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

[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

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[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

[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?

[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

[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,

[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

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[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,

[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

[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

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[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.

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[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

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.

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.

Michael Giberson

/s/ Michael Giberson