U.S. House Committee on Energy and Commerce
Subcommittee on Energy, Climate, and Grid Security
"The Fiscal Year 2025 Federal Energy Regulatory Commission Budget"
July 24, 2024
Documents for the Record

1. Federal Energy Regulatory Commission Request for Rehearing of the National Association of Regulatory Utility Commissioners, Docket No. RM 21-17-000, submitted by Rep. Duncan.
2. A study entitled "The Co-Located Load Solution" July 2024, submitted by Rep. Joyce.
3. An article from Tony Clark and Vincent Duane entitled "What Happens When A Nuclear Plant and a Data Center Shack Up?" April 2024, submitted by the Majority.
4. Comments of WIRES before the Federal Energy Regulatory Commission, Docket No. RM20-10-000, submitted by Rep. Joyce.
5. Letter from Industrial Energy Consumers of America to Chairman Duncan and Ranking Member DeGette, July 23, 2024, submitted by the Minority.
6. A report from PJM Interconnection entitled "PJM Guidance on Co-Located Load" March 22, 2024, submitted by the Majority.
7. Letter from the American Public Gas Association to Chairman Duncan and Ranking Member DeGette, July 22, 2024, submitted by the Majority.
8. Letter from Members of Congress to FERC Chairman Willie L. Phillips, May 23, 2024, submitted by Rep. Sarbanes.
9. An article from Utility Dive entitled "FERC's transmission rule will boost grid reliability and affordability without usurping state authority" July 23, 2024, submitted by the Minority.
10. Letter from State Commissioners to FERC Chairman Phillips and Commissioners Christie, Rosner, See, and Chang, July 22, 2024, submitted by the Minority.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection))) Docket No. RM 21-17-000

REQUEST FOR REHEARING OF THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

Pursuant to Section 313 of the Federal Power Act ("FPA")[1] and Rules 212 and 713 of the Federal Energy Regulatory Commission ("FERC" or "Commission") Rules of Practice and Procedure,[2] the National Association of Regulatory Utility Commissioners ("NARUC") respectfully requests rehearing of the Commission's May 13, 2024 Order *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection* in the above-captioned proceeding, Order No. 1920.[3]

I. INTRODUCTION

Pursuant to 16 U.S.C. §824e,[4] the Commission, in an April 21, 2022, Notice of Proposed Rulemaking ("*NOPR*"), proposed revisions that were "intended to

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1 16 U.S.C. § 8251.

2 18 C.F.R. §§ 385.212 and 385.713 (2018).

3 *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Docket No. RM21-17-000, Order No.1920, 187 FERC ¶ 61,068 (2024) ("*Order 1920*").

4 16 U.S.C.§824e (2012).

remedy deficiencies in the Commission's existing regional transmission planning and cost allocation requirements to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential."[5] The Commission began this process with an Advance Notice of Proposed Rulemaking ("*ANOPR*")[6]. NARUC filed comments responding to both the *ANOPR* and the April 21, 2022 *NOPR*.[7] FERC also established a Joint Federal-State Task Force on Electric Transmission ("*Task Force*") specifically to provide a forum to confer with NARUC's state commission members on many transmission-related topics.[8]

Order 1920 reforms regional transmission planning by requiring transmission operators to: (1) to engage in 20-year long-term planning processes, (2) evaluate transmission needs driven by changing resources and demands; (3) file an *ex ante* "backstop" cost allocation method whether or not an agreement with state entities is

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[5] *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 at P 1 (2022).

[6] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Advanced Notice of Proposed Rulemaking, 176 FERC ¶ 61,024 (2021).

[7] *See* the August 17, 2022 Comments of the National Association of Regulatory Utility Commissioners on the Notice of Proposed Rulemaking on Electric Transmission (RM21-17) ("*NARUC NOPR Comments*") and the October 12, 2021 Motion to Intervene and Comments of the National Association of Regulatory Utility Commissioners (RM21-17).

[8] *Joint Federal-State Task Force on Electric Transmission*, 175 FERC ¶ 61,224 (2021).

reached during the single prescribed engagement period;[9] (4) evaluate regional transmission facilities to address interconnection-related transmission needs; (5) consider whether selecting transmission facilities that incorporate dynamic line ratings and advanced power flow control devices would be more efficient than facilities that do not incorporate such technologies; and (6) promote enhanced transparency and coordination requirements within and between regional and local transmission planning processes to "right-size" replacement facilities.

NARUC genuinely appreciates the Commission's extensive outreach in both the NOPR processes and through the Task Force meetings. NARUC also appreciates the Commission's efforts to consider and implement reforms that may facilitate more efficient and effective transmission planning, while attempting to recognize and

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9 *Order 1920* at P 5 ("Further, this final rule requires transmission providers to file one or more *ex ante* Long-Term Regional Transmission Cost Allocation Methods to allocate the costs of Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected. This final rule further permits, but does not require, transmission providers to adopt a State Agreement Process.") at P 1359 ("[T]he ultimate decision as to whether to file a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process to which Relevant State Entities have agreed will continue to lie with the transmission providers."); P 1429 ("[A]fter the required Engagement Period, transmission providers in each transmission planning region will decide what Long-Term Regional Transmission Cost Allocation Method(s) and any State Agreement Process to file as part of their compliance filings. Therefore, transmission providers in a transmission planning region could elect to propose on compliance a Long-Term Regional Transmission Cost Allocation Method *and not file a State Agreement Process or other ex ante cost allocation method to which Relevant State Entities agreed*. In addition*, we do not impose any obligation on transmission providers to file a cost allocation method for Long-Term Regional Transmission Facilities with which they disagree*, even if such a method were proposed to the transmission providers pursuant to a Commission-approved State Agreement Process, unless the transmission providers have clearly indicated their assent to do so as part of a Commission-approved State Agreement Process in their OATTs.") (emphases added; footnote omitted).

elevate the critical and key role of the states while preserving jurisdictional authorities.

However, in the final order, FERC both rejected key *NOPR* provisions and adopted others that will cause inefficiencies and undermine the Commission's goals. FERC set out to remedy deficiencies in regional and local transmission planning and cost allocation requirements. Nevertheless, in its current state, certain provisions in *Order 1920* risk resulting in unjust, unreasonable, or unduly discriminatory rates in violation of the Federal Power Act ("FPA"), and/or being found beyond the Commission's authority, unsupported by reasoned decision-making, arbitrary and capricious, or unsupported by, or counter to, the record in this proceeding.[10]

On rehearing, NARUC respectfully requests FERC address the necessary deference to and importance of the state agreement and consensus on planning and cost allocation issues outlined in the *NOPR*. The suggested changes will necessarily improve outcomes, reduce potential litigation, and facilitate subsequent state siting proceedings associated with transmission projects. The *NOPR* also suggested eliminating the Construction Work in Progress ("CWIP") incentive. *Order 1920* did not act on that proposal. However, there is substantial unrebutted evidence in the

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[10] *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co*., 463 U.S. 29, 43 (1983) ("The agency must examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made."). *City of Cleveland v. FERC*, 773 F.2d 1368, 1376 (D.C. Cir. 1985).

record that the proposed CWIP Incentive for Long-Term Regional Transmission Facilities arbitrarily shifts acknowledged and excessive risk to consumers due to the long lead-times and a higher risk that such facilities will be built. On rehearing, the Commission should eliminate the CWIP incentive.

II. STATEMENT OF ISSUES AND SPECIFICATION OF ERRORS

Pursuant to Rule 713(c)(2)[11], NARUC respectfully submits that *Order 1920* is arbitrary, capricious, an abuse of discretion, insufficiently supported, contrary to law, and beyond the Commission's authority in the following respects:

[A] CONSTRUCTION WORK IN PROGRESS

Order 1920 arbitrarily shifts acknowledged and excessive risk to consumers by not eliminating the Construction Work in Progress ("CWIP") Incentive for Long-Term Regional Transmission Facilities as proposed in the NOPR. The CWIP Incentive requires consumers to pay for costs incurred during the long lead times associated with transmission projects, projects that may never be constructed. There was, at best, insufficient evidence and record support and no rationale provided for retaining this requirement that ratepayers bear the financial risks of transmission construction. 16 U.S.C. § 824d and 824e. Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co., 463 U.S. 29, 43 (1983); City of Cleveland v. FERC, 773 F.2d 1368, 1376 (D.C. Cir. 1985).

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11 18 C.F.R. § 385.713(c)(2) (2018).

[B] COST ALLOCATION

Order 1920 adopts a cost allocation process that is unjust, unreasonable, and arbitrary and capricious in the following particulars:

[1] *Order 1920 arbitrarily and without adequate explanation removes protections proposed in the NOPR for states and their ratepayers by not requiring Transmission Providers to incorporate state consensus to cost allocation methods for filing as part of the OATT. It potentially undermines the opportunity provided for negotiations on state cost allocation methods by mandating a default ex ante cost allocation. 5 U.S.C. § 706(2)(A); Motor Vehicle Manufacturers Association v. State Farm Mutual Automobile Insurance Co., 463 U.S. 29, 43 (1983). If a State Agreement process is adopted by the appropriate states, that agreement should be binding and subject only to FERC approval. 16 U.S.C. § 824d and 824e.*

[2] *Order 1920 fails to specify that in making the required compliance filing to amend the OATT, Transmission Providers should, at a minimum, be required to detail the required state outreach activities and describe their results – including the details of any cost allocation agreements (whether rejected or not) – to ensure the Commission has all the evidence needed to make a reasonable decision.*

[3] *Order 1920 fails to provide adequate time for Transmission Providers to fully develop proposals to comply with this final rule and for all stakeholders, including Relevant State Entities, to meaningfully engage in the process of developing such proposals. 5 U.S.C. § 706(2)(A); Motor Vehicle Manufacturers Association v. State Farm Mutual Automobile Insurance Co., 463 U.S. 29, 43 (1983).*

[4] *Order 1920 arbitrarily leaves it to a Transmission Provider's sole discretion whether, when, or if to "hold future engagement periods if they believe such period would be beneficial." 5 U.S.C. § 706(2)(A); Motor Vehicle Manufacturers Association v. State Farm Mutual Automobile Insurance Co., 463 U.S. 29, 43 (1983).*

[C] TRANSMISSION PLANNING/SELECTION CRITERIA:

Order 1920 is in error by not requiring public utility Transmission Providers to include in the transmission evaluation process selection criteria promulgated and supported by Relevant State Entities.

As detailed below, *Order 1920* contains factual findings that are not supported by substantial evidence and draws legal conclusions that are not the product of reasoned decision making and/or are an abuse of discretion. If these problems are not corrected on rehearing, they will produce outcomes that are unjust, unreasonable, unduly discriminatory, and in violation of the Federal Power Act.

II. REQUEST FOR REHEARING

Order 1920 erred in a number of key respects. A Commission order will be reversed on review if it is arbitrary or capricious, reflects an abuse of discretion, is not otherwise in accordance with law, or is not supported by substantial evidence.[12] To satisfy its obligation to engage in reasoned decision-making, the Commission must examine the relevant data and articulate a rational connection between the facts found and the choices made.[13] The Commission must reach its conclusion through

[12] *South Carolina Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 54 (D.C. Cir. 2014*); Sacramento Mun. Util. Dist. v. FERC*, 616 F.3d 520, 528 (D.C. Cir. 2010) (*Sacramento*).

[13] *Sacramento*, 616 F.3d at 528; *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004).

decision-making that is "reasoned, principled, and based upon the record."[14]

[A] CONSTRUCTION WORK IN PROGRESS

> *Order 1920 arbitrarily shifts acknowledged and excessive risk to consumers by not eliminating the Construction Work in Progress ("CWIP") Incentive for Long-Term Regional Transmission Facilities as proposed in the NOPR. The CWIP Incentive requires consumers to pay for costs incurred during the long lead times associated with transmission projects, projects that may never be constructed. There was, at best, insufficient evidence and record support and no rationale provided for retaining this requirement that ratepayers bear the financial risks of transmission construction. 16 U.S.C. § 824d and 824e. Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co., 463 U.S. 29, 43 (1983); City of Cleveland v. FERC, 773 F.2d 1368, 1376 (D.C. Cir. 1985).*

The *NOPR* proposed to eliminate the existing CWIP Incentive for Long-Term Regional Transmission Facilities.[15] This policy allows Transmission Providers to recover 100% of their CWIP in rate base before a facility is placed into service. NARUC, numerous states, and consumer advocate comments highlight the obvious: applying the CWIP Incentive to Long-Term Regional Transmission Facilities shifts excessive risk to consumers due to the long lead-times associated with these projects

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[14] *ExxonMobil Oil v. FERC*, 487 F.3d 945, 953 (D.C. Cir. 2007); *see New York v. FERC*, 535 U.S. 1, 36 (2002); *see* also *Transmission Access Policy Group v. FERC*, 225 F.3d 667, 705, 716 (D.C. Cir 2000) (citing *Associated Gas Distributors v. FERC*, 824 F.2d 981, 1021 (D.C. Cir. 1987).

[15] *NOPR,* 179 FERC ¶ 61,028 at 61,205, P 331.

and the high level of uncertainty that they will be built.[16]

The Final Rule declined to take any action regarding the CWIP Incentive as applied to Long-Term Regional Transmission Facilities. Yet, in the *NOPR* at PP 331-332, FERC acknowledged that:

> . . . during the construction of the regional transmission facilities, ratepayers do not receive benefits from the regional transmission facilities, while simultaneously ratepayers directly finance the construction under the CWIP Incentive. Should the regional transmission facilities not be placed in service, then ratepayers will have financed the construction of such facilities that were not used and useful, while ultimately receiving no benefits from such facilities. []. Given the Long-Term Regional Transmission Planning reforms proposed … and the incremental uncertainty and risk that Long-Term Regional Transmission Facilities may not become "used and useful," we are concerned that the CWIP Incentive, if made available for Long-Term Regional Transmission Facilities, may shift too much risk to consumers to the benefit of public utility transmission providers in a manner that renders Commission-jurisdictional rates unjust and unreasonable.
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> *Building. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation & Generator Interconnection*, 179 FERC ¶ 61,028, 61,205 (2022) (Footnotes omitted)

Further, *Order 1920* at PP 1525 -1531, contains unrebutted comments by the California Public Utilities Commission and others, *inter alia*, that (i) "there is no evidence that . . . the CWIP Incentive, ha[s] spurred investment in transmission

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[16] *Order 1920* at PP 1525-1531 (Note - even if the CWIP Incentive is eliminated, Transmission Providers could still accrue carrying costs incurred during the pre-construction or construction phase as Allowance for Funds Used During Construction. AFUDC are recovered from customers <u>after</u> the project is placed into service).

infrastructure," (ii) "the CWIP Incentive could substantially increase the risk of customers paying for transmission facilities that are never built," (iii) [Eliminating CWIP] "better aligns risk and reward between shareholders and customers with respect to Long-Term Regional Transmission Facilities" (iv) "the longer the transmission planning horizon, the higher the risk that resulting transmission facilities will not be needed," (v) "shifting the risk for long-term transmission projects to transmission providers will help ensure that only those long-term projects that are "confidently needed" will be developed." Finally, "Kentucky Commission Chair Chandler, NASUCA, and the California Commission express concern that today's ratepayers are forced to pay for tomorrow's transmission projects, which they refer to as intergenerational inequity, and they are especially concerned if a project will not provide service until a much later date." [17]

The order cites a number of comments that endorse the retention of the CWIP incentive at PP 1532-1544. Most if not all, as New England Systems pointed out, "gain financially from the incentive."[18]

But none of those commenters rebuts the basic concern espoused by State Commissions and State consumer advocates that was the basis for the *NOPR's* original proposal: that ratepayers unquestionably bear the risks that with CWIP;

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[17] *Compare*, *NARUC NOPR Comments* at pp. 54-56.

[18] *Order 1920* at P 1526.

they will have to pay in advance for facilities that may not ever be used.[19] Significantly, *Order 1920* did not rebut or critique this basic fact. Nor did it specify that any of the opposing commentors provided an adequate rebuttal.

Instead, *Order 1920* simply declines to "finalize the *NOPR* proposal to limit the availability of the CWIP incentive for Long-Term Regional Transmission Facilities."[20] The record indicates that CWIP should be eliminated. FERC just defers action on CWIP until it can address *other* potentially inappropriate transmission incentives at the same time – incentives that do not require consumers to pay "in advance."[21] This is not reasoned decision making. The record supports elimination of the CWIP now. There is no reason to delay.

[B] COST ALLOCATION:

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19 *See, NOPR,* 179 FERC ¶ 61,028 at 61,205, P 331. ("In light of the incremental uncertainty associated with the proposed Long-Term Regional Transmission Planning, we preliminarily find that additional protection for ratepayers may be necessary to reasonably balance consumers' interest in just and reasonable rates against investors' interest in earning a return on their investments and reduce the risk to ratepayers of potentially financing over-investment in regional transmission facilities.")

20 *Order 1920* at P. 1547.

21 *Order 1920* at P 1546, also notes, accurately, that the Commission "Abandoned Plant incentive" also needs to be addressed to comprehensively address consumer risks associated with Long Term Regional Transmission Facilities." But unlike CWIP, those costs are not recovered in advance but only accrue upon FERC approval of prudently incurred costs for abandoned plant. Plus, addressing Abandoned Plant is a knottier problem – investors are entitled to recover prudent expenditures in both cases, but with CWIP – they still recover prudently incurred expenditures – but there is no reason to let them recover it before the plant is put in service.

Order 1920 adopts a cost allocation process that is unjust, unreasonable and arbitrary and capricious in the following particulars:

[1] *Order 1920 arbitrarily and without adequate explanation removes protections proposed in the NOPR for states and their ratepayers by not requiring Transmission Operators to incorporate state consensus to cost allocation methods for filing as part of the OATT. It potentially undermines the opportunity provided for negotiations on state cost allocation methods by mandating a default ex ante cost allocation. 5 U.S.C. § 706(2)(A); Motor Vehicle Manufacturers Association v. State Farm Mutual Automobile Insurance Co., 463 U.S. 29, 43 (1983). If a State Agreement process is adopted by the appropriate states, that agreement should be binding and subject only to FERC approval. 16 U.S.C. § 824d and 824e.*

The *NOPR*, the *ANOPR* and *Order 1920*[22] all emphasize the need for state input to facilitate the transmission and cost allocation process.

While *Order 1920,* at PP 254, 259, rejects numerous and credible arguments that the specific transmission planning requirements adopted constituted a "Commission-regulated integrated resource planning/request for a proposal process" or "infringe[d] on the authority reserved to the states by FPA section 201," the order, in P 272 acknowledges, as it must, that "that Long-Term Regional Transmission Planning will affect matters that are within the states' jurisdiction. As stated, this is inevitable."

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[22] *Order 1920* at P 22 ("Given that federal and state regulators each have authority over transmission-related issues and given the impact of transmission infrastructure development on numerous different priorities of federal and state regulators, the Commission determined that the topic was ripe for greater federal-state coordination and cooperation."); P 120 ("[S]tate laws, utility integrated resource plans and resource procurements, and other regulatory actions necessarily affect Long-Term Transmission Needs for Commission-jurisdictional transmission services.").

Later, in P 124, the order concedes that:

> . . . experience with Order No. 1000 has reinforced the critical role that states play in the development of new transmission infrastructure, particularly at the regional level, where transmission projects may physically span, and their costs may be allocated across, multiple states. As the Commission discussed in the *NOPR* and we continue to find in this final rule, facilitating state regulatory involvement in the cost allocation process could minimize delays and additional costs associated with state and local siting proceedings.

State approval is especially important in a multi-state region, where different states have different policies, particularly in light of the mandated planning criteria to be used in the planning of Long-Term Regional Transmission Facilities. These include, *inter alia* (i) "state and local laws and regulations affecting the resource mix and demand," (ii) state and local laws and regulations on decarbonization and electrification," (iii) "state-approved integrated resource plans and expected supply obligations for load-serving entities," (iv) "generator interconnection requests and withdrawals" and (iv) "utility and corporate [clean power purchase] commitments and federal, federally-recognized Tribal, state, and local policy goals."[23] .

[23] *Order 1920* at P 409. *See also* P 474 detailing Factor Category Seven and discussing "public policies and corporate renewable procurement goals," and "clean or renewable energy targets." P 481 ("We agree with commenters that argue that corporate demand for clean energy resources, as demonstrated by the volume of bilateral corporate contracts with renewable energy resources, is already a major driver of changes in the resource mix and demand and that corporate and industrial customer demand for clean energy is projected to increase. We believe that it is necessary for transmission providers to incorporate publicly announced utility commitments in the development of Long-Term Scenarios")

These *Order 1920* requirements to integrate state energy policies and goals into the planning process directly impact state-jurisdictional polices.[24]

The *NARUC Initial Comments* largely supported the *NOPR,* because it included the explicit principle of state agreement to planning and selection criteria and cost allocation.[25] In particular, the *NOPR* proposed to require transmission providers "to seek the agreement of Relevant State Entities within the transmission planning region regarding the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof."[26]

In its *NOPR* Comments at 45, NARUC explicitly rejected:

> [A] requirement that public utility transmission providers include a Long-Term Regional Transmission Cost Allocation method in their OATTs without being obligated to seek agreement from Relevant State Entities.

Unfortunately, in *Order 1920*, the Commission diverged from the *NOPR* cost allocation proposal significantly. It also rejected California's logical proposal to "require Transmission Providers to indicate in their compliance filings whether

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24 The record below presents differing evidence on the level and degree of intrusiveness this new transmission level regime will have on state policy and state jurisdictional activities. But there is no question that State jurisdictional activities will be impacted, including directly though siting proceedings and indirectly on in -state planning and policy. *Compare Order 1920* at PP 190-201.

25 *See* note 7, *supra.*

26 *Order 1920* at P 1306.

Relevant State Entities support the proposal or explain any points of disagreement that they may have with Relevant State Entities."[27]

To sum up. First, *Order 1920* creates a process that integrates individual state energy policies and goals into transmission planning, creates extensive procedures for "consultation" with states, and acknowledges how state input will facilitate the planning process. But then the order establishes conditions that permit the Transmission Providers to completely ignore and not even report upon state input.

This is the very definition of arbitrary and capricious action and unreasonable decision making.

Even if states in a planning region agree, a "State Agreement Process" *cannot* be the sole chosen method for allocating costs of these projects. The Transmission Provider's own *ex ante* formula *must* be the default method, regardless of whether

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[27] *Order 1920* at P 1359.

states have agreed to a different process or method.[28]

Even if states agreed on an alternative *ex ante* cost allocation method, or if they agree on a cost allocation method under the State Agreement Process, the Transmission Provider could choose to file it but also *could ignore it*.[29]

The Order also undermines the very consulting mechanisms it adopts. Telling the states to negotiate for an alternative cost allocation process when the Transmission Provider's *ex ante* formula has already been designated as the default is no real negotiation at all. This process turns the state negotiations into merely a "check the box" exercise. The existence of a required default procedure and the fact that the Transmission Provider does not have to adopt or even explain its

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28 *Id.* P 1359 ("[T]he ultimate decision as to whether to file a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process to which Relevant State Entities have agreed will continue to lie with the transmission providers."); P 1429 ("[A]fter the required Engagement Period, transmission providers in each transmission planning region will decide what Long-Term Regional Transmission Cost Allocation Method(s) and any State Agreement Process to file as part of their compliance filings. Therefore, transmission providers in a transmission planning region could elect to propose on compliance a Long-Term Regional Transmission Cost Allocation Method *and not file a State Agreement Process or other ex ante cost allocation method to which Relevant State Entities agreed*. In addition*, we do not impose any obligation on transmission providers to file a cost allocation method for Long-Term Regional Transmission Facilities with which they disagree*, even if such a method were proposed to the transmission providers pursuant to a Commission-approved State Agreement Process, unless the transmission providers have clearly indicated their assent to do so as part of a Commission-approved State Agreement Process in their OATTs.") (emphases added; footnote omitted); *see also id.* P 1356 n.2895 (citing *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002) (*Atlantic City*)).

29 *Id.*

disagreement with a state consensus on a cost allocation procedure significantly affects both the content of the negotiations and the incentive to participate.

At a minimum, on rehearing, FERC should require Transmission Providers to include "any selection criteria promulgated and supported by relevant state entities."

> [2] *Order 1920 fails to specify that in making the required compliance filing to amend the OATT, Transmission Providers should, at a minimum, be required to detail the required state outreach activities and describe their results – including the details of any state cost allocation agreements (whether rejected or not) – to assure the Commission has all evidence needed to make a reasonable decision.*

As discussed in B [1], *supra,* FERC should amend *Order 1920* to require Transmission Providers to seek agreement from relevant state entities on any Long-Term Regional Transmission Cost Allocation method filed in their OATTs.

But however the Commission addresses that that issue, FERC still should clarify exactly what information Transmission Providers must include in their cost allocation compliance filings describing how they meet the Rule's requirements to incorporate Relevant State Entity input. Specifically, a Transmission Provider's cost allocation compliance filing should include, at a minimum, the setting and communication of deadlines, the general description of discussions, including their outreach to state entities, the extent to which states agreed or disagreed with the filed cost allocation, whether states put forward an alternate cost allocation method by the applicable deadline(s), and, if applicable, the states' alternate proposal, as well as, if applicable, justifications for why the Transmission Provider did not file the states' agreed-to alternate cost allocation proposal. These minimum filing requirements will demonstrate the extent to which Transmission Providers engaged with states and will provide the Commission with all the evidence needed to make its determination as to whether the compliance filing is just and reasonable. This clarification provides incentives for Transmission Providers that disagree with a cost allocation method agreed to by the states to provide objective reasons why they chose not to accept the state offering. The Commission benefits, because the compliance filings will provide much of the information needed to decide if modifications are required. Overall, such a process will increase the likelihood that the Final Rule meets the Commission's goal of more efficiently and effectively planning long-term transmission.

> [3] *Order 1920 fails to provide adequate time for Transmission Providers to fully develop proposals to comply with this final rule and allow stakeholders, including Relevant State Entities, to meaningfully engage in the process of developing such proposals. 5 U.S.C. § 706(2)(A); Motor Vehicle Manufacturers Association v. State Farm Mutual Automobile Insurance Co., 463 U.S. 29, 43 (1983).*

Order 1920 requires each Transmission Provider to submit a compliance filing within ten months of the order's effective date, revising its OATT and providing documentation demonstrating it meets all of the order's requirements.[30]

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[30] *Order 1920* at P 1768.

In response to comments from NARUC, Idaho Power, ISO-NE, and MISO, the Commission extended the compliance period to ten-months instead of the eight-month compliance period proposed in the *NOPR*. *Id.* According to the Order, this

> "will allow transmission providers to fully develop proposals to comply with this final rule and allow stakeholders, including Relevant State Entities, to meaningfully engage in the process of developing such proposals." *Id.*

NARUC appreciates the FERC's extension of the original eight-month period. However, adding just two months is unlikely to allow state entities to meaningfully engage. NARUC and others submitted comments indicating that states would need anywhere from a year to eighteen months.

There are real world examples in the record indicating this is likely the case. For example, NARUC pointed out in its original comments that after MISO filed a cost allocation method that divided postage stamp rates between MISO Midwest and MISO South in February of 2022, discussions by the MISO cost allocation committee of a replacement cost allocation method have already well exceeded twelve months.[31] Idaho Power and ISO NE suggested that the Commission provide Transmission Providers at least a year to comply with the final rule due to the

[31] MISO and its stakeholders have undertaken a Long-Range Transmission Plan for a time period that has exceeded two years. *See Miso Initial Comments* at p. 91.

complexity of the proposals and the need to work with stakeholders,[32] and MISO for the same reasons requested a compliance period for eighteen months.[33]

For planning regions outside of RTOs/ISOs, state commissions may not be conversant with various cost allocation methods and will face a learning curve on substantive issues in cost allocation. Further, state entities likely will have internal legal and procedural issues to sort through regarding a number of issues, including delegating negotiating authority, receiving stakeholder input at the state level, ensuring that their involvement in federal tariffs is not deemed to be prejudging the outcomes of state proceedings, and coordinating with legislative and executive branch entities to ensure that the state regulatory entities have authority to negotiate on behalf of their states and retail ratepayers.

Given existing state retail regulatory duties, ten months is insufficient to allow the Relevant State Entities to effectively coordinate internally and externally.

The Commission should grant rehearing of its decision to require Transmission Providers to submit a compliance filing within ten months of the effective date of the final rule revising its OATT. That decision arbitrarily and capriciously denies state entities adequate time to meaningfully engage in the cost

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32 *Order 1920* at P 1763 (Citing *Idaho Power Initial Comments* at 14, *ISO-NE Initial Comments* at 41).

33 *Id.*

allocation process for Long-Term Regional Transmission Facilities. The record suggests a fourteen-month time would be reasonable.

> [4] *Order 1920 arbitrarily leaves it to Transmission Provider's sole discretion of whether, when or if to "hold future engagement periods if they believe such period would be beneficial." 5 U.S.C. § 706(2)(A); Motor Vehicle Manufacturers Association v. State Farm Mutual Automobile Insurance Co., 463 U.S. 29, 43 (1983).*

NARUC requests that FERC create a mechanism to assure regular re-examination of the default and any other cost allocation included in the Transmission Provider's OATT.[34]

Order 1920 only *requires* one Engagement Period for states to negotiate a different cost allocation from the Transmission Provider's *ex ante* cost allocation before that *ex ante* cost allocation becomes the default.[35] This locks in each Transmission Provider's preferred *ex ante* formula and blocks any avenue for states to challenge it. As described P 1368, *Order 1920* leaves it to the Transmission Provider's sole discretion whether, when, or even if to "hold future engagement periods if they believe such period would be beneficial."

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[34] *Order 1920* at P 1255 ("NARUC requests that the Commission provide a mechanism for future review of cost allocation methods for Long-Term Regional Facilities." (citing *NARUC Initial Comments* at 49-50).

[35] *Id.* P 1368; *see also id.* P 1291.

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NARUC pointed out the flaws in this approach in its initial comments.[36] These transmission facilities will be planned over a longer period than projects built for reliability or economic reasons. States that do not currently have public policies requiring extensive transmission investments may forego an opportunity to participate in discussions regarding cost allocation, but their public policies may evolve over time. For the reforms proposed in this *NOPR* to be successful, the positions of relevant state entities should not be frozen in time. This is even more important because even the extended compliance period required by *Order 1920* may not be sufficient to allow states to engage in the arduous task of reaching agreement over cost allocation methodologies.

The order does not engage or rebut NARUC's contentions at any level.

On rehearing, FERC should provide a mechanism for ensuring that Transmission Providers remain in compliance with the requirement to include relevant state entities in cost allocation for Long-Term Regional Transmission Facilities. FERC should either require the Transmission Provider to open a new negotiation period with the relevant state entities periodically. or require them to file a modification to their OATT if states reach the requisite agreement on a different cost allocation methodology than that reflected in the OATT then on file.

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36 *NARUC NOPR Comments* at pp. 49-50.

[C] TRANSMISSION PLANNING/SELECTION CRITERIA:

Order 1920 is in error by not requiring public utility Transmission Providers to include in the transmission evaluation process selection criteria promulgated and supported by relevant state utilities.

Order 1920 adopts the NARUC-supported *NOPR* proposal with modifications, requiring Transmission Providers to consult with and seek, *but not necessarily obtain*, support from Relevant State Entities regarding the evaluation process, including the selection criteria to be used to identify and evaluate Long-Term Regional Transmission Facilities for selection. It also requires Transmission Providers to demonstrate their "good faith efforts" to consult.[37]

FERC has acknowledged,[38] and NARUC has explained in its comments on the *NOPR,*[39] why state input is crucial to any transmission planning procedure. This includes selection criteria. As pointed out earlier, even to the casual observer, *Order 1920's* requirements for providers to use a series of state policy-centric factors in long term scenarios emphasizes the need for state commission expertise and input into all aspects of the transmission planning process.[40]

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37 *Order 1920* at PP 972, 994, 996.

38 *NOPR* at P 56,244,300, 301.

39 *NARUC NOPR Comments* at pp 42-44.

40 See discussion and footnotes under III. B. [1], *supra.*

In P 996, the Order clarifies that Transmission Providers are required "to seek support from Relevant State Entities, but [not] to obtain their support, before proposing an evaluation process and selection criteria." In the same paragraph, the Order indicated that it will not provide states with "veto authority over transmission providers' proposed selection criteria" and in P 997 "disagrees with NARUC "that, in the absence of a requirement that transmission providers obtain the support of Relevant State Entities, transmission providers will be empowered to ignore the input of Relevant State Entities."

But NARUC's comments did not seek veto authority, nor did NARUC seek state endorsement of all criteria raised. Rather NARUC said, at p 45 of its *NOPR* Comments:

> Given the Commission's stated goal of accommodating individual states' energy policies and goals into Long-Term Regional Transmission Planning, NARUC opposes any resolution that permits public utility transmission providers to override or ignore any selection criteria promulgated and supported by relevant state entities.

Including state supported selection criteria is efficient and likely to result in better outcomes for the planning process; it also reduces the likelihood of inefficient litigation. The record in this proceeding, including *Order 1920*'s requirements for State consultations, supports inclusion of such state-supported criteria. The Order nowhere specifically responds to this NARUC request for treatment of state supported criteria.

IV. CONCLUSION

For the foregoing reasons, NARUC respectfully requests that the Commission grant rehearing of the May 2024 Order to address the errors specified herein.

Respectfully submitted,

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Date: June 12, 2024

CERTIFICATE OF SERVICE

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

Respectfully Submitted

/s/ Robert C. Cain II

Date: June 12, 2024

The Co-Located Load Solution

Michael Kormos
JULY 2024

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The Co-Located Load Solution

An influx of large new loads is projected to seek to connect to the transmission grid over the next several years—including most prominently hyperscale data centers. The standard utility models are struggling to accommodate large data center projects on a workable timeline, and can take five years or longer.[1] These delays are caused in part by the increasing size of data centers, which in the past did not typically exceed 100 megawatts (MWs) but now can be up to ten times larger to accommodate artificial intelligence and other sophisticated applications.

Connecting a new gigawatt-sized load to the power grid would almost certainly require construction of new transmission lines, which is one of the most difficult challenges faced by the power sector. Based on my experience as chief operations officer of PJM Interconnection and related roles in the power industry, it can take up to a decade to plan, design, permit, and construct new transmission lines if they are contested (as are most large projects). These long delays risk impeding economic growth as well as technological advances.

In order to bring large data center projects online efficiently and equitably, the electric industry should be focused on finding solutions that best manage reliability, affordability (for all), efficiency, and speed. In the restructured markets where sellers compete to serve new demand, one such solution is for the new load to serve its own power needs "off the grid," and the most promising configuration is for this load to co-locate behind-the-meter with an existing power plant.

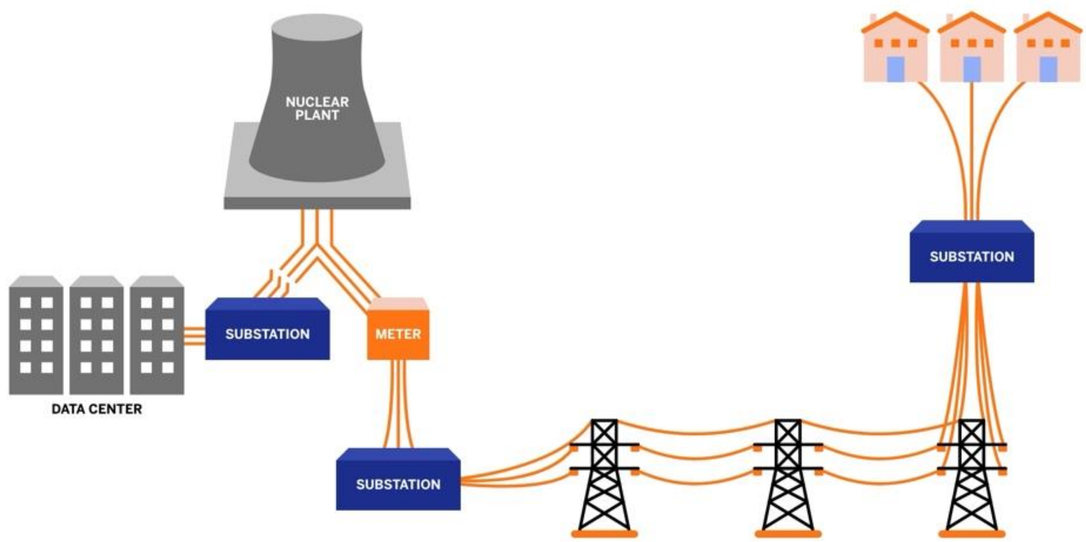
By *not taking service from the transmission grid*, the new load expedites the timeline but must pay for its behind-the-meter delivery facilities and assume the costs and risks of not being served by the grid. Because the new load has no ability to "lean" on the grid,[2] there is no need for expensive new network transmission projects to connect the load or the associated regional cost allocations to other customers. In addition, by partnering with an existing plant, the load avoids the long lead time for grid interconnection and the generator secures a steady customer, which can be critical for plants needing predictable, long-term

1 *See*, *e.g.*, "AI, data center electricity demand could drive advanced nuclear investment: NERC head Jim Robb," Utility Dive (June 6, 2024) ("it takes me about four years to build a substation," according to David Schleicher, Northern Virginia Electric Cooperative CEO), https://www.utilitydive.com/news/ai-data-center-electricity-demand-advanced-nuclear-investment-Robb/718181/; "Elk Grove Mayor Meets With ComEd on Substations for Data Centers," Journal & Topics (Mar. 14, 2024) (Mayor of Elk Grove, Illinois, "expressed frustration with ComEd, saying the electricity utility was 'dragging their feet' in building substations to support the growing data center industry"), https://www.journal-topics.com/articles/elk-grove-mayor-meets-with-comed-on-substations-for-data-centers/.

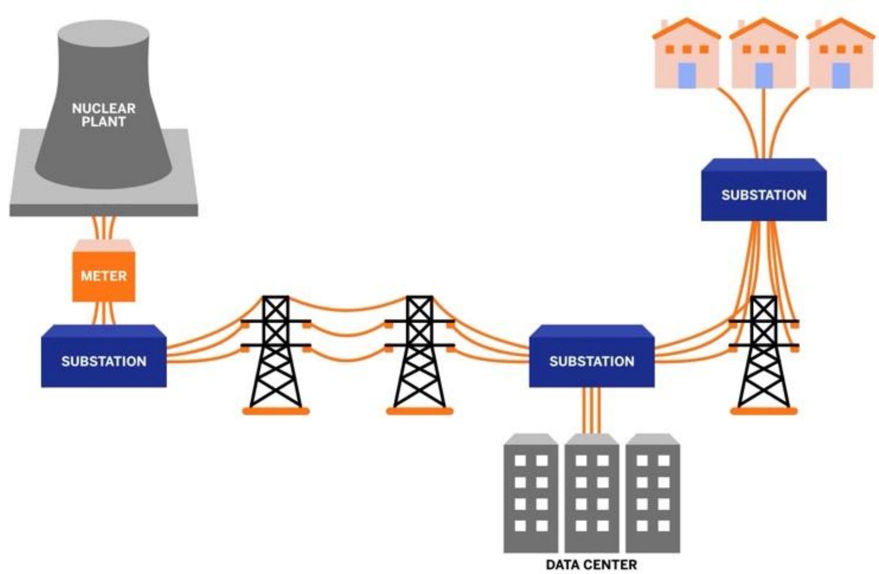
2 To be clear, the co-located behind-the-meter load configuration I suggest here is one where the load is unable to take energy or other services from the grid and in fact pays for and installs equipment to automatically disconnect in the event its co-located power supply trips. The load instead must rely on its co-located generator(s), batteries or other back-up resources to meet its needs. While other co-located load configurations may be considered, I have not done so here.

revenues to ensure continued operation and justify renewal of operating licenses and potential uprates.

Co-Located Behind-the-Meter Configuration

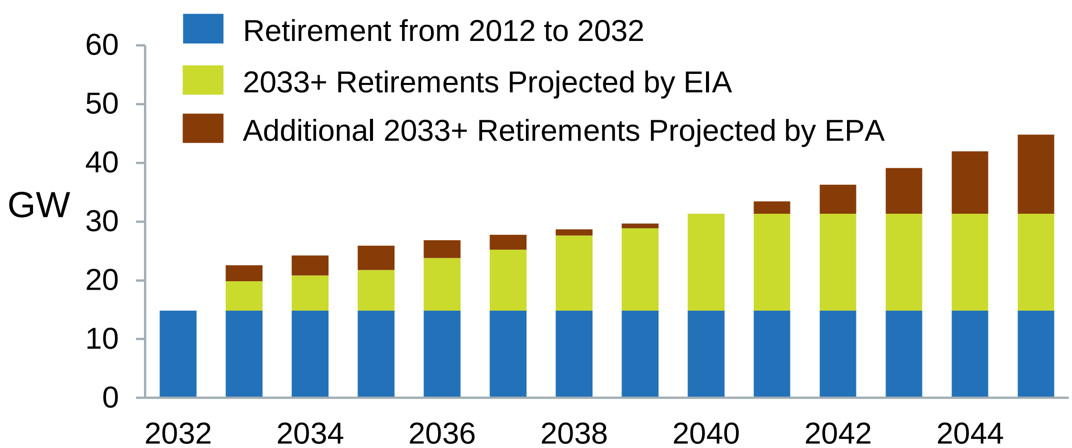


Grid-Supplied Front-of-Meter Configuration



While co-location could involve the pairing of any type of power plant with any large load, existing nuclear plants provide some of the best opportunities for data centers. Nuclear plants are large, often with multiple units, carbon-free and sustainable, and capable of and preferring to run at maximum power for up to 18 to 24 months, which matches perfectly with the data center load profile.[3] Nuclear units have the highest reliability and availability of any of the existing resources.

Despite their benefits, nuclear units have, in the recent past, faced economic challenges that led many to announce retirements. In the last decade, over 10 GW of capacity retired, mostly due to economic factors, and 20 nuclear units representing 20.3 GW of capacity avoided retirement by seeking and obtaining state-based economic support. Although the federal government has stepped in to prevent further retirements through enactment of the nuclear production tax credit (PTC), that program expires in 2032 at which time federal agencies project a new wave of nuclear retirements far exceeding the generating capacity lost over the last decade.[4]



Under a co-location configuration, the data center gets the carbon-free electricity it wants without lengthy delays (but must pay for any on-site delivery facilities), and the nuclear plant gets a steady customer (forestalling premature retirement and enabling NRC license extension and potential uprates). And with the nuclear unit now supplying the data center load and not some distant network load, deliverability on the transmission grid is freed up for other existing and newly-interconnecting resources, typically wind and solar projects.

3 Nuclear plants have the added benefits of usually being remote, secure, and well-buffered, minimizing the potential for noise, visual or other impacts that can be associated with data center development.

4 U.S. Energy Info. Admin., *Annual Energy Outlook 2023, Table 9 (Electric Generating Capacity, Reference Case)*, https://www.eia.gov/outlooks/aeo/data/brower/#/?id=9-AEO2023&cases=ref2023&sourcekey=0; EPA, *Power Sector Modeling, Post-IRA 2022 Reference Case* (last updated Mar. 1, 2024), https://www.epa.gov/power-sector-modeling/post-ira-2022-reference-case; EPA, *Power Sector Modeling, Pre-IRA 2022 Reference Case* (last updated Dec. 13, 2023), https://www.epa.gov/power-sector-modeling/pre-ira-2022-reference-case.

Separating Co-Location Facts from General Concerns About New Load

Some have raised questions about whether pairing data centers with nuclear behind-the-meter increases costs for other customers and ratepayers via higher prices, system upgrades, or cost shifts, or otherwise harms reliability. Based on my years of experience operating power systems, I think these concerns have very little to do with co-location itself. In most cases the questions raised are a consequence of adding load *anywhere* on the grid and not *how* it is served, whether connected to the grid or co-located behind-the-meter.

1. Serving any new load will affect market prices

One frequently mentioned issue relating to co-located load is the impact on energy and capacity markets by "removing" an existing generator that is currently serving network load. All things being equal, co-locating data centers with nuclear units will not raise network prices any more than serving the same load in front of the meter in the same general location.[5] Any new demand will affect price, so unless we assume the new load *would disappear or not otherwise be served*, how the load is served does not materially change the effect on market prices. While every situation is unique, dedicating a portion of existing generation to a particular customer behind-the-meter through a direct connection will have the same effect on the supply/demand dynamic as serving the same amount of new load through deliveries over the transmission system from participating in the market or from a remote generator under a power purchase agreement. This new load, regardless of configuration, can be met using existing market and system planning tools.

2. Serving any new load may affect infrastructure costs

Another common misconception is that if an existing generator is used to serve a behind-the-meter load, new infrastructure (most likely transmission) will be needed and existing customers will have to pay for it. In my experience, it is far more likely that connecting a data center to the grid in front of the meter will require more transmission upgrades than co-locating it behind a generator, which does not rely upon the grid for service.

Larger loads (those approaching 1000 MWs) must connect to the grid on an extra high voltage line (230 kV or greater). This requires an extra high voltage substation and associated facilities to accommodate the front-of-the-meter data center. The construction costs for this type of transmission project will depend on the circumstances but can range from $150 million up to $250 million.[6] In a co-location configuration, these costs will be paid

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5 Given both nuclear plants and data centers operate generally as baseload facilities, the impact of adding new load or "removing" such supply will have virtually the same effect on market prices.

6 *See* "Transmission Expansion Advisory Committee – PPL Supplemental Projects," April 2, 2004 at https://www.pjm.com/-/media/committees-groups/committees/teac/2024/20240402/20240402-item-08---ppl-supplemental-projects.ashx (identifying $244 million PPL supplemental project); *see also* PJM, Transmission Expansion Advisory Committee: AEP Supplemental Projects, at 7 (June 4, 2024),

by the co-located load. In a front-of-the-meter configuration, by contrast, some of these costs will be allocated to grid customers.

Moreover, in a front-of-the-meter configuration, there will be additional costs associated with other transmission upgrades required to get power to the new substation built for that customer. The costs can be significant. In Northern Virginia, for example—where no data centers have co-located—data center growth combined with generator retirements has required over $5 billion of transmission investment to reliably serve the new load. The costs of those new transmission facilities, like all transmission facilities, will be *shared by all customers* in accordance with PJM's and the transmission owner's tariffs.

As discussed later, serving that same load behind-the-meter at a power plant can reduce the need for new transmission lines compared to a grid-connected configuration. The nuclear unit is also giving up use of the transmission system to others. Some transmission investment might be required in a co-location configuration to replace the generation with excess or new units. But if the load were in front of the meter, it is far more likely that a greater amount of transmission investment would be needed. The overall costs to grid customers should be significantly less in a co-location configuration.

So again, unless we are simply assuming these large new loads will not be served, any addition of that load will result in incremental infrastructure costs and the co-located configuration ensures that the costs incurred to serve the new load are paid for by the data center, not by customers of the surrounding utilities.

3. Serving any new load may affect reliability

The next common refrain is reliability, and that we should not let nuclear resources "take megawatts off the grid" to serve new loads because we cannot adequately replace the critical generation in a timely manner. Again, the issue is not whether we are serving the load behind-the-meter versus using the transmission grid to serve the load in front of the meter but instead is about serving new load, period. And again, unless one assumes the new load *would not otherwise be built or delayed for years,* the effect on grid reliability is the same. Tools already are in place in every restructured market to bring on any new resources needed to serve network load.

As an aside, the challenges of integrating new generation resources to replace retiring fossil generation and to meet all new load are a rightful focus of policymakers. In my view, markets should provide better incentives to attract new resources and the generation interconnection process should be significantly improved to get needed resources timely connected. What should not happen, however, is discrimination against one type of large new load (data centers) or one type of generation (nuclear). It cannot be that, after many years of financial struggles by nuclear units, we are now troubled by arrangements with counterparties that are willing to contract to ensure continued operation of those units. We

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https://www.pjm.com/-/media/committees-groups/committees/teac/2024/20240604/20240604-item-05---aep-supplemental-projects.ashx (identifying $155.69 million AEP supplemental project).

must find mechanisms to allow all new types of load to be connected in their preferred configuration and on their timeline and not claim some new load can connect but others must wait or not be served at all.

4. Behind-the-meter service imposes no new costs on grid customers

The last general claim is that behind-the-meter load causes "cost shifts" that negatively impact existing customers. For example, in the recent Exelon/AEP protest to the Susquehanna Interconnection Service Agreement amendment, a consultant from Concentric claimed up to $140 million in "cost shifts" from the data center to grid customers. This calculation is nothing more than the revenue that the transmission owner would have been paid if the data center had connected in front of the meter where it would take grid service and benefit from being connected from the grid. But in the co-location scenario, the extension cord to the grid is cut – the data center does not cause grid costs to be incurred, cannot take any service from the grid, and is not a customer of the transmission owner. There are no costs to shift in the co-location scenario.

It is true that existing grid customers cannot share the costs of their service with the data center supplying its own service, but no one can reasonably expect to share costs with someone *who is not taking service*.

Not only is there no cost shift, but co-location can help grid customers save money. The existing grid customers do not pay for new costs assumed by the data center or the costs for any upgrades identified in the host generator's updated interconnection studies. As elaborated below, many risks (*e.g.*, outage risk) are directly the responsibility of the loads in this co-located configuration, alleviating the need for other customers to share in costs to cover such risks.

* * * * *

We must not compare serving new data center load behind-the-meter with not serving it at all, as some suggest. Adding new load in any location may add new costs, so the question is how the configurations at issue—grid-connected or behind-the-meter—result in efficiency, reliability, and affordability for *all customers*, including the new data center load.

The Benefits of Co-Location

The beneficiaries of co-location behind-the-meter extend well beyond the data center and the host generator. In many cases, these configurations are better for all than if the data center were served in front of the meter. Co-location behind-the-meter helps to:

1. Serve the Load

Remember that co-location allows us to serve large new loads that otherwise would have to wait years for service, and thus to meet the technology needs and fuel economic growth on a much more expedited basis. As I noted above, connecting a new gigawatt-sized load to the power grid will almost always require construction of new transmission infrastructure, which can take years to plan, design, permit, and construct. Our goal should always be to serve customers when and how they want to be served, and co-location offers an excellent alternative.

2. Improve Grid Efficiency

The best and most cost-efficient way to supply a new large load is by generating as close as possible to that customer. The further the generation is from the load, the more expensive it becomes to move the power and the more at risk the system is to overloading existing transmission lines. By placing a data center where it can be directly served by a generator versus locating the load somewhere remote from the ultimate generation needed to serve it, the grid requires fewer upgrades to serve that new demand.

Similarly, the geographic proximity inherent in co-location also is likely to reduce energy losses ("line losses") resulting from transmitting long-distances from the power plant to data center, which at the transmission level are in the range of 1-3 percent. For a gigawatt-sized data center, that would avoid the loss of 90,000-260,000 megawatt hours of electricity. Given that large data center customers generally seek sources of carbon-free power, this prevents the unnecessary loss of an increasingly important commodity: clean electricity.

3. Transfer Risk from the Grid to the Co-Located Load

Greater risks equal greater costs and the co-locating data center load bears its own risks, while imposing no incremental risks on the network.

The risks the data center itself takes on are significant. If the data center were supplied from the grid, it could expect supply certainty in 99+% of hours given the diversity of resources in a region like PJM. This is very different for load connected to a single resource, even a very-well run nuclear resource that can be expected to run ~93% of the time.[7] To the extent a co-located load seeks to improve the reliability of the individual resource(s) it is co-located with,

[7] *See* DOE, Office of Nuclear Energy, *5 Fast Facts About Nuclear Energy* (June 11, 2024), https://www.energy.gov/ne/articles/5-fast-facts-about-nuclear-energy#:~:text=Nuclear%20energy%20is%20one%20of%20the%20most%20reliable%20energy%20sources%20in%20America (noting that nuclear power plants operated at full capacity more than 93% of the time in 2023).

it must pay for additional back-up (*e.g.*, on site back-up generators, batteries, etc.). Some customers might also choose to size to one unit at a dual unit site and use the second unit during refueling outages, *i.e.*, have the second unit be part of its additional supply.

Another way to view this is from the perspective of the data center itself: a grid-supplied data center avails itself of the redundancy and high availability inherent in a wholesale market overseen by an RTO as well as all the grid-supplied ancillary services. If the data center were in front of the meter and thus on the network, if one grid supply resource fails, another would be started to make up for the lost output from the failed resource, allowing grid connected load to continue seamless service under most scenarios.

In contrast, a co-located center must accept the outage risk associated with a discrete resource which will always be higher than grid power even if that resource is individually highly reliable. It also must carry—and pay for—its own reserves. This is a critical distinction between the two configurations: the services co-located data centers receive from a generator are not the same as the services the data center would receive if supplied by the power grid.

4. Charge Data Centers Instead of Grid Customers for More of the Transmission Facilities

Not only are risks transferred to the data center, so too are many of the costs. The data center pays for the private behind-the-meter delivery facilities as well as the electricity. And as I discussed above, in my experience it is very likely that a data center connecting to the grid will impose significantly more grid upgrade costs that will be socialized than a data center supplied behind-the-meter. The costs for this can be substantial (easily in the billions) and can be spread beyond the data center customer to all other customers.

5. Protect Reliability

Reliability always is paramount, and the data center/nuclear pairing will be studied appropriately to ensure reliability is maintained on the electric grid. If anything, co-location helps reliability by not trying to move more power a further distance.

The independent grid operator responsible for reliability studies the impacts of the new configuration at the nuclear facility to ensure reliability is maintained. In the PJM process, for example, PJM conducts a "necessary study" to determine whether a generator's modification to include behind-the-meter load has any reliability impact on the generator's interconnection with the grid.[8] If so, the generator pays for changes at its facility and any necessary network upgrades to cure the potential issue. PJM also reduces the available capacity for sale through the reduction of the capacity interconnection rights of the generator to reflect any behind-the-meter sales. Changes to the Interconnection Service

[8] PJM has provided detailed guidance for the current process to connect co-located load and all the steps required to ensure reliability. *See* PJM Guidance on Co-Located Load (March 22, 2024) (Updated April 17, 2024), https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/pjm-guidance-on-co-located-load.ashx. Numerous proposals to adjust these rules have been raised at PJM and in other fora.

Agreement on file at FERC may also be made to clarify reliability procedures given the behind-the-meter configuration.

Because a co-located data center served in a behind-the-meter scenario has equipment to prevent it from taking service from the grid, the grid will not be planned for or otherwise accommodate the load. Data centers almost always have their own backup power supply, further reducing demands that would exist if their backup supply was the network, or if the backup supply itself relied on the network for transmission services.

In the case of a nuclear unit, it will also remain connected to the network, as required by law. Any power at the nuclear station not committed to the behind-the-meter load still will be available for sale to the network or to others. The electricity is not disappearing or retiring. It is being used to serve load, just as it would if it were injecting into the grid and delivering to the data center over the transmission system.

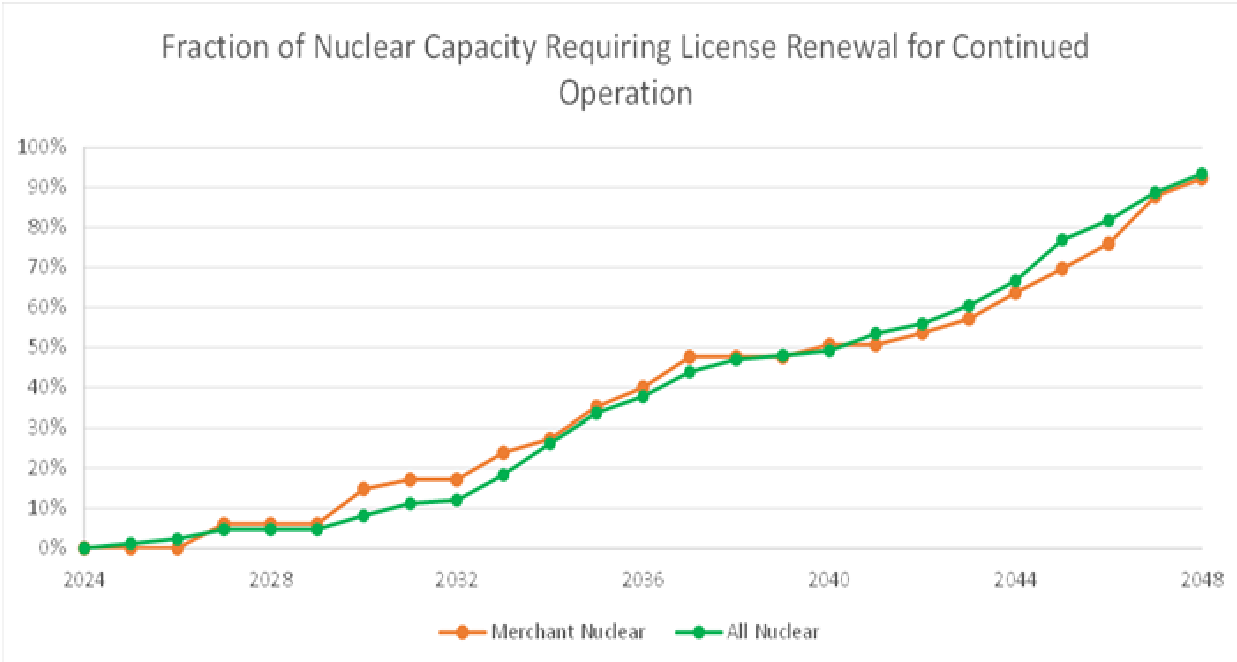
6. Facilitate Steady Customers for Nuclear Units to Remain in Service

Speaking of nuclear, the behind-the-meter configuration supports long-term investment in nuclear power plants and the grid and environmental benefits they provide. It creates the financial security needed to support a subsequent license renewal (the application itself cost tens of millions of dollars), making it more likely the nuclear plant and its emissions-free output remain available well into the future and able to consider uprate projects to increase output.

Over the last decade, nuclear resources faced significant financial uncertainty and one-third of the fleet either retired or obtained state support to preserve the assets and prevent higher prices and increased emissions.[9] The federal government followed with the PTC, which provides near-term financial stability for the nuclear fleet. However, it expires in 2032 just as a large portion of the fleet will be going through the NRC regulatory process to extend operating licenses, which can take five years or longer to complete. Thirty percent of the merchant nuclear units will need to renew operating licenses in the next 10 years to prevent shutdown, increasing to 50 percent over the following decade. Hosting a data center with a long-term power sales agreement would certainly play the key role in a unit owner's decision

[9] *See*, *e.g.*, D. Murphy & M. Berkman, The Brattle Group, The Impacts of Illinois Nuclear Power Plants on the Economy and the Environment (2019) (prepared for Ill. IBEW State Council and Ill. AFL-CIO), https://www.brattle.com/wpcontent/uploads/2021/05/17147_the_impacts_of_illinois_nuclear_power_plants_on_the_economy_and_the_environment.pdf; D. Murphy & M. Berkman, The Brattle Group, Pennsylvania Nuclear Power Plants' Contribution to the State Economy (2016) (prepared for Penn. Building and Construction Trades Council, et al.), https://www.brattle.com/wpcontent/uploads/2017/10/5732_pennsylvania_nuclear_power_plants_contribution_to_the_state_economy.pdf; D. Murphy & M. Berkman, The Brattle Group, Salem and Hope Creek Nuclear Power Plants' Contribution to the New Jersey and Local Economies (2020) (prepared for PSEG), https://www.brattle.com/wpcontent/uploads/2021/05/20628_salem_and_hope_creek_nuclear_power_plants_contribution_to_the_new_jersey_an d_local_economies.pdf.

of whether to undertake the multi-year regulatory process and related investments needed to relicense.

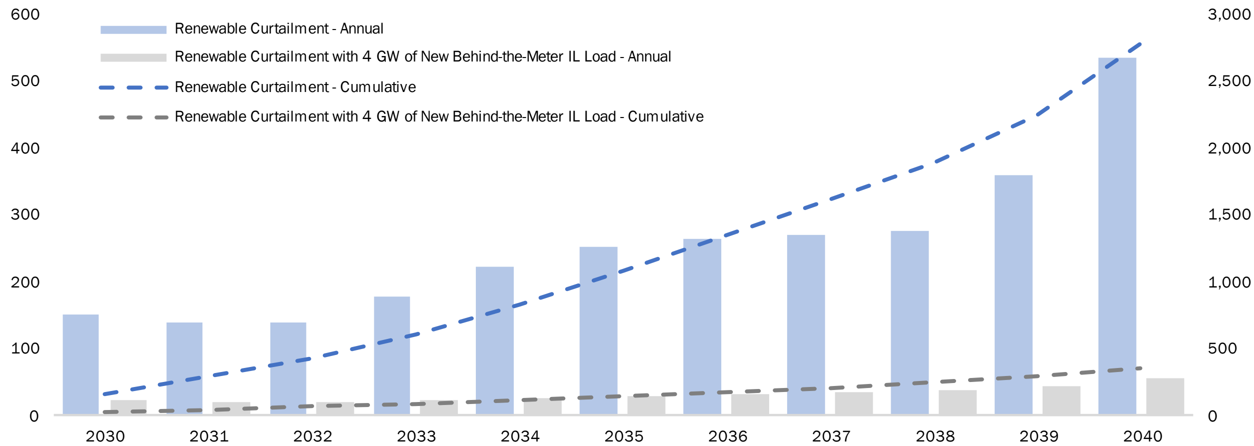


7. Increase Interconnection Opportunities for Renewables

Finally, other beneficiaries of co-location would be renewable projects being curtailed because of inadequate capacity on the transmission system to deliver from remote locations to load centers. Co-location of data center and nuclear generation frees up transmission headroom for new generator resources by making available the transmission capacity currently used by the host power plant. This benefit can be significant, such as in Illinois where transmission congestion is projected to increase in the next decade as the state adds more wind and solar generation to meet decarbonization goals. Co-locating data centers at Illinois nuclear plants could reduce curtailment of wind and solar output by over 80%.[10]

10 Analysis provided by Constellation Energy reflecting anticipated wind and solar expansion needed to comply with the Climate and Equitable Jobs Act.

Renewable Curtailments – Annual, GWh (Bars)
Renewable Curtailments – Cumulative, GWh (Lines)



Co-locating data centers at nuclear plants also could benefit renewable projects idling in the interconnection queue. As mentioned above, PJM's rules, for example, require a co-locating generating resource to forgo its capacity interconnection rights which can then free up capacity rights for another resource, which based on PJM's current queue is likely to be wind, solar or batteries. This can allow those resources to more quickly connect to the transmission grid with no (or fewer) transmission upgrades needed.

There Is No Cost Shift Without a Fundamental Market Redesign

Notwithstanding these benefits and the fact that new load connecting behind-the-meter imposes no new costs on grid customers—and cannot use grid power—some opposing voices still claim that transmission and related services are being provided to the disconnected load through the co-located generator. They claim because the *generator* remains connected to the grid, any load connected to the generator is "free riding" on the network including because they are synchronized through the generator.[11] For proof, they point to ancillary and other grid services provided to generation from the grid and claim that the co-located load benefits. This argument is creative but reflects a fundamental misunderstanding of the open access rate design established by the Federal Energy Regulatory Commission (FERC) thirty years ago.

While it is true nuclear plants must remain connected to the grid, any surface appeal this "cost shift through the generator" argument has falls apart when we look at current practices and precedent. Generators always have been connected to the grid and have never been

11 Simply being synchronized to the grid through a generator which in turn is synchronized to the power grid does not mean the co-located load receives the same service as those relying on the grid for service. This misses the point elaborated below that the co-located load is not taking service from the grid, even if the co-located generator may be.

charged for most of the services in question. This is a core design choice made by FERC when it adopted its open access transmission requirements in Order No. 888.[12]

Like any grid-connected generator, the co-located generator will continue to deliver any generation not consumed by the data center onto the grid for the benefit of the network's customers. Reducing the output of these generators has no material bearing on the system or its costs. It would be discriminatory to charge only a few generators for these services and would take a fundamental market design shift to start charging all generators for things like fluctuations in their output before these alleged cost shifts could be credible. In other words, for there to be a credible cost shift here, two things would need to happen: *first*, FERC would need to overhaul the basic open access rates applicable to all generators to start charging them for these services; and, *second*, co-located generators would have to be the only generators that do not pay them.[13]

Such a market redesign also would require regulators to reevaluate how costs are allocated when generation is located behind a grid customer's meter, i.e., when it is *generation* that is behind-the-meter, not *load*. Load that owns generation, such as a municipal customer with city-owned generation or a retail customer with roof-top solar, use that generation to reduce the volume of grid-delivered electricity for which they pay. It would be highly discriminatory to apply grid charges to load co-located behind-the-meter of a generator without doing the same to the portion of a customer's load met by behind-the-meter generation.

To put all this in context, let's consider each type of grid service and how it applies to a co-located behind-the-meter load configuration where the generator is connected to the grid and the co-located load takes power only from the generator:

- ***Transmission service*** – Since the co-located load is not able to take power from the grid, no system power is transmitted from the grid to the load. Indeed, equipment is installed to automatically switch the load off in the event the nuclear resource and any backup generation supply become unavailable so that the co-located load is never served by the grid. Any power that is transmitted over the grid is an injection from the existing nuclear unit to and for the benefit of network load and—like all generating resources in every RTO/ISO market—the generator is not required to pay any transmission service, either network or point to point to serve internal network load. The generator has an

12 *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 (1996).

13 Prompted by the increase in variable-output renewable generation across the country, FERC undertook a multi-year investigation fifteen years ago to evaluate whether open access rules should be altered to assign generators the cost of certain ancillary services. FERC declined to do so, instead providing a framework for any public utility that might seek to impose such costs on generators that includes, among other things, requirements to justify with operational data any distinction between different types of generators. *Integration of Variable Energy Resources*, 139 FERC ¶ 61,246 at P 315-335 (2012).

interconnection service agreement, which will be amended as needed, that provides for the ability to inject power into grid. No cost shift.

- ***Distribution service*** – Since any power supplied by the co-located resources to the load would be provided over a privately-owned line and not a utility's distribution (or transmission) system, no distribution services are being provided by the utility. Sale of power from the generating facility to the co-located load remains subject to the state's authority, including how the state assesses charges used to fund infrastructure and social programs. Depending on the state, there could be state-level charges that co-located load would pay—not for utility distribution infrastructure, but for those state-jurisdictional services or programs. No cost shift.

- ***Capacity*** – Whether the new load is in front of the meter or behind-the-meter being served by existing resources, new resources or excess from existing resources will be needed to meet remaining customer demand. As described above, reducing the amount of output an existing generator sells into the market or adding new load to be served by that market has the same effect on capacity—one adds to the "demand" side of the equation, while the other subtracts from the "supply" side.[14] No cost shift.

- ***Energy*** – Since the co-located load would have no ability to draw power from the grid, there is no grid energy purchased. Any energy sold into the market by the generator in excess of what the co-located load is consuming is treated like every other generator connected to the grid, subject to both day-ahead and real-time pricing. As with any generator connected to the grid, generators have the right and the ability to sell energy to anyone on the grid including externally to other systems. Like capacity, any new load behind-the-meter or in front of the meter is going to increase energy requirements by either reducing the supply curve or increasing the demand curve but the effect on the overall market is the same. No cost shift.

- ***Ancillary Services***

    - **Regulation and Frequency Response (aka Load Following)** – Variations in the co-located generator/load balance will change the amount of megawatts a generator is injecting into the grid. This is not the same as withdrawing power from the grid. While it is true the grid is absorbing the variations in the generator's injections, the grid does this for every generator regardless of whether on-site load is being served. Many resource types, particularly intermittent wind and solar, inject into the grid at levels that vary from moment to moment, with grid injections fluctuating up (or down) quite quickly and significantly in response to variable weather patterns or other factors. No generator—regardless of type—in any RTO/ISO region pays for regulation service to

[14] While current PJM rules do not give a generator serving behind-the-meter load the ability to retain its rights to sell that capacity into the PJM markets, those rules could evolve in a way that enables the generator to retain such rights (and the related obligations), making that alternative available to co-located data center customers.

ensure the grid is prepared to absorb their moment-to-moment fluctuations in power output. Nuclear units are no exception. It would require a fundamental policy change to begin charging all generators for this service, as discussed above. No cost shift without fundamental market redesign.

- **Operating Reserves** – Reserves are primarily to respond to a reduction in generator output or outages; they allow the grid to make up for a sudden change in the generation/load balance.[15] As with regulation service, generators do not pay for reserve services regardless of generator type and regardless of whether they have co-located, on-site load. As for the co-located load, it provides its own reserves through its supply arrangement with the host generator and has no ability to obtain reserves from the grid, nor does the presence of the co-located load increase or affect the existing grid reserves required in any way. Instead, if its co-located generator has an outage, the co-located load is on its own to either shed its load or provide its own reserves via interruptible power supplies and backup generation. No cost shift without fundamental market redesign.

- **Reactive Power** – Co-located generators are under the same NERC and RTO requirements to provide reactive power to the system as any other units. If, for example, PJM determines as part of its "necessary study" that any reactive deficiencies are caused by the co-location configuration, it will require the co-located generator to supply the reactive power—most likely through the installations of capacitors at the location that are paid for entirely by the generator—before the co-located load is connected to the generator. Generator already pays/contributes in kind.

- **Black Start** – Today no generator pays for black start, yet all generators (and all loads) benefit from the grid being restored. To the extent the nuclear plant's location is included and prioritized in any restoration plan, FERC could change the current paradigm and find that it may be appropriate for generators to pay a share regardless of whether it hosts co-located load. The cost would be minimal. Using PJM as an example, assigning a 1,000 MW nuclear unit a share of PJM's total $73 million annual black start costs would amount to a $590,000 per year charge for the nuclear unit that reduces costs assigned to others by 0.008 percent. Even if black start charges were assessed to generators, it does not follow that full network service should apply to co-located load. Generators could pay, but it would require fundamental market redesign.

- **Station Power Services and Emergency Services Supporting Nuclear Units** – To the extent that a nuclear resource is relying on grid-supplied power to meet its station power service needs and/or NRC license obligations, it should pay for those services. This is no different than how any other resource connected to the grid is treated and there is no reason to alter that treatment just because there is a load behind that

[15] Rapid load changes or dispatch error can also cause the needs for reserves.

resource because that load is unable to avail itself of those services. Generator already pays.

The only way serving co-located behind-the-meter generation could create a cost shift to grid customers is if we implement market design changes to begin charging *all* generators for load following, reserves, and black start but then excused a generator supporting a behind-the-meter load from those charges. I am not aware of any current efforts to enact any such proposals as the general view is that the provision of these services to generators *benefits the grid much more than it costs*.

Next Steps

Policymakers, regulators, and industry have a basic obligation to serve load. There is no dispute that it will take years for large data centers and other loads to connect to the grid under the standard utility models. Our collective focus should be on finding solutions that best manage reliability, affordability (for all), efficiency, and speed, without standing in the way of data centers choosing to pay for and provide their own transmission facilities and power supply (and backup power supply). Under the co-location behind-the-meter model, data centers and nuclear plants can do so without risking reliability or shifting costs to network customers, including those in other states. This data center/nuclear pairing is not only symbiotic for the parties, but for anyone with an interest in the promises of the digital age and a sustainable future.

Biography

Michael Kormos is an electric utility consultant with extensive experience solving complex problems and leading large teams across the energy industry. Until 2021, Mr. Kormos was Sr. Vice President, Transmission & Compliance for Exelon Corporation, where he was responsible for the operations and long-term planning for transmission systems of Exelon utilities Atlantic City Electric, Baltimore Gas & Electric, ComEd, Delmarva Power, PECO, and PEPCO. Mr. Kormos shaped Exelon and its utilities' policy positions on issues related to the Federal Energy Regulatory Commission, Regional Transmission Organizations (RTOs), and national transmission matters.

Before joining Exelon, Mr. Kormos spent 27 years at PJM Interconnection, the RTO responsible for transmission systems in 13 Mid-Atlantic and Midwestern states, and Washington, D.C. As PJM's Chief Operations Officer, he supported the development and implementation of competitive wholesale markets in PJM and earlier in his career at PJM, he oversaw an operational expansion that tripled size of the system controlled by PJM. He also held management and engineering positions in transmission operations while at PJM.

Mr. Kormos has also served on the board of director for Reliability First Corporation; an officer of the Eastern Interconnection Planning Collaborative and the Eastern Interconnection Data Sharing Network; and as a member of the North America Energy Reliability Corporation operating committee.

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WHAT HAPPENS WHEN A NUCLEAR PLANT AND A DATA CENTER SHACK UP?

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The runaway appetite of data centers for electricity, supercharged by the prospects for AI, is producing staggering forecasts for generation and transmission expansion. This comes alongside other new demand, such as the resurgence of onshore manufacturing and the electrification of heating and transport. At the same time, environmental policy is hastening the retirement of fossil-fueled power stations and the resources lining up to replace them are inadequate in capability, insufficient in number and stuck in lugubrious interconnection processes.

Considering the disquieting mathematics of expected supply to meet forecasted demand, policymakers need to take a hard look at data center interconnections. We cannot and should not use regulation to prevent the interconnection of data centers. But policymakers should examine how data centers are coming on-line. Most have connected in the traditional manner – as retail load, served off the distribution system. A more recent approach involves the colocation of data center campuses with dedicated generation “inside the fence.”

Colocation models can involve the promise of developing new generation to supply an accompanying data center campus. This raises the interesting prospect of demand spurring innovation and investment in new purpose-built generation, such as small modular reactors or hydrogen fueled solutions, and for self-sufficient microgrids to support accelerating data center load. Exciting, no doubt, but still more theoretical than immediate reality.

What “colocation” means today - in the present time - is the development of data center campuses adjacent to existing plants, particularly existing nuclear power stations. The campus is designed to tap directly into the plant. This affords the data center a dedicated, time-matched source of zero-emission supply and service which, arguably, is more reliable than a grid-connected configuration.

So, what’s not to like? Before examining that question, note that the model of colocated campuses at existing nuclear stations is happening in RTOs, and not at non-RTO facilities like Brown’s Ferry, Vogtle or Turkey Point – even as Tennessee, Georgia and Florida themselves see notable data center load growth. Not a coincidence, we’d argue. Powerful economic incentives in RTO regions work to motivate data campuses to colocate with existing nuclear plants and skip the path of slow, messy and more expensive grid interconnection.

Policymakers and regulators in RTO regions must examine closely whether incentives inherent to organized markets are inviting a model of colocation that (i) results in unfair rate impacts to consumers, (ii) challenges reliable system operations, and (iii) promotes a “shell game” for marketing rights around zero-emission electricity.

THREE ECONOMIC INCENTIVES

The leading examples of data center/nuclear colocation involve plants participating in RTO markets and owned by non-utility merchants - operators not tied directly to retail customers and ones whose fortunes depend on RTO wholesale market prices. Until recently, these markets struggled to retain installed nuclear and insufficient market revenue resulted in several plants retiring. What a difference a couple of years makes. Palisades, which shuttered in Michigan just two years ago, is well on its way to an historic return. Talen emerged from bankruptcy just last year. And merchant operators Constellation and Vistra enjoy stock prices that are presently soaring. But it’s not as if the RTOs important to these nuclear operators, like PJM, have fixed their markets to start paying these plants a living wage. For example, in 2023 average energy prices (LMP) in PJM decreased 61.2% from 2022. PJM’s market monitor reports this was the largest annual price decrease ($49.06 per MWh) and the largest annual percentage price decrease since the creation of PJM markets in 1999.

So, while the RTO market is an important predicate to the recent success of these operators, something other than market performance (i.e, the price outcomes in these markets) is at work to explain their dramatic turnaround. This “something” can be understood by examining (i) federal and state clean energy subsidies and programs, (ii) their impact on both wholesale prices and retail prices in RTO regions, and (iii) how they combine to create powerful economic incentives which drive a merchant nuke to cohabitate with a data campus.

1. Volatile and Generally Suppressed Wholesale Market Prices

As mentioned, prices in RTO markets are broken. Average energy and capacity prices are artificially low due to the penetration (through subsidy and support) of zero-marginal cost resources. Allowing these price taking resources to participate in price formation suppresses clearing prices because their uneconomic entry effectively moves the supply curve to the left.

Merchant nukes live or die based on what the RTO's wholesale market pays them for energy, capacity and grid services. That is, unless they can find other, non-market sources of revenue. One such opportunity, a power purchase agreement (PPA), looks increasingly appealing to nuclear operators in RTO markets. Not only does a PPA offer the seller a higher average price than what the market would deliver, it offers a certain price - one not subject to the volatility of the RTO's wholesale electricity markets. Particularly for publicly traded operators, this certainty can be transparently communicated to investors whose valuation of the company's stock is otherwise discounted on account of uncertain price outcomes in RTO markets.

2. The Nuclear PTC Under the IRA and State Zero Emission Credits

Usually, however, the seller under a fixed-price PPA must worry that prices in the RTO's wholesale market might rise and its fixed-price PPA commitment becomes an out of the money liability. Not really a concern for operators in RTO markets as it turns out, because this risk is fully hedged by virtue of the nuclear PTC under the IRA and by retail ratepayers (in some jurisdictions) providing ZECs. But there's more! Not only is the downside risk to the nuclear plant now covered, the upside which can take the form of PPA revenues or RTO market revenues (realized by that portion of the plant which remains grid-connected) and which may exceed the returns necessary to maintain the financial health of the plant as a whole, can be retained usually without offsetting any of the value of the PTC or ZEC subsidy.

Okay, so low RTO wholesale market prices and the raft of recent legislative support enabling nuclear plant owners to lock in a floor price that creates the condition for nuclear PPAs. These two incentives explain why contracting outside the RTO's markets may be attractive to sellers of nuclear energy. These arrangements, however, can be done financially without actually pulling nuclear MWs and MWhs off the grid. In RTOs, where a nuclear plant and data center physically shack up, we're seeing a third incentive at work – this one motivating the behavior of the buyer.

3. Avoiding Costs - Some that were once Manifest in RTO Wholesale Markets but now Appear in Downstream Retail Markets

A customer that colocates avoids "wires charges" – the fixed costs of the poles, wires, transformers and substations that comprise the transmission and distribution network. These costs are increasing and the call for massive investment in grid infrastructure to support the energy transition, harden the grid from extreme weather, physical and cyber vulnerabilities and replace aged infrastructure, only promises further escalation.

Less obvious are other non-bypassable charges that show up in the retail bill. These charges support state programs whose costs in the past were relatively modest – such as low-income assistance or energy efficiency weatherization – but now represent a significant percentage of the cost of delivered energy because they serve to fund RECs, and ZECs and other subsidy programs for clean energy and advanced technologies. These charges are tied to the bill from the local distribution utility. So, avoiding this utility by colocating allows the customer to bypass supposedly non-bypassable charges.

Even less obvious is that, because the widely accepted "missing money" problem in RTO energy market is worsening (on account of the price suppression discussed above), costs that should be manifest in wholesale energy market prices, are being reconstituted (to some degree) by RTOs as transmission or capacity market costs or other operating charges that for various reasons are not captured in LMP. These charges collectively are significant and go by various names such as uplift, conservative operations, operating reserves, start-up, no-load and reliability must run costs.

And guess what? All these costs, along with a share of administrative costs to fund the RTO, NERC, FERC, etc., are also allocated by the RTO to the local distribution utility, and passed through in retail rates, alongside wires charges and other non-bypassable charges.

For states that have adopted full utility restructuring and retail open access, this presents an acute problem. When policies work to suppress wholesale electricity prices and correspondingly inflate retail costs for delivered electricity, there's simply not much left for retail suppliers to compete over or to motivate retail customers into switching suppliers. But what will excite a customer is a power supply arrangement that allows it to avoid altogether the retail utility and, in so doing, bypass this burgeoning bucket of supposedly non-bypassable charges.

So, it takes a unique confluence of incentives and unintended consequences to create conditions supporting inside-the-nuclear-fence load. Nuclear units that operate outside of RTOs and those that remain part of a regulatory framework where the investment is dedicated to franchised customers who in turn pay cost of service rates are unlikely candidates for colocation strategies. And beyond data centers, it takes imagination to envision other energy-intensive operations (such as electric arc furnaces or smelters) finding a way to colocate with existing nuclear facilities. So, while this phenomenon might have a limited runway, it would be a mistake for policymakers, regulators, and retail customers in RTO regions to dismiss it as no big deal. We see three areas that call for inquiry.

QUESTIONS ARISING FROM COLOCATION

1. Economics and Fairness

Once energy and capacity is dedicated to serve inside the fence load it's removed from the RTO's wholesale energy and capacity markets.[1] Losing these resources from the supply stack increases clearing prices for grid-connected customers. These supply and demand economics don't change when the data campus is connected to and served by the grid. But the traditional approach to load interconnection comes with greater transparency and established regulatory processes that permit policymakers, customers and other stakeholders to understand and debate the impact of these interconnections.

For example, in Virginia, the proposal to meet grid-connected data center growth through both new natural gas generation (such as Dominion's 1000MW Chesterfield County project) and new large transmission projects in the mid-Atlantic is spawning debate at PJM, in Richmond and at FERC. Here consumers, environmentalists and neighboring states are raising questions of burden and debate the allocation of these burdens, including costs that will fall outside of Virginia and on consumers in other PJM states.

The debate and processes that characterize traditional grid interconnection stand in marked contrast to the essentially unregulated connection of colocated load. This opacity impedes policymakers from weighing the public interest in say, the equity in having a specific data campus industrial rate schedule, or the pros and cons of tax or economic development incentives to attract data center investment, or possibly regulating energy efficiency standards or requirements for back-up generation required from data center customers.

But the real cost shift occasioned by colocation goes back to the wires and so-called "non-bypassable" charges discussed earlier. Let's illustrate using simple but representative rate estimates. Assume a typical rate on file for a utility to serve a grid-connected data center at retail in the mid-Atlantic is $0.08 per kWh. Average energy prices (LMP) in PJM in 2023 according to the IMM's State of the Market Report came in around $0.03 per kWh.

[1] In PJM, situations where the nuclear plant can assure that its inside the fence customer will be immediately curtailed if the plant goes off-line raises a question whether the inside the fence load is "consuming" capacity from the plant. This engenders debate over the metaphysical definition of capacity. PJM's position is that the plant cannot sell its full MW capacity value into PJM's auctions and must account for the portion that has already been "sold" bilaterally to the colocated load. Some operators disagree and would prefer to continue fully participating in PJM's capacity market as they have done historically, essentially asking the RTO to close its eyes to the huge data campus that has sprung up inside its fence.

Even accounting for historic LMP variability and the wholesale seller's lost revenue opportunities (as could be realized in the RTO's capacity and ancillary service markets) the chasm separating 8 cents from 3 cents shows how both nuclear seller and data campus buyer are driven to form a PPA priced somewhere in the middle.

Some significant portion of this 5-cent differential represents wires costs and other non-bypassable charges that are fixed and must therefore be shifted to grid-connected customers. This cost shift should be accepted, so the argument goes, because colocating means the data campus doesn't use the grid and thus, shouldn't have to pay for it.

Going off-grid does not justify avoiding most non-bypassable charges. Because retail electric rates serve as a convenient funding and collection mechanisms for programs that have no relationship to distribution and transmission itself, the non-bypassable charges resulting from these programs are distinct from actual "wires charges" and equity demands they be borne by all electricity consumers. But the case is also strong to charge actual "wires charges" to colocation customers. It's hardly the case that colocation occurs without impact to the grid – impact that causes expensive infrastructure additions. We'll turn to these impacts below – but for the moment, consider PJM's recently approved $5 billion grid expansion plan, much of it driven by data centers in Northern Virginia coming on-line in the traditional grid-connected configuration. Does anyone believe the transmission needs identified by PJM would go away or cost materially less if each of these data centers had found a way to colocate?

Colocation, simply stated, subsidizes the data campuses involved. The arrangement will create needs for new transmission and generation and other customers, including those competitor data centers interconnecting the old-fashioned way, will be stuck paying the full tab left behind by the cohabitating couple.

2. Reliability

The interstate transmission grid was planned and developed over the past century to support the delivery of fossil and nuclear plants to load centers. The retirement of fossil plants, and their replacement with renewable generation that performs differently and requires different support from the transmission network, present reliability challenges that NERC and system operators are voicing with increasing volume and alarm.

On the heels of fossil retirement, now comes data center colocation with existing nuclear. Of course, colocation doesn't result in the retiring of the nuclear plant. But from the perspective of the system operator, charged with maintaining operational security and resource adequacy, the effect isn't much different. When a nuke dedicates output to inside the fence load, it deprives the system operator of a resource it otherwise would rely on to serve grid customers, provide grid services to support delivery of electricity and serve as capacity to meet resource adequacy requirements.

It's not apparent sufficient efforts, such as rigorous load flow modeling, have been undertaken to study what happens to a transmission network when resources it was designed to deliver are physically disconnected from the network. But common sense says it will spur yet more demand for new transmission infrastructure to replace the inertia/frequency response, stability and voltage support the nuke previously provided.

And, of course, there's no escaping the need for simply more generation to replace what's lost due to the colocation arrangement. New demand, both grid-connected or inside the fence, will pressure existing infrastructure and create the need for new supply. But the trending towards colocation tells us that it's quicker and easier to build a data campus with inside the fence interconnection facilities to existing generation, than it is to build the new generation and transmission needed to support the data center if it were to interconnect in the more traditional manner. This raises obvious cost allocation and fairness questions.

3. The Zero-Emission Shell Game

Finally, colocation feeds the myth of the "sustainable" data center. Connecting a 500 MW data campus to siphon 500 MWs from an existing nuke isn't reducing system emissions or advancing decarbonization goals. It merely kicks the carbon can down the road.

Colocation may make data center owners and their users feel good about their individual carbon footprints. But their action has just made the carbon picture of the rest of the system worse, and the total system no better. And unless the capacity lost to the system from colocation is replaced with new nuclear or the almost unimaginable equivalent of wind/solar/storage and transmission (or some breakthrough new zero emission technology), then when all is said and done, interconnection of the data campus has increased carbon emissions.

WHAT SHOULD POLICYMAKERS DO?

Ideally, we would fix price formation in RTO markets to remove the incentives driving merchant nuclear owners toward colocation. This is a herculean task, complicated by steps already taken by policymakers at both state and federal levels providing powerful financial support and subsidy for zero-emission generation, distorting RTO markets and suppressing RTO revenues to all sellers.

Looking downstream from the RTO, colocation still involves a retail sale. State regulators therefore have some ability to regulate the terms and conditions of this sale. This creates the possibility to reimpose on the data center many of the non-bypassable charges that have been bypassed. State lawmakers would need to examine their individual regulatory regimes to determine how extensive such regulation could be and whether it would be sufficiently effective to avoid cross-subsidization or undue cost shifts between customers.

One action that would effectively deter colocation would be to eliminate the federal PTC and accelerate the expiry of state ZECs for any portion of nuclear capacity dedicated to inside the fence load. Through these support mechanisms, the public has already purchased the environmental attributes of the plant. It can be argued that once this plant is severed from the grid, and thus no longer “in the public service” so to speak, the burden of paying for zero-emissions should shift from the public to the inside the fence customer. Preserving these incentives for grid-connected nuclear generation and future colocation arrangements that couple new zero-emission resources with dedicated load would encourage an equitable and truly carbon progressive form of colocation.

CONCLUSION

Let’s be clear, we can’t afford to lose any nuclear plants due to suppressed RTO wholesale market prices. Neither are we casting stones. The firms entertaining these arrangements are making rational economic decisions based on the incentives imbedded in the regulatory and policy structures in which they operate. But asking tax and ratepayers to support these plants only to see them excuse themselves from the supply stack and, in so doing, leave a complicated mess of cost and reliability burdens at the feet of these same tax and ratepayers seems facially unfair. And that’s before even considering the distortions arising from the convergence of different policies that unintentionally result in subsidies to data campuses and financial windfalls for merchant nukes.

The early naivete that led many to think costs to transition to a decarbonized grid would be modest, is giving way to a more sober appraisal informed by real world experience. With this context in mind, policymakers should scrutinize how data campus load is coming on-line. If affordability, reliability and fairness across customer classes are still duties of regulators and lawmakers – and they are – then the nuclear/data campus colocation arrangements presently underway in RTO regions should be sparking heated debate as to what’s in the public interest.

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**

COMMENTS OF WIRES

Pursuant to the Supplemental Notice of Proposed Rulemaking ("Supplemental NOPR") issued by the Federal Energy Regulatory Commission ("Commission" or "FERC") on April 15, 2021 in the above-captioned proceeding,[1] WIRES, on behalf of its members, hereby submits the following comments.

I. INTRODUCTION

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.[2] Since its inception, WIRES has focused on supporting investment in needed and beneficial transmission infrastructure – investments that Congress and the Commission have recognized are critical to establish a resilient, reliable, cost-effective, modern, and clean bulk power system.[3] For that reason, WIRES opposes the Supplemental NOPR and respectfully urges the Commission to maintain the existing RTO-participation incentive.

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[1] *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, Supplemental Notice of Proposed Rulemaking, 175 FERC ¶ 61,035 (2021).

[2] For more information about WIRES, please visit www.wiresgroup.com.

[3] This filing is supported by the full supporting members of WIRES but does not necessarily reflect the views of the RTO/ISO associate members of WIRES.

II. BACKGROUND

This proposed rulemaking involves the incentive under section 219 of the Federal Power Act ("FPA") that the Commission currently provides to transmitting utilities for Regional Transmission Organization ("RTO") participation. In the Energy Policy Act of 2005 ("EPAct 2005"), Congress directed the Commission to issue a rule that established incentives "for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion."[4] Although most of the incentives in section 219 focus on transmission infrastructure investment, Congress also instructed the Commission to "provide for incentives to each transmitting utility or electric utility that joins a Transmission Organization."[5]

A unanimous Commission responded by issuing Order No. 679.[6] This order allows utilities that join and remain in RTOs to receive a 50-basis-point return on equity ("ROE") incentive. During the rulemaking process, some commenters specifically argued that the incentive should only apply to new members, not existing ones, because "incentives should incite or spur a desired future action, and thus it makes no sense to provide incentives . . . for past behavior."[7] The Commission disagreed:

> [E]ntities that have already joined, and that remain members of, an RTO, ISO, or other Commission-approved Transmission Organization, are eligible to receive this incentive. *The basis for the incentive is a recognition of the benefits that flow from membership in such organizations and the fact that continuing membership is generally voluntary. Our interpretation of the statute is that eligibility for this incentive flows to an entity that 'joins' a Transmission Organization and is not tied to when the entity joined.* As some commentators note, to do otherwise could create perverse incentives for an entity to actually leave

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[4] 16 U.S.C. § 824s(a).

[5] *Id.* at § 824s(c).

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

[7] *Id.* at P 315.

> Transmission Organizations and then join another one. It would also be unduly discriminatory for the Commission to consider the benefits of membership in determining the appropriate ROE for new members but not for similarly situated entities that are already members.[8]

On rehearing, the Commission affirmed its decision in Orders No. 679-A[9] and 679-B.[10] The Commission also codified the policy in sections 35.35(b)(2) and 35.35(e) of its regulations.[11] As a result, ever since the issuance of Order No. 679, for the past 15 years the RTO-participation incentive has enjoyed the benefit of regulatory certainty. The Commission has consistently applied its policy, and transmitting utilities have relied upon that policy in choosing to join or remain in an RTO and in making large capital investments. Not coincidentally, RTO membership has increased over time, as have the considerable benefits provided by RTOs for consumers, which are often described as the RTO "value proposition."

On March 20, 2020, the Commission issued a Notice of Proposed Rulemaking on *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*.[12] Among other things, the NOPR proposed significant enhancements to the RTO-participation incentive. Under existing policy, the incentive is not fixed and is evaluated on a case-by-case basis, though applicants have uniformly requested a 50-basis-point incentive, which the Commission has granted without modification.[13] In the NOPR, the Commission proposed doubling the incentive for RTO participation to 100-basis-points, which an applicant could receive regardless of whether its participation was voluntary.[14]

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8 *Id.* at P 331 (emphasis added).

9 Order No. 679-A, 117 FERC ¶ 61,345.

10 Order No. 679-B, 119 FERC ¶ 61,062.

11 18 C.F.R. §§ 35.35(b)(2) & 35.35(e).

12 *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, Notice of Proposed Rulemaking, 170 FERC ¶ 61,204 (2020) ("NOPR").

13 *Id.* at P 92.

14 *Id.* at PP 97-98.

The Commission justified the increase by noting that the RTO incentive furthers the stated purpose of section 219, which is "to provide incentive-based rate treatments that benefit consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion."[15] The Commission found that the incentive had encouraged the formation of and participation in RTOs, which, in turn, had resulted in significant benefits to consumers, including total annual benefits and savings to customers in PJM of between $3.2 billion and $4 billion, $2.2 billion in annual benefits in SPP with a benefit-to-cost ratio of 14-to-1, and between $3.2 billion and $3.9 billion in MISO.[16] The Commission identified a wide range of benefits, which had increased over time:

> These benefits include access to large competitive markets, optimization of the transmission system, regional transmission planning that supports more efficient or cost-effective transmission development to meet regional transmission needs, reduction of the costs of carrying reserves through reserve sharing, and increased access to an expanded set of diverse resources. All of these attributes reduce the cost of delivered power by facilitating broader and more robust access to more sources of power, and to the lowest-cost source of power, over a wide geographic footprint. These benefits have increased over time. PJM notes that its value proposition for consumers has increased over the past 13 years to a current estimate of $3.2 to $4.0 billion, an increase from an estimated $2.2 billion in 2011.[17]

The Commission recognized that while the benefits of RTO participation were significant and increasing over time, so too were the burdens. RTO participation included a host of "duties and responsibilities" that had grown since Order No. 679 was issued in 2006:

> These [duties and responsibilities] include: loss of operational control of transmission facilities to a third party; an obligation to build new transmission facilities at the direction of the RTO/ISO; diminished decision-making control over assets while retaining the responsibility of maintaining the system; meeting reliability standards; obligations to obey RTO/ISO rules; and an obligation to provide electric service even when

[15] *Id.* at P 93.

[16] *Id.*

[17] *Id*. at P 94.

> foundational agreements can change, thereby changing the terms and conditions under which the transmitting utility initially agreed to participate in the RTO/ISO.[18]

The Commission has also tasked RTOs and their members to implement the Commission's most important policy initiatives, including competitive wholesale markets in Order No. 2000,[19] nonincumbent transmission development in Order No. 1000,[20] demand response in Order No. 745,[21] price formation and aligning dispatch and settlement intervals in Order No. 825,[22] energy storage in Order No. 841,[23] and, most recently, aggregated distributed energy resources in Order No. 2222.[24] Not surprisingly, the Commission concluded in the NOPR that "[a]lthough RTO/ISO participation provides substantial benefits for consumers, we agree with commenters that the RTO-Participation Incentive also compensates transmitting utilities for the ongoing duties and responsibilities of RTO/ISO membership."[25]

What followed, however, was startling, when the Commission issued a Supplemental Notice of Proposed Rulemaking on April 15, 2021 with two dissents and a separate

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[18] *Id*. at P 96.

[19] *Regional Transmission Organizations*, Order No. 2000, 89 FERC ¶ 61,285 (1999).

[20] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014). Although the nonincumbent transmission development requirements of Order No. 1000 also apply outside of RTO regions, they have, in practice, had the most impact in RTO regions. *See* FERC Staff, *2017 Transmission Metrics*, at 4-5 (2017), https://www.ferc.gov/sites/default/files/2020-04/transmission-investment-metrics_0.pdf.

[21] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 134 FERC ¶ 61,187 (2011), *vacated*, *Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), *rev'd*, 577 U.S. 260 (2016).

[22] *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 155 FERC ¶ 61,276 (2016).

[23] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, 162 FERC ¶ 61,127 (2018), *order on reh'g and clarification*, Order No. 841-A, 167 FERC ¶ 61,154 (2019), *petition denied*, *NARUC v. FERC*, 964 F.3d 1177 (D.C. Cir. 2020).

[24] *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 and clarification*, Order No. 2222-A, 174 FERC ¶ 61,197 (2021).

[25] NOPR, 170 FERC ¶ 61,204 at P 93.

concurrence.[26] The Supplemental NOPR unveiled a starkly different proposal than the one in the NOPR. Instead of proposing a fixed 100-basis-point incentive for RTO participation, the Commission proposed to reduce the incentive to 50-basis-points and restricted eligibility for the incentive to the first three years after a transmitting utility transferred operational control of its facilities to the RTO.[27] The Commission further proposed that utilities that had joined and remained in an RTO for three or more years were required to submit a compliance filing to remove the incentive from their transmission tariff.[28]

The Commission's rationale for this abrupt policy reversal was scant and conclusory in nature. First, the Commission concluded that it had the "latitude" to act given the meaning of "join" in section 219.[29] Second, the Commission speculated that providing the incentive indefinitely might not be necessary to incentivize a transmitting utility to join an RTO.[30] Third, the Commission was concerned with costs to ratepayers, "particularly given the substantial benefits of Transmission Organization membership to participating utilities."[31] The Supplemental NOPR does not appear to take into account the full measure of burdens and risks borne by RTO members or the benefits, both quantitative and qualitative, provided by existing RTOs to consumers.

The Supplemental NOPR risks undermining the development of competitive wholesale markets in the electric industry and the establishment of RTOs, which now serve about two-thirds of the United States. In Order No. 888, the Commission restructured the electric industry and required open access to transmission. Other orders followed, including Orders No. 889, 890,

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[26] Supplemental NOPR, 175 FERC ¶ 61,035.
[27] *Id.* at P 5.
[28] *Id.* at P 1.
[29] *Id.* at P 9.
[30] *Id.*
[31] *Id.*

and 2000, that recognized the value of competition and supported competitive wholesale markets. More than 20 years ago, in Order No. 2000, the Commission envisioned that RTOs would improve power market performance and promote economic efficiency:

> These benefits will include: increased efficiency through regional transmission pricing and the elimination of rate pancaking; improved congestion management; more accurate estimates of ATC; more effective management of parallel path flows; more efficient planning for transmission and generation investments; increased coordination among state regulatory agencies; reduced transaction costs; facilitation of the success of state retail access programs; facilitation of the development of environmentally preferred generation in states with retail access programs; improved grid reliability; and fewer opportunities for discriminatory transmission practices. All of these improvements to the efficiencies in the transmission grid will help improve power market performance, which will ultimately result in lower prices to the Nation's electricity consumers.[32]

Experience has confirmed the benefits to consumers anticipated by the Commission.

III. COMMENTS ON THE SUPPLEMENTAL NOPR

In spite of the significant benefits to consumers and burdens and risks to utilities of participation in RTOs, the Commission proposes to slash the RTO-participation incentive in the Supplemental NOPR. WIRES respectfully opposes this proposal. First, the Commission can only change its existing rule if it meets the dual burden of section 206 of the FPA: the Commission must show both that its existing rule is unjust and unreasonable and that the replacement rule is just and reasonable. Here, the Commission cannot meet this burden, for the existing rule is just and reasonable and the replacement rule is unduly discriminatory and results in a confiscatory rate. Second, Order No. 679 was properly decided, and the language, purpose, and legislative history of FPA section 219 requires that the RTO-participation incentive be available to a transmitting utility that participates in an RTO for the entire duration of its membership. Third, compelling policy reasons support the existing RTO-participation incentive,

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[32] Order No. 2000, 89 FERC ¶ 61,285 at 89-90.

including facilitating the development and integration of renewables, encouraging competitive generation markets and the growth of RTOs, and minimizing the risk of RTO exit.

A. The Commission Cannot Carry Its Burden under Section 206 of the FPA

In the NOPR, the Commission acknowledged that it was proceeding under its FPA sections 205 and 206 authority.[33] Section 219 specifically requires that revisions to its rules be subject to the requirements of sections 205 and 206.[34] Section 206 of the FPA also applies to "rules" and "regulations" affecting rates or charges, and requires that such rules and regulations be just, reasonable, and not unduly discriminatory or preferential.[35] Under section 206, the Commission bears the burden of showing that the existing rule is unjust, unreasonable, or unduly discriminatory or preferential and that its replacement rule is just and reasonable and not unduly discriminatory or preferential.[36] Here, the Commission cannot carry its burden under either prong of section 206.

1. The Current Rule Is Not Unjust, Unreasonable, or Unduly Discriminatory or Preferential

In support of the Supplemental NOPR, the Commission's reasoning is conclusory at best. With little or no analysis or support in the record, the Commission cites a legal rationale, a policy argument, and a concern over cost:

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[33] *See* NOPR, 170 FERC ¶ 61,204 at P 139 ("We conclude that neither an Environmental Assessment nor an Environmental Impact Statement is required for this NOPR under section 380.4(a)(15) of the Commission's regulations, *which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA* relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts, and regulations that affect rates, charges, classification, and services.") (emphasis added).

[34] 16 U.S.C. § 824s(d) ("All rates approved under the rules adopted pursuant to this section, including any revisions to the rules, are subject to the requirements of sections 205 and 206 that all rates, charges, terms, and conditions be just and reasonable and not unduly discriminatory or preferential.").

[35] 16 U.S.C. § 824e(a) ("any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential").

[36] *Emera Maine v. FERC*, 854 F.3d 9, 21 (D.C. Cir. 2017). *See also* 16 U.S.C. § 824e(b) ("In any proceeding under this section, the burden of proof to show that any rate, charge, classification, rule, regulation, practice, or contract is unjust, unreasonable, unduly discriminatory, or preferential shall be upon the Commission or the complainant.").

> Given that the statute only directs an incentive for entities that 'join' a Transmission Organization, we believe that the Commission has latitude under the statute to tailor this incentive more narrowly to encourage joining, rather than remaining in, a Transmission Organization. We believe that providing the Transmission Organization incentives indefinitely may not be necessary to incentivize a transmitting utility to join a Transmission Organization and, given the large impact that such an incentive has on ratepayers, may not appropriately balance utility and ratepayer interests, particularly given the substantial benefits of Transmission Organization membership to participating utilities.[37]

Each of those assertions, however, fails to establish that the current rule is unjust, unreasonable, or unduly discriminatory or preferential. The legal rationale is a cautious one. It does not assert that the text of the statute compels changing existing Commission policy; instead, it maintains that the Commission has "latitude" to act. But asserting that the Commission has the latitude to act is a far cry from alleging that the existing rule is unlawful. Moreover, in context, a sounder reading of section 219 construes "joins" as shorthand for "membership" in an RTO. And it is continuing membership rather than the initial act of joining that realizes the benefits of RTO participation for consumers. There is little value – and, indeed, there is detriment – in a utility joining and then exiting an RTO. Conversely, for market efficiency, reliability, and transmission planning purposes, an RTO benefits from having a stable membership.

Similarly, the Commission's policy rationale is equally unavailing. The assertion that "providing the Transmission Organization incentives indefinitely may not be necessary to incentivize a transmitting utility to join a Transmission Organization"[38] appears to be based on speculation. No quantitative evidence supports this assertion, and it is improbable at best as a qualitative matter. Since the issuance of Order No. 679, utilities have understood that they are eligible for the incentive as long as they join and remain in an RTO. While participation by utilities in RTOs over the last 15 years has generally remained stable with the incentive, now is

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[37] Supplemental NOPR, 175 FERC ¶ 61,035 at P 8.

[38] *Id.*

not the time for the Commission to engage in a risky experiment to see if that will remain the case without the incentive.

The fact of the matter is that over the past 15 years the burdens and risks of being in an RTO have only increased over time. In the NOPR, the Commission identified a panoply of utility duties and responsibilities that come with RTO membership:

> The duties and responsibilities associated with RTO/ISO membership have also increased since Order No. 679. These include: loss of operational control of transmission facilities to a third party; an obligation to build new transmission facilities at the direction of the RTO/ISO; diminished decision-making control over assets while retaining the responsibility of maintaining the system; meeting reliability standards; obligations to obey RTO/ISO rules; and an obligation to provide electric service even when foundational agreements can change, thereby changing the terms and conditions under which the transmitting utility initially agreed to participate in the RTO/ISO.[39]

Similarly, in its Comments to the NOPR, WIRES included a study from London Economics International ("London Economics") that explains the risks of RTO participation.[40] There are three categories of risk:

1. **governance of an RTO,** which obliges TOs to relinquish control over regional transmission planning and operations to the RTO;

2. **federal policies and regulatory changes** over the last ten years, which have introduced challenges and uncertainties for RTO-participating TOs;

3. **emergence of state and local policies** predominantly in RTO franchise areas, which have accelerated the pace of industry transformation and created uncertainties around transmission system use.[41]

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39 NOPR, 170 FERC ¶ 61,204 at P 96.

40 Comments of WIRES, Docket No. RM20-10-000 (July 1, 2020) (London Economics International LLC, *Economic Considerations in the Matter of Economic Transmission Incentives*, at 12 (July 1, 2020) ("London Economics Report")).

41 London Economics Report at 12.

With respect to RTO governance, transmitting utilities "relinquish control over transmission policy, stakeholder governance, and rate design."[42] RTO members are also subject to Commission policies designed to promote competition and innovation, including nonincumbent transmission development, demand response, efficient price formation, energy storage, and aggregated distributed energy resources.[43] In addition, "the geographic areas experiencing the greatest influence from state and local policies are highly correlated with the location of RTOs."[44]

Responding to RTO governance issues, federal policy, and state and local policy has resulted in increasingly complicated and time-consuming stakeholder processes as the electric industry goes through a period of unprecedented change. Some RTOs hold more than 300 meetings per year, which increases the cost and complexity for their members.[45] As a logical matter, in light of the significant burdens of RTO membership, it is hard to see how reducing the incentive will result in greater utility participation. In fact, it may actually lead to departures.

The Commission asserts that the incentive's costs are high (around $400 million a year) and that utilities benefit from RTO membership.[46] But while the increasing burdens of RTO membership have been amply documented, the Commission has failed to specify how utilities benefit from RTO membership. Furthermore, it is unclear how those benefits compare to the well-documented obligations and burdens of RTO membership. The Commission, however, must articulate the benefits and weigh them against the burdens.

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[42] *Id.* at 14.

[43] *Id.* at 16-20.

[44] *Id*. at 20-21.

[45] *Id*. at 14.

[46] Supplemental NOPR, 175 FERC ¶ 61,035 at P 8 n.21.

More critically, there is a fatal flaw in the Commission's logic with respect to the Commission-identified benefits of existing RTO participation: many of those benefits ultimately flow primarily to consumers and *not* to utilities. For example, utilities typically do not benefit financially from reduced energy prices, more efficient dispatch, cost savings achieved through reserve sharing, or lower capacity costs. All of those benefits accrue to consumers.[47] However, the Commission has failed to account for the way in which the benefits of RTO participation to consumers dwarf the cost of the incentive, which is an analysis that the Commission must perform to demonstrate that the existing rule is unjust, unreasonable, or unduly discriminatory or preferential. As the NOPR recognized, PJM estimates total annual benefits and savings of $3.2 to 4 billion.[48] SPP estimates annual savings of $2.2 billion.[49] MISO estimated regional benefits of $3.1 billion to $3.9 billion in 2020.[50] From the benefits data reported from those three RTOs alone, the ratio of benefits (about $8 billion using the lowest number when a range is specified) to costs ($400 million), would be 20 to 1.

Other benefits may be harder to quantify but, as a qualitative matter, have long been recognized by the Commission. In the NOPR, the Commission summarized a host of benefits provided by existing RTO membership:

> These benefits include access to large competitive markets, optimization of the transmission system, regional transmission planning that supports more efficient or cost-competitive transmission development to meet regional transmission needs, reduction of the costs of carrying reserves through reserve sharing, and increased access to an expanded set of

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[47] In restructured markets, the utility obtains few, if any, of these benefits, which flow directly to its customers. Even where utilities remain vertically integrated, state regulators typically require utilities to pass through any revenues that their rate-based generation earns in the RTO markets to customers, such that the utility itself does not benefit from the market efficiencies.

[48] NOPR, 170 FERC ¶ 61,204 at P 93 (citing *PJM Interconnection, L.L.C.*, Comments, Docket No. PL19-3-000, at 6-7 (filed June 26, 2019)).

[49] *Id.* (citing SPP, *14-to-1 The Value of Trust*, at 3 (May 29, 2019)), https://www.spp.org/documents/58916/14-to-1%20value%20of%20trust%2020190524%20web.pdf.

[50] MISO, *2020 Value Proposition*, at 5 (Feb. 12, 2021), https://cdn.misoenergy.org/2020%20MISO%20Value%20Proposition%2Calculation%20Details521882.pdf.

> diverse resources. All of these attributes reduce the cost of delivered power by facilitating broader and more robust access to more sources of power, and to the lowest-cost sources of power, over a wider geographic footprint. These benefits have increased over time.[51]

London Economics has noted that "[q]ualitatively, these benefits arise because RTO participation enables functional improvements in operations, supply procurement (energy and reserve markets) and planning."[52] By any metric, given the Commission-cited benefits provided by existing RTO membership – benefits not contested in the Supplemental NOPR – the current rule has led to a just and reasonable outcome that has provided significant benefits to consumers. Put another way, on this record, it cannot be said that the existing policy is unjust, unreasonable, or unduly discriminatory or preferential. Therefore, the Commission should withdraw its proposal.

2. The Supplemental NOPR's Replacement Rule Is Unjust, Unreasonable, and Unduly Discriminatory or Preferential

In contrast to the existing incentive's justness and reasonableness, the proposed replacement rule is deeply flawed. The Commission has proposed to provide the incentive for three years to utilities that join an RTO and to end the incentive for utilities that have belonged to an RTO for more than three years.[53] The duration limit is unjust and unreasonable in failing to account for the risks of RTO membership and the benefits provided to ratepayers. It is also unduly discriminatory in imposing an uncompensated burden on one group of transmitting utilities but not the other. RTO members are unduly harmed by the duration limit because they have made significant past investment decisions in reliance on the incentive, which has been in place for more than 15 years. For all of those reasons, the replacement rule should be rejected.

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[51] NOPR, 170 FERC ¶ 61,204 at P 94.

[52] London Economics Report at 28.

[53] Supplemental NOPR, 175 FERC ¶ 61,035 at P 1.

a. The Duration Limit Is Unjust and Unreasonable

The Commission's proposal is deficient in three important respects because it fails to account properly for benefits of existing RTO participation to consumers and the burdens and risks of RTO membership for utilities. First, with respect to benefits, it is hornbook law that ratemaking is not a science but an art.[54] Nevertheless, the Commission's discretion is not boundless,[55] and it exceeds the outer limits of its discretion in providing no compensation to utilities for RTO participation despite the documented quantitative benefits identified by the Commission and benefit-to-cost ratio provided by RTOs to consumers (which greatly exceed the cost of the incentive). Significant qualitative factors add to the RTO value proposition, which further supports providing the incentive to utilities that remain in an RTO. To engage in reasoned decision making, the Commission must consider such benefits in determining whether its proposal is just and reasonable. The Commission has failed to do so in the Supplemental NOPR, mistakenly attributing the benefits of existing RTO participation to *utilities* and relying on this faulty assumption to justify limiting the incentive to the first three years of a utility's membership.

Second, a foundational principle of ratemaking is that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."[56] As London Economics has shown, transmitting utilities in RTOs face risks related to RTO governance, Commission policy, and state and local policy that transmitting utilities in

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[54] *See Cities of Bethany, Bushnell, Cairo, Carmi, Casey, Flora, Greenup, Marshall, Metropolis, Newton, Rantoul, and Roodhouse, Illinois v. FERC*, 727 F.2d 1131, 1138 (D.C. Cir. 1984) ("ratemaking is less a science than it is an art"); *Alabama Elec. Coop, Inc. v. FERC*, 684 F.2d 20, 27 (D.C. Cir. 1982) (same).

[55] *See Illinois Commerce Comm'n v. FERC*, 756 F.3d 556, 564 (7th Cir. 2014) (if the Commission believes cost-benefit analysis is not feasibly for transmission cost allocation purposes, "it must explain why that is so and what the alternatives are").

[56] *FPC v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944).

bilateral markets do not.[57] As an example, transmitting utilities in RTOs are far more likely to have to compete for transmission projects under Order No. 1000 than transmitting utilities in bilateral markets. Under Order No. 1000, RTOs have completed around 30 competitive transmission project solicitations resulting in approximately 15 competitive projects to date.[58] In comparison, no competitive solicitation has advanced in a non-RTO region.[59] In the absence of an incentive, the transmitting utility in an RTO is treated the same as a transmitting utility in a bilateral market even though they clearly do not share "corresponding risks."

Third, in disregarding the burdens and risks of RTO membership, the Commission's proposal results in a confiscatory rate. A "guiding principle" in ratemaking is that a rate cannot be so low as to be confiscatory.[60] The Supreme Court has noted that "the 'lowest reasonable rate' is one which is not confiscatory in the constitutional sense."[61] In determining whether a rate methodology is confiscatory, the Commission has recognized that it "is not bound myopically to consider only certain costs and revenues, but ignore all others. The Commission may consider whether the 'end result' of its rate methodology is reasonable."[62]

Here, in ignoring the burdens and risks of RTO participation, the Supplemental NOPR's end result is unreasonable. The Commission has recognized that RTO membership has "duties and responsibilities" and that those burdens have increased over time.[63] The Supplemental NOPR, however, ignores those burdens and fails to compensate transmitting utilities for the burdens and risks associated with RTO participation after the first three years of membership.

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57 London Economics Report at 12-26.

58 *Id.* at 17 n.45.

59 *Id.*

60 *Duquesne Light and Power v. Barasch*, 488 U.S. 299, 307-08 (1989).

61 *Id.* at 308 (quoting *FPC v. Natural Gas Pipeline Co.*, 315 U.S. 575, 585 (1942)).

62 *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services Into Markets Operated by the Cal. Indep. Sys. Operator and the Cal. Power Exchange Corp.*, 114 FERC ¶ 61,070, at P 81 (2006).

63 NOPR, 170 FERC ¶ 61,204 at P 96.

The burdens and risks for utilities of RTO membership continue as long as they remain in an RTO.[64] Over the last two decades, the Commission has directed RTOs to advance many of the Commission's most important policy priorities. This has required transmitting utilities in RTOs to commit the resources to respond to and to effectuate the policy – resources that could otherwise have been used in business activities that are more beneficial to the utility.

It is no answer to suggest that an aggrieved utility can simply leave the RTO. The process of exiting an RTO is time consuming and costly. Invariably, as Commission experience has shown, departures from RTOs can trigger litigation over cost allocation responsibilities.[65] The utility will need the approval of the RTO, state regulators, and the Commission. Until the utility is allowed to depart, it must continue to meet all of its many obligations as an RTO member. Thus, the Supplemental NOPR establishes a confiscatory rate in failing to account for the continuing burdens and risks of RTO membership.

b. The Duration Limit Is Unduly Discriminatory

Limiting the RTO-participation incentive to three years would unduly discriminate between transmitting utilities that belong to an RTO and transmitting utilities that do not. The former would be subject to a range of risks and burdens of RTO membership without compensation, while the latter would not. Under FPA sections 205, 206, and 219, the Commission cannot approve rates that are "unduly discriminatory or preferential." Undue discrimination occurs when similarly situated entities are treated in a manner that results in

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64 *See* London Economics Report at 12.

65 *See MISO Transmission Owners v. FERC*, 860 F.3d 837, 839 (6th Cir. 2017) (Duke's departure from MISO triggered exit fee and litigation over cost allocation for projects MISO approved after Duke announced its departure but before it left).

"arbitrary differences"[66] or that "grant[s] any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage."[67]

Here, the Commission creates an arbitrary difference between transmitting utilities that belong to an RTO and those that do not. With respect to incentives, after a three-year period for RTO members, the utilities are treated the same as utilities outside of an RTO even though they clearly are not. As the Commission has previously recognized, RTO members have ongoing responsibilities and obligations that non-RTO members do not. Without providing compensation to offset those regulatory and governance burdens, the Commission would set rates that unduly discriminate against RTO members. In other words, the Supplemental NOPR proposal would create two classes of transmitting utilities, one of which bears the risks and burdens of RTO membership without compensation after three years and the other of which does not.

B. EPAct 2005 Supports Providing the Incentive to Utilities that Previously Joined and Remain in an RTO

The existing RTO-participation incentive properly interprets EPAct 2005. First, the Commission's precedent in Orders No. 679,[68] 679-A,[69] and 679-B,[70] all of which were issued unanimously, has consistently applied the incentive to transmitting utilities that join and remain in an RTO. These orders are entitled to deference because they were issued contemporaneously by the Commission that implemented EPAct 2005 and that was most aware of its text, purpose, and legislative history. Second, the text of section 219 also supports this result. In context, "joins" does not relate to a single moment in time, but speaks more broadly to the concept of

[66] *Dynegy Midwest Generation, Inc. v. FERC*, 633 F.3d 1122, 1127 (D.C. Cir. 2011) (finding undue discrimination where transmission owners in MISO had the discretion to choose between two different schedules for reactive power compensation, one of which provided compensation under a cost-based rate and the other of which did not for reactive power produced within the deadband).

[67] 16 U.S.C. § 824d(b).

[68] Order No. 679, 116 FERC ¶ 61,057.

[69] Order No. 679-A, 117 FERC ¶ 61,345.

[70] Order No. 679-B, 119 FERC ¶ 61,062.

membership or participation. Third, legislative history supports this reading, as does the policy rationale underlying the incentive.

1. Commission Precedent Is Clear and Compelling

Since the passage of EPAct 2005, the Commission has been unwavering in holding that section 219 allows utilities that join and remain in an RTO to be eligible to receive the RTO-participation incentive.[71] In Order No. 679, the Commission squarely considered the issue of eligibility, as some commenters had argued that "the incentive should only apply going forward for new members, not for those who already joined" and that "incentives should incite or spur a desired future action, and thus it makes no sense to provide incentives to transmission owners for past behavior."[72] In response, the Commission refused to "make a generic finding on the duration of incentives."[73] Instead, "[a]n entity will be presumed to be eligible for the incentive if it can demonstrate that it has joined an RTO, ISO, or other Commission-approved Transmission Organization, and its membership is on-going."[74]

The Commission explained that the concept of "joins" was not tied to a moment in time, given the purpose of EPAct 2005, policy considerations, and the desire to avoid undue discrimination:

> [E]ntities that have already joined, and that remain members of, an RTO, ISO, or other Commission-approved Transmission Organization, are eligible to receive this incentive. *The basis for the incentive is a recognition of the benefits that flow from membership in such organizations and the fact that continuing membership is generally voluntary. Our interpretation of the statute is that eligibility for this incentive flows to an entity that 'joins' a Transmission Organization and is not tied to when the entity joined.* As some commentators note, to do otherwise could create perverse incentives for an entity to actually leave

[71] Indeed, even before Order No. 679, the Commission had provided a 50-basis-point incentive for utilities that joined an RTO. *See Midwest Indep. Transmission Sys., Inc.*, 102 FERC ¶ 61,143 at P 5 (2003), *aff'd in part and petition granted in part, Pub. Serv. Comm'n of Kentucky v. FERC*, 397 F.3d 1004 (D.C. Cir. 2005).

[72] Order No. 679, 116 FERC ¶ 61,057 at P 315.

[73] *Id.* at P 327.

[74] *Id.*

> Transmission Organizations and then join another one. It would also be unduly discriminatory for the Commission to consider the benefits of membership in determining the appropriate ROE for new members but not for similarly situated entities that are already members.[75]

The Commission hewed to its position on rehearing. In Order No. 679-A, the Commission reiterated that the incentive should be available for utilities that join and remain in RTOs. This result was consistent with EPAct 2005's purpose and policy rationales that recognized the value of RTOs, the desirability of spreading their benefits "to as many consumers as possible," and the importance of providing existing members with "an inducement to stay":

> We affirm the finding in the Final Rule that the incentive applies to all utilities joining transmission organizations, irrespective of the date they join, based on a reading of section 219 in its entirety. Section 219 specifically provides that "the Commission shall . . . provide for incentives to each transmitting utility or electric utility that joins a Transmission Organization." The stated purpose of section 219 is to provide incentive-based rate treatments that benefit consumers by ensuring reliability and reducing the cost of delivered power. *We consider an inducement for utilities to join, and remain in, Transmission Organizations to be entirely consistent with those purposes. The consumer benefits, including reliability and cost benefits, provided by Transmission Organizations are well documented, and the best way to ensure those benefits are spread to as many consumers as possible is to provide an incentive that is widely available to member utilities of Transmission Organizations and is effective for the entire duration of a utility's membership in the Transmission Organization. To limit the incentive to only utilities yet to join Transmission Organizations offers no inducement to stay in these organizations for members with the option to withdraw, and hence risks reducing Transmission Organization membership and its attendant benefits to consumers.* Because the incentive is applicable to utilities that join Transmission Organizations and is consistent with the requirements of section 219 of the FPA, the incentive complies with EPAct 2005 and the FPA.[76]

In Order No. 679-B, the Commission unequivocally declared, "[A]n inducement for utilities to join, and remain in, [a] Transmission Organization is consistent with the purpose of section 219, which is to provide incentive-based rate treatments that benefit consumers by

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[75] *Id.* at P 331 (emphasis added).

[76] Order No. 679-A, 117 FERC ¶ 61,345 at P 86 (emphasis added).

ensuring reliability and reducing the cost of delivered power."[77] The orders are entitled to deference because they were issued by the Commission that was most familiar with EPAct 2005 and that implemented its directives. "Great weight" should be given to an agency's "'contemporaneous construction of a statute by the . . . [officials] charged with the responsibility of setting its machinery in motion; of making the parts work efficiently and smoothly while they are yet untried and new.'"[78] Not surprisingly, in the 15 years since the issuance of Order No. 679, the Commission has routinely supported the incentive for utilities that joined and remain in an RTO, and utilities have relied upon a reasonable expectation that they were eligible for the incentive as they assessed the costs and benefits of RTO membership.[79]

2. Congress Intended the Commission to Provide Incentives for Utilities that Join and Remain in RTOs

The text of section 219 supports the continued eligibility of utilities for the RTO-participation incentive if they join and remain in an RTO. The language of section 219(c) is mandatory in nature: "In the rule issued under this section, the Commission *shall*, to the extent within its jurisdiction, provide for incentives to each transmitting utility or electric utility that joins a Transmission Organization."[80] In context, it is clear that Congress intended "joins" to

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[77] Order No. 679-B, 119 FERC ¶ 61,062 at P 19.

[78] *United States v. Am. Trucking Ass'ns*, 310 U.S. 534, 549 (1940) (quoting *Norwegian Nitrogen Co. v. United States*, 288 U.S. 294, 315 (1933)). *See also Shapiro v. United States*, 335 U.S. 1, 12 n.13 (1948) (according special weight to "the contemporaneous interpretation of an administrative agency affected by a statute, especially where it appears that the agency has actively sponsored the particular provisions which it interprets"); *White v. Winchester Country Club*, 315 U.S. 32, 41 (1942) (agency's "substantially contemporaneous expressions of opinion are highly relevant and material evidence of the probable general understanding of the times and of the opinions of men who probably were active in the drafting of the statute").

[79] *See Pacific Gas & Elec. Co.*, 148 FERC ¶ 61,245 (2014), *reh'g order*, 154 FERC ¶ 61,245 (2016), *petition granted*, *Cal. Pub. Util. Comm'n v. FERC*, 879 F.3d 966 (9th Cir. 2018); *Pacific Gas & Elec. Co.*, 152 FERC ¶ 61,252 (2015), *reh'g order*, 154 FERC ¶ 61,118 (2016), *petition granted, Cal. Pub. Util. Comm'n v. FERC*, 879 F.3d 966 (9th Cir. 2018) ("*CPUC*"). In *CPUC*, the Ninth Circuit granted the state commission's petition for review, holding that the RTO incentive was unavailable to a utility required to remain in CAISO as a matter of state law. *CPUC*, however, supports WIRES' position in that the Ninth Circuit implicitly found that a utility was eligible for the incentive unless state law mandated its participation.

[80] 16 U.S.C. § 824s(c) (emphasis added).

mean more than the one-time act of joining. Instead, as the Commission has previously recognized, Congress meant for "joins" to mean "joins and remains in," as in RTO membership.

First, the plain meaning of "join" supports this meaning. The *Merriam-Webster Dictionary* defines "join" in part as "to become a member of a group or organization."[81] According to the *American Heritage Dictionary*, "join" can mean "[t]o become a part or member of" or "[t]o become a member of a group."[82] Membership continues as long as an entity remains in the larger group. Under this definition, "join" does not begin and end at a single moment in time but instead denotes a continuing status until the membership concludes.[83] Reinforcing this point is the fact that no language in section 219 specifically limits the incentive's duration, which Congress could have provided had it wished to do so.

Moreover, the statute allows the incentive for a utility "*that* joins" an RTO.[84] Once the utility joins an RTO it is eligible for that incentive under the statute as long as it remains in the RTO. As Commissioner Danly has argued, "'That' in this sentence is a relative pronoun. Its function is to introduce a restrictive relative clause. It does no more than identify the universe of entities eligible for the incentive….There is also no limitation in the verb [joins]."[85] Had Congress intended to provide a one-time incentive, it could have used "to" instead of "that" to focus on the act of joining or it could have specified a time limit on the incentive's duration.[86]

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[81] *Join*, MERRIAM-WEBSTER.COM,, https://www.merriam-webster.com/dictionary/join (last visited Jun. 23, 2021).

[82] *Join*, AHDICTIONARY.COM., https://www.ahdictionary.com/word/search.html?q=join (last visited Jun. 23, 2021).

[83] In other areas of the law, statutes have been read similarly. "Possession" of contraband, for example, continues as long as one possesses the contraband and does not occur only when one first receives the contraband. *United States v. Berndt*, 530 F.3d 553, 554-55 (7th Cir. 2008). Similarly, escape from federal custody occurs as long as one is on escape status and does not occur only at the moment of escape. *United States v. Bailey*, 444 U.S. 394, 413 (1980) ("we think it clear beyond peradventure that escape from federal custody . . . is a continuing offense, and that an escapee can be held liable for failure to return to custody as well as for his initial departure").

[84] Supplemental NOPR, 175 FERC ¶ 61,035 (Danly, Comm'r, dissenting at 1).

[85] *Id*. (Danly, Comm'r, dissenting at 1, n.4).

[86] *Id.* (Danly, Comm'r, dissenting at 1).

The statute's purpose supports this reading of "joins." In section 219, Congress directed the Commission to establish incentives "for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion."[87] That purpose can only be accomplished if a utility joins and remains in an RTO. The value of an RTO depends on its membership and the stability of that membership; in other words, achieving the benefits of RTO participation for consumers is contingent on a utility's continuing membership in the RTO. Under the Commission's reading of the statute, not only would utilities have less incentive to join an RTO, they would have less incentive to remain as well. As a result, a cramped reading of "joins" would frustrate the very purpose of the statute. This the Commission cannot do, for when a statute is open to more than one interpretation it must be read "in the manner which effectuates rather than frustrates the major purpose of the legislative draftsmen."[88]

Section 219's legislative history supports the Commission's determination in Order No. 679 and its progeny. The House's version of EPAct 2005 titled this section "Additional incentives for RTO *participation*."[89] This is consistent with the recollection of former Representative Joe Barton, who was the Chairman of the House Energy and Commerce Committee from 2004 to 2007 and House sponsor of the Energy Policy Act of 2005. Mr. Barton explains that the incentive was not meant to be "a one-time payment or a one-time deal":

> [S]ection 219(c) does not contain a 'sunset' clause and at no point does it implicitly, or expressly, state that the incentive to a utility that joins a Transmission Organization should be limited in duration. Consistent with my instructions to Conference Committee staff around ambiguity, if the committee had intended that the incentive to a utility that joins a Transmission Organization was meant to be a one-time payment or one-

[87] 16 U.S.C. § 824s(a).

[88] *Shapiro v. United States*, 335 U.S. 1, 31 (1948). *See also D.B. v. Cardall*, 826 F.3d 721, 739 (4th Cir. 2016) ("When a statute is subject to two contrary interpretations, we should adopt the one that 'effectuates rather than frustrates the major purpose of the legislative draftsmen.'").

[89] H.R. 6, 109th Cong. § 218(b) (as passed by House, Apr. 21, 2005) (emphasis added).

> time deal, I would have instructed Conference Committee staff to make that clear in the language of the statute. Both myself, and the Conference Committee staff at the time, were more than capable of drafting language to that effect. The fact that section 219(c) does not expressly limit the incentive to a utility for joining a Transmission Organization indicates that I did not intend for that provision to be a 'loss leader' or one-time deal to get a utility to join a Transmission Organization.[90]

Contemporaneous testimony from the Commission's General Counsel, Cynthia Marlette, establishes that the Commission sought to incentivize "membership" in an RTO, not the one-time act of joining it, in recognition of the "major benefits" provided by RTOs. On February 10, 2005, Ms. Marlette provided a statement to the House Committee on Energy and Commerce, Subcommittee on Energy and Air Quality:

> The Commission's policy is to encourage *membership* in RTOs, since RTOs enhance the reliability and economic efficiencies of a region's transmission grid and power supply. The conference report on H.R. 6 endorses voluntary participation in RTOs in section 1232's "Sense of the Congress" statement. This provision is beneficial in light of the major benefits that RTOs can bring to electric markets. In addition, increased *membership* in FERC-approved RTOs or ISOs by governmental transmitting utilities would provide even further benefits to electric customers, and section 1232 of the conference report on H.R. 6 would facilitate this result for federal power marketing agencies and the Tennessee Valley Authority.[91]

Ms. Marlette's statement is particularly relevant because of her role as the Commission's General Counsel. In *Shapiro v. United States*, the Supreme Court gave "special consideration" to the written statement of an agency's General Counsel that was presented at a congressional hearing on legislation that was later enacted.[92] The Court observed:

> We may accord to the construction expounded during the course of the hearings at least that weight which this Court has in the past given to the contemporaneous interpretation of an administrative agency affected by a statute, especially where it appears that the agency has actively sponsored

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90 Affidavit of the Honorable Joe Barton, at P 6 (June 2, 2021) (attached hereto as **Exhibit 1**).

91 *Energy Policy Act of 2005: Hearing on H.R. 6 Before the Subcommittee on Energy and Air Quality of the H. Comm. On Energy and Com.*, 109th Cong. 30 (2005) (statement of Cynthia Marlette, General Counsel, FERC) (emphasis added), *reprinted in* 8 Legislative History of P.L. 109-58 Energy Policy Act of 2005 (2005).

92 *Shapiro v. United States*, 335 U.S. at 12 n.13.

> the particular provisions which it interprets. And we may treat those contemporaneous expressions of opinion as 'highly relevant and material evidence of the probable general understanding of the times. . . .'[93]

In sum, the Commission should not abandon its longstanding policy of providing an incentive for RTO membership for the entire duration of a utility's participation in an RTO. The text of section 219 requires that a utility "that joins" an RTO be eligible for the incentive as long as it remains in the RTO. The statute itself does not contain specific language limiting the duration of the incentive. Its stated purpose – "benefitting consumers by ensuring reliability and reducing the cost of delivered power"[94] – is promoted by encouraging utilities to remain in an RTO. Order No. 679, which reflects the Commission's contemporaneous interpretation of section 219, furthers this purpose, because it recognizes the value of RTOs and provides an incentive for utilities' continued participation. Finally, legislative history supports this interpretation over the one the Commission sets forth in the Supplemental NOPR.

C. Compelling Policy Reasons Support Retaining the Incentive

Now is not the time to undermine RTOs at the expense of other urgent policies. Retaining membership in RTOs is more important than ever as policymakers address the climate crisis and support the energy transition. First, the climate crisis requires decarbonization of the power industry and electrification of other parts of the economy. RTOs, given their role in overseeing electric grids, can help many regions achieve those goals. Second, the decision to join an RTO is generally a voluntary one. This means that incentives are critical for attracting new members and retaining existing ones. Finally, if existing RTO members lose the incentive, there is a very real risk that some will decide that the risks and burdens of membership outweigh

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[93] *Id.* (quoting *White*, 315 U.S. at 41).

[94] 16 U.S.C. § 824s(a).

the benefits. Departures from RTOs could unravel the very markets that the Commission has spent two decades developing and nurturing.

1. Addressing the Climate Crisis and Supporting the Energy Transition

The Biden Administration's goal is to have zero carbon emissions from the power industry by 2035 and for the economy to be carbon neutral by 2050. To reach those goals will require a vast addition of renewable resources and electrification of the economy. According to the National Renewable Energy Laboratory, "widespread electrification can lead to historically unprecedented growth" in load in absolute terms.[95] Similarly, to meet electrification-related demand, the Brattle Group estimates that 70 GW to 200 GW of additional new power generation will be needed by 2030 and another 200 GW to 800 GW of generation between 2030 and 2050.[96] The transition to a low carbon future will require optimizing the capacity of existing transmission, as well as planning and developing additional transmission.[97]

RTOs help facilitate this transition and enable electrification. They support renewable development in a multitude of ways envisioned by Order No. 2000, including regional transmission pricing and the elimination of rate pancaking, improved congestion management, more accurate measurements of Available Transfer Capability, reduced transaction costs, and fewer opportunities for discriminatory transmission practices.[98] RTOs also facilitate regional

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[95] Trieu Mai, Paige Jadun, Jeffrey Logan, Colin McMillan, Matteo Muratori, Daniel Steinberg, Laura Vimmerstedt, Ryan Jones, Benjamin Haley, and Brent Nelson, *Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States*, at xiv (2018), https://www.nrel.gov/docs/fy18osti/71500.pdf.

[96] The Brattle Group, *The Coming Electrification of the North American Economy, Why We Need a Robust Transmission Grid*, at iv (Mar. 2019), https://wiresgroup.com/wp-content/uploads/2020/05/2019-03-06-Brattle-Group-The-Coming-Electrification-of-the-NA-Economy.pdf.

[97] *Id.* at iii.

[98] Order No. 2000, 89 FERC ¶ 61,285, at 89-90. *See also* Rich Glick and Matthew Christiansen, *FERC and Climate Change*, 40 ENERGY L.J. 1, 17 n.69 (2019) ("One of the many beneficial effects of these large regional markets is their potential to more effectively integrate variable energy resources by, among other things, reducing curtailment, eliminating rate pancaking, and identifying regional transmission needs. By integrating variable energy resources more effectively, organized markets can facilitate greater competition for a range of services, with corresponding benefits to ratepayers.").

transmission planning and cost allocation, which will be critical to integrating renewable resources at the lowest cost to consumers. Their markets are transparent, which promotes liquidity and the use of financially settled offtake arrangements such as virtual power purchase agreements.[99]

RTOs have led the way in reliably integrating ever-higher amounts of renewable energy. On March 13, 2021, CAISO set a new record of 92.5 percent renewable penetration.[100] Two weeks later, on March 29, 2021, SPP set its own record and reached 84.2 percent.[101] RTOs are able to achieve this success because of the integrated nature of their transmission systems and their load, resource, and geographic diversity, which helps address the variability of renewable resources. As a result, now is the time for the Commission to encourage, not chill, RTO participation from transmitting utilities.

2. The Best Tool in the Toolkit

At present, the only tool the Commission has to encourage RTO participation is the use of incentives. Longstanding Commission policy is that a transmitting utility's decision on whether or not to join an RTO is a voluntary one. The current incentive encourages utilities to join and remain in RTOs. Conversely, a duration limit has the opposite effect, undoubtedly altering the calculus for both utilities that do not yet belong to an RTO and utilities that do. In

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99 Other market structures can meet functions identified in this paragraph. Since its formation in November 2014, the Western Energy Imbalance Market has resulted in $1.28 billion in gross benefits for consumers and reduced the curtailment of renewable energy. *See Western EIM - Benefits*, https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx (last visited Jun. 23, 2021). In addition, a group of utilities in the Southeast has proposed creating the Southeast Energy Exchange Market ("SEEM"), which is an integrated, automated intra-hour energy exchange but not an energy imbalance market. *See* SEEM, *Frequently Asked Questions*, https://southeastenergymarket.com/faq/ (last visited Jun. 23, 2021). SEEM's proposal is currently pending before the Commission.

100 California ISO, *Key Statistics, Peaks for March 2021*, at 1 (Apr. 2021), http://www.caiso.com/Documents/KeyStatistics-Mar-2021.pdf.

101 Kassia Micek & Daryna Kotenko, *SPP Breaks Four Renewable, Wind Records Causing Power Prices to Dip Negative*, S&P GLOBAL (Mar. 30, 2021), https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/033021-spp-breaks-four-renewable-wind-records-causing-power-prices-to-dip-negative.

assessing the benefits of membership, the former will know that the incentive only lasts for a few years. The latter will recognize that their eligibility has ended. Unless it is clear that the benefits of RTO participation for a utility outweigh the risks and burdens, a rational transmitting utility would prefer to leave. Put another way, the Commission has used a carrot, not a stick, to encourage RTO participation. If the carrot has resulted in a just and reasonable outcome, the Commission should not now offer a slice of a carrot and expect the same response or outcome.

3. Mitigating the Risk of RTO Exit

Given the risks and burdens associated with RTO participation, the Supplemental NOPR creates a risk that existing members will leave RTOs, which would jeopardize regional decarbonization and transmission planning efforts. The Supplemental NOPR represents a dramatic break from what has been viewed as settled Commission policy. Utilities that have joined RTOs have long had a reasonable expectation that they would receive the incentive and counted on the incentive as they weighed the benefits and burdens of continued RTO participation. In the absence of the incentive, a rational utility would opt to leave an RTO if it concludes that the risks and burdens outweigh the benefits.

Indeed, the Supplemental NOPR appears to bet that in the absence of the incentive transmitting utilities would see enough benefit from RTO membership that they would not exit. But nowhere does the Commission explain the basis for this crucial assumption. If the Commission's assumption is wrong, the harm to RTOs and consumers could be immense and undo decades of Commission effort to support these markets. In a very real sense, the benefit of RTOs depends on a network effect in which an RTO's value increases with the number of participating utilities. Conversely, each departure may reduce the RTO's efficiency and value proposition as gaps and seams emerge in its system and service.

IV. CONCLUSION

For the reasons discussed in its Comments, WIRES respectfully submits that the Commission should not limit the period of time that a transmitting utility is eligible to receive an incentive to join and remain in an RTO. Such a limitation would be contrary to section 206 of the FPA, inconsistent with the text, purpose, and legislative history of section 219, and impede important public policies designed to support a cleaner, more reliable and resilient grid.

Respectfully submitted,

/s/ Norman C. Bay

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EXHIBIT 1

Exhibit 1

AFFIDAVIT OF
THE HONORABLE JOE BARTON

THE STATE OF TEXAS)
)
COUNTY OF Ellis)

I, Joe Barton, make this affidavit and hereby on oath state the following:

1. I am over the age of 18, and I am fully competent to provide this Affidavit. The facts set forth in this Affidavit are within my personal knowledge and are true and correct.
2. I served in the United States House of Representatives from 1985 to 2019, representing the State of Texas's 6th Congressional District.
3. From 2004 to 2007, I served as the Chairman of the House Energy and Commerce Committee. During that time, I was the House sponsor of the Energy Policy Act of 2005, and I was the Chairman of the House-Senate Energy Conference Committee for the Energy Policy Act of 2005. As Chairman of the Conference Committee on this bill, Conference Committee staff acted at my direction. As part of my instructions to the Conference Committee staff, I told them that I did not want there to be any ambiguity with respect to the provisions of the bill.
4. The Energy Policy Act of 2005 revised the Federal Power Act to include section 219 entitled "Transmission Infrastructure Investment." Section 219(c) included a provision directing the Federal Energy Regulatory Commission to "provide for incentives to each transmitting utility or electric utility that joins a Transmission Organization."
5. As I recall, section 219 was not controversial among the members of the Conference Committee. The general instruction from the principal members of the Conference Committee to the Conference Committee staff was to draft a provision that would provide incentives to build more transmission. As to the Transmission Organization incentive, one of the main goals of the Conference Committee was to ensure that the provision did not mandate that a utility join a Transmission Organization, but directed the Federal Energy Regulatory Commission to provide an appropriate incentive for those electric utilities that opt to participate.

6. Contrary to the interpretation proffered in the Federal Energy Regulatory Commission's April 21, 2021 Notice of Proposed Rule Making, section 219(c) does not contain a "sunset" clause and at no point does it implicitly, or expressly, state that the incentive to a utility that joins a Transmission Organization should be limited in duration. Consistent with my instructions to Conference Committee staff around ambiguity, if the committee had intended that the incentive to a utility that joins a Transmission Organization was meant to be a one-time payment or one-time deal, I would have instructed Conference Committee staff to make that clear in the language of the statute. Both myself, and the Conference Committee staff at the time, were more than capable of drafting language to that effect. The fact that section 219(c) does not expressly limit the incentive to a utility for joining a Transmission Organization indicates that I did not intend for that provision to be a "loss leader" or one-time deal to get a utility to join a Transmission Organization.

Signed this 2 day of JUNE, 2021

Joe Barton

BEFORE ME, the undersigned authority, this day personally appeared in person and by oath stated that the facts herein stated are true and correct.

SWORN TO AND ASCRIBED BEFORE ME on this 2nd day of June, 2021.

HUNTER C THEDFORD
Notary Public, State of Texas
My Commission Expires
September 16, 2023
NOTARY ID 13217364-5

Notary Public in and for the State of Texas

My commission expires: September 16, 2023

Industrial Energy Consumers of America (IECA)
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July 23, 2024

The Honorable Jeff Duncan
Chairman
Subcommittee on Energy, Climate, and Grid Security
Committee on Energy and Commerce
Washington, DC 20515

The Honorable Diana DeGette
Ranking Member
Subcommittee on Energy, Climate, and Grid Security
Committee on Energy and Commerce
Washington, DC 20515

Re: Comments for the Record on "The Fiscal Year 2025 Federal Energy Regulatory Commission Budget" Hearing

Dear Chairman Duncan and Ranking Member DeGette:

Thank you for the opportunity to provide comments for the record on "The Fiscal Year 2025 Federal Energy Regulatory Commission Budget" hearing.

The Industrial Energy Consumers of America is a nonpartisan association of leading manufacturing companies with $1.3 trillion in annual sales, over 12,000 facilities nationwide, and with more than 1.9 million employees. IECA membership represents a diverse set of industries including: chemicals, plastics, steel, iron ore, aluminum, paper, food processing, fertilizer, insulation, glass, industrial gases, pharmaceutical, consumer goods, building products, automotive, independent oil refining, and cement.

I. Consumers Urge Congress to Amend the Natural Gas Act, Section 5 to Give FERC Authority to Refund Overcharges by Interstate Natural Gas Pipelines

Interstate natural gas pipelines are monopolies. Therefore, consumers need responsible protections to prevent abuse. This is one such example.

The consumer complaint section under the Natural Gas Act (NGA) Section 5 makes natural gas consumers vulnerable to billions of dollars in overcharges from interstate pipeline companies. To protect consumers, Congress needs to amend Section 5 to give the Federal Energy Regulatory Commission (FERC) the authority to grant refunds to natural gas consumers when FERC confirms that a pipeline is overcharging above just and reasonable rates.

A 2023 study[1] released by the Natural Gas Supply Association analyzed the cost recovery of 20 major interstate pipeline companies. The study shows that from 2018 to 2022, the 20 pipelines

[1] "2023 Pipeline Cost Recovery Report," Natural Gas Supply Association, 2018-2022.

were able to collect $5.1 billion over that five-year period, more than they would have collected on an average 12% return on equity allowed by FERC.

With FERC refund authority in place, both parties would have more incentive to come to the table and negotiate a just and reasonable rate. We know this is true because it works for electric consumers and transmission providers. Congress amended the Federal Power Act (FPA) Section 206 in 1988 to give FERC refund authority to electric consumers that prove their rates to be unjust and unreasonable.

We are aware that the natural gas pipeline companies are opposed to reform of Section 5 of the Natural Gas Act[2] and are telling members of Congress that the legislation will hamstring efforts to build new interstate natural gas pipelines. This is simply not true. IECA is strongly in support of building new pipeline capacity and would not support this legislation if we thought that it did.

One hundred percent of IECA's members are manufacturing companies who rely upon natural gas pipelines for the supply of natural gas. We do not have an alternative. We have companies with facilities who are unable to get sufficient pipeline capacity to operate their facilities at capacity and/or invest in new ones. For example, there is insufficient pipeline capacity all along the entire East Coast and manufacturing companies receive operational flow orders (OFOs) about 90 percent of the time.

Lastly, if demand is high and there is insufficient pipeline capacity, manufacturing companies are always the first to be curtailed. When this happens, we are forced to reduce operating capacity or shutdown and this costs tens of millions of dollars per day. Therefore, it is in our best interests to support the building of pipelines.

II. FERC is Failing in its Duty to Initiate Interstate Natural Gas Pipeline Rate Cases to Reduce Rates That are Not Just and Reasonable

A second example of needed consumer protections from monopoly power is action by the FERC to regularly review pipeline rates to ensure that consumers are not charged abusive rates. The NGSA study confirms that several interstate natural gas pipelines have exorbitant rates well above the 12% return on equity. Despite this, FERC is failing to take legal action to rein them in. In past years, FERC would initiate at least three rate cases or more. In 2023, FERC did not initiate a single rate case.

We urge the Committee to ask FERC why they are not initiating more rate cases, which would reduce costs to consumers.

Sincerely,

Paul N. Cicio
Paul N. Cicio
President & CEO

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[2] "Rate Dispute Escalates Between US Gas Pipelines, Shippers," Energy Intelligence, May 3, 2024, https://www.energyintel.com/0000018f-39e7-d00d-a7df-3df7b8060000

cc: House Committee on Energy and Commerce

The Industrial Energy Consumers of America is a nonpartisan association of leading manufacturing companies with $1.3 trillion in annual sales, over 12,000 facilities nationwide, and with more than 1.9 million employees worldwide. It is an organization created to promote the interests of manufacturing companies through advocacy and collaboration for which the availability, use and cost of energy, power or feedstock play a significant role in their ability to compete in domestic and world markets. IECA membership represents a diverse set of industries including: chemicals, plastics, steel, iron ore, aluminum, paper, food processing, fertilizer, insulation, glass, industrial gases, pharmaceutical, consumer goods, building products, automotive, independent oil refining, and cement.

Disclaimer: The information contained in this document is intended to be used for general informational purposes only and is subject to change. PJM is not responsible for the user's reliance on information contained in this document, which does not supersede or modify any terms or conditions that are set forth in a PJM service agreement (e.g., Wholesale Market Participation Agreement (WMPA), Interconnection Service Agreement (ISA), Generation Interconnection Agreement (GIA)), the PJM Open Access Transmission Tariff, other PJM Governing Documents, or PJM Manuals. In the event of a conflict, the PJM service agreement, the PJM Open Access Transmission Tariff, other PJM Governing Documents, or PJM Manuals shall control.

There has been a significant interest in the use of co-located load configurations in PJM. A co-located load configuration refers to end-use customer load that is physically connected to the facilities of an existing or planned Customer Facility[1] on the Interconnection Customer's[2] side of the Point of Interconnection ("POI") to the PJM Transmission System ("co-located Customer Facility"). Co-located load is distinct from and does not include Station Power load. Examples of co-located load include a data center, crypto currency mining operation, hydrogen hub, etc. Although co-located load is located behind the POI, it still is electrically connected and synchronized to the PJM Transmission System when consuming power and therefore benefits from the use of the Transmission System and Ancillary Services. This document provides guidance on the use of co-located load configurations.[3]

PJM Guidance on Co-located Load Configurations

1. PJM recommends that all co-located load be served from the PJM Transmission System as PJM Network Load with applicable firm transmission service (e.g., Regional Network Integration Transmission Service (NITS) under PJM Tariff, Part III). Under this arrangement the following applies:

    a. The MW consumption of the co-located load and the MW output of the co-located generation Customer Facility (net of Station Power load) must be separately metered. The co-located load must be reported via InSchedules and the MW output of the co-located generation Customer Facility (net of Station Power load) must be reported to Power Meter for PJM settlement purposes. For operational security, real-time metering (MW & MVAR) and telemetry for the co-located load is also required.

    b. If the co-located generation Customer Facility elects to be designated as Behind the Meter Generation (BTMG), it will be allowed to net the co-located load directly against the output of the generation facility, but any portion of the Customer Facility designated as BTMG must forfeit its designation as a Generation Capacity Resource. In this case, the MW consumption of the co-located load and the MW output of the co-located BTMG Customer Facility (net of

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[1] For purposes of this guidance document, "Customer Facility" is used synonymously with "Generating Facility" as used in the GIA and WMPA in Part IX of the PJM Tariff and "Participant Facility" as used in the pre-Transition Date WMPA.

[2] For purposes of the this guidance document, "Interconnection Customer" is used synonymously with "Project Developer" as used in the GIA and WMPA found in Part IX of the PJM Tariff and "Wholesale Market Participant" as used in the pre-Transition Date WMPA.

[3] This guidance document does not apply to co-located load configurations involving Generation Capacity Resources located outside the PJM Region.

Station Power load) may be netted. If the net result is consumption from the grid, Station Power consumption should be reported via Power Meter and net load consumption should be reported via InSchedules for PJM settlement purposes. If the net result is an injection to the grid, that single value should be reported via Power Meter for PJM settlement purposes. For operational security, real-time metering (MW & MVAR) and telemetry for the co-located load is also required.

   c. Co-located load that is part of the PJM Transmission System as PJM Network Load with applicable firm transmission service does not need to decrease the Capacity Interconnection Rights (CIRs) of the co-located Customer Facility unless the co-located generation elects to be designated as BTMG.

   d. Co-located load that is part of the PJM Transmission System as PJM Network Load with applicable firm transmission service could qualify for any curtailment capability it may have as demand response (up to the peak load contribution (“PLC”) level of the load).

   e. The foregoing co-located load configuration does not reduce the co-located Customer Facility’s Maximum Facility Output (MFO).

2. If the co-located load is **not** PJM Network Load (load without applicable firm transmission service under PJM Tariff, Part III), then the following applies:

   a. The MW consumption of the co-located load and the MW output of the co-located generation Customer Facility (net of Station Power load) are netted and reported as a single value to Power Meter to be used for PJM settlement purposes. As no load is being served from the system, no load is reported via InSchedules for PJM settlement purposes. For operational security, real-time metering (MW & MVAR) and telemetry for the co-located load is also required.

   b. The co-located Customer Facility’s CIRs must be reduced to reflect the amount of capacity dedicated to the co-located load where this MW amount is based on the highest expected hourly demand of the co-located load. The CIRs/capacity value may be retained for additional MWs above the capacity dedicated to the co-located load but these additional MWs must first be dedicated to the PJM system load. If first rights to the capacity cannot be dedicated to PJM system load then the CIR/capacity value of the co-located Customer Facility that is a Generation Capacity Resource must be reduced to reflect the amount of capacity to which PJM will not have the first rights.

   c. The MFO specified in the existing PJM service agreement may remain unchanged if the Interconnection Customer anticipates providing the Customer Facility’s full output capability to the PJM Transmission System whenever the co-located load is shutdown or otherwise not being served by the co-located Customer Facility.

   d. The capacity value of the co-located Customer Facility that is a Generation Capacity Resource cannot exceed the CIR MWs specified in the PJM service agreement for the resource.

e. PJM does not support co-located configurations for which there exists the possibility of an unexpected injection or withdrawal of power on the PJM Transmission System. Therefore, all co-located load that is not PJM Network Load (load without applicable firm transmission service) must have System Protection Facilities in place to prevent the unexpected injection or withdrawal of power at the POI for the co-located Customer Facility. If the protection schemes were to fail (which they should not), PJM will assess the settlements and compliance implications for such unexpected injections or withdrawal in coordination with the Transmission Owner and local Electric Distribution Company. Notifications of a failure of the protection scheme must be made immediately to PJM Operations, Legal and Settlements.

f. If the co-located load configuration allows for a back-up Generation Capacity Resource(s) to serve the co-located load, then that back-up Generation Capacity Resource(s) must meet all the existing requirements of a PJM Generation Capacity Resource including the capacity and energy must-offer requirement. If the back-up Generation Capacity Resource is unable to meet the existing requirements then the CIR/capacity value of the co-located Customer Facility that is a Generation Capacity Resource must be reduced to reflect the amount of capacity to which the facility can meet the requirements.

   i. Co-located load must first be reduced to zero before the back-up Generation Capacity Resource or Energy Resource can serve the co-located load.

   ii. Coordination with PJM Operations is required before the back-up Generation Capacity Resource or Energy Resource can serve the co-located load. If authorized by PJM Operations[4], an outage must be submitted in eDART with proper cause code for the period of service of the co-located Customer Facility. If not authorized by PJM, it is not acceptable to claim an outage.

g. Co-located load that is not PJM Network Load (load without applicable firm transmission service) is not eligible to participate as a demand response resource.

3. Co-located must either be PJM Network Load (with applicable firm transmission service) or **<u>not</u>** PJM Network Load (load without applicable firm transmission service). There is no option to change between configurations unless it is a permanent change. For example, co-located load that elects to operate not as PJM Network Load cannot switch to a PJM Network Load configuration if the co-located Customer Facility is unavailable. The co-located load configuration that is studied and memorialized in a PJM service agreement may not be changed unless the Interconnection Customer undergoes a subsequent necessary studies process and the results of such process are memorialized in an amended service agreement.

4. Co-located load is not equivalent to Station Power load. Station Power load includes heating, lighting, air-conditioning and office equipment needs of buildings on the site of a generation facility that is used in the operation, maintenance, or repair of such generation facility. Station Power load does not include power required to operate synchronous condensers.

[4] PJM Operations may deny for reasons including but not limited to capacity related emergencies.

5. The Interconnection Customer, Wholesale Market Participant, or Project Developer identified in co-located Customer Facility's ISA, WMPA, or GIA is responsible for ensuring that the proposed co-located load configuration is in accordance with the applicable PJM service agreement (e.g., ISA, WMPA, or GIA), PJM Tariff, Operating Agreement, other PJM governing documents, PJM Manuals, and all applicable federal, State and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any governmental authority having jurisdiction over the relevant parties, their generating facilities and any other respective facilities, and/or the respective services they provide.

    a. To the extent there are any differences between ownership of the Customer Facility and the co-located load, such differences must be discussed and disclosed in advance to PJM and the Interconnected Transmission Owner. The Interconnection Customer will be required to represent to PJM and the Interconnected Transmission Owner that any third-party ownership of the co-located load will not interfere with the Interconnection Customer's obligations under all applicable requirements.

6. In accordance with PJM Tariff, Part VI, Attachment O, Appendix 2, section 3, PJM Tariff, Part IX, Subpart B, Appendix 2, section 3, and section 4.5 of PJM Manual 14G, the Interconnection Customer, Wholesale Market Participant, or Project Developer identified in co-located Customer Facility's PJM service agreement shall provide PJM and the Interconnected Transmission Owner with notice of any planned modifications to the co-located Customer Facility and shall provide the relevant drawings, plans, specifications, and models to PJM and the Interconnected Transmission Owner in advance of beginning the work. Such advance notification is required so that PJM and the Interconnected Transmission Owner can evaluate potential reliability impacts of the proposed co-located load configuration, including verification that adequate protection is in place to prevent the unexpected injection or withdrawal of power at the POI for the co-located Customer Facility as part of a necessary studies process. A failure to provide advance notification is a breach of the applicable PJM service agreement, and subject to the breach, cure, and default provisions of such agreement. A failure to provide proper notice may also be considered a violation of PJM Governing Documents that may warrant a referral of the violation to the FERC's Office of Enforcement. For the PJM notification, the Interconnection Customer should contact the specific Client Manager assigned to the Interconnection Customer, or the general Client Manager mailing list (ClientManagers@pjm.com). The modification request will then be forwarded by Client Management to the Transmission Coordination & Analysis department to initiate the necessary study process.

7. The necessary studies process provides PJM an opportunity to perform studies to evaluate the potential reliability impact of a proposed addition or reduction of a co-located load configuration on the PJM Transmission System, and determine what, if any, system reinforcements are required prior to the addition or reduction of the planned co-located load configuration. PJM reserves the right to take other actions to protect system reliability caused by removing capacity MWs from the PJM markets including seeking emergency authority to prevent or delay the addition of co-located load. Prior to beginning the necessary studies process, a necessary studies agreement must be drafted and executed by PJM and the Interconnection Customer, a necessary study deposit provided, and all required technical data submitted. In some instances, the Interconnected Transmission Owner may require additional studies based on the planned co-located load configuration, and such studies may result in additional study costs. The execution of a Construction Service Agreement (CSA) may be

required if the results of the necessary studies process identifies the need to construct system reinforcements and the related PJM service agreement (e.g., ISA, GIA, WMPA) would be amended to reflect these necessary system upgrades, related costs, and posting of the requisite security.

Any applicable PJM service agreement (e.g., ISA, GIA, WMPA, CSA) must be executed and/or amended to reflect all changes resulting from the incorporation of a co-located load configuration. Service to the co-located load pursuant to the co-located load configuration may not commence until the necessary PJM service agreement(s) has been fully executed by the parties, filed with and accepted by the Commission, and all required system reinforcements, system protection facilities, and metering are in place.

AMERICAN PUBLIC GAS ASSOCIATION

July 22, 2024

The Honorable Jeff Duncan
Chairman, House Subcommittee on Energy, Climate, and Grid Security
2229 Rayburn House Office Building
Washington, DC 20515

The Honorable Diana DeGette
Ranking Member, House Subcommittee on Energy, Climate, and Grid Security
2111 Rayburn House Office Building
Washington, DC 20515

Re: Subcommittee on Energy, Climate, & Grid Security hearing titled "The Fiscal Year 2025 Federal Energy Regulatory Commission Budget."

Dear Chairman Duncan and Ranking Member DeGette,

The American Public Gas Association (APGA)[1] is the trade association representing more than 730 communities across the U.S. that own and operate their retail natural gas distribution entities. These include not-for-profit gas distribution systems owned by municipalities and other local government entities, all accountable to the citizens they serve.

We appreciate the Subcommittee's decision to conduct this hearing. Two specific issues that APGA's member systems care about are directly tied to FERC's mission of ensuring Americans have access to affordable, reliable energy. In your discussion with the Chairman and Commissioners on how the agency can continue fulfilling its core mission and furthering America's energy leadership, we urge both Congress and FERC to prioritize actions that enable public gas utilities to continue to meet the energy needs of the millions of community members that they serve.

Congress can act now to protect natural gas consumers by keeping energy rates just and reasonable. Reforms to Section 5 of the Natural Gas Act (NGA) should be introduced and passed to grant FERC the proper authority to remedy overcharges. Also, to protect consumers, Congress should encourage FERC to use its current authority to end the unfair bidding practice referred to as "junk and jewel" that often results in unjust rates for natural gas shippers.

NGA Section 5 Reform

The NGA and the Federal Power Act (FPA) establish FERC's authority to regulate natural gas and electric transmission entities, respectively. Both laws outline regulatory processes for over-collections (also referred to as overcharges) that interstate transmission entities charge to shippers, which include APGA's public gas utility members. FERC has the authority to determine whether transmission entities, namely interstate natural gas pipelines and electric transmission companies, have charged an "unjust and unreasonable rate."

[1] For more information, visit apga.org.

Under section 206 of the FPA, FERC or an electric transmission customer can file a rate complaint. If FERC finds that an electric transmission entity has charged an "unjust and unreasonable" rate, then FERC may order that the entity refund any overcharged funds from the time the complaint was filed, which is known as the Refund Effective Date.

The NGA offers no such recourse. Under section 5 of the NGA, entities that believe they have been overcharged can still file a complaint against an interstate natural gas pipeline. However, the NGA only gives FERC the authority to grant prospective rate relief – it cannot order refunds of over-collections, unlike the refunds that are available under section 206 of the FPA. Natural gas transmission customers thus are not able to recoup monies that are determined to be unjustly collected. This creates an incentive for interstate natural gas pipelines to prolong such cases because they can keep all of the overcharged rates.

Closing this loophole will set the proper incentive for pipelines to resolve Section 5 proceedings more quickly. Bipartisan, bicameral legislation to remedy this inconsistency has been introduced in the House in the past several sessions of Congress.[2] In the 118th Congress, we urge members of the House to introduce similar language to the Senate's Making Pipelines Accountable to Consumers and Taxpayers Act (MPACT).[3]

Junk and Jewel

FERC currently has the authority to remedy another prevalent practice of the pipelines that unfairly increases their profits at the expense of energy consumers. "Junk and jewel" is the colloquial term for the practice of interstate pipelines packaging high-value capacity (the "jewel") with non-contiguous and operationally unrelated, low-value capacity (the "junk") together in single auctions. This practice may result in unjust rates for the shippers looking to acquire the valuable capacity, as it can allow pipelines to over-recover rates set by FERC, or discriminate against certain shippers who do not have the resources to bid for capacity that they cannot utilize. "Junk and jewel" postings can also interfere with market pricing signals and reduce the desire for pipelines to build additional capacity that public gas utilities, as well as investor-owned utilities and large gas consumers, including gas-fired electric generation plants, need.

In March, FERC issued a Notice of Inquiry (NOI) seeking comment on whether this practice should continue to be allowed. To justify the position that it shouldn't continue, the American Gas Association (AGA), American Public Gas Association (APGA), Natural Gas Supply Association (NGSA), and Process Gas Consumers Group (PGC) filed joint comments, citing examples of numerous postings from 2023 and 2024 showing how often valuable capacity is being paired with capacity of low or no value in a single auction.[4] We are hopeful that FERC will review the comments received in response to the NOI and amend its current policy of permitting this practice. In the meantime, we urge Congress to encourage FERC to listen to the concerns raised by impacted groups.

***

We thank you for all your efforts and strongly encourage the Subcommittee to prioritize the reintroduction of legislation to protect consumers and reform Section 5 of the NGA. We also ask that the Subcommittee amplify our concerns about the unfair "junk and jewel" practice with the Commission.

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[2] H.R. 3979 – Protecting Natural Gas Consumers from Overcharges Act of 2021

[3] S.4171 – MPACT Act of 2024

[4] Joint Comments on FERC's NOI 6/27/2024

Sincerely,

Stuart Saulters

Vice President of Government Relations
American Public Gas Association

Congress of the United States

Washington, DC 20515

May 23, 2024

The Honorable Willie L. Phillips
Chairman
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Dear Chairman Phillips:

We are writing to request that the Commission grant the PJM Load Parties' request for rehearing of the Commission's May 6, 2024 Order ("May 6 Order") authorizing PJM Interconnection, LLC (PJM) to reapply a flawed capacity market design that will expose Marylanders on the Delmarva Peninsula to grossly inflated electricity prices *of more than four times the just and reasonable rate* with no commensurate electric reliability benefit.[1]

In granting PJM's petition and denying the Maryland Public Service Commission's Motion to Reopen Docket No. ER13-19, the Commission held that the "unequivocal ruling" of the Third Circuit Court of Appeal's decision in *PJM Power Providers*[2] "requires" recalculating the 2024/2025 Base Residual Auction ("BRA") and vacating the portion of the Commission's orders that allows PJM's 2023 Tariff Amendments.[3] In short, the Commission acted as if it were powerless to establish just and reasonable rates.

We are deeply concerned that acceptance of PJM's proposal to recalculate and use faulty market inputs for the 2024/2025 BRA results side-steps the Commission's long-standing policy against rerunning markets and results in costs to Delmarva Zone customers that quadruple those of just and reasonable rates.

Under the Federal Power Act, it is incumbent upon the Commission to ensure the rates our citizens pay for electricity are fair, just and reasonable. In their concurring statements, the Chairman and Commissioners noted that the cost impact of rerunning the 2024/2025 capacity auction would lead to a "patently inequitable outcome[],"[4] "in no universe [would these costs] be considered just and reasonable,"[5] and the consequences of PJM's approach lead to an "inequitable result."[6] Allowing PJM to reapply the same flawed market design that the Commission has repeatedly characterized as being unjust and unreasonable would be unwarranted.[7]

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1 The PJM Load Parties include–among others–the Maryland Public Service Commission and the Maryland Office of People's Counsel, parties that filed protests opposing PJM's petition.

2 *PJM Power Providers Grp. v. FERC*, Nos. 23-1778, et al., 2024 U.S. App. LEXIS 5963 (3d Cir. Mar. 12, 2024).

3 *PJM Interconnection, L.L.C.*, 187 FERC ¶ 61,065 at P 24.

4 *Id.*, Chairman Phillips, concurring at P1.

5 *Id.*, Comm'r Christie, concurring at P2.

6 *Id.*, Comm'r Clements, concurring at P 2.

7 *PJM Interconnection, L.L.C.*, 182 FERC ¶ 61,109, at P 173.

With the Commission's acknowledgement of the draconian consequences of a flawed market design preceding the prior Capacity Resource Auction, PJM already set the fair prices for electric capacity well over a year ago. Therefore, we ask that the Commission grant the rehearing request and urge the Commission to require PJM to retain the 2024/2025 BRA results posted by PJM on February 28, 2023, as those rates will ensure fair electricity prices for our citizens.

Sincerely,

Steny H. Hoyer
Member of Congress

John P. Sarbanes
Member of Congress

Benjamin L. Cardin
United States Senator

Chris Van Hollen
United States Senator

Andy Harris, M.D.
Member of Congress

Jamie Raskin
Member of Congress

David J. Trone
Member of Congress

Glenn Ivey
Member of Congress

C. A. Dutch Ruppersberger

C. A. Dutch Ruppersberger
Member of Congress

UTILITY DIVE

OPINION

FERC's transmission rule will boost grid reliability and affordability without usurping state authority

The rule will not force customers who don't benefit from new transmission lines to pay for them.

Published July 23, 2024

By Andrew French, Joseph Sullivan, Ann Rendahl, Gabriel Aguilera and Davante Lewis

Andrew French is the chair of the Kansas Corporation Commission, Joseph Sullivan is the vice chair of the Minnesota Public Utilities Commission, Ann Rendahl is a commissioner at the Washington Utilities and Transportation Commission, Gabriel Aguilera is a commissioner at the New Mexico Public Regulation Commission and Davante Lewis is a commissioner at the Louisiana Public Service Commission.

Thousands of miles of transmission lines transport energy all across the country. From amber waves of grain to purple mountain majesties, the energy grid makes up the backbone of American economic prosperity and comfort.

But while we have been enjoying the security and convenience provided by energy reliability and resilience, much of the existing grid system has reached or surpassed its intended life span with a majority of the grid's transmission assets dating back to the 1950s. New demands have only heightened the strain on the system.

Major power outages from weather-related events have increased more than 65% since 2000. Plus, U.S. electricity demand growth is expected to more than double over the next five years.

The current framework often focuses on planning transmission by utility footprint, or only within one state. Even worse, upgrades to the grid are often planned in an expensive and piecemeal fashion, addressing individual issues as they arise. As state regulators, we have a strong working knowledge of the systems within our states and have pledged to work in the best interests of our states' customers.

In some cases, that means planning transmission across states and throughout a transmission planning region in order to ensure that the grid is as reliable and cost-effective as possible. Compared to other ways of addressing needed growth, the right investments in well-planned transmission will be the most affordable option for customers. It would also create 3.3 million jobs and connect thousands of gigawatts of new energy generation to the grid needed to meet increased demand and promote economic development.

To facilitate better planning, the Federal Energy Regulatory Commission recently voted to approve Order No. 1920 — a landmark rule that requires transmission to be planned on a regional basis through a long-term, forward-looking assessment of changing circumstances. The rule also requires selection of projects pursuant to a comprehensive, specific set of economic and reliability transmission benefits.

While previous planning procedures took a more reactive approach to transmission deployment, FERC's new rule builds on a more proactive and intentional approach. When transmission is planned in a forward-looking and comprehensive way, the projects that get selected and developed can be more efficient, both in terms of cost and the capacity to move power.

If we want to have a grid ready to withstand the challenges of the coming decades — and enable future economic prosperity — we need to start planning now.

The Federal Power Act gives FERC authority over "the transmission of electric energy in interstate commerce." Just as outlined in its operating mandate from Congress, FERC's rule is fuel neutral and provides a framework to produce more just and reasonable rates for the benefit of all ratepayers.

Additionally, Order No. 1920 does not take away any existing authority of states. In fact, this rule formalizes and requires engagement with states in a way that has not been done before. This new role for state utility regulators — like us — puts states in the driver's seat for deciding key issues and encourages active participation in the regional planning process.

Furthermore, this rule from FERC will not force some states to pay for the public policy choices of other states, such as clean energy initiatives. The reality is that customers will only pay grid costs that are justified by concrete benefits to those same customers, such as more reliable power or access to lower cost energy resources. Plus, FERC must approve all cost allocation proposals, which can also be reviewed by the courts, to ensure that the costs to customers are roughly commensurate with the benefits they receive — aligning with long standing precedent. We represent states with diverse energy goals, but we are all satisfied FERC's new planning rule will produce beneficial and fair outcomes for our residents and businesses.

As state utility commissioners, we know that these changes to how regions plan transmission will provide customers across the U.S.

reliable, cost-effective electricity, while also making the grid more resilient, secure and able to handle the challenges that the future will hold. America’s livelihood depends on it.

July 22, 2024

To: The Honorable Willie L. Phillips, Mark C. Christie, David Rosner, Lindsay S. See,
Judy W. Chang Commissioners
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Docket No. RM 21-17-000 Building for the Future Through Electric Regional Transmission Planning and Cost Allocation

Dear Chairman Phillips and Commissioners Christie, Rosner, See and Chang:

We, the undersigned state regulatory commissioners, have come together to express our support for the Federal Energy Regulatory Commission's (FERC) Order No. 1920. The signatories to this letter represent a diverse array of state regulators, including broad diversity of geographic representation throughout the country; a number of Commissioners who participated in the Joint Federal State Task Force on Electric Transmission; Commissioners who serve on leadership roles within regional, state and national regulatory associations, as well as the four Regional State Committees related to the multi-state Regional Transmission Organizations (RTOs) operating in the United States. We also represent a diversity of political backgrounds and ideological perspectives, and operate in a range of regulatory frameworks, including vertically-integrated and restructured markets and RTO and non-RTO areas. We believe this letter is necessary to fully capture the diversity of opinion among state utility regulators regarding Order No. 1920, as reflected by the signatories below.

On May 13, 2024, FERC issued Order No. 1920 to regulate the process of evaluating and selecting Long-Term Transmission Facilities by transmission providers. Notably, the Order was issued after the development of an extensive record that was informed by the work of the Joint Federal State Task Force on Electric Transmission. This Task Force consisted of both FERC and state utility commissioners and met eight times between November 2021 and February 2024. The Task Force identified numerous transmission planning issues as well as gaps in how transmission infrastructure is paid for by transmission providers.

At a time when limited grid capacity threatens to hamper America's economic growth and harm reliability, FERC has recognized the role predictable long range transmission planning will play in developing this important infrastructure. The current status quo of incremental, reactive transmission planning has led to more expensive outcomes for consumers and businesses than the proactive multi-purpose approach FERC has developed. Just as importantly, the current approach to transmission planning hampers our collective ability to proactively incorporate the transmission needed to maintain reliability in the face of the extreme weather events that are increasingly causing widespread grid disruptions across the country. And critically, Order No. 1920 requires – for the first time – direct consultation with state regulatory authorities in the development of cost allocation tariffs, while avoiding a regime by which a single holdout could effectively veto a cost sharing framework for transmission that could provide benefits across a whole region.

For these reasons, we applaud FERC's leadership in passing this landmark order.

Additionally, Order No. 1920 will provide for the following:

1. The Order clearly states that if you don't benefit, you don't pay. This "beneficiary pays rule" is the same policy from Order No. 1000 issued in 2011 and is founded in multiple court decisions interpreting the Federal Power Act.

2. The Order requires transmission providers to plan for future load and generation, using the best available information, to select the best plan for consumers, and allocate costs according to a narrow set of specified benefits focused on reliability, resiliency, and economics.

3. Order 1920 recognizes that transmission systems are tightly integrated across wide areas that cross state borders. In accepting this reality, it appropriately sets clear and consistent federal rules regarding necessary transmission planning and cost allocation.

4. The Order provides for an unprecedented expansion of State roles and provides for State involvement at multiple stages in the planning and cost allocation process.

5. The Order appropriately recognizes that there needs to be a default policy in place on cost allocation in case States cannot agree.

6. Nothing in Order 1920 causes one State to be forced to pay for lines that only have public policy benefit to others. Again, Order 1920 builds on long-standing FERC precedent that customers need only pay costs that are 'roughly commensurate' with the benefits they are expected to receive.

7. States and RTOs that already have long range transmission planning processes that work within their region and are consistent with the principles of Order 1920 will be free to continue those activities under their own authorities and using their own approaches.

Thank you for the Commission's leadership on this important issue. The years long inclusive process utilized to develop Order No. 1920 is an example of cooperative federalism. This Order has been informed at every level by the views, perspectives, and authorities of the States and is designed to lead to the effective planning of the interstate transmission system and an equitable sharing of the costs associated with transmission buildout, the outcome of which will be a lower delivered cost of energy for the ratepayers of our States. We look forward to continuing to partner with FERC on effective implementation of Order No. 1920 and on the many other pressing energy issues facing our country.

Sincerely,

State Regulatory Commissioners in Support of FERC Order 1920 (listed below).

Riley Allen, Commissioner, State of Vermont Public Utility Commission

Philip L. Bartlett II, Chair, Maine Public Utilities Commission

Kumar P. Barve, Commissioner, Maryland Public Service Commission

Eric Blank, Chairman, Colorado Public Utilities Commission

Alessandra Carreon, Commissioner, Michigan Public Service Commission

Michael T. Carrigan, Commissioner, Illinois Commerce Commission

David W. Danner, Chair, Washington Utilities and Transportation Commission

Megan Decker, Chair, Oregon Public Utilities Commission

Milt Doumit, Commissioner, Washington Utilities and Transportation Commission

Sarah Freeman, Commissioner, Indiana Utility Regulatory Commission

Andrew French, Chairperson, Kansas Corporation Commission

Marissa P. Gillett, Chairman, Connecticut Public Utilities Regulatory Authority

Hwikwon Ham, Commissioner, Minnesota Public Utilities Commission

Frederick H. Hoover, Chair, Maryland Public Service Commission

Darcie Houck, Commissioner, California Public Utilities Commission

Davante Lewis, Commissioner, Louisiana Public Service Commission

Ann McCabe, Commissioner, Illinois Commerce Commission

Valerie Means, Commissioner, Minnesota Public Utilities Commission

Stacey Paradis, Commissioner, Illinois Commerce Commission

Katherine Peretick, Commissioner, Michigan Public Service Commission

Les Perkins, Commissioner, Oregon Public Utilities Commission

Ann E. Rendahl, Commissioner, Washington Utilities and Transportation Commission

Alice Reynolds, President, California Public Utilities Commission

Michael T. Richard, Commissioner, Maryland Public Service Commission

Doug P. Scott, Chairman, Illinois Commerce Commission

Dan Scripps, Chair, Michigan Public Service Commission

Katie Sieben, Chair, Minnesota Public Utilities Commission

Bonnie A. Suchman, Commissioner, Maryland Public Service Commission

Joseph Sullivan, Vice Chair, Minnesota Public Utilities Commission

Letha Tawney, Commissioner, Oregon Public Utilities Commission

Emile C. Thompson, Chairman, District of Columbia Public Service Commission

Ted Trabue, Commissioner, District of Columbia Public Service Commission

John Tuma, Commissioner, Minnesota Public Utilities Commission

July 22, 2024

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Judy W. Chang Commissioners
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At a time when limited grid capacity threatens to hamper America's economic growth and harm reliability, FERC has recognized the role predictable long range transmission planning will play in developing this important infrastructure. The current status quo of incremental, reactive transmission planning has led to more expensive outcomes for consumers and businesses than the proactive multi-purpose approach FERC has developed. Just as importantly, the current approach to transmission planning hampers our collective ability to proactively incorporate the transmission needed to maintain reliability in the face of the extreme weather events that are increasingly causing widespread grid disruptions across the country. And critically, Order No. 1920 requires – for the first time – direct consultation with state regulatory authorities in the development of cost allocation tariffs, while avoiding a regime by which a single holdout could effectively veto a cost sharing framework for transmission that could provide benefits across a whole region.

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Sincerely,

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Doug P. Scott, Chairman, Illinois Commerce Commission

Dan Scripps, Chair, Michigan Public Service Commission

Katie Sieben, Chair, Minnesota Public Utilities Commission

Bonnie A. Suchman, Commissioner, Maryland Public Service Commission

Joseph Sullivan, Vice Chair, Minnesota Public Utilities Commission

Letha Tawney, Commissioner, Oregon Public Utilities Commission

Emile C. Thompson, Chairman, District of Columbia Public Service Commission

Ted Trabue, Commissioner, District of Columbia Public Service Commission

John Tuma, Commissioner, Minnesota Public Utilities Commission