UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act	**)))**	**Docket No. RM20-10-000**

JOINT SUPPLEMENTAL COMMENTS OF WIRES, THE EDISON ELECTRIC INSTITUTE, AND GRIDWISE ALLIANCE

Pursuant to Rule 212[1] of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"), WIRES,[2] the Edison Electric Institute ("EEI"),[3] and GridWise Alliance, Inc. ("GridWise")[4] (collectively, "Joint Commenters") respectfully move for leave to submit the following joint supplemental comments ("Joint Comments") on behalf of their members in response to the Commission's Notice of Proposed

[1] 18 C.F.R. § 212 (2024).

[2] WIRES is a non-profit trade association of investor-, publicly-, and cooperatively-owned transmission providers and developers, transmission customers, regional grid managers, and equipment and service companies. WIRES promotes investment in electric transmission and consumer and environmental benefits through development of electric transmission infrastructure. This filing is supported by the full supporting members of WIRES but does not necessarily reflect the views of the Regional Transmission Organization/Independent System Operator ("RTO/ISO") members of WIRES. For more information about WIRES, please visit www.wiresgroup.com.

[3] EEI is the association that represents all investor-owned electric companies in the United States. EEI members provide electricity for nearly 250 million Americans and operate in all 50 states and the District of Columbia. As a whole, the electric power industry supports more than seven million jobs in communities across the United States. EEI's member companies own and operate generation, transmission, and distribution facilities in regions in all areas of the country. EEI members are united in their commitment to get the energy they provide as clean as they can, as fast as they can, while keeping reliability and affordability front and center, as always, for the customers and communities they serve.

[4] GridWise is a membership organization of electricity industry stakeholders focused on accelerating innovation that delivers a more secure, reliable, resilient, and affordable grid to support decarbonization of the U.S. economy. GridWise is unique in its focus on the electric grid's broader ecosystem, advocating the value of integrating technologies that modernize and transform the grid. GridWise drives impactful change through its diverse membership of utilities, manufacturers, and researchers united in a common belief that the electric grid is the critical enabling infrastructure of a decarbonized economy. For more information about GridWise, please visit www.gridwise.org.

Rulemaking ("NOPR")[5] and Supplemental NOPR[6] docket related to its transmission incentives policy[7] and corresponding regulations.[8]

I. EXECUTIVE SUMMARY

Joint Commenters have consistently supported Commission policies that establish regulatory frameworks in furtherance of necessary, cost-effective transmission infrastructure investments. Joint Commenters understand the need for the Commission to refine its policies when there is a demonstrated need to do so. However, as discussed more fully below, there is no evidence to suggest that the Commission's current incentives policy is failing to achieve Congress's intended purpose of encouraging new transmission investment,[9] particularly considering the significant need for new transmission infrastructure. In fact, quite the opposite is true, as the Commission's current transmission incentives policy is working to the benefit of customers, Transmission Owners, and the public interest. With the rising demand for electricity, the Commission's existing transmission incentives policy has become even more essential. This need is underscored by developments since the issuance of the generic rulemaking in this docket five years ago, including:

[5] *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, 170 FERC ¶ 61,204 (2020).

[6] *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, 175 FERC ¶ 61,035 (2021) ("Supplemental NOPR").

[7] 16 U.S.C. § 824s.

[8] 18 C.F.R. § 35.35.

[9] *See* Energy Policy Act of 2005, Pub. L. No. 109-58, sec. 1241, 119 Stat. 594 (2005) ("EPAct 2005" or "Act") (providing that the Commission establish, by rule, incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power through reduced transmission congestion; additionally, the rule must, among other things, 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.).

- The administration has made it a priority to ensure that there is an adequate and continuous energy supply, and to ensure a reliable grid.[10]

- Unforeseen and significant changes in the electricity demand outlook in the United States, setting the stage for substantial, if not unprecedented, load growth stemming from the development of large data centers, reshoring of industry, and general electrification pressures. Electric transmission development will be essential to serve this growing demand.[11]

- The end of the coronavirus pandemic, which was characterized by an economic slowdown and reduced energy consumption, created challenges for forecasting post-pandemic transmission needs and exerted unique pressures on policy makers of all kinds.[12]

- Surging demand growth and announced plans for retirement of thermal generators present increased resource adequacy challenges over the next ten years, necessitating increased need for additional transmission infrastructure.[13]

- The Commission issued its new, ambitious regional transmission planning procedures in Order Nos. 1920 and 1920-A, which are intended to identify considerable new transmission portfolios. These procedures may also introduce new risks through the selection of larger and more complex projects that will be subject to the Commission's reevaluation rules.[14]

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[10] *See, e.g.*, various executive orders issued by the administration regarding the nation's energy policy.

[11] *See, e.g.*, John D. Wilson, Zach Zimmerman, & Rob Gramlich, GRID STRATEGIES, *Strategic Industries Surging: Driving US Power Demand* (Dec. 6, 2024) (*available at* https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf) (projecting 128 GW in load growth in the Unted States from 2025-2029).

[12] *See id.* at 30 (describing wide variability in load projection in the Southwest Power Pool, Inc. ("SPP") region in years following the coronavirus pandemic).

[13] NERC, 2024 Long-Term Reliability Assessment, Executive Summary at 6 (Dec. 2024) (*available at* www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf) (highlighting that the loss of thermal generators and replacement by new solar, battery, and hybrid resources may pose future reliability concerns because "the performance of these replacement resources is more variable and weather dependent than the generators they are replacing."); s*ee also* FERC Staff, 2024 State of the Markets Report at 4 (March 20, 2025) (*available at* https://www.ferc.gov/media/state-markets-report-2024) (citing to NERC 2024 Long-Term Reliability Assessment).

[14] *Building for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068 (2024), *order on reh'g & clarification*, Order No. 1920-A, 189 FERC ¶ 61,126 (2024).

- An overall transition into a period of higher international tensions and geopolitical competition in which promoting domestic energy independence and security is considered a heightened priority.[15]

Accordingly, Joint Commenters request that the Commission thoroughly evaluate how current transmission incentives are aligned with today's needs and goals. Joint Commenters submit these comments to assist the Commission in understanding how the current transmission incentives policy, as it exists today, is well-structured to achieve the Commission's and Congress's goals, while remaining aligned with broader national energy policy considerations. It is the view of Joint Commenters that the public interest, consistent with national energy policy and statutory intent, would be best served by terminating the dockets that propose to diminish existing transmission incentives. However, short of closing dockets, should the Commission find it necessary to continue reviewing its transmission incentives policy, it must either (i) provide an opportunity for additional comments in this docket to allow interested parties to update the evidentiary record to reflect developments (detailed above) from the last five years; or (ii) initiate a new, generic rulemaking proceeding in which a new evidentiary record can be compiled for review and comment by interested parties.

II. BACKGROUND

It has been **six years** since the Commission issued a Notice of Inquiry ("NOI")[16] in Docket No. PL19-3-000, seeking comments on the scope and implementation of its electric transmission

[15] *See Unleashing American Energy*, Exec. Order No. 14154, 90 FR 8353 (Jan. 20, 2025) ("Exec. Order No. 14154"); *see also* Columbia University Center on Global Energy Policy, *Energy and Climate Issues During the Trump Administration's First 100 Days* (Jan. 23, 2025) (*available at* https://www.energypolicy.columbia.edu/energy-and-climate-issues-during-the-trump-administrations-first-100-days/).

[16] *Inquiry Regarding the Commission's Electric Transmission Incentives Policy*, Notice of Inquiry, 166 FERC ¶ 61,208 (2019).

incentives policy established pursuant to the EPAct 2005[17] and section 219 of the Federal Power Act ("FPA").[18] The NOI informed the Commission's NOPR,[19] issued **five years** ago, proposing modification to its electric transmission incentives policy to focus the grant of project-specific incentives on the benefits to customers of transmission investment, standardize the Regional Transmission Organization Participation Incentive ("RTO incentive") at a uniform level of 100 basis points for joining and remaining in an RTO, and retain non-ROE incentives, including the Abandoned Plant and Construction Work in Progress ("CWIP") Incentives.[20] The NOPR also proposed to change the effective date for the Abandoned Plant Incentive for regionally cost allocated projects from the date the Commission issues an order granting 100% recovery of abandoned plant costs to the date transmission projects are selected for inclusion in a regional transmission planning process for the purposes of cost allocation.[21]

A year later, the Commission issued a Supplemental NOPR[22] proposing to eliminate the existing RTO incentive for utilities that have participated in an RTO for three or more years. In response to the Supplemental NOPR, a variety of diverse interests, including transmission owning utilities, a bipartisan group of nine former FERC Commissioners and Chairs, RTOs, trade organizations, non-utility Fortune 500 corporations, large manufacturers and commercial energy buyers, states, and others, built a robust administrative record replete with data and expert testimony – backed by comprehensive legal analyses and compelling policy arguments –

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[17] *See supra* n. 9.

[18] 16 U.S.C. § 824s.

[19] *See supra* n. 5.

[20] NOPR at P 38 and section II.D (while the Commission proposed incremental reforms to the Abandoned Plant Incentive, it did not propose any reforms to the CWIP Incentive).

[21] NOPR at P 6.

[22] *See supra* n. 6.

supporting the retention of the currently-effective RTO incentive. The reply comment deadline for the Commission's Supplemental NOPR was **July 26, 2021**, just shy of **four** years ago.

As shown in the Executive Summary, there have been dramatic changes in the intervening six years since the Commission issued the NOI that further underscore the compelling need for development of transmission infrastructure. The national energy landscape has undergone, and will continue to experience, a transformational shift driven by economic growth, emerging demands from an energy intensive industry, changing expectations surrounding the electric supply mix, and evolving geopolitical considerations. The Commission's existing transmission incentives policy continues to facilitate critically needed investments in transmission infrastructure, leaving no doubt that the existing incentives policy should remain unchanged.

III. THE COMMISSION'S CURRENT TRANSMISSION INCENTIVE FRAMEWORK ALIGNS WITH THE STATUTE AND NATIONAL ENERGY POLICY

Electric transmission infrastructure development is the cornerstone of modernizing America's energy systems, boosting job creation, and securing energy independence. With the declaration of a national energy emergency, President Trump has emphasized the urgent need to revamp and expand the nation's electric grid to meet growing demands, ensure reliable power supply, and lower the total cost of delivered energy. The administration's focus on supporting large scale energy infrastructure development, including infrastructure necessary to supply electricity to support a growing economy with significant electricity needs, notably artificial intelligence data centers and "reshoring" of manufacturing capabilities, underscores the critical role of a robust, modern electric transmission network. This infrastructure is not only essential for accommodating the increasing power demands from various sectors, but also for maintaining and enhancing the overall resilience and efficiency of the nation's energy system, which itself underlies the broader economy. A reliable, resilient and efficient energy delivery system is the foundation to providing cost-effective electric service to customers of all kinds, thereby aligning with the administration's broader goals of fostering economic growth and energy security.

The United States is encountering circumstances akin to those that led Congress to enact EPAct 2005. This legislation introduced section 219 to the FPA and mandated that the Commission develop a rule for incentive-based rate treatments designed to benefit consumers by ensuring reliability and lowering the cost of delivered power. In EPAct 2005, Congress explicitly acknowledged increased levels of transmission infrastructure development were needed, without which consumers would be burdened with higher costs due to lack of investment and the resulting inefficient and unreliable service. In 2006, the Commission implemented this Congressional directive through Order No. 679,[23] which established carefully tailored incentives to address risks and challenges associated with developing beneficial transmission projects and to recognize the benefits and risks of membership in RTOs for certain entities. After nearly two decades, it is undeniable that the Commission's transmission incentives policy has provided the signal and support for transmission investments that ultimately benefit electric customers. In doing so, the Commission has helped lay the groundwork for the United States to achieve state, regional, and national objectives. Actions that eliminate or otherwise result in a less effective Commission incentives policy would be contrary to the notion that there is an urgent need for cost-effective transmission infrastructure.

Today's regulatory decisions will determine whether the United States can promote economic development at home, providing the types of jobs that support and sustain communities, and maintain its lead in the global race to develop artificial intelligence. As the Commission

[23] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057 (2006) ("Order No. 679"), *order on reh'g*, Order No. 679-A, 117 FERC ¶ 61,345 (2006), *order on reh'g* 119 FERC ¶ 61,062 (2007).

evaluates what, if any, revisions are needed to its incentives policy, it must consider that deviation from long-established and well-understood policies would disrupt expectations, create uncertainty, possibly chill investment, and increase costs for customers by eliminating rate treatments that reduce risk and aid in lower financing costs to the benefit customers. Challenges associated with transmission development are becoming more pronounced in many regions, making it increasingly difficult to develop and construct transmission infrastructure, and particularly the larger, longer distance projects that are sorely needed. If transmission incentives are repealed, or if the Commission's incentive policy is significantly diminished, the results would undermine Congress's goals intended by section 1241 of the Act. At the very least, such changes would create an imbalance between consumer and investor interests and likely result in higher costs. This is the kind of circumstance Congress hoped to avoid when it passed EPAct 2005. Ultimately, regulatory certainty and a stable utility sector benefit customers, investors, and utilities alike. Consistent regulatory approaches and actions are crucial in facilitating the construction of essential electric transmission infrastructure. The Commission's current transmission incentives policy has been effective in achieving Congress's goals, and it has never been more needed than right now.

A. RTO-PARTICIPATION INCENTIVE

FPA section 219(c) specifically requires the Commission "provide for incentives to each transmitting utility or electric utility that joins a Transmission Organization." That is the **only** specific conduct in all of section 219 for which Congress mandated an incentive. As noted in the affidavit of The Honorable Joe Barton,[24] who served as Chairman of the House-Senate Energy Conference Committee and sponsored EPAct 2005, and contrary to the Commission's

[24] *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, Comments of WIRES, Exhibit 1, Affidavit of the Honorable Joe Barton, Docket No. RM20-10-000 (2021).

interpretation in the Supplemental NOPR, section 219(c) does not explicitly or implicitly limit the duration of the incentive for joining a Transmission Organization. Like former Chairman Barton, former FERC Chairman James Danly also recognized Congress's intent in his dissent on the Supplemental NOPR stating "if Congress intended the RTO adder to only apply as an incentive 'to join' an RTO, it would have said so. It did not. The statute requires incentives be awarded to an entity 'that joins' an RTO, full stop, no limitation."[25] There is no ambiguity to this statutory language, nor is there any express or implied delegation of authority to the Commission to make any manner of interpretation as to how and under what circumstances the Commission is required to provide this incentive. The Commission is, ultimately, "a creature of statute and has only those authorities delegated to it by the Congress."[26] Any action that would restrict eligibility for this incentive beyond the requirement that a transmission owner join an RTO is *ultra vires*.[27]

Ultimately, Congress's foresight was correct. For some utilities, participation in RTOs has resulted in significant net economic benefits for customers.[28] The Commission recognized as much when it explained the RTO incentive was being proposed "in recognition of the benefits such organizations bring to customers, as outlined in detail in Order No. 2000." Since Order No. 2000, participation in RTOs has imposed significant risks and responsibilities on

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[25] Supplemental NOPR, Danly Dissent at P 5.

[26] *Enron Power Mktg., Inc. v. FERC*, 296 F.3d 1148, 1153 (D.C. Cir. 2002).

[27] *Transohio Sav. Bank v. Director, Office of Thrift Supervision*, 967 F.2d 598, 621 (D.C. Cir. 1992) ("Agency actions beyond delegated authority are 'ultra vires,' and the court must invalidate them.").

[28] *See, e.g.,* Midcontinent Independent System Operator, Inc., *Value Proposition* (Mar. 6, 2025) ("MISO 2025 Value Proposition") (*available at* https://cdn.misoenergy.org/2024%20Value%20Proposition%20Annual%20View684260.pdf) (calculating an estimated $5.1 billion in annual benefits delivered by MISO, with cumulative benefits surpassing $50 billion since 2007); *see also* Southwest Power Pool, Inc., *2023 Member Value* (Apr. 26, 2024) (*available at* https://spp.org/documents/71573/2023%20spp%20mvs%20report.pdf) (calculating annual net benefits to members of more than $3.621 billion, provided at a benefit-to-cost ratio of 20-to-1).

Transmission Owners, while the benefits of RTO membership have largely accrued to customers in the RTO footprint.[29] Thus, the RTO incentive is vitally important, as it serves to offset these increased risks and responsibilities as an essential component in maintaining the cohesion of RTOs.

Regarding risks, Transmission Owners that have joined RTOs transferred operational control of their transmission facilities to the independent RTO required to perform certain functions (*e.g.*, planning, market monitoring, congestion management, etc.). The scope of those functions has expanded significantly, which could not have been anticipated during the early stages of RTO formation. The level of complexity has also grown, and the control over individual decision-making has decreased. This includes certain investment decisions made by the RTO that may lead to an obligation to undertake high-risk transmission projects, risks that, in part, may be addressed through the availability of the RTO incentive. RTOs also manage outage coordination on a significant scale, which reduces the Transmission Owners' ability to take outages for maintenance or put new facilities in-service. Transmission Owners in RTOs must also comply with a more expansive set of federal regulations, such as Order Nos. 719,[30] 745,[31]

[29] London Economics International LLC, *Economic Considerations in the Matter of Electric Transmission Incentives*, at 28-29 (Jul. 1, 2020) (*available at* https://wiresgroup.com/economic-considerations-in-the-matter-of-electric-transmission-incentives/).

[30] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 125 FERC ¶ 61,071 (2008), *order on reh'g*, Order No. 719-A, 128 FERC ¶ 61,059 (2009), *order denying reh'g & clarification*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[31] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 134 FERC ¶ 61,187 (2011), *order on reh'g & clarification*, Order No. 745-A, 137 FERC ¶ 61,215 (2011), *order denying reh'g*, Order No. 745-B, 138 FERC ¶ 61,148 (2012).

841,[32] and 2222,[33] which significantly and disproportionally impact RTO regions. Through these actions, the Commission has fundamentally altered the business model, exposed certain future capital investments of Transmission Owners to competition, increased the potential that investments will be delayed and deprive customers of the benefits, and created significant uncertainty and related regulatory risk. The RTO incentive compensates Transmission Owners for the risks incurred in delivering the benefits to customers, and those documented benefits (*e.g.*, access to lower cost power, efficient dispatch over wide-area footprint, and enhanced reliability)[34] far outweigh the cost of the RTO incentive.

Eliminating or significantly revising the RTO incentive (limiting the duration, reducing the size) on the basis that it is causing rates to become unjust and unreasonable is highly misleading. The cost of the RTO incentive cannot be viewed in isolation of the benefits to customers and should also be considered in the context of the added burdens the Commission has placed on transmitting utilities in RTOs (*e.g.*, Order Nos. 2222, 841, 745). These considerations are especially relevant as the United States seeks to drive the development of large-load data centers and manufacturing onshore. The RTO incentive will continue encouraging utility membership and facilitating investments required to promptly accommodate new large loads. Furthermore, it cannot be overlooked that the availability of the RTO incentive has largely overlapped the period during which RTOs/ISOs in the United States have existed in their current form. This makes it especially hard to unwind the interrelated nature of the incentive and RTO

[32] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, 162 FERC ¶ 61,127 (2018).

[33] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 172 FERC ¶ 61,247 (2020), *order on reh'g & clarification*, Order No. 2222-A, 174 FERC ¶ 61,197 (2021), Order No. 2222-B, 175 FERC ¶ 61,227 (2021).

[34] MISO 2025 Value Proposition at 1.

participation, and therefore to forecast the full effects of eliminating the incentive. Such negative ramifications of removing the RTO incentive would not be known until it was too late and could include utility elections to leave RTOs/ISOs, utility decisions not to join an RTO, or higher financing costs resulting from the loss of a mechanism to reflect and compensate for RTO participation risk. It would be imprudent for the Commission to diminish essential incentives for transmission development at this juncture, as doing so may undermine and compromise the ability of RTOs to advance necessary transmission and associated customer benefits.

B. ABANDONED PLANT INCENTIVE

Adopted by the Commission in 2006 in Order No. 679, the Abandoned Plant Incentive addresses regulatory obstacles and promotes capital attraction to capital-intensive, long-term infrastructure projects.[35] The Commission reasoned that permitting recovery in rates of 100% of prudently incurred costs, and a return on the unrecovered costs expended from the date of the Commission order on the projects that are cancelled or abandoned due to factors beyond the control of the developer, will reduce regulatory uncertainty associated with investments in new transmission capacity and therefore meet the objectives of FPA section 219. FPA section 219 has not changed and the potential for a transmission facility to be cancelled or abandoned has not either. The Abandoned Plant Incentive is a risk-reducing ratemaking tool that allows utilities to seek pre-approval from FERC for the opportunity to later file to recover 100% of prudently incurred costs for certain transmission projects that are cancelled or abandoned due to factors beyond the control of the developer. These situations typically occur in RTO regions, where the independent transmission provider has the authority to instruct transmission developers to commence construction and later determine whether a project should be canceled due to

[35] Order No. 679 at PP 163-167.

changing conditions. The risk-reducing nature of the Abandoned Plant Incentive boosts the ability of utilities to keep financing costs down by reducing utility risk exposure, even in the face of challenges encountered during the state and federal permitting processes, as well as risks stemming from other obstacles that are present at different stages in the project development process.

Today, an applicant may request the Abandoned Plant Incentive at any point in project development, including prior to initiating state permitting processes. This is crucial, as pursuing state permits for large-scale projects is a costly and time-consuming exercise to which utilities must devote significant resources to develop analyses and filings to meet state permitting requirements. While transmission developers would prefer to wait until state permits have been obtained before ordering expensive, long-lead equipment, this often is not possible due to competing demands of the planning region's need date for the project, supply chain constraints, and other time-consuming project development workstreams like land acquisition. Deposits on equipment often are the largest up-front expense prior to physical construction and may require 3-5-years lead time to achieve the expected in-service date.

Equally important, waiting until any necessary state siting permits are in hand prior to ordering equipment would most likely compromise the in-service date as it often takes 2-4 years to complete the permitting and siting processes. For these reasons, any restriction on the availability of the Abandoned Plant Incentive prior to a project receiving state permits could be at odds with the need for early-stage capital commitments in light of current supply chain challenges and resultant long lead times. Further, it could cause transmission developers needless harm from a credit perspective. One reason the regulated investments contribute significantly to a company's score is the expectation of recovering invested capital. Without this expectation, the investment may not be assessed as fully regulated by the rating agencies; and, in turn, may require stronger financial metrics to maintain the same credit rating, assuming all else being equal. Thus, any such limitation would undermine objectives of FPA section 219.

Customer protection is frequently discussed within the context of the Abandoned Plant Incentive. To receive the Abandoned Plant Incentive, a transmission developer must first request approval from the Commission. While this provides the *opportunity* for 100 % cost recovery, in the event a project is cancelled for reasons beyond the transmission developer's control, the developer must make a second filing under FPA section 205 where it carries the burden to demonstrate that the cancellation is beyond its control and the costs were prudently incurred. This two-tiered process with an opportunity for public comment ensures customer protection while giving the utility the opportunity to mitigate the risk that projects may be abandoned for reasons beyond the utility's control.

Another way to consider the customer benefits of the Abandoned Plant Incentive is a mechanism that helps address transmission development risks. Ultimately, project cancellation risk for large projects exists and is considerable, even if it is low probability. The presence of this risk will inevitably change investors' perception of a utility seeking to secure financing and consequently may affect a utility's rates. The Abandoned Plant Incentive provides the Commission with a mechanism to comprehensively address project-specific risk, thereby isolating its impacts from the broader ratemaking structure. Importantly, absent the Abandoned Plant Incentive, this risk would inevitably have to be addressed elsewhere, most likely through alternative means, such as higher costs of capital. If these project cancellation risks were to be handled through this alternative mechanism, the higher capital costs would apply to the entire rate base and lead to higher costs to customers regardless of whether any projects are cancelled.

This is likely an inferior, and more costly, outcome compared to using the Abandoned Plant Incentive.

The numbers demonstrate the value of the Abandoned Plant Incentive and the balance it represents. Since 2006, the Commission has granted transmission developers the Abandoned Plant Incentive for **more than 190 projects in over 120 docketed cases**[36] across the entire country. These projects, which received Abandoned Plant Incentives, amounted to more than **$70 billion of transmission infrastructure** to serve customers.[37] Of the projects approved for the Abandoned Plant Incentive, approximately **10 projects were cancelled** and successfully sought and received Abandoned Plant Cost Recovery.[38] The Commission allowed Abandoned Plant Cost Recovery for those projects, amounting to approximately **$290 million recovered from**

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[36] The docketed incentives cases in question are listed in Appendix A to these Joint Comments. The cases listed represent a number of projects for which the Abandoned Plant Incentive (at 100%) was requested and approved, with an effort to exclude projects that were not completed. The list, which is informative, may not be exhaustive.

[37] This dollar value represents the sum of estimated project costs listed in the incentive application for the projects referenced as receiving the Abandoned Plant Incentive.

[38] *See, The Potomac Edison Co.*, 190 FERC ¶ 61,074 (Feb. 7, 2025); *Potomac-Appalachian Transmission Highline, LLC*, 185 FERC ¶ 61,198 (Dec. 19, 2023) (approving the settlement resolving all issues in dispute in Docket Nos. ER09-1256 and ER12-2708 regarding the PATH Project); *Duquesne Light Co.*, 184 FERC ¶ 61,018 at PP 22-23 (July 11, 2023) (finding that Duquesne qualified to recover 100 % of its prudently incurred abandoned plant costs for the Dravosburg and Beaver Valley Projects); *Pacific Gas and Elec. Co.*, 170 FERC ¶ 61,017 (Jan. 17, 2020), *order on reh'g*, 172 FERC ¶ 61,057 (July 16, 2020); *Baltimore Gas and Elec. Co.*, 156 FERC ¶ 61,014 (July 6, 2016) (approving settlement addressing BG&E's cost recovery associated with the Mid-Atlantic Power Pathway ("MAPP") Project); *Southern Cal. Edison Co.*, 148 FERC ¶ 61,126 (Aug. 15, 2014) (granting SoCal Edison's request to recover prudently-incurred project costs associated with abandonment of a portion of the Tehachapi Renewable Transmission Project); *Potomac Elec. Power Co.*, 146 FERC ¶ 61,147 (Feb. 28, 2014) (approving the settlement addressing recovery of abandonment costs associated with abandonment of the MAPP Project); *Pub. Serv. Elec. and Gas Co.*, 144 FERC ¶ 61,176 (Aug. 30, 2013) (approving the settlement to recover costs associated with the abandonment of the Branchburg-Roseland-Hudson Project); *Southern Cal. Edison Co.*, 159 FERC ¶ 62,038 (Apr. 10, 2017) (approving uncontested settlement); *Pacific Gas & Elec. Co.*, 170 FERC ¶ 61,057 (Jan. 17, 2020), *order on reh'g*, 172 FERC ¶ 61,057 (July 16, 2020).

customers and representing roughly 0.4 % of the planned capital cost.[39] These statistics demonstrate that the vast majority of Transmission Owners/developers that seek and are granted the Abandoned Plant Incentive seldom, if ever, find it necessary to seek cost recovery. However, if the ability for the Transmission Owner to mitigate the risk is diminished or eliminated, the change will have a significant impact on transmission developers and customers. That is, the transmission sector may be perceived as inherently riskier by investors. Consequently, this could lead to an increased cost of capital, which may affect customers more substantially in the long term than the incentive itself.

One question that frequently arises in discourse surrounding the Abandoned Plant Incentive is whether the Commission's policy for determining whether to grant the incentive could be better and more clearly targeted. While the desire for more objective criteria is understandable, it is neither necessary nor advisable. There have been significantly more transmission projects proposed and built than the 190 filed with the Commission for the Abandoned Plant Incentive. The Commission over time and through cases has guided Transmission Owners and developers not to seek incentives for "routine" projects,[40] and to avail themselves of risk-reducing incentives before seeking a project-specific ROE incentive.[41] Transmission Owners and developers have learned to self-police the requests, with many recent incentive requests sought for large regional transmission projects that, in the developer's judgment, present more types of risk or greater overall risk to completion than other projects.

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[39] These numbers represent the sum of Commission-approved abandoned plant recovery amounts. The percentage is calculated by dividing the total approved abandoned plant amount by the total estimated cost of projects that received the Abandoned Plant Incentive.

[40] *Baltimore Gas & Electric Co*., 120 FERC ¶ 61,084 at P 48-55 (2007)

[41] *Promoting Transmission Investment through Pricing Reform*, 141 FERC ¶ 61,129 (2012) ("2012 Policy Statement").

The statutory rebuttable presumption also acts as a gate keeper, *i.e.*, the need to develop a worthy defense of a project's reliability and congestion benefits. Thus, narrowing the types of projects that may seek the grant of the Abandoned Plant Incentive is ultimately an unnecessary step. Practically, such a reform would entail a more involved effort for the Commission to stand in the shoes of the developer and identify those projects that "most deserve" the incentive, *i.e.*, to filter for those projects that are most likely to be abandoned. The effort will create burden – both in developing and implementing the policy – with little benefit.

In the end, if the policy is well-constructed, all the projects that deserve the Abandoned Plant Incentive will get it, and the same projects will recover abandonment costs when warranted, with the same rate impact to customers. If projects that do not ultimately file for abandoned plant recovery receive the incentive, there is very little downside, and there may indeed be an upside for customers. It is important to bear in mind that granting the Abandoned Plant Incentive is costless to customers in the vast majority of cases – customers only face cost in the case that a project is cancelled, and the Commission approves cost recovery. Rather, in most cases customers likely benefit from the ensuring higher cost recovery certainty and lowered perceived project risk. Indeed, there may be a benefit in expanding the risk-reducing benefits of the Abandoned Plant Incentive to leverage this dynamic. Unless the Commission intends to simplify and expand its availability, there is no reason to expend effort to modify the Commission's approach to granting the Abandonment Incentive.

C. CWIP INCENTIVE

Order No. 679 also allows utilities to apply to include 100% of CWIP in rate base – known as the "CWIP Incentive" – for projects that meet specific criteria and receive approval. This incentive aims to ease the substantial financial pressure developers often face by otherwise having to defer recovery of financing costs for capital investment until the asset is placed in service. This limitation on cost recovery can pose particular challenges for investors in large transmission projects being developed over a prolonged development cycle, *e.g.*, 5-10 years. According to traditional electric ratemaking principles, project costs, including financing, are typically recoverable through rates only after an asset is in service and deemed "used and useful." However, due to the unique characteristics associated with construction of electric transmission, which can take several years, the Commission allowed the CWIP Incentive as an exception to this principle to incentivize further transmission development, improve cash flow to service debt and equity investor returns during construction periods, stabilize rates, and ultimately reduce costs for customers.

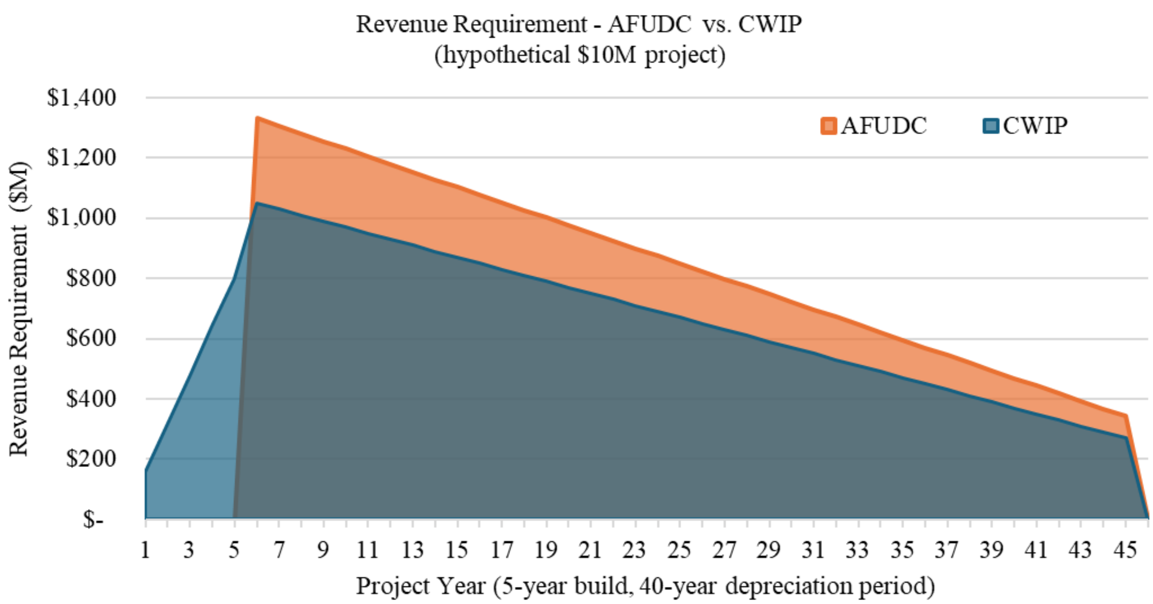
Similar to the Abandoned Plant Incentive, the CWIP Incentive is an example of balancing the interests of investors, utilities, and customers. In addition to improving cash flow and helping utilities to maintain credit metrics – and therefore to keep borrowing costs low – one of the main advantages of the CWIP Incentive is its ability to include 100% of construction costs in the rate base prior to the commercial operation of facilities, offering substantial benefits for customers. Since 2006, FERC has granted the CWIP Incentive to transmission developers for **more than 130 projects in over 75 docketed cases**.[42] Projects receiving the CWIP Incentive have amounted to more than **$30 billion in transmission infrastructure** to serve customers.[43] By utilizing CWIP, developers can potentially lower costs for customers over the life of the project. For example, for one illustrative hypothetical, compared to traditional ratemaking, the CWIP

[42] The docketed incentives cases in question are listed in Appendix B to these Joint Comments. The cases listed represent a count of projects for which the CWIP Incentive was requested and approved, with an effort to exclude projects that were not completed. The list, which is informative, may not be exhaustive.

[43] This dollar value represents the sum of estimated project costs listed in the incentive application for the projects referenced as receiving the CWIP Incentive.

Incentive is estimated to provide **14% savings** on a nominal basis. On a net present value basis, it offers approximately **9-11% savings** for customers if one assumes a discount rate in the range of historical average CPI growth.[44] This is because recovering a return on investment as it unfolds overtime costs customers less than accruing that return and then capitalizing it over the life of the project (illustrated in Figure 1 below).

Figure 1: Illustrative Revenue Requirement Comparison Between AFUDC and CWIP



These savings are greatest for larger projects that take longer to develop. Moreover, the ability to recover revenue return during construction results in more favorable borrowing costs, which also reduces costs to customers in the near and longer term. As capital expenditures grow, the impact on cash flows and credit metrics will differ among Transmission Owners. If utilities'

[44] This result was based on a hypothetical project with a linear outlay of capital during a 5-year construction period, a 40-year depreciation period, an 8% weighted average cost of capital (WACC) for the developer, and an assumption that AFUDC accrues at a level equal to WACC. For the NPV adjusted calculation, a discount rate in the 2-3% range was assumed. This result also assumes all is equal between the two cases, particularly credit ratings and borrowing costs (that could, in practice, increase in the AFUDC case as the result of cash flow pressures).

credit metrics are constrained, it could – and for some utilities *would* – lead to higher customer costs through increased utility financing costs not only for a specific project, but could impact all projects for a particular company because of cash-flow concerns of creditors.

Critically, the above benefits are magnified when CWIP is available at an early stage of the development process. Similar to the Abandoned Plant Incentive, any restriction of the availability of the CWIP Incentive prior to a project receiving state permits is unnecessary to protect customers and undermines the very purpose of the transmission incentive framework the Commission laid out in Order No. 679 pursuant to EPAct 2005. Further, having access to CWIP earlier in the development cycle is especially important for smaller capitalized companies who lack the internal equity and need to finance earlier in the process, even before a state permit is issued. For these companies, having CWIP approved improves the financial position of the project thus enabling lower financing rates, further lowering costs to customers. For the above reasons, the Commission should retain the CWIP Incentive unchanged.

IV. CONCLUSION

As detailed above, if the Commission aims to stimulate, rather than hinder, critical energy infrastructure development, it is the view of Joint Commenters that the Commission's existing transmission incentives policy is effective and appropriate as currently constituted. With this in mind, Joint Commenters proffer that Commission action to terminate the above-captioned rulemaking proceeding is the clearest path to achieve regulatory certainty and align transmission incentive policy with national energy policy. Joint Commenters recognize that the Commission may not yet be prepared to close the instant docket. Short of closing this docket, should the Commission find it necessary to continue reviewing its transmission incentives policy, it must either (i) provide an opportunity for additional comments in this docket to allow interested parties to update the evidentiary record to reflect developments (as detailed herein) from the last five years; or (ii) commence a new, generic rulemaking proceeding on the issue of transmission incentives policy in which a new evidentiary record can be compiled for review and comment by interested parties.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day had served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 3rd day of April 2025.

/s/ Larry Gasteiger
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APPENDIX A

List of FERC Dockets Approving Abandonment Incentive

Appendix A:

List of FERC Dockets Approving Abandonment Incentive, with Project Names (non-exhaustive)

	DOCKET	APPLICANT(S)	PROJECT NAME
1	EL06-54	Allegheny Power	Trans-Allegheny Interstate Line
2	EL07-62	Southern California Edison	DPV5
3	EL07-62	Southern California Edison	Tehachapi
4	EL07-62	Southern California Edison	Rancho Vista Substation
5	EL08-23	PPL/PSEG	Susquehanna-Roseland Line
6	EL08-32	Central Minnesota Municipal Power Agency & Midwest Municipal Transmission Group	Brookings Project (CapX2020)
7	EL08-74	Central Maine Power Co.	Maine Power Reliability Project (MRRP)
8	EL08-75	PacifiCorp	Populus-Terminal (Energy Gateway Project Segment B)
9	EL08-75	PacifiCorp	Mona-Oquirrh (Energy Gateway Project Segment C)
10	EL08-75	PacifiCorp	Sigurd-Red Butte-Crystal (Energy Gateway Project Segment G)
11	EL08-75	PacifiCorp	Windstar-Aeolus-Bridger-Populus (Energy Gateway Project Segment D)
12	EL08-75	PacifiCorp	Populus - Hemingway (Energy Gateway Project Segment E)
13	EL08-75	PacifiCorp	Aeolus-Mona (Energy Gateway Project Segment F)
14	EL08-75	PacifiCorp	Walla Walla-McNary (Energy Gateway Project Segment A)
15	EL08-75	PacifiCorp	Hemingway-Captain Jack (Energy Gateway Project Segment H)
16	EL08-82	Vectren South	Gibson-Brown-Reid Project
17	EL10-1	Southern California Edison	Eldorado-Ivanpah Transmission Project
18	EL10-3	Citizens Energy Corporation	Sunrise Power Link: Imperial Valley-San Diego
19	EL10-54	Desert Southwest Power	Desert Southwest Transmission Project
20	EL10-80	Ameren Services Company	Illinois Rivers Project (Grand Rivers Project)
21	EL10-80	Ameren Services Company	Big Muddy River Project (Grand Rivers Project)
22	EL11-10	Southern California Edison	Whirlwind Substation Expansion
23	EL11-10	Southern California Edison	Devers - Colorado River/Devers- Valley + Substation Expansion

	DOCKET	APPLICANT(S)	PROJECT NAME
24	EL11-10	Southern California Edison	South of Kramer
25	EL11-10	Southern California Edison	West of Devers
26	EL11-21	Central Transmission	Byron- Pleasant Valley Project
27	EL11-33	Northeast Transmission Development	Liberty East
28	EL11-33	Northeast Transmission Development	Kanawha
29	EL11-45	Missouri River Energy Services	Fargo-Monticello (CapX2020)
30	EL11-45	Missouri River Energy Services	Twin Cities-Brookings(CapX2020)
31	EL12-102	NIPSCO	Reynolds to Greentown
32	EL12-49	NIPSCO	Reynolds/Burr Oak/Hiple
33	EL12-67	WPPI Energy	La Crosse Project (CapX 2020)
34	EL13-19	Dairyland Power Cooperative	Hampton-Rochester-La Cross Project (CapX 2020)
35	EL14-51	Pacific Gas & Electric	Central Valley Transmission Upgrade Project
36	EL15-102	DCR Transmission	Delaney-Colorado River Project
37	EL15-103	SDG&E	South Orange County Reliability Enhancement Project
38	EL15-11	San Diego Gas & Electric	Sycamore Canyon-Peñasquitos Transmission Line
39	EL16-102	Citizens Energy	Central Valley Power Connect
40	EL16-47	Pacific Gas & Electric	Wheeler Ridge Junction 230 kV Substation
41	EL16-68	DesertLink	Harry Allen to Eldorado 500 kV Transmission Project
42	EL17-52	Republic Transmission	Duff-Coleman EHV
43	EL17-63	So. Cal. Edison	Alberhill System Project,
44	EL17-63	So. Cal. Edison	Eldorado-Lugo-Mohave Series Capacitor Project
45	EL18-29	Citizen’s Energy (Partnering with SDG&E)	Sycamore-Peñasquitos
46	EL19-88	NY Power Authority	AC Projects
47	EL20-29	LS Power Grid California, LLC	Gates 500 kV Dynamic Reactive Support Project
48	EL20-29	LS Power Grid California, LLC	Round Mountain 500 kV Area Dynamic Reactive Support Project
49	EL20-51	Southern California Edison	Riverside Transmission Reliability Project
50	EL20-60	Pacific Gas & Electric	Gates 500 kV Dynamic Reactive Support Project

	DOCKET	APPLICANT(S)	PROJECT NAME
51	EL20-60	Pacific Gas & Electric	Round Mountain 500 kV Dynamic Reactive Support Project
52	EL20-70	Tucson Electric Power Company	Southline Transmission Project
53	EL21-15	Citizens S-Line Transmission LLC	S-Line 230 kV Transmission Upgrade Project
54	EL22-17	Niagara Mohawk	Smart Path Connect Project
55	ER06-1549	Duquesne Light Co.	DTEP
56	ER07-1415	Xcel Energy Services Inc.	Buffalo Ridge Incremental Generation Outlet (BRIGO)
57	ER07-1415	Xcel Energy Services Inc.	Twin Cities-Brookings Country (CapX2020)
58	ER07-1415	Xcel Energy Services Inc.	Twin Cities – Fargo (CapX 2020)
59	ER07-1415	Xcel Energy Services Inc.	Twin Cities – LaCrosse (CapX 2020)
60	ER07-1415	Xcel Energy Services Inc.	Bemidji - Grand Rapids (CapX 2020)
61	ER08-1423	Pepco Holdings, Inc.	MAPP Project
62	ER08-1548	Eversource/National Grid	NEEWS Project
63	ER09-249	Public Service Electric & Gas	MAPP Project
64	ER09-35	Tallgrass Transmission	Tallgrass Project
65	ER09-36	Prairie Wind Transmission	Prairie Wind Project
66	ER09-548	ITC Great Plains	KETA (Kansas Electric Transmission Authority) Project
67	ER09-548	ITC Great Plains	Kansas V Plan
68	ER09-745	Baltimore Gas & Electric	MAPP Project
69	ER09-75	Pioneer Transmission	Pioneer Project (Greentown-Rockport)
70	ER10-147	Great River Energy	Brookings Line (CapX2020)
71	ER10-147	Great River Energy	Fargo Line (CapX2020)
72	ER10-147	Great River Energy	Bemidji Line (CapX2020)
73	ER10-159	Public Service Electric & Gas	Branchburg-Roseland-Hudson
74	ER10-183	Otter Tail Power	Brookings Line (CapX2020)
75	ER10-183	Otter Tail Power	Fargo Line (CapX2020)
76	ER10-183	Otter Tail Power	Bemidji Line (CapX2020)
77	ER11-112	Oklahoma Gas & Electric	Woodward-Hitchland
78	ER11-112	Oklahoma Gas & Electric	Woodward-Kansas
79	ER11-134	ALLETE	Fargo Line (CapX2020)

	DOCKET	APPLICANT(S)	PROJECT NAME
80	ER11-134	ALLETE	Bemidji Line (CapX2020)
81	ER11-2926	Oklahoma Gas & Electric	Sunnyside-Hugo
82	ER11-2926	Oklahoma Gas & Electric	Sooner-Rose Hill
83	ER11-2926	Oklahoma Gas & Electric	Seminole-Muskogee
84	ER11-2926	Oklahoma Gas & Electric	Tuco-Woodward
85	ER11-2926	Oklahoma Gas & Electric	Sooner-Cleveland
86	ER11-3352	Public Service Electric & Gas	Burlington-Camden
87	ER11-3352	Public Service Electric & Gas	West Orange-Fairmount Heights
88	ER11-3352	Public Service Electric & Gas	Southern Reinforcement Project (Mickleton-Camden-Gloucester)
89	ER11-4069	RITELine Illinois, RITELine Indiana	RITELine Project
90	ER12-1593	DATC Midwest Holdings	Project 1
91	ER12-1593	DATC Midwest Holdings	Project 2
92	ER12-1593	DATC Midwest Holdings	Project 3
93	ER12-1593	DATC Midwest Holdings	Project 4
94	ER12-1593	DATC Midwest Holdings	Project 5
95	ER12-1593	DATC Midwest Holdings	Project 6
96	ER12-1593	DATC Midwest Holdings	Project 7
97	ER12-2216	Ameren	Spoon River
98	ER12-2216	Ameren	Mark Twain
99	ER12-242	MidAmerican Energy	MVP-3 (O'Brian-Kossuth-Webster)
100	ER12-242	MidAmerican Energy	MVP-4 (Black Hawk - Franklin)
101	ER12-242	MidAmerican Energy	MVP-16 (Oak Grove/Galesburg)
102	ER12-242	MidAmerican Energy	MVP-7 (Ottumwa-Adair)
103	ER12-2554	Transource Missouri	Iatan-Nashua Project
104	ER12-2554	Transource Missouri	Sibley-Nebraska City Project
105	ER12-296	Public Service Electric & Gas	Northeast Grid Reliability Project
106	ER12-342	Otter Tail Power	Big Stone South-Brookings (CapX2020)
107	ER12-342	Otter Tail Power	Ellendale-Big Stone South (CapX2020)
108	ER13-2468	Central Minnesota Public Power Agency	Big Stone South – Brookings (CapX2020)

	DOCKET	APPLICANT(S)	PROJECT NAME
109	ER13-307	Montana-Dakota Utilities	Ellendale-Big Stone Project
110	ER14-1608	Public Service Electric & Gas	Bergen-Linden Corridor Project
111	ER14-1661	MidAmerican Central California Transco	Central Valley Transmission Upgrade Project
112	ER14-1708	ComEd	Grand Prairie Gateway Transmission Line Project
113	ER15-1682	TransCanyon DCR	Delaney to Colorado River Transmission Line (And future CAISO projects).
114	ER15-1689	Dairyland Power Cooperative	Badger Coulee Project
115	ER15-2114	Transource West Virginia	Thorofare Project
116	ER15-2239	NextEra Energy Transmission West, LLC	Estrella Project
117	ER15-572	New York Transco	Edic-to-Pleasant Valley (AC Projects)
118	ER15-572	New York Transco	Oakdale-to-Fraser (AC Projects)
119	ER15-572	New York Transco	Fraser-to-Coopers Corner Project (TOTS)
120	ER15-572	New York Transco	Ramapo-to-Rock Tavern Project (TOTS)
121	ER15-572	New York Transco	Staten Island Unbottling Project - Upgrades (TOTS)
122	ER16-118	ALLETE	Great Northern Transmission Line
123	ER16-453	Northeast Transmission Development LLC	Artificial Island (Partial - 230kV line and substation)
124	ER16-619	PSE&G	Artificial Island (Partial - MVAR and Optical Wire Grounding awarded to PSE&G)
125	ER17-2116	ITC Midwest	Huntley-Wilmarth Project
126	ER17-419	Transource MD / Transource PA	West Line Project (Market Efficiency Project 9A)
127	ER17-419	Transource MD / Transource PA	Rice Substation Project (Market Efficiency Project 9A)
128	ER17-419	Transource MD / Transource PA	East Line Project (Market Efficiency Project 9A)
129	ER17-419	Transource MD / Transource PA	Furnace Run Substation (Market Efficiency Project 9A)
130	ER18-125	NextEra Energy Transmission New York	Empire State Line Project
131	ER18-1693	Gridliance West, LLC	Bob-Mead Project
132	ER18-193	Dairyland Power Cooperative (Joint ownership with ATC and ITC Midwest)	Middleton – Hickory Creek
133	ER18-2510	FirstEnergy/Potomac Edison	Project 9A (Subsegment - various upgrades and substation projects)

	DOCKET	APPLICANT(S)	PROJECT NAME
134	ER19-1129	Duquesne Light Co. LLC	Dravosburg-Elrama Expansion Project
135	ER19-1359	The United Illuminating Company	Pequannock Substation Project
136	ER19-2023	Tucson Electric Power Co.	Nogales Project
137	ER19-297	FirstEnergy (OBO Mid-Atlantic Interstate Transmission, LLC)	New Substation/Transmission Lines (Generator Deactivation Project)
138	ER19-303	Duquesne Light Co. LLC	Beaver Valley Deactivation Transmission Project (Same family as above in ER19-297)
139	ER19-355	ITC Midwest	Cardinal-Hickory Creek Transmission Line Project (345kV)
140	ER19-360	ATC, LLC	Cardinal-Hickory Creek Transmission Line Project (345kV)
141	ER20-1068	Dayton Power & Light	TEP Projects (Category 1 -Baseline)
142	ER20-1068	Dayton Power & Light	TEP Projects (Category 2 - Supplemental)
143	ER21-195	LS Power Grid Ca, LLC	Gates 500 kV Dynamic Reactive Support Project
144	ER21-195	LS Power Grid Ca, LLC	Round Mountain 500 kV Area Dynamic Reactive Support Project
145	ER22-1886	NEET Southwest	Minco-Pleasant Valley-Draper 345 kV Competitive Transmission Project
146	EL22-73	NV Energy	Greenlink Nevada Transmission Project
147	ER23-515	Great River Energy	Iron Range-Benton County-Cassie's Crossing project
148	ER23-762	Dayton Power & Light	TEP II Cat. 1 Projects
149	ER23-762	Dayton Power & Light	TEP II Cat. 2 Projects
150	ER23-926	LS Power Grid, LLC	Collinsville Project
151	ER23-1407	Transource	Transource North Delta Substation Project
152	ER23-1544	Otter Tail Power	Jamestown Project
153	ER23-1544	Otter Tail Power	Big Stone South Project
154	ER23-1653	Jersey Central Power & Light Company	JCP&L Offshore Wind Upgrades
155	ER23-1924	Republic Transmission	Hiple Project
156	ER23-2033	ITC Midwest	Skunk River-Ipava 345 kV Long Range Transmission Plan
157	ER23-2123	Silver Run Electric, LLC	Silver Run Expansion Project
158	ER23-2402	Montana-Dakota Utilities Co.	Jamestown-Ellendale Transmission Project
159	ER23-2487	Ameren	ATXI East-Central Corridor
160	ER23-2487	Ameren	Northern Missouri Corridor Projects

	DOCKET	APPLICANT(S)	PROJECT NAME
161	ER23-2585	ATC, LLC	Tremval-Rocky Run-Columbia Project
162	ER23-2586	ATC, LLC	Tremval-Eau Claire-Jump River Project
163	ER23-2587	ATC, LLC	Wilmarth-North Rochester-Tremval Project
164	ER23-2630	NEET Southwest	Crossroads-Hobbs-Roadrunner 345 kV Competitive Transmission Project
165	ER23-2791	METC	Hiple-Helix LRTP Project
166	ER24-163	PECO, BG&E, Pepco	Brandon Shores Project
167	ER24-232	NY Transco	Propel New York Energy Alternate Solution 5 Project
168	ER24-260	Dairyland Power Cooperative	Wilmarth-North Rochester-Tremval
169	ER24-409	NIPSCO	Big Stone South – Alexandria – Cassie's Crossing
170	ER24-409	NIPSCO	Wilmarth – North Rochester – Tremval
171	ER24-409	NIPSCO	Tremval – Eau Claire – Jump River
172	ER24-409	NIPSCO	Tremval – Rocky Run – Columbia
173	ER24-565	Ameren Transmission Company of Illinois	Fairport to Denny to IA/MO State Border 345 kV Competitive Transmission Project
174	ER25-324	Citizen's Electric Corporation	Grand Tower Project
175	ER23-2744	Potomac Edison	Doubs-Goose Creek 500 kV Transmission Line
176	ER25-416	Niagara Mohawk	NMPC Phase 2 Projects
177	ER25-325	Rochester Public Utilities	Wilmarth-North Rochester-Tremval project
178	ER25-19	Potomac Edison	Woodside-Goose Creek 500 kV line
179	ER25-19	Potomac Edison	MVF1-101
180	EL24-86	New York Power Authority	East Garden City Substation
181	EL24-107	Pacific Gas & Electric	Manning 500/230 kV Substation
182	EL24-107	Pacific Gas & Electric	Collinsville 500/230 kV Substation
183	EL24-107	Pacific Gas & Electric	Newark-Northern Receiving Station High-Voltage Direct Current (HVDC) transmission line
184	EL24-107	Pacific Gas & Electric	Metcalf-San Jose B HVDC line
185	ER24-1967	Rochester Gas & Electric	NMPC Phase 2 Projects
186	ER24-1968	NYSEG	NMPC Phase 2 Projects
187	ER24-1886	Ameren Transmission Co. of Illinois	DennyZachary-Thomas Hill-Maywood 345 kV Competitive Transmission Project
188	ER24-1313	Exelon Corp.	Window 3 Project

	DOCKET	APPLICANT(S)	PROJECT NAME
189	ER24-1473	ALLETE	Eastern Segment of the Big Stone South Project
190	ER24-1473	ALLETE	Iron Range Project
191	EL24-71	Southern CA Edison	Del Amo-Mesa-Serrano and LugoVictor-Kramer
192	EL24-71	Southern CA Edison	Del Amo-Mesa-Serrano 500 kV Reinforcement Project
193	EL24-71	Southern CA Edison	Lugo-Victor-Kramer 230 kV Upgrade Project
194	ER24-472	NEET MidAtlantic Indiana	MidAtlantic Resiliency Link Project

APPENDIX B

List of FERC Dockets Approving CWIP Incentive

Appendix B:

List of FERC Dockets Approving CWIP Incentive, with Project Names (non-exhaustive)

	DOCKET	APPLICANT(S)	PROJECT NAME
1	EL06-54	Allegheny Power	Trans-Allegheny Interstate Line
2	EL07-42	Commonwealth Edison	West Loop Phase II
3	EL07-62	Southern California Edison	DPV4
4	EL07-62	Southern California Edison	Tehachapi
5	EL07-62	Southern California Edison	Rancho Vista Substation
6	EL08-23	PPL/PSEG	Susquehanna-Roseland Line
7	EL08-32	Central Minnesota Municipal Power Agency & Midwest Municipal Transmission Group	Brookings Project (CapX2020)
8	EL08-74	Central Maine Power Co.	Maine Power Reliability Project
9	EL08-82	Vectren South	Gibson-Brown-Reid Project
10	EL10-1	Southern California Edison	Eldorado-Ivanpah Transmission Project
11	EL10-19	Western Grid	Battery Storage Project
12	EL10-54	Desert Southwest Power	Desert Southwest Transmission Project
13	EL10-80	Ameren Services Company	Illinois Rivers Project (Grand Rivers Project)
14	EL10-80	Ameren Services Company	Big Muddy River Project (Grand Rivers Project)
15	EL11-10	Southern California Edison	Whirlwind Substation Expansion
16	EL11-10	Southern California Edison	Devers - Colorado River/Devers- Valley + Substation Expansion
17	EL11-10	Southern California Edison	South of Kramer
18	EL11-10	Southern California Edison	West of Devers
19	EL11-45	Missouri River Energy Services	Fargo-Monticello (CapX2020)
20	EL11-45	Missouri River Energy Services	Twin Cities-Brookings(CapX2020)
21	EL12-102	NIPSCO	Reynolds to Greentown
22	EL12-20	PPL Electric Utilities	Northeast/Pocono Reliability Project
23	EL12-49	NIPSCO	Reynolds/Burr Oak/Hiple
24	EL12-67	WPPI Energy	La Crosse Project (CapX 2020)
25	EL17-63	Southern California Edison	Alberhill System Project,

	DOCKET	APPLICANT(S)	PROJECT NAME
26	EL17-63	Southern California Edison	Mesa 500 kV Substation Project
27	EL17-63	Southern California Edison	Eldorado-Lugo-Mohave Series Capacitor Project
28	EL19-88	NY Power Authority	AC Projects
29	EL20-51	Southern California Edison	Riverside Transmission Reliability Project
30	EL20-70	Tucson Electric Power Company	Southline Transmission Project
31	ER06-1549	Duquesne Light Co.	DTEP
32	ER07-1415	Xcel Energy Services Inc.	Buffalo Ridge Incremental Generation Outlet (BRIGO)
33	ER07-1415	Xcel Energy Services Inc.	Twin Cities-Brookings Country (CapX2020)
34	ER07-1415	Xcel Energy Services Inc.	Twin Cities – Fargo (CapX 2020)
35	ER07-1415	Xcel Energy Services Inc.	Twin Cities – LaCrosse (CapX 2020)
36	ER07-1415	Xcel Energy Services Inc.	Bemidji - Grand Rapids (CapX 2020)
37	ER07-576	Baltimore Gas & Electric	Northwest to Finksburg (TOI)
38	ER07-576	Baltimore Gas & Electric	Downtown Cable (TOI)
39	ER07-576	Baltimore Gas & Electric	Conastone (baseline)
40	ER07-576	Baltimore Gas & Electric	Waugh Chapel (baseline)
41	ER07-653	United Illuminating	Middletown to Norwalk
42	ER08-1402	Duquesne Light Co.	Brady Project/ Brunot Island–Carson
43	ER08-1423	Pepco Holdings, Inc.	MAPP Project
44	ER08-1548	Eversource/National Grid	NEEWS Project
45	ER09-36	Prairie Wind Transmission	Prairie Wind Project
46	ER09-548	ITC Great Plains	KETA (Kansas Electric Transmission Authority) Project
47	ER09-548	ITC Great Plains	Kansas V Plan
48	ER09-75	Pioneer Transmission	Pioneer Project (Greentown-Rockport)
49	ER10-147	Great River Energy	Brookings Line (CapX2020)
50	ER10-147	Great River Energy	Fargo Line (CapX2020)
51	ER10-147	Great River Energy	Bemidji Line (CapX2020)
52	ER10-159	Public Service Electric & Gas	Branchburg-Roseland-Hudson
53	ER10-183	Otter Tail Power	Brookings Line (CapX2020)
54	ER10-183	Otter Tail Power	Fargo Line (CapX2020)

	DOCKET	APPLICANT(S)	PROJECT NAME
55	ER10-183	Otter Tail Power	Bemidji Line (CapX2020)
56	ER11-112	Oklahoma Gas & Electric	Woodward-Hitchland
57	ER11-112	Oklahoma Gas & Electric	Woodward-Kansas
58	ER11-134	ALLETE	Fargo Line (CapX2020)
59	ER11-134	ALLETE	Bemidji Line (CapX2020)
60	ER11-2926	Oklahoma Gas & Electric	Sunnyside-Hugo
61	ER11-2926	Oklahoma Gas & Electric	Sooner-Rose Hill
62	ER11-2926	Oklahoma Gas & Electric	Seminole-Muskogee
63	ER11-2926	Oklahoma Gas & Electric	Tuco-Woodward
64	ER11-2926	Oklahoma Gas & Electric	Sooner-Cleveland
65	ER11-3352	Public Service Electric & Gas	Burlington-Camden
66	ER11-3352	Public Service Electric & Gas	West Orange-Fairmount Heights
67	ER11-3352	Public Service Electric & Gas	Southern Reinforcement Project (Mickleton-Camden-Gloucester)
68	ER11-4069	RITELine Illinois, RITELine Indiana	RITELine Project
69	ER12-1593	DATC Midwest Holdings	Project 1
70	ER12-1593	DATC Midwest Holdings	Project 2
71	ER12-1593	DATC Midwest Holdings	Project 3
72	ER12-1593	DATC Midwest Holdings	Project 4
73	ER12-1593	DATC Midwest Holdings	Project 5
74	ER12-1593	DATC Midwest Holdings	Project 6
75	ER12-1593	DATC Midwest Holdings	Project 7
76	ER12-2216	Ameren	Spoon River
77	ER12-2216	Ameren	Mark Twain
78	ER12-242	MidAmerican Energy	MVP-3 (O'Brian-Kossuth-Webster)
79	ER12-242	MidAmerican Energy	MVP-4 (Black Hawk - Franklin)
80	ER12-242	MidAmerican Energy	MVP-16 (Oak Grove/Galesburg)
81	ER12-242	MidAmerican Energy	MVP-7 (Ottumwa-Adair)
82	ER12-2554	Transource Missouri	Iatan-Nashua Project
83	ER12-2554	Transource Missouri	Sibley-Nebraska City Project
84	ER12-296	Public Service Electric & Gas	Northeast Grid Reliability Project

	DOCKET	APPLICANT(S)	PROJECT NAME
85	ER12-342	Otter Tail Power	Big Stone South-Brookings (CapX2020)
86	ER12-342	Otter Tail Power	Ellendale-Big Stone South (CapX2020)
87	ER13-2468	Central Minnesota Public Power Agency	Big Stone South – Brookings (CapX2020)
88	ER13-307	Montana-Dakota Utilities	Ellendale-Big Stone Project
89	ER14-1608	Public Service Electric & Gas	Bergen-Linden Corridor Project
90	ER14-1708	ComEd	Grand Prairie Gateway Transmission Line Project
91	ER15-1682	TransCanyon DCR	Delaney to Colorado River Transmission Line
92	ER15-2114	Transource West Virginia	Thorofare Project
93	ER15-572	New York Transco	Edic-to-Pleasant Valley (AC Projects)
94	ER15-572	New York Transco	Oakdale-to-Fraser (AC Projects)
95	ER16-118	ALLETE	Great Northern Transmission Line
96	ER17-419	Transource MD / Transource PA	West Line Project (Market Efficiency Project 9A)
97	ER17-419	Transource MD / Transource PA	Rice Substaion Project (Market Efficiency Project 9A)
98	ER17-419	Transource MD / Transource PA	East Line Project (Market Efficiency Project 9A)
99	ER17-419	Transource MD / Transource PA	Furnace Run Substation (Market Efficiency Project 9A)
100	ER17-706	Gridliance West, LLC	Bob Tap Project
101	ER18-125	NextEra Energy Transmission New York	Empire State Line Project
102	ER18-1693	Gridliance West, LLC	Bob-Mead Project
103	ER19-1129	Duquesne Light Co. LLC	Dravosburg-Elrama Expansion Project
104	ER19-1359	The United Illuminating Company	Pequonnock Substation Project
105	ER19-303	Duquesne Light Co. LLC	Beaver Valley Deactivation Transmission Project
106	ER20-1068	Dayton Power & Light	TEP Projects (Category 1 -Baseline)
107	ER20-1068	Dayton Power & Light	TEP Projects (Category 2 - Supplemental)
108	ER22-1707	Duquesne Light	Brunot Island – Carson 345 kV Underground Cable Forced Cooling Project
109	ER23-514	Great River Energy	Iron Range-Benton County-Cassie's Crossing project
110	ER23-762	Dayton Power & Light	TEP II Cat. 1 Projects
111	ER23-762	Dayton Power & Light	TEP II Cat. 2 Projects

	DOCKET	APPLICANT(S)	PROJECT NAME
112	ER23-1544	Otter Tail Power	Jamestown Project
113	ER23-1544	Otter Tail Power	Big Stone South Project
114	ER23-2284	Missouri River Energy Services	Big Stone Project
115	ER23-2402	Montana-Dakota Utilities Co.	Jamestown-Ellendale Transmission Project
116	ER23-2487	Ameren	Transmission Plan
117	ER23-2487	Ameren	Northern Missouri Corridor Projects
118	ER24-232	NY Transco	Propel New York Energy Alternate Solution 5 Project
119	ER24-260	Dairyland Power Cooperative	Wilmarth-North Rochester-Tremval
120	ER24-409	NIPSCO	Big Stone South – Alexandria – Cassie's Crossing
121	ER24-409	NIPSCO	Wilmarth – North Rochester – Tremval
122	ER24-409	NIPSCO	Tremval – Eau Claire – Jump River
123	ER24-409	NIPSCO	Tremval – Rocky Run – Columbia
124	ER25-324	Citizen's Electric Corporation	Grand Tower Project
125	ER25-325	Rochester Public Utilities	Wilmarth-North Rochester-Tremval project
126	EL24-107	Pacific Gas & Electric	Manning 500/230 kV Substation
127	EL24-107	Pacific Gas & Electric	Collinsville 500/230 kV Substation
128	EL24-107	Pacific Gas & Electric	Newark-Northern Receiving Station HVDC
129	EL24-107	Pacific Gas & Electric	Metcalf-San Jose B HVDC line
130	ER24-1967	Rochester Gas & Electric	NMPC Phase 2 Projects
131	ER24-1968	NYSEG	NMPC Phase 2 Projects
132	ER24-1473	ALLETE	Eastern Segment of the Big Stone South Project
133	ER24-1473	ALLETE	Iron Range Project
134	EL24-71	Southern California Edison	Del Amo-Mesa-Serrano and LugoVictor-Kramer
135	EL24-71	Southern California Edison	Del Amo-Mesa-Serrano 500 kV Reinforcement Project
136	EL24-71	Southern California Edison	Lugo-Victor-Kramer 230 kV Upgrade Project
137	ER24-472	NEET MidAtlantic Indiana	MidAtlantic Resiliency Link Project