will be required to file tariff revisions that ensure the level of independence reflected above. In non-RTO/ISO, transmission owners and operators are not currently required to turn over operation of their transmission assets, and they largely plan for transmission needs independent of third-party oversight. This Complaint's requested relief seeking regional planning for almost all transmission projects above 100 kV would require these non-RTO/ISO planning regions to establish and fund an Independent Transmission Planner to serve the same planning and oversight duties as the transmission system operator or transmission provider in RTO/ISO regions.

The ITP would be designated and funded in each planning region, although transmission assets would continue to be controlled and operated in non-ISO/RTO regions by the transmission owner. Interested stakeholders should be involved with developing, and transmission owners should be required to file, any necessary tariff changes to implement an independent planner and

[1032] Any conditions surrounding an RTO/ISO's Section 205 filing rights may be subject to a region-specific determination, based on the particular characteristics and governing agreements in a particular RTO/ISO.

[1033] This Complaint and the accompanying testimony of Mr. Giberson use the term *Independent Transmission Planner or ITP*, given the frequency of the use of that term and concept in other proceedings. However, the Commission could utilize the term Independent System Planner, given FERC's longstanding use of the term Independent System Planner and the use of that term in several FERC regulated RTOs/ISOs in the United States. *See* www.ferc.gov/power-sales-and-markets/rtos-and-isos (last accessed Dec. 18, 2024).

to establish rules for competitive processes for all transmission projects 100 kV and above in the transmission owner's service territory. The ITP should be tasked with conducting transmission planning processes, generator interconnection studies, competitive solicitations, and coordination with other regions. The independent nature of this role is crucial to ensure that all interested parties are able to participate in transmission planning, submit project proposals for competition, and have their proposals given equal evaluation as an incumbent's proposal. Without such an independent role, incumbent transmission owners wield significant power for their own self-interest, foreclosing opportunities for considering competitive solutions. The ITP would likely need to have separate FPA Section 205 filing rights and a separate governing tariff. FERC would specify criteria for qualification as an ITP in non-RTO/ISO regions. An existing regional transmission planning entity could serve as the ITP if it meets the criteria and is approved by FERC.

c) The Independent Transmission Planner Must Be Involved In Limited Scenarios/Exceptions Where Facilities at or above 100 kV Are Not Regionally Planned

Complainants recognize that, under FERC's Seven Factor Test from Order No. 888, certain facilities at or above 100 kV will be considered distribution facilities that are not subject to FERC's jurisdiction and thus not subject to the regional planning requirements requested in this Complaint. The Independent Transmission Planner would not be involved in the planning of those distribution facilities. Complainants also recognize that certain emergency scenarios or *force majeure* circumstances may justify overriding Regional Planning. For example, a severe storm may knock down a 230 kV line that needs to be repaired as soon as possible. Regional Planning may not be practical in that circumstance. However, the ITP should still be involved in the process and decision-making regarding the solution to address that emergency or very immediate need. Accordingly, the ITP would have authority to issue the necessary directives to the respective incumbent transmission owner when addressing that emergency or immediate transmission system need.

Additionally, Complainants recognize that merchant transmission may be subject to different standards in a planning process.[1034] However, the ITP shall be afforded an opportunity to be involved at various critical stages of merchant transmission development to ensure that the regional plan is harmonious with the planned merchant transmission development and does not result in duplication of projects or overbuilding.

Complainants also recognize that large load interconnections currently are processed by the local incumbent utility and are not subject to Regional Planning. Directly assigned costs to those new large loads would not be subject to Regional Planning. However, any "rolled-in" network upgrades would be subject to Regional Planning. The ITP would be involved in the evaluation and review of those "rolled-in" network upgrades that would be subject to Regional Planning. Accordingly, the ITP should be involved in the review of the costs and proposed solutions attributed to large load interconnections that cause a need for network upgrades at 100 kV and above.

d) Description of proposed tariff changes (required by Section 206)

Complainants request the Commission to comprehensively require all necessary revisions to all FERC-jurisdictional tariffs, including revisions to the *pro forma* Open Access Transmission Tariff, to prevent the circumvention of regional planning in the future. Therefore, the

[1034] Different rules already apply to merchant transmission. Unlike traditional utilities, which recover their costs through cost-of-service transmission rates recovered from customers pursuant to transmission tariffs, investors in merchant transmission projects assume the risk associated with their projects. *See* Allocation of Capacity on New Merchant Transmission Projects and New Cost-Based, Participant-Funded Transmission Projects: Priority Rights to New Participant-Funded Transmission, 142 FERC ¶ 61,038 (2013) (policy statement refining FERC rules around the allocation of capacity for new merchant transmission projects and new nonincumbent, cost-based, participant-funded transmission projects).

Commission should require regional planning tariffs to apply regional planning to all transmission facilities meeting the definition of Bulk Electric System 100 kV and above for all planning drivers, subject to the few narrow exceptions/clarifications, as described above around 1) distribution facilities; 2) emergency rebuilds/*force majeure* circumstances; and 3) merchant transmission. However, even if emergency rebuilds or merchant transmission are not directly subjected to the regional planning process, the ITP shall still be afforded a role in the development and deployment of such transmission projects.

Complainants further request all regional planning tariffs to require the appointment of a new Independent Transmission Planner standard to be applied to each Order No. 1000 planning region,[1035] with a directive for each and all Order No. 1000 planning regions to meet the heightened Independent Transmission Planner standard requirements below:

a) The planning for Order No. 1000 region may only be composed of entities with directly interconnected existing transmission 100 kV and above unless the Order No. 1000 region is an RTO.

b) The new Independent Transmission Planner standard for the Order No. 1000 Region has no operational requirements associated with the transmission planned, and therefore, does not meet the requirements of being an ISO or RTO;

c) Independence of Order No. 1000 Region – this requirement would be met with establishment of the following criteria related to the Independent Transmission Planner standard[1036]:

(1) a review of the governance and voting process for tariff changes and planning rules without undue transmission owner influence for each Order No. 1000 Region;

(2) No Common Interest Agreements or other agreements that are unknown to other regional stakeholders allowed;

[1035] *See* Giberson Testimony at 34:8-39:4.
[1036] An RTO/ISO may already meet the Independent Transmission Planner requirement.

(3) Order No. 1000 Region directly accountable to FERC, with project plans and portfolios of projects filed with FERC for informational purposes[1037] ;

(4) Relief is not suggesting that the Section 205 filing rights of Order No. 1000 regions are provided or changed. Order No. 1000 Regions retain existing filing rights.

d) Planning Authority: The Independent Transmission Planner standard for the Order No. 1000 Region will have planning authority for all transmission facilities over 100 kV (regional can include lower voltage facilities under the Independent Transmission Planner standard at region's discretion) subject to facilities over 100 kV that qualify as distribution facilities not subject to FERC jurisdiction. With this planning authority would also come the requirement for full access to needed information from transmission owners to properly plan the grid in a holistic manner.

(1) Minimum planning requirements include all of the following:

(a) Reliability

(b) Resilience

(c) Market efficiency (at 100 kV and above threshold)

(d) Public Policy Projects and required Order No. 1920 planning, including but not limited to, sensitivity and scenario analysis requirements

(e) State Agreement Projects[1038]

(f) Planning Aging Infrastructure Notifications and Aging Infrastructure Sensitivities

(i) Identified as infrastructure expected to be at the end of operational like as judged on a 10 year minimum forward looking basis

(ii) Final notification of end of operational life 7 years in advance (other than established emergency)

(g) Substations

(h) Able to review non-transmission solutions to identified needs including cost recovery

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[1037] Currently, project plans and portfolios are only reviewed and approved by RTO/ISO board ands non-RTO/ISO transmission provider boards or governing bodies. Given that these plans directly affect transmission rates that will eventually be charged to consumers, such plans should be filed with FERC at least for informational purposes. FERC could retain the authority to review and investigate the plans. The plans must include detailed cost data, information, and underlying assumptions.

[1038] Order No. 1920 envisions the use of State Agreement Projects. *See* Order No. 1920-A at PP 693, 700-705, 708.

(i) Generator Interconnection Queue: to include:

(i) "At-Risk" generation with at least a three-year advance planning horizon.

e) Funding Authority.[1039] Order No. 1000 Region would be allowed to charge membership fees and study costs to fund its planning.

To be clear, the heightened Independent Transmission Planner legal minimum threshold standard would be applied to each and all Order No. 1000 Regions. Compliance with the Independent Transmission Planner standard may not require a new legal entity to comply with the requirements of the replacement rate as it builds on the existing Order No. 1000 legal framework and the identified Order No. 1000 regions, but the participants in each Order No. 1000 region may create such an entity. Other Order No. 1000 responsibilities for regional planning remain unchanged.

The Independent Transmission Planner standard applied to Order No. 1000 regions would be consistent with the Commission's prior determination in Order No. 2000 that the RTO maintain "ultimate responsibility for both transmission planning and expansion within its region."[1040] All Independent Planner Tariff standards must be delineated in governing documents that are filed with the Commission and not merely discussed in non-binding business practice manuals.[1041]

If the RTO/ISO will also serve as the ITP, then the Commission must direct the revision of any RTO/ISO governing documents, including agreements between the RTO/ISO and the owners of the transmission facilities, to ensure that those governing documents do not impede,

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[1039] *See* Giberson Testimony at 37:6-8.

[1040] Order No. 2000 at ¶ 62.

[1041] *See* 16 U.S.C. § 824d(c) (requiring the "classifications, practices, and regulations affecting . . . rates and charges" to be filed with the Commission); *Prior Notice & Filing Requirements Under Part II of the Fed. Power Act*, 64 FERC ¶ 61,139, at 61,988, *order on reh'g*, 65 FERC ¶ 61,081 (1993) (interpreting the FPA as requiring practices significantly affecting rates and services to be filed with the Commission); *Tenaska Power Servs. Co. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 102 FERC ¶ 61,095 at P 32 (2003) (finding the filing requirement to apply to RTO business practices).

restrain, or hamper the RTO/ISO from truly planning independently. Complainants recognize that several governing documents, both within and outside RTOs/ISOs, will likely need to be revised if this Complaint is granted.

Subject to the narrow exceptions discussed herein, the Commission should direct revisions of local planning tariffs of FERC-jurisdictional public utilities to remove local planning of Bulk Electric System transmission facilities 100 kV and above. Consistent with Order No. 1000 requirements, the Order No. 1000 Region must produce a regional plan. This Complaint asks the Commission to issue relief that is universal and uniform to preclude evasion from relief for consumers via future transmission owner efforts to engage in transmission development outside a regional planning context, through necessary protections of and oversight by an Independent Transmission Planner. To prevent efforts to circumvent the proposed 100 kV threshold, the Commission could require all proposed transmission solutions between 69 kV and 99 kV to be independently evaluated by the Independent Transmission Planner to determine whether more than one transmission pricing zone benefits from the transmission project/solution. The Commission should also establish a clear definition of a regional project to prevent any kind of gaming or circumvention from regional planning. Per Order No. 1000-A, the Commission defined a regional project as one where "any costs of a new transmission facility are allocated regionally or outside of a public utility transmission provider's retail distribution service territory or footprint."[1042] The Commission could retain that existing definition of a regional facility, edited as follows:

- **Regional Transmission Facility** = a transmission facility that operates at or above 100 kv or provides benefits to two or more transmission utility zones, retail service territories, or regional footprints, as shown by an industry standard power

[1042] Order No. 1000-A at P 430.

flow analysis, such as Distribution Factor ("DFAX") or Line Outage Distribution Factor ("LODF") analysis.

Complainants emphasize the criticality of the above edit to the Order No. 1000 Regional Transmission Facility definition to prevent gaming that has occurred over the past decade. At the same time, the cost causation principle and the "beneficiary pays" principle must remain firmly in place.[1043] Both today and in the future, it is entirely possible and appropriate for independently and regionally planned projects to be locally and entirely cost allocated to one zone if that zone is the sole beneficiary.[1044] All cost causation rules remain and apply, even if transmission 100 kV and above is planned under the Independent Transmission Planner standard. The Commission recognizes the importance of preventing "one group of customers to pay for more than their fair share of the costs of transmission development" or for one group of customers to be charged costs that are not "roughly commensurate" with the benefits expected to be received form the transmission facility.[1045]

Pursuant to its authority under Section 206 of the Federal Power Act, the Commission should clarify how it addresses contractual issues arising in agreements between transmission owners and the RTO/ISO (which could be the independent system planner). Previously, the Commission read contractual provisions among transmission owners and PJM to prohibit more robust regional planning that a majority of PJM stakeholders had demanded.[1046] Drawing from

[1043] In Order No. 1920-A, the Commission reiterated that "any cost allocation must comply with cost causation and the 'beneficiary pays' principle." Order No. 1920-A at P 8 (citing *PJM Interconnection, L.L.C.*, Opinion No. 494, 119 FERC ¶ 61,063, at P 66 (2007) (requiring PJM to set forth a "beneficiary pays" method in its tariff and consistently apply that approach each time a new regionally-planned transmission facility is approved), *on reh'g*, Opinion No. 494-A, 122 FERC ¶ 61,082 (2008), *remanded Ill. Com. Comm'n v. FERC*, 576 F.3d 470, 474-78 (7th Cir. 2009) (*ICC v. FERC I*)).
[1044] *See* Order No. 1000-A at PP 424, 429 ("If the cost of a new transmission facility is allocated entirely to an area consisting of one transmission provider that has one or more smaller transmission providers within its borders, this might qualify as a local cost allocation, not a regional cost allocation.").
[1045] Order No. 1920-A at P 8 (citing *ICC v. FERC I*, 576 F.3d at 477).
[1046] *PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,136, at PP 12, 89, *order on reh'g*, 173 FERC ¶ 61,225 (2020); *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,242, at P 54 (2020), *order on reh'g*, 176 FERC ¶ 61,053 (2021); *Am. Mun. Power v. FERC*, 86 F.4th 922 (D.C. Cir. 2023) (denying consumer-oriented petitions for review). Although the

the evidence in this Complaint, the Commission should determine that existing contractual provisions in governing documents/agreements of RTOs/ISOs that do not provide, or attempt to limit or impair, regional planning or an independent transmission planning standard, as articulated above, are not just and reasonable. The Commission should mandate that FERC-jurisdictional public utilities give authority to Independent Transmission Planners. If the use of an independent transmission system planner is voluntary, then public utilities will contract around the ITP and act in their self-interest to plan as they deem fit as they have for the last three decades.

VII. OTHER REQUIRED INFORMATION FOR COMPLIANCE WITH RULE 206

A. Identification of the action or inaction (18 C.F.R. § 385.206(b)(1))

As discussed fully in the Complaint, the action violating the Commission's obligation to ensure just and reasonable transmission rates is the retained ability of individual transmission owners to plan FERC-jurisdictional transmission facilities at 100 kV and above at their discretion based on criteria they determine. The Commission long ago recognized that its ability to ensure just and reasonable rates is hampered "*in areas where the pro forma OATT leaves transmission providers with substantial discretion*."[1047] Allowing "local" planning of transmission facilities at 100 kV and above is precisely one of those areas with the retained substantial discretion to plan locally rather than regionally preventing just and reasonable

D.C. Circuit denied a consumer-oriented petition for review challenging FERC's orders restricting regional planning for end-of-life facilities in PJM, the Court's affirmation of the Commission's orders was based on the Court's determination that FERC reasonably interpreted the PJM Tariff as authorizing PJM Transmission Owners to remain responsible for planning Supplemental Projects. This Complaint presents evidence – that was not previously before FERC or the D.C. Circuit – to show that Local Planning Tariff provisions, such as PJM Tariff Attachment M-3 and PJM Operating Agreement Section 1 (Definition of *Supplemental Project*), are unjust and unreasonable.

[1047] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 26, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (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).

transmission rates. FERC-jurisdictional transmission facilities at 100 kV and above is part of the interconnected grid operating as a single machine in each of the Eastern Interconnection and Western Interconnection. Nevertheless, existing tariffs allow individual transmission owners to plan transmission facilities impacting that grid without any determination that the Self-Planned Transmission is the more efficient or cost-effective transmission for the regional grid and all of the needs of that grid. This includes rebuilding the grid of yesterday simply because it has reached the end of operational life without a determination for whether the transmission facilities needed for the gird as it existed half a century ago remain the more efficient or cost-effective facilities for the grid needed for tomorrow. The planning of such transmission on an individual transmission owner level prevents or hampers appropriate regional analysis of the needs of all transmission customers over the interconnected grid, resulting in balkanized planning to the detriment of consumers and the Commission's ability to determine and ensure just and reasonable rates. To remedy these unjust and unreasonable tariff provisions leading to unjust and unreasonable transmission rates the Complaint asks that all planning for transmission 100 kV and above be conducted at the regional level, in existing Order No. 1000 required regions and that individual transmission owner tariffs be amended to allow local planning only for transmission facilities below 100 kV, or those facilities found to be non-jurisdictional under the Seven Factor Test.

In addition, for the Commission to ensure that the regional planning itself does not continue to be dominated by individual transmission owner self-interest, substantial discretion, and unduly discriminatory planning, the Complaint establishes that existing tariffs are unjust and unreasonable to the extent that regional planning processes are not independent from the transmission owners. Transmission "planning" is a determination of those future transmission facilities that address transmission needs in the more efficient or cost-effective manner. As the Complaint outlines, the combination of individual transmission owner planning authority and non-independent regional planning has led to over reliance on individual transmission owner decisions and an under reliance on regional planning, notwithstanding the regional nature of the grid. Significant areas of the country have no true regional planning.

B. Explanation of the Violation (18 C.F.R. § 385.206(b)(2))

As fully recounted in the Complaint, the Commission has made clear that regional transmission planning is essential to the Commission's obligation to ensure just and reasonable transmission rates.[1048] The current unfettered discretion of existing transmission owners to individually plan transmission facilities at 100 kV and above, which the Commission has recognized as having regional impact, has prevented full regional planning and the Commission's determination of just and reasonable rates. As outlined fully in the Complaint, the violation is the failure of local planning to ensure just and reasonable rates as existing tariffs that allow individual transmission owners to plan regionally impactful transmission 100 kV and above are practices directly affecting rates. The Commission is obligated to address those practices once established, as the Complaint does, that they result in unjust and unreasonable rates.

[1048] Order No. 1000 at P 78, holding "We conclude that it is necessary to act under section 206 of the FPA to adopt the regional transmission planning reforms of this Final Rule, as discussed more fully below, to ensure just and reasonable rates and to prevent undue discrimination by public utility transmission providers. . . . the existing requirements of Order No. 890 are inadequate to ensure that public utility transmission providers in each transmission planning region, in consultation with stakeholders, identify and evaluate transmission alternatives at the regional level that may resolve the region's needs more efficiently or cost-effectively than solutions identified in the local transmission plans of individual public utility transmission providers." *See* Order No. 1920-A at PP 1 (finding the existing regional transmission planning and cost allocation processes to be unjust, unreasonable and unduly discriminatory or preferential), 804 (concluding that existing requirements governing transparency in local transmission planning processes and coordination between local and regional transmission planning processes are unjust, unreasonable, and unduly discriminatory or preferential).

The Complaint has identified billions of dollars in locally planned transmission that either was not reviewed at the regional level or received only superficial review. The tariffs that allow local planning are practices affecting rates, and causing those rates to be unjust and unreasonable.

C. Business, Commercial, Economic, or Other Issues Presented (18 C.F.R. § 385.206(b)(3))

Complainants represent large end-use consumers, consumer advocates, municipal utilities and cooperatives, public interest organizations, and thinktanks. As recognized by the Commission in Order No. 1920, the transmission component of a consumer's bill has been substantially increasing in recent years. Order No. 1920 found that "**transmission spending has continued to increase nationwide**."[1049] The Commission recognized in Order No. 1920 that transmission costs have become an increasing share of customers' overall electricity bills, underscoring the importance of ensuring that transmission investments are efficient and cost-effective.[1050] Transmission developers invested approximately \$20-\$25 billion annually in transmission facilities in the United States from 2013-2020.[1051] The Commission found that the "record demonstrates that **transmission investment is likely to substantially increase in coming**

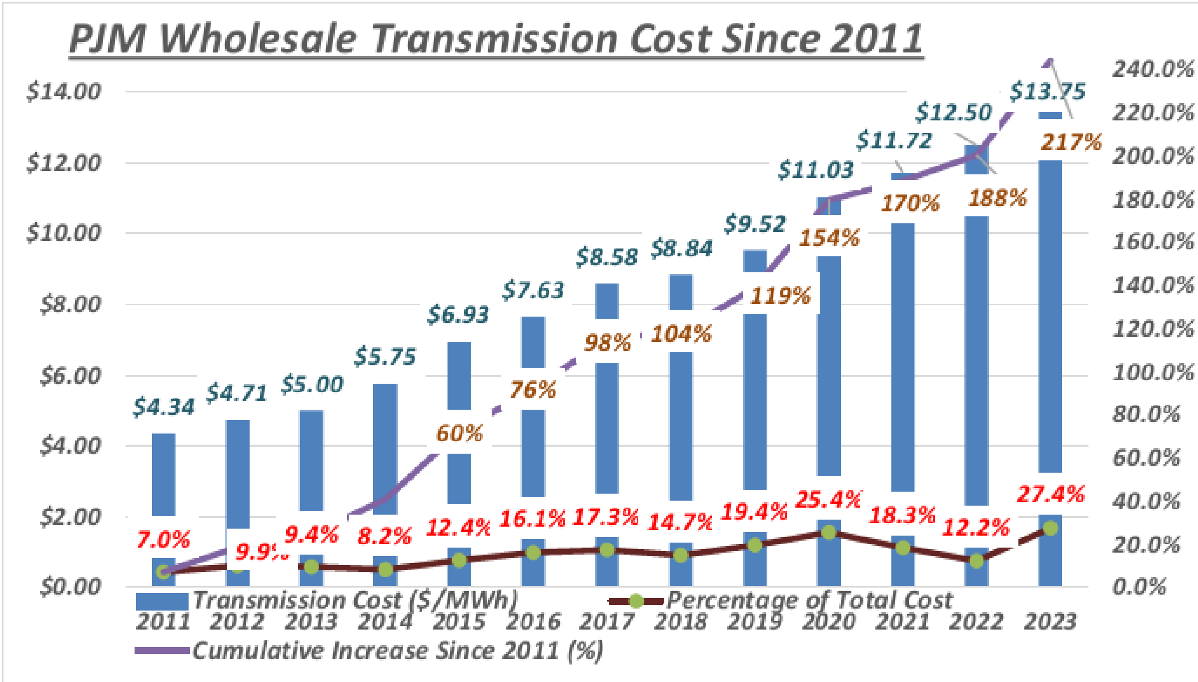
[1049] Order No. 1920 at P 92 (emphasis added).
[1050] Order No. 1920 at P 92 (citing Resale Iowa Initial Comments at 3 ("[T]ransmission costs have comprised an increasing percentage of [] total wholesale electric costs [for Resale Iowa's members]. Currently, transmission and ancillary services constitute approximately 43% of such costs, as compared to 18.1% in 2009."); Industrial Customers Initial Comments at 5 (showing that transmission costs made up just 7% of the total PJM electricity bill in 2011 but 27% by 2020); Rob Gramlich and Jay Caspary, Americans for a Clean Energy Grid, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure*, at 26-28 (Jan. 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/ACEG_Planning-for-the-Future1.pdf (ACEG Jan. 2021 Planning Report) (stating that the current approach to transmission planning "results in higher total energy bills for customers than would result from more forward-looking, holistic transmission planning"); *see also* California Municipal Utilities Initial Comments at 10 (projecting that between 2022 and 2040, total high and low-voltage transmission access charges will nearly double and noting that "[g]one are the days when transmission was a *de minimis* portion of the overall bill and increases had little impact on the end consumer"); Public Systems Initial Comments at 5 (noting that "New England's Regional Network Service transmission rate has grown *nine-fold*, from \$15.60 per kW-year (in 2003) to \$140.98 per kW-year (in 2021)")).
[1051] Order No. 1920 at P 92 (citing (citing Brattle-Grid Strategies Oct. 2021 Report at 2; Brattle Apr. 2019 Competition Report at 2-3 & fig.1.).

years"[1052] and there will be "**sustained transmission spending through at least 2050**."[1053] In the absence of implementing effective Local Planning reforms, consumers will continue to be subjected to paying unjust and unreasonable rates associated with projects that have not been independently determined to be the most efficient and cost-effective solution to solving the alleged need.

D. Financial Impact (18 C.F.R. § 385.206(b)(4))

As identified in the Complaint, the transmission component of consumers rates has increased substantially over the past ten to fifteen years, resulting in billions of dollars of individual transmission owner Self-Planned Transmission. In 2023, there was over $25 billion in transmission investment, with about $12.5 billion in individual transmission owner planned transmission projects.[1054] In PJM alone, 1584 locally planned projects with a cost estimate of $18.1 billion are slated to go in service before December 31, 2028.[1055] For a recent example detailing the substantial increase in PJM wholesale transmission costs in the PJM region since 2011, please see the Supplemental Comments of American Municipal Power, Inc. filed on March 6, 2024 in Docket No. RM21-17. AMP included the following chart to demonstrate the marked increase in PJM wholesale transmission costs[1056]:

[1052] Order No. 1920 at P 93 (emphasis added).
[1053] Order No. 1920 at P 93 (emphasis added).
[1054] *See* Brattle 2023 Transmission Investment Analysis at 1.
[1055] IMM Report at 721-722.
[1056] *See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, "Supplemental Comments of American Municipal Power, Inc.," at p. 3, Docket No. RM21-17 (Mar. 6, 2024).



The 2023 MISO Transmission Expansion Plan included $9 billion in investment in 572 new transmission facilities and two-thirds of that investment, $6 billion, will be spent on 382 Other Projects that are Locally Planned.[1057] The 2024 MTEP Report includes $6.7 billion in local reliability projects, [1058] including $4 billion characterized as Other Projects.[1059] Without Commission action, billions of dollars more in projects across the nation will be Locally Planned with little or no regional review. Adding insult to injury, through transmission rates, whether direct transmission rates or bundled retail, consumers pay for the inefficient individual transmission owner's Local Planning processes, thus forcing them to fund activities against their economic interest and exclusively in the transmission owner's economic self-interest.

[1057] The 2023 MTEP Report includes 382 Other Projects, 45 Baseline Reliability Projects, 2 Market Participant Funded Projects, 142 Generator Interconnection Projects, and 1 Multi-Value Project.
[1058] *See* MTEP24 Preview: Local Reliability, JTIQ, and Regional Projects, System Planning Committee of the Board of Directors (Oct. 30, 2024), *available at* https://cdn.misoenergy.org/20241030 System Planning Committee of the BOD Item 03b MTEP24 Preview655620.pdf; *see* MTEP24 Full Report (last accessed Dec. 18, 2024).
[1059] *See* MTEP24 Full Report at p. 180.

Complainants emphasize the criticality of the Commission's investigation into Local Planning processes in non-RTO/ISO regions where neither Complainants nor interested stakeholders have much access to cost data for Local Projects in those regions.

To the extent that the Commission looks at the financial impact on the individual transmission owner, the only known financial impact is a benefit in that the transmission owner will no longer have to plan 100 kV and above, which will be done at the regional level. Of course, consumers will pay those costs through the transmission rates, but with the assurance that the more efficient or cost-effective project for the region will be planned.

E. Practical/Operational Impact (18 C.F.R. § 385.206(b)(5))

Practically, more operational resources and coordination among stakeholders and interested parties will need to be utilized to more fully engage and implement the regional planning procedures requested by the Complaint. Financial resources will need to be allocated by public utilities and RTOs/ISOs to fund an independent transmission planner. While there will be costs and resources associated with a transition to a more comprehensive regional transmission planning construct, ultimately costs and resources will be saved in the long-run due to the efficiencies and cost-saving measures that will be harnessed by regional planning. Further, greater coordination and transparency into transmission planning processes can help better illuminate issues at the onset, allowing for a more timely and cost-effective solution. Oversight by an independent transmission planner will also help ensure cost-effective and efficient planning solutions.

F. Other Pending Proceedings (18 C.F.R. § 385.206(b)(6))

Consumers have made prior efforts to rein in local transmission planning, or at least to have the Commission exercise greater jurisdictional control over such planning but the Commission has rejected those efforts on narrow grounds without addressing the underlying fundamental issue: unchecked local planning impairs, or outright prevents, the Commission's statutory mandate to ensure just and reasonable rates. A summary of proceedings and stakeholder efforts relating to local transmission planning issues is provided below.

1. CPUC Complaint Regarding Self-Planned Transmission Projects

In 2017 the California Public Utility Commission, Northern California Power Agency, City and County of San Francisco, State Water Contractors, and Transmission Agency of Northern California, filed a complaint with the Commission challenging the local transmission planning process of Pacific Gas & Electric.[1060] The Complaint noted that although 40% of PG&E's 2016 and 2017 capital expenditures related to transmission projects that would be submitted through CAISO's regional process, "[t]he other 60% of capital transmission expenditures, PG&E explained, are for projects *developed and reviewed through an entirely internal process* where projects are authorized solely by PG&E's Chief Financial Officer and PG&E's project managers."[1061] As the Commission noted, the Complaint alleged:

> Complainants assert that PG&E's transmission rates have been increasing rapidly for years, in part due to its self-approved projects. For instance, PG&E's wholesale revenue requirement has increased by an average of 9.72 percent over the past 11 of its rate cases (filed, except for one year, annually). Complainants state that in its current TO18 rate case, PG&E requests an increase to its currently effective wholesale transmission revenue requirement of $386.6 million, or 29.3 percent.[1062]

The gravamen of the Complaint was that the Pacific Gas & Electric's planning that resulted in it replacing $1.5 billion (in 2016 and 2017 alone) of its system through self-approved

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[1060] Complaint, California Public Utility Commission, Northern California Power Agency, City and County of San Francisco, State Water Contractors, and Transmission Agency of Northern California v. Pacific Gas & Electric Company, filed February 2, 2017, in Docket EL17-45-000 ("CPUC Complaint").
[1061] CPUC Complaint at 3 (emphasis added).
[1062] *California Public Utility Commission, at al., v. Pacific Gas & Electric Company*, 164 FERC ¶ 61,161 (2018) at P 21 ("*CPUC et al. v PG&E*").

projects violated the Commission planning requirements of Order No. 890.[1063] The Commission rejected the Complaint. In rejecting the Complaint, the Commission held that it was based on the faulty premise that Order No. 890 planning requirements apply to "any transmission-related projects and activities that are capitalized in a PTO's transmission rate base, including the asset [replacement] projects and activities at issue here."[1064] In finding that its Order No. 890 requirements only applied to an "expansion" of the transmission system, the Commission actually reduced transparency into individual transmission owner transmission planning making it even harder for consumer interests to ensure just and reasonable transmission rates.

In ruling that the mandated transparency and other requirements of Order 890 only apply to an electrical expansion of the existing grid, the Commission retreated from the discriminatory conduct concerns that lead to Order No. 890 and provided a road map for self-interested transmission owners to thwart the Commission's regional planning requirements. Consumers pay the price for the Commission's decision. As noted above, the Commission issued Order N. 890 in part because the "legacy systems constructed by vertically-integrated utilities prior to the adoption of Order No. 888 support 'only limited amounts of inter-regional power flows and transactions. Thus, existing systems [could not] fully support all of society's goals for a modern electric-power system.'"[1065] In Order No. 890 the Commission found that "[w]e cannot rely on

[1063] *CPUC et al. v PG&E* at P 66.
[1064] *Id*. In the order, and in subsequent orders, the Commission adopted the transmission owner preferred phrase "asset management projects." As the Commission noted, a number of phrases had been used to describe the category of projects that "encompass the maintenance, repair, and replacement work done on existing transmission facilities as necessary to maintain a safe, reliable, and compliant grid based on existing topology." *Id*. at P 65, fn 119. Although "asset management projects" may be an appropriate reference to maintenance or repair work on existing facilities, the reference is an inaccurate description to refer to "replacement" of existing transmission when that transmission has reached the end of useful life as that replacement is a new asset, not management of the old asset. Thus, Complainants will not use that term for the category of new transmission facilities replacing, whether needed or not, existing transmission that has reached operational life.
[1065] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 58 (*quoting* Eric Hirst, U.S. Transmission Capacity: Present Status and Future Prospects at v (Aug. 2004).

the self-interest of transmission providers to expand the grid in a non-discriminatory manner."[1066] The Commission also stated that the Commission promulgated Order No. 890 to remedy undue discrimination, in part, by providing customers with avenues to ensure that "the planning and expansion of transmission facilities [ ] meet the[ir] reasonable needs."[1067] Yet in *CPUC et al. v PG&E* the Commission held that refusal to expand the grid by instead rebuilding these very inadequate legacy systems not only did not need to meet Order No. 890's local planning principles for openness, transparency, and coordinated planning, rebuilding yesterday's grid was not covered by Order No. 890 at all!

In reaching this conclusion, the Commission disclaimed that it was making a decision different from its rulings related to PJM.[1068] Interestingly, while that may have been accurate, what the Commission actually did in *CPUC et al v. PG&E* was to provide self-interested transmission owners a road map to thwart the Commission's regional planning goals, and the interests of transmission customers, entirely by rebuilding yesterday's grid.

2. PJM: Replacement Process Senior Task Force and Consumer Challenges to Revised Local Planning Tariffs

In January 2016, PJM stakeholders brought forth a problem statement and issue charge "expressing concern regarding the increasing costs of aging transmission infrastructure and the long-term planning processes being used to review and approve projects being proposed to address the concern."[1069] As the PJM stakeholders noted in their Motion to Lodge, "[a]fter

[1066] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 422.
[1067] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 425.
[1068] *CPUC et al. v PG&E*, at P 72, order denying rehearing, 168 FERC ¶ 61,171 at PP 51-59.
[1069] *See* Motion to Lodge, filed February 2, 2018 in ER17-179-000 & EL16-71-000 by American Municipal Power, Inc., Delaware Municipal Electric Corporation, Division of the Public Advocate for the State of Delaware, New Jersey Division of Rate Counsel, Old Dominion Electric Cooperative, and PJM Industrial Customer Coalition (PJM Customers") ("Customers Motion to Lodge) at 2. By order dated February 15, 2018, the Commission rejected the Motion to Lodge, finding that the "supplemental materials provided *are cumulative to the existing record* in this proceeding, and the arguments presented represent a late-filed answer that we reject pursuant to Rule 213(a)(2) of

several contentious meetings, in May 2016, the MRC [Markets and Reliability Committee] approved the problem statement, issue charge and charter of the TRPSTF [Transmission Replacement Process Senior Task Force]."[1070] The PJM Customers recounted that the Task Force had spent several months identifying stakeholder interests when, in late August 2016 the Commission issued a show cause order against all transmission owners in PJM and PJM itself regarding the manner in which individual transmission owner project planning was occurring in PJM.[1071] As a result of the PJM Show Cause Order, the Task Force was put on hold.

In the PJM Show Cause the Commission raised a concern with the development of "Supplemental Projects," a category of PJM transmission owner-initiated projects "not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by PJM, and is not a state public policy project . . . ."[1072] The PJM transmission owners sought rehearing of the PJM Show Cause Order, arguing, in part, that

> earlier and increased stakeholder involvement *could interfere with the transmission owners' internal planning activities for localized projects* within the transmission owner's own footprint that are necessary for them to meet their state law obligations . . ..[1073]

The PJM transmission owners responded to the PJM Show Cause Order by asserting that

> Supplemental Projects include projects that address reliability issues that do not rise to the level of a PJM Reliability Criteria violation, such as replacing equipment that has reached the end of its operational life, replacing failed equipment, transmission construction to address electrical topology and engineering issues within the PJM Transmission Owner's zone, maintain or improve

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the Commission's Rules of Practice and Procedure." *Monongahela Power Co. et al.* 162 FERC ¶ 61,129 (Feb. 15, 2018) at P 69, *reh'g denied* 164 FERC ¶ 61,217 (Sept. 26, 2018).

[1070] *Id*.

[1071] *Id.*; *Monongahela Power Co. et al.*, 156 FERC ¶ 61,134 (PJM Show Cause Order), *reh'g dismissed*, 157 FERC ¶ 61,178 (2016).

[1072] PJM Show Cause Order at fn 10.

[1073] Limited Request for Rehearing of the Indicated PJM Transmission Owners filed September 26, 2016, in Docket No. EL16-71-000 (emphasis added).

> service to its local load, add new retail distribution customers and enhance system resiliency or security.[1074]

As such, the transmission owners acknowledged that the Supplemental Projects could be anything they wanted them to be. Although the transmission owners asserted that the PJM processes met the requirements of Order No. 890, they nevertheless proposed changed to the PJM Operating Agreement, where PJM Planning rules reside, to provide additional transparency around Supplemental Projects. At the same time, in a new Docket, the transmission owners submitted a new Tariff provision, Attachment M-3, that would supplant the Operating Agreement provisions for the transmission owners local planning.[1075]

Because the Commission lost its quorum in early 2017, the PJM Show Cause proceeding and the PJM transmission owners tariff filing were delayed. By June 2017 the PJM Customers "had a uniform desire to conclude the suspension and reinstate the [Task Force] [and] the MRC voted to reinstate the [Task Force].[1076] Upon reinstatement of the Task Force meetings, PJM transmission owners requested that a statement be read before each Task Force meeting indicating that the transmission owners ""do not believe that meaningful discussion or progress is possible where the subject matter overlaps the issues currently pending before the FERC and **will not compromise our litigation position** in task force discussions."[1077] The PJM Customers provided the Commission information in the Motion to Lodge regarding the significant increase in the percentage of Supplemental Projects versus regionally planned projects as of 2017,[1078] a number which, as discussed below has only grown since that time.

[1074] PJM Transmission Owners Response to PJM Show Cause Order, filed October 25, 2016 in EL16-71-000.
[1075] PPL Electric Utility Corp., et al, October 25, 2016 submittal in ER17-179-000 (M-3 Filing).
[1076] Motion to Lodge in ER17-179-000 and EL16-71-000 at 4.
[1077] *Id*. at 5. Although the Motion to Lodge links to the transmission owners' statement, the link is no longer active on the PJM website.
[1078] *Id*. at 6-10.

The Commission determined that the "transmission planning practices currently employed by the PJM Transmission Owners are unjust and unreasonable and unduly discriminatory and preferential insofar as they violate Order No. 890's coordination and transparency principles as well as the PJM Operating Agreement and the PJM OATT."[1079] The Commission also rejected the transmission owners Section 205 filing.[1080] As a result of finding that the existing processes were unjust and unreasonable and unduly discriminatory and preferential, and that the proposed replacement likewise was not just and reasonable, the Commission established "a just and reasonable transmission planning process for Supplemental Projects by requiring revisions to both the PJM Operating Agreement and the PJM OATT."[1081] In finding the existing processes violative of Section 206, the Commission held:

> not persuaded by the PJM Transmission Owners' contention that 'the types of needs that Supplemental Projects address make it appropriate and, in many cases necessary, for PJM Transmission Owners to identify 'proposed solutions' when they present their analysis of th[e] needs' underlying those solutions. The PJM Transmission Owners have not supported their position that transmission planning requires the simultaneous presentation of needs and solutions. They do not explain why it is useful, much less 'inevitable and unavoidable,' for stakeholders to review the needs underlying Supplemental Projects, or the models, criteria, and assumptions underlying those needs, at the same time that the PJM Transmission Owners identify the Supplemental Projects to meet those needs. Although the PJM Transmission Owners state that 'the analysis of local system needs often cannot be divorced from the identification of potential solutions,' they neither explain that statement nor explain why this fact prevents them from posting their models, criteria, and assumptions before they identify Supplemental Projects as the Commission is requiring in this proceeding.[1082]

[1079] *Monongahela Power Co. et al.* 162 FERC ¶ 61,129 (Feb. 15, 2018) at P 71.
[1080] *Id*.
[1081] *Id*.
[1082] *Id*. at P 80.

The Commission itself set the just and reasonable rate, and in doing so, rejected the objections of PJM Customers and others about moving the local planning processes away from the PJM Operating Agreement, where Member approve changes, to the Tariff where the transmission owners could make changed. Although it was not obligated to do so,[1083] the Commission required the adoption of Attachment M-3 to the tariff, with revisions, subjecting future local planning revisions to exclusive transmission owner control. This decision would come back to haunt consumers in PJM.

3. PJM: Consumers' Objection To Secret Self-Planned Transmission

On the tails of the adoption, at the Commission's direction, of Attachment M-3 of the PJM tariff, the PJM transmission owners proposed Attachment M-4 in January 2020[1084] which would allow individual transmission owners to plan regionally impactful high voltage transmission in secret. The filing of Attachment M-4 was permitted by the Commission's determination, referenced above, that allowed the PJM transmission owners to move local planning out of the PJM Operating Agreement, changes to which are controlled by PJM Members, and into the tariff, thus permitting transmission owners to unilaterally file under Section 205.

In the Attachment M-4 filing the transmission owners proposed to plan transmission to remove existing transmission facilities from NERC CIP-014 physical security obligations notwithstanding that those facilities were fully compliant with the CIP-014 physical security requirements.[1085] The CIP-014 standards related to critical facilities, which the Commission

[1083] *Id.* at P 92, *citing W. Resources, Inc. v. FERC*, 9 F.3d 1568, 1579 (D.C. Cir. 1993) for the proposition that the Commission "may" determine the just and reasonable rate after finding a Section 205 filing has failed to meet the just and reasonable burden.
[1084] PJM Transmission Owners Submission of Proposed Tariff Revisions for a Limited Subset of Supplemental Projects that Require Special Planning Procedures, filed January 17, 2020 in Docket No. ER20-841-000("Attachment M-4 Filing").
[1085] *Id*. at 10.

defined as "one that, if rendered inoperable or damaged, could have a critical impact on the operation of the interconnection through instability, uncontrolled separation or cascading failures on the Bulk-Power System."[1086] Not only would individual transmission owners plan transmission to remove existing transmission facilities from designation as critical under CIP-014, although ratepayers had already paid for compliance with those standards, the planning would not be revealed to consumers until the projects were placed in service.[1087]

The filing was protested or challenged by numerous Consumer focused interests. As an initial matter, in an unusual step, the PJM Members Committee voted to oppose planning interconnection critical facilities secretly at the local level.[1088] The Organization of PJM States, Inc. asked that the Commission find the filing deficient for failure to meet even minimal transparency or coordination requirement.[1089] The New Jersey Board of Public Utilities, a member of the Organization of PJM States, Inc., filed additional comments arguing that "the failure to balance the Transmission Owners' ("TOs") interest in confidentiality and the public interest in transparency renders the filing unjust and unreasonable."[1090] Protests were filed by the PJM Industrial Customer Coalition,[1091] American Municipal Power, Inc.,[1092] the Joint Consumer Advocates,[1093] Old Dominion Electric Cooperative.[1094] Securing America's Future

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1086 *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014)("CIP-014 Standard Order").
1087 Attachment M-4 Filing at 4.
1088 *See*, Limited Protest of the PJM Industrial Customer Coalition, filed February 7, 2020, in Docket No. ER20-841-000 at 1, fn 3, *citing* January 2020 PJM Members Committee Resolution, available at https://pjm.com/-/media/committeesgroups/committees/mc/2020/20200123/20200123-item-01-mc-resolution-revised-following-20200123-mcclean.ashx (last accessed April 15, 2024).
1089 Comments of the Organization of PJM States, Inc., filed February 7, 2020, in Docket No. ER20-841-000.
1090 Comments of the New Jersey Board of Public Utilities, filed February 7, 2020, in Docket No. ER20-841-000.
1091 Limited Protest of the PJM Industrial Customer Coalition, filed February 7, 2020, in Docket No. ER20-841-000.
1092 Protest of American Municipal Power, Inc., filed February 7, 2020, in Docket No. ER20-841-000.
1093 Protest and Comments of Joint Consumer Advocates, filed February 7, 2020, in Docket No. ER20-841-000. The Joint Consumer Advocates were the New Jersey Division of Rate Counsel, Office of the People's Counsel for the District of Columbia, Delaware Division of the Public Advocate, West Virginia Consumer Advocate, Maryland Office of People's Counsel, Pennsylvania Office of Consumer Advocate, Citizens Utility Board, and the Indiana Office of Utility Consumer Counselor.
1094 Protest of Old Dominion Electric Cooperative, filed February 7, 2020, in Docket No. ER20-841-000.

Energy filed Comments noting that while "the physical security of certain critical transmission stations and substations is paramount to our regional and national security [because e]very aspect of our economy and daily lives depends on a functioning electric system"[1095] they disagreed with the transmission owners filing as "national security and regional market competitiveness are ***not*** mutually exclusive."[1096] Finally, the PJM Independent Market Monitor argued the "The TO Filing Has No Merit and Should Not Be Approved."[1097]

The Commission accepted the Attachment M-4 filing by Order dated March 17, 2020, finding that notwithstanding that CIP-014 applied to facilities that could impact the interconnection as a whole, they are appropriately locally planned.[1098] The Commission concluded that notwithstanding the regional nature of the CIP-014 Standard, because there was no PJM regional criteria, the proposed projects were the PJM category of Self-Planned Transmission, supplemental Projects which is a "transmission expansion or enhancement **that is not required** for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the

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[1095] Comments of Securing America's Future Energy (SAFE), filed February 7, 2020, in Docket No. ER20-841-000 at 3.
[1096] *Id*. at 4-10 (emphasis in original).
[1097] Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, filed February 28, 2020 in Docket No. ER20-841-000 at 3-4.
[1098] *Appalachian Power Company*, 170 FERC ¶ 61,196 (March 2020) at P 58.

Interconnection and is not a state public policy project pursuant to Operating Agreement, Schedule 6, section 1.5.9(a)(ii).”[1099]

Reduced to it essential nature from a consumer perspective, because the Attachment M-4 projects were not needed they could be planned locally by individual transmission owners. And in secret.

4. PJM: Stakeholder Proposal re End-of-Life Projects

As noted in the PJM Show Cause proceeding, at the time of that proceeding projects to replace existing facilities reaching the end of operational life were planned as Supplemental Projects in PJM, except for those transmission owners that filed their end of life criteria as Form No. 715 criteria.[1100] Because of the ongoing explosion of such project even after the Commission’s direction to adopt Attachment M-3 PJM stakeholders pushed to ensure that end of operational life planning occurred at the regional level.[1101] On June 18, 2020, a super majority of PJM Members approved a proposal to require that planning for Transmission Facilities[1102] reaching the end of operational life were planned by PJM on a holistic basis with other regional needs. The Members proposal retained the exclusive right of the transmission owner to determine when its transmission had reached the end of its operational life, but once the

[1099] *Id*.
[1100] PJM Interconnection, L.L.C., filed July 2, 2020 in Docket No. ER20-2308-000 (“Stakeholder Filing”) at 3 (noting that “end of life criteria not included in a Transmission Owner’s individual Form No. 715 currently are included as Supplemental Projects.”); *see also*, *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254 (D.C. Cir. 2018), *reh’g denied*, 905 F.3d 671 (D.C. Cir. 2018).
[1101] PJM Interconnection, L.L.C., filed July 2, 2020 in Docket No. ER20-2308-000 (“Stakeholder Filing”).
[1102] Transmission Facilities is a defined term in the PJM Operating Agreement: “facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC’s Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.” Operating Agreement, Definitions, S-T, available at https://www.pjm.com/directory/merged-tariffs/oa.pdf (last accessed Dec. 18, 2024).

transmission owner made that declaration then PJM would plan, what, if any, transmission was appropriate to replace the retiring assets.[1103]

Recognizing that the Members proposal was likely to achieve the super-majority vote requirement in the PJM Members Committee to pass, a subset of PJM transmission owners filed before the Members' proposal could be filed to ensure that projects replacing existing Transmission Facilities remained primarily planned by individual transmission owners and placed in their "local" plan through Attachment M-3.[1104] Notwithstanding that the PJM transmission owners had previously included replacement Transmission Facilities as Supplemental Projects, to the tune of $1,975 billion in 2022,[1105] following the roadmap the Commission provided in response to the CPUC Compliant, the PJM transmission owners removed end-of-life replacement projects out of the Supplemental Project definition and established a new category that tracked, to some extent, the Commission's exclusion in rejected the CPUC Complaint.

Although the competing proposals were pending simultaneously, the Commission addressed them serially and did not consolidate the filings. In ruling on the transmission owners local planning proposal, the Commission found that as a matter of contract the transmission owners had not in the Consolidated Transmission Owners Agreement ("CTOA") transferred to PJM planning for replacement of existing facilities, notwithstanding that "replacement" is not referenced in the CTOA. In making this finding, the Commission declared that the transmission owners reservation of "maintenance" was a reservation of planning authority over replacement

[1103] Stakeholder Filing at 10.
[1104] *Am. Transmission Sys., Inc.*, Amendments to Attachment M-3 to the PJM Interconnection, L.L.C. Open Access Transmission Tariff of the PJM Transmission Owners, Docket No. ER20-2046-000 (June 12, 2020) ("Attachment M-3 Revision Filing").
[1105] Greg Poulos, *PJM Long-Term Regional Transmission Planning from a Consumer Perspective*, slide 5 (Nov. 9, 2023), available at 20231215-informational-only---consumer-advocates-of-pjm-states-feedback-on-pjm-ltrtp-process.ashx (last accessed Dec. 18, 2024).

Transmission Facilities because such projects "relate solely to maintenance of existing facilities" and "are solely projects that maintain the existing infrastructure by repairing or replacing equipment."[1106] On rehearing the Commission again downplayed the impact on consumers of the decision to replace Transmission Facilities built decades ago for a different purpose and as different grid as merely decisions to "maintain" existing Transmission Facilities because the billions of dollars spent on these projects were "maintaining" the grid rather than "enhancing the grid."[1107] This is precisely the point of the Complaint, it is unjust and unreasonable to allow individual transmission owners to make the decision regarding whether regional Transmission Facilities should be rebuilt or whether the grid should be "enhanced" to the benefit of consumers and the region. The Commission also rejected argument that its decision trampled on Order No. 2000, finding that Order No. 2000's requirement that PJM remain responsible for planning because regional transmission organization membership was voluntary and *Atlantic City*[1108] did not allow FERC to require the Transmission Owners to transfer planning rights.[1109] The Commission also determined that "a PJM Transmission Owner may choose not to include [End-of-Life] criteria in its Form No. 715 in which case the transmission project will be planned under the Attachment M-3 Revisions."[1110]

In ruling on the Members' Proposal the Commission relied on its finding that the PJM transmission owners specifically retained the right to "maintain" their existing Transmission Facilities concluded that replacement those Transmission Facilities was an extension of maintenance.

[1106] *PJM Interconnection, L.L.C. and American Transmission Systems Inc.*, 172 FERC ¶ 61,136 (2020) at. P 83.
[1107] *PJM Interconnection, L.L.C. and American Transmission Systems Inc.*, 173 FERC ¶ 61,225 (2020) at P 17.
[1108] *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002).
[1109] 173 FERC ¶ 61,225 at P 39.
[1110] *Id*. at P 60. The Commission determined that inclusion of end-of-life criteria in Form No. 715 criteria was "voluntary" notwithstanding that Form No. 715 is a mandatory filing of all criteria used to determine availability of transmission capability.

5. Complaint Of Office of the Ohio Consumers' Counsel

On September 23, 2023, the Office of the Ohio Consumers' Counsel ("OCC") filed a complaint[1111] against PJM and PJM transmission owners operating in Ohio.[1112] The OCC Complaint noted that in 2022 the Ohio utilities planned $668 Million in local transmission, and $6 billion since 2017.[1113] The OCC Complaint asserts that the PJM Tariff and Operating Agreement require that PJM review and approve the need, prudence and cost effectiveness of regional transmission projects, but further asserts that the "Tariff and Operating Agreement do not contain similar protections regarding *local* transmission projects, identified in the PJM Tariff and Operating Agreement as 'Supplemental Projects.'"[1114]

The OCC Complaint argues that the Commission has left a regulatory gap because not every state, Ohio among them, "has authority to review all local transmission projects to determine whether they are needed, prudent and cost-effective before their costs are charged to consumers."[1115] The OCC Complaint asks that FERC "develop and implement a backstop mechanism for Ohio consumers protection."[1116]

The OCC Compliant remains pending. The OCC Complaint is focused on Ohio and PJM. As such, the relief requested in it would not address the issues raised in this Complaint that local planning for transmission facilities at 100 kV or above is unjust and unreasonable, however,

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1111 The Office of the Ohio Consumers' Counsel v. PJM Interconnection, L.L.C., et al., filed September 28, 2023 in Docket No. EL23-105-000 ("OCC Complaint").
1112 The public utilities providing transmission service in Ohio are: affiliates of American Electric Power Corporation, being Ohio Power Company and AEP Ohio Transmission Company, Inc.; the FirstEnergy affiliate American Transmission Systems, Inc.; AES Ohio, a/k/a The Dayton Power and Light Company; and Duke Energy Ohio, LLC. at 5.
1113 OCC Complaint at 1-2.
1114 *Id*. at 3.
1115 *Id*.
1116 *Id*.

granting the relief requested in this Complaint would appear to address the concerns raised in the OCC Complaint.

6. Consumer Advocate Concerns With Inefficient, Costly Transmission Planning

The National Association of State Utility Consumer Advocates ("NASUCA"), a voluntary association of 58 state utility consumer advocate offices throughout the country, has identified several transmission planning principles that are consistent with the concerns raised and relief sought in this complaint.[1117] Stressing the importance of adequate consumer protections, NASUCA explained that the electric transmission system must be well-planned, based on cost-efficient planning principles, and providing meaningful opportunity for input for those who it serves.[1118] NASUCA emphasized the need for holistic planning because "regional solutions may resolve the need for multiple, more costly local projects."[1119] Failure to plan holistically can "lead to ineffective transmission and interconnection solutions, poorly sited transmission facilities, and stranded assets,"[1120] the costs of which hang over ratepayers, like Damocles' sword. Further, NASUCA asserted that independent transmission monitors could help "promote nondiscriminatory and equitable planning and create consumer protections…and cost transparency."[1121]

In 2023 the Director of the Consumer Advocates of PJM States began noting that even with the minimal requirements of Attachment M-3, the tariff provisions were being violated by the submission in the Fall of 2023 a transmission "need" at one meeting and a "solution" at

[1117] *See* "Comments of NASUCA," Docket No. RM21-17 (filed Oct. 12, 2021) (hereinafter, "NASUCA ANOPR Comments").
[1118] NASUCA ANOPR Comments at 2.
[1119] NASUCA ANOPR Comments at 4.
[1120] NASUCA ANOPR Comments at 4-5.
[1121] NASUCA ANOPR Comments at 7.

another when in fact construction of the transmission element had been completed in 2022.[1122] Ten days after his first questions regarding projects completed before needs had been identified, Mr. Poulos raised a second set of questions when eleven more projects came to light.[1123] To date it is unclear the total number of Self-Planned Transmission projects in PJM that were submitted to stakeholders after construction began (or had been completed) or how many transmission owners have engaged in the practice. In September 2024, Mr. Poulos further presented his concerns on the need for holistic, cost-effective regional planning in PJM.[1124] Despite the Commission's efforts to expand regional transmission planning in Order No. 1920, Mr. Poulos emphasized that the Commission's implementation of a federal right-of-first refusal to incentivize incumbent transmission owners to place local projects into regional plans will actually end up reducing transparency and the "cost-effectiveness for a larger swath of the regional grid," as Order No. 1920 "exacerbates the transparency/cost-effectiveness concerns rather than addressing the real issues" rooted in local planning.[1125]

7. Complaint Of Colorado Cities

On February 16, 2024, the Municipal Energy Agency of Nebraska, the City of Aspen, Colorado, the City of Glenwood Springs, Colorado, and the Town of Center, Colorado, filed a complaint under Sections 206 and 306 of the Federal Power Act against Public Service Company

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[1122] *See* "Consumer Perspective: Consumer Advocate evaluation of PJM Planning Processes," (Dec. 10, 2024) G. Poulos, Consumer Advocates of the PJM States, Slide 14, *available at* https://www.pjm.com/-/media/DotCom/committees-groups/user-groups/pieoug/2024/20241210/20241210-consumer-advocate-transmission-planning-updates.pdf (last accessed Dec. 18, 2024) (hereinafter "Poulos Dec. 10, 2024 Presentation").
[1123] *See id.*
[1124] *See* "Consumer Perspective: FERC Order 1920 and PJM's compliance filing," G. Poulos, Consumer Advocates of the PJM States, *available at* https://www.nasuca.org/wp-content/uploads/2024/01/item-08-greg-poulos-caps-presentation.pdf (last accessed Dec. 18, 2024) ("Poulos Sep. 2024 Presentation"). On December 10, 2024, Mr. Poulos further presented at the PIOUG meeting. *See* Poulos Dec. 10, 2024 Presentation.
[1125] Poulos Sep. 2024 Presentation at Slide 14.

of Colorado.[1126] The Colorado Cities Complaint raised a host of issues with Public Service Colorado's planning of a proposed $2 billion 560-mile, double circuit 345 kV "local" project. The Complaint asserts that Public Service Colorado violated both its local planning tariff and its regional tariff in the manner in which it planned the project.[1127]

In its answer, Public Service Colorado demonstrated the difficulty of challenging local planning on a project-by-project basis.[1128] Notwithstanding that the PSCo Answer "Admits" that the 560-mile double circuit 345 kV Power Pathway "will benefit Colorado and that PSCo attempted to partner with other Colorado utilities to develop the Colorado Power Pathway but was unable to reach agreement"[1129] PSCo asserts that it is nevertheless appropriate to allocate all of the costs to its transmission customers, whether retail or wholesale, as a Self-Planned Transmission addition through local planning.[1130] PSCo infers that discussing the $2 billion project through WestConnect's subregional Colorado Coordinated Planning Group (CCPG),[1131] in the 80x30 Task Force created in the CCPG subregional planning group, provided wholesale transmission customers the Order No. 890 required local planning notice that the project was a local project under PSCo's local tariff.[1132] The 80x30 Task Force Final Report noted that "the CCPG launched the 80x30TF in August 2020 to provide a forum for all stakeholders to collaboratively identify transmission infrastructure that will enable Colorado *utilities* to meet the

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[1126] Complaint of Municipal Energy Agency of Nebraska, the City of Aspen, Colorado, the City of Glenwood Springs, Colorado, and the Town of Center, Colorado, v. Public Service Company of Colorado, filed February 16, 2024 in Docket No. EL24-74-000 ("Colorado Cities Complaint").
[1127] Colorado Cities Complaint at 21-40.
[1128] Motion to Dismiss and Answer of Public Service Company of Colorado, filed March 21, 2024 in Docket No. EL24-74-000 ("PSCo Answer").
[1129] PSCo Answer Appendix A-6.24.
[1130] *Id*.
[1131] http://regplanning.westconnect.com/ccpg.htm (last accessed Dec. 18, 2024).
[1132] PSCo Answer Appendix A-17.54,

state's decarbonization goals."[1133] Six days after the WestConnect subregional planning group's Task Force Final Report suggesting a sub-regionally beneficial project, PSCo filed the project with the Colorado Public Utility Commission as a locally planned project. Finally, although PSCo admits that it did not reveal the $2 billion Colorado Power Pathway in its Commission approved Local Planning tariff process until 8 days **after** it was submitted to the Colorado Commission for approval as a locally planned project, PSCo denied that such after-the-fact submission was "inconsistent with the requirements of the PSCo Tariff."[1134]

The response of PSCo and Xcel to the Colorado Cities Complaint confirms that the minimal stakeholder vetting requirements under the local planning process are meaningless:

> In sum, the Tariff requires PSCo to hold two open meetings, obtain stakeholder input on public policy requirements and solutions, and publicly post public policy requirements. PSCo satisfied these requirements. So what the Colorado Cities' advance is a claim that the stakeholder engagement requirement prohibited PSCo from proposing the Colorado Power Pathway to the Colorado Public Utilities Commission on March 2, 2021, because PSCo had not yet presented the project at an open meeting.[] That is, under the Colorado Cities' preferred Tariff interpretation, PSCo may only proceed with a local public policy project if it first vets the project through stakeholders at an open meeting.[] The Tariff imposes no such constraint on PSCo. The Colorado Cities point to no Tariff provision that confines when PSCo can submit transmission projects to the Colorado Public Utilities Commission, because none exist. The Colorado Cities also point to no vote or veto right over PSCo's public policy requirement planning decisions in PSCo's Tariff, because none exist.[1135]

On November 7 2024, the Commission denied the Complaint.[1136] The Commission agreed with PSCo and held that the Commission "disagree[s] with Colorado Cities argument that [the Local Planning] Tariff provisions require open discussion of local public policy needs 'before a

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[1133] Phase I Transmission Report for the Colorado Coordinated Planning Group 80x30 Task Force, dated February 24, 2021, available at https://doc.westconnect.com/Documents.aspx?NID=19294 (emphasis added) (last accessed Dec. 18, 2024).
[1134] PSCo Answer Appendix A-17.55.
[1135] "Motion to Answer and Answer of Public Service Company of Colorado et al.," *Mun. Eneryg Agency of Nebraska and the Colorado Cities of Aspen and Glenwood Springs and the Town of Center Coloardo v. Pub. Serv. Co. of Colorado*, Docket NO. EL24-74, At 21 (filed Apr. 29, 2024) (footnotes omitted).
[1136] "Order Denying Complaint," *Municipal Energy Agency of Nebraska and the Colorado Cities et al. v. Public Service Co. of Colorado*, 189 FERC ¶ 61,099.

proposed transmission project is fully baked and submitted to the Colorado Commission for a [certificate of public necessity.]'"[1137] The Commission found it acceptable that PSCo held meetings at the regional planning level in which it discussed a project which it ultimately submitted as 560 mile double circuit 345 kV "local" project.[1138] Further, notwithstanding that the public policy requirements addressed by PSCo applied also to other Commission-jurisdictional public utilities, the Commission found it find that no public policy needs were identified at the regional level (which includes the Colorado subregion) because "the Tariff provides the public utility transmission provider with discretion in identifying regional transmission needs driven by public policy requirements, as well as solutions to address those needs."[1139]

In denying the complaint the Commission held that the Colorado Cities had failed to meet their burden under Sec. 206 of the FPA with respect to the local cost allocation issue raised.[1140] In rejecting the cost allocation concerns raised in the complaint, the Commission relied on its "longstanding policy [ ] that network transmission facilities benefit all network transmission customers, [such that] their costs are therefore appropriately recovered through network transmission rates without a customer-by-customer evaluation."[1141] The Commission noted that

> Given a finding that the system operates as an integrated whole, transmission costs have generally been rolled-in, absent a finding of special circumstances. The principal reason behind adoption of this methodology is that an integrated system is designed to achieve maximum efficiency and reliability at a minimum cost on a systemwide basis. Implicit in this theory is the assumption that

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[1137] *Id*. at P 78.
[1138] *Id*. at PP 81-83.
[1139] *Id*. at P 87.
[1140] *Id*. at P 40.
[1141] *Id*. at P 43, *citing City of Anaheim*, 113 FERC ¶ 61,091 (2005) at P 35.

> all customers . . . receive the benefits that are inherent in such an integrated system.[1142]

The Commission's reliance on the fact that "the system operates as an integrated whole" is the same fact underlying this complaint. The "system" does not recognize transmission owner boundaries nor the planning rules under which new facilities were planned.[1143] Nor does it recognize artificial transmission owner boundaries when determining whether a facility has an impact on the system as an integrated whole.

On December 9, 2024, the Colorado Cities filed a request for rehearing, which is pending with the Commission in Docket No. EL24-74-000.

8. Duke v. FPL Complaint

In August 2021 Duke Energy filed a complaint with the Commission regarding development the FPL 'Local' Project referenced above.[1144] Duke argued that it was filing the complaint to protect its customers.

Of relevance to this Complaint, Duke asserted, via an affidavit, that FPL violated its local planning OATT, that the project was planned at 161 kV to "to be below the 230 kV statutory threshold"[1145] that would trigger state review or trigger regional planning, that 22% to 39% of the transfers anticipated for the FLP 'Local' Project would actually flow over Duke's facilities, and

> **less than seven percent of the transfers will flow over the [FPL 'Local' Project]**. In other words, of a scheduled 850 MW transfer between FPL and Gulf Power, or vice versa, the [FPL 'Local' Project] is expected to carry less than 59 MW, while the remaining

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1142 *Id*.
1143 *Old Dominion Elec. Coop. v FERC*, 898 F.3d 1254, 1262 (2018).
1144 Duke Energy Florida, LLC v. Florida Power & Light, Co., et al. Docket No. EL21-93-000, filed August 06, 2021 ("Duke Complaint"). On August 29, 2022, Duke Energy Florida, LLC filed a Notice of Withdrawal of Complaint "after FERC's acceptance of the Settlement
Agreement [between Duke and FPL] became final." *Id*. at 1.
1145 *Id*. at 3. Duke notes that although the FPL 'Local' Project is 161 kV, "[i]t interconnects with Gulf Power's existing 230 kV Sinai Cemetery substation in Sneads, Jackson County, and FPL's existing 230 kV Raven substation in Lake City, Columbia County. . . . Because the FPL 'Local' Project operates at a lower voltage at the points of interconnection, the voltage will be stepped down from 230 kV at the source and stepped back up to 230 kV at the sink via 230/161 kV transformers." Duke Complaint Exhibit B at ¶10.

> 790 MW or more will need to be accommodated by neighboring transmission systems."[1146]

Duke asserted that FPL was aware of the regional implications, telling the Florida Public Service Commission "that 'energy is projected to flow between FPL and Gulf not only over the new line, but also over existing transmission lines owned by other utilities systems . . ..'"[1147] As Duke noted, the FPL 'Local' Facilities had implications on the Southern Company's transmission facilities sufficient for FPL to settle with Southern Company.[1148]

Duke noted that although it was clear to all transmission owners involved that the proposed FPL 'Local' Project had regional impact, no regional planning was conducted. Instead, in "May 2019, transmission owners on either side of the Georgia-Florida interface, including FPL, Gulf Power, DEF, and Southern Company, **voluntarily** launched a joint planning study to identify adverse impacts on the interface and their respective transmission systems . . .."[1149] Finally, focusing on the real party in interest, consumers, Duke asserted "[u]nless these adverse impacts are **resolved fully**, the [FPL 'Local' Project] Transfers will impair reliability of [Duke's] system **and regionally**, and would force [Duke] to take its own mitigating actions, causing further unjustified cost increases to [Duke's] wholesale and retail customers."[1150]

Because FPL retains local planning authority for transmission above 100 kV, and the regional planning threshold is 230 kV, FPL is able to advance a billion-dollar project notwithstanding that other transmission owners in the region publicly acknowledge that the project is inefficient and ill-suited to the proposed use. As reported by the New York Times "[i]n

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[1146] *Id*. at 3 (emphasis added).
[1147] *Id*. at 11.
[1148] *Id*. at 15 & fn 32, *citing* Settlement Agreement between Southern Companies, Florida Power & Light Company and Gulf Power Company, Ala. Power Co., Ga. Power Co., Miss. Power Co., Docket No. ER20-2734-000 (filed Aug. 25 2020).
[1149] *Id*. at 18 (emphasis added). Duke went on to note that the study "produced hundreds of power flow studies" which were summarized in testimony to the Commission.
[1150] *Id*. at 2-3 (emphasis added).

any normal utility review, you would wonder why anyone would choose a line with much [sic] higher losses . . . It costs a lot of money."[1151] The article notes that "Florida Power & Light paid nearly $100 million to another major utility, Duke Energy, to settle a complaint with federal regulators that the transmission project would burden its own system and cost its customers millions."[1152] But the reality is that FPL did not pay Duke, FPL's customers paid. While Duke and Southern should have been challenging the appropriateness of the design in a manner that would reduce or eliminate the parallel flows in the most efficient or cost-effective manner,[1153] ultimately they had the same incentive as FPL: to maintain local planning authority and benefit from the rate base additions of affected system upgrades.

As the result of the lack of regional or interregional planning, and as a direct result of the availability of local planning, Consumers in every impacted transmission territory are the losers. And they are the losers because this Commission, with both exclusive jurisdiction and an obligation to ensure just and reasonable transmission rates has for two decades continued to allow self-interested transmission owners to retain local planning authority for which there is little or no oversight.

G. Relief Requested (18 C.F.R. § 385.206(b)(7))

The requested relief is detailed in Section VI.B.5.

H. Attachments (18 C.F.R. § 385.206(b)(8))

Evidentiary support for the Complaint is included within the body and footnotes of this Complaint, including several active web links. The following items are included as attachments:

[1151] https://www.nytimes.com/2022/05/31/business/energy-environment/florida-power-light-electric-line.html quoting Robert McCullough, Principal, McCullough Research (last accessed Dec. 18, 2024).
[1152] *Id*.
[1153] Duke's witness testified that "alternative designs would be better suited to support the requested transfer and avoid very high amounts of unscheduled loop flow across third party transmission systems." Duke Complaint Exhibit B at ¶ 37.

- Attachment A (Form Notice of Complaint)
- Attachment B (the list of relevant local tariff provisions of FERC-jurisdictional RTOs/ISOs and individual FERC-jurisdictional public utility transmission owners that allow the individual transmission owner to plan transmission facilities at 100 kV or above that it alone declares necessary, on criteria it alone sets, notwithstanding the regional impact of the planned transmission)
- Attachment C (Declaration of Michael A. Giberson, R Street Institute)
- Attachment D (Service List of FERC Corporate Contacts For RTOs/ISOs and Transmission-Owning, FERC-Jurisdictional Public Utilities Not Located in RTOs/ISOs)

I. Other Processes Resolve Complaint (18 C.F.R. § 385.206(b)(9) & (10))

In informal settings, RTO/ISO stakeholder forums, and formal Commission and appellate proceedings, Complainants and other stakeholders and interested parties have long voiced their concerns about the detrimental impact of localized planning on the respective grid and on the rates of consumers. Some of those proceedings are discussed above in more detail. Likewise, the Commission has repeatedly raised concerns with the over-reliance on Local Planning, but as discussed herein, chose not to address it in Order No. 1000 and Order No. 1920. Complainants believe a strong, uniform determination by the Commission is necessary to prevent the proliferation of Self-Planned Transmission through Local Planning tariffs and future creative workarounds to regional planning processes.

The Enforcement Hotline, Dispute Resolution Service, and tariff-based dispute resolution mechanisms were not used. Given the nature of this dispute and the comprehensive relief sought against the tariffs of all FERC-jurisdictional public utilities and RTO/ISO tariffs facilitating

Local Planning, the use of and tariff specific alternative dispute resolution mechanisms would have been impractical, inefficient, and unlikely to produce a resolution. Furthermore, further use of stakeholder processes would have been impractical, time-consuming, protracted, and unlikely to produce a resolution on the policy and legal issues raised by this Complaint.

J. Notice of Complaint (18 C.F.R. § 385.206(b)(10))

A form notice of Complaint is appended to the Complaint at Attachment A.

VIII. CONCLUSION

WHEREFORE, for the reasons raised herein, the Complainants request that the Commission grant this Complaint and exercise its discretionary remedial authority as necessary to protect customers, ensure just and reasonable rates, and maximize regional transmission planning that identifies or selects the more efficient or cost-effective transmission projects. Complainants request that the persons listed in the signature blocks below be included on the Commission's official service list for this proceeding.

Respectfully submitted,

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Dated: December 19, 2024

CERTIFICATE OF SERVICE

I hereby certify that I have caused a copy of the foregoing document and attachments to be served electronically on the Respondents to the individuals listed on the Commission's Corporate Officials List and interested persons, in accordance with 18 CFR § 385.206(c).

/s/ Kenneth R. Stark

Dated: December 19, 2024

ATTACHMENT A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Industrial Energy Consumers of America, American Forest & Paper Association, R Street Institute, Glass Packaging Institute, Public Citizen, PJM Industrial Customer Coalition, Coalition of MISO Transmission Customers, Association of Businesses Advocating for Tariff Equity, Carolina Utility Customers Association, Inc., Pennsylvania Energy Consumer Alliance, Resale Power Group of Iowa, Wisconsin Industrial Energy Group, Multiple Intervenors (NY), Arkansas Electric Energy Consumers, Inc., Public Power Association of New Jersey, Oklahoma Industrial Energy Consumers, Large Energy Group of Iowa, Industrial Energy Consumers of Pennsylvania, Maryland Office of People's Counsel, Pennsylvania Office of Consumer Advocate, Consumer Advocate Division of the Public Service Commission of West Virginia, and Missouri Industrial Energy Consumers,	)	
Complainants	)	Docket No. EL25-_________
v.	)	
Avista Corporation, Idaho Power Company MATL LLP; NorthWestern Corporation, PacifiCorp; Portland General Electric Company; Puget Sound Energy, Inc.; Duke Energy Florida, LLC; Florida Power & Light Company; Tampa Electric Company; Dominion Energy South Carolina, Inc.; Duke Energy Carolinas, LLC; Duke Energy Progress, Inc. and Louisville Gas and Electric Company and Kentucky Utilities Company; Southern Company Services Inc., as agent For Alabama Power Company; Georgia Power Company; Georgia Power Company and Mississippi Power Company; Arizona Public Service Company; Black Hills Power, Inc.; Black Hills Colorado Electric Utility Company; LP, Cheyenne Light; Fuel & Power Company; El Paso Electric Company, NV Energy, Inc.;	)	

Public Service Company of Colorado; Public Service Company of New Mexico; Tucson Electric Power Company; UNS Electric, Inc.; California Independent System Operator, Inc.; Southwest Power Pool, Inc.; PJM Interconnection, L.L.C.; Midcontinent Independent System Operator Inc.; New York Independent System Operator, Inc.; and Independent System Operator of New England Inc.,	)
Respondents	)

NOTICE OF COMPLAINT
(December 19, 2024)

Take notice that on December 19, 2024, Industrial Energy Consumers of America, American Forest & Paper Association, R Street Institute, Glass Packaging Institute, Public Citizen, American Economic Liberties Project, PJM Industrial Customer Coalition, Coalition of MISO Transmission Customers, Association of Businesses Advocating for Tariff Equity, Carolina Utility Customers Association, Inc., Pennsylvania Energy Consumer Alliance, Resale Power Group of Iowa, Wisconsin Industrial Energy Group, Multiple Intervenors (NY), Arkansas Electric Energy Consumers, Inc., Public Power Association of New Jersey, Oklahoma Industrial Energy Consumers, Large Energy Group of Iowa, Industrial Energy Consumers of Pennsylvania, Maryland Office of People's Counsel, Pennsylvania Office of Consumer Advocate, Consumer Advocate Division of the Public Service Commission of West Virginia, and Missouri Industrial Energy Consumers (collectively, "the Complainants") filed a formal complaint against the above-referenced Commission—jurisdictional regional transmission organizations, independent system operators, and public utilities pursuant to Sections 206, 306 and 309 of the Federal Power Act, 16 U.S.C. §§ 824e, 825c, and 825h and 18 C.F.R. § 385.206 (2019), requesting that the Commission find that the existing local transmission planning tariff of Respondents are unjust and unreasonable, and unduly discriminatory or preferential. Because those local tariff planning provisions and rules are practices that affect Commission-jurisdictional rates and result in unjust and unreasonable rates due to the preclusion of the selection of the more cost-effective and efficient transmission solution through regional planning, the Complainants ask the Commission to require regional planning tariffs of FERC-jurisdictional public utilities to apply regional planning to all transmission facilities meeting the definition of Bulk Electric System 100 kilovolts ("kV") and above for all planning drivers. Complainants further request the Commission to require revisions of all regional planning tariffs of FERC-jurisdictional public utilities to require the appointment of an Independent System Planner ("ISP") for each Order No. 1000 planning. The Complaint requests a refund effective date on the date the Complaint is filed.

Complainants certify that copies of the Complaint were served on contacts for the public utilities and transmission providers as listed on the Commission's list of Corporate Officials.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§ 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding.

Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondents' answers and all interventions, or protests must be filed on or before the comment date. The Respondents' answers, motions to intervene, and protests must be served on the Complainant.

The Commission encourages electronic submissions of protests and interventions in lieu of paper using the "eFiling link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, DC 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 p.m. Eastern Daylight Time on February 3, 2025.

Debbie-Anne A. Reese
Secretary

ATTACHMENT B

LOCAL PLANNING TARIFF PROVISIONS

Attachment B

Tariff Provisions on Local Projects

The following includes a list of the Transmission Planning Provisions found within most of the respondent transmission providers and transmission-owning public utilities' Open Access Transmission Tariffs. To the best of Complainants' knowledge, the below compilation includes applicable and relevant provisions governing local transmission planning.

FERC-Jurisdictional RTOs/ISOs

PJM Interconnection, L.L.C. ("PJM") Operating Agreement ("OA") – Supplemental Projects

PJM OA, § 1, Definitions S–T, *Supplemental Project*, available at: pjm.com/directory/merged-tariffs/oa.pdf (last visited Dec. 18, 2024).

OA 1. DEFINITIONS, S – T

"Supplemental Project" shall mean a transmission expansion or enhancement that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection and is not a state public policy project pursuant to Operating Agreement, Schedule 6, section 1.5.9(a)(ii). Any system upgrades required to maintain the reliability of the system that are driven by a Supplemental Project are considered part of that Supplemental Project and are the responsibility of the entity sponsoring that Supplemental Project.

PJM Open Access Transmission Tariff, Attachment M-3, available at: https://pjm.com/directory/merged-tariffs/oatt.pdf (last visited Dec. 18, 2024).

Each Transmission Owner shall be responsible for planning and constructing in accordance with Schedule 6 of the Operating Agreement as provided in this Attachment M-3, to the extent applicable, (i) Asset Management Projects, as defined herein, (ii) Supplemental Projects, as defined in section 1.42A.02 of the Operating Agreement, and (iii) any other transmission expansion or enhancement of Transmission Facilities that is not planned by PJM to address one or more of the following planning criteria:

1. NERC Reliability Standards (which includes Applicable Regional Entity reliability standards);
2. Individual Transmission Owner planning criteria as filed in FERC Form No. 715 and posted on the PJM website, provided that the Additional Procedures for the Identification and Planning of EOL Needs, set forth in section (d), shall apply, as applicable;
3. Criteria to address economic constraints in accordance with section 1.5.7 of the Operating Agreement or an agreement listed in Schedule 12-Appendix B;
4. State Agreement Approach expansions or enhancements in accordance with section 1.5.9(a)(ii) of the Operating Agreement; or
5. An expansion or enhancement to be addressed by the RTEP Planning Process pursuant

to section (d)(2) of this Attachment M-3 in accordance with RTEP Planning Process procedures in Schedule 6 of the Operating Agreement.

Midcontinent Independent System Operator, Inc. ("MISO") – Other Projects

MISO, Open Access Transmission Tariff, attach. FF § III.A.2.k, retrieved from https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/ (last accessed Dec. 18, 2024).

k. Other Projects: Unless otherwise agreed upon pursuant to Section III.A.2.a. of this Attachment FF, the costs of Network Upgrades that are included in the MTEP, but do not qualify as Baseline Reliability Projects, New Transmission Access Projects, Targeted Market Efficiency Projects, Market Efficiency Projects, or Mult-Value Projects shall be eligible for recovery pursuant to Attachment O of this Tariff by the Transmission Owner(s) and/or ITC(s) paying the costs of such project, subject to the requirements of the ISO Agreement.

MISO OATT, Schedule 1, Appendix B.I, available at https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/ (last visited Dec. 18, 2024).

The following transmission facilities of the Owners shall constitute the Transmission System for which MISO shall be responsible for operating and planning by the terms of the Agreement: (i) all networked transmission facilities above 100 kilovolts (hereinafter "kV"); and (ii) all networked transformers whose two (2) highest voltages qualify under the voltage criteria of item (i). Network transmission facilities (including terminal equipment) are (i) transmission elements capable of carrying power in both directions for sustained periods, and (ii) components that are connected to such transmission facilities and are used for voltage or stability control of the Transmission System, including shunt inductors, shunt capacitors, and synchronous condensers. Appendix H to the Agreement identifies the facilities that constitute the Transmission System for which MISO shall have operating and planning responsibility . . .

With regard to Non-transferred Transmission Facilities, MISO shall review and comment on the plans developed by the Owners of these facilities. With respect to such facilities, MISO shall have only that planning authority necessary to carry out its responsibilities under the Tariff. Thus, MISO, when performing System Impact and Facilities Studies under the Tariff, shall treat these Non-transferred Transmission Facilities just as it would facilities comprising the Transmission System. Similarly, MISO shall require Owners to make ATC determinations involving such Non-transferred Transmission Facilities under the Tariff. MISO shall coordinate the analyses of ATC associated with Non-transferred Transmission Facilities with the affected Owners. Any disputes concerning Non-transferred Transmission Facilities shall be subject to the dispute resolution procedures under Attachment HH of the Tariff.

The planning of all Non-transferred Transmission Facilities, as well as all distribution facilities, shall be done by the Owners. Furthermore, each Owner, in carrying out its planning responsibilities to meet the reliability needs of all loads connected to the Owner's transmission facilities and to pursue projects that will promote expanded trading in generation markets, to better integrate the grid and to alleviate congestion may, as appropriate, develop and propose plans involving modifications to any of the Owner's transmission facilities which are part of the Transmission System. All such plans developed by the Owners may be incorporated into the MISO regional plan, as described in Section VI of this Appendix B. Plans developed by the Owners that involve only Non-transferred Transmission Facilities may be incorporated into the MISO regional plan, as appropriate. The Owners shall continue to have planning responsibilities for meeting their respective transmission needs in collaboration with MISO subject to the requirements of applicable state law or regulatory authority.

MISO, OATT, Sched. 1, App. B.VI.

The Planning Staff, working in collaboration with representatives of the Owners, the OMS Committee, and the Planning Advisory Committee, shall develop the MISO Plan, consistent with Good Utility Practice and taking into consideration long-range planning horizons, as appropriate. The Planning Staff shall develop this plan for expected use patterns and analyze the performance of the Transmission System in meeting both reliability needs and the needs of the competitive bulk power market, under a wide variety of contingency conditions. The MISO Plan will give full consideration to all market participants, including demand-side options, and identify expansions needed to support competition in bulk power markets and in maintaining reliability. This analysis and planning process shall integrate into the development of the MISO Plan among other things: (i) the transmission needs identified from Facilities Studies carried out in connection with specific transmission service requests; (ii) the transmission needs identified by the Owners in connection with their planning analyses to provide reliable power supply to their connected load customers and to expand trading opportunities, better integrate the grid and alleviate congestion; (iii) the transmission planning obligations of an Owner, imposed by federal or state law(s) or regulatory authorities, which can no longer be performed solely by the Owner following transfer of functional control of its transmission facilities to MISO; (iv) the inputs provided by the Planning Advisory Committee; (v) the inputs, if any, provided by the state regulatory authorities having jurisdiction over any of the Transmission Owners; and (vi) the OMS Committee. In the course of this process, the Planning Staff shall seek out opportunities to coordinate or consolidate, where possible, individually defined transmission projects into more comprehensive cost-effective developments subject to the limitations imposed by prior commitments and lead time constraints. This multi-party collaborative process is designed to ensure the development of the most efficient and cost-effective MISO Plan that will meet reliability needs and expand trading opportunities, better integrate the grid, and alleviate congestion, while giving consideration to the inputs from all stakeholders.

The Planning Staff shall test the MISO Plan for adequacy and reliability based on all applicable criteria. The MISO Plan shall adhere to applicable reliability requirements of NERC, Regional Entities, or successor organizations, and Owners' planning criteria filed with federal, state, or local regulatory authorities, and applicable federal, state and local system planning and operating reliability criteria. If the Planning Staff and any Owner's planning representatives cannot reach agreement on any element of the MISO Plan, the dispute may be resolved through the Dispute

Resolution process provided in Attachment HH of the Tariff or by the FERC or state regulatory authorities, where appropriate. The MISO Plan shall have as one of its goals the satisfaction of all regulatory requirements. That is, MISO shall not require that projects be undertaken where it is expected that the necessary regulatory approvals for construction and cost recovery will not be obtained.

Independent System Operator of New England, Inc. ("ISO-NE")

ISO-NE, Open Access Transmission Tariff, § I.2.2, Definitions, *Local Longer-Term Transmission Upgrade*, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_1/sect_i.pdf (last accessed Dec. 18, 2024).

Local Longer-Term Transmission Upgrade is any addition, modification, and/or upgrade to the New England Transmission System with a voltage level below 115 kV that is required in connection with the construction of a Longer-Term Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Section 16 of Attachment K to the OATT.

ISO-NE, Open Access Transmission Tariff, Attachment K, available at https://www.iso-ne.com/static-assets/documents/2021/07/sect_ii_att_k.pdf (last accessed Dec. 18, 2024).

2.5 Local System Planning Process

The LSP process described in Appendix 1 to this Attachment applies to the transmission system planning for the Non-PTF in the New England Transmission System. The PTOs will utilize interested members of the Planning Advisory Committee for advisory stakeholder input in the LSP process that will meet, as needed, at the conclusion of, or independent of, scheduled Planning Advisory Committee meetings. The LSP meeting agenda and meeting materials will be developed by representatives of the pertinent PTOs and PTO representatives will chair the LSP meeting. The ISO will post the LSP agenda and materials for LSP.

Section 1.1 of Appendix 1 (Local System Planning Processes) in Attachment K to the OATT states that local projects "will not be subject to approval by the ISO or the ISO Board under the [Regional System Plan]." https://www.iso-ne.com/static-assets/documents/2021/07/sect_ii_att_k.pdf (last visited Dec. 18, 2024).

New York Independent System Operator, Inc. ("NYISO")

NYISO, Open Access Transmission Tariff, § 40.1, Attachment HH, Definitions, *Local System Upgrade Facilities*, retrieved from: https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOOATT.pdf (last accessed (Dec. 18, 2024).

Local System Upgrade Facilities shall mean the System Upgrade Facilities necessary to physically interconnect a proposed Project to the Connecting Transmission Owner's transmission system, consistent with applicable interconnection and system protection design standards. Local System Upgrade Facilities include any electrical facilities required to make the physical connection (e.g., a new ring bus for a line connection or facilities required to create a new bay for a substation connection). Local System Upgrade Facilities also include any system protection or communication facilities that may be required for protection of the Connecting Transmission Owner's and/or Affected Transmission Owner's transmission facility (line or substation) involved in the interconnection. Local System Upgrade Facilities do not include System Upgrade Facilities required to mitigate any adverse reliability impact(s) of the Project(s) identified through analysis such as power flow, short circuit, or stability (e.g., replacement of a circuit breaker at a nearby substation that becomes overdutied as a result of the Project(s)).

NYISO, OATT, § 31.2.2, Attachment Y, retrieved from https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOOATT.pdf (last accessed (Dec. 18, 2024).

The Reliability Planning Process set forth in Sections 31.2.1 through 31.2.13 of this Attachment Y establishes the process that the ISO, Transmission Owners, Market Participants, and other interested parties shall follow to plan to meet Reliability Needs of the BPTFs that are identified in the RNA. The objectives of the process are to: (1) evaluate the Reliability Needs of the BPTFs over the Study Period pursuant to Reliability Criteria (2) identify, through the development of appropriate scenarios, factors and issues that might adversely impact the reliability of the BPTFs; (3) provide a process whereby solutions to identified needs are proposed, evaluated on a comparable basis, and implemented in a timely manner to ensure the reliability of the system; (4) provide a process by which the ISO will select the more efficient or cost effective regulated transmission solution to satisfy the Reliability Need for eligibility for cost allocation under the ISO Tariffs; (5) provide an opportunity first for the implementation of market-based solutions while ensuring the reliability of the BPTFs; and (6) coordinate the ISO's reliability assessments with neighboring Control Areas.

The ISO will provide, through the analysis of historical system congestion costs, information about historical congestion including the causes for that congestion so that Market Participants and other stakeholders can make appropriately informed decisions.

NYISO, OATT, § 31.1.3, Attachment Y

The Transmission Owners will continue to plan for their transmission systems, including the BPTFs and other NYS Transmission System facilities. The planning process of each Transmission Owner is referred to herein as the LTPP, and the plans resulting from the LTPP are referred to herein as LTPs, whether under consideration or finalized. Each Transmission Owner will be responsible for administering its LTPP and for making provisions for stakeholder input into its LTPP. The ISO's role in the LTPP is limited to the procedural activities described in this Attachment Y.

The finalized portions of the LTPs periodically prepared by the Transmission Owners will be used as inputs to the CSPP described in this Attachment Y. Each Transmission Owner will prepare an LTP for its transmission system in accordance with the procedures described in Section 31.2.1.

Attachment B

California Independent System Operator, Inc. ("CAISO")

CAISO, Open Access Transmission Tariff, § 24.4.8, retrieved from section24-comprehensivetransmissionplanningprocess-asof-dec21-2023.pdf (last accessed Dec. 18, 2024).

24.4.8 Additional Contents of Comprehensive Transmission Plan

In addition to the detailed descriptions of specific needed transmission additions and upgrades, the draft and final comprehensive Transmission Plan may include: (1) the results of technical studies performed under the Study Plan; (2) determinations and recommendations regarding the need for identified transmission upgrades and additions and their identification as either Local or Regional Transmission Facilities; (3) assessments of transmission upgrades and additions submitted as alternatives to the potential solutions to transmission needs identified by the CAISO and studied during the Transmission Planning Process cycle; (4) results of Economic Planning Studies (except for the 2010/2011 cycle); (5) an update on the status of transmission upgrades or additions previously approved by the CAISO, including identification of mitigation plans, if necessary, to address any potential delay in the anticipated completion of an approved transmission upgrade or addition; (6) a description of transmission additions and upgrades with an estimated capital investment of $50 million or more for which additional studies are required before being presented to the CAISO Governing Board for approval following completion of the studies; (7) a description of Category 2 transmission upgrades or additions recommended for consideration in future planning cycles; (8) identification of Interregional Transmission Projects that were submitted in the current planning cycle, could potentially meet regional needs, and will be evaluated in the next planning cycle; and (9) determinations and recommendations regarding the need for Interregional Transmission Projects that have been evaluated and found to be more cost effective and efficient solutions to regional transmission needs and that satisfy all requirements relevant to meeting such needs.

CAISO, Open Access Transmission Tariff, § 24.4.10:

. . . . A Participating Transmission Owner will have the responsibility to construct, own, finance and maintain any Local Transmission Facility deemed needed under this section 24 that is located entirely within such Participating Transmission Owner's PTO Service Territory or footprint. The provisions of Section 24.5 will apply to a Regional Transmission Facility deemed needed under this section 24. Section 24.5 will also apply to any transmission upgrades or additions that are associated with both Regional Transmission Facilities and Local Transmission Facilities but for which the CAISO determines that it is not reasonable to divide construction responsibility among multiple Project Sponsors . . . .

CAISO, Open Access Transmission Tariff, § 26.1(b):

Allocation of Transmission Revenue Requirement. Each Participating TO or Approved Project Sponsor shall provide in its TO Tariff or Approved Project Sponsor Tariff filing with FERC an appendix to such filing that states the Participating TO's or Approved Project Sponsor's Regional Transmission Revenue Requirement, its Local Transmission Revenue Requirement (if applicable) and its Gross Load used in developing the rate. The allocation of each Participating TO's Transmission Revenue Requirement between the Regional Transmission Revenue Requirement and the Local Transmission Revenue Requirement shall be undertaken in accordance with Section 11 of Schedule 3 of Appendix F. To the extent necessary, each Participating TO shall make conforming changes to its TO Tariff.

<u>Southwest Power Pool, Inc. ("SPP")</u>

SPP Open Access Transmission Tariff, Attachment O, retrieved from: https://sppviewer.etariff.biz/tariff (last accessed Dec. 18, 2024).

<u>Attachment O Transmission Planning Process</u>

SPP OATT, Attachment O, § II.1.e:

In accordance with Section II.5 of this Attachment O, the Transmission Provider shall review, and include as appropriate, all Zonal Reliability Upgrades as proposed by the Transmission Owners to meet Zonal Planning Criteria, including such plans developed by Transmission Owners that have their own FERC approved local planning process, to ensure coordination of the projects set forth in such plans with the potential solutions developed in the regional planning process.

SPP, OATT, Attachment O, § II.1.i:

In accordance with its NERC reporting requirements, the Transmission Provider shall publish an annual reliability report that shall include a list of the following:

> i)Regional upgrades required to maintain reliability in accordance with the NERC Reliability Standards and SPP Criteria;
>
> ii) Zonal Reliability Upgrades required to maintain reliability in accordance with more stringent Zonal Planning Criteria; and
>
> iii)Upgrades developed with neighboring Transmission Providers, including results from the coordinated system plans.

SPP, OATT, Attachment O, § II.5(a)

Each Zone within the SPP Region may develop Zonal Planning Criteria that, at a minimum, conform to the NERC Reliability Standards and SPP Criteria. There shall be only one set of Zonal Planning Criteria per Zone. The Facilitating Transmission Owner within the Zone shall hold open meeting(s) to discuss the development of the Zonal Planning Criteria and shall invite all other Transmission Owners and Transmission Customers that receive Long-Term Service to serve load within that Zone. Any initial development of and subsequent modification(s) to the Zonal Planning Criteria of a Zone shall be discussed in open meeting(s). Zonal Planning Criteria for Zone 10 shall be subject to Attachment AD of the Tariff.

Attachment B

SPP, OATT, Attachment O, § III.3

In accordance with the Integrated Transmission Planning Manual, the Transmission Provider shall incorporate, as appropriate, the following as part of its planning studies:

(a) NERC Reliability Standards;
(b) SPP Criteria;
(c) Zonal Planning Criteria as set forth in Section II;
(d) Transmission projects previously identified and approved for construction through an Attachment O planning process;
(e) Previously approved Zonal Reliability Upgrades developed by Transmission Owners, including those that have their own FERC-approved local planning process, to meet Zonal Planning Criteria;
(f) Long-term firm transmission service;
(g) Load forecasts, including the impact on load of existing and planned demand management programs, exclusive of demand response resources;
(h) Capacity forecasts, including generation additions and retirements;
(i) Existing and planned demand response resources;
(j) Congestion within SPP and between the SPP Region and other regions and balancing areas;
(k) Renewable energy standards;
(l) Fuel price forecasts;
(m) Energy efficiency requirements;
(n) Other relevant environmental or government mandates;
(o) Public Policy Requirements identified through the annual survey of stakeholders and additional Public Policy Requirements as determined by the Transmission Provider and stakeholders
(p) Operational experience gained from markets operated by the Transmission Provider;
(q) Other input requirements identified during the stakeholder process and included in the Integrated Transmission Planning Assessment scope; and
(r) Identified persistent operational issues.

SPP, OATT, Attachment O, § VII.2

Owners of transmission facilities shall provide to the Transmission Provider: . . . e) Their individual company-specific planning criteria; . . . .

SPP, OATT, Attachment O, § IX(1)

The Transmission Provider's costs associated with the planning process and associated studies set forth in this Attachment O shall be recovered pursuant to Schedule 1-A1 of the Tariff.

2)The Transmission Provider's costs associated with studies for potential Sponsored Upgrades, shall be the responsibility of the entities requesting such studies.

3)The Transmission Provider's costs for studies associated with requests for long-term firm transmission service shall be recovered pursuant to Sections 19 and 32 of the Tariff.

4)The Transmission Provider's costs for studies associated with requests for interconnection service shall be recovered pursuant to Attachment V of the Tariff.

SPP, OATT, Attachment O, § X

The costs associated with new or upgraded transmission facilities shall be allocated in accordance with Attachment J to the Tariff.

SPP, OATT, Attachment J.I-II

Where a System Impact and/or Facilities Study indicates the need to construct Direct Assignment Facilities to accommodate a request for Transmission Service, the Transmission Customer shall be charged the full cost of such Direct Assignment Facilities. Such costs shall be specified in a Service Agreement.

Where applicable the costs of completed Network Upgrades shall be allocated as specified in Sections III, IV, V and VI of this Attachment. The revenue requirements of Base Plan Upgrades, approved Balanced Portfolios, JTIQ Upgrades, and approved Interregional Projects will be recovered through Schedule 11, subject to filing such rate or revenue requirements with the Commission, and where applicable Directly Assigned Upgrade Costs. These costs may be recovered in whole or in part through the Base Plan Zonal Charge, Region-wide Charge, and/or a direct assignment charge. The cost allocable to each of these charges shall be determined in accordance with Section III of this Attachment and Attachments H and AV of this Tariff. The revenue requirements for other Network Upgrades may be recovered by Transmission Owners through Schedules 7, 8, and 9 subject to their filing such rate or revenue requirements with the Commission.

Attachment B

Transmission Providers in Non-RTO/ISO Regions

Avista Corporation

Avista Corporation (AVAT)**,** FERC Electric Tariff Volume No. 8 (Dec. 1, 2023), available at https://www.oasis.oati.com/woa/docs/AVAT/AVATdocs/OATT_12.1.2023_(1).pdf (last accessed Dec. 18, 2024).

Attachment K, Part I

The Transmission Provider's transmission planning process includes local and regional components to provide for comprehensive, open and coordinated planning of the Transmission Provider's Transmission System and the interconnected transmission network.

Attachment K, Part II

The planning processes described in this Attachment K are intended to result in coordinated local and regional transmission plans while preserving the responsibilities of the Transmission Provider under other provisions of its Tariff to provide transmission and interconnection service on its Transmission System. With respect to any request for transmission service or interconnection received by the Transmission Provider, nothing in this Attachment K shall preclude the Transmission Provider from responding if and as the Transmission Provider determines is appropriate under its Tariff.

Attachment K, Part III

On a biennial basis, the Transmission Provider shall complete its local transmission planning process for the purpose of identifying Single System Projects to mitigate future reliability and load-service requirements for its Transmission System. The Transmission Provider shall document the results of the local transmission planning process in a biennial Local Planning Report in year one and shall update such results, if necessary, in year two. The Local Planning Report shall include any reliability impacts identified on the Transmission Provider's Transmission System and a list of the Single System Projects proposed to mitigate those issues. Any impacts on neighboring transmission systems and the projects to mitigate those impacts shall be identified and coordinated through the NorthernGrid processes. Reliability issues shall be identified by performing technical studies, including powerflow, transient voltage stability, short circuit, and voltage collapse analyses. The Local Planning Report shall identify proposed Single System Projects for a specified year within the one to five year planning horizon and a specified year within the six to ten year planning horizon, pursuant to the Transmission Provider's compliance with applicable NERC and WECC reliability criteria. For years in which the biennial Local Planning Report is being developed, the planning process shall begin no later than the second quarter of the year and shall conclude no later than the fourth quarter of such year as required to proceed with the design, development, and funding of the proposed transmission projects identified ("Year One"). During the second year of the biennial process, an update to the Local Planning Report will be completed ("Year Two").

2.3 Cost Recovery for Local Transmission Planning Process Participation The Transmission Provider shall hold all local transmission planning process meetings within the Transmission Provider's retail electric service territory in a central location to minimize local travel costs for participants. The Transmission Provider will provide facilities for the meetings, any needed documents and supplies, and other items specific to the planning process. The Transmission Provider will not provide recovery of any costs incurred by parties participating in this Attachment K planning process. The Transmission Provider will seek recovery of its costs of the Attachment K process in its applicable state and federal rate setting processes. If any Interested Stakeholder is unable to attend a meeting or otherwise participate in the local transmission planning process, the Transmission Provider shall provide electronic or hardcopies of all reports, meeting notes, and any additional pertinent materials (except CEII) upon written request within thirty (30) calendar days. To the extent any CEII, WECC Proprietary Data, or Avista Proprietary Data is requested under this section, such request shall be made in accordance with sections 2.1.1, 2.1.2, and 2.1.3 of this Attachment K.

4. Local Planning Process Planning Criteria The Transmission Provider shall evaluate in its local transmission planning process transmission solutions, including transmission and Non-Transmission Alternatives submitted in accordance with Part III, section 5.3.1, to local transmission needs (including local transmission needs driven by Public Policy Requirements) that are selected by the Transmission Provider and listed on Transmission Provider's OASIS as local transmission needs to be evaluated in the local planning process. In evaluating such transmission solutions, the Transmission Provider shall apply the following as planning criteria for its local transmission planning process:

(A) degree of development of alternative;

(B) relative economics and effectiveness of performance;

(C) current applicable state, regional, and federal planning requirements and regulations;

(D) current applicable NERC/WECC planning standards;

(E) such additional current applicable criteria as are then accepted or developed by Transmission Provider; and

(F) Transmission Provider will also consider the ability to satisfy an identified local transmission need, including a local transmission need driven by Public Policy Requirements.

Idaho Power Company

Idaho Power Company (IPCO), IPCo eTariff, Attachment K (Nov. 18, 2024), retrieved from https://www.oasis.oati.com/IPCO/IPCOdocs/Section_21_Transmission_Planning.pdf (last accessed Dec. 18, 2024)

Attachment B

Preamble

In accordance with the Commission's regulations, Transmission Provider's planning process is performed on a local, regional, and interregional basis. Part A of this Attachment K addresses the local planning process. Part B of this Attachment K addresses the regional planning process. Part C of this Attachment K addresses interregional coordination with the planning regions in the United States portion of the Western Interconnection. Part E of this Attachment K addresses requests for economic studies, and Part F of this Attachment K describes the dispute resolution process.

1.39 Local Transmission Plan "Local Transmission Plan" means a transmission provider's plan (depending upon context, the Transmission Provider or an Enrolled Party) that identifies planned new transmission facilities and facility replacements or upgrades for such transmission provider's Transmission System.

Part A

2.1 Transmission Service Request Impacts Local Transmission Plan With the input of affected stakeholders, Transmission Provider shall prepare one (1) Local Transmission Plan during each two-year study cycle. The Transmission Provider shall evaluate the Local Transmission Plan by modeling the effects of Economic Study Requests timely submitted by Eligible Customers and stakeholders in accordance with Section 3 and Part E of this Attachment K. The Local Transmission Plan shall study a twenty (20) year planning horizon.

3.2 Sequence of Events

3.2.1 Quarter 1 . . . Transmission Provider will gather:

a. Network Customers' projected loads and resources, and load growth expectations (based on annual updates and other information available to it);

b. Transmission Provider's projected load growth and resource needs for Native Load Customers (based on its state mandated integrated resource plan, to the extent that such an obligation exists, or through other planning resources);

c. Point-to-point transmission service customers' projections for service at each Point of Receipt and Point of Delivery (based on information submitted by the customer to the Transmission Provider) including projected use of rollover rights;

d. Information from all Transmission Customers and the Transmission Provider on behalf of Native Load Customers concerning existing and planned Demand Resources and their impacts on demand and peak demand; and

e. Transmission needs driven by Public Policy Requirements.

The Transmission Provider shall take into consideration, to the extent known or which may be obtained from its Transmission Customers and active queue requests, obligations that will either commence or terminate during the applicable study window. Any stakeholder may submit data to be evaluated as part of the preparation of the draft Local Transmission Plan, including alternate solutions to the identified needs set out in prior Local Transmission Plans, Public Policy Requirements, and transmission needs driven by Public Policy Requirements. In doing so, the stakeholder shall submit the data as specified in "Section 21 – Transmission Planning" of the Transmission Provider's business practices . . . . All stakeholder submissions, including transmission needs driven by Public Policy Requirements, will be evaluated on a basis comparable to data and submissions required for planning the transmission system for both retail and wholesale customers, and alternative proposals, including proposals driven by Public Policy Requirements, will be evaluated based on a comparison of their relative economics and ability to meet reliability criteria.

3.2.2 Quarter 2 . . . Transmission Provider will define and post on OASIS the basic methodology, criteria, assumptions, databases, and processes the Transmission Provider will use to prepare the Local Transmission Plan.

6: Cost Allocation: Cost allocation principles expressed here are applied in a planning context of transparency and do not supersede cost obligations as determined by other parts of the Transmission Provider's Tariff which include but are not limited to transmission service requests, Idaho Power Company - IPCo eTariff - Tariff Open Access Transmission Tariff - Attachment K Part A Local Planning Process Effective Date: 4/1/2020 - Docket #: ER20-0890-000 - Page 223 generation interconnection requests, Network Upgrades, or Direct Assignment Facilities, or as may be determined by any state having jurisdiction over the Transmission Provider.

6.1 Individual Transmission Service Request Costs Not Considered: The costs of upgrades or other transmission investments subject to an existing transmission service request pursuant to the Transmission Provider's Tariff are evaluated in the context of that transmission service request. Nothing contained in this Attachment K shall relieve or modify the obligations of the Transmission Provider or the requesting Transmission Customer contained in the Transmission Provider's Tariff.

6.2 Rate Recovery: Notwithstanding any other section of this Attachment K, Transmission Provider will not assume cost responsibility for any project if the cost of the project is not reasonably expected to be recoverable in its retail and/or wholesale rates.

6.3 Categories of Included Costs: The Transmission Provider shall categorize projects set forth in the Local Transmission Plan for allocation of costs into the following types:

a. Type 1: Type 1 transmission line costs are those related to the provision of service to the Transmission Provider's Native Load Customers. Type 1 costs include, to the extent such agreements exist, costs related to service to others pursuant to grandfathered transmission agreements that are considered by the Transmission Provider to be Native Load Customers.
b. Type 2: Type 2 costs are those related to the sale or purchase of power at wholesale to non-Native Load Customers.
c. Type 3 costs are those incurred specifically as alternatives to (or deferrals of) transmission line costs (typically Type 1 projects), such as the installation of distributed resources (including distributed generation, load management and energy

efficiency). Type 3 costs do not include Demand Resources projects which do not have the effect of deferring or displacing Type 1 costs.

6.4 Cost Allocation Principles: Unless an alternative cost allocation process is utilized and described in the Local Transmission Plan, the Transmission Provider shall identify anticipated cost allocations in the Local Transmission Plan based upon the end-use characteristics of the project according to categories of costs set forth above and the following principles:

a. Principle 1: The Commission's regulations, policy statements and precedent on transmission pricing shall be followed.
b. Principle 2: To the extent not in conflict with Principle 1, costs will be allocated consistent with the provisions of Section 17 of this Attachment K.

8 Recovery of Planning Costs: Unless Transmission Provider allocates planning-related costs to an individual stakeholder as set out herein, or as otherwise permitted under the Tariff, all costs incurred by the Transmission Provider related to the Local Transmission Plan process or the regional or interregional planning process shall be included in the Transmission Provider's transmission rate base.

Montana-Alberta Tie Line LLP (MATL)

Montana Alberta Tie Line, Open Access Transmission Tariff for the Montana Alberta Tie Line, Attachment K, retrieved from: https://www.oasis.oati.com/MATL/MATLdocs/MATL_LLP_OATT_8.8.16.pdf (last accessed Dec. 18, 2024).

1.0 General

Preamble:

In accordance with the Commission's regulations, Transmission Provider's planning process is performed on a local, regional, interregional and interconnection-wide basis. Part 2 of this Attachment K addresses the local planning process. Part 3 of this Attachment K addresses the regional planning process . . . . The Transmission Provider retains the responsibility for the local planning process and Local Transmission System Plan and may accept or reject in whole or in part, the comments of any stakeholder unless prohibited by applicable law or regulation.

Definitions

1.31 "Local Transmission System Plan or Local Transmission Plan (LTSP or LTP) " means the transmission plan of the Transmission Provider that identifies the upgrades and other investments to the Transmission System and Demand Resources necessary to reliably satisfy, over the planning horizon, Network Customers' resource and load growth expectations for designated Network Load and Network Resource additions; Transmission Provider's resource and load growth expectations for Native Load Customers; Transmission Provider's transmission obligation for Public Policy Requirements; Transmission Provider's obligations pursuant to grandfathered, non- OATT agreements; and Transmission Provider's Pointto-Point Transmission Customers' projected service needs including obligations for rollover rights.

Attachment B

Part II. The Transmission Provider Local Transmission Planning Process

2.1.2 Purpose and Objective. The Transmission Provider's transmission planning process includes local and regional components to facilitate comprehensive, open and coordinated planning of the Transmission Provider's Transmission System. The purpose of the Transmission planning process detailed in Part II of this Attachment K is to set forth the process by which the Transmission Provider will plan for the enhancement and expansion of the Transmission System to ensure that the Transmission System can meet the needs of both the Transmission Provider and its Transmission Customers on a comparable and nondiscriminatory basis. This is intended to be a coordinated, open and transparent planning process with the Transmission Customers and other Interested Stakeholders, including interconnected systems within its region and Interested Persons in the regional planning process.

2.3.3 Contents of the Local Transmission Plan. The Local Transmission Plan shall utilize at least a five year planning horizon, and reflect at least five year capacity and load forecasts, if any. The Local Transmission Plan shall reflect transmission enhancements and expansions, load and energy forecasts, including expected demand response, transmission needs driven by Public Policy Requirements and generation additions and retirements for at least the ensuing five years, if any. The Local Transmission Plan shall identify, based on the results of the planning studies, a list of proposed transmission enhancements and expansions for at least each of the ensuing five years that are determined by Transmission Provider to be appropriate at the time of the issuance of the Local Transmission Plan. The Local Transmission Plan also shall include a list of transmission enhancements and expansions identified in the prior Local Transmission Plan that have not been completed at that time. The Local Transmission Plan shall take into account reliability and rating studies in accordance with WECC path rating procedures.

2.3.4 The Transmission Provider may also identify expansions, modifications or additions to the transmission line resulting from discussions with customers, market participants, interconnection requests or transmission service requests. For these types of expansions, the Transmission Provider will use the following process:

(a) In responding to a request for expansion of the Transmission Provider line, the Transmission Provider shall form a planning group inviting all Interested Stakeholders and connecting Balancing Authorities to participate. The invitation will be posted on the Transmission Provider's OASIS for 30 days;

(b) Following a minimum 30 day review process with the planning group, the Transmission Provider shall conduct an economic feasibility study for the proposed expansion, funded by the requesting customer and/or the Transmission Provider, as negotiated. The study results shall be posted on the Transmission Provider's OASIS;

(c) The Transmission Provider may then decide to hold an Open Season, or conduct an alternative process in conformance with FERC policy, to value and allocate the potential capacity;

(d) If the results of the Open Season, or other such alternative process, are acceptable to the Transmission Provider and if the initial studies indicate that additional capacity is feasible, the Transmission Provider shall conduct reliability and rating studies in accordance with WECC path rating procedures; (e) If all regulatory approvals are obtained, and upon satisfaction of all outstanding conditions in its long term transmission contracts, the Transmission Provider will enter into agreements for the expansion.

2.4.5 Criteria Used. Studies will be performed in accordance with NERC Reliability Standards TPL-001 through TPL-004, the WECC reliability criteria, and any other reliability criteria, including regional or local applicable criteria in establishing assumptions.

MATL will also evaluate and select from among alternative proposed solutions to local transmission needs (including those driven by Public Policy Requirements) using factors that include the following:

(i) sponsorship and degree of development of proposed solution;
(ii) (ii) feasibility;
(iii) (iii) coordination with any affected transmission system;
(iv) economics;
(iv) (v) effectiveness of performance;
(v) (vi) satisfaction of identified local transmission need(s), including those driven by Public Policy Requirements and including the extent to which the proposed solution satisfies multiple identified local transmission needs;
(vi) (vii) mitigation of any Material Adverse Impacts of Local Need Solution of such proposed solution on any transmission system;
(vii) (viii)consistency with applicable state, regional, and federal planning requirements and regulations;

No single factor shall necessarily be determinative in evaluating proposed solutions in developing the MATL Plan

NorthWestern Corporation (NWMT)

Northwestern Corporation, Montana OATT, Attachment K, filed Oct. 22, 2021, FERC Docket No. ER22-00179-000, available at https://www.oasis.oati.com/woa/docs/NWMT/NWMTdocs/Att_K_-_Transmission_Planning_Process.pdf (last accessed Dec. 18, 2024).

Preamble

In accordance with the Commission's regulations, Transmission Provider's planning process is performed on a local, regional, and interregional basis. Part B of this Attachment K addresses the local planning process. Part C of this Attachment K addresses the regional planning process . . . . . The Transmission Provider retains the responsibility for the local planning process and Local

Transmission Plan and may accept or reject, in whole or in part, the comments of any stakeholder unless prohibited by applicable law or regulation.

Part A. Definitions
1.38 Local Transmission Plan
Local Transmission Plan means a transmission provider's plan (depending upon context, the Transmission Provider or an Enrolled Party) that identifies planned new transmission facilities and facility replacements or upgrades for such transmission provider's Transmission System.

Part B. Local Transmission Planning Process
2.1.3 Comparability Between Customers. The Transmission Provider shall develop a transmission plan that meets the needs of its transmission customers and treats all similarly situated customers (including network and retail native load and its own merchant function) on a comparable basis. Information obtained in quarters 1 and 5 pursuant to Section 2.5 below will be used in the preparation of the next study cycle Local Transmission Plan. Transmission Provider may, following stakeholder input, also include results of completed Economic Studies, completed pursuant to Part E below, in either the draft Local Transmission Plan or the next study cycle, depending on whether the study was requested in Quarter 1 or Quarter 5. In developing the Local Transmission Plan, Transmission Provider shall apply applicable reliability criteria, including criteria established by the Transmission Provider, the Western Electricity Coordinating Council, the North American Electric Reliability Corporation, and the Federal Energy Regulatory Commission.

2.1.4 Comparability Between Resources. Comparability between resources, including similarly situated customer-identified projects, will be accomplished in the following manner. 2.1.4.1 Comparability between resources will be achieved in NWE's Local Transmission Plan by including all valid data received from customers (including load forecast data, generation data, transmission needs driven by Public Policy Requirements and Demand Resource data) in the Local Transmission Plan development.

2.1.4.2 The Transmission Provider projects and similarly situated customer-identified projects (e.g., transmission solutions, transmission needs driven by Public Policy Requirements and solutions utilizing Demand Resource load adjustment) will be treated on a comparable basis and given comparable consideration in the transmission planning process. Comparability will be achieved by allowing customer-defined projects sponsor participation throughout the transmission planning process and by considering customer-defined projects (transmission solutions and solutions utilizing Demand Resources load modeled as a load adjustment) in the Local Transmission Plan development. The Transmission Provider retains discretion as to which solutions to pursue and is not required to include all customer-identified projects in its plan.

2.2 Open Planning Process
2.2.1 Open Planning Process: Transmission Provider shall prepare the Local Transmission Plan using an open process that includes input from interested persons and stakeholders at every step consistent with the principles, practices, policy and procedures set forth in this Attachment K. The Transmission Provider shall: (1) determine the goals and define the scenarios related to the Local Transmission Plan; (2) perform the Technical Study; (3) make any necessary determination, based on the data produced during the Technical Study and at the Transmission

Providers sole discretion, regarding the Local Transmission Plan itself or include timely submitted Economic Study Request results; and (4) report study results, as required by applicable law or regulation to interested stakeholders and affected parties.

2.3.2.1.4 Transmission Provider will post on its OASIS website the basic methodology, criteria, process, its assumptions and databases that the Transmission Provider will use to prepare the Local Transmission Plan. Transmission Provider will also post on its OASIS website (i) a list of transmission needs driven by Public Policy Requirements that will be evaluated for potential solutions in the biennial transmission planning process and (ii) if not all transmission needs driven by Public Policy Requirements will be evaluated for potential solutions, an explanation as to how other transmission needs driven by Public Policy Requirements introduced by stakeholders were considered during the identification stage, and why they were not selected for further evaluation.

2.4 Transparency

2.4.4 The responsibility for the Local Transmission Plan shall remain with the Transmission Provider who may accept or reject in whole or in part, the comments of any stakeholder unless prohibited by applicable law or regulation.

2.6 Cost Allocation

2.6.1 Cost allocation principles expressed here are applied in a planning context, and do not supersede cost obligations as determined by other parts of the Tariff, which include but are not limited to transmission service requests, generation interconnection requests, Network Upgrades, Direct Assigned Facilities, or other cost allocation principles as may be determined in states with jurisdiction over the Transmission Provider.

2.6.2 The types of projects covered under this Cost Allocation (i.e., projects that are not covered under existing OATT allocation rules) include the following: a new project that is confined to Transmission Provider's Balancing Area that is not for load service (including a new project extending beyond the Transmission Provider's Balancing Area, which will be subject to regional cost allocation rules); a new project involving several transmission owners; a new project resulting from an open season participation; and a project resulting from an Economic Study Request that is not used for Transmission Provider load service.

2.6.3 Individual Transmission Service Requests Costs and Interconnect Requests Not Considered

2.6.3.1 The costs of upgrades or other transmission investments subject to a generation interconnect or an existing transmission service request pursuant to the Tariff are evaluated in the context of that request. Nothing contained in this Attachment K shall relieve or modify the obligations of the Transmission Provider or the requesting Transmission Customer contained in the Tariff.

2.6.4 Cost Allocation Principles

2.6.4.1 Costs will be identified using the principle that cost causers should be cost bearers and that beneficiaries should pay in an amount that are reflective of the direct demonstrable benefits received. The costs will be determined by the technical study used to define the mitigation requirements and the direct costs of that mitigation. The benefits will be determined by the technical study as the direct demonstrable benefits that are a direct result of that mitigation.

2.6.4.2 Proportional Allocation: Costs and associated transmission rights for new local projects that fall outside Transmission Provider's OATT will be allocated on a proportional allocation based on the capacity (MW) requested or benefit received (quantified as MW benefit or other agreed upon measure), unless a mutually agreeable cost allocation method can be reached between Transmission Provider and the project participants or sponsors, which will be subject to FERC approval of the participation agreement. Allocation of costs and benefits for network upgrades required by the local project will be allocated on a pro-rated share of the network facility capacity (MW) use, which will be quantified by technical study.

2.6.4.2.1 Transmission Provider will follow the Local Cost Allocation Project Outside OATT Methodology that is posted on Transmission Provider's OASIS to develop a non-binding cost estimate for an indicative cost allocation. The local cost allocation methodology can be found under Section "1.M - Local Cost Allocation Methodology" of the Transmission Provider's business practices, available on Transmission Provider's OASIS at: Attachment_K_Business_Practice-Order1000-FinalApproved.pdf (last accessed Dec. 18, 2024).

2.6.4.2.2 For a project on the Transmission Provider's system that is undertaken for economic reasons or congestion relief at the request of an entity, the project cost will be allocated to the requesting entity.

2.6.4.4 The Commission's regulations, policy statements and precedent on transmission pricing shall be followed.

2.6.4.5 The cost allocation for regional projects will be allocated consistent with the provisions of Section 8 of this Attachment K

2.8 Recovery of Planning Costs

Unless Transmission Provider allocates planning-related costs to an individual stakeholder, or as otherwise permitted by the Tariff, all costs of the Transmission Provider related to the Local Transmission Plan process or as part of a regional or interregional planning process shall be included in the Transmission Provider's transmission rate base.

Pacificorp (PPW)

Pacificorp, Open Access Transmission Tariff FERC Electric Tariff Volume No. 11, updated Oct. 28, 2024, Attachment K retrieved from https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20241028_OATTMaster.pdf (last accessed Dec. 18, 2024).

Attachment B

Part A: Definitions

§ 1.39: Local Transmission Plan
"Local Transmission Plan" means a transmission provider's plan (depending upon context, the Transmission Provider or an Enrolled Party) that identifies planned new transmission facilities and facility replacements or upgrades for such transmission provider's Transmission System.

Part B: Local Transmission Planning Process
§ 2: Local Planning Process

§ 2.1.1: Preparation of a Local Transmission System Plan

With the input of affected stakeholders, Transmission Provider shall prepare one (1) Local Transmission Plan during each two-year planning cycle. The Local Transmission Plan on its own does not effectuate any transmission service requests or designation of a future Network Resource. A request for Point-to-Point Transmission Service must be made as a separate and distinct submission by an Eligible Customer in accordance with the procedures set forth in Part II of the Tariff and posted on the Transmission Provider's OASIS. Similarly, Network Customers must submit Network Resource and Network Load additions/removals pursuant to the process described in Part III of the Tariff. The Local Transmission Plan shall study a ten (10) year planning horizon, unless an Eligible Customer's request submitted through the Tariff process specifically identifies a future new resource location on a 20 year horizon. In that case the Local Transmission Plan will be extended to 20 years.

§ 2.1.2: The Transmission Provider shall consider the information obtained pursuant to Section 2.4 below, and transmission needs driven by Public Policy Requirements, in the preparation of the next planning cycle Local Transmission Plan. Transmission Provider may, following stakeholder input, also include results of completed Economic Studies, completed pursuant to Section 12 below, in either the draft Local Transmission Plan or the next planning cycle, depending on whether the study was requested in Quarter 1 or Quarter 5. In developing the Local Transmission Plan, Transmission Provider shall apply applicable reliability criteria, including criteria established by the Transmission Provider, WECC, the North American Electric Reliability Corporation, and the Federal Energy Regulatory Commission. In developing the Local Transmission Plan, Transmission Provider shall also identify upgrades and other investments to the Transmission System and Demand Response Resources necessary to reliably satisfy, over the planning horizon, Network Customers' resource and load growth expectations for designated Network Load and Network Resource additions; Transmission Provider's resource and load growth expectations for Native Load Customers; Transmission Provider's transmission obligation for Public Policy Requirements; Transmission Provider's obligations pursuant to grandfathered, non-OATT agreements; and Transmission Provider's Point-to-Point Transmission Service Customers' projected service needs including obligations for rollover rights.

§ 2.2.2 Sequence of Events.

2.2.2.1 Quarter 1: Transmission Provider will gather: (1) Network Customers' projected loads and resources and load growth expectations (based on annual updates under Part III of the Tariff and other information available to the Transmission Provider); (2) Transmission Provider's projected load growth and resource needs for Native Load Customers; (3) Eligible Customers' projections of Point-to-Point Transmission Service usage at each Point of Receipt and Point of Delivery (based on information submitted by Eligible Customers to the Transmission Provider pursuant to Section 2.3.1.1 below) including projected use of rollover rights;(4) information from all Transmission and Interconnection Customers concerning existing and planned Demand Response Resources and their impacts on demand and peak demand; and (5) transmission needs driven by Public Policy Requirements submitted by all stakeholders.

The Transmission Provider shall take into consideration, to the extent known or which may be obtained from its Transmission Customers, obligations that will either commence or terminate during the planning cycle. Any stakeholder may submit data to be evaluated as part of the preparation of the draft Local Transmission Plan, and/or the development of sensitivity analyses, including alternate solutions to the identified needs set out in prior Local Transmission Plans and transmission needs driven by Public Policy Requirements. In doing so, the stakeholder shall submit the data as specified in the Transmission Provider's transmission planning business practice, posted on Transmission Provider's OASIS. Transmission Provider shall use Point-to-Point Transmission Service usage forecasts and Demand Response Resources forecasts to determine system usage trends, and such forecasts do not obligate the Transmission Provider to construct facilities until formal requests for either Point-to-Point Transmission Service or Generator Interconnection Service requests are received pursuant to Parts II and IV of the Tariff.

§ 2.2.2.2. Quarter 2: Transmission Provider will, with stakeholder input, define and post on OASIS the basic methodology, planning criteria, assumptions, databases, and processes the Transmission Provider will use to prepare the Local Transmission Plan. The Transmission Provider will also select appropriate base cases from the databases maintained by the WECC, and determine the appropriate changes needed for the Local Transmission Plan development. The Transmission Provider may adjust any base case to make that base case consistent with local planning assumptions and data . . . All stakeholder submissions will be evaluated on a basis comparable to data and submissions required for planning the transmission system for both retail and wholesale customers, and solutions will be evaluated based on a comparison of their relative economics and ability to meet reliability criteria.

§ 2.6. Cost Allocation. Cost allocation principles expressed here are applied in a planning context of transparency and do not supersede cost obligations as determined by other parts of the Tariff which include but are not limited to transmission service requests, generation interconnection requests, Network Upgrades, Direct Assigned Facilities, or other cost allocation principles as may be determined by any state having jurisdiction over the Transmission Provider.

§ 2.6.1. Individual Transmission Service Request Costs Not Considered. The costs of upgrades or other transmission investments subject to an existing transmission service request pursuant to the Tariff are evaluated in the context of that transmission service request. Nothing contained in this Attachment K shall relieve or modify the obligations of the Transmission Provider or the requesting Transmission Customer contained in the Tariff.

§ 2.6.2. Rate Recovery. Notwithstanding any other section of this Attachment K, Transmission Provider will not assume cost responsibility for any project if the cost of the project is not reasonably expected to be recoverable in its retail and/or wholesale rates.

§ 2.6.3. Categories of Included Costs. The Transmission Provider shall categorize projects set forth in the Local Transmission Plan for allocation of costs into the following types:

§ 2.6.3.1. Type 1: Type 1 transmission line costs are those related to the provision of service to the Transmission Provider's Network and Native Load Customers. Type 1 costs include, to the extent such agreements exist, costs related to service to others pursuant to grandfathered transmission agreements.

§ 2.6.3.2. Type 2: Type 2 costs are those related to Point-to-Point Transmission Service and requests for service.

§ 2.6.3.3. Type 3: Type 3 costs are those incurred specifically as alternatives to (or deferrals of) transmission line costs (typically Type 1 projects), such as the installation of distributed resources (including distributed generation, load management and energy efficiency). Type 3 costs do not include Demand Response Resources projects which do not have the effect of deferring or displacing Type 1 costs.

§ 2.6.4. Cost Allocation Principles. Unless an alternative cost allocation process is utilized and described in the Local Transmission Plan, the Transmission Provider shall identify anticipated cost allocations in the Local Transmission Plan based upon the end-use characteristics of the project according to categories of costs set forth above and the following principles:

§ 2.6.4.1. Principle 1: The Commission's regulations, policy statements and precedent on transmission pricing shall be followed.

§ 2.6.4.2. Principle 2: To the extent not in conflict with Principle 1, costs will be allocated consistent with the provisions of Section 8 of this Attachment K.

§ 2.8. Recovery of Planning Costs. Unless Transmission Provider allocates planning-related costs to an individual stakeholder as permitted under the Tariff, all costs incurred by the Transmission Provider related to the Local Transmission Planning process, or as part of the regional, or interregional planning process, shall be included in the Transmission Provider's transmission rate base.

Portland General Electric Company (PGE)

Portland General Electric Company, Pro Forma Open Access Transmission Tariff, Attachment K, retrieved from https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_OATT_10082024-v9.pdf (last accessed Dec. 18, 2024)

Attachment B

Preamble
In accordance with the Commission's regulations, Transmission Provider's planning process is performed on a local, regional, and interregional basis. Part A of this Attachment K addresses the local planning process.

1 Definitions

1.39 Local Transmission Plan or LTP
"Local Transmission Plan" or "LTP" means a transmission provider's plan (depending upon context, the Transmission Provider or an Enrolled Party) that identifies planned new transmission facilities and facility replacements or upgrades for such transmission provider's Transmission System

Part A. Local Planning Process

2 PREPARATION OF A LOCAL TRANSMISSION PLAN

3.2 Sequence of Events

3.2.2 Quarter 2 (of the first year of the Planning Cycle)

Transmission Provider will define and post on OASIS the basic methodology, criteria, assumptions, databases, and processes the Transmission Provider will use to prepare the Near Term Local Transmission Plan. The Transmission Provider will insert its system details in Near Term summer and winter peak WECC base cases for purposes of conducting its studies; assess the timely submitted local Economic Study Requests for the summer/winter WECC base cases using the previous biennial cycle's Local Transmission Plan as a reference; and select one Economic Study for evaluation during the first year of the current biennial cycle.

3.2.3 Quarters 3 and 4 (of the first year of the Planning Cycle)

Transmission Provider will select Longer Term summer/winter base cases from WECC; identify project needs, schedule for implementation, and cost responsibility; and prepare and post on Transmission Provider's OASIS a draft Near Term Local Transmission Plan. Any stakeholder may submit comments; changes to the data provided in Quarter 1; additional information about new or changed circumstances relating to loads, resources, and transmission projects; or alternative solutions to be evaluated as part of the Near Term Local Transmission Plan. All comments, data, and information shall be submitted as specified in the Transmission Provider's "Business Practice: Transmission Planning", available on Transmission Provider's OASIS.

All stakeholder submissions will be evaluated on a basis comparable to data and submissions required for planning the transmission system for both retail and wholesale customers, and alternative proposals will be evaluated based on a comparison of their relative economics and ability to meet reliability criteria. The Transmission Provider may elect to post interim iterations of the draft Near Term Local Transmission Plan, consider economic modeling results, and solicit public comment prior to the end of the applicable quarter. Transmission Provider will post on its OASIS the 30-day notice for its public meeting to present, solicit, and receive comments on

Transmission Provider's draft Near Term Local Transmission Plan, and Transmission Provider will subsequently conduct the public meeting to review the draft Near Term Local Transmission Plan. Transmission Provider will finalize the Near Term Local Transmission Plan taking into account (1) the Economic Study Request modeling results, if any; (2) written comments received from the owners and operators of interconnected transmission systems; (3) written comments received from Transmission Customers and other stakeholders; and (4) timely comments submitted during the public meetings, as set forth in Section 3.3, below.

3.2.7 Quarters 7 and 8 (of the second year of the Planning Cycle)

All stakeholder submissions will be evaluated on a basis comparable to data and submissions required for planning the transmission system for both retail and wholesale customers, and alternative proposals will be evaluated based on a comparison of their relative economics and ability to meet reliability criteria. Transmission Provider may elect to post interim iterations of the draft Longer Term Local Transmission Plan, consider economic modeling results, and solicit public comment prior to the end of the applicable quarter. Transmission Provider will post on its OASIS the 30-day notice for its public meeting to present, solicit, and receive comments on its draft Longer Term Local Transmission Plan, and Transmission Provider will subsequently conduct the public meeting to review the draft Longer Term Local Transmission Plan. Transmission Provider will finalize the Longer Term Local Transmission Plan taking into account (1) the Economic Study Request modeling results, if any; (2) written comments received from the owners and operators of interconnected transmission systems; (3) written comments received from Transmission Customers and other stakeholders; and (4) timely comments submitted during public meetings, as set forth in Section 3.3, below.

6 COST ALLOCATION

Cost allocation principles expressed here are applied in a planning context for purposes of transparency and do not supersede cost obligations as determined by other parts of the Transmission Provider's Tariff, which include but are not limited to transmission service requests, generation interconnection requests, Network Upgrades, or Direct Assignment Facilities, or as may be determined by any state having jurisdiction over the Transmission Provider.

6.1 Individual Transmission Service Request Costs Not Considered

The costs of upgrades or other transmission investments subject to an existing transmission service request submitted pursuant to Transmission Provider's Tariff are evaluated in the context of that transmission service request. Nothing contained in this Attachment K shall relieve or modify the obligations of the Transmission Provider or the requesting Transmission Customer that they may have under Transmission Provider's Tariff.

6.2 Categories of Included Costs

The Transmission Provider shall categorize projects set forth in the Local Transmission Plan, for purposes of allocating costs, into the following types:

a. Type 1: Type 1 transmission line costs are those related to the provision of service to the Transmission Provider's Native Load Customers. Type 1 costs include, to the extent such agreements exist, costs related to service to others pursuant to grandfathered transmission agreements that are considered by the Transmission Provider to be Native Load Customers.

b. Type 2: Type 2 costs are those related to the sale or purchase of power at wholesale to non-Native Load Customers.

c. Type 3: Type 3 costs are those incurred specifically as alternatives to (or deferrals of) transmission line costs (typically Type 1 projects), such as the installation of distributed resources (including distributed generation, load management and energy efficiency). Type 3 costs do not include Demand Response Resource projects, which do not have the effect of deferring or displacing Type 1 costs.

6.3 Cost Allocation Principles

Unless an alternative cost allocation process is utilized and described in the Local Transmission Plan, the Transmission Provider shall identify anticipated cost allocations in the Local Transmission Plan based upon the end-use characteristics of the project according to categories of costs set forth above and the following principles:

a. Principle 1: The Commission's regulations, policy statements and precedent on transmission pricing shall be followed.

b. Principle 2: To the extent not in conflict with Principle 1, costs will be allocated consistent with the provisions of Section 17 of this Attachment K.

8 RECOVERY OF PLANNING COSTS

Unless Transmission Provider allocates planning-related costs to an individual stakeholder as set out herein, or as otherwise permitted under the Tariff, all costs incurred by the Transmission Provider related to the Local Transmission Plan process or the regional or interregional planning processes shall be included in the Transmission Provider's transmission rate base.

Puget Sound Energy, Inc. (PSE)

Pudget Sound Energy, FERC Electric Tariff of Pudget Sound Energy, Inc. filed with the Federal Energy Regulatory Commission, Attachment K, retrieved from: https://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Current_OATT_Effective_11.19.2024.pdf (last accessed Dec. 18, 2024).

Part A. Definitions

1.38 Local Transmission Plan

"Local Transmission Plan" means a transmission provider's plan (depending upon context, the Transmission Provider or an Enrolled Party) that identifies planned new transmission facilities and facility replacements or upgrades for such transmission provider's Transmission System.

Attachment B

Part B. Local Transmission Planning Process

2. PSE Plan

2.1 Development and Update of PSE Plan

Transmission Provider shall prepare one Local Transmission Plan (the “PSE Plan”) during each two-year study cycle. The Transmission Provider shall prepare the PSE Plan in year one and provide any necessary updates to the PSE Plan in year two. The PSE Plan will identify transmission needs over the ensuing ten-year planning horizon and potential solutions to those needs.

2.7.1 Identification of Needs

The factors considered when selecting local transmission needs (including those driven by Public Policy Requirements) for analysis in developing the PSE Plan shall include the following:

a. the level and form of support for addressing the potential local transmission need (such as indications of willingness to purchase capacity and existing transmission service requests that could use capacity consistent with solutions that would address the potential local transmission need);
b. the feasibility of addressing the potential local transmission need;
c. the extent, if any, that addressing the potential local transmission need would also address other potential transmission needs; and,
d. the factual basis supporting the potential local transmission need.

No single factor shall necessarily be determinative in selecting any potential local transmission need for analysis in developing the PSE Plan.

With respect to identified local transmission needs driven by Public Policy Requirements, if any, Transmission Provider will post on its OASIS an explanation of which of such need(s) will be evaluated in Transmission Provider’s local transmission planning process or an explanation of why any of such need(s) will not be evaluated in the local transmission planning process.

2.7.2 Identification of Solutions

Transmission Provider will identify solutions to the local transmission needs. The factors considered when selecting solutions to the local transmission needs in the PSE Plan shall include the following:

a. sponsorship and degree of development of proposed solution;
b. feasibility;
c. coordination with any affected transmission system;
d. economics
e. effectiveness of performance of wired, non-wired and/or a combination of wired and non-wired solutions;

f. satisfaction of identified local transmission need(s), including those driven by Public Policy Requirements and including the extent to which the proposed solution satisfies multiple identified local transmission needs;
g. mitigation of any Material Adverse Impacts on any transmission system;
h. consistency with applicable state, regional, and federal planning requirements and regulations; and,
i. consistency with such additional criteria as are then accepted or developed by PSE.

No single factor shall necessarily be determinative in evaluating proposed solutions in developing the PSE Plan.

2.10 Attachment K Planning Costs

The Transmission Provider will not provide reimbursement of any costs incurred by other entities or persons participating in the planning processes under this Attachment K. Except as may be otherwise provided in this Attachment K, the Transmission Provider's costs associated with the Attachment K processes, including Transmission Provider's share of the NorthernGrid planning costs, will be subject to recovery in Transmission Provider's rates.

Duke Energy Florida, LLC (DEF)

Joint Open Access Transmission Tariff of Duke Energy Carolinas, LLC, Duke Energy Carolinas LLC, and Duke Energy Progress, LLC, Attachment N-2, retrieved from https://www.ferc.duke-energy.com/Tariffs/Joint_OATT.pdf (last accessed Nov. 26, 2024).

Attachment N-2: Transmission Planning Process (DEF Zone)

Transmission Provider plans for the existing and future requirements of all customers of Transmission Provider's transmission system in a coordinated, open, comparable, nondiscriminatory and transparent manner both at the local and regional level. The Transmission Planning Process described herein includes Transmission Service for Transmission Provider's Native Load Customers, Network Customers, Firm Point-to-Point Transmission Customers, and Generator Interconnection Service for Interconnection Customers. The Transmission Planning Process is intended to provide transmission customers the opportunity to interact with the transmission planning personnel of the Transmission Provider in order for transmission customers to provide timely and meaningful input into the development of the transmission plan. Transmission Provider's Transmission Planning Process works in conjunction with and is an integral part of the Florida Reliability Coordinating Council's ("FRCC") Regional Transmission Planning Process (reference the FRCC website for this document1) which facilitates coordinated planning by all transmission providers, owners and stakeholders within Peninsular Florida, east of the Apalachicola River (the "FRCC Region").

1: Coordination

1.2 CEERTS Projects

1.2.1:

Attachment B

As set forth herein, the Transmission Provider, in collaboration with other transmission providers, FRCC staff, and other FRCC members, shall identify and evaluate whether there are more efficient or cost-effective regional transmission solutions to regional transmission needs relative to the transmission facilities in the initial regional transmission plan. The regional analysis shall utilize the standards, criteria, rules, tools, data, models, methods and studies of the local transmission plans, as delineated in Appendix 1, supplemented as necessary for the regional analysis as set forth herein. The regional analysis shall determine if there is a solution meeting CEERTS project criteria under section 1.2.3.

1.2.3 To be eligible for approval by the FRCC Board for inclusion in the regional plan, a proposed CEERTS project must meet these threshold criteria:

A. Be a transmission line 230 kV or higher and 15 miles or longer; or be a substation flexible AC transmission system ("FACTS") device, e.g., series compensation or static var compensator, designed to operate at 230 kV or 939 more; and

B. Be materially different from projects already in the regional plan. For purposes of this section, the FRCC will consider a CEERTS project to be materially different from another CEERTS project if it displaces a different local project or projects or is not considered a minor adjustment to an existing local or CEERTS project that it is displacing. Minor adjustments could include changes in equipment size, different terminal bus arrangement, or a slight change in route.

Local transmission facilities located solely within a Transmission Provider's footprint (e.g. Control Area) that are not selected in the regional transmission plan for purposes of cost allocation cannot qualify as CEERTS projects. Such facilities are the responsibility of the Transmission Provider to meet reliability needs and/or other obligations within its retail distribution service territory or footprint.

3.4 Studies conducted pursuant to the FRCC Regional Transmission Planning Process utilize the applicable reliability standards and criteria of the SERC and NERC that apply to the Bulk Power System as defined by NERC. Such studies also utilize the specific design, operating and planning criteria used by FRCC transmission providers/owners. The transmission planning criteria are available to all customers and stakeholders. Transmission planning assumptions, transmission projects/upgrades and project descriptions, scheduled in-service dates for transmission projects and the project status of upgrades will be available to all customers through the FRCC periodic project update process. The FRCC updates and distributes transmission projects/upgrades project descriptions, scheduled in-service dates, and project status on a regular basis, no less than quarterly. The FRCC also updates and distributes on a periodic basis the load flow data base. The FRCC publishes the individual transmission providers' system impact study schedules so that other potentially impacted transmission owners can assess whether they are affected and elect to participate in the study analysis. The FRCC planning studies are also distributed by the FRCC and updated as needed. All entities that have transmission projects/upgrades in the regional transmission plan shall provide updates on such projects at least annually.

9 Cost Allocation

9.3.1 Except for a CEERTS project for which it is not the project developer, each Transmission Owner in the FRCC Region shall be responsible for upgrading or expanding its transmission system in accordance with the FRCC Regional Transmission Planning Process consistent with applicable NERC and SERC Reliability Standards and shall participate, directly or indirectly (as the member of a participating Transmission Owner, e.g., Seminole Electric Cooperative, Inc. and Florida Municipal Power Agency), in the FRCC Regional Transmission Planning Process in planning all upgrades and expansions to its system.

9.4 Cost Allocation for CEERTS Projects

9.4.1 There are three potential sets of CEERTS project costs that will be allocated: developer costs, related local project costs, and displacement costs. The general principle is to allocate all of the prudently-incurred costs of a CEERTS project to the entities that benefit from the project in proportion to the benefits received, although a CEERTS project developer may accept a cost cap for the developer costs, in which case the developer's costs up to the cost cap will be allocated. Cost allocations are determined in terms of percentages, with each beneficiary allocated a percentage of the CEERTS project costs. Entities that receive no benefit from a CEERTS project will not be allocated any project costs.

Duke Energy Carolinas, LLC (DEC); Duke Energy Progress, LLC (DEP)

Joint Open Access Transmission Tariff of Duke Energy Carolinas, LLC, Duke Energy Carolinas LLC, and Duke Energy Progress, LLC, Attachment N-1, retrieved from https://www.ferc.duke-energy.com/Tariffs/Joint_OATT.pdf (last accessed Dec. 18, 2024).

Attachment N-1: Transmission Planning Process (DEP Zone and DEC Zone)

1. Introduction

Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP) (sometimes referred to individually as Company and collectively Companies), entities with transmission facilities located in the states of North Carolina and South Carolina, ensure that their entire Transmission Systems (i.e., both the portions located in North Carolina and the portions located in South Carolina) are planned in accordance with the local transmission planning requirements imposed by Order Nos. 890 and 1000 through the process developed and implemented by the Carolinas Transmission Planning Collaborative (CTPC Process or Local Planning Process). The Carolinas Transmission Planning Collaborative includes load serving entities (LSE) in the States of North Carolina and South Carolina (collectively, CTPC Participants or Participants) within the DEC and DEP footprint.

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

Part I: Local Planning Process

2. CTPC Process Overview Including the Process for Consulting with TAG Participants

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

4. DESCRIPTION OF THE LOCAL PLANNING PROCESS

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

4.1: Overview of the Local Planning Process

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

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

4.2 Overview of Study Process for Local Reliability Projects

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

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

5.1 Identification of Study Criteria, Assumptions, and Methodology

Attachment B

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

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

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

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

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

5.5 Selection of Preferred Local Transmission Plan

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

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

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

5.6 Local Transmission Plan Report

5.6.1 After the Solutions Meeting, the PWG prepares a draft "Local Transmission Plan Report" based on the study results and the recommended solutions and provides the draft to the OSC for review. The draft Report describes the plan in a manner that is understandable to the TAG participants (e.g., describing any needs, the underlying assumptions, applicable planning criteria, and methodology used to determine the need), rather than simply reporting engineering results. The report includes a comprehensive summary of all the study activities as well as the recommended solutions including estimates of costs and construction schedules and a summary of the PWG's selection evaluation required by Section 5.5. The benefits evaluated for the recommended Multi-Value Strategic Transmission solutions will be described in the draft Local Transmission Plan Report.

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

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

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

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

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

5.7 No Limitation on Additional Meetings and Communications

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

7. TRANSMISSION COST ALLOCATION FOR JOINT LOCAL PROJECTS

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

7.2 Joint Local Reliability Project Cost Allocation

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

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

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

7.2.4 Unless a Joint Local Reliability Project is determined by the CTPC Participants to be the most cost-effective solution to a reliability need, it will not be selected to be included in the Local Transmission Plan. But, if a Joint Local Reliability Project is determined by the CTPC Participants to be the most cost effective solution, it will have its costs allocated based on an avoided cost approach, whereby each Company looks at the stand-alone approach to maintaining reliable service and shares the savings of not implementing the stand-alone approach on a pro-rata basis. [avoided cost approach formula omitted]

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

8. COST ALLOCATION FOR PLANNING COSTS

8.1 CTPC-Related Planning Process Costs

8.1.1 Each CTPC Participant bears its own expenses.

8.1.2 TAG participants bear their own expenses.

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

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

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

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

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

Tariff when a customer makes a specific request that must be studied.

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

10.2 Sub-Local Planning The Companies coordinate with their network and native load customers to ensure adequate and reliable electric service to all points of delivery within their control areas. The focus of the CTPC Process is planning higher-voltage facilities and transfers of bulk power and thus "sub-local planning" focuses on lower-voltage facilities and the delivery of energy to customer locations. Customer meetings may be held, when necessary, to discuss the respective plans of the customer and the provider and how such plans impact local areas. Any sub-local area plans developed by a Company are rolled into the CTPC transmission Base Case models. The same data and assumptions would be used in sublocal planning as are used in the CTPC Process.

Florida Power & Light Company (FPL)

Florida Power & Light Company, FERC FPA Electric Tariff Open Access Transmission Tariff, Attachment K retrieved from https://www.oasis.oati.com/FPL/FPLdocs/FPL_OATT-Current-01-05-17.pdf (last accessed Dec. 18, 2024).

Attachment K: Transmission Planning Process

Transmission Provider plans for the existing and future requirements of all customers of Transmission Provider's transmission system in a coordinated, open, comparable, non-discriminatory and transparent manner both at the local and regional level. The Transmission Planning Process described herein includes Transmission Service for Transmission Provider's Native Load Customers, Network Customers, Firm Point-to-Point Transmission Customers, and Generator Interconnection Service for Interconnection Customers. The Transmission Planning Process is intended to provide transmission customers the opportunity to interact with the transmission planning personnel of the Transmission Provider in order for transmission customers to provide timely and meaningful input into the development of the transmission plan. Transmission Provider's Transmission Planning Process works in conjunction with and is an integral part of the Florida Reliability Coordinating Council's ("FRCC") Regional Transmission Planning Process (reference the FRCC website for this document1) which facilitates coordinated planning by all transmission providers, owners and stakeholders within Peninsular Florida, east of the Apalachicola River (the "FRCC Region").

The FRCC is a member services organization which carries out activities on behalf of its members to maintain grid reliability in the FRCC Region, which is electrically unique because it is a peninsula and is tied to the Eastern Interconnection only on one side. FRCC's members include investor owned utilities, cooperative utilities, and municipal utilities, The FRCC Board of Directors has the responsibility to ensure that the FRCC Regional Transmission Planning Process is fully implemented. The FRCC Planning Committee ("FRCC PC"), which allows representation from all FRCC members, directs the FRCC Transmission Technical Subcommittee and any other supporting group, in conjunction with the FRCC Staff, to conduct the necessary studies to fully implement the FRCC Regional Transmission Planning Process. The descriptions of the FRCC Regional Transmission Planning Process set forth herein summarize the elements of that process as they relate to Transmission Provider and the principles of the Final Rule in Docket No. RM05-25-000.

The Florida Public Service Commission ("FPSC") is an integral part of the planning process by providing input, guidance, and regulatory oversight under this process. Additionally, the FPSC conducts workshops on an annual basis to review the transmission and generation expansion plans for Florida. The FPSC, under Florida law, has the authority to ensure an adequate and reliable electric system for Florida. As set forth below, Transmission Provider's Transmission Planning Process is a seamless process that fully integrates both the local and regional transmission planning and is designed to satisfy the following principles, as defined in the FERC Final Rule in Docket No. RM05-25-000: (1) coordination, (2) openness, (3) transparency, (4) information exchange, (5) comparability, (6) dispute resolution, (7) regional coordination, (8) economic planning studies, and (9) cost allocation for new projects. Descriptions of the FRCC Regional Transmission Planning Process are contained herein as they relate to Transmission Provider's Transmission Planning Process.

1.2 CEERTS Projects

1.2.1 This section 1.2 sets forth provisions for consideration of proposed CEERTS projects in the regional transmission planning process in which Transmission Provider participates and applies to reliability, economic and public policy regional transmission projects. As discussed above, the FRCC Board of Directors has the responsibility to ensure that the FRCC Regional Transmission Planning Process is fully implemented. The process results in a Board-approved regional plan. The biennial transmission planning process, in which CEERTS projects are identified, evaluated, and considered for regional cost allocation, contains several steps in which the FRCC Board is kept informed and must act in order to keep the process moving forward. The FRCC Board typically meets at least four times per year. If a regular meeting of the Board is not scheduled within the timeframes specified for the evaluation of a CEERTS project, special meetings of the Board will be called by the Chair, as needed, in order to meet the scheduled milestones for CEERTS project evaluation within the biennial transmission planning process timeline.

As set forth herein, the Transmission Provider, in collaboration with other transmission providers, FRCC staff, and other FRCC members, shall identify and evaluate whether there are more efficient or cost-effective regional transmission solutions to regional transmission needs relative to the transmission facilities in the initial regional transmission plan. The regional analysis shall utilize the standards, criteria, rules, tools, data, models, methods and studies of the local transmission plans, as delineated in Appendix 1, supplemented as necessary for the regional analysis as set forth herein. The regional analysis shall determine if there is a solution meeting CEERTS project criteria under section 1.2.3.

The regional analysis shall include consideration of potential transmission solutions to transmission needs driven by public policy requirements, as such needs are identified pursuant to section 11. The provisions for stakeholder involvement and input in the regional transmission plan, and ability to propose CEERTS projects on their own initiative, as set forth in this section 1.2, are fully applicable to potential transmission solutions to transmission public policy needs driven by public policy requirements.

1.2.2 Any entity desiring to propose a CEERTS project for regional cost allocation must submit such a CEERTS project to the FRCC no later than June 1st of the first year of the biennial regional projects planning cycle. The entity proposing a CEERTS project is referred to herein as the project sponsor. The project sponsor for a CEERTS project need not be the project developer for that project.

In addition to the right of individual entities to submit potential CEERTS projects, Transmission Provider shall participate with other transmission providers and other interested entities, through the FRCC PC, in the identification and evaluation of potential CEERTS projects for submission. The FRCC PC, or a designated subcommittee thereof, shall proactively seek out potential CEERTS projects from its analysis of the most recent Board-approved plan. This will occur during the period February through April of the first year of the biennial regional projects planning cycle. The general steps of the process are as follows:

A. Gather all relevant information relating to the most recent Board-approved plan (e.g., Final Project Information Form, approved Long Range Study, early project suggestions from interested entities); and request and collect all necessary supplemental information from transmission providers and other entities (e.g., project details and cost estimates for projects identified for potential displacement, list of potentially feasible projects not selected in the initial regional transmission plan).

B. Analyze the current plan information to identify potential opportunities for CEERTS projects. Seek justification for remedies that do not have projects planned, and synergies with the planned projects that potentially could be modified, combined, or accelerated for a more cost effective or efficient regional transmission solution. The analysis will include comparative load flow studies to evaluate various potential transmission CEERTS projects. For example, comparative load flow studies will be run to identify and evaluate potential CEERTS projects that could displace transmission projects in the initial regional transmission plan.

1. If a potential CEERTS project is identified that addresses a regional reliability or economic transmission need(s) for which no transmission projects are currently planned, an analysis will be performed to identify local and/or regional alternative transmission project(s) which would also fully and appropriately address the same transmission need(s). These local and/or regional alternative transmission project(s) will be identified through comparative load flow studies. The alternative project(s) will be used to determine the Total Estimated Alternative Project Cost Benefit in the CEERTS Project Cost-Benefit Analysis described in section 1.2.9.C.

2. If a potential regional public policy transmission need has been identified for which no transmission projects are currently planned and for which no CEERTS project has otherwise been submitted for evaluation, an analysis will be performed to identify a potential CEERTS project that would satisfy that regional public policy transmission need in a least-cost manner by evaluating various potential transmission project alternatives.

C. Develop potential CEERTS project alternatives and solicit project sponsorship from enrolled transmission providers and other entities which may have an interest in sponsoring potential CEERTS projects.

1) A potential CEERTS project developed by this process will contain the following minimum set of transmission project information:

a) General description of the transmission facilities being proposed;

b) General path of the transmission lines; and

c) Transmission systems that would interconnect with the potential CEERTS project.

2) The FRCC shall post a notice on its website of any potential CEERTS projects identified through this process. Notice would be posted by May 1 of the first year of the biennial regional projects planning cycle to provide time for meeting sponsorship requirements by June 1.

3) Each identified potential CEERTS project will require at least one sponsor in order to be submitted to the FRCC for consideration. Multiple sponsors of the same project will be considered joint sponsors and shall equally share the required $100,000 deposit unless the sponsors otherwise mutually agree to a different sharing of the deposit. Potential CEERTS projects identified in this process shall not have competing sponsors for the same project. An entity that is not a sponsor or joint sponsor of a potential CEERTS project shall not be eligible to be a developer of that project unless the sponsors discontinue development of that project.

4) The sponsor or joint sponsors shall submit the potential CEERTS project for consideration in the first year of the biennial regional projects planning cycle.

1.2.3 To be eligible for approval by the FRCC Board for inclusion in the regional plan, a proposed CEERTS project must meet these threshold criteria:

A. Be a transmission line 230 kV or higher and 15 miles or longer; or be a substation flexible AC transmission system ("FACTS") device, e.g., series compensation or static var compensator, designed to operate at 230 kV or more; and

B. Be materially different from projects already in the regional plan. For purposes of this section, the FRCC will consider a CEERTS project to be materially different from another CEERTS project if it displaces a different local project or projects or is not considered a minor adjustment to an existing local or CEERTS project that it is displacing. Minor adjustments could include changes in equipment size, different terminal bus arrangement, or a slight change in route.

Local transmission facilities located solely within a Transmission Provider's footprint (e.g. Control Area) that are not selected in the regional transmission plan for purposes of cost allocation cannot qualify as CEERTS projects. Such facilities are the responsibility of the Transmission Provider to meet reliability needs and/or other obligations within its retail distribution service territory or footprint.

1.2.4 A CEERTS project submittal must include the following elements (to be provided in the context of the most current FRCC Board-approved regional transmission plan):

A. Those project sponsors that do not also intend to be a project developer must submit sufficient information related to the proposed CEERTS project that will permit the potential CEERTS project to be adequately considered within the FRCC regional transmission planning process. Below is the minimum set of information that must be submitted:

(1) General description of the transmission facilities being proposed;

(2) General path of the transmission lines; and

(3) Transmission systems that would interconnect with the proposed CEERTS project.

B. Those project sponsors that intend to be the project developer shall so indicate and shall submit the following information:

(4) Transmission project technical information:

(a) Description of the transmission facilities being proposed (e.g., voltage levels);
(b) General path of the transmission lines; and

(c) Interconnection points with the existing transmission system.

(5) A cost estimate and a recommended in-service date for the project. A project developer may also submit a demonstration of its cost containment capabilities, including

any binding agreement to accept a cost cap for the developer's cost of the transmission project if it is selected as a CEERTS project.

(6) If the project sponsor is an incumbent, it must indicate which funding option set forth in section 9.4.5.A it intends to select.

(7) A high-level summary of who will own, operate and maintain the CEERTS project, to the extent available.

C. A project sponsor may also submit any studies and analysis it performed

(8) Reliability impact assessment.

(9) Load flow analysis that demonstrates performance utilizing the FRCC load flow model. The sponsor, if not an FRCC member, may obtain this model upon request from the FRCC ("Request for Florida Reliability Coordinating Council (FRCC) Transmission Information" document is posted on the FRCC website).

(10) Identification of projects in the regional transmission plan that would be affected or avoided as well as any additional projects that may be required. A demonstration through a technical evaluation process that the CEERTS project is equal to or superior to avoided projects from the current regional transmission plan.

D. A deposit of $100,000 shall be submitted by the project sponsor at the time the project is submitted (e.g., June 1st of the biennial regional projects planning cycle) for each CEERTS project. This deposit will be used for FRCC internal labor costs for analysis of the project as well as any out-of-pocket expenses such as for independent consultants (unexpended amounts shall be refunded, with interest, to the project sponsor). The actual costs incurred by the FRCC to analyze the CEERTS project will be borne by the project sponsor and the deposit will be trued up based on the documented cost of the analysis. An accounting of the actual costs of the CEERTS project analysis including an explanation of how the costs were calculated will be provided to the project sponsor after the analysis has been completed. Any disputes regarding the accounting for specific deposits will be addressed through the Dispute Resolution Procedures in Appendix 5.

9 Cost Allocation

Subsections 9.1 – 9.3 apply to cost allocation for third party impacts resulting from the FRCC regional planning process; subsection 9.4 applies to cost allocation for CEERTS projects. The cost allocation provisions contained in the section relate to cost allocation procedures for specific circumstances as described herein. All other transmission cost allocation not specifically described below is provided in accordance with OATT provisions for generation interconnection and for network and point-to-point transmission service.

9.1 If a transmission expansion is identified as needed under the FRCC Regional Transmission Planning Process and such transmission expansion results in a material adverse system impact upon a third-party transmission owner, the third party transmission owner may choose to utilize the FRCC Principles for Sharing of Certain Transmission Expansion Costs as outlined below in this Attachment K. The FPSC is involved in this process and provides oversight, guidance and may exercise its statutory authority as appropriate. A more detailed description of the FRCC Principles for Sharing of Certain Transmission Expansion Costs can be found on the FRCC website.

9.2 The FRCC Principles for Sharing of Certain Transmission Expansion Costs: (i) sets forth certain principles regarding the provision of financial funding to Transmission Owners (note: for this purpose, “Transmission Owner” means an electric utility owning transmission facilities in the FRCC Region) that undertake remedial upgrades to, or expansions of, their systems resulting from upgrades, expansions, or provisions of services on the systems of other Transmission Owners, and (ii) procedures for attempting to resolve disputes among Transmission Owners and other parties regarding the application of such principles. These principles shall not apply to transmission upgrades or expansions if, and to the extent that, the costs thereof are subject to recovery by a Transmission Owner pursuant to FERC Order No. 2003 or Order No. 2006.

9.3 Principles

9.3.1 Except for a CEERTS project for which it is not the project developer, each Transmission Owner in the FRCC Region shall be responsible for upgrading or expanding its transmission system in accordance with the FRCC Regional Transmission Planning Process consistent with applicable NERC Reliability Standards and shall participate, directly or indirectly (as the member of a participating Transmission Owner, e.g., Seminole Electric Cooperative, Inc. and Florida Municipal Power Agency), in the FRCC Regional Transmission Planning Process in planning all upgrades and expansions to its system.

§ 9.3.2 If, and to the extent that, the need for a 230 kV or above upgrade to, or expansion of, the transmission system of one Transmission Owner (the "Affected Transmission Owner") is reasonably expected to result from, upgrade(s) or expansion(s) to, or new provisions of service on, the system(s) of another Transmission Owner or Transmission Owners (hereinafter "Precipitating Events"), and if such need is reasonably expected to arise within the FRCC planning horizon, the Affected Transmission Owner shall be entitled to receive Financial Assistance (as defined herein) from each other such Transmission Owner and other parties, to the extent consistent with the other provisions hereof. Such upgrade or expansion to the Affected Transmission Owner's system shall hereinafter be referred to as the "Remedial Upgrade." Upgrade(s), expansion(s), or provisions of service on another Transmission Owner's system that may result in the need for a Remedial Upgrade on the Affected Transmission Owner's system for which Financial Assistance is to be provided hereunder include the following Precipitating Events:

- A new generating unit(s) to serve incremental load
- A new or increased long-term sale(s)/purchase(s) to or by others (different uses)
- A new or modified long-term designation of Network Resource(s)
- A new or increased long-term, firm reservation for point-to-point transmission service

Attachment B

Specific non-Precipitating Events are as follows: 1) Transmission requests that have already been confirmed prior to adoption of these principles; 2) Qualifying rollover agreements that are subsequently rolled over; 3) Redirected transmission service for sources to the extent the redirected service does not meet the Threshold Criteria described in subsection 9.3.5.A. Existing flows would not be considered "incremental."; and 4) Repowered generation if the MW output of the facility is not increased, regardless of whether the repowered unit is used more/less hours of the year.

9.3.3 Except for a CEERTS project for which it is not the project developer and except to the extent that an Affected Transmission Owner is entitled to Financial Assistance from other parties as provided herein, each Transmission Owner shall be responsible for all costs of upgrades to, and expansions of, its transmission system; provided, however, that nothing herein is intended to affect the right of any Transmission Owner or another party from obtaining remuneration from other parties to the extent allowed by contract or otherwise pursuant to applicable law or regulation (including, for example, through rates to a Transmission Owner's customers).

9.3.4 Except for a CEERTS project for which it is not the project developer, each Transmission Owner shall be solely responsible for the execution, or acquisition, of all engineering, permitting, rights-of-way, materials, and equipment, and for the construction of facilities comprising upgrades or expansions, including Remedial Upgrades, of its transmission system; provided, however, that nothing herein is intended to preclude a Transmission Owner from seeking to require another party to undertake some or all of such responsibilities to the extent allowed by contract or otherwise pursuant to applicable law.

9.3.5 Threshold Criteria: The following criteria ("Threshold Criteria") must be satisfied in order for an Affected Transmission Owner to be entitled to receive Financial Assistance from another party or parties in connection with a Remedial Upgrade: A change in power flow of at least a 5% or 25 MW, whichever is greater, on the Affected Transmission Owner's facilities which results in a NERC Reliability Standards violation; The Transmission Expansion must be 230 kV or higher voltage; and The costs associated with the Transmission Expansion must exceed $3.5 million.

9.3.6 In order for a Transmission Owner to be entitled to receive Financial Assistance from another party or parties hereunder in connection with a particular Remedial Upgrade, that Transmission Owner must: (i) participate, directly or indirectly, in the FRCC Regional Transmission Planning Process, and (ii) identify itself as an Affected Transmission Owner and identify the subject Remedial Upgrade in a timely manner once it learns of the need for that Remedial Upgrade.

9.3.7 The following principles govern the nature and amount of Financial Assistance that an Affected Transmission Owner is entitled to receive from one or more other parties with respect to a Remedial Upgrade: A recognition of the reasonably determined benefits that result from the Remedial Upgrades due to the elimination or deferral of otherwise planned transmission upgrades or expansions. Remedial Upgrade costs, net of recognized benefits, shall be allocated fifty-fifty, respectively, based on:

- The sources or cluster of sources which are causing the need for the transmission expansion; and

- The load in the area or zone associated with the need for the Transmission Expansion. (For these purposes, network customer loads embedded within a transmission provider's service area in the Transmission Zone would not be separately allocated any costs as such loads would be paying their load ratio share of the affected transmission provider's costs.)

- Initially, there are six zones in the FRCC Region. A request by a party to modify one or more zones should be substantiated on its merits (e.g., technical analysis, area of limited transmission capability). Below are principles that will guide how the boundaries of zones are determined:

- Electrically, a substantial amount of the generation within a zone is used to serve load also within that zone.

- Transmission facilities in a zone are substantially electrically independent of other zones.

- Zones represent electrical demarcation areas in the FRCC transmission grid that can be supported from a technical perspective.

- The Financial Assistance provided to an Affected Transmission Owner related to one or more transmission service requests keyed to new sources of power is subject to repayment without interest over a ten year period through credits for transmission service charges by the funding party and at the end of ten years through payment of any outstanding balance.

9.4 Cost Allocation for CEERTS Projects

9.4.1 There are three potential sets of CEERTS project costs that will be allocated: developer costs, related local project costs, and displacement costs. The general principle is to allocate all of the prudently-incurred costs of a CEERTS project to the entities that benefit from the project in proportion to the benefits received, although a CEERTS project developer may accept a cost cap for the developer costs, in which case the developer's costs up to the cost cap will be allocated. Cost allocations are determined in terms of percentages, with each beneficiary allocated a percentage of the CEERTS project costs. Entities that receive no benefit from a CEERTS project will not be allocated any project costs.

9.4.2 Project beneficiaries for a CEERTS project will be Transmission Providers within the FRCC Region enrolled in the regional planning process (on behalf of their retail and wholesale customers) which will benefit from the project.

9.4.3 The cost allocation for CEERTS reliability/economic projects is based on the following formula using terms defined in section 1.2.9.C: ((TP Estimated Avoided Project Cost Benefit + TP Estimated Alternative Project Cost Benefit + TP Estimated Transmission Line Loss Value Benefit) / (Total Estimated Avoided Project Cost Benefit + Total Estimated Alternative Project Cost Benefit + Total Estimated Transmission Line Loss Value Benefit)) * Estimated CEERTS

Project Cost. The cost allocation dollar amounts calculated here using estimated cost information will further be translated to a percentage for each beneficiary as a ratio of their allocated share of the total estimated cost of the CEERTS project. These percentages will be used to allocate actual CEERTS project costs that are recoverable pursuant to the applicable subsection of section 9.4.5. Examples of CEERTS project cost allocation are provided in Appendix 4, Examples 1 and 2.

9.4.4 The costs for CEERTS public policy projects that are identified through the process described in section 11 will be allocated to the enrolled transmission providers whose transmission systems provide access to the public policy resources. The cost allocation for each enrolled transmission provider will be as follows:

- Individual enrolled transmission provider MWs = number of megawatts of public policy resources enabled by the public policy project for the customers (including Native Load) within their transmission service territory.

- Total MWs = total number of megawatts of public policy resources enabled by the public policy project.

- Individual enrolled transmission provider cost allocation percentage = (Individual enrolled transmission provider MWs/Total MWs).

An example of the CEERTS public policy cost allocation is provided in Appendix 4, Example 3. These percentages will be used to allocate actual CEERTS project costs that are recoverable pursuant to the applicable subsection of section 9.4.5.

The process to interconnect individual generation resources is provided for under the generator interconnection section of each utility's OATT and not under this process.

Requests for transmission service that originate in a utility's system and terminate at the border shall be handled through that utility's OATT.

9.4.5 Transmission Project Funding and Rate Base/Cost Recovery:

A. If incumbent enrolled transmission providers are the only transmission developers for a particular project, then they shall have two options in the initial transmission project funding and subsequent cost recovery of developer costs. Note that if an incumbent enrolled transmission provider develops a CEERTS project and is not FERC-jurisdictional, it will make any requisite FERC filings through the declaratory order process used for non-jurisdictional enrolled transmission providers rather than under FPA section 205:

(1) Incumbent enrolled transmission providers may fund the transmission project in proportion to their cost responsibility for the project. For the portions of the projects that each of the companies were building that are related to their cost responsibility, the companies would include those transmission costs as identified in a Contribution in Aid to Construction (CIAC) filing at FERC within their respective rate bases and transmission revenue requirements. The costs would be reflected in FERC filed OATT rates in Account 107, Construction Work in Progress. When the assets go into service, the balance will be moved to Account 101, Electric Plant in Service and the Units of Property will be unitized to the FERC Accounts corresponding

to the Units of Property. This treatment is for accounting purposes: a FERC filing and FERC approval would still be required to include Construction Work in Progress in rates. For the portion of the funding that was being provided for the transmission to be built by someone other than the incumbent, the payments by the incumbent (for their cost responsibility) would be recorded in Account 303, Miscellaneous Intangible Plant and amortized by debiting Account 404, Amortization of Limited-Term Electric Plant, and crediting Account 111, Accumulated Provision for Amortization of Electric Utility Plant. The amortization of the investment would be derived using a composite factor based on the most recently approved depreciation rates for the constructing company. The calculation of the composite factor would be based on the Units of Property installed in the transmission project. The amortization will begin when the project is declared in service. The costs and amortization would be reflected in FERC filed OATT rates until the investment is fully amortized to expense. The company receiving the money would treat these monies as a CIAC and thus have no associated net book investment in its transmission rate base. CIAC agreements will be filed with FERC prior to any CIAC payments being made to the constructing developer. Enrolled transmission providers with formula-based OATT rates shall submit a separate FPA section 205 filing with FERC for authorization to include the intangible asset investment and amortization expense in the formula rate. Traditional cost-based ratemaking procedures would be used to determine the impact of including the intangible asset investment in rate base and the amortization expense in operating expenses in deriving OATT rates. CIAC agreements filed with FERC would include workpapers to support the costs included in the determination of revenue requirements. See Example 1 provided in Appendix 6 for more detail and accounting treatment.

(2) Incumbent enrolled transmission providers may fund the portion of the transmission project that their company would be building/developing. Incumbent enrolled transmission providers would include the total transmission project costs that they are funding within their respective rate bases and transmission revenue requirements for recovery in their routine rate processes. For those portions of the project costs that are over and above their cost responsibility, the incumbent enrolled transmission providers would file with FERC for authorization to recover their Transmission Revenue Requirement ("TRR") associated with those project costs to be directly assigned to the beneficiary(ies) responsible for that portion of the cost assignment. The TRR when received by the incumbent developer would be treated as a revenue credit recorded in Account 456, Miscellaneous Revenue in its cost of service to offset the inclusion of other beneficiary(ies) assigned cost in rate base and revenue requirement. In addition to including the TRR for those portions of the project costs that were over and above their cost responsibility, the incumbent enrolled transmission providers would also include any TRR costs allocated to them in their FERC-filed cost of service in support of FERC approved OATT rates. Enrolled transmission providers with formula-based OATT rates shall submit a separate FPA section 205 filing with FERC for authorization to include their allocated TRR costs in the formula rate. See Example 2 provided in Appendix 6 for more detail and accounting treatment.

B. If a non-incumbent developer builds the CEERTS project, it shall file with FERC for authorization to recover its developer costs in the form of a TRR from the incumbent enrolled transmission providers in accordance with their cost responsibilities as determined by the cost allocation methodologies. The incumbent enrolled transmission providers may include those costs allocated to them in their respective wholesale rates (e.g., in FERC-filed cost of service in support of FERC approved OATT rates). Enrolled transmission providers with formula-based OATT rates shall submit a separate FPA section 205 filing with FERC to include their allocated TRR costs in the formula rate. See Example 3 provided in Appendix 6 for more detail and accounting treatment.

C. Incumbent enrolled transmission providers with formula-based OATT rates shall be allowed to revise their formula rates to include the intangible asset investment balance as directly assignable transmission function rate base, and amortization expense should be included as transmission function specific expense. Formula-based OATT rates shall be revised by submitting a separate FPA section 205 filing with FERC.

D. Enrolled transmission provider(s) will be responsible for recovering their related local project costs from the beneficiaries allocated such costs through a FPA section 205 filing if the enrolled transmission provider is FERC-jurisdictional or through FERC's declaratory order process if the enrolled transmission provider is non-jurisdictional.

E. Enrolled transmission provider(s) will be responsible for recovering their actual displacement costs, if applicable, through a FPA section 205 filing if the enrolled transmission provider is FERC-jurisdictional or through FERC's declaratory order process for non-jurisdictional enrolled transmission owners. In such filing, the enrolled transmission provider(s) will allocate displacement costs in the same manner as the CEERTS project costs are allocated.

10 Recovery of Planning Costs

10.1 Planning study costs incurred by the Transmission Provider in the performance of studies requested by a customer/stakeholder associated with transmission service or generator interconnection service are separately addressed in this tariff under provisions that require the customer/stakeholder to pay the cost of such studies. Planning study costs incurred by the Transmission Provider in the performance of the first five economic planning studies will be absorbed by the Transmission Provider in its normal course of business of performing its obligations under this Attachment K. The cost of the sixth and additional economic planning studies in a calendar year will be assessed to the requesting entity as set forth in Section 8.1. Other general transmission planning costs not associated with the above studies are routine cost-of-service items that would be reflected in both wholesale and retail transmission rates as appropriate.

Tampa Electric Company (TEC)

Tampa Electric Company , Open Access Transmission Tariff, FERC Electric Tariff, Fourth Revised Volume No. 4, Attachment K (Feb. 1, 2023), retrieved from https://www.oasis.oati.com/woa/docs/TEC/TECdocs/Tariff___Fourth_Revised_Volume_No._4__effective_5-1-24.pdf (last accessed Dec. 18, 2024).

Attachment K: Transmission Planning Process

Attachment B

Transmission Provider plans for the existing and future requirements of all customers of Transmission Provider's transmission system in a coordinated, open, comparable, non-discriminatory and transparent manner both at the local and regional level. The Transmission Planning Process described herein includes Transmission Service for Transmission Provider's Native Load Customers, Network Customers, Firm Point-to-Point Transmission Customers, and Generator Interconnection Service for Interconnection Customers. The Transmission Planning Process is intended to provide transmission customers the opportunity to interact with the transmission planning personnel of the Transmission Provider in order for transmission customers to provide timely and meaningful input into the development of the transmission plan. Transmission Provider's Transmission Planning Process works in conjunction with and is an integral part of the Florida Reliability Coordinating Council's ("FRCC") Regional Transmission Planning Process (reference the FRCC website for this document1), which facilitates coordinated planning by all transmission providers, owners and stakeholders within Peninsular Florida, east of the Apalachicola River (the "FRCC Region").

The FRCC is a member services organization, which conducts activities on behalf of its members to maintain grid reliability in the FRCC Region, which is electrically unique because it is a peninsula and is tied to the Eastern Interconnection only on one side. FRCC's members include investor-owned utilities, cooperative utilities, and municipal utilities. The FRCC Board of Directors has the responsibility to ensure that the FRCC Regional Transmission Planning Process is fully implemented. The FRCC Planning Committee ("FRCC PC"), which allows representation from all FRCC members, directs the FRCC Transmission Technical Subcommittee and any other supporting group, in conjunction with the FRCC Staff, to conduct the necessary studies to fully implement the FRCC Regional Transmission Planning Process. The descriptions of the FRCC Regional Transmission Planning Process set forth herein summarize the elements of that process as they relate to Transmission Provider and the principles of the Final Rule in Docket No. RM05-25-000. The Florida Public Service Commission ("FPSC") is an integral part of the planning process by providing input, guidance, and regulatory oversight under this process. Additionally, the FPSC conducts workshops on an annual basis to review the transmission and generation expansion plans for Florida. The FPSC, under Florida law, has the authority to ensure an adequate and reliable electric system for Florida. As set forth below, Transmission Provider's Transmission Planning Process is a seamless process that fully integrates both the local and regional transmission planning and is designed to satisfy the following principles, as defined in the FERC Final Rule in Docket No. RM05-25-000: (1) coordination, (2) openness, (3) transparency, (4) information exchange, (5) comparability, (6) dispute resolution, (7) regional coordination, (8) economic planning studies, and (9) cost allocation for new projects. Descriptions of the FRCC Regional Transmission Planning Process are contained herein as they relate to Transmission Provider's Transmission Planning Process.

1Coordination

1.1 Transmission Provider consults and interacts directly with its customers in providing transmission service and generator interconnection service as well as with its neighboring transmission providers, on a regular basis. A transmission customer may request and/or schedule a meeting with Transmission Provider to discuss any issue related to the provision of transmission service at any time. Transmission Provider consults and interacts with its customers any time during the study process that either the transmission customer or the Transmission Provider deem necessary and/or at various stages of the planning process (e.g., Scoping Meeting, Feasibility, System Impact and Facilities Studies). An open dialogue between the transmission customer and the Transmission Provider takes place regarding customer needs. This interaction and dialogue between the customer and Transmission Provider are further described under the Local Transmission Network Planning Process as set forth in Appendix 1 to this Attachment K. Topics such as load growth projections, planned generation resource additions/deletions, new delivery points and possible transmission alternatives are discussed. This dialogue is intended to provide timely and meaningful input and participation of customers during the early stages of development of the transmission plan. Additionally, the transmission customer shall have an opportunity to comment at any time during the evaluation process and/or when study findings (Feasibility, System Impact and Facilities Studies) are communicated by the Transmission Provider to the customer. Transmission Provider communicates with its neighboring transmission providers on a regular basis, and Transmission Provider facilitates communication and consultation between its customers and its neighboring transmission service providers/owners, specifically, if during the transmission service study process, a neighboring system's facilities are identified as being affected. This coordination process continues in a seamless manner at the local as well as the regional level, leading to each Transmission Provider providing an initial transmission plan which, when consolidated, becomes the initial regional transmission plan. The initial transmission plan submitted to the FRCC by the Transmission Provider, which results from the Local Transmission Network Planning Process as set forth in Appendix 1 to this Attachment K, will be posted by the FRCC in accordance with the FRCC Regional Transmission Planning Process (reference link to Initial Plans on the FRCC website). This initial transmission plan is reviewed by the FRCC as well as all interested transmission customers/users. The Transmission Provider relies on the FRCC Committee process to finalize its initial transmission plan as submitted to the FRCC. In addition to transmission customers/users being provided timely and meaningful input and participation during the planning process with the Transmission Provider, the transmission customers/users are also given an additional opportunity to raise any issues, concerns or minority opinions that they believe have not been adequately addressed by any Transmission Provider's initial transmission plan submittal during the FRCC review process. This FRCC review process normally commences shortly after the submittal of the Ten Year Site Plans to the FPSC on April 1 of each year. Once issues raised by interested stakeholders are addressed, including consideration of proposed "Cost Effective or Efficient Regional Transmission Solutions" ("CEERTS") projects as set forth in section 1.2 below, the FRCC PC approves the proposed regional transmission plan and presents it to the FRCC Board for approval. Upon approval by the Board, which is expected in February of each year, the FRCC sends the final regional transmission plan to the FPSC. Unresolved issues may be resolved under the Dispute Resolution Procedures in Appendix 6.

1.2 CEERTS Projects

1.2.1. This section 1.2 sets forth provisions for consideration of proposed CEERTS projects in the regional transmission planning process in which Transmission Provider participates and applies to reliability, economic and public policy regional transmission projects. As discussed above, the FRCC Board of Directors has the responsibility to ensure that the FRCC Regional Transmission Planning Process is fully implemented. The process results in a Board-approved regional plan. The biennial transmission planning process, in which CEERTS projects are identified, evaluated, and considered for regional cost allocation, contains several steps in which the FRCC Board is kept informed and must act in order to keep the process moving forward. The FRCC Board typically meets at least four times per year. If a regular meeting of the Board is not scheduled within the timeframes specified for the evaluation of a CEERTS project, special meetings of the Board will be called by the Chair, as needed, in order to meet the scheduled milestones for CEERTS project evaluation within the biennial transmission planning process timeline. As set forth herein, the Transmission Provider, in collaboration with other transmission providers, FRCC staff, and other FRCC members, shall identify and evaluate whether there are more efficient or cost-effective regional transmission solutions to regional transmission needs relative to the transmission facilities in the initial regional transmission plan. The regional analysis shall utilize the standards, criteria, rules, tools, data, models, methods and studies of the local transmission plans, as delineated in Appendix 1, supplemented as necessary for the regional analysis as set forth herein. The regional analysis shall determine if there is a solution meeting CEERTS project criteria under section 1.2.3. The regional analysis shall include consideration of potential transmission solutions to transmission needs driven by public policy requirements, as such needs are identified pursuant to section 11. The provisions for stakeholder involvement and input in the regional transmission plan, and ability to propose CEERTS projects on their own initiative, as set forth in this section 1.2, are fully applicable to potential transmission solutions to transmission public policy needs driven by public policy requirements.

1.2.2 Any entity desiring to propose a CEERTS project for regional cost allocation must submit such a CEERTS project to the FRCC no later than June 1st of the first year of the biennial regional projects planning cycle. The entity proposing a CEERTS project is referred to herein as the project sponsor. The project sponsor for a CEERTS project need not be the project developer for that project.

In addition to the right of individual entities to submit potential CEERTS projects, Transmission Provider shall participate with other transmission providers and other interested entities, through the FRCC PC, in the identification and evaluation of potential CEERTS projects for submission. The FRCC PC, or a designated subcommittee thereof, shall proactively seek out potential CEERTS projects from its analysis of the most recent Board-approved plan. This will occur during the period February through April of the first year of the biennial regional projects planning cycle. The general steps of the process are as follows:

A. Gather all relevant information relating to the most recent Board-approved plan (e.g., Final Project Information Form, approved Long Range Study, early project suggestions from interested entities); and request and collect all necessary supplemental information from transmission providers and other entities (e.g., project details and cost estimates for projects identified for potential displacement, list of potentially feasible projects not selected in the initial regional transmission plan).

B. Analyze the current plan information to identify potential opportunities for CEERTS projects. Seek justification for remedies that do not have projects planned, and synergies with the planned projects that potentially could be modified, combined, or accelerated for a more cost effective or efficient regional transmission solution. The analysis will include comparative load flow studies to evaluate various potential transmission CEERTS projects. For example, comparative load flow studies will be run to identify and evaluate potential CEERTS projects that could displace transmission projects in the initial regional transmission plan.

> i. If a potential CEERTS project is identified that addresses a regional reliability or economic transmission need(s) for which no transmission projects are currently planned, an analysis will be performed to identify local and/or alternative transmission project(s) which would also fully and appropriately address the same regional transmission need(s). These local and/or regional alternative transmission project(s) will be identified through comparative load flow studies. The alternative project(s) will be used to determine the Total Estimated Alternative Project Cost Benefit in the CEERTS Project Cost-Benefit Analysis described in section 1.2.9.C.
>
> ii. If a potential regional public policy transmission need has been identified for which no transmission projects are currently planned and for which no CEERTS project has otherwise been submitted for evaluation, an analysis will be performed to identify a potential CEERTS project that would satisfy that regional public policy transmission need in a least-cost manner by evaluating various potential transmission project alternatives.

C. Develop potential CEERTS project alternatives and solicit project sponsorship from enrolled transmission providers and other entities which may have an interest in sponsoring potential CEERTS projects.

A potential CEERTS project developed by this process will contain the following minimum set of transmission project information:

> 1. General description of the transmission facilities being proposed;
>
> 2. General path of the transmission lines; and
>
> 3. Transmission systems that would interconnect with the potential CEERTS project.

ii. The FRCC shall post a notice on its website of any potential CEERTS projects identified through this process. Notice would be posted by May 1 of the first year of the biennial regional projects planning cycle to provide time for meeting sponsorship requirements by June 1.

iii. Each identified potential CEERTS project will require at least one sponsor in order to be submitted to the FRCC for consideration. Multiple sponsors of the same project will be considered joint sponsors and shall equally share the required $100,000 deposit unless the sponsors otherwise mutually agree to a different sharing of the deposit. Potential CEERTS projects identified in this process shall not have competing sponsors for the same project. An entity that is not a sponsor or joint sponsor of a potential CEERTS project shall not be eligible to be a developer of that project unless the sponsors discontinue development of that project.

iv. The sponsor or joint sponsors shall submit the potential CEERTS project for consideration in the first year of the biennial regional projects planning cycle.

1.2.3 To be eligible for approval by the FRCC Board for inclusion in the regional plan, a proposed CEERTS project must meet these threshold criteria:

A. Be a transmission line 230 kV or higher and 15 miles or longer; or be a substation flexible AC transmission system (“FACTS”) device, e.g., series compensation or static var compensator, designed to operate at 230 kV or more; and

B. Be materially different from projects already in the regional plan. For purposes of this section, the FRCC will consider a CEERTS project to be materially different from another CEERTS project if it displaces a different local project or projects or is not considered a minor adjustment to an existing local or CEERTS project that it is displacing. Minor adjustments could include changes in equipment size, different terminal bus arrangement, or a slight change in route.

Local transmission facilities located solely within a Transmission Provider’s footprint (e.g. Control Area) that are not selected in the regional transmission plan for purposes of cost allocation cannot qualify as CEERTS projects. Such facilities are the responsibility of the Transmission Provider to meet reliability needs and/or other obligations within its retail distribution service territory or footprint.

1.2.4 A CEERTS project submittal must include the following elements (to be provided in the context of the most current FRCC Board-approved regional transmission plan):

A. Those project sponsors that do not also intend to be a project developer must submit sufficient information related to the proposed CEERTS project that will permit the potential CEERTS project to be adequately considered within the FRCC regional transmission planning process. Below is the minimum set of information that must be submitted:

1. General description of the transmission facilities being proposed;

2. General path of the transmission lines; and

3. Transmission systems that would interconnect with the proposed CEERTS project.

B. Those project sponsors that intend to be the project developer shall so indicate and shall submit the following information:

1. Transmission project technical information:

a) Description of the transmission facilities being proposed (e.g., voltage levels);

b) General path of the transmission lines; and

c) Interconnection points with the existing transmission system.

2. A cost estimate and a recommended in-service date for the project. A project developer may also submit a demonstration of its cost containment capabilities, including any binding agreement to accept a cost cap for the developer's cost of the transmission project if it is selected as a CEERTS project.

3. If the project sponsor is an incumbent, it must indicate which funding option set forth in section 9.4.5.1 it intends to select.

4. A high-level summary of who will own, operate and maintain the CEERTS project, to the extent available.

C. A project sponsor may also submit any studies and analysis it performed to support its proposed CEERTS project, including the below:

1. Reliability impact assessment.

2. Load flow analysis that demonstrates performance utilizing the FRCC load flow model. The sponsor, if not an FRCC member, may obtain this model upon request from the FRCC ("Request for Florida Reliability Coordinating Council (FRCC) Transmission Information" document is posted on the FRCC website).

3. Identification of projects in the regional transmission plan that would be affected or avoided as well as any additional projects that may be required. A demonstration through a technical evaluation process that the CEERTS project is equal to or superior to avoided projects from the current regional transmission plan.

D. A deposit of $100,000 shall be submitted by the project sponsor at the time the project is submitted (e.g., June 1st of the biennial regional projects planning cycle) for each CEERTS project. This deposit will be used for FRCC internal labor costs for analysis of the project as well as any out-of-pocket expenses such as for independent consultants (unexpended amounts shall be refunded, with interest, to the project sponsor). The actual costs incurred by the FRCC to analyze the CEERTS project will be borne by the project sponsor and the deposit will be trued up based on the documented cost of the analysis. An accounting of the actual costs of the CEERTS project analysis including an explanation of how the costs were calculated will be provided to the project sponsor after the analysis has been completed. Any disputes regarding the accounting for specific deposits will be addressed through the Dispute Resolution Procedures in Appendix 6.

1.2.5 During the 30-45 days following the submittals under section 1.2.2, the FRCC PC shall review the project sponsor submittals and ensure that they meet the threshold criteria in section 1.2.3 and the minimum requirements in section 1.2.4. If a submittal is incomplete, the FRCC PC shall inform the CEERTS sponsor in writing within 15 days after the next regularly scheduled FRCC PC meeting of the specific deficiency(ies), and the CEERTS sponsor shall be given an opportunity, within 30 days, to submit the information required for a complete submittal. This may be referred to as Step 1.

1.2.6 At the next FRCC Board meeting following the review in section 1.2.5, the FRCC PC shall provide an update to the FRCC Board related to all projects that have been submitted and deemed complete. The FRCC PC shall post this information on the FRCC website (subject to any posting restrictions to protect CEII or other confidential information). This may be referred to as Step 2. At that time, the FRCC PC shall also post on the FRCC website (subject to any posting restrictions to protect CEII or other confidential information) any determination that a proposed CEERTS project is not materially different from a project or projects already in the regional plan. Such posting will include an explanation of the basis for the determination that the proposed CEERTS project is not materially different.

1.2.7 During the succeeding three to five months following the FRCC Board meeting in section 1.2.6, for those CEERTS projects that cleared sections 1.2.3 through 1.2.5 above, the FRCC PC, together with an independent consultant, will conduct a technical analysis for the purpose of either developing CEERTS project information or validating CEERTS project information and analysis provided by the sponsor. Such analysis will be performed in a manner consistent with other technical analyses performed by the FRCC PC. This may be referred to as Step 3.

A. The development/validation process will either develop the needed CEERTS project parameters or validate the information and analysis provided by the sponsor. This analysis will examine the following:

1. Transmission project technical information:

a) Description of the transmission facilities being proposed (e.g., voltage levels);

b) General path of the transmission lines; and

c) Interconnection points with the existing transmission system.

2. Load flow analysis that demonstrates adequate North American Electric Reliability Corporation (“NERC”) Reliability Standards performance utilizing the FRCC load flow model;

3. Whether it can be demonstrated through a technical evaluation process that the CEERTS project is equal to or superior to avoided projects from the current regional transmission plan or equal to or superior to the alternative transmission project(s) that address(es) the same transmission need(s), which alternative must be identified if there are no transmission projects currently planned for the relevant transmission need(s) (see section 1.2.2.B);

a) The FRCC PC shall verify that the proposed CEERTS project addresses transmission need(s) for which there are no transmission projects currently planned, and that the alternative project(s) to the CEERTS project could also meet such need(s). After the alternative project(s) are verified to meet such needs, the FRCC PC shall request that the entities responsible for the alternative project(s) provide cost information to the FRCC PC to be used in the FRCC PC’s analysis;

4. Identification of projects in the regional transmission plan that would be affected or avoided as well as any additional projects that may be required.

a) The FRCC PC shall request that the entities responsible for the existing project(s) that could be impacted by the proposed CEERTS project, or entities who would be required to implement additional local projects provide cost information to the FRCC PC to be used in their analysis;

5. Cost estimate for the proposed CEERTS project; and 6. In-service date for the project.

B. The FRCC PC will also consider any proposed non-transmission alternatives on a comparable basis with the CEERTS project, as described in section 5. C. The FRCC PC will provide the CEERTS sponsor and stakeholders an opportunity to review and provide input on a report that includes its findings from the technical analysis performed, and then the report will be provided to the FRCC Board with a recommendation as to whether the proposed CEERTS project should proceed to the next evaluation step in section 1.2.8 below. The CEERTS sponsor and stakeholders shall be given 15 days to provide written comments on the report to the FRCC Board following the date on which the FRCC PC provides the report and its recommendations to the Board.

1.2.8 Over a period of two to three months from receipt of the FRCC PC report and any comments on the report provided by the CEERTS sponsor and stakeholders pursuant to section 1.2.7.C, the FRCC Board will review the FRCC PC report and any comments received and determine if the CEERTS project should proceed to the next evaluation step as described in section 1.2.9 below. The CEERTS sponsor shall be invited to be present and participate in any FRCC Board meeting that addresses the FRCC PC report in order to answer questions and to present its views regarding the CEERTS project and the FRCC PC report. If a CEERTS sponsor does not agree with the FRCC Board's determination, then the Dispute Resolution Procedures in Appendix 6 are available for use by the CEERTS sponsor. This may be referred to as Step 4.

1.2.9 Over a period of two to four months from FRCC Board approval of the continuation of the CEERTS project evaluation in section 1.2.8, the process described below will be performed by the FRCC PC under the direction of the FRCC Board. This may be referred to as Step 5.

A. A meeting will be organized by the FRCC PC to provide the CEERTS sponsor an opportunity to fully describe its proposed CEERTS project. This meeting is the venue to fully discuss the CEERTS project, taking into account the technical analysis performed by the FRCC PC, as well as any potential revisions, including transmission technical aspects, transmission project costs, and affected projects. This meeting also provides the opportunity for potentially affected transmission providers to discuss these matters. If no developer is a sponsor of the proposed project, then this meeting also provides an opportunity for potential developers to express interest in being considered as the developer of the CEERTS project (if no entity expresses interest as the project developer then the project will not move forward and the projects in the regional plan that would have been avoided by the CEERTS project will remain in the regional plan). If multiple qualified project developers express an interest in developing a CEERTS project for which the sponsor does not plan to be the developer, then such developers must each submit, within the 30 days following the meeting held pursuant to this section 1.2.9.A, the project information identified in section 1.2.4.B.2 through 1.2.4.B.4 and these project developer proposals will be evaluated in the remainder of the steps identified in sections 1.2.9 and 1.2.10. This forum will enable the CEERTS project to be fully reviewed by all affected parties.

B. The FRCC PC will consider the proposed project in light of the criteria set forth in sections 1.2.7.A. and 1.2.7.B above and as set forth below.

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1. A cost-benefit analysis must be performed in accordance with section 1.2.9.C for reliability/economic projects by an independent consultant. If the result of this analysis is a benefit-to-cost ratio of greater than 1.00, the CEERTS project will move forward in the process.

2. For a project proposed to meet a public policy transmission need that requires a solution, as verified by the FRCC PC under section 11, the FRCC PC will determine whether the proposed CEERTS project meets the public policy transmission needs identified. There is no cost-benefit analysis performed, except for the validation of the CEERTS project being the least-cost solution. The CEERTS project may be the only solution proposed, in which case it would be accepted in accordance with the project sponsorship model being used within the FRCC. However, in the event there are equally effective alternative CEERTS project solutions that have been proposed to satisfy the public policy transmission needs, then the least-cost CEERTS project would be selected. The total estimated cost of the CEERTS public policy project is determined by the methodology set forth in section 1.2.9.C.4.

C. CEERTS Project Cost-Benefit Analysis An independent consultant will be retained to perform a cost-benefit analysis and will issue a written report of findings to the FRCC PC for sponsor and stakeholder review as set forth in section 1.2.9.D. The independent consultant will determine if the benefit-tocost ratio, which is the sum of the "Total Estimated Avoided Project Cost Benefit," "Total Estimated Alternative Projects Cost Benefit" and "Total Estimated Transmission Line Loss Value Benefit" divided by the "Estimated CEERTS Project Cost," is greater than 1.0.

Such analysis will consider estimated costs and benefits for the 10-year period of the planning horizon that is used to prepare the regional transmission plan under development at the time the analysis is prepared plus an additional, sequential 10-year period (the "20-year period"). Levelized annual costs and benefits to determine the appropriate revenue requirements will be used and deemed appropriate.

1. Total Estimated Avoided Project Cost Benefit

   The Estimated Avoided Project Cost Benefit for each enrolled transmission provider in the FRCC that has one or more projects being displaced by a CEERTS project will be determined by the independent consultant in the below manner. A CEERTS project that was previously selected and included in the most recent Board-approved transmission plan may be displaced by a newly-proposed CEERTS project. If a newly-proposed CEERTS project would displace a previously-approved CEERTS project, the portion of the costs of the newly-proposed CEERTS project associated with the benefits calculated using the costs of the displaced previously-approved CEERTS project would be allocated to the enrolled transmission providers that were allocated the costs for the previously-approved CEERTS project (see Appendix 4, Example 4 for a hypothetical example of this cost allocation process).

   Each enrolled transmission provider that has one or more projects being displaced is considered a beneficiary of the proposed transmission facility(ies) and will develop an original installed capital cost estimate for each project being displaced and indicate in what year each such project would be projected to be in service.

The independent consultant will review each enrolled transmission provider’s cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant’s report.

The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate, depending on which will be used for further calculations, for each year that the displaced project would have been expected to be in service during the 20-year period, but for the CEERTS project. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the enrolled transmission provider’s current FERC approved rate of return on equity (if any); commitments regarding incentive rates; weighted average cost of capital; and on-going capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.

The net present value of the estimated annual revenue requirements for each project will be determined using the average discount rate of enrolled transmission providers weighted by their total capitalization (Enrolled TP Discount Rate). Each enrolled transmission provider will provide its discount rate and total capitalization to the independent consultant for purposes of this calculation. Such net present value will be the “TP Estimated Avoided Project Cost Benefit” for each enrolled transmission provider’s displaced project(s).

All such TP Estimated Avoided Project Cost Benefits will be summed to determine the Total Estimated Avoided Project Cost Benefit.

2. Total Estimated Alternative Projects Cost Benefit

The Estimated Alternative Project Cost Benefit for each enrolled transmission provider in the FRCC that has one or more alternative projects for which a CEERTS project addresses a need for which there are no transmission projects currently planned will be determined by the independent consultant in the below manner. These projects will include those alternative transmission projects to a CEERTS project that were identified under section 1.2.2.B.1:

Each enrolled transmission provider that has one or more alternative projects is considered a beneficiary of the proposed transmission facility(ies) and will develop an original installed capital cost estimate for each alternative project and indicate in what year each such project would be needed to be in service.

The independent consultant will review each enrolled transmission provider's cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report.

The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate, depending on which will be used for further calculations, for each year that the alternative project would have been expected to be in service during the 20-year period, but for the CEERTS project. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the enrolled transmission provider's current FERC-approved rate of return on equity (if any); commitments regarding incentive rates; weighted average cost of capital; and on-going capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.

The net present value of the estimated annual revenue requirements for each project will be determined using the average discount rate of enrolled transmission providers weighted by their total capitalization (Enrolled TP Discount Rate). Each enrolled transmission provider will provide its discount rate and total capitalization to the independent consultant for purposes of this calculation. Such net present value will be the "TP Estimated Alternative Project Cost Benefit" for each enrolled transmission provider's displaced project(s).

All such TP Estimated Alternative Project Cost Benefits will be summed to determine the Total Estimated Alternative Project Cost Benefit.

3. Total Estimated Transmission Line Loss Value Benefit The Total Estimated Transmission Line Loss Value Benefit is calculated for each enrolled transmission provider by the independent consultant as follows: The change in transmission losses caused by the CEERTS project will be determined by the FRCC PC.

The FRCC PC will run simulations of the approved transmission plan with all projects, adjusted (if necessary) to include the alternative transmission projects that were identified that would have been needed to satisfy a transmission need for which no transmission projects are in the current transmission plan (see section 1.2.2.B), to establish base transmission losses for each enrolled transmission provider represented in the plan over the planning horizon. Base case losses will be determined for the years during which the CEERTS project is expected to be in service during the planning horizon, under both peak and offpeak conditions.

The approved transmission plan will then be modified to (1) include a proposed CEERTS project; (2) remove all alternative transmission projects; and (3) adjust or remove any affected or avoided transmission projects in the approved transmission plan as well as add any additional projects that would be required (see section 1.2.7.A.4) (after verifying that all reliability requirements are met) with the appropriate in-service dates. The modified plan is then analyzed for losses. The CEERTS case losses are determined for each enrolled transmission provider represented in the plan for the years during which the CEERTS project is expected to be in service during the planning horizon, at both peak and off-peak conditions. Enrolled transmission providers with reduced losses are beneficiaries of the CEERTS project.

The change in losses for year 10 of the planning horizon will be held constant for years 11-20 of the 20-year period. The change in losses (whether negative or positive) in each year that the CEERTS project is in service for the 20-year period is determined for each enrolled transmission provider. The value of the change in losses for each enrolled transmission provider will be determined by the independent consultant as follows: The independent consultant will use fuel cost and heat rate data from the U.S. Energy Information Administration ("EIA") to value losses. The net present value of the value of losses will be determined for each enrolled transmission provider using the Enrolled TP Discount Rate. Such net present value will be the "TP Estimated Transmission Line Loss Value Benefit." The TP Estimated Transmission Line Loss Value Benefit for each enrolled transmission provider will be summed to determine the Total Estimated Transmission Line Loss Value Benefit.

4. Estimated CEERTS Project Cost The Estimated CEERTS Project Cost is determined using the following formula: Estimated CEERTS Project Cost = Estimated Developer Cost + Total Estimated Related Local Project Costs + Total Estimated Displacement Costs

The Estimated Developer Cost will be determined by the independent consultant as follows: The developer of a CEERTS project will provide an original installed capital cost estimate for the developer's project and indicate which year the project is expected to be in service. The independent consultant will review the developer's original cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report. The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate for the developer's project, depending on which will be used for further calculations, for the years during which the CEERTS project is expected to be in service during the 20-year period. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the rates of return on equity approved by FERC for the developer or its affiliates (if any); commitments regarding incentive rates; proposed weighted average cost of capital; and on-going capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report. The net present value of the estimated annual revenue requirements will be determined using the Enrolled TP Discount Rate. The net present value of these estimated annual revenue requirements shall be the Estimated Developer Cost.

The Total Estimated Related Local Project Cost will be determined as follows by the independent consultant: Each enrolled transmission provider that will need to construct a local project to implement the CEERTS project will develop an original installed capital cost estimate for each such related local project and indicate what year such project is projected to be in service. The independent consultant will review the enrolled transmission provider's cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report. The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate for each year that the local project is expected to be in service during the 20-year period. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the enrolled transmission provider's current FERC-approved rate of return on equity (if any);

commitments regarding incentive rates; weighted average cost of capital; and ongoing capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report. The net present value of the estimated annual revenue requirement for each local project will be determined using the Enrolled TP Discount Rate. Such net present value will be the TP Estimated Avoided Project Cost for the displaced project. All TP Estimated Related Local Project Costs will be summed to determine the Total Estimated Related Local Project Cost. The calculation of Total Estimated Displacement Cost will be performed by the independent consultant as follows: Any enrolled transmission provider that has incurred, or expects to incur, costs associated with a project that is being displaced by a CEERTS project will provide an accounting to the independent consultant as to the level of its actual and expected expenditure on any displaced projects and any planned mitigation of such expenditures. The independent consultant will review the displacement cost estimate. The independent contractor will estimate the level of displacement cost that the enrolled transmission provider that has expended funds on a displaced project will recover by assuming that the enrolled transmission provider will be permitted to recover 100% of such displacement costs. The independent consultant will calculate an annual transmission revenue requirement associated with the displacement cost estimate for each year so that the displacement costs would be recovered during the 20-year period. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions and will describe such relevant factors and assumptions used in the report. The net present value of the estimated annual revenue requirements shall be calculated using the Enrolled TP Discount Rate. Such net present value will be the Estimated Displacement Cost. All such Estimated Displacement Costs will be summed to determine the Total Estimated Displacement Cost.

D. The FRCC PC will provide the CEERTS sponsor and stakeholders an opportunity to review and provide input on a report that includes its findings from the cost-benefit analysis performed that determined how benefits and beneficiaries were identified and applied to a proposed CEERTS project. The report will then be provided to the FRCC Board with the FRCC PC's recommendation based upon its review as set forth above. For any CEERTS public policy project(s), this report will include an explanation of why the CEERTS project(s) does or does not provide an opportunity to satisfy the public policy need. The CEERTS public policy analysis is more completely described in section 11.1. The CEERTS sponsor and stakeholders shall be given an opportunity to also provide written comments on the report to the FRCC Board. The CEERTS sponsor shall be invited to be present and participate in any FRCC Board meeting that addresses the FRCC PC report to answer questions and to present its views regarding the CEERTS project and the FRCC PC report.

E. The FRCC Board will review the FRCC PC report and any comments on the report that may be provided by the CEERTS sponsor and stakeholders and determine if the proposed CEERTS project is a more cost effective or efficient solution to regional transmission needs under applicable criteria in this section 1.2.9 and section 11.1. F. If a CEERTS project is selected, the

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FRCC will perform analyses to determine whether the CEERTS project could potentially result in reliability impacts to the transmission system(s) in another transmission planning region. If a potential reliability impact is identified, the FRCC will coordinate with the public utility transmission providers in the other transmission planning region on any further evaluation. The evaluation may identify required upgrades in the other transmission planning region. The costs of those upgrades are addressed in section 9.4.6.

9 Cost Allocation Subsections 9.1 – 9.3 apply to cost allocation for third party impacts resulting from the FRCC regional planning process; subsection 9.4 applies to cost allocation for CEERTS projects. The cost allocation provisions contained in the section relate to cost allocation procedures for specific circumstances as described herein. All other transmission cost allocation not specifically described below is provided in accordance with OATT provisions for generation interconnection and for network and point-to-point transmission service. 9.1 If a transmission expansion is identified as needed under the FRCC Regional Transmission Planning Process and such transmission expansion results in a material adverse system impact upon a third-party transmission owner, the third party transmission owner may choose to utilize the FRCC Principles for Sharing of Certain Transmission Expansion Costs as outlined below in this Attachment K. The FPSC is involved in this process and provides oversight, guidance and may exercise its statutory authority as appropriate. A more detailed description of the FRCC Principles for Sharing of Certain Transmission Expansion Costs can be found on the FRCC website.

9.2 The FRCC Principles for Sharing of Certain Transmission Expansion Costs: (i) sets forth certain principles regarding the provision of financial funding to Transmission Owners2 that undertake remedial upgrades to, or expansions of, their systems resulting from upgrades, expansions, or provisions of services on the systems of other Transmission Owners, and (ii) procedures for attempting to resolve disputes among Transmission Owners and other parties regarding the application of such principles. These principles shall not apply to transmission upgrades or expansions if, and to the extent that, the costs thereof are subject to recovery by a Transmission Owner pursuant to FERC Order No. 2003 or Order No. 2006.

9.3 Principles

9.3.1 Except for a CEERTS project for which it is not the project developer, each Transmission Owner in the FRCC Region shall be responsible for upgrading or expanding its transmission system in accordance with the FRCC Regional Transmission Planning Process consistent with applicable NERC and SERC Reliability Standards and shall participate, directly or indirectly (as the member of a participating Transmission Owner, e.g., Seminole Electric Cooperative, Inc. and Florida Municipal Power Agency), in the FRCC Regional Transmission Planning Process in planning all upgrades and expansions to its system.

9.3.2 If, and to the extent that, the need for a 230 kV or above upgrade to, or expansion of, the transmission system of one Transmission Owner (the "Affected Transmission Owner") is reasonably expected to result from, upgrade(s) or expansion(s) to, or new provisions of service on, the system(s) of another Transmission Owner or Transmission Owners (hereinafter

“Precipitating Events”), and if such need is reasonably expected to arise within the FRCC planning horizon, the Affected Transmission Owner shall be entitled to receive Financial Assistance (as defined herein) from each other such Transmission Owner and other parties, to the extent consistent with the other provisions hereof. Such upgrade or expansion to the Affected Transmission Owner’s system shall hereinafter be referred to as the “Remedial Upgrade.” Upgrade(s), expansion(s), or provisions of service on another Transmission Owner’s system that may result in the need for a Remedial Upgrade on the Affected Transmission Owner’s system for which Financial Assistance is to be provided hereunder include the following Precipitating Events:

- A new generating unit(s) to serve incremental load
- A new or increased long-term sale(s)/purchase(s) to or by others (different uses)
- A new or modified long-term designation of Network Resource(s)
- A new or increased long-term, firm reservation for point-to-point transmission service

Specific non-Precipitating Events are as follows:

1) Transmission requests that have already been confirmed prior to adoption of these principles; 2) Qualifying rollover agreements that are subsequently rolled over; 3) Redirected transmission service for sources to the extent the redirected service does not meet the Threshold Criteria described in subsection § 9.3.5.1. Existing flows would not be considered “incremental.”; and 4) Repowered generation if the MW output of the facility is not increased, regardless of whether the repowered unit is used more/less hours of the year.

9.3.3 Except for a CEERTS project for which it is not the project developer and, except to the extent that an Affected Transmission Owner is entitled to Financial Assistance from other parties as provided herein, each Transmission Owner shall be responsible for all costs of upgrades to, and expansions of, its transmission system; provided, however, that nothing herein is intended to affect the right of any Transmission Owner or another party from obtaining remuneration from other parties to the extent allowed by contract or otherwise pursuant to applicable law or regulation (including, for example, through rates to a Transmission Owner’s customers).

9.3.4 Except for a CEERTS project for which it is not the project developer, each Transmission Owner shall be solely responsible for the execution, or acquisition, of all engineering, permitting, rights-of-way, materials, and equipment, and for the construction of facilities comprising upgrades or expansions, including Remedial Upgrades, of its transmission system; provided, however, that nothing herein is intended to preclude a Transmission Owner from seeking to require another party to undertake some or all of such responsibilities to the extent allowed by contract or otherwise pursuant to applicable law.

9.3.5 Threshold Criteria: The following criteria (“Threshold Criteria”) must be satisfied in order for an Affected Transmission Owner to be entitled to receive Financial Assistance from another party or parties in connection with a Remedial Upgrade: 9.3.5.1 A change in power flow of at least a 5% or 25 MW, whichever is greater, on the Affected Transmission Owner's facilities which results in a NERC or SERC Reliability Standards violation; 9.3.5.2 The Transmission Expansion must be 230 kV or higher voltage; and 9.3.5.3 The costs associated with the Transmission Expansion must exceed $3.5 million.

9.3.6 In order for a Transmission Owner to be entitled to receive Financial Assistance from another party or parties hereunder in connection with a particular Remedial Upgrade, that Transmission Owner must: (i) participate, directly or indirectly, in the FRCC Regional Transmission Planning Process, and (ii) identify itself as an Affected Transmission Owner and identify the subject Remedial Upgrade in a timely manner once it learns of the need for that Remedial Upgrade.

9.3.7 The following principles govern the nature and amount of Financial Assistance that an Affected Transmission Owner is entitled to receive from one or more other parties with respect to a Remedial Upgrade:

9.3.7.1 A recognition of the reasonably determined benefits that result from the Remedial Upgrades due to the elimination or deferral of otherwise planned transmission upgrades or expansions.

9.3.7.2 Remedial Upgrade costs, net of recognized benefits, shall be allocated fifty-fifty, respectively, based on: - The sources or cluster of sources which are causing the need for the transmission expansion; and - The load in the area or zone associated with the need for the Transmission Expansion. (For these purposes, network customer loads embedded within a transmission provider's service area in the Transmission Zone would not be separately allocated any costs as such loads would be paying their load ratio share of the affected transmission provider's costs.)

9.3.7.3 Initially, there are six zones in the FRCC Region. A request by a party to modify one or more zones should be substantiated on its merits (e.g., technical analysis, area of limited transmission capability). Below are principles that will guide how the boundaries of zones are determined:

- Electrically, a substantial amount of the generation within a zone is used to serve load also within that zone.
- Transmission facilities in a zone are substantially electrically independent of other zones.

- Zones represent electrical demarcation areas in the FRCC transmission grid that can be supported from a technical perspective. 9.3.7.4 The Financial Assistance provided to an Affected Transmission Owner related to one or more transmission service requests keyed to new sources of power is subject to repayment without interest over a ten year period through credits for transmission service charges by the funding party and at the end of ten years through payment of any outstanding balance.

9.4 Cost Allocation for CEERTS Projects

9.4.1 There are three potential sets of CEERTS project costs that will be allocated: developer costs, related local project costs, and displacement costs. The general principle is to allocate all of the prudently-incurred costs of a CEERTS project to the entities that benefit from the project in proportion to the benefits received, although a CEERTS project developer may accept a cost cap for the developer costs, in which case the developer's costs up to the cost cap will be allocated. Cost allocations are determined in terms of percentages, with each beneficiary allocated a percentage of the CEERTS project costs. Entities that receive no benefit from a CEERTS project will not be allocated any project costs.

9.4.2 Project beneficiaries for a CEERTS project will be transmission providers within the FRCC Region enrolled in the regional planning process (on behalf of their retail and wholesale customers) which will benefit from the project.

9.4.3 The cost allocation for CEERTS reliability/economic projects is based on the following formula using terms defined in section 1.2.9.C: ((TP Estimated Avoided Project Cost Benefit + TP Estimated Alternative Project Cost Benefit + TP Estimated Transmission Line Loss Value Benefit) / (Total Estimated Avoided Project Cost Benefit + Total Estimated Alternative Project Cost Benefit + Total Estimated Transmission Line Loss Value Benefit)) * Estimated CEERTS Project Cost. The cost allocation dollar amounts calculated here using estimated cost information will further be translated to a percentage for each beneficiary as a ratio of their allocated share of the total estimated cost of the CEERTS project. These percentages will be used to allocate actual CEERTS project costs that are recoverable pursuant to the applicable subsection of section 9.4.5. Examples of CEERTS project cost allocation are provided in Appendix 4, Examples 1 and 2.

9.4.4 The costs for CEERTS public policy projects that are identified through the process described in section 11 will be allocated to the enrolled transmission providers whose transmission systems provide access to the public policy resources. The cost allocation for each enrolled transmission provider will be as follows: • Individual enrolled transmission provider MWs = number of megawatts of public policy resources enabled by the public policy project for the customers (including Native Load) within their transmission service territory. • Total MWs = total number of megawatts of public policy resources enabled by the public policy project. • Individual enrolled transmission provider cost allocation percentage = (Individual enrolled transmission provider MWs/Total MWs). An example of the CEERTS public policy cost allocation is provided in Appendix 4, Example 3. These percentages will be used to allocate actual CEERTS project costs that are recoverable pursuant to the applicable subsection of section

9.4.5. The process to interconnect individual generation resources is provided for under the generator interconnection section of each utility's OATT and not under this process. Requests for transmission service that originate in a utility's system and terminate at the border shall be handled through that utility's OATT.

9.4.5 Transmission Project Funding and Rate Base/Cost Recovery:

9.4.5.1 If incumbent enrolled transmission providers are the only transmission developers for a particular project, then they shall have two options in the initial transmission project funding and subsequent cost recovery of developer costs. Note that if an incumbent enrolled transmission provider develops a CEERTS project and is not FERC-jurisdictional, it will make any requisite FERC filings through the declaratory order process used for nonjurisdictional enrolled transmission providers rather than under FPA section 205: 1. Incumbent enrolled transmission providers may fund the transmission project in proportion to their cost responsibility for the project. For the portions of the projects that each of the companies were building that are related to their cost responsibility, the companies would include those transmission costs as identified in a Contribution in Aid to Construction (CIAC) filing at FERC within their respective rate bases and transmission revenue requirements. The costs would be reflected in FERC filed OATT rates in Account 107, Construction Work in Progress. When the assets go into service, the balance will be moved to Account 101, Electric Plant in Service and the Units of Property will be unitized to the FERC Accounts corresponding to the Units of Property. This treatment is for accounting purposes: a FERC filing and FERC approval would still be required to include Construction Work in Progress in rates. For the portion of the funding that was being provided for the transmission to be built by someone other than the incumbent, the payments by the incumbent (for their cost responsibility) would be recorded in Account 303, Miscellaneous Intangible Plant and amortized by debiting Account 404, Amortization of Limited-Term Electric Plant, and crediting Account 111, Accumulated Provision for Amortization of Electric Utility Plant. The amortization of the investment would be derived using a composite factor based on the most recently approved depreciation rates for the constructing company. The calculation of the composite factor would be based on the Units of Property installed in the transmission project. The amortization will begin when the project is declared in service. The costs and amortization would be reflected in FERC filed OATT rates until the investment is fully amortized to expense. The company receiving the money would treat these monies as a CIAC and thus have no associated net book investment in its transmission rate base. CIAC agreements will be filed with FERC prior to any CIAC payments being made to the constructing developer. Enrolled transmission providers with formula-based OATT rates shall submit a separate FPA section 205 filing with FERC for authorization to include the intangible asset investment and amortization expense in the formula rate. Traditional cost-based ratemaking procedures would be used to determine the impact of including the intangible asset investment in rate base and the amortization expense in operating expenses in deriving OATT rates. CIAC agreements filed with FERC would include workpapers to support the costs included in the determination of revenue requirements. See Example 1 provided in Appendix 7 for more detail and accounting treatment. 2. Incumbent enrolled transmission Providers may fund the portion of the transmission project that their company would be building/developing. Incumbent enrolled transmission providers would include the total transmission project costs that they are funding within their respective rate bases and transmission revenue requirements for recovery in their routine rate processes. For those portions of the project costs that are over and above their cost responsibility, the incumbent enrolled transmission providers would file with FERC for authorization to recover their Transmission Revenue Requirement (“TRR”) associated with those project costs to be directly assigned to the beneficiary(ies) responsible for that portion of the cost assignment. The TRR when received by the incumbent developer would be treated as a revenue credit recorded in Account 456, Miscellaneous Revenue in its cost of service to offset the inclusion of other beneficiary(ies) assigned cost in rate base and revenue requirement. In addition to including the

TRR for those portions of the project costs that were over and above their cost responsibility, the incumbent enrolled transmission providers would also include any TRR costs allocated to them in their FERC-filed cost of service in support of FERC-approved OATT rates. Enrolled transmission providers with formula-based OATT rates shall submit a separate FPA section 205 filing with FERC for authorization to include their allocated TRR costs in the formula rate. See Example 2 provided in Appendix 7 for more detail and accounting treatment. 9.4.5.2 If a non-incumbent developer builds the CEERTS project, it shall file with FERC for authorization to recover its developer costs in the form of a TRR from the incumbent enrolled transmission providers in accordance with their cost responsibilities as determined by the cost allocation methodologies The incumbent enrolled transmission providers may include those costs allocated to them in their respective wholesale rates (e.g., in FERC-filed cost of service in support of FERC approved OATT rates). Enrolled transmission providers with formula-based OATT rates shall submit a separate FPA section 205 filing with FERC to include their allocated TRR costs in the formula rate. See Example 3 provided in Appendix 7 for more detail and accounting treatment. 9.4.5.3 Incumbent enrolled transmission providers with formula-based OATT rates shall be allowed to revise their formula rates to include the intangible asset investment balance as directly assignable transmission function rate base, and amortization expense should be included as transmission function specific expense. Formula-based OATT rates shall be revised by submitting a separate FPA section 205 filing with FERC. 9.4.5.4 Enrolled transmission provider(s) will be responsible for recovering their related local project costs from the beneficiaries allocated such costs through a FPA section 205 filing if the enrolled transmission provider is FERC-jurisdictional or through FERC’s declaratory order process if the enrolled transmission provider is non-jurisdictional. 9.4.5.5 Enrolled transmission provider(s) will be responsible for recovering their actual displacement costs, if applicable, through a FPA section 205 filing if the enrolled transmission provider is FERC-jurisdictional or through FERC's declaratory order process for non-jurisdictional enrolled transmission owners. In such filing, the enrolled transmission provider(s) will allocate displacement costs in the same manner as the CEERTS project costs are allocated.

9.4.6 Neighboring Transmission Planning Region Potential Cost Impacts Not Included in FRCC’s CEERTS Cost: The costs associated with any required upgrades identified through the FRCC’s CEERTS project evaluation process identified in section 1.2.9.F for the neighboring transmission planning region will not be included in the CEERTS cost within the FRCC. However, nothing in this Attachment K prevents the beneficiaries or project sponsor of a CEERTS project that causes the need for upgrades in another region from voluntarily negotiating a resolution of the project impacts with the transmission owners(s) in the other region. 9.4.7 Allocation of Transmission Rights: Enrolled transmission providers allocated costs of CEERTS projects shall have priority with regard to any transmission rights associated with such projects, in proportion to their respective share of such costs. Any use of the transmission rights allocated to the Transmission Provider, including use by the Transmission Provider itself, shall be governed by this Tariff.

10 Recovery of Planning Costs

10.1 Planning study costs incurred by the Transmission Provider in the performance of studies requested by a customer/stakeholder associated with transmission service or generator interconnection service are separately addressed in this tariff under provisions that require the customer/stakeholder to pay the cost of such studies. Planning study costs incurred by the Transmission Provider in the performance of the first five economic planning studies will be absorbed by the Transmission Provider in its normal course of business of performing its obligations under this Attachment K. The cost of the sixth and additional economic planning studies in a calendar year will be assessed to the requesting entity as set forth in section 8.1. Other general transmission planning costs not associated with the above studies are routine cost-of-service items that would be reflected in both wholesale and retail transmission rates as appropriate.

Dominion Energy South Carolina, Inc. (SCEG)

Dominion Energy South Carolina, Inc. Open Access Transmission Tariff, Attachment K, https://www.oasis.oati.com/woa/docs/SCEG/SCEGdocs/DOMINION_ENERGY_SOUTH_CAROLINA_OATT_07.18.24.pdf (last accessed Dec. 18, 2024)

Attachment K

I. INTRODUCTION DESC has a history of cooperative and coordinated planning with its customers for services provided to those customers. DESC also has a history of working and coordinating with neighboring utilities to ensure the most cost-effective and/or efficient transmission expansion plans are selected that achieve reliability requirements and accommodate identified economic opportunities. The local transmission planning process refers to the process that DESC performs for its individual retail distribution service territory and pursuant to Order No. 890. DESC annually prepares a local transmission expansion plan for its own area (the “Local Transmission Plan”), which is developed through an open and non-discriminatory process, to meet the needs of all customers (Native Load, Network Service, Long-term Point–to– Point Service and Generator Interconnection Service). These local planning activities include long-standing coordinated assessment processes that include all transmission providers of interconnected systems by sharing local transmission expansion plans to determine if they are simultaneously feasible, to ensure the most efficient or cost-effective alternatives for needed transmission expansion are considered and to ensure that consistent assumptions and data are used in identifying system enhancements required to meet reliability standards. In 2007, in accordance with Order No. 890's nine planning principles, DESC expanded its transmission planning process in order to promote a more open, transparent and coordinated approach to transmission planning in South Carolina on a local level and on a regional level. As an addition to the planning process, DESC established with The South Carolina Public Service Authority (Santee Cooper), the South Carolina Regional Transmission Planning (SCRTP) process, the South Carolina Regional Stakeholder Group (SCSG), and a dedicated website for this process. This process, described more fully below, was developed in order to promote openness, transparency, comparability and the exchange of information consistent with the principles expressed in Order No. 890, thereby reducing the potential for and the false perception of undue discrimination in the planning process. The elements of DESC's current planning process address the nine planning principles that the Commission articulated in Order No. 890. While not displacing or impeding local planning, Order No. 1000 built upon Order No. 890’s nine planning principles to require more formalized transmission planning within and between regions. To comply with the requirements of Order No. 1000, DESC and Santee Cooper together will produce a regional transmission plan, which includes the regional transmission projects that have been selected for purposes of cost allocation (the “Regional Transmission Plan”). Those projects selected in the plan for purposes of cost allocation must have been determined to be more cost-effective or efficient than those projects identified in DESC and Santee Cooper’s individual Local Transmission Plans or the Regional Transmission Plan. Like the Local Transmission Plan, the Regional Transmission Plan is designed to meet the specific service requests for all customers taking service under the DESC OATT and treats similarly-situated customers comparably. DESC and Santee Cooper will serve as the initial enrolled Transmission Providers of the region, and will utilize the SCRTP structure, including the SCSG meetings and the SCRTP website, as the mechanism for communicating with Stakeholders in the regional transmission planning process. Enrollment will subject Enrollees to cost allocation if, during the period in which they are enrolled, it is determined in accordance with this Attachment K that the Enrollee is a beneficiary of a new transmission project(s) selected in the regional transmission plan for purposes of cost allocation, provided that the Enrollee has not withdrawn in accordance with its rights in Section III.B. Consistent with Order No. 1000, the Transmission Providers may continue to meet their reliability needs or service obligations by choosing to build new transmission facilities that are located solely within their individual Balancing Areas or footprints and that are not submitted for regional cost allocation. In accordance with Order No. 1000’s interregional coordination requirements, the enrolled Transmission Providers within the SCRTP coordinate with the public utility transmission providers in the Southeastern Regional Transmission Planning Process (“SERTP”) to address transmission planning coordination issues related to interregional transmission facilities. The interregional transmission coordination procedures are hereby provided in Appendix K-6 and any additional materials may be provided on the SCRTP Regional Planning website.

II. Definitions

G. Regional Project: A project proposed for purposes of regional cost allocation that meets the criteria listed in Section VII.A.

H. Upgrade: An improvement to, addition to, or replacement of a part of an existing transmission facility.

<u>III.A: *Local Transmission Planning*</u>: The SCRTP process provides interested entities the opportunity via the SCSG meetings and the SCRTP website to understand and provide input, comments and questions regarding the study process prior to formulation of the Local

Transmission Plan. The SCSG meeting process allows for the exchange of information and input into the planning process on a comparable basis and thereby eliminates the potential for undue discrimination. To promote transparency and enable Stakeholders to replicate the result of the Transmission Provider's planning studies and thereby reduce the incidence of after-the-fact disputes regarding whether transmission planning has been conducted in an unduly discriminatory fashion, DESC will make available, during the relevant SCSG meetings and/or on the SCRTP website, information concerning the basic methodology, criteria, and process the Transmission Provider uses to develop its plan. Information will be placed on the SCRTP website, with some information being placed under the restricted access section and available to those entities that are eligible to receive Confidential and/or CEII information.

Regional Transmission Planning: The SCRTP Process also provides entities an opportunity to propose and review Regional Projects for inclusion in the Regional Transmission Plan. This process establishes a transparent and non-discriminatory process for Stakeholder involvement in the regional transmission planning process, including access to models and data used in the transmission planning process in a manner consistent with the access given to Stakeholders through the Order No. 890 planning process.

III.E.1: Local transmission Planning Process

Meeting 2:

DESC will review: • the initial study results (for Stakeholder input) and final study results (including Stakeholder input) of its RTP studies, which include studies conducted to measure the performance of the DESC transmission system against the applicable NERC Reliability Standards and the DESC Internal Transmission Planning Criteria. This review may occur by web conference or conference call, if needed, to maintain study schedules. Stakeholders will have the opportunity to provide comments and feedback on these results. All comments and feedback will be considered in the ongoing and perpetual planning process; • two-party and multi-party RTP studies conducted with interconnected and other Eastern Interconnection transmission planners. This review may occur by web conference or conference call, if needed, to maintain study schedules. Stakeholders will have the opportunity to provide comments and feedback on these results. All comments and feedback will be considered in the ongoing and perpetual planning process; • the most recent regional and interregional reliability assessment studies. This review may occur by web conference or conference call, if needed, to maintain study schedules; • any revisions to the Local Transmission Plan being considered. Stakeholders can discuss possible alternatives to the proposed revisions. These alternatives may be in the form of other transmission expansion solutions, generation solutions, load-management solutions, etc. Viable alternative solutions to proposed upgrades will be considered in the ongoing and perpetual planning process; and • information on how to acquire all data used to conduct the studies, such as, base cases, reports and criteria. All data released will be subject to Non-disclosure and Confidentiality agreements, as necessary.

IV: LOCAL TRANSMISSION PLANNING

Transmission planning appropriately begins at the individual transmission system level. At the system level, the DESC transmission planning process provides a reliable, timely and economical Local Transmission Plan that on a non-discriminatory basis (1) meets DESC's obligation to serve native load, including native load growth, (2) provides the future transmission requirements of grandfathered wholesale agreements, (3) provides firm pointto-point transmission service, (4) provides network integration transmission service and (5) provides generator interconnection service.

The Local Transmission Plan is produced on an annual basis and provides for timely modifications and additions to the DESC transmission system to ensure reliable and economical transmission of electric power for our customers. Goals of the DESC local transmission planning process include developing a local plan and facilities to:

1. Transmit electric power from DESC generators to DESC native load and grandfathered wholesale customers.

2. Transmit electric power from off-system purchases to DESC native load and grandfathered wholesale customers

3. Provide Transmission Service to Point-to-Point (PTP) and Network Customers 3. Provide Interconnection Service to all generators

4. Maintain synchronism with the Eastern Interconnection

The Local Transmission Plan is a ten (10) year expansion plan for the DESC transmission system considering the current performance and capabilities of the transmission system and the required future performance and capabilities of the transmission system. The DESC local transmission planning process ensures that the DESC transmission system is compliant with NERC Reliability Standards and DESC's Transmission Planning Criteria. DESC also seeks to evaluate and plan additions/facilities, for customers, economically, with overall cost savings in mind. DESC's Local Transmission Plan is based on the following drivers:

1. Reliability Standards and Planning Criteria
2. Native load distribution needs
3. Native load Industrial Customer needs
4. Firm PTP Transmission Service needs
5. Network/Wholesale Customer needs
6. Generator Interconnection needs
7. DESC’s Integrated Resource Plan (IRP)
8. Actual system performance
9. Transmission needs driven by Public Policy Requirements

V.B. Cost Allocation for Local Economic Projects

V.B.1. General The following provides DESC’s methodology for allocating the actual costs of new local transmission facilities that do not fit under the general Tariff rate structure. In particular, this methodology addresses the allocation of the actual costs of local economic transmission upgrades that are identified in the Economic Planning Studies and that are not otherwise associated with transmission service provided under the Tariff and are not associated with the provision of transmission service under other arrangements, such as DESC's provision of bundled service to its Native Load Customers. Transmission Service on DESC's transmission system must be applied in a manner consistent with the requirements and procedures as stated in the Transmission Provider's Tariff.

V.B.2. Cost Allocation Methodology for Economic Upgrades:

a. Identification of Economic Upgrades: DESC's Local Transmission Plan will identify the transmission upgrades that are necessary to ensure the reliability of the transmission system and to otherwise meet the needs of long-term firm transmission service commitments ("Reliability Upgrades"). All of the upgrades identified in the Economic Planning Studies that are not identified in the transmission expansion plans, and are thus not such Reliability Upgrades, shall constitute "Economic Upgrades."

b. Request for Performance of Economic Upgrades: Within thirty (30) calendar days of the posting of the final results of the underlying Economic Planning Study(ies), one or more entities ("Initial Requestor(s)") that would like DESC to construct one or more Economic Upgrades identified in the Economic Planning Study(ies) may submit a request to comments@scrtp.com for the Transmission Provider to construct such Economic Upgrades on the secured area of the SCRTP website, along with an identification of the amount of megawatts of transmission capacity for which the Initial Requestor(s) would like to take cost responsibility. The request must consist of a completed request application, the form of which will be posted on the SCRTP website ("Economic Upgrade Application"). Other entities ("Subsequent Requestor[s]") that also would like the Transmission Provider to construct the Economic Upgrades sought by the Initial Requestor[s] may also notify the Transmission Provider of their intent by submitting such intent to comments@scrtp.com, along with the amount of megawatts of transmission capacity that they would like to take cost responsibility within thirty (30) calendar days of the Initial Requestor's submitting its Economic Upgrade Application (collectively, the Initial Requestor[s] and the Subsequent Requestor[s] shall be referred to as the "Requestor[s]").

c. Allocation of the Costs of the Economic Upgrades: The actual costs of the Economic Upgrades shall be allocated to each Requestor based upon the amount of megawatts of transmission capacity that it requested responsibility for in its respective request posted on the SCRTP website. Should the total amount of transmission capacity identified by the Requestors not equal the amount of transmission capacity that is estimated to be added to the Transmission System by constructing the Economic Upgrade, then the Requestors' cost responsibility will be adjusted on a pro rata basis based upon the amount of capacity identified by the Requestors' relative to the total transmission capacity estimated to be added by the Economic Upgrades so that all of the cost responsibility for the Economic Upgrades is allocated to the Requestors. If one or more of the Requestors do not identify the amount of megawatts for which they are willing to take cost responsibility, then the Requestors shall bear the actual costs of the Economic Upgrades in equal shares based upon the number of Requestors. The Requestors shall bear cost responsibility for the actual costs of the Economic Upgrades. Should a Requestor later not enter into an agreement with the Transmission Provider for the construction of the Economic Upgrades, then the remaining Requestors' cost responsibility will be recalculated on a pro rata basis based upon the amount of megawatts requested.

d. Cost Allocation for the Acceleration, Expansion, Deferral, or Cancellation of Reliability Upgrades: Should the Transmission Provider conclude that the construction of an Economic Upgrade would accelerate the construction of, or require the construction of a more expansive Reliability Upgrade, then the Requestors shall bear the cost of such acceleration or expansion. Should the Transmission Provider conclude that the construction of the Economic Upgrade would result in the deferral or cancellation of a Reliability Upgrade, then the actual cost of the Economic Upgrades allocated to the Requestors shall be reduced by the amount of savings caused by the deferral or cancellation.

e. Implementing Agreements and Regulatory Approvals: The Transmission Provider will not be obligated to commence design or construction of any Economic Upgrades until (i) a binding agreement(s) with all of the Requestors for such construction by the Transmission Provider and payment by the Requestors of their allocated cost responsibility is executed by the Parties and (ii) all of the Requestors provide the Transmission Provider security, in a form acceptable to the Transmission Provider, for the full costs of the design and construction. Furthermore, the Transmission Provider shall not be obligated to commence construction, or to continue construction, if all necessary regulatory approvals are not obtained, with the Transmission Provider having to make a good faith effort to obtain all such approvals. The actual costs associated with obtaining such regulatory approvals shall be included in the total costs of the Economic Upgrades and shall otherwise be borne by the Requestors.

Louisville Gas and Electric Company (LGE) and Kentucky Utilities Company (KU)

Joint Pro Forma Open Access Transmission Tariff, Louisville Gas and Electric Company and Kentucky Utilities Company, Attachment K (Jan. 24, 2015), retrieved from https://www.oasis.oati.com/woa/docs/LGEE/LGEEdocs/LGE_and_KU_Joint_Pro_Forma_OATT_as_filed_of_date_12_7_2021.pdf (last accessed Dec. 18, 2024)

3. Transparency

The planning criteria are available at: http://www.oatioasis.com/LGEE/index.html under the heading "Business Practices, Waivers, and Exemptions" and then "LG&E-KU Transmission Planning Guidelines." See Appendix 3.

The Transmission System Planning Guidelines are to be made available on the OASIS. These guidelines outline the basic criteria, assumptions, and data that underlie transmission planning for the Transmission System, including:

- Adherence to NERC and SERC reliability standards;
- Treatment of native load;
- Transmission contingencies and measurements;

- Thermal and voltage limits;
- Minimum operating voltage at Generators; and
- Modeling considerations.

<u>Southern Company Services Inc, Alabama Power Company, Georgia Power Company, Mississippi Power Company (Southern Companies)</u>

Open Access Transmission Tariff of Alabama Power Company, Georgia Power Company, Mississippi Power Company and Mississippi Power Company, Tariff Volume 5, Attachment K (May 1, 2024), Retrieved from https://www.oasis.oati.com/woa/docs/SOCO/SOCOdocs/Southern-OATT_current.pdf (last accessed Dec. 18, 2024).

<u>Attachment K – The Southeastern Regional Transmission Planning Process</u>

The Transmission Provider participates in the Southeastern Regional Transmission Planning Process ("SERTP") . . . . This Southeastern Regional Transmission Planning Process provides a coordinated, open and transparent planning process between the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers and other interested parties, including the coordination of such planning with interconnected systems within the region, to ensure that the Transmission System is planned to meet the transmission needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and nondiscriminatory basis. Transmission needs consist of the physical transmission system delivery capacity requirements necessary to reliably and economically satisfy the load projections; resource assumptions, including on-system and off-system supplies for current and future native load and network customer needs; public policy requirements; and transmission service commitments within the region.2 The Transmission Provider's coordinated, open and transparent planning process is hereby provided in this Attachment K, with additional materials provided on the Regional Planning Website.

Local Transmission Planning

The Transmission Provider has established the SERTP as its coordinated, open and transparent planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties to ensure that the Transmission System is planned to meet the transmission needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and not unduly discriminatory basis. The Transmission Provider plans its transmission system to reliably meet the needs of its transmission customers on a least-cost, reliable basis in accordance with applicable requirements of federal and state public utility laws and regulations. The Transmission Provider incorporates into its transmission plans the needs and results of the integrated resource planning activities conducted within each of its applicable state jurisdictions pursuant to its applicable duty to serve obligations. In accordance with the foregoing, its contractual requirements, and the requirements of NERC Reliability Standards, the Transmission Provider conducts comprehensive reliability assessments and thoroughly coordinates with neighboring and/or affected transmission providers.

Through its participation in the SERTP, the Transmission Provider's local planning process satisfies the following nine principles, as defined in Order No. 890: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects. This planning process also addresses at Section 9 the requirement to provide a mechanism for the recovery and allocation of planning costs consistent with Order No. 890. This planning process also includes at Section 10 the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements consistent with Order No. 1000.

The Transmission Provider uses the SERTP as its open, coordinated, and transparent planning process for both its local and regional planning processes for purposes of Order Nos. 890 and 1000, such that the Transmission Provider's ten-year local transmission expansion plan and the regional transmission plan are vetted with Stakeholders in accordance with the SERTP's open, coordinated, and transparent transmission planning provisions provided herein. Specifically, the Transmission Provider develops its local transmission expansion plan concurrently with the development of the regional transmission plan, with the expectation that in any given transmission planning cycle, the Transmission Provider's ten-year local transmission expansion plan, along with those of the other Sponsors, will be included in the regional transmission plan. Therefore, references to "transmission expansion plan" in this Attachment K include the Transmission Provider's local transmission expansion plan. Through this concurrent development of the Transmission Provider's local transmission expansion plan and the regional transmission plan, Stakeholders are provided the opportunity to provide input throughout the SERTP's processes, with the procedures and timeline of the SERTP for Stakeholders to provide input on the local transmission expansion plan prescribed in Sections 1 through 10.

Arizona Public Service Company (AZPS)

Arizona Public Service Company, Pro Forma Open Access Transmission Tariff, Attachment E, retrieved from https://www.oasis.oati.com/woa/docs/AZPS/AZPSdocs/APS_OATT_Volume_2_20240423.pdf (last accessed Dec. 18, 2024)

I. Overview of the APS Transmission Planning Process

Arizona Public Service Company (APS) is a vertically integrated public utility engaged in the business of generating, transmitting and distributing electricity in eleven of Arizona's fifteen counties. APS provides electric transmission and related reliability services under state and federal statutes and regulations. APS's transmission planning process is based on the following three core objectives:

- Maintain reliable electric service.
- Improve the efficiency of electric system operations, including the provision of open and non-discriminatory access to the transmission facilities under its control.
- Identify and promote new investments in transmission infrastructure in a coordinated, open, transparent and participatory manner.

APS's transmission planning process is intended to facilitate a timely, coordinated and transparent process --- one that facilitates the development of electric infrastructure in order to maintain reliability and meet load growth so that APS can continue to provide reliable and economic transmission service.

Attachment B

The APS transmission planning process includes a series of open planning meetings that APS will conduct at least twice a year to allow anyone including, but not limited to, network and point-to-point transmission customers, sponsors of transmission solutions, generation solutions and solutions using non-transmission alternatives (NTAs), interconnected neighbors, regulatory and state bodies and other stakeholders input into and participation in all stages of APS's transmission plan development

II. APS Local Transmission Planning

II.A. APS Planning Process

1. APS and Stakeholder Alternative Solutions Evaluation Basis APS's local planning process is an objective process that evaluates use of the transmission system on a comparable basis for all customers. All solution alternatives that have been presented on a timely basis (per Section II.A.5 of this Attachment E), including transmission solutions, generation solutions and solutions utilizing NTAs, whether presented by APS or another stakeholder, are evaluated on a comparable basis. The same criteria and evaluation process is applied to competing solutions and/or projects, regardless of type or class of stakeholder. Solution alternatives are evaluated against one another on the basis of the following criteria to select the preferred solution or combination of solutions: (1) ability to fulfill the identified need practically; (2) ability to meet applicable reliability criteria or North American Electric Reliability Corporation (NERC) Planning Standards issues; (3) technical, operational and financial feasibility; (4) operational benefits/constraints or issues; (5) cost-effectiveness over the time frame of the study or the life of the facilities, as appropriate (including adjustments, as necessary, for operational benefits/constraints or issues, including dependability); and (6) where applicable, consistency with state or local integrated resource planning requirements, or regulatory requirements, including cost recovery through regulated rates.

***

4. APS Transmission Local Planning Study Process

a) Overview. APS's local transmission planning process consists of an assessment of the following needs:

(1) Provide adequate transmission to access sufficient resources in order to reliably and economically serve retail and network loads;

(2) Where feasible, identify NTAs, such as demand response resources, that could meet or mitigate the need for transmission additions or upgrades;

(3) Support APS's local transmission and subregional transmission systems;

(4) Provide for interconnection of new generation resources;

(5) Coordinate new interconnections with other transmission systems;

(6) Accommodate requests for long-term transmission access; and

(7) Consider local transmission needs driven by Public Policy Requirements.

II.A.5.b.3 Criteria Used to Determine Whether a Transmission Planning Study Request is a Local Study Request. Based in part on the number and type of local study requests received, APS shall consider the following criteria to determine whether the economic transmission planning study request is a local study request:

(a) Whether the study request does not affect interconnected transmission systems; and

(b) The remedies are confined to the APS transmission system and resolved within the APS transmission system.

II.A.5.b.4: Criteria Used to Determine Whether a Local Study Request Qualifies as a Local Priority Economic Transmission Planning Study Request. APS shall consider the following criteria to determine whether a local study request qualifies as a local priority economic transmission planning study request:

(a) Which portion(s) of the APS local transmission system shall be under consideration in the study.
(b) Whether the request raises fundamental design issues of interest to multiple parties.
(c) Whether the request raises public policy issues of national, regional or state interest.
(d) Whether the objectives of the study can be met by other existing or planned studies.
(e) Whether the study shall provide information of broad value to customers, regulators, transmission providers and other interested stakeholders.
(f) Whether similar requests for studies or scenarios can be represented generically if the projects are generally electrically equivalent.
(g) Whether requests can be aggregated into energy or load aggregation zones with generic transmission expansion between them.
(h) Whether the study request requires the use of production cost simulation or can it be better addressed through technical studies, i.e., power flow and stability analysis.

Black Hills Power, Inc. (BHP)

Black Hills Power Inc., Joint Open Access Transmission Tariff, FERC Docket No. ER23-00956-000, Attachment K (Jan. 27, 2023), retrieved from: https://etariff.ferc.gov/TariffBrowser.aspx?tid=2860 (last accessed Dec. 18, 2024).

Attachment K: Transmission Planning Process

I Overview of the Black Hills/Basin Electric/Powder River Transmission Planning Process

Black Hills Power, Inc., Basin Electric Power Cooperative, and Powder River Electric Cooperative, collectively the "Transmission Provider", jointly own a transmission system in South Dakota, Wyoming and Nebraska consisting of facilities 115 kV and higher, with some specific 69 kV facilities, known as the Common Use System. Transmission Provider provides Point To Point ("PTP") and Network Integration Transmission Services ("NITS") under the Joint Open Access Transmission Tariff ("JOATT"). Black Hills Power, Inc. is the Tariff Administrator and accordingly shall administer the Transmission Provider's responsibilities related to the regional transmission planning process contained in this Attachment K, as applicable.

Transmission Provider's transmission planning process is intended to facilitate the development of electric infrastructure that maintains reliability, responds to service requests and meets load growth, and is based on the following objectives:

- Maintain reliable electric service.
- Improve the efficiency of electric system operations, including the provision of open and non-discriminatory access to its transmission facilities.
- Identify and promote new investments in transmission infrastructure in a coordinated, open, transparent and participatory manner.

I.A. Definitions

I.A.1. LTP: Local Transmission Plan is the transmission plan of the Transmission Provider that identifies the upgrades and other investments to the Transmission System or demand response necessary to reliably satisfy, over the planning horizon, Network Customers' resource and load growth expectations for designated Network Load; Transmission Provider's resource and load growth expectations for Native Load Customers; Transmission Provider's obligations pursuant to grandfathered, non-JOATT agreements; and the Transmission Provider's Point-to-Point customers' projected service needs including obligations for rollover rights.

II. Local Planning Process

II.B. Preparation of a LTP

1. The Transmission Provider will prepare, with the input of interested Stakeholders, one LTP every year. The preparation of the LTP will be done in accordance with the general policies, procedures, and principles set forth in this Attachment K.

2. The Transmission Provider will establish a process by which Stakeholders can discuss, question, or propose alternatives for input assumptions and upgrades identified by the Transmission Provider. The Transmission Provider will consider information obtained from Stakeholders for future planning cycles. The Transmission Provider may, following Stakeholder input, also include results of completed Economic Studies.

3. The Transmission Provider will use a ten (10) year or other applicable planning horizon for the LTP. The transmission planning process will use reliability criteria established by the Transmission Provider, WECC, NERC and FERC.

4. The LTP on its own does not effectuate any transmission service requests. Transmission Service Requests must be made in accordance with the procedures set forth in Part II of the JOATT and posted on the Transmission Provider's OASIS. Similarly, Network Customers must submit Network Resource and load additions or removals pursuant to the process described in Part III of the JOATT.

5. The Transmission Provider will take the LTP into consideration, as appropriate when preparing generation interconnect, transmission service and economic studies. The Transmission Provider will take the generation interconnect,

transmission service and economic study results into consideration as appropriate when preparing the LTP.

6. The Transmission Provider will prepare and develop the LTP using an open and coordinated process that includes input from Stakeholders as defined in Section II.D.3. Stakeholder input will occur at various phases throughout the study process consistent with the principles, practices, policy and procedures set forth in this Attachment K. The Transmission Provider, with interested Stakeholder input, will: (1) determine the Study Plan, define scenarios and develop base cases related to the LTP; (2) perform the Technical Study; (3) determine the preliminary LTP, based on the data produced during the Technical Study and if applicable, include timely submitted Economic Study Request results; and (4) report study results and the LTP to Stakeholders and Affected Parties.

7. <u>Limitations on Disclosure</u>: While the Transmission Provider's LTP planning process will be conducted in the most open manner possible, the Transmission Provider has an obligation to protect sensitive information such as, but not limited to, Critical Energy Infrastructure Information (CEII) and the proprietary materials of third parties. Nothing in this Attachment K will be construed as compelling the Transmission Provider to disclose materials in contravention of any applicable regulation, contractual arrangement, or lawful order unless otherwise ordered by a governmental agency of competent jurisdiction. The Transmission Provider may employ mechanisms such as confidentiality agreements, protective orders, or waivers to facilitate the exchange of sensitive information where appropriate and available.

8. The Transmission Provider will adhere to all applicable laws and regulations in preparing the LTP, including but not limited to CEII. Any Stakeholder or Transmission Provider participating in the planning process must adhere to the Commission's guidelines concerning CEII as set out in the Commission's regulations, Order Nos. 683 and 683-A (or and successor thereto). Additional information concerning CEII, including a summary list of data that is determined by the supplying party to be deemed CEII, will be posted on the Transmission Providers' OASIS.

II.C.2.a: Quarter 1: Data Collection, Study Scope and Scenario Development

(i) The Transmission Provider will gather: (1) Network Customers' projected loads and resources, and load growth expectations (based on annual updates under Part III of the JOATT); (2) Transmission Provider's projected loads and resource needs for its Native Load Customers; (3) Point-to-Point Customer's projections for long-term (greater than 1 year) needs at each receipt and delivery point (based on information submitted by Eligible Customers to the Transmission Provider) including projections of rollover rights; (4) information from all Transmission Customers and the Transmission Provider on behalf of Native Load Customers concerning existing and planned demand resources and their impact on demand and peak demand and (5) information from sponsors of transmission solutions, generating solutions and solutions utilizing demand response resources. The Transmission Provider will take into consideration, to the extent known or which may be obtained from its Transmission Customers and Stakeholders, obligations that will either commence or terminate during the applicable study window. Customer Economic Study Requests will also be submitted to the Transmission Provider during this quarter. The Transmission Provider will, with Stakeholder input, define the proposed LTP study scope, objectives, scenarios to be considered in development of the LTP. The Transmission Provider will post the official timelines for data submittals on its OASIS.

II.C.2.b: Quarter 2-3: Technical Study

(i) The Transmission Provider will develop base cases that include load and resource data to represent the defined scenarios.

(ii) The Transmission Provider will conduct a combination of powerflow, transient stability studies, post transient power flow or other studies deemed necessary to properly analyze the transmission system.

(iii) The Transmission Provider will consider transmission and non-transmission solutions to mitigate system performance that does not meet reliability criteria. The Transmission Provider may consider the results from prior applicable Economic Studies.

(iv) The Transmission Provider may elect to post interim iterations of the draft plan or preliminary technical study results, and solicit comments prior to the end of the applicable quarter. The Transmission Provider will seek interested Stakeholder input regarding advantages and disadvantages associated with proposed solutions in the transmission plan or technical study.

II.C.2.c: Quarter 4: Decision and Reporting

(i) The Transmission Provider will solicit Stakeholder input when determining selection criteria and weighting to be used in determining the best transmission or non-transmission solution identified in the draft LTP. Advantages and disadvantages to each solution will also be considered.

(ii) Selection criteria may include, but are not limited to, the following:

a. Total present value of upgrade costs
b. Time available to implement upgrade
c. System performance with each solution
d. Probability of scenario requiring a solution
e. Environmental assessment and/or costs
f. Non-quantifiable assessment

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II.D. D. Information Exchange

1.Types of Forecast Data: Stakeholders will submit annually information regarding their needs and proposed expansion plans to facilitate the LTP planning process. The obligation to make such submittals will not replace or supersede any requirements related to service or interconnection requests of point-to-point Transmission Customers and Network Customers or interconnected generators under other relevant sections and appendices of this JOATT. To facilitate the LTP, the Transmission Customer will provide the Transmission Provider the following types of data during the first quarter of every year per the schedule posted on the Transmission Providers' OASIS:

a. Historical Data: monthly historical energy, peak load and minimum load data for the prior calendar year and the historical energy, peak load and minimum load data for all months of the current year as it becomes available.

b. Load Forecast Data: Network Transmission Customer will provide their ten (10) year monthly energy, peak load and resource and minimum load and resource forecast data.

c. Point-to-point and other Transmission Customers: To maximize the effectiveness of the transmission planning process, it is essential that all other Transmission Customers provide their ten (10) year forecast of its projected use of rollover of existing reservations and any expected additional reservations. The forecast will specify the Point of Receipt and Point of Delivery at the bust level.

d. Generation Forecast Data: Stakeholders will provide data from their own generators including, but not limited to, technical engineering data for their generators and interconnection facilities, peak capability (MW) and expected maintenance schedule.

e. Demand Response Resource, Demand Reduction, Conservation and Demand-side Management: Stakeholders will provide demand response resource savings, conservation savings, and other customer load reduction alternatives that would reduce or alter the load of the Transmission Customer.

f. Interruptible and Other: Stakeholders will be asked to supply a peak load forecast with and without the interruptible portion of the forecast data applied.

g. Other Supply Sources: Stakeholders will provide monthly energy and peak data for electrical supply sources not from Generators including, but not limited to, point of receipt and point of delivery.

2. Peak Load Forecast Temperature Adjustment: The Transmission Provider may request the temperature adjustment methodology to adjust the winter and summer peak load forecasts to an alternative (e.g., 1-in-2, 1-in-10 and 1-in-20) probability assumption.

3. Additional Information: Stakeholders will also provide, upon reasonable request, to the Transmission Provider the following information or other information as requested by the Transmission Provider:

a. Discussion of reasons for significant increase or decreases in load or generation forecast.

b. Source and vintage of load forecast and generation resource information.

c. Interruptible JOATT loads and demand response resources.

d. Weather assumptions associated with load forecasts.

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II.F. Cost Allocation

1. Obligations: Cost allocation principles expressed here do not supersede cost obligations as determined by other parts of the JOATT which include but are not limited to transmission service requests, generation interconnection requests, Network Upgrades or Direct Assigned Facilities. Nothing contained in this Attachment K will relieve or modify the obligations of the Transmission Provider or Transmission Customer Pursuant to the JOATT.
2. Cost Allocation for New Projects

   a. The Transmission Provider will utilize a case-by-case approach to allocate costs for new projects. This approach will be based on the following principals:

   i. Open Season Solicitation of Interest: For any project identified in a Transmission Provider planning study (for reliability and/or economic projects) in which the Transmission Provider is the project sponsor, the Transmission Provider may elect to provide an "open season" solicitation of interest to secure additional project participants. Upon a determination by the Transmission Provider to hold an open season solicitation of interest for a project, the Transmission Provider will:
      a. Announce and solicit interest in the project through informational meetings, its website and/or other means of dissemination as appropriate.
      b. Hold meetings with interested parties and meetings with public utility staffs from potentially affected states.
      c. Post information via WECC's planning project review reports.
      d. Develop the initial project specifications, the initial cost estimates and potential transmission line routes; guide negotiations and assist interested parties to determine cost responsibility for initial studies; guide the project through the applicable line siting processes; develop final project specifications and costs; obtain commitments from participants for final project cost shares; and secure execution of construction and operating agreements.

   ii. Transmission Provider Coordination within a Solicitation of Interest Process: The Transmission Provider, whether as a project sponsor or a participant will coordinate as necessary with any other participant or sponsor, as the case may be, to integrate into the Transmission Provider's LTP any planned project on or interconnected with the Transmission Provider's system.

   iii. Transmission Provider Projects without a Solicitation of Interest: The Transmission Provider may elect to proceed with small and/or reliability projects without an open season solicitation of interest, in which case the Transmission Provider will proceed with the project pursuant to its rights and obligations as a Transmission Provider.

(iv) Allocation of Costs:

a. Proportional Allocation: For any project entered into where an open season solicitation process has been used, project costs and associated transmission rights would generally be allocated proportionally to project participants subject to approval of the participation agreement by FERC. In the event the open season process results in a single participant, the full cost and transmission rights will be allocated to that participant.

b. Economic Benefits or Congestion Relief: For a project wholly on the Transmission Provider's system that is undertaken for economic reasons or congestion relief at the request of a Requestor, the project costs will be allocated to the Requestor.

c. Transmission Provider Rate Recovery: Notwithstanding the foregoing provisions, the Transmission Provider will not assume cost responsibility for any project if the cost of the project is not reasonably expected to be recoverable in its retail and/or wholesale rates.

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10. Recovery of Planning Costs: The costs to complete a high priority Local Transmission Provider Economic Planning Study will be recovered through the Transmission Provider's transmission rate base. The cost for Additional Economic Studies will be borne by the sponsor of the Economic Study Request.

Black Hills Colorado Electric, LLC (BHCT)

Black Hills Colorado Electric, LLC, Open Access Transmission Tariff, FERC Docket No. ER23-00957-000, Attachment K (Apr. 1, 2023), retrieved from https://etariff.ferc.gov/TariffBrowser.aspx?tid=2302 (last accessed Dec. 18, 2024).

Attachment K

I. Overview of the Black Hills Colorado Electric, LLC Transmission Planning Process

Black Hills Colorado Electric, LLC ("Black Hills"), is a vertically integrated public utility engaged in the business of generating, transmitting and distributing electricity in south central Colorado.

Black Hills' transmission planning process is intended to facilitate the development of electric infrastructure that maintains reliability, responds to service requests and meets load growth, and is based on the following objectives:

- Maintain reliable electric service.
- Improve the efficiency of electric system operations, including the provision of open and non-discriminatory access to its transmission facilities.

- Identify and promote new investments in transmission infrastructure in a coordinated, open, transparent and participatory manner.

The transmission planning process conducted by Black Hills includes a series of open planning meetings that allows interested parties, including, but not limited to, NITS and PTP customers, sponsors of transmission solutions, generation solutions and solutions utilizing demand response resources, interconnected transmission providers, state and local regulatory bodies and other stakeholders (jointly, "Stakeholders"), input into and participation in all stages of development of the transmission plan.

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I.A. Definitions

1. LTP**:** Local Transmission Plan is the transmission plan of Black Hills that identifies the upgrades and other investments to the Transmission System or demand response necessary to reliably satisfy, over the planning horizon, Network Customers' resource and load growth expectations for designated Network Load; Black Hills' resource and load growth expectations for Native Load Customers; Black Hills' obligations pursuant to grandfathered, non-OATT agreements; and the Black Hills' Point-to-Point customers' projected service needs including obligations for rollover rights.

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II. Local Planning Process

II.C. Preparation of a LTP

1. Black Hills will prepare, with the input of interested Stakeholders, one LTP every year. The preparation of the LTP will be done in accordance with the general policies, procedures, and principles set forth in this Attachment K.

2. Black Hills will establish a process by which Stakeholders can discuss, question, or propose alternatives for input assumptions and upgrades identified by Black Hills. Black Hills will consider information obtained from Stakeholders for future planning cycles. Black Hills may, following Stakeholder input, also include results of completed Economic Studies.

3. Black Hills will use a ten (10) year or other applicable planning horizon for the LTP. The transmission planning process will use reliability criteria established by Black Hills, WECC, NERC and FERC.

4. The LTP on its own does not effectuate any transmission service requests. Transmission Service Requests must be made in accordance with the procedures set forth in Part II of the OATT and posted on Black Hills' OASIS. Similarly, Network Customers must submit Network Resource and load additions or removals pursuant to the process described in Part III of the OATT.

5. Black Hills will take the LTP into consideration, as appropriate when preparing generation interconnect, transmission service and economic studies. Black Hills will take the generation interconnect, transmission service and economic study results into consideration as appropriate when preparing the LTP.

6. Black Hills will prepare and develop the LTP using an open and coordinated process that includes input from Stakeholders as defined in Section II.D.3. Stakeholder input will occur at various phases throughout the study process consistent with the principles, practices, policy and procedures set forth in this Attachment K. Black Hills, with interested Stakeholder input, will: (1) determine the Study Plan, define scenarios and develop base cases related to the LTP; (2) perform the Technical Study; (3) determine the preliminary LTP, based on the data produced during the Technical Study and if applicable, include timely submitted Economic Study Request results; and (4) report study results and the LTP to Stakeholders and Affected Parties.

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II.G. <u>Cost Allocation</u>

1. <u>Obligations</u>: Cost allocation principles expressed here do not supersede cost obligations as determined by other parts of the OATT which include but are not limited to transmission service requests, generation interconnection requests, Network Upgrades or Direct Assigned Facilities. Nothing contained in this Attachment K will relieve or modify the obligations of Black Hills or Transmission Customer Pursuant to the OATT.

2. <u>Cost Allocation for New Projects</u>

   a. Black Hills will utilize a case-by-case approach to allocate costs for new projects. This approach will be based on the following principals:

      (i) Open Season Solicitation of Interest: For any project identified in a transmission provider planning study (for reliability and/or economic projects) in which Black Hills is the project sponsor, Black Hills may elect to provide an “open season” solicitation of interest to secure additional project participants. Upon a determination by Black Hills to hold an open season solicitation of interest for a project, Black Hills will:

         (a) Announce and solicit interest in the project through informational meetings, its website and/or other means of dissemination as appropriate.

         (b) Hold meetings with interested parties and meetings with public utility staffs from potentially affected states.

         (c) Post information via WECC’s planning project review reports.

         (d) Develop the initial project specifications, the initial cost estimates and potential transmission line routes; guide negotiations and assist interested parties to determine cost responsibility for initial studies; guide the project through the applicable line siting processes; develop final project specifications and costs; obtain commitments from participants for final project cost shares; and secure execution of construction and operating agreements.

(ii) Black Hills Coordination within a Solicitation of Interest Process: Black Hills, whether as a project sponsor or a participant will coordinate as necessary with any other participant or sponsor, as the case may be, to integrate into Black Hills' LTP any planned project on or interconnected with Black Hills' system.

(iii) Black Hills Projects without a Solicitation of Interest: Black Hills may elect to proceed with small and/or reliability projects without an open season solicitation of interest, in which case Black Hills will proceed with the project pursuant to its rights and obligations as Black Hills.

(iv) Allocation of Costs:

(a) Proportional Allocation: For any project entered into where an open season solicitation process has been used, project costs and associated transmission rights would generally be allocated proportionally to project participants subject to approval of the participation agreement by FERC. In the event the open season process results in a single participant, the full cost and transmission rights will be allocated to that participant.

(b) Economic Benefits or Congestion Relief: For a project wholly on Black Hills' system that is undertaken for economic reasons or congestion relief at the request of a Requestor, the project costs will be allocated to the Requestor.

(c) Black Hills Rate Recovery: Notwithstanding the foregoing provisions, Black Hills will not assume cost responsibility for any project if the cost of the project is not reasonably expected to be recoverable in its retail and/or wholesale rates.

3. Regional Cost Allocation: The cost allocation for regional projects will be allocated consistent with the cost allocation principles of West Connect (see Attachment K Hyperlink List

Cheyenne Light, Fuel & Power Company (CLPT)

Cheyenne Light, Fuel & Power Company, Open Access Transmission Tariff, FERC Docket No. ER23-00958-000, Attachment K (Jan. 27, 2023), retrieved from: https://etariff.ferc.gov/TariffBrowser.aspx?tid=3375 (last accessed Dec. 18, 2024).

Attachment K

I. Overview of the Cheyenne, Light Fuel and Power Company Transmission Planning Process

Attachment B

Cheyenne Light, Fuel and Power Company ("Cheyenne Light"), is a vertically integrated public utility engaged in the business of generating, transmitting and distributing electricity in southeastern Wyoming.

Cheyenne Light's transmission planning process is intended to facilitate the development of electric infrastructure that maintains reliability, responds to service requests and meets load growth, and is based on the following objectives:

- Maintain reliable electric service.
- Improve the efficiency of electric system operations, including the provision of open and non-discriminatory access to its transmission facilities.
- Identify and promote new investments in transmission infrastructure in a coordinated, open, transparent and participatory manner.

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I.A. Definitions

1. LTP**:** Local Transmission Plan is the transmission plan of Cheyenne Light that identifies the upgrades and other investments to the Transmission System or demand response necessary to reliably satisfy, over the planning horizon, Network Customers' resource and load growth expectations for designated Network Load; Cheyenne Light's resource and load growth expectations for Native Load Customers; Cheyenne Light's obligations pursuant to grandfathered, non-OATT agreements; and the Cheyenne Light's Point-to-Point customers' projected service needs including obligations for rollover rights.

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II. Local Planning Process . . . .

C. Preparation of a LTP . . . .

3. Cheyenne Light will use a ten (10) year or other applicable planning horizon for the LTP. The transmission planning process will use reliability criteria established by Cheyenne Light, WECC, NERC and FERC. . . .

5. Cheyenne Light will take the LTP into consideration, as appropriate when preparing generation interconnect, transmission service and economic studies. Cheyenne Light will take the generation interconnect, transmission service and economic study results into consideration as appropriate when preparing the LTP. . . .

II.D.2.a.(i):

Cheyenne Light will gather: (1) Network Customers' projected loads and resources, and load growth expectations (based on annual updates under Part III of the OATT); (2) Cheyenne Light's projected loads and resource needs for its Native Load Customers; (3) Point-to-Point Customer's projections for long-term (greater than 1 year) needs at each receipt and delivery point (based on information submitted by Eligible Customers to Cheyenne Light) including projections of rollover rights; (4) information from all Transmission Customers and Cheyenne Light on behalf of Native Load Customers concerning existing and planned demand resources and their impact on demand and peak demand and (5) information from sponsors of transmission solutions, generating solutions and solutions utilizing demand response resources. Cheyenne Light will take into consideration, to the extent known or which may be obtained from its Transmission Customers and Stakeholders, obligations that will either commence or terminate during the applicable study window. Customer Economic Study Requests will also be submitted to Cheyenne Light during this quarter. Cheyenne Light will, with Stakeholder input, define the proposed LTP study scope, objectives, scenarios to be considered in development of the LTP. Cheyenne Light will post the official timelines for data submittals on its OASIS.

II.D.2.b: Quarter 2-3: Technical Study

(i) Cheyenne Light will develop base cases that include load and resource data to represent the defined scenarios.

(ii) Cheyenne Light will conduct a combination of power-flow, transient stability studies, post transient power flow or other studies deemed necessary to properly analyze the transmission system.

(iii) Cheyenne Light will consider transmission and non-transmission solutions to mitigate system performance that does not meet reliability criteria. Cheyenne Light may consider the results from prior applicable Economic Studies.

(iii) Cheyenne Light may elect to post interim iterations of the draft plan or preliminary technical study results, and solicit comments prior to the end of the applicable quarter. Cheyenne Light will seek interested Stakeholder input regarding advantages and disadvantages associated with proposed solutions in the transmission plan or technical study.

II.D.2.c Quarter 4: Decision and Reporting

(i) Cheyenne Light will solicit Stakeholder input when determining selection criteria and weighting to be used in determining the best transmission or non-transmission solution identified in the draft LTP. Advantages and disadvantages to each solution will also be considered.

(ii) Selection criteria may include, but are not limited to, the following:

(a) Total present value of upgrade costs

(b) Time available to implement upgrade

(c) System performance with each solution

(d) Probability of scenario requiring a solution

(e) Environmental assessment and/or costs

(f) Non-quantifiable assessment

Attachment B

II.E. Information Exchange

1. Types of Forecast Data: Stakeholders will submit annually information regarding their needs and proposed expansion plans to facilitate the LTP planning process. The obligation to make such submittals will not replace or supersede any requirements related to service or interconnection requests of point-to-point Transmission Customers and Network Customers or interconnected generators under other relevant sections and appendices of this OATT. To facilitate the LTP, the Transmission Customer will provide Cheyenne Light the following types of data during the first quarter of every year per the schedule posted on Cheyenne Lights' OASIS:
   a. Historical Data: monthly historical energy, peak load and minimum load data for the prior calendar year and the historical energy, peak load and minimum load data for all months of the current year as it becomes available.
   b. Load Forecast Data: Network Transmission Customer will provide their ten (10) year monthly energy, peak load and resource and minimum load and resource forecast data.
   c. Point-to-point and other Transmission Customers: To maximize the effectiveness of the transmission planning process, it is essential that all other Transmission Customers provide their ten (10) year forecast of its projected use of rollover of existing reservations and any expected additional reservations. The forecast will specify the Point of Receipt and Point of Delivery at the bust level.
   d. Generation Forecast Data: Stakeholders will provide data from their own generators including, but not limited to, technical engineering data for their generators and interconnection facilities, peak capability (MW) and expected maintenance schedule.
   e. Demand Response Resource, Demand Reduction, Conservation and Demand-side Management: Stakeholders will provide demand response resource savings, conservation savings, and other customer load reduction alternatives that would reduce or alter the load of the Transmission Customer.
   f. Interruptible and Other: Stakeholders will be asked to supply a peak load forecast with and without the interruptible portion of the forecast data applied.
   g. Other Supply Sources: Stakeholders will provide monthly energy and peak data for electrical supply sources not from Generators including, but not limited to, point of receipt and point of delivery.
2. Peak Load Forecast Temperature Adjustment: Cheyenne Light may request the temperature adjustment methodology to adjust the winter and summer peak load forecasts to an alternative (e.g., 1-in-2.11-in-10 and 1-in-20) probability assumption.
3. Additional Information: Stakeholders will also provide, upon reasonable request, to Cheyenne Light the following information or other information as requested by Cheyenne Light:

a. Discussion of reasons for significant increase or decreases in load or generation forecast.
b. Source and vintage of load forecast and generation resource information.
c. Interruptible OATT loads and demand response resources.
d. Weather assumptions associated with load forecasts.

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II.G. Cost Allocation

1. Obligations: Cost allocation principles expressed here do not supersede cost obligations as determined by other parts of the OATT which include but are not limited to transmission service requests, generation interconnection requests, Network Upgrades or Direct Assigned Facilities. Nothing contained in this Attachment K will relieve or modify the obligations of Cheyenne Light or Transmission Customer Pursuant to the OATT.

2. Cost Allocation for New Projects

a. Cheyenne Light will utilize a case-by-case approach to allocate costs for new projects. This approach will be based on the following principals:

(i) Open Season Solicitation of Interest: For any project identified in a transmission provider planning study (for reliability and/or economic projects) in which Cheyenne Light is the project sponsor, Cheyenne Light may elect to provide an "open season" solicitation of interest to secure additional project participants. Upon a determination by Cheyenne Light to hold an open season solicitation of interest for a project, Cheyenne Light will:

(a) Announce and solicit interest in the project through informational meetings, its website and/or other means of dissemination as appropriate.

(b) Hold meetings with interested parties and meetings with public utility staffs from potentially affected states.

(c) Post information via WECC's planning project review reports.

(d) Develop the initial project specifications, the initial cost estimates and potential transmission line routes; guide negotiations and assist interested parties to determine cost responsibility for initial studies; guide the project through the applicable line siting processes; develop final project specifications and costs; obtain commitments from participants for final project cost shares; and secure execution of construction and operating agreements.

(ii) Cheyenne Light Coordination within a Solicitation of Interest Process: Cheyenne Light, whether as a project sponsor or a participant will coordinate as necessary with any other participant or sponsor, as the case may be, to integrate into Cheyenne Light's LTP any planned project on or interconnected with Cheyenne Light's system.

(iii) Cheyenne Light Projects without a Solicitation of Interest: Cheyenne Light may elect to proceed with small and/or reliability projects without an open season solicitation of interest, in which case Cheyenne Light will proceed with the project pursuant to its rights and obligations as Cheyenne Light.

(iv) Allocation of Costs:

(a) Proportional Allocation: For any project entered into where an open season solicitation process has been used, project costs and associated transmission rights would generally be allocated proportionally to project participants subject to approval of the participation agreement by FERC. In the event the open season process results in a single participant, the full cost and transmission rights will be allocated to that participant.

(b) Economic Benefits or Congestion Relief: For a project wholly on Cheyenne Light's system that is undertaken for economic reasons or congestion relief at the request of a Requestor, the project costs will be allocated to the Requestor.

(c) Cheyenne Light Rate Recovery: Notwithstanding the foregoing provisions, Cheyenne Light will not assume cost responsibility for any project if the cost of the project is not reasonably expected to be recoverable in its retail and/or wholesale rates.

3. Regional Cost Allocation: The cost allocation for regional projects will be allocated consistent with the cost allocation principles of WestConnect

El Paso Electric Company (EPE) –

El Paso Electric Company, Open Access Transmission Tariff, FERC Electric Tariff, Volume No. I, Attachment K, retrieved from: https://www.epelectric.com/files/html/Transmission/OATT%20effective%2007%2012%202024.pdf (last accessed Dec. 18, 2024)

Attachment K – Transmission Planning Process

I. El Paso Electric Company Local Transmission Planning

1. Overview

EPE transmission planning process will consist of an assessment of the following needs:

a. Providing adequate transmission to access sufficient resources (supply or demand resources) in order to reliably and economically serve retail, wholesale and network loads in the EPE service area;

b. Where feasible, identifying non-transmission alternatives such as demand response resources that could meet or mitigate the need for new transmission;

c. Supporting EPE’s local transmission and sub-transmission systems; and

d. Coordinating new interconnections with other transmission systems.

2. Transmission Planning Cycle, 10-Year System Expansion Plan and EPE Transmission System

b. The purpose of the Plan will be to identify and evaluate, on a regular basis, any future electric transmission system modifications and additions or alternatives that may be required to serve the anticipated area load growth or other customers’ transmission needs in the EPE service territory for a ten year planning horizon. The transmission facilities in EPE's local transmission plan are not subject to approval at the regional level unless EPE seeks to have such transmission facilities selected in the regional plan for purposes of regional cost allocation.

3. Stakeholder’s Responsibility for Providing Data

a. . . . the EPE planning cycle typically will commence with the issuance by EPE of a notice to Stakeholders that wish to have their needs considered, including sponsors of transmission solutions, generation solutions and solutions utilizing demand response resources, or other non-transmission alternatives, in EPE’s Plan to submit information and data regarding their needs

b. EPE will use the information and data provided by such Stakeholders to, among other things, assess network load and generation and demand resource projections, transmission needs, operating dates and retirements for generation resources in EPE’s system and to update regional models used to conduct planning studies.

. . .

d. Information Submitted by Stakeholders

(i)Point-to-point Transmission Customers, Network Customers, interconnected generators, prospective providers of demand-side management and sponsors of transmission solutions, generation solutions and solutions utilizing demand response resources or other non-transmission alternatives, and other customers must provide information to EPE over a ten year planning horizon regarding their needs, proposed expansion plans and updates to previously provided forecasts to the extent they wish to have such information included in developing the EPE Plan. The obligation to make such submittals, however, will not replace or supersede any requirements related to service or interconnection requests of point-to-point Transmission Customers and Network Customers or interconnected generators under other relevant sections and appendices of EPE’s Open Access Transmission Tariff (“OATT”).

(ii) Information for projected loads and resources, including demand response resources, provided by Stakeholders must be submitted in a form that matches the load and resource information developed by System Planning at EPE. The specific power flow and stability program used by EPE and the related data format for both load and generator data will be posted on EPE’s OASIS.

(iii) For loads and demand response resources, the submitted data must include both MW and MVAR (both peak and off-peak values) and for generators, it must include D-Curves, terminal voltage, MW maximum and minimum capabilities and step-up transformer data. Stability data will depend on the type of generator. The format for this information will be supplied to the generator as needed.

(v) In order to preserve the effectiveness of the EPE planning cycle, Stakeholders must provide relevant data for their ten year needs as described above for the following, consistent with protection requirements for Critical Energy Infrastructure Information ("CEII") and proprietary and confidential information:

3 Generators – planned additions or upgrades (including status and expected in-service date), planned retirements, and environmental restrictions. Such data submittals, however, will not replace or supersede any requirements for interconnected generators under other relevant sections and appendices of EPE's OATT. [*sic*]

(b) Demand response resources – existing and planned demand resources and their impacts on demand and peak demand.

(c) Network Customers – forecast information for load and resource requirements and identification of demand response reductions.

(d) Point-to-point Transmission Customers – projections of need for service, including transmission capacity, duration and receipt and delivery points. Such data submittals, however, will not replace or supersede any requirements for transmission service requests under other relevant sections and appendices of EPE's OATT.

(e) Transmission sponsors – planned additions or upgrades (including status and expected in-service date) and planned retirements.

9. EPE Planning Methodology and Protocols

a. Data, Assumptions and Criteria. EPE's power flow base cases for the Plan will be structured using data from WECC base cases. EPE will review and modify as needed transformer and transmission line data, substation load data as per the most recent native system load forecast and resource data, including Stakeholder data received in a timely manner. The Stakeholder data will include data from sponsors of transmission solutions, generation solutions and solutions utilizing demand resources. EPE planning case assumptions will be chosen to model the maximum stress on the EPE system. EPE will use reliability criteria established by WECC and NERC, such as Reliability Standards TPL-001 through TPL004, and internal EPE criteria as published in EPE's annual Federal Energy Regulatory Commission ("FERC") Form No. 715, to determine if system plan cases meet acceptable criteria and, if not, what facilities are needed to meet that requirement. Data compiled by EPE in connection with the development of its Plan will be provided to regional and subregional planners, through EPE's data submittal to the WECC database as outlined in Exhibit 1, to update their models, which in turn will be used in subsequent system Plans by EPE and potentially by others. This data will then be used in the economic planning studies performed by West Connect, TEPPC, EPE or a Requester.

b. EPE and Stakeholder Alternative Solutions Evaluation Basis. EPE's planning process is an objective process that evaluates use of the transmission system on a comparable basis for all customers. All solution alternatives that have been presented on a timely basis (per Section I.A.3 of this Attachment K), including transmission solutions, generation solutions and solutions utilizing demand response resources or other non-transmission alternatives, whether presented by EPE or another Stakeholder, will be evaluated on a comparable basis. The same criteria and evaluation process will be applied to competing solutions and/or projects, regardless of type or class of Stakeholder. Solution alternatives will be evaluated against one another on the basis of the following criteria to select the preferred solution or combination of solutions: (1) ability to practically fulfill the identified need; (2) ability to meet applicable reliability criteria or NERC Planning Standards issues; (3) technical, operational and financial feasibility; (4) operational benefits/constraints or issues; (5) cost-effectiveness over the time frame of the study or the life of the facilities, as appropriate (including adjustments, as necessary, for operational benefits/constraints or issues, including dependability); and (6) where applicable, consistency with State or local integrated resource planning requirements, or regulatory requirements, including cost recovery through regulated rates.

NV Energy, Inc.

Nevada Power Company and Sierra Pacific Power Company ("NV Energy")

Nevada Power Company and Sierra Pacific Power Company, Open Access Transmission Tariff, Docket No. ER15-179-000, Attachment K, effective Nov. 1, 2014, retrieved from: http://www.oasis.oati.com/woa/docs/NEVP/NEVPdocs/OATT_Effective_1-21-24.pdf (last accessed Dec. 18, 2024).

Attachment K

Preamble

In accordance with the Commission's regulations, Transmission Provider's planning process is performed on a local, regional, and interregional basis. Part A of this Attachment K addresses the local planning process. Part B of this Attachment K addresses the regional planning process. Part C of this Attachment K addresses interregional coordination with the planning regions in the United States portion of the Western Interconnection. Thereafter, Part D of this Attachment K addresses local and regional Economic Study Requests and Part E of this Attachment K provides a Dispute Resolution process for addressing related procedural or substantive concerns that may arise.

1. Definitions . . . .

1.39 Local Transmission Plan or LTP

"Local Transmission Plan" or "LTP" means a transmission provider's plan (depending upon context, the Transmission Provider or an Enrolled Party) that identifies planned new transmission facilities and facility replacements or upgrades for such transmission provider's Transmission System.

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Part A. Local Planning Process

2 Preparation of a Local Transmission Plan

2.1 Local Transmission Plan With the input of affected stakeholders, Transmission Provider shall prepare one (1) Local Transmission Plan during each two-year Planning Cycle. The Transmission Provider shall evaluate the Local Transmission Plan by modeling the effects of up to two (2) local Economic Study Requests per each two-year study cycle, if timely requests are submitted by Eligible Customers and/or stakeholders in accordance with Section 3 and Part D of this Attachment K. The planning horizon for the Local Transmission Plan consists of a Near Term Case (years 1-5) and Longer Term Case (years 6-10). If an Eligible Customer's local Economic Study Request, submitted pursuant to Section 21, specifically identifies a future new resource location on a 20-year horizon, the Longer Term Case will be extended to years 6- 20. Although the Local Transmission Plan is developed biannually, the Transmission Provider annually assesses the plan.

3.2 Sequence of Events

3.2.1 Quarter 1 (of the first year of the Planning Cycle)

a. Select Near Term summer/winter base cases from WECC;

b. Gather and allocate aggregate loads and load growth forecasts for Network Customers;

c. Gather and allocate aggregate load forecasts for Native Customers (based on annual updates and other information that may be available);

d. Identify any new generation resources and any expected or planned Demand Response Resources and their associated impacts on demand and peak demand for Network and Native Load Customers (based on its state mandated integrated resource plan, to the extent that such an obligation exists, or through other planning resources);

e. Identify point-to-point transmission service customers' projections for service at each receipt and delivery point (based on information submitted by the customer to the Transmission Provider) including projected use of rollover rights; and . . .

3.2.2 Quarter 2 (of the first year of the Planning Cycle) Transmission Provider will define and post on OASIS the basic methodology, criteria, assumptions, databases, and processes the Transmission Provider will use to prepare the Near Term Local Transmission Plan. The Transmission Provider will insert its system details in Near Term summer and winter peak WECC base cases for purposes of conducting its studies; assess the timely submitted local Economic Study Requests for the summer/winter WECC base cases using the previous biennial cycle's Local Transmission Plan as a reference; and select one Economic Study for evaluation during the first year of the current biennial cycle.

3.2.3 Quarters 3 and 4 (of the first year of the Planning Cycle)

. . . All stakeholder submissions will be evaluated on a basis comparable to data and submissions required for planning the transmission system for both retail and wholesale customers, and alternative proposals will be evaluated based on a comparison of their relative economics and ability to meet reliability criteria. The Transmission Provider may elect to post interim iterations of the draft Near Term Local Transmission Plan, consider economic modeling results, and solicit public comment prior to the end of the applicable quarter. Transmission Provider will post on its OASIS the 30-day notice for its public meeting to present, solicit, and receive comments on Transmission Provider's draft Near Term Local Transmission Plan, and Transmission Provider will subsequently conduct the public meeting to review the draft Near Term Local Transmission Plan. Transmission Provider will finalize the Near Term Local Transmission Plan taking into account (1) the Economic Study Request modeling results, if any; (2) written comments received from the owners and operators of interconnected transmission systems; (3) written comments received from Transmission Customers and other stakeholders; and (4) timely comments submitted during the public meetings, as set forth in Section 3.3, below.

3.2.4 Quarter 4 (of the first year of the Planning Cycle)

Transmission Provider will finalize the annual assessment of its Near Term Local Transmission Plan; include updated information on loads, resources, and existing transmission projects; and add new projects.

3.2.5 Quarter 5 (of the second year of the Planning Cycle)

Transmission Provider will:

a. Gather and allocate aggregate loads and load growth forecasts for Network Customers;

b. Gather and allocate aggregate load forecasts for Native Load Customers (based on annual updates and other available information);

c. Identify any new generation resources and any expected or planned Demand Response Resources and their associated impacts on demand and peak demand for Network and Native Load Customers (based on its state mandated integrated resource plan, to the extent that such an obligation exists, or through other planning resources);

d. Identify point-to-point transmission service customers' projections for service at each receipt and delivery point (based on information submitted by the customer to the Transmission Provider) including projected use of rollover rights; and

e. Gather transmission needs driven by Public Policy Requirements submitted by stakeholders.

The Transmission Provider shall take into consideration, to the extent known or which may be obtained from its Transmission Customers and active queue requests, contractual obligations that will either commence or terminate during the applicable study window. Any stakeholder may submit data to be evaluated as part of the preparation of the draft Longer Term Local Transmission Plan, and/or the development of sensitivity analyses. Such data may include alternative solutions to the identified needs set out in prior Longer Term Local Transmission Plans, Public Policy Requirements, and transmission needs driven by Public Policy Requirements. In doing so, the stakeholder shall submit the data and/or proposals as specified in the Transmission Provider's "Business Practice: Transmission Planning," available on Transmission Provider's OASIS . . . .

All stakeholder submissions, including transmission needs driven by Public Policy Requirements, will be evaluated on a basis comparable to data and submissions required for planning the transmission system for both retail and wholesale customers, and alternative proposals, including proposals driven by Public Policy Requirements, will be evaluated based on a comparison of their relative economics and ability to meet reliability criteria. The Transmission Provider will define and post on its OASIS the basic methodology, criteria, assumptions, databases, and processes that will be used to prepare the Longer Term Local Transmission Plan; reassess the Near Term Local Transmission Plan developed in Quarter 3, to include relevant customer input; and accept local Economic Study Requests that are timely submitted in accordance with Part D, Section 21.3 of this Attachment K.

6 Cost Allocation

Cost allocation principles expressed here are applied in a planning context for purposes of transparency and do not supersede cost obligations as determined by other parts of the Transmission Provider's Tariff, which include but are not limited to transmission service requests, generation interconnection requests, Network Upgrades, or Direct Assignment Facilities, or as may be determined by any state having jurisdiction over the Transmission Provider.

6.1 Individual Transmission Service Request Costs Not Considered

The costs of upgrades or other transmission investments subject to an existing transmission service request submitted pursuant to Transmission Provider's Tariff are evaluated in the context of that transmission service request. Nothing contained in this Attachment K shall relieve or modify the obligations of the Transmission Provider or the requesting Transmission Customer that they may have under Transmission Provider's Tariff.

6.2 Categories of Included Costs

The Transmission Provider shall categorize projects set forth in the Local Transmission Plan, for purposes of allocating costs, into the following types:

a. Type 1: Type 1 transmission line costs are those related to the provision of service to the Transmission Provider's Native Load Customers. Type 1 costs include, to the extent such agreements exist, costs related to service to others pursuant to grandfathered transmission agreements that are considered by the Transmission Provider to be Native Load Customers.

b. Type 2: Type 2 costs are those related to the sale or purchase of power at wholesale to non-Native Load Customers.

c. Type 3: Type 3 costs are those incurred specifically as alternatives to (or deferrals of) transmission line costs (typically Type 1 projects), such as the installation of distributed resources (including distributed generation, load management and energy efficiency). Type 3 costs do not include Demand Response Resource projects, which do not have the effect of deferring or displacing Type 1 costs.

6.3 Cost Allocation Principles

Unless an alternative cost allocation process is utilized and described in the Local Transmission Plan, the Transmission Provider shall identify anticipated cost allocations in the Local Transmission Plan based upon the end-use characteristics of the project according to categories of costs set forth above and the following principles:

a. Principle 1: The Commission's regulations, policy statements and precedent on transmission pricing shall be followed.
b. Principle 2: To the extent not in conflict with Principle 1, costs will be allocated consistent with the provisions of Section 17 of this Attachment K.

6.4 Rate Recovery

Notwithstanding any other section of this Attachment K, Transmission Provider will not assume cost responsibility for any project if the cost of the project is not reasonably expected to be recoverable in its retail and/or wholesale rates.

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8. Recovery of Planning Costs

Unless Transmission Provider allocates planning-related costs to an individual stakeholder as set out herein, or as otherwise permitted under the Tariff, all costs incurred by the Transmission Provider related to the Local Transmission Plan process or the regional or interregional planning processes shall be included in the Transmission Provider's transmission rate base.

Public Service Company of Colorado (PSCo)

Open Access Transmission Tariff of Northern States Power Company, Public Service Company of Colorado, and Southwestern Public Service Company, the Utility Operating Company Subsidiaries of Xcel Energy Inc., FERC FPA Electric Tariff Third Revised Volume No. 1, Attachment R, effective Apr. 16, 2016, retrieved from https://corporate.my.xcelenergy.com/s/transmission/oasis-oatt (last accessed Dec. 18, 2024).

Transmission Planning Process of Public Service Company of Colorado

I. Overview of the PSCo Transmission Planning Process

Public Service Company of Colorado ("PSCo" or the "Company") is a vertically integrated public utility engaged in the business of generating, transmitting and distributing electricity in the state of Colorado in the Western Interconnection. PSCo provides Point-to-Point ("PTP") and Network Integration Transmission Services ("NITS") under the Xcel Energy Operating

Companies' Joint Open Access Transmission Tariff ("Joint OATT") and non-OATT transmission services pursuant to certain grandfathered agreements ("GFAs"). The native loads of PSCo are subject to the non-rate terms and conditions of the Joint OATT.

PSCo's transmission planning process is intended to facilitate the development of electric infrastructure that maintains reliability, responds to service requests and meets load growth, and is based on the following objectives:

- Maintain reliable electric service.
- Improve the efficiency of electric system operations, including the provision of open and non-discriminatory access to its transmission facilities.
- Identify and promote new investments in transmission infrastructure in a coordinated, open, transparent and participatory manner.

II. PSCo Local Transmission Planning

Participation in PSCo's local transmission planning process is open to all affected parties, including but not limited to all PTP and NITS transmission and interconnection service customers, sponsors of transmission solutions, generation solutions, and solutions utilizing demand response resources, state and local authorities, and other Stakeholders.

***

B. Types of Planning Studies

1. Reliability Planning Studies

Reliability planning studies are performed to ensure that all NITS and PTP customer and PSCo retail native load customer requirements for planned loads and resources, including demand response resources, are met for each year of the ten year planning horizon, and that all North American Electric Reliability Corporation ("NERC"), WECC, and local Reliability Standards are met. These reliability planning studies shall be coordinated with WestConnect and other regional transmission planning organizations as appropriate. The Reliability Planning Study Process is described below in Section C.

2. Economic Planning Studies

The purpose of economic planning studies is to identify significant and recurring congestion on the PSCo transmission system and/or address the integration of new resources and/or loads. Such studies may analyze any, or all, of the following: (i) the location and magnitude of the congestion, (ii) possible remedies for the elimination of the congestion, (iii) the associated costs of congestion, (iv) the costs associated with relieving congestion through system enhancements (or other means), and, as appropriate (v) the economic impacts of integrating new resources or/and loads. The process for requesting and conducting Economic Planning Studies is discussed in Section D below.

3. Public Policy Requirements

For purposes of this Attachment R-PSCo, “Public Policy Requirements” means those requirements enacted by state or federal laws or regulations, including those enacted by local governmental entities, such as a municipality or county. Public Policy Requirements, as applicable, are incorporated into the load forecasts and/or are modeled in the local planning studies. For example, PSCo considers Public Policy Requirements in accordance with the Colorado renewable energy standard and resource adequacy plans that are consistent with the Colorado Electric Resource Plan. Proposed public policy (public policy proposed before a governmental authority but not yet enacted) may be studied if time and resources permit.

C. PSCo Reliability Transmission Planning Study Process

1. Transmission Plan Needs Assessment

PSCo’s transmission planning process consists of an assessment of the following

needs:

- To provide adequate transmission to access sufficient resources in order to reliably and economically serve retail and wholesale loads.
- Where feasible, to integrate proposed alternatives such as demand response resources that could meet or mitigate the need for transmission additions or upgrades.
- To support PSCo’s local transmission and sub-transmission systems.
- To provide for interconnections for new generation resources and load service.
- To coordinate new transmission-to-transmission interconnections with other transmission systems.
- To accommodate requests for long-term transmission access.
- To consider local transmission needs driven by Public Policy Requirements.

2. Transmission Customer’s Responsibility for Providing Data

a. PSCo uses information provided by its transmission customers to, among other things, assess network load and resource projections (including demand response resources), transmission needs, in-service dates and retirements for generation resources on PSCo’s system, and to update interregional and regional models used to conduct planning studies.

b. Submission of Data by NITS and PTP Transmission Customers
NITS and PTP Customers are required to submit their projected network load and network resources (including demand response resources) for the upcoming ten year period, pursuant to the Joint OATT. NITS and PTP customers shall also be required to provide the additional data listed in sections d.(iii) and (iv) below, pursuant to the Joint OATT and pursuant to any contractual agreements, by September 1 each year.

…

d. Transmission Customer Data to be Submitted

To the maximum extent practical and consistent with protection of proprietary or confidential information, data submitted by NITS customers and PTP customers should provide the following information for the ten year planning horizon:

(i) Generators – planned additions or upgrades (including status and expected in-service dates), planned retirements, planned permanent derates, and environmental restrictions.
(ii) Demand response resources – existing and planned demand resources and their impacts on demand and peak demand.
(iii) NITS customers – forecast information for load and resource requirements over the planning horizon and identification of generation resources and demand response reductions.
(iv) PTP customers – projections of need for service over the planning horizon, including transmission capacity, duration, and receipt and delivery points.

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7. PSCo Transmission Planning Study Criteria and Guidelines
Stakeholders should refer to the Xcel Energy Interconnection Guidelines for PSCo planning criteria, guidelines and assumptions. (See PSCo Attachment R Hyperlinks List posted on the PSCo OASIS

Public Service Company of New Mexico (PNM) –
Open Access Transmission Tariff of Public Service Company Of New Mexico, FERC Docket No. ER20-03041-000, Attachment K, effective Jan 10, 2021, retrieved from https://etariff.ferc.gov/TariffBrowser.aspx?tid=2177 (last accessed Dec. 18, 2024).

Attachment K – Transmission Planning Process

I. Overview of the PNM Transmission Planning Process.

PNM is a vertically integrated public utility engaged in the generation and transmission of electric power and energy in the states of New Mexico and Arizona and in the distribution of electric power and energy in the State of New Mexico. PNM provides electric transmission and related reliability services under state and federal statutes and regulations. PNM's transmission planning process is based on the following three core objectives:

• Maintain safe and reliable electric service;
• Improve the efficiency of electric system operations, including the provision of open and non-discriminatory access to the transmission facilities under its control; and
• Identify and promote new investments in transmission infrastructure in a coordinated, open, transparent and participatory manner.

PNM's transmission planning process is intended to facilitate a timely, coordinated and transparent process that fosters the development of electric infrastructure that both maintains reliability and meets load growth so that PNM can continue to provide reliable and cost-effective service to its customers.

The PNM transmission planning process includes a series of open planning meetings that PNM will conduct at least twice a year to allow anyone including, but not limited to, network and point-to-point transmission service customers, sponsors of transmission solutions, generation solutions and solutions utilizing non-transmission alternatives ("NTAs"), interconnected neighbors, regulatory and state bodies and other stakeholders, input into and comment on the PNM transmission plan through all stages of its development.

In addition to its local transmission planning process, PNM coordinates its transmission planning with other transmission providers and stakeholders in the Desert Southwest area, and the Western Interconnection as a whole, through its active participation in the Southwest Area Transmission Planning ("SWAT") group, membership in WestConnect,1 membership in the Western Electricity Coordinating Council ("WECC") and participation in the WECC Transmission Expansion Planning Policy Committee ("TEPPC") and its Technical Advisory Subcommittee ("TAS").

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II. PNM Local Transmission Planning

A. PNM Planning Process

Participation in PNM's local planning process is open to all affected parties, including but not limited to, all network and point-to-point transmission customers, sponsors of transmission solutions, generation solutions and solutions utilizing NTAs, interconnected neighbors, regulatory and state bodies, and other stakeholders.

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3. Types of Planning Studies

a. Transmission Planning Studies. PNM will conduct local reliability studies to ensure that all North American Electric Reliability Corporation ("NERC"), WECC, and local reliability standards are met for each year of the ten-year planning horizon, including all PNM customer's requirements for planned loads and resources, including NTAs. These reliability studies will be coordinated with the other regional transmission planning organizations through SWAT studies.

b. Economic Studies. Economic planning studies are performed to identify significant and recurring congestion on the transmission system and the effects of load growth, load management programs and adding new resources Such studies may analyze any, or all, of the following: (i) the location and magnitude of the congestion, (ii) possible remedies for the elimination of the congestion, in whole or in part, including transmission solutions, generation solutions, and solutions utilizing NTAs, (iii) the associated costs of congestion, (iv) the cost associated with relieving congestion through system enhancements (or other means), and as appropriate (v) the economic impacts of load growth , load management programs and adding new resources. PNM will perform, or cause to be performed, economic planning studies at the request of any transmission customer or stakeholder. All economic planning studies performed, either by PNM or TEPPC, will utilize the TEPPC public data base or other appropriate public data.

c. Consideration of Public Policy Requirements. For purposes of this Attachment K, "Public Policy Requirements" means those requirements enacted by state or federal laws or regulations, including those enacted by local governmental entities, such as a municipality or county. Enacted Public Policy Requirements, as applicable, are incorporated into the load forecasts and/or are modeled in the local planning studies. For example, PNM incorporates existing and planned energy efficiency, demand response and distributed generation programs that are required as a result of state-mandated renewable energy standards and energy efficiency rules in its transmission planning analysis. Proposed public policy (public policy proposed before a governmental authority, but not yet enacted), may be studied if time and resources permit.

4. PNM's Local Transmission Planning Study Process

a. Overview. PNM's local transmission planning process consists of an assessment of the following needs:

i. Provide adequate transmission to access sufficient resources in order to reliably and economically serve retail and network loads.

ii. Where feasible, identify NTA's that could meet or mitigate the need for transmission additions or upgrades

iii. Support PNM's local transmission and sub-transmission systems.

iv. Provide for interconnection of new generation resources.

v. Coordinate new interconnections with other transmission systems.

vi. Accommodate requests for long-term transmission access.

vii. Consider transmission needs driven by Public Policy Requirements.

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c. Transmission Customer's Responsibility for Providing Data

i. Use of Customer Data. PNM uses the information provided by its transmission customers to, among other things, assess network load and resource projections (including NTAs), transmission needs, operating dates and retirements for generation resources in PNM's system and to update regional models used to conduct planning studies.

ii. Submission of Data by Network Transmission Customers. Network Customers are required, pursuant to the PNM Open Access Transmission Tariff ("OATT") to submit their ten-year projected network load and network resources (including NTAs) to PNM on an annual basis. Such information shall be submitted annually by March 1st of each year to the PNM Contact for Transmission Planning Process: (see Section II.A.1).

iii. Submission of Data by Other Transmission Customers. All other transmission customers shall provide their ten-year needs in the form of relevant data for inclusion in the PNM transmission planning process. Such information shall be submitted annually by March 1st each year by forwarding such data to the PNM Contact for Transmission Planning Process (see Section II.A.1.).

iv. Transmission Customer Data to be submitted. To the maximum extent practical and consistent with protection of proprietary information, data submitted by network transmission customers and other transmission customers shall include for the ten-year planning horizon:

a. Generators – planned additions or upgrades (including status and expected in-service date), planned retirements and environmental restrictions.
b. NTAs – include, without limitation, technologies that defer or possibly eliminate the need for new and/or upgraded transmission lines, such as distributed generation, demand side management (load management, such as energy efficiency and demand response programs), energy storage facilities and smart grid equipment that can help eliminate or mitigate a grid reliability problem, reduce uneconomic grid congestion, and/or help to meet grid needs driven by Public Policy Requirements.
c. Network customers – forecast information for load and resource requirements over the planning horizon and identification of demand response reductions.
d. Point-to-Point transmission customers – projections of need for service over the ten-year planning horizon, including transmission capacity, duration, and receipt and delivery points.

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II.4.g. PNM Local Study Criteria and Guidelines. Customers are advised to refer to the PNM Study Criteria and Guidelines on the PNM OASIS. (see Hyperlinks List on PNM's OASIS at www.oasis.oati.com/pnm/index.html).

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II.D. Ten-year Transmission System Plan

Each year PNM uses the planning process described in Section II.A above to update its Ten-year Transmission System Plan. The PNM Ten-year Transmission System Plan identifies all of its new transmission facilities, 115 kV and above, and all facility replacements/upgrades required over the next ten-years to reliably and economically serve its loads

Tucson Electric Power Company (TEP) –

Tucson Electric Power Company, Open Access Transmission Tariff, Attachment K, retrieved from: http://www.oasis.oati.com/woa/docs/TEPC/TEPCdocs/TEP_Attachment_K.pdf (last accessed Dec. 18, 2024).

Attachment B

Attachment K

I. Overview of the Tucson Electric Power Company and UNS Electric, Inc. Transmission Planning Process

Tucson Electric Power Company ("TEP") and UNS Electric, Inc. ("UNSE"), wholly owned subsidiaries of UNS Energy Corporation, are vertically integrated public utilities engaged in the business of generating, transmitting and distributing electricity in four of Arizona's fifteen counties. TEP and UNSE provide electric transmission and related reliability services under both the state and federal arena. TEP's and UNSE's transmission planning processes are based on the following three core objectives:

• Maintain reliable electric service.

• Improve the efficiency of electric system operations, including the provision of open and non-discriminatory access to its transmission facilities.

• Identify and promote new investments in transmission infrastructure in a coordinated, open, transparent and participatory manner.

The TEP and UNSE transmission planning processes invite open participation and facilitate active involvement by interested stakeholders from inception to completion, recognizing the integrated nature of their transmission systems with neighboring facilities as the basis for an open and transparent process. Therefore, TEP and UNSE encourage stakeholders to provide guidance, input and comment on the applicable transmission plan through all stages of its development. This is accomplished through TEP and UNSE leadership, facilitation and coordination of plan development with essential support and cooperation by key stakeholders. Stakeholders include, but are not limited to, native and network customers; point-to-point customers; sponsors of transmission solutions, generation solutions and solutions utilizing non-transmission alternatives (i.e., demand side management, distributed generation, energy storage facilities, smart grid equipment, etc.); interconnected transmission providers, load serving entities and generators; independent power producers; regulatory entities, state bodies and local jurisdictions; industry consultants and vendors; local, sub-regional and regional utility entities; and other stakeholders. The work plan for the long-range transmission plan, which includes scope, schedule, study methodology, criteria and standards, scenario and strategy development, technical and economic analysis, and documentation is developed through facilitated open stakeholder meetings and teleconferences.

***

II. Local Transmission Planning

A. TEP and UNSE Planning Process

Participation in each of TEP's and UNSE's local planning process is open to all affected parties, including but not limited to all transmission and interconnection customers, sponsors of transmission solutions, generation solutions, and solutions utilizing non-transmission alternatives, state authorities, and other stakeholders.

***

2. Types of Planning Studies; Consideration of Public Policy Requirements

a. Transmission Planning Studies. TEP, on behalf of itself and UNSE, will conduct local reliability studies to ensure that all North American Electric Reliability Corporation ("NERC"), WECC, and local reliability standards are met for each year of the ten year planning horizon, including all TEP and UNSE customers' requirements for planned loads and resources, including non-transmission alternatives. These reliability planning studies will be coordinated with the other subregional transmission providers through the SWAT studies.

b. Economic Planning Studies. Economic planning studies are performed by TEP on behalf of itself and UNSE to identify significant and recurring congestion on the transmission system and/or address the integration of new resources and loads. Such studies may analyze any, or all, of the following: (i) the location and magnitude of the congestion, (ii) possible remedies for the elimination of the congestion, in whole or in part, including transmission solutions, generation solutions, and solutions utilizing non-transmission alternatives, (iii) the associated costs of congestion, (iv) the costs associated with relieving congestion through system enhancements (or other means), and as appropriate (v) the economic impacts of integrating new resources and loads. TEP will perform, or cause to be performed, economic planning studies at the request of any transmission customer or stakeholder. All economic planning studies performed, either by TEP or TEPPC, will utilize the TEPPC public data base.

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3. TEP and UNSE Local Transmission Planning Study Process.

a. Overview: TEP's and UNSE's local transmission planning process consists of an assessment of the following needs:

i. Provide adequate transmission to access sufficient resources in order to reliably and economically serve retail and network loads [*sic*]

ii. Where feasible, identify non-transmission alternatives that could meet or mitigate the need for transmission additions or upgrades.

iii. Support TEP's and UNSE's local transmission and subregional transmission systems.

iv. Provide for interconnection for new generation resources.

v. Coordinate new interconnections with other transmission systems.

vi. Consider local transmission needs driven by Public Policy Requirements.

***

3.c. Transmission Customer's Responsibility for Providing Data.

i. Use of Customer Data. TEP uses information provided by TEP and UNSE transmission customers to, among other things, assess network load and resource projections (including non-transmission alternatives), transmission needs, operating dates and retirements for generation resources in TEP's and UNSE's system and regional models used to conduct planning studies.

ii. Submission of Data by Transmission Customers. Transmission customers are required, pursuant to each of the TEP and UNSE Open Access Transmission Tariff ("OATT"), to submit their ten year projected network load and network resources (including nontransmission alternatives) to TEP and UNSE, as applicable, on an annual basis. TEP and UNSE require that network transmission customers submit this information electronically to Transcoord@tep.com by September 1 each year. All other transmission customers must also submit this information electronically to Transcoord@tep.com by September 1 each year in order to be included in the local transmission planning process for the transmission plans that TEP will submit for itself and UNSE to the ACC the following January.

iii. Transmission Customer Data to be Submitted. To the maximum extent practical and consistent with protection of proprietary information, data submitted by network transmission customers and other transmission customers should include for the ten year planning horizon:

- Generators - planned additions or upgrades (including status and expected in-serve date), planned retirements and environmental restrictions.
- Non-transmission alternatives - alternatives include, without limitation, technologies that defer or possibly eliminate the need for new and/or upgraded transmission lines, such as distributed generation, demand side management (load management, such as energy efficiency and demand response programs), energy storage facilities and smart grid equipment that can help eliminate or mitigate a grid reliability problem, reduce uneconomic grid congestion, and/or help to meet grid needs driven by Public Policy Requirements.
- Network customers - forecast information for load and resource requirements over the planning horizon and identification of demand response reductions.
- Point-to-point transmission customers - projections of need for service over the ten year planning horizon, including transmission capacity, duration, and receipt and delivery points.

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3.g. TEP and UNSE Local Study Criteria and Guidelines. Customers should refer to the TEP Transmission Planning Process and Guidelines for (TEP Planning Guidelines) TEP and UNSE local planning criteria, guidelines, assumptions and data. The TEP Transmission Planning and Process Guidelines are posted on the TEP OASIS (see TEP Attachment K List of Hyperlinks).

3.h. TEP, UNSE and Stakeholder Alternative Solutions Evaluation Basis. TEP's and UNSE's local planning process is an objective process performed by TEP, for itself and on behalf of UNSE, that evaluates use of the transmission system on a comparable basis for all customers. All solution alternatives that have been presented on a timely basis (per Section II.A.4 of this Attachment K), including transmission solutions, generation solutions and solutions utilizing non-transmission alternatives, whether presented by TEP, UNSE or another stakeholder, will be evaluated on a comparable basis. The same criteria and evaluation process will be applied to competing solutions and/or projects, regardless of type or class of stakeholder. Solution alternatives will be evaluated against one another on the basis of the following criteria to select the preferred solution or combination of solutions: (1) ability to practically fulfill the identified need; (2) ability to meet applicable reliability criteria or NERC Transmission Planning Standards issues; (3) technical, operational and financial feasibility; (4) operational benefits/constraints or issues; (5) costeffectiveness over the time frame of the study or the life of the facilities, as appropriate (including adjustments, as necessary, for operational benefits/constraints or issues, including dependability); and (6) where applicable, consistency with State or local integrated resource planning requirements, or regulatory requirements, including cost recovery through regulated rates.

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II.D. Ten Year Transmission System Plan Each year TEP uses the planning process described in Section II.A.3 above to update the TEP and UNSE Ten Year Transmission System Plans (see TEP Attachment K List of Hyperlinks). Each of the TEP and UNSE Ten Year Transmission System Plans identifies all new transmission facilities, 115 kV and above, and all facility replacements and/or upgrades required over the next ten years to reliably and cost effectively meet customers' needs.

UNS Electric, Inc. (UNS) –

Open Access Transmission Tariff of UNS Electric, Inc., Attachment K, effective Oct. 1, 2015, retrieved from: https://www.oasis.oati.com/woa/docs/AECI/AECIdocs/AECI_OATT_Effective_11_9_2022.pdf (last accessed Dec. 18, 2024).

Attachment K

I. Overview of the Tucson Electric Power Company and UNS Electric, Inc. Transmission Planning Process

Tucson Electric Power Company ("TEP") and UNS Electric, Inc. ("UNSE"), wholly owned subsidiaries of UNS Energy Corporation, are vertically integrated public utilities engaged in the business of generating, transmitting and distributing electricity in four of Arizona's fifteen counties. TEP and UNSE provide electric transmission and related reliability services under both the state and federal arena. TEP's and UNSE's transmission planning processes are based on the following three core objectives:

• Maintain reliable electric service.

• Improve the efficiency of electric system operations, including the provision of open and non-discriminatory access to its transmission facilities.

• Identify and promote new investments in transmission infrastructure in a coordinated, open, transparent and participatory manner.

The TEP and UNSE transmission planning processes invite open participation and facilitate active involvement by interested stakeholders from inception to completion, recognizing the integrated nature of their transmission systems with neighboring facilities as the basis for an open and transparent process. Therefore, TEP and UNSE encourage stakeholders to provide guidance, input and comment on the applicable transmission plan through all stages of its development. This is accomplished through TEP and UNSE leadership, facilitation and coordination of plan development with essential support and cooperation by key stakeholders. Stakeholders include, but are not limited to, native and network customers; point-to-point customers; sponsors of transmission solutions, generation solutions and solutions utilizing non-transmission alternatives (i.e., demand side management, distributed generation, energy storage facilities, smart grid equipment, etc.); interconnected transmission providers, load serving entities and generators; independent power producers; regulatory entities, state bodies and local jurisdictions; industry consultants and vendors; local, sub-regional and regional utility entities; and other stakeholders. The work plan for the long-range transmission plan, which includes scope, schedule, study methodology, criteria and standards, scenario and strategy development, technical and economic analysis, and documentation is developed through facilitated open stakeholder meetings and teleconferences.

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II. Local Transmission Planning

A. TEP and UNSE Planning Process

Participation in each of TEP's and UNSE's local planning process is open to all affected parties, including but not limited to all transmission and interconnection customers, sponsors of transmission solutions, generation solutions, and solutions utilizing non-transmission alternatives, state authorities, and other stakeholders.

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2. Types of Planning Studies; Consideration of Public Policy Requirements

a. Transmission Planning Studies. TEP, on behalf of itself and UNSE, will conduct local reliability studies to ensure that all North American Electric Reliability Corporation ("NERC"), WECC, and local reliability standards are met for each year of the ten-year planning horizon, including all TEP and UNSE customers' requirements for planned loads and resources, including non-transmission alternatives. These reliability planning studies will be coordinated with the other subregional transmission providers through the SWAT studies.

b. Economic Planning Studies. Economic planning studies are performed by TEP on behalf of itself and UNSE to identify significant and recurring congestion on the transmission system and/or address the integration of new resources and loads. Such studies may analyze any, or all, of the following: (i) the location and magnitude of the congestion, (ii) possible remedies for the elimination of the congestion, in whole or in part, including transmission solutions, generation solutions, and solutions utilizing non-transmission alternatives, (iii) the associated costs of congestion, (iv) the costs associated with relieving congestion through system enhancements (or other means), and as appropriate (v) the economic impacts of integrating new resources and loads. TEP will perform, or cause to be performed, economic planning studies at the request of any transmission customer or stakeholder. All economic planning studies performed, either by TEP or TEPPC, will utilize the TEPPC public data base.

Attachment B

3. TEP and UNSE Local Transmission Planning Study Process.

a. Overview: TEP's and UNSE's local transmission planning process consists of an assessment of the following needs:

i. Provide adequate transmission to access sufficient resources in order to reliably and economically serve retail and network loads [*sic*]

ii. Where feasible, identify non-transmission alternatives that could meet or mitigate the need for transmission additions or upgrades.

iii. Support TEP's and UNSE's local transmission and subregional transmission systems.

iv. Provide for interconnection for new generation resources.

v. Coordinate new interconnections with other transmission systems.

vi. Consider local transmission needs driven by Public Policy Requirements.

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c. Transmission Customer's Responsibility for Providing Data.

i. Use of Customer Data. TEP uses information provided by TEP and UNSE transmission customers to, among other things, assess network load and resource projections (including non-transmission alternatives), transmission needs, operating dates and retirements for generation resources in TEP's and UNSE's system and regional models used to conduct planning studies.

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iii. Transmission Customer Data to be Submitted. To the maximum extent practical and consistent with protection of proprietary information, data submitted by network transmission customers and other transmission customers should include for the ten-year planning horizon:

• Generators - planned additions or upgrades (including status and expected in-serve date), planned retirements and environmental restrictions.

• Non-transmission alternatives - alternatives include, without limitation, technologies that defer or possibly eliminate the need for new and/or upgraded transmission lines, such as distributed generation, demand side management (load management, such as energy efficiency and demand response programs), energy storage facilities and smart grid equipment that can help eliminate or mitigate a grid reliability problem, reduce uneconomic grid congestion, and/or help to meet grid needs driven by Public Policy Requirements.

• Network customers - forecast information for load and resource requirements over the planning horizon and identification of demand response reductions.

• Point-to-point transmission customers - projections of need for service over the ten year planning horizon, including transmission capacity, duration, and receipt and delivery points.

II.3.g. TEP and UNSE Local Study Criteria and Guidelines. Customers should refer to the TEP Transmission Planning Process and Guidelines for (TEP Planning Guidelines) TEP and UNSE local planning criteria, guidelines, assumptions and data. The TEP Transmission Planning and Process Guidelines are posted on the TEP OASIS (see TEP Attachment K List of Hyperlinks).

II. D. Ten Year Transmission System Plan Each year TEP uses the planning process described in Section II.A.3 above to update the TEP and UNSE Ten Year Transmission System Plans (see TEP Attachment K List of Hyperlinks). Each of the TEP and UNSE Ten Year Transmission System Plans identifies all new transmission facilities, 115 kV and above, and all facility replacements and/or upgrades required over the next ten years to reliably and cost effectively meet customers' needs.

ATTACHMENT C

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Industrial Energy Consumers of America *et al.*	)	
	)	
	)	Docket No. EL25-________
v.	)	
	)	
Avista Corporation; Idaho Power Company *et al.*	)	

DECLARATION OF MICHAEL A. GIBERSON

OF R STREET INSTITUTE

ON BEHALF OF THE COMPLAINANTS

ATTACHMENT C

I: INTRODUCTION

Q: PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A: My name is Michael A. Giberson. I am a Senior Energy Fellow with the R Street Institute. The R Street Institute is located at 1411 K Street N.W., Suite 900; Washington, D.C. 20005.

Q: WHAT IS YOUR PROFESSIONAL EXPERIENCE?

A: I have thirty years of experience in energy regulatory policy and energy economics. Highlights include working as a regulatory policy analyst with Argonne National Laboratory where I provided research assistance to the U.S. Department of Energy's Office of Oil and Gas Policy, several years as a freelance regulatory analyst writing on federal transmission policies and wholesale power market development for trade publications, and two years with Potomac Economics, the premiere economic consulting firm in electric wholesale market power monitoring and power market design. Before becoming engaged with the R Street Institute, I was associate professor of practice in business economics with the Center for Energy Commerce in the Rawls College of Business, Texas Tech University. In the more than thirteen years I was on the faculty of Texas Tech University I taught courses in Business Economics, Energy Economics, U.S. Energy Policy, the electric power industry, and renewable energy.

I have authored or co-authored academic publications on issues including cost-based rate regulation, natural gas pipeline regulation, reliability policy, wind energy economics, and U.S. energy policy more generally. In addition, I have written monographs on competition in retail electric power and renewable energy policy and have submitted regulatory comments in state and federal regulatory proceedings on wholesale-retail market coordination, transmission policy, and ratemaking processes. Finally, I have presented on electricity policy before state legislative committees.

Q: WHAT IS YOUR EDUCATIONAL BACKGROUND?

A: I have a Bachelor of Arts degree in Economics with a General Business minor from Texas Tech University, and Master of Arts and PhD degrees in Economics from George Mason University (GMU). My doctoral studies included a focus on Industrial Organization and Public Choice Economics, and my dissertation topic was the coordination of trade between interconnected power markets. My dissertation was completed under the supervision of Professor Vernon L. Smith, founding director of the Interdisciplinary Center for Economic Science at GMU.

Q: PLEASE DESCRIBE THE R STREET INSTITUTE.

A: The R Street Institute is a Washington, DC-based think tank engaged in policy research in support of free markets and limited, effective government. The energy and environmental policy program, to which I contribute, has long advocated for competition in wholesale and retail energy marketplaces and effective regulation of industry in cases in which competition cannot be made effective in meeting industry and consumer needs. The program’s work on transmission policy has been extensive, spanning legal and economic research to regulatory interventions to convenings of national transmission consumer groups.

Q: WHY IS THE R STREET INSTITUTE WORKING IN SUPPORT OF THE COMPLAINT?

A: As noted, R Street is dedicated to helping competition work where it can and to ensuring effective regulation in cases where competition cannot be made to work. Electricity has long been subject to extensive regulatory oversight because of historical assessments about the ability or inability of competition to operate effectively. While this historical assessment has been challenged in part by restructuring reforms of the last few decades, most transmission services remain provided by regulated entities with cost-based rates. Transmission development is an area where effective regulation and independent transmission planning can support cost-reducing competition. Without effective regulation, the status quo today, we get neither the right transmission projects nor transmission at the lowest possible cost.

The existing regulatory regime does not ensure the provision of power at the least reasonable cost. Non-energy costs—primarily transmission and distribution costs—have been growing at rates outpacing inflation for several years and are increasingly becoming the largest bill components for electric power consumers.[1] R Street has been actively engaged in opposing regulation that gives incumbent transmission owner preferential treatment because competitive engagement in planning and development processes has been shown to reduce costs for consumers and better identify regional transmission needs in an efficient, cost-effective manner. The testimony here pursues a complementary effort to ensure that all Federal Energy Regulatory

[1] US EIA, "Major utilities' spending on the electric distribution system continues to increase," *Today in Energy*, May 27, 2021. https://www.eia.gov/todayinenergy/detail.php?id=48136; US EIA, "Utilities continue to increase spending on the electric transmission system," *Today in Energy*, March 26, 2021. https://www.eia.gov/todayinenergy/detail.php?id=47316; Robert Walton, "Aging grids drive $51B in annual utility distribution spending," *Utility Dive*, July 25, 2018. https://www.utilitydive.com/news/aging-grids-drive-51b-in-annual-utility-distribution-spending/528531/.

Commission (Hereinafter, Commission or FERC) jurisdictional transmission investments at 100 kV and above are fully and exclusively considered in regional transmission planning efforts, removing today's ineffective tariff framework that allows individual transmission owners to plan Commission-jurisdictional transmission regardless of voltage or regional impact. Electricity consumers need transmission investments, and the Federal Power Act requires that investment be done in a cost-effective manner. Current practices result in poorly coordinated investments that fail to meet consumer needs cost-effectively and so cannot result in just and reasonable rates. Granting the Complaint at this time is critically important, given the hundreds of billions of dollars of transmission upgrades that the Commission believes is necessary to address aging infrastructure and accommodate changing grid conditions.

Q: PLEASE SUMMARIZE YOUR TESTIMONY

A: The purpose of my testimony is to establish that the Commission's obligation to ensure just and reasonable rates requires all transmission facilities 100 kV and above meeting the Bulk Electric System (BES) definition to be planned exclusively through Commission-required regional planning processes.

My testimony traces the evolution of the U.S. power system from isolated local systems into today's three vast interconnected grids. This history reveals how industry practices that were once sensible–like individual utility transmission planning–have become incompatible with operating an integrated transmission system. I discuss key regulatory developments including Order No. 888's Seven Factor Test for determining Commission-jurisdictional transmission, and the development of NERC's BES definition at the direction of Congress and the Commission.

This historical context establishes why a uniform 100 kV threshold for mandatory regional planning is both natural and overdue, and necessary to obtain just and reasonable rates. The testimony provides multiple examples from RTOs and non-RTO regions demonstrating how the lack of such a threshold has resulted in costly, inefficient grid development. These examples show the issues raised in the Complaint are widespread and require comprehensive reform.

I explain how billions of dollars in transmission spending now occurs through processes that do not require consideration of alternatives, exposure to competitive bidding, or evaluation for cost-effectiveness. This spending cannot produce just and reasonable rates. The testimony demonstrates that transmission owners face perverse incentives to overinvest in local projects while potentially underinvesting in more efficient regional solutions. I cite evidence of transmission owners exploiting exemptions from regional planning requirements to pursue projects that boost their rate base without demonstrating the investments serve the public interest.

The testimony also explains why an independent transmission planner is necessary to overcome these incentives and address inefficiencies in current planning processes. Even when planning occurs through Commission-recognized regional processes, transmission owners can exert undue influence through selective disclosure of critical information about generation plans, load forecasts, and asset conditions.

In conclusion, I explain why these two reforms – mandatory regional planning for facilities 100 kV and above, and independent transmission planning oversight – are necessary to achieve just and reasonable rates in today's highly integrated transmission system. The evidence shows current practices result in poorly coordinated investments that fail to meet consumer needs cost-effectively. Reform is critically important given the hundreds of billions of dollars in transmission investment the Commission anticipates will be needed to address aging infrastructure and accommodate changing grid conditions.

II: EFFICIENT GRID DEVELOPMENT REQUIRES REGIONAL TRANSMISSION PLANNING

Q: YOUR SUMMARY MENTIONS THE HISTORY OF GRID DEVELOPMENT. EXPLAIN THE HISTORY RELEVANT TO THE COMPLAINT.

A: Understanding the history of the industry can help us recognize the circumstances that drove the adoption of common industry practices, and more to our purpose, recognize that even well-established industry practices often need to change in response to emerging industry conditions. The electric power industry in the United States developed from small, isolated power companies to today's vast grids of the Eastern, Western, and Texas interconnections. We have grown from a case in which coordinated system planning was irrelevant to a case where coordinated system planning is essential.

In the United States' early electrification, power distribution systems were local and utilized direct current for transmission over copper lines, necessitating power plants to be situated no more than a mile from their load due to inefficiencies. The local nature of industry planning was inherent to the technology and its cost characteristics. However, the advent of high-voltage alternating current transmission lines at the close of the 19th century enabled longer-distance power transmission, prompting electric companies to construct larger generators to serve larger service areas. This shift advantaged larger firms over the smaller, local systems and generators prevalent at the time. The scope of planning grew, though it remained decidedly local in modern perspective.

The early 20th century witnessed the merger and consolidation of many smaller entities through various holding company structures, leading to eight major holding companies controlling roughly three-quarters of the investor-owned utility sector by 1932. Despite the financial consolidation of utilities in holding companies, most electric systems saw little physical integration. The Pennsylvania-New Jersey Interconnection, precursor to today's PJM Interconnection, was the prominent exception as several utilities in those states formed a power pool in 1927 to share access to large hydroelectric resources in its area.[2]

Initially, electric utilities were regulated primarily through municipal franchise agreements, and after 1907 increasingly by state governments. But, as utilities began connecting to each other and as transmission lines increasingly crossed state borders, in 1927 the U.S. Supreme Court recognized electricity as an interstate commodity.[3] This acknowledgment soon led to the enactment of the Public Utility Holding Company Act and the Federal Power Act in 1935.

The Public Utility Holding Company Act mandated that interstate holding companies simplify their structures and come under the U.S. Securities and Exchange Commission's oversight, a move resisted by the utility sector. Significant litigation followed, culminating in Supreme Court decisions that affirmed the law's constitutionality, emphasizing the utility operations' critical role in interstate commerce and the national economy. The Federal Power Act addressed what was

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[2] Thomas P. Hughes, *Networks of Power: Electrification in Western Society, 1880-1930*, Johns Hopkins University Press (1983). The summary also draws upon Richard F. Hirsch, *Power Loss: The Origins of Deregulation and Restructuring in the American Electric Utility System*, The MIT Press (1999) and John L. Neufeld, *Selling Power: Economics, Policy, and Electric Utilities Before 1940*, University of Chicago Press (2016).

[3] On the connection between the physical nature of electric energy and its connection to legal standards governing interstate commerce see *Brief Amicus Curiae of Electrical Engineers, Energy Economists and Physicists in Support of Respondents in No. 00-568,* New York v. Federal Energy Regulatory Comm'n, No. 00-568 (May 31, 2001).

called the *Attleboro* gap by establishing federal regulation of interstate transmission and utility interconnections, affirming their significance to national interest and leaving only the siting of transmission facilities to states.[4]

Q: HOW DID THE GRID EVOLVE INTO TODAY'S INTERCONNECTED SYSTEM?

A: After World War II the industry evolved with larger generation and transmission facilities to leverage economies of scope and scale, significantly expanding the transmission network during the 1950s and 1960s. Utility-to-utility connections were so pervasive by the 1960s that connections among them produced a grid nearly spanning from the Atlantic to the Pacific coasts. In fact, for an 8-year period from 1967 until 1975, the transmission grid in the continental United States did operate as a single, interconnected machine.[5]

The landscape further transformed with the Public Utility Regulatory Policies Act of 1978 (PURPA), fostering non-utility generation and their demand for fair access to the transmission grid. These developments, along with the Energy Policy Act of 1992, produced a need for transparent regional planning for an interconnected grid, acknowledging the increasingly interstate nature of the industry and supporting its continued growth and evolution.

Q: HOW DOES HISTORY INFORM HOW TRANSMISSION SHOULD BE PLANNED?

A: As the grid has grown ever more tightly interconnected, system planning processes have not kept pace. Most transmission planning still originates with individual utilities assessing

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[4] *Public Util. Comm'n of R.* 1. v. *Attleboro Steam* & *Elec. Co.*, 273 U. S. 83, 89 (1927).

[5] Julie Cohn, "When the Grid Was the Grid: The History of North America's Brief Coast-to-Coast Interconnected Machine," *Proceedings of the* IEEE, Vol. 107, No. 1, January 2019. https://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=8594689

conditions on their own systems and planning to meet only their specific retail or system needs, a throwback to the early 1900s. However, the industry has grown into "a complex system of interconnected facilities that operates, in effect, as a single 'machine' within each" of the three interconnections that jointly cover the continental United States rather than as hundreds of individual machines.[6] The physics of electricity on an alternating current network means that a power fluctuation at one point in the system will influence flows throughout the interconnected system. Whereas once there was little or no need for one utility to work with its neighbors, today such cooperation is essential.

This principle of mutual influence of individual power systems interconnected in an AC network has been demonstrated multiple times in the history of the industry.[7] Indeed, the principle is demonstrated daily as transmission operators must account for loop flows and other unscheduled flows on their systems. One of the primary values contributed by RTOs is coordinating power flows in ways that minimize the joint cost of producing and delivering electrical energy over a broad region. The challenges of reliably operating an interconnected grid were amply revealed by the Northeast Blackout in 1965 in which a line outage on a 230-volt transmission line in Ontario, Canada rapidly propagated to New York State and surrounding areas, leaving 30 million people without power.[8] In 1996, two blackouts struck western states and reached into interconnected areas in Canada and Mexico.[9] In 2003, a massive blackout originated in Ohio, rapidly spreading to, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey and the Canadian province of Ontario. As many as 50 million people were without

[6] National Academies of Sciences, Engineering, and Medicine. *Enhancing the resilience of the nation's electricity system*. National Academies Press, 2017.
[7] Cohn, *op. cit*.
[8] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, (Apr. 2004) at pp. 104-106.
[9] *ibid*, pp. 104-106.

power at the blackout's peak. The events up to and including the 2003 blackout led Congress to enact the Energy Policy Act of 2005 calling for an Electric Reliability Organization and the development of enforceable reliability standards. Despite extensive improvement in grid control technologies, the present-day grid has not banished harmful effects from the interconnecting of power systems: in January 2019, faulty control systems at a single generating unit in Florida produced frequency oscillations propagating throughout the eastern interconnection—detectable in Maine, Minnesota, and even Manitoba—and causing other entities in the Eastern Interconnection to take protective actions.[10]

Yet focus on the occasional failures overlooks the significant benefits that come from connecting power systems. The Commission's proposed transmission planning rule had listed 12 distinct benefits realizable by better regional transmission planning.[11] These benefits span from multiple reliability and resilience factors to providing cost savings and promoting resource competition. In fact, that utilities continue to choose to increase levels of interconnection with their neighbors despite the large potential risks and costs demonstrates they find significant net benefits from operating as part of a vast, interconnected machine. In Order No. 1920, the Commission requires transmission providers to use seven benefits in Long-Term Regional Transmission Planning: (1) avoided or deferred reliability transmission facilities and aging infrastructure replacement; (2) a benefit that can be characterized and measured as 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 weather

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[10] North American Electric Reliability Corporation, *Eastern Interconnection Oscillation Disturbance: January 11, 2019 Forced Oscillation Event*, December 2019. https://www.nerc.com/pa/rrm/ea/Pages/Oscillation-Event-Report.aspx

[11] Federal Energy Regulatory Commission, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, RM21-17-000, April 21, 2022. Pp. 26539-26540.

events and unexpected system conditions; and (7) capacity cost benefits from reduced peak energy losses.[12]

Q: DOES THE GRID GET PLANNED AS ONE LARGE INTERCONNECTED MACHINE?

A: No. Notwithstanding the interconnected nature of the transmission grid, and recognition that the reliability of that grid must be addressed uniformly, planning for Commission-jurisdictional transmission remains subject to the individual planning activities of hundreds of different transmission owners and disparate regional planning standards and practices. The history of grid development when compared to the grid that exists today and the grid we need tomorrow, demonstrate why the Commission, in its statutory obligation to ensure just and reasonable rates, cannot continue to allow individual transmission owner planning at 100 kV and above. Each new line added or expanded on the grid will affect flows on other lines, including other lines contemporaneously being added or expanded. These potential interactions with contemporaneous projects are obviously relevant to the expected value of a project, but absent regional coordination at the planning stage the project developer will not know whether other grid developments will increase or decrease the value of its own project. A single utility simply does not have the information needed to plan cost-effective transmission investments on its own.

And if the single utility lacks information to plan cost-effective transmission investments, then it cannot possibly demonstrate that its individually-planned transmission investments are just and

[12] Order No. 1920 at P 720. See also Order No. 1920-A at P 380.

reasonable. Individual utility planned transmission investment would not result in economically efficient outcomes nor just and reasonable rates except by happenstance.

When utilities are linked together it produces new opportunities for low-cost power. More pointedly, it produces new options for regulators to consider when evaluating whether utilities are serving consumers at least cost. While the existing grid gradually developed through individual utilities developing transmission to serve "their" retail customers, since the 1930s the Courts and Congress have recognized that transmission of electricity is inherently an interstate activity. As an interstate activity, state retail franchises should not be employed in ways that interfere with the economically effective development of transmission. It is important to note here the fallacy that transmission is a "natural monopoly."[13] First, as the United States Court of Appeals for the D.C. Circuit said when transmission owners made that very argument, "The leading antitrust treatise, on which petitioners rely, instructs that "competition for a natural monopoly can be just as beneficial to consumers as competition within an ordinary market."[14] Just as the Court reasoned, competition, and even the threat of competition, has resulted in savings for consumers for those projects that have been available for competition, as compared to projects that have not been available for competition.

The natural monopoly theory is also inappropriately applied in discussions of regional planning as it is based on the assertion that "It remains more efficient to have one owner of the system in a given area."[15] Each of the three interconnections are composed of multiple transmission owners

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[13] Rob Gramlich, Richard Doying, and Zach Zimmerman, *Fostering Collaboration Would Help Build Needed Transmission*. Grid Strategies LLC. February 2024. https://gridstrategiesllc.com/wp-content/uploads/2024/02/GS_WIRES-Collaborative-Planning.pdf

[14] *South Carolina Public Service Authority v. FERC*, 762 F.3d 41, 68-69 (2014) citing Phillip E. Areeda & Herbert Hovenkamp, *Antitrust Law* ¶ 658b3 (3d ed. 2008).

[15] Gramlich, et al. at p. II.

connecting to others within their own interconnections in complex ways. There are transmission lines with joint ownership, lines owned by different owners crossing, and separately owned lines running parallel to each other. The single area owner assumption has not been true of the many parts of the transmission grid for decades. What the parties preaching "collaboration" are really identifying as more efficient transmission planning is not having a single owner but having unified planning in a region that coordinates all system needs. The theoretical ideal might be a single planner for each of the three interconnections. The currently practical approach is requiring regional planning for transmission 100 kV and above across each existing Commission-approved planning regions and interregional planning between those regions. What the Commission and industry analysts across the country recognize is that the current system with sanctioned individual transmission owner planning is the least economically efficient planning approach,[16] and as I noted above, will only achieve the preferred transmission planning result by happenstance. Or, to phrase it in today's terminology, the most economical transmission expansion can only be identified at the regional and interregional scale.

Q: HAS THE COMMISSION ENCOURAGED REGIONAL TRANSMISSION PLANNING?

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[16] Joe DeLosa, Johannes Pfeifenberger, and Paul Joskow, "Regulation of Access, Pricing, and Planning of High Voltage Transmission in the U.S." MIT Center for Energy and Environmental Policy Research (CEEPR) Working Paper, 2024-3., https://economics.mit.edu/sites/default/files/inline-files/MIT-CEEPR-WP-2024-03REVISED%203-05-24-2.pdf; Johannes Pfeifenberger, et al. *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Cost*. The Brattle Group and Grid Strategies LLC. October 2021.

A: Yes, the Commission put forward a framework in Order No. 890[17] and Order No. 1000[18] for participation of public utility transmission providers in regional transmission planning processes in explicit recognition of the needs of consumers and generating resources in a changing electric industry. Order No. 890 was issued in 2007 to move the industry to a more open, transparent, and coordinated approach to regional transmission planning, enabling public utility transmission providers to collaboratively identify and respond to regional transmission needs. It underscored the importance of considering a wide array of solutions, including non-transmission alternatives, to address congestion and integrate resources additions efficiently. However, the implementation of Order No. 890 revealed several limitations and challenges, including a failure to require public utility participation in regional efforts and pricing and cost allocation rules that discouraged investment from nonincumbent transmission developers. Few transmission owners chose to voluntarily expose their planning processes to regional coordination.

Order No. 1000, issued in 2011, builds on the framework established by Order No. 890, aiming to address deficiencies in planning and cost allocation processes. Order No. 1000 mandated participation by public utility transmission providers, established a framework for regional cost allocation, and extended transmission planning obligations to include interregional coordination. Order No. 1000 further required three types of projects to be considered in the regional transmission planning process: reliability projects, economic projects, and public policy projects. By mandating costs to be allocated to those who benefit from new transmission facilities, Order No. 1000 sought to ensure that rates remained just and reasonable. Order No. 1000 removed

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[17] Federal Energy Regulatory Commission. (2007). *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,2411.

[18] Federal Energy Regulatory Commission. (2011). *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323

federal rights of first refusal from FERC-jurisdictional tariffs in an effort to foster more transmission competition.

Q: HAS ORDER NO. 1000 BROUGHT ABOUT THE REGIONAL PLANNING NECESSARY TO PRODUCE JUST AND REASONABLE RATES?

A: Generally, no. Order No. 1000 has not produced just and reasonable transmission rates because transmission owners have largely avoided, and have been permitted to avoid, regional planning. Yet, when implemented as intended, Order No. 1000 has resulted in cost-effective regional transmission development. The most efficient transmission development is done through regional economic planning, which employs cost-benefit tests and puts projects out for competitive bidding in RTO regions. Projects planned and developed in this manner have performed well by economic measures and thus result in just and reasonable rates. For example, both the Midcontinent ISO (MISO) Multi-Value Project (MVP) process and the Southwest Power Pool's Priority Projects effort have yielded benefits that would not have been possible through local transmission planning. MISO's 2017 retrospective analysis of early MVP efforts concluded that the benefits were from 2.2 to 3.4 times the project costs.[19] SPP's Balanced Portfolio and Priority Projects were estimated to yield a 3.5 benefit-to-cost ratio.[20]

Yet most transmission spending is occurring on projects without a full evaluation of all regional needs and benefits because utilities deem projects as for reliability or simply pursue avenues of

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[19] MISO, *MTEP17 MVP Triennial Review*, September 2017. https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf

[20] SPP, *The Value of Transmission*, January 26, 2016. https://www.spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf

transmission spending that allow them sole discretion over spending. A survey of transmission planning processes by The Brattle Group concluded that more than 90 percent of transmission spending occurred without a benefit-cost analysis, a number including both reliability projects that are part of regional planning processes and local projects built outside of regional planning processes.[21]

For example, a report by the Rocky Mountain Institute states, "In PJM, spending on local projects (which PJM calls Supplemental projects) increased 26-fold from 2009 to 2023, … while spending on regional projects (which PJM calls Baseline projects) stayed relatively flat."[22] The PJM Independent Market Monitor (IMM) has taken note. While Baseline projects are designed through the regional transmission planning process and must be reviewed for cost effectiveness and approved by the PJM Board of Trustees, Supplemental Projects do not require cost effectiveness review or approval by the. Such local transmission spending in PJM has outpaced spending on "Baseline" projects in every year but one since 2017, and of December 31, 2023, the 1,584 supplemental projects projected to come online on the PJM system from 2024 to 2027 had a total estimated cost of $18.1 billion.[23]

A report produced by the R Street Institute with input from all national transmission consumer groups found billions of dollars in misallocated capital in transmission expansion because of

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[21] Johannes Pfeiffenberger and Joseph DeLosa, "Proactive, Scenario-Based, Multi-Value Transmission Planning," The Brattle Group, Presented to the PJM Long-term Transmission Planning Workshop, June 7, 2022. https://www.brattle.com/wp-content/uploads/2022/06/Proactive-Scenario-Based-Multi-Value-Transmission-Planning.pdf.

[22] Claire Wayner, Kaja Rebane, and Chaz Teplin, "Mind the Regulatory Gap: How to Enhance Local Transmission Oversight," RMI, November 2024, citing Claire Wayner, "Increased Spending on Transmission in PJM — Is It the Right Type of Line?," RMI, March 20, 2023, https://rmi.org/increased-spending-on-transmission-in-pjm-is-it-the-right-type-of-line/. Ethan Howland, "Local transmission spending soars nationwide amid 'serious absence of cost containment'," *Utility Dive*, Nov. 20, 2024. https://www.utilitydive.com/news/local-transmission-asset-condition-spending-regulatory-gap-rmi/733430/

[23] Monitoring Analytics, LLC, *State of the Market Report for PJM 2023*, p. 722. https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2023.shtml

regulatory structure defects that let incumbents overspend on inefficient transmission projects at the expense of efficient transmission expansion.[24] In particular, the report found exemptions to regional planning as the primary culprit, especially enabling incumbent utilities to channel billions per year into locally planned projects.[25] To ensure just and reasonable rates, the report found reforms were needed to ensure that "piecemeal, local projects do not displace more efficient, larger-scale solutions."[26] To be clear, not all new transmission investment will occur in higher-voltage transmission facilities, but the critical objective is to ensure that planning occurs on a broad regional basis to ensure the right mix of transmission facilities, in the right locations and at the right voltages, to meet consumer needs across the region. Planning conducted primarily by incumbent transmission owners that are heavily self-interested in growing their own rate bases will necessarily produce inefficient projects, and thus unjust and unreasonable rates.

The brunt of unjust and unreasonable transmission rates is borne by consumers, who are increasingly active in interventions and other means of addressing the exemptions under Order No. 1000 and lack of independent regional transmission planning. In a 2023 filing before the Commission, a coalition of consumer groups, along with the R Street Institute, articulated the problem statement as "local transmission practices lead to elevated and unnecessary transmission costs with little transparency, accountability, or regulatory oversight."[27] They continued that a root cause of the problem was an unclear definition of "local" projects, including an inconsistent voltage threshold exemption.[28] The consumer coalition noted that 100-230 kV projects should

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[24] Jennifer Chen and Devin Hartman, "Transmission Reform Strategy from a Customer Perspective: Optimizing Net Benefits and Procedural Vehicles," R Street Institute, No. 257, May 2022. https://www.rstreet.org/wp-content/uploads/2022/05/RSTREET257.pdf.

[25] Ibid, p. 3.

[26] Ibid, p. 13.

[27] ECA filing, p. 5. https://www.rstreet.org/wp-content/uploads/2023/06/ECA-20230323-5062-1.pdf.

[28] Ibid, p. 4.

not be considered "local" projects and that the voltage threshold for exemption from regional planning should be set at 100 kV, consistent with the standard definition of the BES.[29] A standard voltage exemption threshold set at 100 kV is the most straightforward approach to achieving the Commission's goal of comprehensive, integrated regional transmission planning.

Q: HAVE THESE ISSUES BEEN FULLY ADDRESSED IN ORDERS NO. 1920 OR 1920-A?

A: No. Order No. 1920 specifically acknowledged that current planning practices lead to inefficient and less cost-effective transmission investment, with customers ultimately paying the price for piecemeal solutions.[30] The Order found that inadequate regional planning and overreliance on local planning processes contribute to unjust and unreasonable rates. However, the Commission chose not to address these specific issues with local planning and the crux of the problem – the local tariff provisions that empower incumbent transmission owner control over local planning – in Order No. 1920 or in Order No. 1920-A. As the Commission explained in Order No. 1920 and reiterated in Order No. 1920-A, because the Notice of Proposed Rulemaking had not proposed changes to local transmission planning processes, such requests were "beyond the scope of this final rule."[31] While Order Nos. 1920 and 1920-A provided means for "right sizing" replacement and other local transmission projects, and these changes are intended to enhance transparency and promote efficiency, the changes do not directly address transmission owner incentives to overinvest in their rate base. Notably, the Commission did not retract or

[29] Ibid, p. 5.
[30] FERC, Order No. 1920, 187 FERC ¶ 61,068 at P 85.
[31] FERC, Order No. 1920-A at P 858.

dispute its findings about the problems with local planning, but explained "Commission will continue to consider potential additional local transmission planning reforms, such as independent transmission monitors, along with other transmission reforms in the future."[32]

Q: CAN YOU DESCRIBE HOW TRANSMISSION CUSTOMERS HAVE REACTED TO RISING RATES?

A: Consumers and their advocates have undertaken narrowly focused actions with the Commission to seek relief in particularly egregious cases of utility discretion. In 2017, the California Public Utilities Commission, along with others, filed a complaint against Pacific Gas & Electric (PG&E) revealing that as much as 60 percent of PG&E's capital expenditures on transmission in 2016 and 2017 were reviewed and authorized solely by the company. PG&E's self-authorized expenditures on transmission-level projects amounted to $1.5 billion over the two years that were the focus of the complaint. In 2019, Florida Power & Light entities (FPL) began planning the 176-mile long "North Florida Resiliency Project" as a local project. According to a complaint filed by another utility in the region, FPL deliberately designed the transmission line at 161 kV to avoid triggering state review or regional planning oversight through the Florida Reliability Coordinating Council. Recently the Maine Office of Public Advocate protested that New England transmission owners have spent or plan to spend nearly $1.5 billion – over half of total planned transmission spending for the next two years - on "Asset Condition" transmission projects in 2023 and 2024 without effective integration into regional planning processes or

[32] Ibid.

adequate regulatory oversight.[33] Last fall the Ohio Consumers' Counsel filed a complaint with the Commission asserting the state's transmission owners have spent nearly $6.5 billion at ratepayer expense without oversight through "Supplemental Projects"—more than three-quarters of the total $8.2 billion spent on transmission from 2017 to 2022.[34] "Asset Condition" transmission projects in New England and "Supplemental Projects" transmission projects in the PJM territory are categories allowing incumbent public utilities discretion to plan, develop, construct, and recover the costs of certain transmission projects that are not analyzed through integrated regional planning processes. This Complaint details significant spending on "Other" projects in the Midcontinent ISO, another category through which public utilities engage in local spending outside of integrated regional planning processes. While the facilities expanded or replaced may be intended to serve local conditions, these facilities will affect power flows throughout their region and they are Commission-jurisdictional transmission facilities.

The evidence from both successes and failures under Order No. 1000 rules unequivocally shows that when adhered to, Order No. 1000's mandate for independent, regional transmission planning effectively ensures just and reasonable rates. However, exemptions within Order No. 1000's structure have paved the way for unjust and unreasonable outcomes. Historically, when the industry was primarily composed of disconnected or weakly interconnected utilities, local transmission planning was reasonably done individually. Times have changed. Today, utilities are tightly connected with neighbors and increasingly reliant on power flows across long distances,

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[33] Ethan Howland, "Eversource, others may be capitalizing on lax reviews for some transmission projects: Maine officials," *Utility* Dive, February 4, 2024. https://www.utilitydive.com/news/eversource-national-grid-iso-new-england-ferc-asset-condition-transmission-maine/706393/.

[34] Ethan Howland, "FERC must review local transmission planned by AEP, Duke, other Ohio utilities: complaint," *Utility* Dive, September 29, 2023. https://www.utilitydive.com/news/ferc-local-transmission-pjm-aep-duke-ohio-occ-consumers-counsel-complaint/695147/; Ohio Consumers' Counsel complaint as filed with the Commission: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20230928-5134&optimized=false

particularly during emergency conditions. Today, utility transmission planning done outside of regional planning processes will inherently lack the information needed to assess whether the proposals represent cost-effective investments. Given that projects planned outside of regional processes cannot be shown to be cost-effective solutions, the transmission owner will be incapable of demonstrating that spending is just and reasonable. The examples cited above demonstrate that public utilities abuse local exemptions to accelerate spending on transmission and boost company returns without demonstrating that the projects are in the public interest. Achieving effective regulation requires eliminating utility discretion to plan and build regionally-impactful lines outside of regional transmission planning processes.

Q: WHAT ACCOUNTS FOR THE DIFFERENCE BETWEEN THE PLANNING SUCCESSES AND FAILURES?

A: Comprehensive regional planning has the scope necessary to ensure transmission spending that justifies its costs. On the other hand, when transmission providers are granted avenues to spend at ratepayer expense without consideration as part of a regional plan, the result has been high levels of spending on projects of uncertain value to consumers. There are two factors that together result in inadequate regional transmission planning.

The background factor is the fundamental tension justifying economic regulation of monopoly-like behavior in the first place: frequently monopolies have incentives to act contrary to the public interest. Many existing transmission owners are affiliated with retail franchise service territories and operate in the same region, or transmission owners are affiliated with generating resources within a region, or affiliated with a retail franchise and generating resources. Such transmission owners may be incentivized to overinvest in capital intensive projects, including transmission expansion, at the expense of customers in their retail franchise area, or plan their transmission expansions in a way that favor their generators at the expense of competing resources.

Order No. 1000 provides for an orderly process for transmission providers and others to engage in the required regional and interregional transmission planning, but the rules contain exemptions under which transmission spending can also proceed at the utility's exclusive discretion. These exemptions give transmission providers the means by which they can operate contrary to the public interest. The Complaint establishes that existing utilities have used their local planning tariffs to engage in precisely this behavior. The California, Florida, Maine and Ohio examples mentioned earlier demonstrate that transmission providers with the ability to shield their transmission planning from regional review, and thus competitive pressures, have taken advantage of the discretion they have been granted to boost transmission spending to the benefit of investors but in ways contrary to the public interest. As previously noted, there are many more examples presented in the Complaint, and together they more than adequately demonstrate that transmission owners can and do act in this manner.

Q: CAN YOU EXPLAIN THE MOTIVES FACED BY SOME TRANSMISSION PROVIDERS IN MORE DEPTH?

A: The first factor, the prospect that a utility shielded from competition will have incentives to act contrary to the public interest, is well established in economic analysis and thoroughly recognized by the Commission. In the jurisdictional transmission environment, the PJM IMM observes, "Transmission owners have a clear incentive to increase investments in rate base given that transmission owners are paid for these projects on a cost of service basis."[35] Standard economic analysis presented in introductory economics classes highlight conditions under which companies shielded from competition can maximize profits by charging prices substantially higher than the cost of providing a good or service and therefore extract above normal returns.[36]

The Commission has often noted this incentive concerning transmission service. In Order No. 888 the Commission said:

> It is in the economic self-interest of transmission monopolists, particularly those with high-cost generation assets, to deny transmission or to offer transmission on a basis that is inferior to that which they provide themselves. The inherent characteristics of monopolists make it inevitable that they will act in their own self-interest to the detriment of others by refusing transmission and/or providing inferior transmission to competitors in the bulk power markets to favor their own generation, and it is our duty to eradicate unduly discriminatory practices.[37]

In Order No. 890 the Commission noted that Order No. 888 had failed to eliminate undue discrimination by utility transmission providers, stating the need for reform "has been apparent for some time":

> In 1999, the Commission held, in adopting Order No. 2000, that the *pro forma* OATT could not fully remedy undue discrimination because transmission providers retained

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[35] Monitoring Analytics, LLC, *State of the Market Report for PJM 2023*, p. 721. https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2023.shtml

[36] See, e.g., Gregory Mankiw, *Principles of Economics* (7th ed.), Chapter 15, "Monopoly," CENGAGE, 2016.

[37] Order No. 888, *FERC Stats. & Regs*. at 31,682.

> both the incentive and the ability to discriminate against third parties, particularly in areas where the *pro forma* OATT left the transmission provider with significant discretion. The Commission made a similar finding in Order No. 2003, holding that opportunities for undue discrimination continue to exist in areas where the *pro forma* OATT leaves transmission providers with substantial discretion.[38]

It is worth emphasizing that last point: prior orders had failed to constrain transmission provider power exactly "in areas where the *pro forma* OATT [left] transmission providers with substantial discretion." In Order No. 1000 the Commission reiterated its concerns regarding incentives faced by transmission providers shielded from competition to act contrary to the public interest.

Transmission providers and others cited evidence of substantial growth in transmission spending, including growth after the issuance of Order No. 890, as evidence that the reforms contemplated in Order No. 1000 were unneeded. The Commission concluded, to the contrary, that the increase in spending made it "even more critical to implement [the Order No. 1000 reforms] to ensure that the more efficient or cost-effective projects come to fruition." Transmission customers and their advocates have repeatedly objected to transmission spending through processes that grant transmission providers shielded from competition with substantial discretion while exempting them from the discipline of independent planning or cost-effectiveness review. Transmission spending has increased after Order No. 1000 as well, but just as the Commission reasoned in that Order, the increase makes it even more critical to ensure that investment is made in a matter that is more efficient or cost-effective.

[38] Order No. 890, *FERC Stats. & Regs*. ¶ 31,241 at P 26.

Q: IS THERE ADDITIONAL RESEARCH THAT ILLUSTRATES INCENTIVES FACED BY TRANSMISSION OWNERS IN AREAS IN WHICH THEY OWN GENERATING RESOURCES OR SERVE RETAIL CUSTOMERS?

A: A recent economic analysis highlights the particularly adverse incentives faced by transmission owners in planning transmission investments when the owners also have generation resources in the same area. Effective, forward-looking regional transmission planning and investment would help connect new, low-cost resources to customers currently unable to reach such resources because of grid congestion. The focus of the Complaint is on over-investment in local transmission projects by transmission owners where such investment is shielded from competition. The economic analysis here reveals the complementary problem of *under*investment in more efficient regional transmission projects. Both abuses result in consumers paying too much for the transmission service to deliver electric energy. The study, *Power Flows: Transmission Lines, Allocative Efficiency, and Corporate Profits*, estimated that four transmission owners would have seen a total loss in net revenues exceeding 1.6 billion dollars in 2022 if their retail service territories were better integrated into the regional grid through efficient transmission expansion.[39] When coupled with evidence that these transmission owners actively work to discourage effective regional transmission planning and investment, as the report describes, it is clear that transmission providers that lack competitive pressures have immense incentives to act contrary to the public interest.

[39] Catherine Hausman, "Power Flows: Transmission Lines, Allocative Efficiency, and Corporate Profits," NBER Working Paper 32091, February 2024. https://www.nber.org/papers/w32091

Another industry expert sums up incentives faced by firms owning both transmission and generation assets in the same region as follows:[40]

> First, building such connections opens the door for competitors who may sell lower-priced power into their region. Second, utilities make far more money constructing power plants than building transmission lines, so they are reluctant to build connections that might permanently reduce their opportunities for future generation investments. Third, major interregional transmission projects are less financially attractive to utility companies in comparison with smaller ones. ... Smaller projects are easier to pull off and more profitable than the larger ones, because they need fewer construction permits, face less review by regulators and industry, and are built by utilities without competition from other developers. Fourth, interregional lines threaten utility companies' dominance over the nation's power supply.

Again, this article highlights the strong incentives some transmission owners face to underinvest in efficient regional transmission projects while the focus of the Complaint is on excessive spending on projects that currently fall under the discretion provided to some transmission owners for local projects. Both economic assessments highlight the strong incentives vertically integrated utilities face to behave in ways that benefit shareholders at ratepayer expense. Of course, even standalone transmission providers with cost-based rates face incentives to overspend on capital projects.[41] It is exactly these incentives to act contrary to the public

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[40] Ari Peskoe, "Profiteering Hampers U.S. Grid Expansion Private utility companies are blocking new interregional transmission lines," IEEE Spectrum, February 22, 2024. https://spectrum.ieee.org/transmission-expansion

[41] H.A. Averch, "Averch–Johnson Effect," In *The New Palgrave Dictionary of Economics* (Palgrave Macmillan, 1987). https://doi.org/10.1057/978-1-349-95121-5_388-1.

interest—to spend inefficiently or fail to spend efficiently--that government regulation was intended to correct.

The report *Mind the Regulatory Gap: How to Enhance Local Transmission Oversight* examines oversight for local transmission projects compared to regional ones and highlights a "regulatory gap" that creates inefficiencies in grid expansion.[42] Local projects, often exempt from rigorous review by state regulators, regional planning entities, and FERC, have become a low-risk investment for utilities. According to researchers, the regulatory gap has led to a significant shift in spending toward smaller, uncoordinated projects that fail to meet broader regional needs, contributing to rising costs, inefficient grid development, and missed opportunities for system-wide benefits like reduced land use and environmental impact. Importantly, FERC's express jurisdiction over interstate commerce covers transmission projects labeled as local, making this regulatory gap unnecessary.

Q: HOW DO CURRENT TARIFFS ENABLE TRANSMISSION PROVIDER DISCRETION?

A: Transmission tariffs filed with the Commission often separate local transmission projects from other transmission development categories and provide transmission owners greater authority to spend on local projects without the degree of oversight provided to other categories of transmission spending. For example, Attachment K to the ISO New England Open Access Transmission Tariff (OATT) states that local projects "will not be subject to approval by the ISO

[42] Claire Wayner, et al. *Mind the Regulatory Gap*, November 2024, https://rmi.org/increased-spending-on-transmission-in-pjm-is-it-the-right-type-of-line/

or the ISO Board under the [Regional System Plan]."[43] Similarly, Attachment K to the Southern Company OATT distinguishes between "Local Transmission Planning" and "Regional Transmission Planning."[44]

Notwithstanding its regional planning requirement, Order No. 1000 allowed individual transmission owners to plan transmission facilities located within a public utility transmission provider's retail distribution service territory or footprint if not submitted or selected in the regional transmission plan for purposes of cost allocation.[45] At the same time, Order No. 1000 allowed such transmission facilities to be included in regional transmission plans for informational purposes, while acknowledging that the presence of the facilities in the required regional transmission plans "does not necessarily indicate an evaluation of whether such transmission facilities are more efficient or cost-effective solutions to a regional transmission need."[46] In Order No. 1000, the Commission anticipated regional planning could identify solutions that "resolve the region's needs more efficiently or cost-effectively than solutions identified in the local transmission plans of individual public utility transmission providers." Instead, current practice has allowed local plans of individual transmission providers to displace, rather than complement, development of more cost-effective regional plans.

Allowing for individual transmission owner local planning discretion for regionally impactful transmission facilities at 100 kV and above requires rethinking. In effect, current practice assumes that a transmission facility worth constructing in the 1960s or 1970s is worth rebuilding,

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[43] ISO New England Open Access Transmission Tariff, Attachment K. https://www.iso-ne.com/staticassets/documents/2021/07/sect_ii_att_k.pdf.
[44] Southern Company Open Access Transmission Tariff, Attachment K, http://www.oasis.oati.com/SOCO/SOCOdocs/Southern-OATT_current.pdf
[45] Order No. 1000, ¶ 63.
[46] Order No. 1000, ¶ 64.

in the same location and at the same voltage, 40 or 50 years later. The substantial changes in the industry, the national economy, and the interconnected transmission grid, and the varied locations of new generation interconnection, over the intervening years render the assumption indefensible. Had transmission provider spending on local projects remained modest, it would not much matter whether the underlying assumption was defensible or indefensible. However, transmission provider spending on local projects has been far from modest. The exception that allowed transmission provider spending for local projects has become the rule, while transmission investment resulting from cost-effective regional planning has become the exception.

Numerous commenters have raised concern over unsupervised local spending in the most recent effort to advanced regional transmission planning, as the Commission acknowledged in its proposed rulemaking to address transmission planning and cost allocation.[47] To assure cost-effective transmission development at just and reasonable rates, the Commission must revise tariff provisions enabling existing transmission owners to bypass full regional planning for new transmission spending, whether fully new transmission or rebuilding transmission facilities that have reached the end of operational life. Replacing the current transmission discretion with a bright-line test for identifying transmission projects subject to regional transmission requirements is necessary to meet planning needs identified in Order No. 1000. To ensure just and reasonable transmission rates, the bright-line rule adopted for regional transmission planning should be identical to the bright-line rule the Commission has adopted for applicability of NERC reliability regulations: a standard 100 kV threshold for facilities meeting the BES definition. The

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[47] Federal Energy Regulatory Commission, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, RM21-17-000, April 21, 2022. See ¶ 390-397.

fact that local transmission facilities receive a rate and regulated return under a FERC-jurisdictional tariff underscores the need for local facilities to follow the same planning processes. Such coordination would reduce confusion and simplify regulatory compliance while ensuring that regionally impactful Commission jurisdictional transmission is regionally planned.

Q: HOW ARE REGIONALLY IMPACTFUL TRANSMISSION FACILITIES CURRENTLY IDENTIFIED?

A: Order No. 1000 requires all public utility transmission providers to participate in a regional transmission planning process that generates a regional transmission plan. However, only transmission projects for which a public utility seeks regional cost allocation require *approval* in the regional planning process. As a result, transmission owners can unilaterally identify through their "local" planning process transmission investments that have regional impact and have them incorporated into the regional planning process without subjecting the proposed projects to any independent review or assessment of the value of the project to the region, or whether there are more efficient or cost-effective projects for consumers. As laid out in the Complaint, projects of all voltages have been planned as "local" even when they are transmission facilities that are part of the BES.

There are only two types of grid facilities not of significant regional importance and not needed to be planned in regional processes. First, any facilities deemed to be distribution level, and thus outside of Commission jurisdiction, would not be included in regional planning processes. Second, those transmission facilities serving a limited group of transmission customers not otherwise integrated into the regional grid need not be planned in regional processes. The

Commission identified a “Seven Factor Test” in Order No. 888 as a tool for distinguishing Commission-jurisdictional transmission facilities from distribution facilities.[48] The seven factors include proximity to retail customers, radial character of line, direction of power flows, whether power can be reconsigned or transported for others, geographic area power consumed within, presence of metering, and voltage levels. The test is used to establish a boundary between federally regulated transmission facilities and state-regulated distribution facilities. The “Mansfield Test” is a Commission-approved method for considering whether transmission resources are sufficiently integrated into the regional grid to warrant cost recovery through regional rates rather than by direct assignment to specific transmission customers.[49] Individual transmission owners should not be planning Commission-jurisdictional transmission above 100 kV as such facilities, as such facilities are not “local.”

Q: HOW DOES THE DEFINITION OF THE BULK ELECTRIC SYSTEM COMPARE TO THE DISTINCTION BETWEEN TRANSMISSION AND DISTRIBUTION FACILITIES PRODUCED BY THE SEVEN FACTOR TEST?

A: Recognizing that transmission facilities have regional impact, the Energy Policy Act of 2005 amended the Federal Power Act to require the Commission to designate an Electricity Reliability Organization (ERO) to devise reliability standards that would apply to the bulk electricity system (BES) and authorized the Commission to make individual reliability standards mandatory.[50] The

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[48] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*. Order No. 888. FERC STATS. & REGS. ¶ 31,036, 61 Fed. Reg. 21,540 (1996) at 31,771

[49] *Mansfield Mun. Elec. Dept. v. New England Power Co.*, 97 FERC ¶ 61,134 (2001), order on reh’g, 98 FERC ¶ 61,115 (2002).

[50] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005).

Commission designated the North American Electric Reliability Corporation (NERC) to serve as ERO. Core to the task was identification of the transmission facilities to which mandatory reliability standards would be applied, or in other words the establishment of a clear definition of the BES.

The definition of the BES underwent several phases of refinement. The original definition of the BES was intended to encompass all grid elements and facilities **necessary** for the reliable operation and planning of the interconnected power system.[51] Concerned about variation across regions, in 2010 the Commission ordered NERC to revise the BES definition to eliminate regional discretion over local variations without Commission or NERC review and to establish a threshold requirement to include all facilities operated at or above 100 kV.[52] The Commission accepted NERC's revised definition establishing a requirement for inclusion of all facilities operated at or above 100 kV in Order No. 773, adopted in 2012. The rules, as refined and reinforced by Order No. 773-A, became effective in 2014.[53]

While the definition of the BES employs a 100 kV voltage threshold, the definition of BES also allows for well-defined exceptions in the form of rules for inclusion of facilities not directly meeting the voltage threshold but determined to be relevant to the reliable operation of the grid, and exclusions of facilities that meet the voltage threshold but are not necessary to the operation of the grid. The BES definition states that local distribution resources are not included in the BES. Thus, the Seven Factor Test described above is relevant to cases in which public utilities

[51] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, order on reh'g, Order No. 693-A, 120 FERC ¶ 61,053 (2007)

[52] *Revision to Electric Reliability Organization Definition of Bulk Electric System*. 133 FERC ¶ 61,150 (Issued November 18, 2010), order on reh'g, Order No. 743-A, 134 FERC ¶ 61,210 (Issued March 17, 2011).

[53] *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*. Order No. 773, 141 FERC ¶ 61,236 (Issued December 20, 2012), order on reh'g, Order No. 773-A, 143 FERC ¶ 61,053 (Issued April 18, 2013).

seek to have facilities excluded from mandatory reliability rules on the grounds that the facilities, even if above 100 kV, are used solely for local distribution and, thus, should be removed from the requested mandatory regional planning requirements.

Q: SHOULD RULES DESCRIBING FACILITIES SUBJECT TO A MANDATORY REGIONAL PLANNING OBLIGATION BE MADE CONSISTENT WITH SIMILAR RULES GOVERNING RELIABILITY STANDARDS?

A: Current rules have primarily targeted reliability standards for jurisdictional transmission facilities 100 kV or above. However, given the interconnectedness of transmission facilities at and above that voltage threshold, it is logical to apply the rationales that drove reliability rules to a bright-line requirement to the rules governing planning of Commission-jurisdictional transmission facilities. Indeed, employing distinct rules for reliability and transmission planning implies the possibility of transmission facilities important enough to be made subject to mandatory federal reliability requirements but not important enough to warrant full consideration in regional transmission processes—or the reverse case in which jurisdictional transmission projects emerge from regional transmission planning processes yet are not deemed significant enough to be subject to reliability rules. While such results may be unlikely, consistency across reliability and transmission planning rules would eliminate any possibility of such incongruous outcomes. Only in cases in which utility facilities over the 100 kV threshold are determined to be distribution facilities via the Seven Factor Test or are found not to be integrated into the transmission grid via a Mansfield Test would such facilities not be required to obtain approval at the regional level.

Q: SHOULD THERE BE ANY OTHER EXCEPTIONS TO THE COMPLAINT'S PROPOSED REQUIREMENT THAT ALL FACILITIES AT OR ABOVE 100 KV BE REGIONALLY PLANNED?

A: The Complaint seeks a bright-line rule for FERC-jurisdictional transmission facilities at or above 100 kV to be regionally planned. The only potential exception would involve an emergency rebuild, such as planning and implementing the reconstruction of and major repairs of a 230 kV line or facility that was substantially damaged during a storm.

III: EFFICIENT TRANSMISSION PLANNING REQUIRES AN INDEPENDENT TRANSMISSION PLANNER

Q: DO YOU HAVE FURTHER RECOMMENDATIONS CONCERNING THE RELIEF SOUGHT IN THE COMPLAINT?

A: The emphasis of my testimony so far has been on the critical role to be played by a bright-line requirement set with a 100 kV threshold for identifying transmission projects that require review and approval through regional transmission planning processes. This one step will go far to ensure future transmission rates will be just and reasonable. However, there are complementary rule changes necessary to ensure the results of such planning processes satisfy Order No. 1000 requirements for transparency in transmission planning and otherwise yield just and reasonable rates.

This necessary second step is a requirement for an independent transmission planner (ITP) or independent system planner[54] to address inefficiencies and biases in current planning processes.

[54] Similar ideas have been advanced under the names of "independent transmission monitor" and "independent transmission planner." Here these terms are treated as synonymous. See, e.g., John Cropley, "States Urge More Transparency on Tx Planning, Independent Monitors," *RTO Insider*, October 7, 2022; Devin Hartman and Kent

Even when transmission planning is done through Commission-recognized regional transmission planning processes, existing transmission owners can exert undue influence over outcomes by selective disclosure of generation investments plans, customer load forecasts, and the life expectancy of existing assets.

Under the current framework, even in regions with Commission-recognized planning processes, transmission owners exert disproportionate influence on outcomes. This influence stems from their ability to selectively disclose information—such as generation investment plans, load forecasts, and asset life expectancies—and skew planning in their favor. Evidence of this bias is stark: in Order No. 1000 regions outside RTOs/ISOs, there have been no regional projects to date. WestConnect's planning process failed to identify regional needs, yet an affiliate of Xcel classified a 560-mile double circuit-345 kV project as a "local" project.[55] And, as described above, even within regions with transmission planning conducted by RTOs, to the extent transmission owners are provided discretion to self-authorize spending on local transmission projects such discretion compromises the independence of the regional transmission planning process. Such discretion undermines the integrity of planning processes, even in regions governed by RTOs/ISOs, where the distinction between "local" and "regional" projects creates a loophole for bypassing scrutiny. As a result, planning decisions often prioritize utility interests over cost-effectiveness, system reliability, and equitable outcomes. An ITP would be instrumental in mitigating these issues. By providing independent oversight, the ITP would

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Chandler, "Stakeholder Soapbox: A Transmission Planning Resolution Emerges," *RTO Insider*, December 14, 2022; Claire Wayner, et al. *Mind the Regulatory Gap*, November 2024.

[55] Ethan Howland, "Colorado cities urge FERC to reject cost allocation for Xcel's $2B Power Pathway transmission project," *Utility Dive*, February 21, 2024. https://www.utilitydive.com/news/colorado-cities-mean-ferc-xcel-psco-cost-allocation-transmission-power-pathway/708035/.

ensure that planning processes incorporate a full and transparent evaluation of costs, benefits, and alternatives.

Furthermore, the ITP would address the inefficiencies of areas outside of RTOs where regional plans are often little more than aggregated utility plans, an approach which fails to adequately consider alternatives or prioritize regional optimization.[56] Given that utilities often have the motive and the means to act contrary to the public interest—as discussed in detail above—utility transmission plans cannot be assumed to result in the best projects developed in a cost-effective manner. In other words, a collection of utility transmission plans cannot be assumed to result in rates that are just and reasonable.

Q: HOW SHOULD THE INDEPENDENT TRANSMISSION PLANNER BE STRUCTURED?

A: The ITP's structure and governance must reflect its mandate for neutrality and transparency. In regions with RTOs, a standalone ITP could be established, or the duties of existing independent market monitoring entities could be expanded to take on the role. The selection of a standalone ITP could be done by the RTO board in a manner like that for market monitors. The Complaint also envisions that certain RTO regions may be able to establish strict levels of independence once local planning opportunities for facilities 100 kV and above are removed. In non-RTO regions in which transmission owners met Order No. 1000 requirements through formation of a regional planning entity, that entity could be designed as the ITP if reformed to meet Commission independence standards. The involvement of state authorities and regional

[56] Chen and Hartman, p. 12.

stakeholders would ensure regional alignment and reduce the risk of individual utility control of the process.

The ITP would oversee both regional and interregional transmission planning processes as well as monitor transmission projects in development to ensure timeliness and effective cost management. In regions lacking RTOs, state authorities in the region would work collaboratively to select the independent transmission planner. The activities of the independent planner could be funded by an administrative fee collected from transmission project developers participating in the regional and interregional transmission planning processes.[57]

Q: HOW WILL AN INDEPENDENT TRANSMISSION PLANNER HELP ENSURE JUST AND REASONABLE RATES?

A: An ITP addresses key inefficiencies and biases in current transmission planning processes that undermine efforts to achieve just and reasonable rates. By enhancing transparency, the ITP will ensure that utilities fully disclose data on project needs, costs, and alternatives, enabling regulators and stakeholders to evaluate decisions more effectively. This independent oversight will prevent utilities from selectively withholding critical information, such as generation plans and load forecasts, that can skew outcomes toward their own interests.

The ITP will also hold utilities accountable for cost management by scrutinizing spending on both local and regional projects. Additionally, the ITP will align local projects with broader system goals, optimizing investments to reduce redundancy, lower costs, and minimize land use

[57] Additional discussion is provided in *Reply Comments of the ITM Coalition*, Docket No. RM21-17-000 (filed Sept. 19, 2022); *Post-Technical Conference Comments of the ITM Coalition*, Docket Nos. AD22-8-000 and AD21-15-000 (filed April 23, 2023).

and environmental impacts. By empowering stakeholders with impartial analyses and supporting data, the ITP will enable meaningful engagement and more equitable planning outcomes, helping to ensure ratepayer funds are used in a manner that serves the public interest. Independent oversight, enhanced transparency of utility information, and more meaningful engagement by non-utility stakeholders will all assist the Commission in ensuring transmission rates are just and reasonable.

Q: WILL THESE TWO CHANGES ENSURE TRANSMISSION RATES ARE JUST AND REASONABLE?

A: These changes are necessary to produce transmission planning practices and transmission rates that are just and reasonable. Currently billions of dollars are being spent by transmission owners through processes that do not require consideration of alternatives, nor exposure to competitive bidding, nor evaluation for cost-effectiveness. Lacking this consideration, the resulting transmission rates cannot be deemed just and reasonable, and challenging the prudency of any project costs incurred for approved projects is not a viable means for consumers to obtain relief against projects that should have never been planned and implemented in the first place. To achieve just and reasonable rates in today's highly integrated transmission grids and to ensure a timely and efficient buildout, all transmission projects rated 100 kV or above must be planned within regional transmission planning processes. Likewise, an independent transmission planning requirement is necessary to overcome the influence of perverse incentives faced by some transmission owners and ensure the quality of regional transmission planning processes.

ATTACHMENT C

This concludes my testimony, and I reserve my right to update this testimony or provide supplemental testimony, as needed, during the course of this proceeding.

Pursuant to 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing is true and correct to the best of my knowledge, information, and belief.

Executed on December 18, 2024.

/s/ Michael Giberson

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