U.S. House Committee on Energy and Commerce
Subcommittee on Energy
"Wires, Rates, and States: Permitting Transmission for Reliable and Affordable Power."
May 13, 2026
Documents for the Record

1. May 13, 2026, A letter from the National Association of Manufacturers addressed to Chairman Latta and Ranking Member Castor, submitted by the Majority and Minority.
2. May 12, 2026, A letter from Persistence Analytics Group addressed to Chairman Guthrie, Chairman Latta, Ranking Member Pallone and Ranking Member Castor, submitted by the Majority.
3. May 13, 2026, A letter from the National Electrical Contractors Association (NECA) addressed to Chairman Guthrie, Chairman Latta, Ranking Member Pallone and Ranking Member Castor, submitted by the Majority.
4. November 11, 2025, A letter from the National Association of Regulatory Utility Commissioners addressed to Chairman Mike Lee, Chairman Moore Capito, Chairman Guthrie, Chairman Graves, Ranking Member Heinrich, Ranking Member Whitehouse, Ranking Member Pallone, and Ranking Member Larsen, submitted by the Majority.
5. April 22, 2026, A letter from the National Association of Regulatory Utility Commissioners addressed to Chairman Mike Lee and Ranking Member Heinrich, submitted by the Majority.
6. April 13, 2026, A letter from the National Association of Regulatory Utility Commissioners addressed to Chairman Swett, Commissioner Rosner, Commissioner See, Commissioner Chang, and Commissioner LaCerte, submitted by the Majority.
7. May 12, 2026, A letter from the National Rural Electric Cooperative Association addressed to Chairman Latta and Ranking Member Castor, submitted by the Majority and Minority.
8. May 13, 2026, A letter from the Steel Manufacturers Association addressed to Chairman Latta and Ranking Member Castor, submitted by the Majority.
9. August 5, 2025, A letter from FERC Chairman Mark Christie titled "Re: NERC Interregional Transfer Capability," addressed to Chairman Guthrie, submitted by the Majority.
10. February 26, 2026, A article from Utility Dive titled "More interregional transmission could save consumers billions: study," submitted by Rep. Peters.

NATIONAL ASSOCIATION OF Manufacturers

Mike Davin
Senior Director, Energy and Resources Policy

Christopher Phalen
Vice President, Domestic Policy

May 13, 2026

The Honorable Bob Latta
Chairman
Subcommittee on Energy
Committee on Energy and Commerce
2125 Rayburn House Office Building
U.S. House of Representatives
Washington, DC 20515

The Honorable Kathy Castor
Ranking Member
Subcommittee on Energy
Committee on Energy and Commerce
2323 Rayburn House Office Building
U.S. House of Representatives
Washington, DC 20515

Dear Chairman Latta and Ranking Member Castor:

On behalf of the National Association of Manufacturers—the largest manufacturing trade association in the U.S., representing companies of all sizes, in every industrial sector, and in all 50 states—we write to submit information for the record ahead of the Subcommittee on Energy hearing entitled "Wires, Rates, and States: Permitting Transmission for Reliable and Affordable Power."

Manufacturing growth and investment in the United States depends on ensuring access to affordable, abundant, and reliable energy. Sufficient generation of and access to all types of energy will allow our industry to meet demand and innovate, build, and grow domestically.

In addition, there is a growing recognition across industrial, commercial, and residential electricity customers that there must be additional investments in the necessary infrastructure to reliably deliver energy to factories and shop floors. Without serious responsible additions and targeted improvements to our electrical transmission and distribution infrastructure, energy projects will be stranded and prices for all customers will increase while reliability will decrease.

By advancing targeted solutions and streamlining permitting, policymakers can empower manufacturers to innovate and improve the American power grid by bolstering reliability, resiliency, and affordability.

Construct and interconnect more transmission and distribution lines: Policymakers should work with all relevant stakeholders, including manufacturers, state and local governments, utilities, consumers, and generators, to develop additional transmission and distribution capacity, while ensuring an appropriate level of federal government oversight and approval, as well as fairness in allocating the associated project and operational costs. Without new and upgraded capacity in this space, we risk stranding assets and rising costs.

Improve and deploy more battery storage technologies to enhance grid balance and lower costs: Manufacturers recognize the incredible potential that battery storage has for stabilizing the electric grid and lowering energy costs. Policymakers should advance solutions that will secure the domestic supply chains for the materials that are used to manufacture batteries and make it easier and more affordable for grid operators to integrate storage into the grid.

Boost and maintain the manufacturing of, and the supply chains for, essential grid components and assets like transformers: Manufacturers are making significant investments in the domestic production of components that are helping to maintain and modernize our electric grid. Unfortunately, countries like China are spending considerable resources to undercut our competitiveness with products that are lower quality and pose cybersecurity risks. Policymakers should strengthen key manufacturing and energy incentives like the Sec. 45X Advanced Manufacturing Production Credit that will help even the playing field and create more manufacturing jobs in the United States.

Enhance grid performance and capacity through upgrades to existing infrastructure: Manufacturers support policies that would invest in reconductoring, other grid-enhancing technologies, and demand response initiatives to complement the buildout of new transmission and distribution lines. Additionally, the NAM supports federal and regional policies to streamline interconnection queues across the country, for both power generation and electricity offtake customers. These policies would expand grid capacity and increase operational efficiencies to support both manufacturing investment and growth as well as retail customer affordability and reliability.

Enact comprehensive permitting reform legislation to streamline the build out of all energy infrastructure: In addition to facilitating the interconnection of additional transmission and distribution lines and improving their efficiency, policymakers should modernize the permitting process for pipelines, enhance and improve safety measures around pipeline systems, and increase efficiencies by embracing new technologies like artificial intelligence. Statutes like the National Environmental Policy Act, the Clean Air Act, the Clean Water Act, and the Endangered Species Act should be modernized to put an end to the cycle of litigation, unclear timelines, and the overhang of uncertainty that threatens billions of dollars in investments in energy and manufacturing.

* * * *

Manufacturers strongly support the Energy and Commerce Committee's focus on smart transmission policies that will improve the grid and reduce costs for the American people. It is critical that policymakers work in bipartisan fashion to enact durable and lasting permitting and transmission policies that will ensure manufacturers in the United States can remain competitive in global markets.

Sincerely,

Mike Davin
Senior Director, Energy and Resources Policy

Christopher Phalen
Vice President, Domestic Policy

Neil P. Osnato
Founder, Persistence Analytics Group LLC
NATIONAL SECURITY & Infrastructure Risk Analytics | Demand Durability, Grid Stress & Load Integrity

May 12, 2026

The Honorable Bob Latta
Chairman
Subcommittee on Energy
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

The Honorable Brett Guthrie
Chairman
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

The Honorable Kathy Castor
Ranking Member
Subcommittee on Energy
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

The Honorable Frank Pallone, Jr.
Ranking Member
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

Re: Hearing on "Wires, Rates, and States: Permitting Transmission for Reliable and Affordable Power"

Dear Chairman Latta, Chairman Guthrie, Ranking Member Castor, and Ranking Member Pallone:

I respectfully submit this letter for consideration in connection with the Subcommittee on Energy hearing titled "Wires, Rates, and States: Permitting Transmission for Reliable and Affordable Power."

The hearing is timely because transmission policy is no longer only a permitting or siting issue. It is now directly tied to AI competitiveness, industrial growth, electricity affordability, reliability, national security, and ratepayer protection.

The core concern is that several critical timelines are no longer aligned. AI and data-center load can emerge on a two- to three-year development cycle, while transmission, generation, substations, transformers, and permitting often move on much longer infrastructure timelines. At the same time, cost-allocation and regulatory frameworks may not be designed to determine quickly enough who caused the need, who benefits, and who should pay.

This creates a risk that projected large-load demand becomes transmission obligation before load durability, cost causation, and beneficiary responsibility are fully validated.

The issue is not whether data centers matter. They do. AI infrastructure, cloud services, healthcare records, financial systems, emergency communications, defense needs, and commercial activity increasingly depend on reliable digital infrastructure.

The issue is whether households, small businesses, and existing customers are protected when large-load growth drives transmission, capacity, reliability, or infrastructure costs.

As Congress considers transmission permitting, affordability, and grid reliability, several questions may be useful for the hearing record:

1. Can transmission planning distinguish committed and durable large-load demand from demand that is speculative, duplicative, timing-sensitive, or dependent on unresolved commercial conditions?
2. Are current cost-allocation rules adequate for AI and data-center-driven infrastructure needs?
3. Should large computational loads have clearer reliability, disclosure, flexibility, or cost-responsibility obligations before they trigger major transmission or capacity costs?
4. How should Congress address the mismatch between fast-moving private load growth and slow-moving public infrastructure approval?
5. How can permitting reform accelerate needed transmission while protecting state and local legitimacy and preventing unfair cost shifts to households and small businesses?
6. Should federal policy require stronger accountability around who caused the infrastructure need, who benefits from the upgrade, and who bears the cost if projected load timing, location, or utilization changes?

Transmission expansion may be necessary, but the country should not build long-duration public obligations around untested assumptions. Reliability and affordability both require a stronger accountability layer before large-load projections harden into ratepayer-backed infrastructure commitments.

A practical policy principle should guide the discussion: large-load customers should pay their fair share, and public customers should not become the default shock absorber for infrastructure costs caused by private load growth that is not yet fully validated.

Congress has an opportunity to modernize transmission policy in a way that supports AI infrastructure, strengthens grid reliability, accelerates needed development, and protects electricity customers. That requires not only faster permitting, but better validation of the assumptions driving the need.

Respectfully submitted,

Neil P. Osnato
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May 13, 2026

The Honorable Brett Guthrie
Chairman
House Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, D.C. 20515

The Honorable Frank Pallone
Ranking Member
House Committee on Energy and Commerce
2323 Rayburn House Office Building
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The Honorable Bob Latta
Chairman
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2125 Rayburn House Office Building
Washington, D.C. 20515

The Honorable Kathy Castor
Ranking Member
House Committee on Energy and Commerce
Subcommittee on Energy
2323 Rayburn House Office Building
Washington, D.C. 20515

Re: NECA Statement of Support for the May 13, 2026 Legislative Hearing, *"Wires, Rates, and States: Permitting Transmission for Reliable and Affordable Power"*

Dear Chairman Guthrie, Ranking Member Pallone, Chairman Latta, and Ranking Member Castor:

On behalf of the National Electrical Contractors Association (NECA) and the more than 4,000 member companies we represent across the United States, thank you for convening the May 13, 2026 legislative hearing, "Wires, Rates, and States: Permitting Transmission for Reliable and Affordable Power." Your continued leadership in examining the federal hurdles that slow needed transmission development—and in pursuing commonsense reforms to unleash American energy—comes at a decisive moment for our grid, our economy, and our national security.

NECA strongly agrees with your framing that "strengthening our grid and winning the race for AI dominance requires the right power at the right time." The electrical contractors who design, build, and energize America's transmission system stand ready to deliver that power. But that can only happen if Congress modernizes the federal permitting framework that currently keeps shovel-ready projects on the sidelines for a decade or more.

About NECA

Founded in 1901, NECA is the voice of the $230 billion electrical construction industry. Our member firms employ a highly skilled workforce of more than 700,000 electricians and

apprentices, trained through the gold-standard joint apprenticeship and training program NECA operates with the International Brotherhood of Electrical Workers (IBEW). Together, NECA contractors build and maintain the high-voltage transmission lines, substations, distribution networks, and grid-edge infrastructure that move electricity from generators to homes, factories, hospitals, and data centers across every state in the country.

NECA contractors are on the front lines of nearly every category of project this Committee has examined: high-voltage transmission and reconductoring, substation hardening, data center electrical build-out, advanced nuclear and SMR site construction, EV and industrial electrification, and the broad spectrum of generation interconnection work. That hands-on perspective—from the engineering desk to the right-of-way—gives NECA a unique vantage point on what is, and is not, working in federal transmission policy today.

On the Front Lines of the Transmission Build-Out

The current load-growth picture is sobering. NERC's most recent long-term assessment projects roughly 224 GW of peak demand growth over the next decade, while at the same time more than 100 GW of dispatchable generation is scheduled to retire—a generation-resource gap measured in hundreds of gigawatts. AI data centers, domestic manufacturing reshoring, and broad-based electrification are driving that demand, and none of it can be served without dramatic expansion and modernization of the transmission backbone.

NECA contractors know from direct experience that the binding constraint is no longer just financing, technology, or skilled labor, it is also permitting delays. Transmission projects routinely face seven-to-ten-year federal review timelines, duplicative NEPA processes across multiple agencies, and a categorical exclusion regime that has not kept pace with the realities of a modernized energy grid.

Permitting Delay Is a Hidden Tax on Ratepayers

The Committee's focus on ratepayer protection is well placed, and NECA member contractors want to underscore a point that is often missed in the permitting debate: every month a transmission line, reconductoring project, or substation upgrade sits in the federal review process, the bill that consumers ultimately pay goes up. Permitting delays equal direct, compounding costs that flows straight through to monthly electricity bills.

NECA contractors see this dynamic on every project. Costs for steel, aluminum, transformers, conductor, and skilled labor escalate year over year, meaning a transmission build or rebuild

quoted today costs materially more two, three, or five years from now. Engineering and environmental consulting teams must be re-mobilized each time a process restarts or a new study is required. And when permitting drags long enough that congestion on the existing system worsens, ratepayers pay twice—first in higher congestion and re-dispatch costs on their current bills, and again in the larger, more expensive project that eventually gets built. Industry and federal analyses have consistently found that transmission congestion alone imposes billions of dollars per year in avoidable costs on American consumers, and that figure grows with every year of delay.

The same logic applies to reconductoring with advanced conductors and other rebuilds-in-place. These are precisely the projects that can deliver more capacity on existing rights-of-way at the lowest cost per megawatt to ratepayers, but only if they can move through federal review in months rather than years. When permitting gets in the way of a reconductoring project, the alternative is almost always a larger, costlier greenfield build, new generation that would not otherwise have been needed, or sustained congestion charges. In every one of those scenarios, the ratepayer loses. Streamlining federal permitting is therefore not in tension with ratepayer protection. It is one of the most powerful ratepayer-protection tools available to this Committee.

NECA Supports the High-Capacity Grid Act, the GRID Power Act, and the RED Tape Act

NECA is pleased to express its strong support for three pieces of legislation central to this Committee's work to strengthen the grid and streamline federal permitting:

- **The High-Capacity Grid Act** (H.R. 6633), introduced by Representative Julie Fedorchak, would direct FERC to establish a best-available transmission conductor standard for new and rebuilt interstate transmission lines. By requiring the highest-capacity, highest-efficiency, lowest-sag conductors on FERC-jurisdictional projects, this bill maximizes the carrying capacity of every mile of right-of-way we already have—delivering more power, faster, at lower cost to ratepayers, and with greater wildfire and weather resilience. For NECA contractors, this is exactly the kind of forward-looking standard that pairs American workmanship with American technology.

- **The Reliable Power Act** (H.R.3616), championed by Representative Balderson and passed by the House last Congress, takes critical steps to ensure that federal regulation does not undermine reliability and to keep dispatchable baseload power on the system

while new infrastructure is built. NECA supported the bill on passage and continues to urge swift action in the Senate.

- **The Reducing and Eliminating Duplicative Environmental Regulations Act, or RED Tape Act** (H.R. 6398), introduced by Representative John Joyce and passed by the House in April, eliminates the outdated Section 309 Clean Air Act requirement that directs EPA to second-guess Environmental Impact Statements already prepared by other federal agencies under NEPA. For NECA contractors, this duplicative review is a textbook example of process layered on process—one that adds months or years to transmission, generation, and industrial project schedules without producing meaningfully better environmental outcomes. Eliminating it restores efficiency and predictability to federal permitting, directly benefiting ratepayers and the workforce that builds these projects. NECA urges the Senate to take up and pass the RED Tape Act without delay.

Together, these bills represent the kind of pragmatic, build-oriented policymaking the moment demands. We commend you and your colleagues for advancing them.

NECA's Recommendations to Win the War for AI

To translate this Committee's leadership into kilowatts delivered—and into lower bills for American families and businesses—NECA respectfully urges the Committee to take two additional steps as it advances the legislation before it on May 13:

1. **Pass transmission-specific permitting reform -** While general permitting reform has stalled, transmission is too important to wait for a grand bargain. NECA urges the Committee to advance standalone, transmission-focused legislation that establishes firm timelines for federal NEPA review of interstate transmission projects, designates a lead agency for One Federal Decision, narrows judicial review windows, and provides clear federal backstop siting authority where states cannot act on multi-state lines of national significance. Without these reforms, delay-related costs will continue to be passed onto ratepayers.

2. Expand categorical exclusions for transmission projects. A significant share of the transmission build-out America needs over the next decade will occur within or immediately adjacent to existing, previously disturbed rights-of-way—reconductoring with advanced conductors, rebuilds-in-place, voltage upgrades, and substation expansions. These projects do not raise meaningful new environmental questions, yet they are routinely swept into full

Environmental Assessments or Environmental Impact Statements. NECA urges the Committee to direct DOE and other relevant agencies to expand existing categorical exclusions—including, but not limited to, the CE under 10 CFR Part 1021 Appendix B4.12 to cover reconductoring and upgrades within existing rights-of-way without artificial mileage caps. The Committee should also codify a transmission-specific CE for projects using advanced conductors and grid-enhancing technologies. Expanding CEs is the single fastest, lowest-cost lever Congress can pull to put more electrons on the grid in time to win the war for AI.

Conclusion

America's electrical contractors and the skilled IBEW workforce we partner with have the capacity, the training, and the will to build the advanced transmission system the country needs. What NECA contractors need from Washington is a permitting framework that matches the speed of the moment. NECA stands ready to serve as a resource to the Committee and your staff as you continue this important work, and we look forward to the testimony and discussion on May 13.

Thank you again for your leadership on these critical issues. Please do not hesitate to contact NECA's Government Affairs team with any questions or requests for additional information.

Sincerely,

Marco Giamberardino
Chief Communications Officer
National Electrical Contractors Association

NARUC

National Association of Regulatory Utility Commissioners

November 11, 2025

The Honorable Mike Lee
363 Russell Senate Office Bldg.
Washington, DC 20510

The Honorable Martin Heinrich
709 Hart Senate Office Bldg.
Washington, DC 20510

The Honorable Shelley Moore Capito
170 Russell Senate Office Bldg.
Washington, DC 20510

The Honorable Sheldon Whitehouse
498 Russell Senate Office Bldg.
Washington, DC 20510

The Honorable Brett Guthrie
2161 Rayburn House Office Bldg.
Washington, DC 20515

The Honorable Frank Pallone
2117 Rayburn House Office Bldg.
Washington, DC 20515

The Honorable Sam Graves
1135 Longworth House Office Bldg.
Washington, DC 20515

The Honorable Rick Larsen
2163 Rayburn House Office Bldg.
Washington, DC 20515

Re: NARUC Support for State Primacy in Electric Transmission Permitting Authority

Dear Members:

On behalf of the National Association of Regulatory Utility Commissioners (NARUC), I am writing to express concern regarding any legislation that could weaken state commissions' authority to site and permit electric transmission lines.

Please find attached (*page 4*) a resolution that NARUC passed in February 2024. Although it is specific to a particular case, the underlying sentiment expressed in the resolution is clear. Since the earliest days of the buildout of the electric grid, states have been the arbiter of transmission permitting within their boundaries, including in some states siting, environmental review, and eminent domain. Even after the initial passage of the Federal Power Act, where Congress created a bright-line jurisdictional divide between state and federal jurisdiction, Congress understood the importance of allowing states to continue to exercise their exclusive permitting authority over electric transmission facilities. The FPA makes clear that State authority survived the specification of the Federal Energy Regulatory Commission's (FERC) transmission and wholesale electricity ratemaking authority.

In 2005, the Energy Policy Act of 2005, (Pub. L. No. 109-58, 1119 Stat. 594, as amended, Pub. L. No. 117-58, 135 Stat. 933 (Nov. 15, 2021)) Congress gave FERC limited transmission siting backstop authority but only in "a national interest electric transmission corridor designated by the Secretary" (NIETC). Before FERC can enable its backstop siting authority for a project that is located in a NIETC, FERC must find that the state commission cannot approve the application, the state does not act within one year of the application or the state denies the application. FERC has never used this backstop siting authority. The NIETC specification procedure is an important restriction on FERC's authority.

The current process of state public utility commissions permitting and siting transmission lines has generally allowed needed projects to get built with safeguards for the public and affected landowners.

While there are proposed projects that have faced significant permitting hurdles in some parts of the nation, it is our observation that many of the delays surrounding the siting and permitting of large interstate transmission lines are due to ***federal*** processes and do not involve state permitting and siting. We are concerned that federal preemption of state permitting everywhere, even where state permitting is working well, only to be replaced by a federal regime, could result in significant delays of needed transmission. Indeed, once a federal nexus is established, such as through FERC siting, it triggers the time-consuming requirements of numerous federal permitting rules and statutes that may be more burdensome than those required in individual states. Such a triggering of federal nexus may also include the opportunity for intervenors to use the federal court system as a means of delaying projects, even those that state officials have found to be unobjectionable. In brief, Congress does not need to preempt the states to fix issues that exist as the result of federal statutes, and doing so incurs the risk of creating new permitting hurdles in places where they do not currently exist.

In closing, for more than a century, state siting and permitting of electric transmission has generally worked well for American electricity customers. If this nation's goal is to build transmission lines in an appropriately expeditious manner, we encourage Congress to first study and reform federal permitting laws and rules that may be impeding transmission development, rather than adopting proposals that may weaken state siting and permitting, and only to replace it with a federal regime that may work even less well for the American people and for landowners who are affected by these projects.

If you have any questions about this letter, please contact NARUC Sr. Director of Energy Policy and Legal Counsel Kim Duffley at 202.898.1350 or kduffley@naruc.org.

Thank you in advance for your consideration.

Sincerely,

Hon. Tricia Pridemore,
President
National Association of Regulatory Utility Commissioners
Commissioner, Georgia Public Service Commission

EL-1 Resolution Supporting States' Jurisdiction to Render Transmission Permitting Authority

Whereas, states have long been the arbiter of transmission permitting within their boundaries, including but not limited to the purposes of siting, environmental review, and eminent domain;

Whereas, before and after the passage of the Federal Power Act, States continued to exercise their permitting authority over electric transmission facilities—an authority that is separate and apart from Federal Energy Regulatory Commission's (FERC) transmission and wholesale electricity ratemaking authority;

Whereas, in 2005, through the enactment of the Energy Policy Act of 2005, (Pub. L. No. 109-58, 1119 Stat. 594, *as amended*, Pub. L. No. 117-58, 135 Stat. 933 (Nov. 15, 2021)) Congress gave FERC limited transmission siting backstop authority but only in "a national interest electric transmission corridor designated by the Secretary" (NIETC);

Whereas, the states share the RTOs' concerns regarding transmission congestion and the need for robust transmission infrastructure because it is in the States' interests to ensure that adequate electric transmission facilities are constructed to meet the needs for economic and reliable utility service to their citizens;

Whereas, the National Association of Regulatory Utility Commissioners takes no position on whether the transmission line at issue should be sited; *now, therefore be it*

Resolved, that the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its February 28, 2024 Winter Policy Summit in Washington, D.C., supports the primary role of States in siting, permitting, and the exercise of eminent domain for transmission; *and be it further*

Resolved, that NARUC will file amicus briefs in the matter of *Transource Pennsylvania, LLC v. Steven*[1] [sic] *M. DeFrank, et al.,* Docket No. 24-1045 (3d. Cir.), CIVIL 1:21-CV-01101 (M.D. Pa.), for the limited and specific purpose of advocating NARUC's policies as a supporter of states' rights. NARUC's amicus filing will be limited to any or all of the following issues: opposing any overreach into state eminent domain authority; opposing an overly narrow interpretation of state siting authority that constrains a state's authority to the Oxford Dictionary definition of the term "siting," especially given the scope of State siting authority under Section 216 of the Federal Power Act; opposing any interpretation of the opinion that suggests that a state can never deny siting or eminent domain for a FERC transmission planning region's selected project; and, opposing the Court's novel expansion of accepted dormant commerce clause jurisprudence regarding what is a per se violation of the dormant commerce clause.

Passed by the Committee on Electricity on February 26, 2024
Adopted by the NARUC Board of Directors on February 28, 2024

[1] The case caption incorrectly spells the name of Stephen M. DeFrank, Chairman of the PA PUC.

NARUC

National Association of Regulatory Utility Commissioners

April 22, 2026

The Honorable Mike Lee
Chairman
Senate Committee on Energy
and Natural Resources
304 Dirksen Senate Office Bldg.
Washington, DC 20510

The Honorable Martin Heinrich
Ranking Member
Senate Committee on Energy
and Natural Resources
304 Dirksen Senate Office Bldg.
Washington, DC 20510

Dear Chairman Lee and Ranking Member Heinrich:

The National Association of Regulatory Utility Commissioners (NARUC) is the national organization representing the state public service commissions that oversee utilities providing essential energy, telecommunications and water services in the 50 states, the District of Columbia and U.S. territories. NARUC members carry out their duties in the public interest and help shape the profile and substance of utility regulation in the United States. As Congress considers major legislation that could reform energy permitting processes, we urge the Senate Energy and Natural Resources Committee to ensure that NARUC members' views are fully considered during your deliberations. State regulators stand ready to provide feedback on legislative proposals that could affect the states' ability to protect our shared constituents, especially those proposals that may preempt state authority to permit and site electric transmission projects.

NARUC agrees that meaningful federal permitting reform is important to addressing rising demand. The Committee has correctly focused on amending existing federal laws to help solve for the real and significant issues that have stifled energy delivery and contributed to rising electricity costs across the United States. Of particular note is possible reform of certain federal laws such as the National Environmental Policy Act which have too often unreasonably delayed infrastructure projects needed for the safe and reliable delivery of energy to consumers. So long as "permitting reform" is defined as streamlining federal processes that are negatively affecting the feasibility of necessary projects, members of your committee will likely find much support among the state regulatory community. However, if "permitting reform" is defined as preempting state oversight of infrastructure siting, then our members will largely view it as counterproductive to both efficiency and to the best interests of consumers and impacted landowners.

It is important to emphasize that delays to building energy infrastructure have largely been the result of federal agencies and processes, not state ones. Put simply, state siting

and permitting processes are generally working well relative to federal permitting. From 2020 through 2025, approximately 2,930 miles of new high-voltage (345 kV and above) transmission lines were built in the United States.[1]

Comparing the number of miles of electric transmission lines constructed in the U.S. (where states have jurisdiction) to the number of miles of interstate natural gas pipelines (where the Federal Energy Regulatory Commission (FERC) has jurisdiction) is illustrative. According to publicly available FERC data, the agency has authorized 1,329 miles of new pipelines total between 2020 and 2025.[2] Put another way, over twice as many miles of state-permitted high-voltage electric transmission lines were placed into service as compared to the miles of natural gas pipelines that have been permitted over the last six years. By-and-large, it is simply not the case that states are laggards compared to the federal government when it comes to efficiently permitting energy infrastructure.

In our experience, it is often not state regulatory processes that add undue delay to projects, it is the creation of a federal jurisdictional nexus. Under existing federal law, when a state-approved transmission project triggers this nexus, such as when a project crosses federally managed land, it means that federal statutes and agencies become involved. This in turn can lead to federal litigation and attendant delays. This is problematic anywhere federal public lands are involved, but is particularly noteworthy throughout the Western U.S. If Congress wishes to make improvements to infrastructure permitting, this is the place to start; to reform federal processes themselves, rather than preempting states.

State commissions wish to preserve cooperative federalism in the energy permitting space. Backstop siting authority already exists in federal law for the limited number of projects that may qualify for it. Legislation that further expands federal siting and which weakens the states' ability to oversee these major projects flies in the face of that spirit of cooperative federalism.

Moreover, even if Congress successfully reforms the federal permitting statutes that have hindered needed infrastructure projects, we strongly urge you to resist any effort to concentrate even more authority over local siting decisions in the federal government. The federal government generally, and the FERC specifically, are poorly situated to process electric transmission permits.

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[1] https://cms.ferc.gov/media/energy-infrastructure-update-december-2022; https://cms.ferc.gov/media/energy-infrastructure-update-october-2021-0; https://cms.ferc.gov/media/energy-infrastructure-update-january-2023-0; https://cms.ferc.gov/media/energy-infrastructure-update-december-2024-revised-data-april-22-2025; https://cms.ferc.gov/media/energy-infrastructure-update-december-2025-0

[2] https://www.ferc.gov/industries-data/natural-gas/approved-major-pipeline-projects-1997-present

States use the permitting process to resolve landowner concerns with transmission developers. Giving this process to the FERC will undoubtedly hinder a landowner's ability to provide meaningful input. Electric transmission projects can be controversial wherever they are proposed, and frankly, electric transmission lines tend to engender greater landowner concerns than pipelines given their generally greater visual imposition on the landscape. But at least with state-led permitting, affected landowners, individuals and communities have access to a local process to have their concerns heard.

A federal process affords no such relief. Intensely impactful decisions that affect average Americans would be made at a faraway agency, by people who likely have no connection to the land or people living near where these major projects are proposed and constructed. Unlike project developers, these citizens do not have teams of representatives advocating for them at the FERC. They typically have only themselves to make themselves heard. With a state permitting process, these citizens have a better chance to make their voices heard, not only during the permitting process, but during the construction and operations phases also. When landowners feel sidelined, local resistance grows, which ultimately makes all needed projects more difficult to build. States are much better positioned to address and balance these local concerns.

Giving the FERC additional broad authority over permitting electric transmission lines would necessitate a major expansion of agency hiring since it would be assuming a new role that dwarfs the work now handled by its existing Office of Energy Projects. In total, state preemption will exacerbate the frustration felt by impacted communities, while straining an already overextended federal bureaucracy. The net effect will be longer delays in permitting rather than any sort of streamlined process.

NARUC appreciates your interest in these important matters and stands ready to assist your offices in crafting legislation that meets the national goal of ensuring that needed energy projects are built efficiently, while also ensuring that those individuals who live closest to the projects have their interests heard.

Sincerely,

Hon. Ann Rendahl
NARUC President
Commissioner, Washington Utilities & Transportation Commission

Tony Clark
Executive Director

NARUC
National Association of Regulatory Utility Commissioners

April 13, 2026

The Honorable Laura Swett, Chairman
The Honorable David Rosner, Commissioner
The Honorable Lindsay See, Commissioner
The Honorable Judy Chang, Commissioner
The Honorable David LaCerte, Commissioner

Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Docket No. RM26-4-000

Dear Chairman Swett and Commissioners Rosner, See, Chang and LaCerte:

We are writing today to supplement earlier comments submitted in this Docket, given the significant activity that has taken place within the states addressing large load interconnection since the Advance Notice of Proposed Rulemaking (ANOPR) was released. The National Association of Regulatory Commissioners (NARUC) continues to recognize that interconnecting large load end-use customers in an expeditious and non-discriminatory manner is of paramount importance.[1] To that end, we emphasize the following key points as you weigh your options moving forward:

- The abundance of recent state undertakings demonstrate that state commissions are in the best position to ensure rational and efficient interconnections of new large loads while protecting *all* customers (including residential, commercial and large manufacturing customers) from improper cost-shifts or unfair interconnection processes.

- Recent state experience shows that the data center landscape continues to be incredibly dynamic, both nationally and on a state-by-state level. Data center infrastructure investments, siting decisions, and strategic planning continue to rapidly evolve. As data center proliferation grows, new opportunities and challenges associated with retail cost allocation, stranded asset risk, and system planning are emerging – and these opportunities and challenges are not necessarily the same for every state or region. Federal regulation of large load interconnections will impede states' abilities to (i) adapt quickly to industry

[1] Initial Comments of NARUC, Docket No. RM26-4-000 at 2, 4, 6 (filed November 21, 2025); Reply Comments of NARUC, Docket No. RM26-4-000, at 2 (filed December 5, 2025).

changes or region-specific challenges as they emerge, and (ii) adequately protect the affordability of service to other retail customers.

- State commissions have the authority, regulatory tools, and unique expertise necessary to allocate transmission costs associated with large load interconnections directly to those end-use customers. There is no regulatory gap. To the extent state commissions require additional information to effectuate cost allocation policies, the states will continue to work with FERC, RTOs/ISOs, and other regulatory partners to share and obtain such information.

A central role of state public utilities commissions is to ensure that regulated public utilities provide non-discriminatory access to safe and reliable service at just and reasonable rates. State public utilities commissions have continued to review and approve either utility tariff language or contracts between the utility and large load to ensure efficient non-discriminatory interconnection, while also balancing and protecting the interests of other retail ratepayers. The Edison Electric Institute submitted a list of what actions its members have taken, as well as a list of state public utility commission dockets, providing ample evidence that best practices are already being appropriately developed by the states in a timely and efficient manner.[2] NARUC also recognizes and supports the general conclusions of the Concentric Energy Advisors Whitepaper recently submitted into the record by WIRES, which highlights the potentially significant negative cost consequences to other retail customers of federal pre-emption of the large load interconnection process.[3]

NARUC will not duplicate the extensive lists of state commission actions here. Rather, NARUC wishes to highlight that states are moving with speed to create best practices either by tariff or contract that work within their specific regions and regulatory structures. NARUC highlights six examples how the states are effectively handling large load customers and the surrounding issues:

Virginia State Corporation Commission

On November 25, 2025, as part of its biennial review of Dominion Energy Virginia's rates, the Virginia State Corporation Commission ("Virginia SCC") approved creation of a new GS-5 rate class for large loads. Among other things, this new large load tariff requires a minimum contract term of 14 years, a maximum ramp period of four years, minimum collateral requirements, and minimum demand charges based on contracted capacity. All these protections will ensure that costs are not shifted to non-large load customers.

Also as part of that proceeding, the Virginia SCC directed Dominion to file its large load interconnection queue procedures with the SCC, which Dominion filed in February 2026.

[2] Comments of Edison Electric Institute, Docket No. RM26-4-000 at 4-16 (filed March 12, 2026). In addition, the Smart Electric Power Association has complied a separate list of various state level activities in the interconnection space. https://sepapower.org/large-load-tariffs-database/.

[3] Supplemental Comments of WIRES, Docket No. RM26-4-000 (filed March 30, 2026).

This assessment considers all large loads, not just data center loads. If FERC issues different federal rules for interconnection of data center loads, this may lead to increased costs or discriminatory procedures for other important end-use customers, such as Virginia manufacturers developing critical components needed for infrastructure buildout required to serve data centers (e.g., Virginia Transformer Corp. located in Roanoke, VA). Moreover, it remains unclear how cost allocation would work if some large loads have already paid for network upgrades through a federal interconnection process, making them exempt from other transmission costs at the retail level. This could lead to costs being shifted to other retail ratepayers, while limiting the states' ability to appropriately allocate costs and protect other customers.

Finally, as part of its November 2025 biennial review order, the Virginia SCC directed Dominion to propose alternative transmission cost allocation methodologies, including the potential for direct assignment, for large load customers. Dominion will file these proposals in its next transmission cost rate proceeding, expected in May 2026.

Georgia Public Service Commission (PSC)

In April 2024, the Georgia PSC entered an order directing Georgia Power to ensure that data centers would decrease, not increase, other retail ratepayers bills, to provide the PSC with quarterly reports on the growth of data center load, and to file cost allocation reports to track and ensure that data centers were paying the total costs. In 2025, the PSC issued numerous orders approving a new framework for data centers including a minimum billing framework and longer contract terms. This new framework is to ensure data centers continue paying for new infrastructure even if they leave the state. The PSC further ordered that utility contracts with companies with over 100 MW of potential usage must be filed with the PSC 30-days prior to execution. The PSC also ordered a 3-year rate freeze for retail ratepayers and instructed the PSC staff to refine load forecasting for large loads. During this 3-year rate freeze, the Commission indicated that it will continue its mission to prevent new data centers from shifting costs to residential customers.

Public Utilities Commission of Ohio

The Public Utilities Commission of Ohio, in July 2025, issued an order approving a new tariff for AEP Ohio. The tariff requires data centers larger than 25 MW to pay a higher minimum demand charge (85% for the largest data centers), commit to a long-term contract of at least eight to twelve years, pay exit fees if they do not fulfill their full contract term, and post collateral or meet certain credit requirements. These terms ensure large loads pay their share even if they use less power than planned and prevent potential stranded asset costs from being passed to other retail ratepayers. The Public Utilities Commission of Ohio

indicated that this tariff aided the utility in the improvement of its load forecast and removed speculative projects that were unlikely to be built. Through the process, AEP's load forecast was reduced from approximately 30,000 MW to 5,600 MW.

Louisiana Public Service Commission

The Louisiana Public Service Commission, in August 2025, issued an order for Entergy's terms of service for data centers as follows: (1) a 15-year electric service agreement ("ESA"), subject to automatic 5-year renewal terms unless timely notice of intent not to renew is received; (2) a Contribution in Aid of Construction (CIAC) agreement pursuant to which the Customer is obligated to provide the capital required to construct the transmission assets up front, secured by a Meta guarantee, as well as significant financial contribution to the construction of the generating units; (3) participation in Entergy's standard large load, high load factor rate schedule with the addition of a customer specific minimum monthly charge that covers the full annual revenue requirement of the planned generators for the first 15-year term of the ESA, regardless of actual usage, as well as the cost of any purchased capacity to fully serve the load; (4) full participation in Entergy's riders, including preexisting and future storm damage and hardening riders; (5) a termination payment guaranteed by Meta that will cover the Customer's obligations under the ESA for the original 15-year term in the event that the Customer withdraws from the agreement prior to 15 years; and (6) construction progress reporting with an obligation to prudently manage construction progress and costs.

Illinois Commerce Commission

The Illinois Commerce Commission, in March 2026, issued its first order amending a ComEd tariff to address data centers. The order amends the general terms and conditions to clarify that each large load will be subject to two deposits: (1) a security deposit to cover the costs ComEd will incur to conduct preliminary planning and engineering analyses, inclusive of the Cluster Study; and (2) a deposit sufficient to secure the costs of procurement of long-lead materials required for the project. The deposit for study costs is altered from a fixed sum to a sliding scale. This sliding-scale approach provides appropriate incentives for customers to submit realistic and supportable demand forecasts and helps mitigate the risk of speculative or inflated requests that could lead to inefficient planning or unnecessary system investment. The deposit to cover long-lead materials is approved to ensure that other customers are not exposed to stranded costs or unnecessary upgrades should a large load not proceed. Lastly, the ICC directed its staff to file a report and draft an order initiating additional proceedings by April 23 to evaluate further ratepayer protections to investigate the unaddressed issues and adopt new ratepayer protections, to address significant reliability,

affordability and policy risks. The Order stated that this exploration should be completed within eight months or as expeditiously as possible.

Michigan Public Service Commission

The Michigan Public Service Commission (MPSC), in November of 2025, approved a large load tariff for Consumers Energy. Notably, while the tariff adopts a set of enhanced protections for data centers and other large load (100MW+) customers, it also requires additional ex parte filings specific to each customer taking service under the tariff that detail the generation and other resources that will be required to serve the large load customer, and how that interconnecting customer will cover the costs of such resources. For DTE Electric Company, the MPSC in December 2025 conditionally approved two special contracts (a primary supply agreement and an energy storage agreement) for DTE Electric Co. to provide service to a new 1,383 MW data center being developed by a subsidiary of Oracle Corp. As part of the Commission's conditional approval of the special contracts in this case, the Commission also directed DTE Electric to file an application for a generally applicable large load customer tariff that aligns with what the MPSC approved for Consumers Energy. As a result, for both Consumers Energy and DTE Electric Co., the end goal is a generally applicable large load tariff that includes elements including minimum contract terms, minimum billing requirements, early termination provisions, and default credit and collateral requirements, while also providing for the consideration of special contracts that detail additional elements around the resources needed to serve an interconnecting large load customer, how that customer will contribute to the costs of those resources, any deviations from the default credit and collateral requirements, and other provisions. The special contracts approved for DTE Electric include an agreement for the data center customer to fully fund energy storage facilities equal to its projected load in addition to an agreement stipulating the data center customer will take service under an existing industrial customer tariff contributing to transmission, distribution, and generation costs in the same manner as other industrial customers. In addition, the Commission approved high minimum-billing demand (80-90%) and exit fees to ensure the full recovery of costs from the data center customers. The Commission also asked both DTE Electric and Consumers Energy to file several specific cost allocation and rate design proposals for data centers in their next rate case, including direct assignment of transmission, generation, and distribution costs to the individual large load customer, as well as a new large load customer rate class. Collateral requirements are included to protect ratepayers from stranded costs if a data center closes. The Consumers Energy tariff sets the default collateral amount at 50% of the minimum billing demand times the number of months remaining on the contract term, in the form of cash or a letter of credit. It allows the utility to propose a different collateral amount or form of collateral with supporting evidence for the Commission's consideration. The special contracts approved for DTE Electric includes full recovery of the costs for the battery storage

facilities within 15 years and also includes credit and collateral requirements to protect ratepayers from stranded costs. The approved large load tariff for Consumers Energy and the special contracts for DTE Electric include monthly minimum billing demand of 80% or higher, as well as exit fees for early termination from 15+ year contracts.

These six examples showcase the kinds of best practices that are rapidly evolving in front of state commissions, including, but not limited to: minimum term of service and exit fees, minimum billing demand, also known as take or pay terms, financial assurance requirements, capacity reassignment clauses, as well large load cost allocation terms. It is beneficial to all interested parties to allow the state commissions to continue creating these best practices that fit within their particular region and regulatory construct.

All these examples demonstrate that states can be nimble in addressing large load interconnection issues. By necessity, processes within RTOs, relying as they do on stakeholder consultation, are far less expeditious. So too with FERC, where proceedings under Section 206 of the Federal Power Act are not subject to the statutory deadlines faced by many state commissions. States are familiar with their specific challenges and regulatory landscapes, and can craft solutions without trying to develop generally applicable terms and conditions applicable nationally. Furthermore, changing the regulatory regime now will result in further uncertainty in the interconnection process and potentially unwind the state initiatives already put in place, such as those described above.

Finally, NARUC wishes to clarify that there is no regulatory gap with respect to state commissions' ability to appropriately allocate transmission costs, including the costs of network upgrades, to large load end-use customers. During the Federal-State Current Issues Collaborative at the Winter Policy Summit, the issue of a potential regulatory gap was mentioned or implied. While an information "gap" may exist with respect to the granularity of information being provided to state regulators from regional transmission organizations, state commissions clearly have the ability to perform cost of service studies and determine the cost allocation of transmission costs among retail ratepayers. State commissions will continue to coordinate with their regional entities and federal partners to close any existing information gaps that may exist, but no action in the ANOPR is necessary to enable state commission to cost-allocate transmission between end-use customers. Indeed, as noted in the discussion of Virginia SCC initiatives above, federal action on end-use transmission cost allocation may hinder state's abilities to ensure cost allocation among all customer classes is fair and reasonable.

NARUC appreciates your consideration of these supplemental comments. This continued collaboration between FERC and state commissions, as well as other stakeholders, is the fastest path forward to the parties' mutual goals to provide for the efficient interconnection of large loads while maintaining appropriate federal-state jurisdictional roles. Adhering to this generally well

understood delineation of responsibilities will help avoid unintended consumer consequences that could arise from a blurring of that line.

Sincerely,

Hon. Ann Rendahl
NARUC President
Commissioner, Washington Utilities & Transportation Commission

Tony Clark
Executive Director

May 12, 2026

The Honorable Bob Latta
Chairman
Subcommittee on Energy
House Committee on Energy and Commerce
United States House of Representatives
Washington, DC 20515

The Honorable Kathy Castor
Ranking Member
Subcommittee on Energy
House Committee on Energy and Commerce
United States House of Representatives
Washington, DC 20515

Dear Chairman Latta and Ranking Member Castor:

The National Rural Electric Cooperative Association (NRECA) appreciates the opportunity to submit this letter for the record of the May 13, 2026, House Energy and Commerce Committee's Energy Subcommittee hearing, "Wires, Rates, and States: Permitting Transmission for Reliable and Affordable Power." NRECA urges Congress to continue recognizing the vital role electric cooperatives play in providing safe, reliable, and affordable electricity - an ability that depends on balancing local decision-making with an appropriate level of limited federal oversight.

NRECA represents America's 900 not-for-profit, at-cost electric cooperatives. Co-ops are uniquely consumer-owned and consumer focused. Each distribution co-op is governed by a board made up entirely of the consumers it serves, and each generation and transmission (G&T) co-op is governed by its member distribution co-ops. This structure ensures that local control and consumer interests guide policies and decisions.

Co-ops provide electricity to one in eight Americans and support economic development for 42 million people across 56% of the nation's landmass. Unlike other segments of the electric sector, co-ops sell most of their power to residential consumers. In addition, one in four co-op households has an annual income below $35,000, and co-ops serve consumers in 92% of the nation's more than 300 persistent-poverty counties. As a result, keeping electricity affordable is especially critical for the rural and economically vulnerable communities co-ops serve.

NRECA supports Congressional efforts to streamline federal permitting and siting, reduce unnecessary regulatory barriers, and ensure timely, predictable decisions from federal agencies. In fact, streamlining the federal environmental permitting bureaucracy – like that imposed by the National Environmental Policy Act (NEPA) and Clean Water Act (CWA) – would be the most powerful stimulus for building new electric infrastructure for generation and transmission. However, transmission policy must continue to recognize that co-ops differ from other utilities - not only because they are not-for-profit, but also because they are primarily regulated at the state and local levels and are not subject to full Federal Energy Regulatory Commission (FERC) jurisdiction.

Current law reflects these differences by applying a "comparability" standard: co-ops must offer other utilities transmission service at rates, terms, and conditions comparable to those they provide themselves, in

exchange for nondiscriminatory access to other utilities' transmission systems. FERC oversees compliance with this standard, while co-ops retain authority to set their own rates, terms, and conditions locally.

Existing FERC regional transmission planning rules also respect this balanced approach by encouraging, rather than requiring, co-op participation. Many co-ops choose to participate voluntarily when doing so benefits the communities they serve. These structures balance the accountability and responsiveness that come with local decision-making while also providing an appropriate, limited level of federal oversight.

As Congress continues to consider legislation to incentivize buildout of the nation's electric grid, NRECA will evaluate those proposals based on these principles:

- Respect co-ops' unique governance structure by balancing local control with appropriate, limited federal oversight.
- Maintain the long-standing comparability framework rather than expanding FERC jurisdiction which will undermine local decision making and likely increase costs.
- Protect voluntary, not mandatory, participation in regional and inter-regional transmission planning.
- Streamline federal environmental permitting processes to incentivize construction of transmission and generation infrastructure.

NRECA looks forward to continuing to work with Congress to ensure that the unique structure of not-for-profit co-ops is recognized and that long-standing precedents for FERC oversight and voluntary participation in transmission planning are preserved. We strongly believe these principles can be maintained without compromising efforts to improve federal permitting processes.

Sincerely,

Louis Finkel
SVP, Government Relations
NRECA

Stands for American Steel.

Steel Manufacturers Association
1150 Connecticut Avenue, Suite 201
Washington, DC 20036

Brandon Farris
Executive Vice President

May 13, 2026

The Honorable Robert E. Latta
Chairman
Subcommittee on Energy
U.S. House of Representatives
Washington, DC 20515

The Honorable Kathy Castor
Ranking Member
Subcommittee on Energy
U.S. House of Representatives
Washington, DC 20515

Dear Chairman Latta and Ranking Member Castor:

The Steel Manufacturers Association appreciates the opportunity to provide a letter in response to the Subcommittee's hearing, "*Wires, Rates, and States: Permitting Transmission for Reliable and Affordable Power*."

SMA stands for American steel. Our members operate in communities across the country and range from the nation's largest publicly traded steel producers to single-facility, family-owned businesses. Steel manufacturers generate $149.4 billion in annual economic impact, employing 87,266 men and women in community-sustaining jobs at an average annual wage of $142,730. They create the essential material that underpins American industry and national security.

Steel manufacturers are investing in America's communities, deploying $25 billion in capital here in the U.S. to modernize, expand, and construct facilities. With this investment comes the need for affordable, reliable power. Each electric arc furnace steelmaker averages a load between 40 to 200 megawatts per mill, with electricity being one of the highest costs of steel production. With more than 100 mills nationwide, our industry is drawing up to 11 gigawatts at peak production across all facilities. The steel industry's power needs will only rise as significant expansion plans move forward.

The fact is the United States is entering an electricity crisis that will hinder efforts to reshore and grow our nation's manufacturing base. PJM Interconnection is a prime example. The region served by the largest power grid in the country is also home to more than 56,000 steel jobs and $94 billion in annual economic activity from our industry. In 2025, the market

saw wholesale electricity prices surge by a staggering 56 percent. And the pressure is building. The U.S. Energy Information Administration (EIA) projects a four percent increase in electricity demand through 2027, the largest four-year growth in more than 25 years. PJM is forecasting its summer demand to grow from 161,000MW to 241,000MW in the next 15 years, a 50 percent increase. Absent deployment of new generation and transmission in the region and elsewhere throughout the country, curtailment of steel production will increase.

SMA appreciates the Subcommittee's focus on expanding power generation and transmission; specifically, steel manufacturers encourage advancement of policies under review at this hearing to ease permitting requirements for new energy infrastructure. SMA also supports efforts to protect ratepayers from rising electricity bills, and we urge subcommittee members to avoid policies that preference certain materials in energy projects, which will only serve to raise project costs through government interference in engineering decisions.

Steel manufacturers are committed to working with Congress and the Trump Administration to grow American energy, for the benefit of our communities and our country's industrial resurgence. Thank you for holding this important hearing.

Sincerely,

Brandon Farris
Executive Vice President
Steel Manufacturers Association

FEDERAL ENERGY REGULATORY COMMISSION
Office of Chairman Mark C. Christie

August 5, 2025

Hon. Brett Guthrie
Chairman
Committee on Energy and Commerce
U.S. House of Representatives
Washington, D.C. 20515

Re: NERC's Interregional Transmission Transfer Capability Study

Dear Chairman Guthrie:

Pursuant to Section 322 of the Fiscal Responsibility Act of 2023, Pub. L. No. 118-5, § 322 (2023) ("Act"), the North American Electric Reliability Corporation ("NERC") was directed to conduct a study on interregional transmission. On November 19, 2024, NERC submitted to the Federal Energy Regulatory Commission ("FERC" or "the Commission"), in FERC Docket No. AD25-4-000, its findings, labeled the "Interregional Transfer Capability Study" (ITCS).

Under the congressional directive, FERC is to submit both the ITCS Final Report along with any findings or recommendations for legislation that FERC may also wish to provide no later than February 25, 2026 (one full year from the end of the public comment period on the ITCS).

Because February 25, 2026 is a long way away, and this issue has been one of intense interest in the Congress and elsewhere, I am making a preliminary submission to Congress today that includes the Final ITCS from NERC,[1] along with NERC's November 19, 2024 transmittal letter to FERC, which summarized the ITCS and accompanied its submission.

While making no recommendations for legislative action, I am providing what I regard as the key takeaway and finding from the NERC Final ITCS:

The study does not provide support for a mandated minimum amount of interregional transmission, but rather finds that individual projects should be evaluated based on their specific facts for their beneficial contribution to reliability and prudence in financial terms.

As NERC explains, the ITCS is a unique assessment centered on reliability. The ITCS analyzes the amount of energy that can be moved or transferred reliably from one area to another area of the interconnected transmission systems. This transfer capability is a measure of the system's ability to address energy deficiencies by relying on resources in neighboring regions and is a key component of a reliable and resilient Bulk Power System. The ITCS provides a roadmap for understanding where it may be beneficial to enhance transmission to support a reliable future grid, without mandating specific projects or a minimum level of transfer capability.

[1] The ITCS Final Report can be accessed on NERC's website: https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf.

Below are some of the ITCS's other key findings:

- Transfer capability varies seasonally and under different system conditions that limit transmission loading – it cannot be represented by a single number.

- Transfer capability varies widely across North America, with total import capability varying between 1% and 92% of peak load.

- Reliability risks are highly dependent on regional conditions. The import capability needed during extreme conditions varied significantly across the country, indicating that a one-size-fits-all requirement may be ineffective. An additional 35 GW of transfer capability is recommended across the United States as a vehicle to strengthen energy adequacy under extreme conditions.

- The importance of maintaining sufficient generating resources underpins the study's assumptions. Higher than expected retirements (without replacement capacity) would lead to increased energy deficiencies and potentially more transfer capability needed than recommended in this study (if surplus energy is available from neighbors).

- The ITCS provides foundational insights for further study, discussion, and decisions. Transmission upgrades alone will not fully address all risks, and a broader set of solutions should be considered, emphasizing the need for local resources, energy efficiency, demand-side, and storage solutions. A diverse and flexible approach allows solutions tailored to each Transmission Planning Region's (TPR) vulnerabilities, risk tolerance, economics, and policies.

Pursuant to the Act, on December 27, 2024, FERC published the ITCS in the *Federal Register* for public comment, with a deadline of February 25, 2025, and FERC or FERC staff will submit a final report with its conclusions and any recommendations to Congress by February 25, 2026.

Sincerely,

Mark C. Christie
Chairman

Enclosure: NERC's Nov. 19, 2024, Transmittal Letter in FERC Docket No. AD25-4-000

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _____**

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION INTERREGIONAL TRANSFER CAPABILITY STUDY AS DIRECTED IN THE FISCAL RESPONSIBILITY ACT OF 2023

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November 19, 2024

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION INTERREGIONAL TRANSFER CAPABILITY STUDY AS DIRECTED IN THE FISCAL RESPONSIBILITY ACT OF 2023

The North American Electric Reliability Corporation ("NERC") respectfully submits the Interregional Transfer Capability Study ("ITCS" or "Study") directed by the United States ("U.S.") Congress in the Fiscal Responsibility Act of 2023 ("Fiscal Responsibility Act") for Federal Energy Regulatory Commission consideration.[1] The ITCS was prepared by NERC as the Electric Reliability Organization ("ERO")[2] in consultation with NERC's six Regional Entities (together with NERC, the "ERO Enterprise")[3] and transmitting utilities.

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[1] Fiscal Responsibility Act , H.R. 3746 (2023) [hereinafter Fiscal Responsibility Act]. *See* Section 322 of the Fiscal Responsibility Act (providing, "The Electric Reliability Organization …in consultation with each regional entity… and each transmitting utility (as that term is defined in section 3(23) of such Act) that has facilities interconnected with a transmitting utility in a neighboring transmission planning region, shall conduct a study of total transfer capability as defined in section 37.6(b)(1)(vi) of title 18, Code of Federal Regulations, between transmission planning regions that contains the following:

(1) Current total transfer capability, between each pair of neighboring transmission planning regions.
(2) A recommendation of prudent additions to total transfer capability between each pair of neighboring transmission planning regions that would demonstrably strengthen reliability within and among such neighboring transmission planning regions.
(3) Recommendations to meet and maintain total transfer capability together with such recommended prudent additions to total transfer capability between each pair of neighboring transmission planning regions.").

[2] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006) [hereinafter Order No. 672]. NERC was certified by the Commission as the ERO, pursuant to § 215(c) of the Federal Power Act ("FPA"), by Commission order issued July 20, 2006. *Order Certifying the North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006) [hereinafter NERC ERO Certification Order].

[3] The Regional Entities are (i) Midwest Reliability Organization ("MRO"); (ii) Northeast Power Coordinating Council, Inc. ("NPCC"); (iii) ReliabilityFirst Corporation ("ReliabilityFirst"); (iv) SERC Reliability Corporation ("SERC"); (v) Texas Reliability Entity, Inc. ("Texas RE"); and (vi) Western Electricity Coordinating Council ("WECC"). Please note, unless otherwise defined herein, all capitalized terms should be assigned the meanings reflected in the NERC Glossary posted on NERC's website.

Over the past 15 months, NERC has developed the attached ITCS (**Appendix A**) in consultation with stakeholders to provide:

(i) Current total transfer capability ("TTC" or "transfer capability") between each pair of neighboring transmission planning regions in the U.S.;[4]

(ii) Recommendations for technically prudent additions to TTC between pairs of neighboring transmission planning regions where these additions would demonstrably strengthen reliability;[5]

(iii) Recommendations on how to meet and maintain TTC now and as enhanced in response to the ITCS findings.

As stated herein and detailed in the attached materials, the ITCS is the first-of-its-kind assessment of transmission transfer capability under a common set of assumptions.[6] Transmission assessments, like the ITCS, are crucial to mitigating future risks to Bulk Power System ("BPS") reliability, although other approaches beyond transmission (such as local generation or demand-side solutions) can also mitigate future energy risks. The ITCS focuses on transfer capability in accordance with the congressional directive, while acknowledging that other processes and pending projects may help support a reliable future grid. The ITCS is not designed to be a transmission plan or blueprint.

The ITCS demonstrates that sufficient transfer capability and resources exist at present to maintain energy adequacy under most scenarios. As discussed below and in the attached ITCS, however, when calculating current transfer capability and projected future conditions,[7] the ITCS

[4] In addition, results that include transfer capabilities between the U.S. to Canada and between Canadian provinces is planned for the first quarter of 2025. While evaluating Canada is outside the specific congressional mandate, the interconnectedness of the North American BPS warrants analysis of Canada.

[5] Prudence means whether the recommendations are the type that a reasonable entity would make in good faith under the same circumstances, and at the relevant point in time. *See infra* Section II.b. The ITCS is not an evaluation of economics, siting, or environmental impacts.

[6] Transfer capability or "TTC" is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission system by way of all transmission lines (or paths) between those areas under specified system conditions. 18 C.F.R. § 37.6(b)(1)(vi).

[7] Via an energy margin analysis that uses a ten-year forward-looking case that accounts for extreme weather, resources, and demand growth as described below and detailed in Appendix A.

identifies potential energy inadequacy across several transmission planning regions in the event of extreme weather. This finding confirms congressional and electric industry concerns that North American transmission infrastructure may become insufficient to maintain energy adequacy when considering the changing resource mix, extreme weather events, and increasing demand. Therefore, using the assumptions underlying the analysis, the ITCS recommends an increase of 35 GW of transfer capability across different regions as technically prudent additions to demonstrably strengthen reliability. The ITCS bases its analysis of prudence and the extent to which recommendations would demonstrably strengthen reliability according to the anticipated impact of the recommendations on BPS reliability in terms of energy adequacy. Further, the ITCS recommends region-specific enhancements to transfer capability, because a one-size-fits all approach across the U.S. may be inefficient and ineffective.

The ITCS is an essential element of the continuing transmission discussion in North America. The ITCS demonstrates a significant opportunity to improve the use of surplus resources when they are available during extreme weather events and shows how interregional transmission can maximize the use of local resources, including storage and demand response. Further, it highlights the continuing importance of integrated transmission and resource planning, as increasing transfer capability without surplus available energy would be inefficient. NERC looks forward to the Commission's proceeding to examine the ITCS, opportunities identified therein, and stakeholder comments in anticipation of the Commission's report to U.S. Congress.

I. EXECUTIVE SUMMARY

The Bulk Power System is a complex grid that has evolved over the past several decades to include an integrated network of generation, transmission, and distribution across vast geographic areas. NERC is focused on assuring the reliability of the BPS throughout the ongoing North American energy transformation. As the grid modernizes, governmental authorities and the electric industry are rising to the challenge to ensure that continued reliability accompanies that growth.

On June 3, 2023, the President signed into law the Fiscal Responsibility Act in which Congress (as part of measures associated with the debt ceiling) required NERC to conduct an assessment by December 2, 2024 of the total transfer capability between transmission planning regions.[8] The resulting ITCS analyzes the amount of energy that can be moved or transferred reliably from one area to another area of the interconnected transmission systems. This transfer capability is a measure of the system's ability to address energy deficiencies by relying on resources in neighboring regions and is a key component of a reliable and resilient BPS. Recent and continuing resource mix changes require greater access and deliverability of resources between neighboring systems to maintain reliability, particularly during widespread, extreme weather conditions.

Ensuring a transmission system with sufficient transfer capability between transmission planning regions is important to support energy adequacy. In the interest of public health, safety, and security, the electric industry must continue advancing improved planning to support reliable energy supplies under an evolving grid with more frequent extreme weather conditions. As a result of the changing resource mix and extreme weather, interregional energy transfers play an

[8] *Supra* note 1.

increasingly pivotal role.[9] NERC assessments and experiences during recent events, such as the Western Interconnection Heatwaves of 2020 and 2022, Winter Storm Uri in 2021, and Winter Storm Elliott in 2022, demonstrate that action is warranted to support energy adequacy going forward. More transfer capability and a carefully planned resource mix are desirable to address these identified challenges (such as extreme weather, existing resource retirements,[10] and natural gas reliance), as well as the ongoing electrification of the economy with its growing transportation sector, industrial loads, and data centers. The ITCS is an integral part of that discourse by providing an independent, reliability-focused assessment of the extent of transfer capability across the transmission system and opportunities to harness that potential as we collectively prepare for the future.

In the first part of the ITCS, NERC calculates current transfer capability in a manner that combines base transfer levels together with first contingency incremental transfer capability for each of the winter and summer seasons, (*see infra* Section II.a.). Based on these calculations, NERC determines that transfer capability varies widely across North America with import capability anywhere between 1% to 92% of the associated peak loads. The ITCS shows that transfer capability varies seasonally, regionally, and under different system conditions. The ITCS also generally finds lower transfer capability in the Mountain States, Great Plains, Southwest, and Northeast, with greater capability in the West Coast, Great Lakes, and Mid-Atlantic areas. The magnitude of transfer capability is not itself a measure of energy adequacy, however, these findings informed the second part of the ITCS.

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[9] An explanation of the grid can be found on the U.S. Energy Information Administration website. U.S. Energy Information Administration, *Electricity Explained* (Mar. 26, 2024), https://www.eia.gov/energyexplained/electricity/ (including detailed subtopics under "Also in Electricity Explained").

[10] *See* Appendix A, ITCS at p. 1 and Chapter 11 (summarizing ITCS limitations and potential further considerations).

The second part of the ITCS contains an energy margin analysis that enabled NERC to identify whether a particular transmission planning region would be at risk for energy inadequacy considering the calculated TTCs and extreme weather events. The ITCS characterizes this risk for energy inadequacy as a "deficiency." In each scenario where the ITCS identifies a deficiency in a transmission planning region, NERC further applied a six-step process to examine the extent to which additional transfer capability could mitigate that deficiency and thereby demonstrably strengthen reliability.[11] The Part 1 TTC calculation (which includes simultaneous import capability analysis) together with the Part 2 prudent additions analysis (which includes energy margin analysis of past weather events applied to the projected resource mix and demand) ensure the reasonableness and therefore prudence of ITCS recommended additions to transfer capability. The last part of the ITCS provides recommendations to meet and maintain transfer capability. The resulting recommendations identify directional (rather than prescriptive) guidance for policymakers and industry. The ITCS provides a roadmap for understanding where it may be beneficial to enhance transmission to support a reliable future grid, without mandating specific projects or a minimum level of transfer capability.

The ITCS is a unique assessment centered on reliability. Transmission planners, regional transmission organizations/independent system operators ("RTOs/ISOs"), and policymakers might consider other factors such as economics, environmental effects, and broader policy objectives when deciding which solutions to implement to address reliability issues. Different markets, RTOs/ISOs, or regions of the U.S. may have different approaches to evaluate transfer capability and prudent additions thereto. The ITCS, for example, in some instances subdivided RTO/ISO and Commission Order No. 1000 areas to avoid masking issues between neighboring

[11] The energy margin analysis (which identified the deficiencies) constitutes steps 1 and 2 of the 6-step process.

transmitting utilities within the scope of the Congressional directive. The ERO Enterprise approach was specifically designed to evaluate TTC and potential prudent additions to transfer capability that would demonstrably strengthen reliability without regard to specific market structures, economic considerations, or policy matters in the expectation that the Commission, U.S. Congress, States, and industry will use NERC's ITCS as part of this broader evaluation.

Based on the analysis in Part 2 of the ITCS, NERC identifies that in the present year, there are relatively few deficiencies across transmission planning regions. As a result, the ITCS suggests that existing infrastructure is generally sufficient at this time to maintain energy adequacy under most scenarios (barring severe conditions such as limitations on gas generation performance during cold weather and natural gas production and transportation challenges for electric generators). This conclusion also establishes 2024 as a useful reference point for future comparisons.

Nevertheless, when examining the ten-year forward-looking case that accounts for the future resource mix and forecasted load, energy inadequacy was identified across almost half of the studied transmission planning regions.[12] This confirms congressional and electric industry concern that, given the changing resource mix, extreme weather, and anticipated demand, transmission infrastructure may place a strain on energy adequacy in the future. As a result, based on calculated deficiencies and the broader six-step approach to identify prudent additions to demonstrably strengthen reliability, the ITCS recommends 35 GW of additional transfer capability across different areas of the U.S. As discussed in Section II.b. below, transmission planning regions across North America would benefit from increased transfer capability. Since the needed import capability, as analyzed, varied significantly across the U.S., a one-size fits all requirement

[12] Specifically, 11 out of 23 transmission planning regions.

or approach to additional transfer capability is expected to be inefficient and ineffective. The increased transfer capability recommended in the ITCS, in addition to other measures outside of its scope, such as resource adequacy and fuel assurance, would demonstrably improve energy adequacy under reasonably anticipated extreme conditions.[13]

Part 3 of the ITCS also provides recommendations how to meet and maintain transfer capability. *See infra* Section II.c. These recommendations should be taken, together with remainder of the ITCS, as foundational insights for further discussions and decisions on regulatory and legislative solutions. Planners, for example, should consider conditions impacting their systems and those of neighboring transmitting utilities while also considering resource adequacy.[14] The ITCS also does not evaluate particular projects. Rather, under a holistic approach, the Study recommends how much additional transfer capability at each interface would strengthen the grid.

I. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to:

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[13] NERC highlights that transmission and TTC are part of a more expansive equation underlying energy adequacy in a modern grid, which includes matters such as available generation. The ITCS relies, for example, on future resource assumptions. If these change it could impact the energy margin analysis underlying the Part 2 analysis.

[14] Please see the ITCS for discussion of additional factors that stakeholders may analyze.

I. INTRODUCTION TO NERC AND THE ERO ENTERPRISE

Electricity is a key component of the fabric of modern society. NERC's mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. The vision of the ERO Enterprise is a highly reliable and secure North American BPS. The Regional Entities help NERC support reliability across various interconnections with differing needs and characteristics.[15]

When Congress enacted the Energy Policy Act of 2005[16] and section 215 of the Federal Power Act, it entrusted the Commission with: (i) approving and enforcing rules to ensure the reliability of the BPS; and (ii) certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval, and with assessing reliability and adequacy of the BPS in North America.[17] Section 215 and Commission regulation reflect certification of an ERO subject to Commission oversight.[18] In 2006, the Commission certified NERC as the ERO.[19]

Consistent with NERC's responsibility to "conduct periodic assessments of the reliability and adequacy of the bulk-power system in North America"[20] such as NERC's Long-Term

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15 NERC's relationship with the Regional Entities is governed by Regional Delegation Agreements or "RDAs" filed with the Commission every five years. 18 C.F.R. § 39.8. A delegation agreement shall not be effective until it is approved by the Commission. *See also*, *N. Am. Elec. Reliability Corp.*, 133 FERC ¶ 61,061 (2010), *order denying reh'g*, 134 FERC ¶ 61,179 (2011), *order on compliance filing*, 137 FERC ¶ 61,028 (2011). *N. Am. Elec. Reliability Corp.*, 153 FERC ¶ 61,135 (2015) (approving pro forma and individual RDAs, subject to compliance filing) and *N. Am. Elec. Reliability Corp.*, Docket No. RR15-12-001 (Mar. 23, 2016) (delegated letter order) (accepting final pro forma and individual RDAs) (collectively "2015 RDA Order"); and Order Conditionally Approving Revised *Pro Forma* Delegation Agreement and Revised Delegation Agreements with Regional Entities, 173 FERC ¶ 61,277 (2020).

16 Pub. L. 109–58, title XII, § 1211(b), Aug. 8, 2005, 119 Stat. 946.

17 16 U.S.C. § 824o(a)(2). *See also* § 824o(c) (providing the ERO certification criteria). *See also* Pub. L. 109–58, title XII, §1211(b), Aug. 8, 2005, 119 Stat. 946 (clarifying, "[t]he Electric Reliability Organization… and any regional entity delegated enforcement authority… are not departments, agencies, or instrumentalities of the United States Government.").

18 Order No. 672 at PP 183-191.

19 *See* NERC ERO Certification Order.

20 16 U.S.C. § 824o(g).

Reliability Assessment ("LTRA"), Summer Assessment, Winter Assessment, and special assessments, the Fiscal Responsibility Act tasked NERC with preparing the ITCS in consultation with the Regional Entities and transmitting utilities.

II. OVERVIEW OF THE INTERREGIONAL TRANFER CAPABILITY STUDY

The Fiscal Responsibility Act requires the ERO, in consultation with the Regional Entities and transmitting utilities with facilities neighboring another in a neighboring transmission planning region (referred to generally as "neighboring transmitting utilities"), to conduct a study of total transfer capability (also known as "TTC") between transmission planning regions that contains:

(1) Current total transfer capability between each pair of neighboring transmission planning regions.

(2) A recommendation of prudent additions to total transfer capability between each pair of neighboring transmission planning regions that would demonstrably strengthen reliability within and among such neighboring transmission planning regions.

(3) Recommendations to meet and maintain total transfer capability together with such recommended prudent additions to total transfer capability between each pair of neighboring transmission planning regions.[21]

Consistent with NERC's collaborative process and congressional directive, the ITCS was prepared over a 15-month period with significant stakeholder engagement, as discussed in Section III below and reflected in Appendices B through D. The ITCS examined current TTC as Part 1 of the analysis. Part 2 of the Study completed an energy margin analysis that compared TTC against 12 weather years (including extreme weather) to identify transmission planning region energy deficiencies that warrant prudent additions to TTC to demonstrably strengthen reliability.[22] As Part 3 of the ITCS, the ITCS recommended methods to meet and maintain current TTC and

[21] *Supra* note 1.

[22] The 12 weather years to ensure the ITCS examined extreme weather were selected from 2007-2023 and are non-contiguous.

enhanced TTC. These recommendations interpreted the ITCS as part of the broader discourse between the Commission, U.S. Congress, States, other policymakers, and the electric industry to leverage the ITCS findings along with more specific regional, policy, market, economic, and environmental considerations. Finally, the ERO Enterprise plans to continue regular assessments of transfer capability that will consider the latest developments in resource mixes, transmission infrastructure, new load projections, and changing weather and climate patterns.

a. Calculating Current Total Transfer Capability

In accordance with the Fiscal Responsibility Act, the fundamental question of the ITCS is the ability of the BPS to support transfers of energy between transmission planning regions when needed to ensure adequate energy to meet demand. The first required component of the ITCS is calculating current transfer capability, or TTC, between pairs of neighboring transmission planning regions.[23]

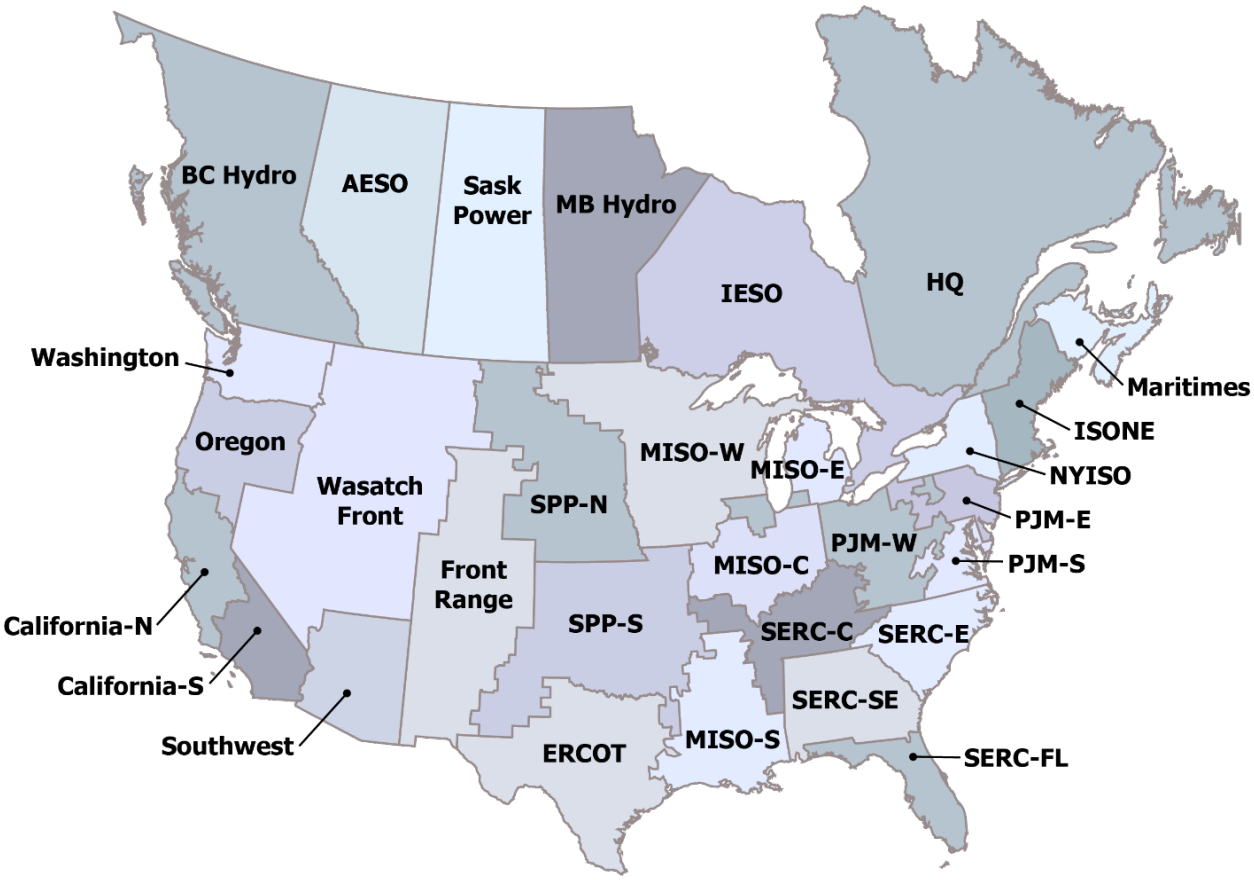
To calculate TTC, the ITCS study team, comprised of ERO Enterprise staff and consultants, first determined appropriate transmission planning regions for purposes of the Study after coordinating with the ITCS Advisory Group. To establish transmission planning regions for purposes of the Study, NERC, working with the Regional Entities, selected a set of interfaces that included all pairs of neighboring transmission planning regions to enable the ITCS performance of transfer analysis from source (exporting) region to sink (importing), and vice versa. Only electrically connected neighboring systems were evaluated to identify the transmission planning regions for purposes of Part 1 of the ITCS.[24] The ITCS regions were smaller than the Commission's Order No. 1000 regions and those that RTOs/ISOs might use to provide a more

[23] *Supra* note 1.

[24] Some geographic neighbors that were not electrically connected were evaluated as potential new connections in Part 2 of the ITCS as NERC evaluated potential recommendations to enhance transfer capability.

granular analysis of potential TTC limitations and to enable the ITCS to identify key constraints to interregional TTC.

As reflected in NERC's August 2024 posted materials, the transmission planning regions were established as follows:



After the identification of transmission planning regions, the ITCS calculated TTC according to the following steps:[25]

i) Select base cases using relevant Eastern Interconnection and Western Interconnection base cases created through Reliability Standard MOD-032-1 processes;[26]

[25] *See* ITCS Appendix A (providing detailed explanation on the Study and its design).

[26] Base cases are computer models that simulate the behavior of the electrical system under various conditions as a snapshot in time. Base cases were not required for ERCOT and Québec Interconnections for purposes of the ITCS as they were only tied with the Eastern Interconnection via dc ties. Also, small ERCOT dc ties to Mexico were omitted from evaluation and the ERCOT-Mexico interface was outside the scope of the document.

ii) Calculate TTC using Area Interchange method as the sum of base transfer levels together with first contingency incremental transfer capability;[27]

iii) Adjust for facility monitoring criteria and thresholds to prevent undue limitation of transfer capability results based on heavily loaded, electrically distant elements to avoid the appearance of artificially constrained TTC;

iv) Ensure special interface considerations (such as pertinent remedial action schemes) are understood and properly reflected in study results; and

v) Analyze total import capabilities of each transmission planning region (although not required under the Fiscal Responsibility Act) as technically requisite to appropriately model system capability for purposes of the Part 2 analysis of any prudent enhancements to TTC.

This analysis identified current TTC as illustrated in the maps discussed in more detail in the ITCS at Appendix A. These TTC results are highly dependent on the base cases and modeling assumptions described in the ITCS. The ITCS did not attempt to optimize dispatch or topology to maximize TTC, just as it also was designed to avoid underestimating TTC. The ITCS used the steps highlighted above to avoid the appearance of artificially constrained TTC.[28]

The ITCS found that transfer capability varies seasonally and under different system conditions that limit transmission loading so that it cannot be represented by a single number. Transfer capability also varies widely across North America, with total import capability between 1% and 92% of peak load. Transfer capabilities were observed as generally higher in the West Coast, Great Lakes, and mid-Atlantic areas, while relatively lower in the Mountain States, Great Plains, Southeast, and the Northeast regions. In addition, the ITCS found limited transfer capability between Interconnections (Western Interconnection, Eastern Interconnection, ERCOT Interconnection ("ERCOT"), and Québec). As NERC discussed these Part 1 results with industry during the Summer of 2024, it explained that the findings suggested that Part 2 analysis would

[27] Contingencies were based on NERC Reliability Standard TPL-001-5.1 category P1 contingencies (100 kV and above).

[28] As this is a study, observed TTC may differ from the conclusions in the ITCS based on operational conditions.

probably identify prudent additions to TTC to strengthen reliability. NERC underscored that the magnitude of transfer capability is not itself a measure of energy adequacy. Rather, the identified TTC provides the foundation for subsequent energy margin analysis in Part 2 of the ITCS.

b. Identifying Prudent Additions to Transfer Capability to Demonstrably Strengthen Reliability

The Fiscal Responsibility Act requires NERC to consider and recommend prudent additions to TTC "between each pair of neighboring transmission planning regions that would demonstrably strengthen reliability within and among such neighboring transmission planning regions."[29] For the purposes of determining a "prudent addition," NERC looked to the standard used in Commission precedent in electric utility ratemaking proceedings, which provides that "prudence" means a determination of whether (1) a reasonable entity (2) would have made the same decision, (3) in good faith, (4) under the same circumstances, and (5) at the relevant point in time.

Determining exactly how much additional transfer capability is "prudent" can depend on the totality of factors and circumstances. For example, as part of examining the totality of circumstances, the Commission has considered matters such as whether activities have enhanced the ability to restore service, achieved significant efficiencies, reduced costs or time delays, and/or made efficient use of resources to ensure reliability.[30] As discussed immediately below, NERC applied a six-step process to ensure that the ITCS's tailored recommendations for prudent additions to transfer capability for certain pairs of neighboring transmission planning regions are those that a reasonable entity would have made in good faith under the same circumstances and at the same point in time considering reliability of the system as the driving factor.

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[29] *Supra* note 1.

[30] *See, e.g.*, *New England Power Co.,* 31 FERC ¶ 61,047 at 61,084 (1985); and *Potomac-Appalachian Transmission Highline, LLC*, 140 FERC ¶ 61,229 at P 82 (Sept. 20, 2012).

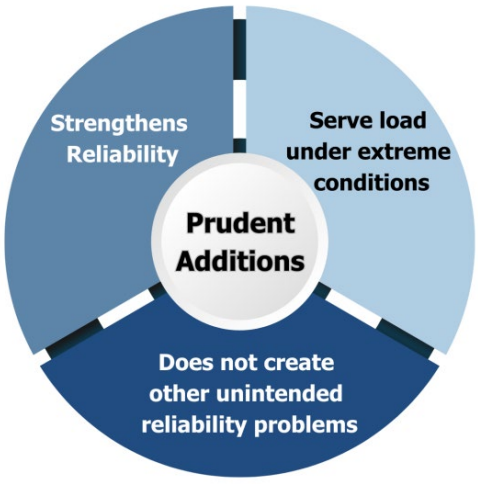
NERC underscores that nothing in the ITCS should be used as justification for a particular project and that no part of the ITCS is intended as evidence regarding prudence in any ratemaking proceeding. The ITCS does not include economic assessments, project-specific recommendations, transmission expansion analysis, operational mitigation or capacity expansion planning. A holistic view of the BPS and a thorough understanding of its behavior will be essential when calculating or increasing transfer capability.

The ITCS particularly examined the extent to which recommended enhancements would be reasonably expected to demonstrably strengthen reliability of the BPS. To do so, the ITCS examined whether the potential recommendation would strengthen reliability, serve load under extreme conditions, and avoid creating unintended reliability concerns as follows:

(1) **Strengthen Reliability:** Provides a potential solution that enables more flexibility between transmission planning regions and access to resources that may be available during local energy deficits.

(2) **Serve Load Under Extreme Conditions:** Provides a solution that serves future demand during extreme conditions, which is a more restrictive design basis than current resource adequacy constructs.

(3) **Does Not Create Unintended Reliability Concerns:** Recommendations for larger connections between transmission planning regions will require detailed system studies to assure system stability.



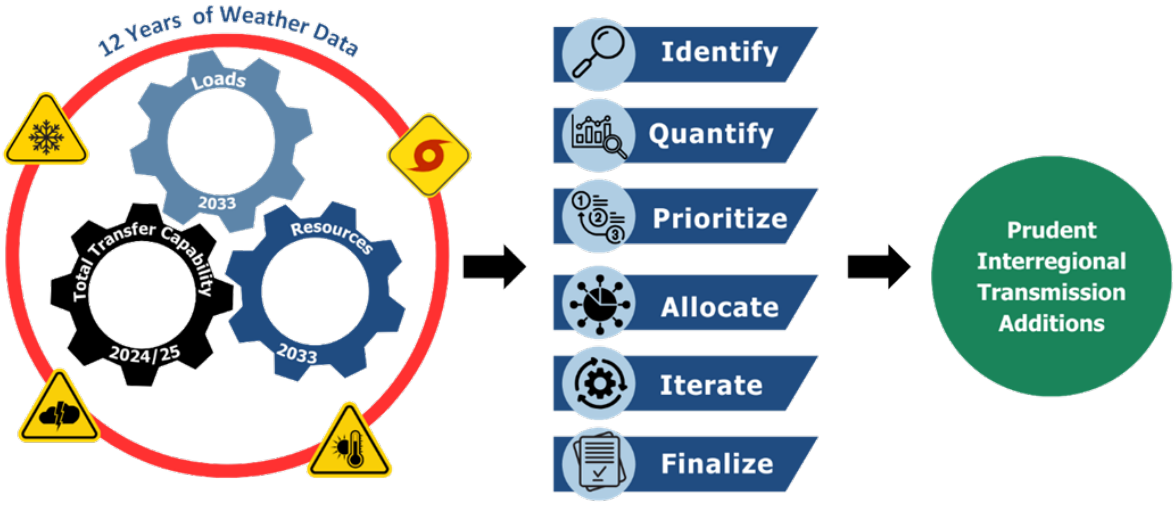
Under Part 2 of the ITCS, the ITCS conducted energy margin analysis of resource availability and interregional transfers across 12-years of meteorological conditions and extreme weather data to examine whether the transfer capability calculated for a pair of neighboring transmission planning regions would be unable to meet energy needs under times of stress, being thus "deficient" and reflecting a risk of energy inadequacy for those regions.

As a result, where the ITCS energy margin analysis found a deficiency and corresponding risk, NERC led a further layer of study that applied several considerations and criteria under a six-step process to evaluate whether, and how much, additional transfer capability would mitigate the potential risk of energy inadequacy created by the deficiency.

The six-step process entails the following and is discussed in detail in Chapter 6 of the ITCS at Appendix A:

i. Identify hours of resource deficiency
ii. Quantify the maximum resource deficiency
iii. Prioritize constrained interfaces
iv. Allocate additional transfer capability
v. Iterate until resource deficiencies are mitigated
vi. Finalize prudent level of transfer capability

A diagram of the analysis will help explain further:



The ITCS recommended prudent additions to transfer capability to the extent that results reflected that enhanced transfer capability would assuage the risk of energy inadequacy (as reflected by the deficiencies shown after energy margin analysis).

In total, across various regions of the U.S., the ITCS recommends 35 GW of additional transfer capability to demonstrably strengthen reliability. These recommendations are detailed in the ITCS at Appendix A and break down according to the following table **Table ES.1**:[31]

[31] In two cases, it was not possible to eliminate all energy deficiencies, even by increasing transfer capability, due to wide-area resource shortages. In ERCOT and California North, resource deficiencies remained even after increasing transfer capability by 14 GW and 1 GW, respectively.

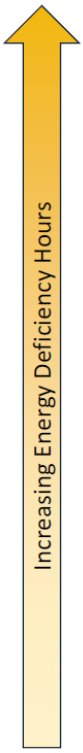


Table ES.1: Recommended Prudent Additions Detail

Transmission Planning Region	Weather Years (WY) / Events	Resource Deficiency Hours	Maximum Deficiency (MW)	Additional Transfer Capability (MW)	Interface Additions (MW)
ERCOT	Winter Storm Uri (WY2021) and nine other events	135	18,926	14,100	Front Range (5,700) MISO-S (4,300) SPP-S (4,100)
MISO-E	WY2020 Heat Wave and two other events	58	5,715	3,000	MISO-W (2,000) PJM-W (1,000)
New York	WY2023 Heat Wave and seven other events	52	3,729	3,700	PJM-E (1,800) Québec (1,900)
SPP-S	Winter Storm Uri (WY2021)	34	4,137	3,700	Front Range (1,200) ERCOT (800) MISO-W (1,700)
PJM-S	Winter Storm Elliott (WY2022)	20	4,147	2,800	PJM-E (2,800)
California North	WY2022 Heat Wave	17	3,211	1,100	Wasatch Front (1,100)
SERC-E	Winter Storm Elliott (WY2022)	9	5,849	4,100	SERC-C (300) SERC-SE (2,200) PJM-W (1,600)
SERC-Florida	Summer WY2009 and Winter WY2010	6	1,152	1,200	SERC-SE (1,200)
New England	WY2012 Heat Wave and two other events	5	984	700	Québec (400) Maritimes (300)
MISO-S	WY2009 and WY2011 summer events	4	629	600	ERCOT (300) SERC-SE (300)
TOTAL				**35,000**	

In making these recommendations, NERC acknowledges that transfer capability is only one part of the overall equation and that other elements such as generation resource availability, new load projections, additional weather information, and demand response should also be taken into account.[32] Moreover, these recommendations do not account for economic, environmental, permitting or policy considerations that the Commission, U.S. Congress, other policymakers, and the electric industry may apply following the ITCS.

[32] Please see NERC's website for more information regarding these issues. *See also*, ITCS, Appendix A, Chapter 11 (providing further considerations). NERC has focused the ITCS on transfer capability in accordance with Congressional directive.

c. Recommendations to Meet and Maintain Sufficient Transfer Capability

The final requirement of the Fiscal Responsibility Act of 2023 is to develop recommendations to meet and maintain transfer capability together with recommended prudent additions.[33] The ITCS provided recommendations to support transfer capability in the future without specifying a particular set of projects or approach. This recognizes that increased transfer capability is one of many options for addressing the identified energy deficiencies. Such options at a high level include:

- Increase transfer capability to neighbors with surplus resources
- Construct local generation
- Increase demand response resources
- Accept the identified risks during extreme events (assuming other reliability thresholds are met).

Timing for these approaches may vary, so further studies are needed for implementation. Grid operators must also be prepared to maintain BPS reliability through emergency measures (including rotating outages if necessary) meanwhile.

If planners elect to increase transfer capability to meet the recommendations listed in the ITCS, options to consider include:

- **Upgraded transmission infrastructure**: Such as building new lines and reconductoring existing lines or raising existing tower structures where feasible.
- **Remedial action schemes ("RAS")**: Increasing transfer capability via adjustments to RAS may be helpful in the short-term while other solutions are implemented. RAS are not advised as a long-term solution as these schemes introduce higher operational complexity.
- **Dynamic line ratings ("DLR")**: DLR could use real-time and forecasted weather conditions to continuously calculate the thermal capacity of transmission lines and

[33] *Supra* note 1.

may at times facilitate increased transfer capability during favorable weather conditions. However, DLR may not be suitable in all situations.

- **Power flow control devices**: Power flow control devices with newer digital control technology that allows for faster responses to system needs may help support transfer capability and enhance the transmission planning process.

With regard to maintaining transfer capability, the ITCS explained that actual transfer capability available during real-time operations may be different from that calculated due to system conditions during actual operations. A certain level of transfer capability cannot always be maintained due to those changing system conditions and, therefore, the ITCS focused on what can be accomplished during the planning horizon. These recommendations to maintain transfer capability include:

- **Coordination Agreements**: Strong coordination procedures and agreements can maximize available support during stress conditions (such as extreme weather events). This coordination could include rigorous maintenance activities and coordinated maintenance to avoid overlapping with periods of increased stress.

- **Future Studies**:

  - **ERO Enterprise Studies**: The ERO Enterprise, working with industry, is planning to conduct regular assessments rolled into future Long-Term Reliability Assessment reports that will consider developments in this area. NERC is also considering the issues as part of its Energy Assessment Strategy.

  - **Planning / Maintenance**: Planners can evaluate changes in transfer capability as part of regular processes.

- **Regulatory and Policy Mechanisms**:

  - The ITCS noted that a uniform minimum transfer capability requirement may not be an effective or efficient approach to ensure energy adequacy.

  - The ITCS recommended that policy makers consider mechanisms to address existing challenges associated with siting/permit approvals, cost-allocation, and multi-party operating and maintenance agreements.

- **Reliability Standards**:

- The ITCS clarified that it is not NERC's intent to develop Reliability Standard modifications to require entities to meet and maintain a certain transfer capability, without prejudice to NERC's consideration of modifications in the future of matters such as assessments associated with planned transfer capability.

- NERC has two standard development projects (Project 2022-03 Energy Assurance with Energy-Constrained Resources and 2024-02 Planning Energy Assurance) related to energy assurance and the assessment of energy adequacy.

System studies are urged to ensure careful deployment of ITCS recommendations. To give these recommendations meaning, transmission planners and planning coordinators will need detailed studies to select projects or actions that take advantage of the opportunity identified in the ITCS without inadvertent consequences. The ITCS explained limitations on its scope as well as steps that stakeholders could take to further build on the opportunities identified therein.[34] As highlighted throughout the ITCS and this filing, the ITCS is intended as a launch-pad to further North America's efforts to plan infrastructure and coordination that supports a modern grid.

NERC urges policymakers and industry to carefully consider how to leverage the recommended additions to transfer capability outlined in the ITCS. As mentioned above, the recommendations identify directional, rather than prescriptive, guidance. The ITCS provides a roadmap for understanding where transmission may benefit from enhancement, without mandating specific projects or a minimum level of transfer capability. While the ITCS recommends increased transfer capability on particular interfaces, NERC does not endorse projects or particular approaches. This is intentional because planners must evaluate potential downstream impacts of increased transfer capability. For example, while greater transfer capability can improve energy adequacy, there can be situations where a large transfer of energy has consequences for other

[34] Without limitation on future analysis or action, NERC does not recommend any Reliability Standards changes at this time as a result of the ITCS.

aspects of reliable system operations such as system stability, voltage control, and measures to minimize the potential for cascading outages. Transmission planning regions must coordinate system enhancements to support rational and effective implementation of the ITCS findings. Further, planners might consider other options not within the scope of the ITCS. While the ITCS focuses on transfer capability per congressional directive, regions might construct additional resources or increase demand response resources. Further, the ITCS acknowledges that existing or planned projects may also be responsive to the opportunities and recommendations identified in the ITCS. As stated above, the ITCS findings should be considered foundational insights for further discussions and decisions.

III. CONSULTATION WITH REGIONAL ENTITIES AND TRANSMITTING UTILITIES

The Fiscal Responsibility Act requires that NERC conduct the ITCS in consultation with the six Regional Entities and neighboring transmitting utilities.[35] Consultation is understood as a meaningful exchange of information prior to final decision-making.[36] Consistent with Congressional directive and NERC's regular collaborative process as the ERO Enterprise coordinating with stakeholders to ensure reliability, NERC frequently consulted with the Regional Entities and transmitting utilities throughout the design and execution of the ITCS.

As illustrated below, the stakeholder engagement process included 14 Advisory Group meetings, three letters to transmitting utilities seeking input and feedback, presentations at NERC Board of Trustee ("Board") meetings and over 100 industry and trade group meetings. In addition,

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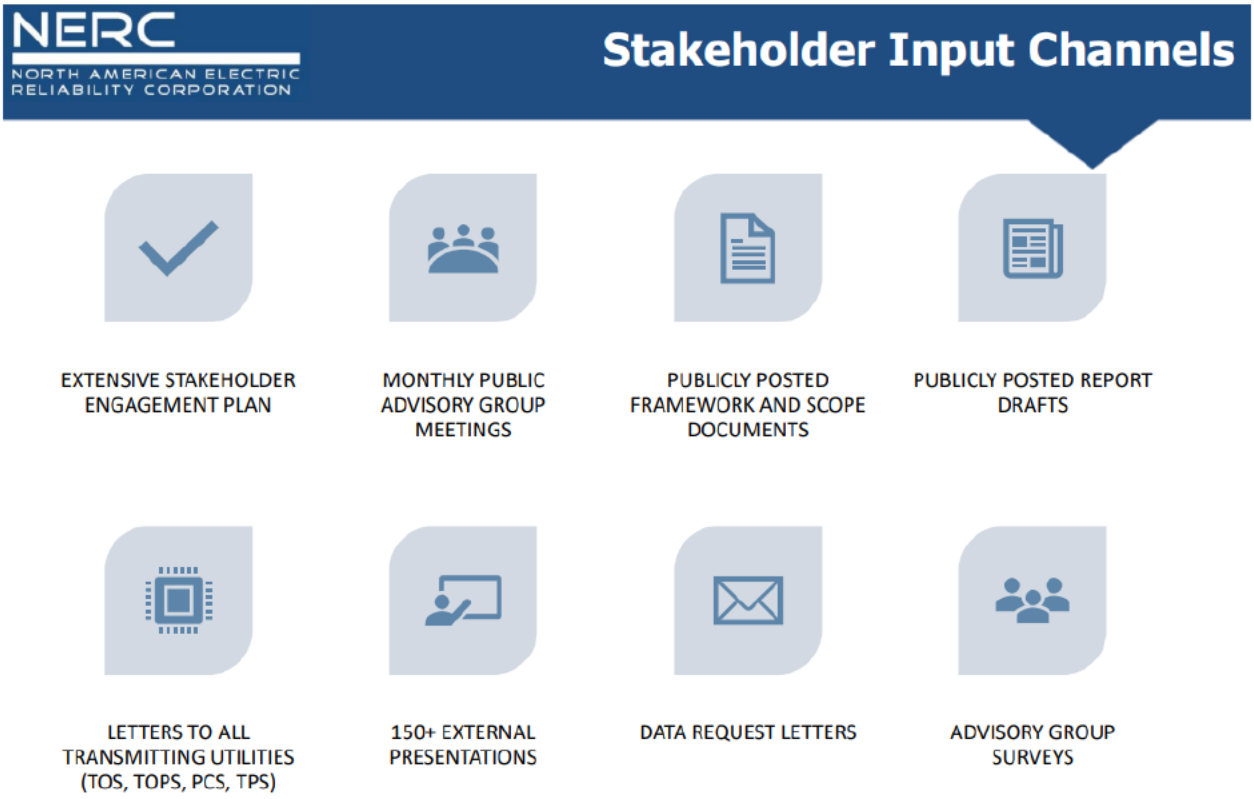
35 *Supra* note 1.

36 *See, e.g.*, *Envtl. Def. Ctr., Inc. v. U.S. Envtl. Protection Agency*, 344 F.3d 832 (9th Cir. 2003) (highlighting that consultation was reflected by activities such as circulating a draft report to stakeholders, establishing an advisory committee, holding several meetings as part of that advisory committee, and obtaining input from State and municipal representatives on drafts); and *South Carolina v. United States*, 329 F. Supp. 3d 214 (2018) (finding that the Department of Energy engaged in a meaningful exchange of information and views with governor prior to the decision); *cf. Cal. Wilderness Coalition v. U.S. Dep't of Energy*, 631 F.3d 1072, 1087, 1080, 1085) (2011) (explaining that consultation entails a meaningful exchange and more than public comment).

to facilitate these conversations and ongoing exchange of perspectives as NERC led the ITCS, NERC publicly published scoping documents and quarterly updates associated with the ITCS on NERC's ITCS webpage. Further, NERC published the parts of the ITCS via a series of three reports (an introductory Overview report, transfer capability analysis Part 1 report, and prudent recommended additions to transfer capability Part 2 and 3 report) prior to finalizing and consolidating these portions into the attached ITCS (**Appendix A**).



This consultation process is consistent with the ITCS Framework that NERC published in the summer of 2023. That Framework established NERC's plan to engage with its executive leadership, Regional Entities across different levels of leadership and technical expertise, and industry. This plan included the ERO Enterprise's coordination with an ITCS Advisory Group comprised of diverse industry experts (including, for example, those from the Department of Energy ("DOE"), the Commission, and transmission planners from across the BPS), as well as

additional outreach to transmitting utilities. *See*, **Appendix B** (list of stakeholder engagement activities), **Appendix C** (letters to transmitting utilities for feedback); and **Appendix D** (Advisory Group and ITCS Study Team Rosters and List of Public Meetings).

In accordance with the Framework illustrated above, NERC involved Regional Entities in the ITCS on a weekly basis to design and execute the ITCS and has met with the Advisory Group approximately every month to obtain input on ITCS design, execution, and findings. These groups were also asked to provide feedback on draft materials, such as the initial draft Framework, subsequent scope documents for different parts of the ITCS, and the portions of the ITCS that were rolled out in phases and culminated in the ITCS attached at **Appendix A**. All Advisory Group meeting presentations were publicly posted on NERC's ITCS webpage. Comments from Advisory Group members on various parts of the ITCS were also posted on NERC's ITCS webpage along

with NERC's consideration and responses. The process ensured that NERC received input during each stage of the ITCS from its initial framing to more detailed scoping and throughout the ITCS while the ERO Enterprise study team examined the issues and finalized decisions.[37]

To maximize the opportunity for stakeholder consultation, NERC published draft portions of the ITCS on its webpage (after seeking Advisory Group feedback) in stages. First, NERC published an Overview report introducing the ITCS and its approach in June 2024. Second, NERC published its calculated total transfer capability in August 2024. Third, in November 2024, NERC published its proposed recommended prudent additions to total transfer capability in certain regions of the U.S. and recommended means to meet and maintain transfer capability today and as enhanced after consideration of the ITCS recommendations. (Part 2 & 3 Report). These three parts were consolidated after final revisions into the attached ITCS (**Appendix A**). NERC plans to issue a fourth report in 2025 studying transfer capabilities from the U.S. to Canada and between Canadian provinces.[38]

In addition, NERC sent three sets of letters to all transmitting utilities in 2024 to obtain feedback on the ITCS.[39] The first letter was sent in January of 2024 seeking input generally on the ITCS, posted framework, and scope documents. The second letter was sent in September of 2024 to solicit input from transmitting utilities on the ITCS Overview report, total transfer capability report (Part 1), and Advisory Group materials (which included material on considerations and criteria to determine any recommended prudent additions to transfer capability). NERC's third letter to transmitting utilities was issued November 4, 2024, after the

[37] Examples included the decision to study simultaneous import capability and use 2024/2025 system conditions (or "base cases") to calculate current total transfer capability.

[38] While this part is outside the specific congressional mandate, the interconnectedness of the North American BPS warrants analysis of Canada.

[39] The Fiscal Responsibility Act required NERC to consult with neighboring transmitting utilities, however, to facilitate the broadest opportunity for consultation NERC sent these letters to all transmitting utilities.

final in-person Advisory Group meeting, to solicit input on NERC's proposed recommended prudent additions and recommendations on how to meet and maintain current total transfer capability and transfer capability as enhanced by any additions (the Part 2 & 3 report). NERC's preliminary recommendations for prudent additions were also shared with the Advisory Group in September 2024 with publicly posted materials available on the ITCS webpage to provide ample opportunity for comments before the Part 2 and 3 publication and before finalizing a final report.

NERC takes this opportunity to thank all those stakeholders and members of the ERO Enterprise who participated in the ITCS. This feedback has been instrumental in developing a nuanced study that is unique in terms of its geographic magnitude and overall approach to assessing energy adequacy under extreme conditions.

IV. CONCLUSION

Therefore, for the reasons set forth above, NERC hereby submits this ITCS to the Commission as directed by the U.S. Congress in the Fiscal Responsibility Act. The ITCS finds that while current total transfer capability is largely sufficient to support energy adequacy at present, when calculating energy margin analysis and extreme weather over a forward-looking ten-year outlook, there may likely be insufficient transfer capability. Based on the identified deficiencies that reveal certain transmission planning regions at risk for energy inadequacy, the ITCS recommends 35 GW of additional total transfer capability as a prudent measure to demonstrably strengthen reliability subject to coordination between governmental authorities, policy makers, and industry. NERC also plans to continue evaluating transfer capability as a regular part of its assessments going forward such as the LTRA. NERC on behalf of itself and the full ERO Enterprise, looks forward to continuing to participate in this discourse and preparing North America to meet the needs of the modern grid.

Respectfully submitted,

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Document Content(s)

UTILITY DIVE

More interregional transmission could save consumers billions: study

However, East Coast generators would see reduced revenue, giving them an incentive to oppose new transmission lines, researchers said.

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Ethan Howland
Senior Reporter

Adding transmission capacity between regions could save consumers billions in power supply costs by allowing lower cost power flow to high cost areas, according to a research paper published on Feb. 24, 2026, by Proceedings of the National Academy of Sciences. Getty Images

Adding transmission capacity between U.S. regions could save consumers billions in power supply costs by allowing lower cost power flow to high cost areas, according to a research paper released Tuesday.

Low-cost generators in the Midwest and Great Plains states could see a significant revenue increase if electricity from their resources could flow freely to high-cost East Coast areas, the study published in Proceedings of the National Academy of Sciences found.

The researchers found that improved transmission connections between U.S. regions would have saved $5.8 billion to $7.1 billion in generation costs in 2022 — a year with high natural gas prices — and $3.4 billion to $5 billion in 2023.

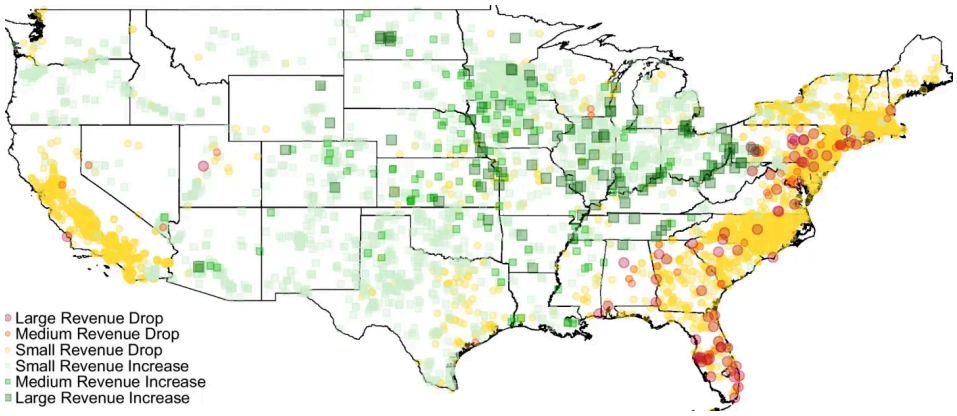
It is likely that cost savings would be even higher, according to the study, which didn't model the benefits of increased transmission capacity during extreme weather and other factors.

However, those savings — which would mean reduced revenue for some generators — are an incentive for power plant owners to fight against more efficient regional power flows, the paper's authors said.

"The U.S. process for siting, building, and paying for new transmission lines gives incumbent companies many opportunities to delay or block projects that are not in their private economic interest," the authors — Dasom Ham, Owen Kay and Catherine Hausman — said. "As analysts and policymakers propose grid reforms, it will be important to consider the incentives of suppliers and therefore the role of grid governance."

Hausman is an associate professor at the Gerald R. Ford School of Public Policy at the University of Michigan and a research associate at the National Bureau of Economic Research. Kay is a research economist at the Dallas Federal Reserve and Ham is a PhD student at the University of Michigan.

The savings from allowing lower cost power to flow to higher cost areas could reduce revenue for some power plant owners by more than $20 million a year, according to the study.



Power plant revenue gains and losses in the 2020—2023 period with increased market integration. "Large" revenue changes are defined as greater than $20 million/year; "medium" revenue changes as $10-$20 million; and "small" revenue changes as $0-$10 million.
Permission granted by Catherine Hausman

Market integration would benefit generators in the Great Lakes, Great Plains and Rocky Mountain regions but hurt power producers in the Northeast and Southeast, the researchers said.

There has been little interregional transmission development in recent years, with interregional lines making up only 2% of new circuit-miles installed from 2011 through 2020, the study noted.

In some cases, incumbent generators have fought interregional transmission projects, with NextEra Energy Resources and other power plant companies opposing a transmission line to bring hydropower from Canada into New England and Entergy opposing power projects linking the Southeast and Texas, the study's authors said.

Integrating power markets would make it more attractive to build gas-fired power plants in the Midwest, Northwest and the Rocky Mountain region and less attractive to build in the Northeast, Southeast and California, the authors said.

FERC sends transmission report to Congress

Meanwhile, the Federal Energy Regulatory Commission on Wednesday gave Congress a staff report on the North American Electric Reliability Corp.'s Interregional Transfer Capability Study.

"Increasing interregional transfer capability can be a potent tool in addressing reliability issues and warrants further examination," FERC Chairman Laura Swett said in a statement. "However, it is crucial to recognize that this measure is not a cure-all solution and should be considered in conjunction with potential economic impacts and other reliability strategies."

The NERC study delineated 35 GW of "prudent" interregional transmission additions that could improve grid reliability. It didn't make specific project recommendations and FERC staff didn't offer any recommendations to Congress on potential statutory changes.

FERC staff said that nearly all public comments on the NERC report supported a process to evaluate transfer capability between neighboring regions.

Any follow-up studies could also consider economic factors, such as the costs of building transfer capability, as well as alternate solutions, including intra-regional transmission, generation additions, storage, improved gas-electric coordination, demand-side management and operational practices and controls, FERC staff said.