UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning and Cost Management	Docket Nos. AD22-8-000
Joint Federal-State Task Force on Electric Transmission	AD21-15-000

COMMENTS OF THE WATT COALITION

March 23, 2022

Introduction

The Working for Advanced Transmission Technologies ("WATT") Coalition respectfully offers these comments on the issue of transmission cost containment, and the specific questions posed by the Federal Energy Regulatory Commission ("FERC" or "the Commission") in the notice posted on December 23, 2022 in the above-captioned proceedings.

This is a timely line of work for FERC and state commissions. The U.S. will need to invest in the transmission system in response to aging infrastructure and economic or policy-driven changes to the generation resource mix. Together, these investments should save ratepayers money in the long term by providing access to the lowest cost generation and preventing costly consequences of extreme conditions, among other benefits. The value to ratepayers will be far greater if existing infrastructure and future transmission investments are optimized with Grid Enhancing Technologies (GETs).

Today's transmission paradigm in the United States has blocked GETs deployments;[1] even the most proactive U.S. adopters are lagging far behind utilities in Europe,[2] the Middle East,

[1] See testimony from the Federal Energy Regulatory Commission's September 10, 2021 Workshop to Discuss Certain Performance-Based Ratemaking Approaches, https://www.ferc.gov/news-events/events/workshop-discuss-certain-performance-based-ratemaking-approaches-09102021

[2] See examples in "Technopedia: Showcase of Grid Enhancing Technologies," ENTSO-E, June 2021, https://www.entsoe.eu/events/2021/06/29/webinar-on-grid-enhancing-technologies/

Australia,[3] and South America.[4] The WATT Coalition urges FERC and states to pursue reforms that will integrate GETs into transmission planning and operations.

About the WATT Coalition

The WATT Coalition is a trade association focused on facilitating the adoption of advanced technologies on the US electric transmission system that improve reliability, lower cost, and accelerate decarbonization—benefiting American citizens and businesses. The WATT Coalition includes associate members benefiting from GETs and technology members, offering expertise in Advanced Power Flow Control, Dynamic Line Ratings (DLR), and Topology Optimization.

How Grid Enhancing Technologies contribute to transmission cost containment

The recent Draft National Transmission Needs Study from the Department of Energy shows transmission congestion costs ballooning across the country and points to the need for significant transmission expansion.[5] Consulting firm Grid Strategies estimates that nationwide congestion cost consumers over $6 billion every year between 2016 and 2020,[6] and market monitor reports show congestion more than doubling in 2021. GETs expand transmission capacity at the lowest cost, reducing consumer bills and maximizing the benefits of grid investments. The three GETs support the optimal utilization of grid infrastructure in these ways:

- Topology optimization finds reconfigurations for the grid that can prevent curtailment of low-cost generation, and address planned or unplanned outages.
- Advanced Power Flow Control can help implement reconfigurations, and push or pull power over different circuits such that all assets are used safely and efficiently.
- Dynamic Line Ratings measure true capacity of transmission lines to make full use of existing infrastructure.

GETs are not a permanent replacement for new transmission lines, but they serve important roles in reducing lowering consumer costs:

1. GETs reduce congestion costs. By increasing the capacity of the existing system, the existing poles and wires can deliver the cheapest generation more often.

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[3] See, e.g., Carroll, David, "Australian grid operator turns to Smart Wires technology to unlock renewables," PV Magazine, September 16, 2022, https://www.pv-magazine.com/2022/09/16/australian-grid-operator-turns-to-smart-wires-technology-to-unlock-renewables/

[4] See also "A Guide to Case Studies of Grid Enhancing Technologies," Idaho National Lab, October 2022, https://inl.gov/wp-content/uploads/2023/03/A-Guide-to-Case-Studies-for-Grid-Enhancing-Technologies.pdf which features both modeling and physical deployments.

[5] Draft National Transmission Needs Study, US Department of Energy, February 2023, https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf

[6] Schneider, Jesse, "Transmission Congestion Costs in U.S. RTOs," November 12, 2020, https://gridstrategiesllc.com/2019/09/17/transmission-congestion-costs-in-the-u-s-rtos/

2. GETs create more room on the grid for renewable energy, which is the lowest cost generation available in the U.S. and is often sited far from load or in areas without recent transmission investment.
3. GETs optimize existing transmission lines to be used to their full capacity, avoiding or delaying costly upgrades or rebuilds. By considering GETs, planners can identify which lines truly need to be fully rebuilt, saving money on lines that can be salvaged with GETs and increasing the overall value of any transmission investments.
4. GETs can reduce congestion costs while transmission lines are under development and construction, a process that often takes years and leads to disruptive medium-term outages.

How states and FERC can ensure that GETs are incorporated into transmission planning and operations to ensure just and reasonable rates through transmission cost containment

FERC has several open dockets and proposed rules that include policies to increase the utilization of GETs in transmission planning and operations through requirements or incentives. The questions and proposals raised in the Commission's December 23, 2022 notice are complementary to the existing proposals and investigations, and the WATT Coalition commends FERC for this additional inquiry.

WATT responds to specific questions below, but we highlight two opportunities for FERC to improve the efficacy of the transmission system and the efficiency of transmission investments:

- The Independent transmission monitor (ITM), which can review transmission operations with access to all CEII information, would help identify opportunities for GETs to improve transmission system efficacy.
- Stakeholder transparency into transmission capacity and the causes of constraints would help GETs vendors and independent power producers participate in solving problems.

We appreciate FERC's consideration of our responses and will be available to expand on any of the ideas below.

Post-Technical Conference Questions for Comment

Local Transmission Planning Under Order No. 890 and Planning for Asset Management[7] Projects

1.a) Do the existing Order No. 890 transmission planning requirements provide state regulators and other stakeholders with sufficient transparency into and information about public utility transmission providers' local transmission planning criteria and the resulting identification of transmission system needs? If not, please explain how the Commission could revise the coordination, openness, transparency, and information exchange principles in Order No. 890 to provide for enhanced transparency and information sharing. Further, please explain what, if any, additional transparency measures would assist state regulators and other stakeholders in understanding how public utility transmission providers develop their local transmission planning criteria, how those criteria drive local transmission needs, and how public utility transmission providers consider local transmission projects to address those needs.

> Transparency in line with Order 890 is insufficient to allow stakeholders to participate in or contest utility decisions.
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> Order 890 was released several years before Dynamic Line Ratings were first commercialized, and well before advanced power flow control and topology optimization were on the market, and thus was not designed with these technologies in mind. Without expanded transparency around transmission data, transmission customers cannot evaluate where GETs might reduce their costs or improve their transmission service. More transparency on the actual system constraints and which solutions transmission provides evaluate, and to what degree, would support implementation of lower-cost solutions through stakeholder engagement.
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> For example, WATT members and consultants cannot access data around the scale or cause of transmission congestion in most markets, except at the most general level. One list of top congestion constraints that was shared upon request did not indicate whether the constraints were based on thermal line ratings or other equipment or stability limits. Without more specific data, regulators will have to guess at appropriate policy updates, such as requirements for GETs applications like those proposed in FERC's Notice of Inquiry on the Implementation of Dynamic Line Ratings.[8]
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> WATT is concerned that if and when a transmission provider evaluates a GETs solution, they may not take the multiple values of enhanced transmission capacity, situational awareness, and operational flexibility into account. These values should be accounted for on economic and reliability grounds, and stakeholders must have sufficient information to confirm that the transmission provider has made a sound evaluation of GETs in its transmission planning and operations. The opportunity to both question and have a meaningful response from utilities is critical.[9] That is not required under Order 890.

1.b) Is there any information beyond that required under the Order No. 890 transmission planning principles that the Commission should consider requiring public utility transmission providers to provide in their local transmission planning processes? For example, should the Commission require that public utility transmission providers make available to state regulators and other stakeholders cost estimates used during transmission planning for all transmission facility alternatives considered to address the transmission needs, including, but not limited to,

[8] Implementation of Dynamic Line Ratings, 178 FERC ¶ 61,110, February 17, 2022.

[9] See, e.g., October 6, 2022 Technical Conference Transcript (Transcript) Marshall, 104: 25-105:4.

those transmission facilities that are chosen to address the local transmission planning criteria, or for a subset of those facility alternatives? What would be the advantages and disadvantages of such a requirement? If so, how should cost estimates used during transmission planning for these transmission facilities be calculated?

> Ensuring that utilities have procedures in place to default to the lowest-cost solutions, such as GETs, is one way to ensure that TOs have evaluated alternatives to all transmission development. Transmission owners must also be encouraged to solve all constraints that can be addressed, while saving customers money and maintaining or improving reliability.
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> Stakeholders and regulators should have sufficient access to transmission system data to raise questions or propose solutions. Stakeholders should have access to this information, and an ITM would provide additional expert oversight. TOs would thus be incentivized to proactively demonstrate that they have picked a cost-effective solution to a constraint.
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> FERC should require transmission owners to:
> - Make information about transmission capacity and planned upgrades and expansions available publicly, where permissible under Critical Energy/Electric Infrastructure Information (CEII) regulations.
> - Make available a list of transmission constraints that caused or are projected to cause $500,000 of yearly congestion, and the identified cause of that constraint, e.g. transformer, circuit breaker, bus bar, wave trap, etc., its rating limit, along with the next limiting element type and its identified rating limit.
> - Make available a list of Grid Enhancing Technologies and other non-wires alternatives that transmission providers might use to resolve constraints, and conditions under which each would be applied.

1.c) Are there barriers to state regulators and other stakeholders accessing the information that public utility transmission providers provide through their local transmission planning processes (e.g., fees, background checks, etc.)? Do state regulators and other stakeholders have access to the expertise necessary to analyze the information presented and to evaluate the public utility transmission providers' local transmission planning decisions? What actions could the Commission take to reduce any such barriers?

> WATT is primarily concerned that there is insufficient access to technical information. Many stakeholders have the expertise to evaluate data about transmission system operations and planning, and FERC should ensure that TOs are required to share data that enables generator development and support system constraint modeling. In addition, it is imperative that stakeholders can access the information on a timely basis.
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> The creation of ITMs could, individually or in collaboration with FERC's Office of Public Participation, provide a clearinghouse for stakeholder questions or challenges

about utility plans and assumptions. An ITM can centralize and consolidate information about local, regional, and inter-regional transmission plans, and identify efficiencies and complementary solutions.

2.a) Should the Commission require public utility transmission providers to provide transparency concerning their asset management decisions? Are there any aspects of Pacific Gas & Electric's STAR Process or Southern California Edison's SRP that would be beneficial to consider? What other considerations are relevant to the transparency of asset management project decisions?

FERC should require transmission providers to give stakeholders transparency concerning asset management decisions as well as advanced notice of possible changes, and awareness of the process to make those changes.

FERC should go beyond requiring transparency on asset management decisions and allow stakeholders to propose changes to asset management. MISO is developing a process[10] for stakeholders to request grid reconfigurations to reduce transmission congestion for economic reasons. Similar efforts should be undertaken at all RTOs and include all GETs (at the appropriate timescales), and regions outside of RTOs should have corresponding processes for incorporating GETs into transmission operations.

2.b) Are there barriers to state regulators and other stakeholders analyzing any additional information that the Commission could require public utility transmission providers to provide concerning their asset management projects? For example, do state regulators and other stakeholders have access to the expertise necessary to analyze the information presented? What actions could the Commission take to reduce any such barriers?

One role for an ITM would be to provide expertise to the states in their review of regional transmission plans. In doing so, states would be afforded an independent assessment of plans presented in Order 890 planning processes.

3) Could additional transparency facilitated by project-specific disclosure requirements or standardized filing requirements help increase the cost effectiveness of local transmission planning and asset management decisions? Examples include additional transparency and access to local planning criteria, utilities' rankings of their project priorities (subject to CEII protections), requirements for utilities to provide either publicly or to the Commission a standardized disclosure describing the need for a local transmission project or asset management project and why it is a cost-effective solution to that need before money is spent on the planned transmission project (other than any planning costs incurred), and a requirement for utilities to

[10] See the draft "Process to Support Congestion Cost Reconfigurations in the MISO Footprint," Midcontinent Indepednet System Operator, December 2022, https://cdn.misoenergy.org/20221202%20RSC%20Item%2008%20DRAFT%20Congestion%20Cost%20Reconfiguration%20Process_redline627177.pdf

provide advance notice of a project nearing its end of life, among others. To the extent that such requirements may be appropriate, what specific requirements should the Commission impose? For example, for a standardized disclosure described above, should the Commission require utilities to provide such information to stakeholders as part of their local transmission planning process under Order No. 890, or should the Commission require utilities to make a filing with the Commission? At what point in the transmission planning process should these filings be made? Should any such filings be informational, or should they require Commission action? In designing any such requirements, how should the Commission weigh the administrative burden of those requirements against the transparency provided?

> The disclosures listed above would be helpful for stakeholders. End-of-life replacements are of particular concern: they make up a significant portion of projects in many planning regions,[11] and GETs may be an alternative to asset replacement, either on their own or in combination with other multi-value upgrades. It should not be assumed that like-for-like replacement is the most prudent choice. Stakeholders should have the opportunity to request additional solutions be evaluated by the TOs for all local transmission projects.

Independent Transmission Monitor (ITM)

5.a) Please provide a concise but detailed job description for an ITM in both RTOs/ISOs and non-RTOs/ISOs. For example, should the ITM serve as a technical expert that publishes after-the-fact reports assessing public utility transmission providers' transmission plans? Should an ITM assist state regulators and other stakeholder with evaluating potential transmission facilities and their costs? Should an ITM participate in proceedings before the Commission? Should an ITM develop and monitor benchmark estimates of costs using data collected over time? Should an ITM assess continuing need for certain transmission projects? Should an ITM attend local and regional transmission planning meetings? Please list specific roles that would be appropriate for an ITM, and please explain at which stage of the transmission planning process those roles should be leveraged (i.e., inputs and assumptions, planning study results, selection, cost allocation, project development).

> The WATT Coalition strongly supports FERC requiring all regions to have ITMs. An ITM should evaluate the existing and planned transmission system and report publicly to regulators and stakeholders as to whether it generates optimal results for customers, and suggest opportunities for improvement, including the evaluation of GETs.
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> Based on ITM reports, regulators should develop changes and enhancements to transmission planning and operations based on the ITM's objective findings. The ITM should have a solely advisory role, *not* designing or implementing policy, and must be independent from regulators, RTOs, TOs and other industry actors.

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[11] *See*, *e.g.*, PJM Transmission Expansion Advisory Committee, Project Statistics (May 12, 2020).

The ITM role should be the same in RTO and non-RTO areas. FERC has previously seen the value of independent monitoring outside of RTO regions. In the generator replacement provisions in the tariffs of Public Service of Colorado, Dominion South, PacifiCorp, and Duke, FERC obligated a monitor to be hired to ensure that incumbent market power did not keep third parties out.[12]

5.b) What are the potential benefits of an ITM? Please describe with specificity, and address whether these benefits are particular to RTO/ISO or non-RTO/ISO regions, or present in both.

For GETs specifically, the benefits of an ITM would be:

- An independent expert party identifying opportunities for GETs to improve transmission system value to ratepayers, and
- A neutral resource for RTOs, TOs and regulators to understand the applications of new technologies and approaches for implementing them.

In addition, an entity offering independent expert oversight of transmission operations would help correct information asymmetries while maintaining CEII standards. Today, GETs vendors and other stakeholders can only approximate the value of GETs on the U.S. grid, and cannot investigate utility assumptions in determining whether a solution can be implemented.

The ITM's oversight and evaluations would prevent transmission operators from refusing to allow the implementation of lowest-cost solutions to transmission constraints.

5.c) Are there specific challenges, including how the roles and responsibilities of the ITM relate to Commission jurisdiction, regarding the creation of an ITM, or the responsibilities that an ITM might have that the Commission should consider? If so, please describe.

The Commission should include directives for priority areas of oversight. Some areas of focus should be 1) projects without existing oversight, and 2) stakeholder-requested projects demonstrating a certain level of expected cost-savings or value - WATT suggests a $500,000/year savings threshold over business as usual.

5.d) What information would the ITM need access to in carrying out these responsibilities? Should the ITM have access to transmission planning and cost information, including CEII

[12] See, e.g., Public Service Company of Colorado, 175 FERC ¶ 61,100 (2021), Dominion Energy S.C., Inc., 173 FERC ¶ 61,171 (2020), PacifiCorp, 182 FERC ¶ 61,003 (2023) and Duke Energy Carolinas, LLC, Duke Energy Progress LLC, and Duke Energy Florida, LLC, 180 FERC ¶ 61,156 (2022)

information? Please describe with specificity the information that the ITM should be able to review.

> An ITM needs access to all information possible, including CEII information, about the transmission system and markets, including data across jurisdictional seams to evaluate regional and interregional constraints and opportunities. This policy should be consistent with IMM information access policies.

5.e) If an ITM were established, should the Commission periodically review the need for, role, and/or scope of that entity?

> Given the evolution of transmission technology and other factors, FERC should review the scope of the ITM occaisionally. ITM staff should be consulted in this review to find opportunities to expand or focus the ITM's role to improve outcomes.

5.f) Would the ITM's functions potentially overlap with the functions of a public utility transmission provider, particularly in an RTO/ISO? If so, where would the overlap occur? Where should the ITM be housed, and what are the pros and cons of that arrangement (e.g., internal or external independent entity similar to or incorporated within IMMs, an office within the Commission itself, or some other arrangement)? How should an ITM be funded?

> The ITM should not be housed at the RTO or at existing market monitors. An ITM should have maximum independence from RTOs. ITM capabilities would be very different from the IMMs, and we hope the that the number of available ITM providers would exceed the number of entities offering independent market monitoring services to ensure a diversity of providers.

5.e) How, if at all, should an ITM's role differ between RTO/ISO regions and non-RTO/ISO regions? What legal authority (or authorities) could the Commission rely on in establishing an ITM, and does that authority differ with respect to RTO/ISO and non-RTO/ISO regions? Should the Commission require an ITM in both RTOs/ISOs and non-RTOs/ISOs? If so, please state the legal justification in both RTOs/ISOs and non-RTOs/ISOs. What implications does the Commission's scope of authority have with regard to the potential structure and duties of the ITM?

> The ITM's role should be the same in all regions, regardless of the presence of an RTO/ISO.

5.g) How often and at what stages of the local and regional transmission planning processes and interregional transmission coordination process should an ITM review and evaluate transmission facility cost information, if at all (e.g., during the transmission planning cycle, during the development of the transmission facility, or following the completion of construction of the transmission facility)? What types of costs should an ITM review and evaluate (e.g., capital costs, labor costs, etc.), if any? What should an ITM do with the information that is reviewed and evaluated?

> The ITM should not have a role in transmission planning. The ITM should look holistically at the transmission system and identify opportunities for improvements and consumer value through various technological or operational improvements or regional and interregional transmission links. These observations should be presented to regulators and stakeholders outside of the planning process, and *inform* the existing planning and review processes.

5.i) Should the Commission establish a minimum threshold (e.g., costs, voltage, etc.) for transmission facilities that would be reviewed by an ITM? If so, what should that threshold be and why? In RTO/ISO regions, should an ITM review only transmission facilities that address local transmission planning criteria and asset management transmission projects?

> An ITM should be directed to focus on opportunities to increase the value of the transmission system to customers, and contain costs. An economic threshold, such as requiring a study of potential solutions for lines or circuits with $500,000 in reported congestion,[13] could generate significant ratepayer savings.

5.j) Should an ITM be subject to standards of conduct or other professional criteria? If so, what should those standards be?

> An ITM should be held to the highest standard of independence from any transmission provider or planning entity.

Commission's Formula Rates and Prudence Practices

7.a) Should the Commission alter the rebuttable presumption of prudence of expenditures in certain circumstances, such as with respect to specific types of expenditures (e.g., asset management expenditures), where alternatives to transmission have not been considered, or where a state regulator has not reviewed a project for need and cost? If so, how should the standard be altered and in which circumstances?

> Investment trends suggest that transmission providers are investing heavily in small-scale projects that carry the presumption of prudence, potentially instead of larger projects that would have more oversight. Grid Strategies reviewed transmission investments and notes that relatively few new miles of transmission are built, while transmission spending is

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[13] Comments of the WATT Coalition, American Clean Power Association, Advanced Energy Economy and Solar Energy Industries Association in FERC AD-22-5-000, April 25, 2022. https://watt-transmission.org/wp-content/uploads/2022/04/DLR-NOI-Comments-WATT-ACP-AEE-SEIA.pdf

growing.[14] The WATT Coalition believes this is reason to increase oversight and ensure that the most cost-effective tools, including GETs, are being deployed to resolve transmission constraints at the local level.

8) Other than transparency criteria, are there ways that the Commission could consider local planning criteria that utilities use in determining how the prudence standard is applied to specific expenditures? For example, with respect to local transmission and/or asset management projects, should the Commission establish certain guidance for planning such projects and only apply the rebuttable presumption of prudence to projects that follow the Commission-determined guidelines for planning such projects? What are the pros and cons of that approach?

FERC should only apply the presumption of prudence if transmission providers have robust procedures for evaluating GETs and deploying them. The transmission owners should report instances where GETs were evaluated and the reasons they were or were not deployed.

Federal and State Regulation of Transmission Facilities

9) Some panelists at the technical conference argued that there is a regulatory gap with regard to ensuring that a cost-effective mix of local, asset management, and regional reliability transmission projects is developed. Generally speaking, for such projects they contend that state siting processes, the formula rate process, and the Commission's prudence standard and existing transparency requirements, may not provide adequate assurance that utilities will choose a cost-effective mix of projects. Do you agree that there is a regulatory gap for local projects and/or asset management projects, and if so, why or why not? Does the presence or extent of a regulatory gap depend on the underlying state regulatory framework? If so, how? If you agree that one or more regulatory gaps exist, how should the Commission address these gaps? For example, should the Commission modify the prudence standard and/or formula rate protocols for transmission or asset management projects falling within such a regulatory gap? Should the Commission establish new transmission planning requirements to help ensure that such projects are cost-effective? In your response, please discuss whether the Commission's approach should depend on the underlying state regulatory framework. Also please discuss the extent to which your recommended reforms, standing alone, will address the perceived gaps, or whether they should or must be coupled with other solutions.

The WATT Coalition agrees that there is insufficient oversight of small transmission projects in many regions, and that additional oversight would unlock ratepayer benefits. FERC should:

1) Require utilities to prove their investments are prudent by demonstrating that they have evaluated all options, including GETs, to resolve a constraint, and,

[14] Caspary et. al. "Fewer New Miles: Transmission in the 2010s." https://gridstrategiesllc.com/2022/08/16/fewer-new-miles-the-us-transmission-grid-in-the-2010s/

2) Lower the rate of return on projects that do not have oversight, as they are functionally risk-free to the utility and do not justify a full ROE.

GETs are most likely to defer of obviate the need for transmission projects at the small and local scale. In other instances, the combination of a small upgrade of physical transmission infrastructure – a short reconductoring or new transformer, for instance – could have enhanced value if paired with a GET deployment. Today, transmission owners are not proposing GETs solutions and, in the experience of WATT members, refuse to deploy and implement GETs solutions proposed by customers.

10) Some panelists argued that certain types of projects do not receive adequate state, regional, or federal scrutiny with regard to project prudence/need. For example, the Commission has held that asset management and end-of-life decisions are not subject to Order No. 890 planning requirements, and panelists highlighted that in some states such projects do not require a certificate of public convenience and necessity. Do you agree that some projects are not subject to adequate review, and if so, why or why not? What particular types of projects do not receive adequate scrutiny (if any), and should there be some form of heightened scrutiny for them? If so, what kind of heightened scrutiny would be appropriate, and how would that scrutiny be applied?

Utility end-of-life and asset management decisions are generally not reviewed – these are areas where GETs could likely allow for cheaper solutions, and no U.S. transmission utility that the WATT Coalition is aware of includes study of these solutions by default. This shows a need for greater oversight.

Signed,

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