COMMENTS OF PUBLIC INTEREST ORGANIZATIONS TO THE DEPARTMENT OF ENERGY'S 2026 DRAFT TRANSMISSION NEEDS STUDY

I. Introduction

Clean Air Task Force, Environmental Defense Fund, Montana Environmental Information Center, Natural Resources Defense Council, Renewable Northwest, Southern Environmental Law Center, Sustainable FERC Project, and Western Resource Advocates (together "Public Interest Organizations" or "PIOs") respectfully submit these comments on the Department of Energy's (DOE or Department) Draft 2026 National Transmission Needs Study.[1] PIOs support several important findings and analytical improvements in the Draft and urge DOE to preserve and strengthen them in the final Study. Most importantly, DOE's broad definition of transmission need is a significant strength of the Draft Study,[2] demonstrating substantial congestion value at regional seams,[3] analyzing congestion in the Southeast and other areas without transparent locational marginal price data,[4] and recognizing that interregional transmission can provide significant reliability, resilience, congestion, and resource-adequacy benefits.[5] DOE should ensure that any final Needs Study retains these findings.

These findings are important because the Needs Study can inform regional and interregional transmission planning and guide the Department's exercise of its transmission-related authorities.[6] At the same time, several aspects of the Draft warrant revision. The final Study should therefore identify both existing transmission deficiencies and reasonably foreseeable future needs. It should identify areas that are expected to experience congestion,

[1] U.S. Dep't of Energy, *National Transmission Needs Study: Draft for Consultation and Public Comment* v–viii, 38–59 (July 2026) [hereinafter *2026 Draft Needs Study*].
[2] *See* Section II, *supra*.
[3] *See* Section V.A, *supra*.
[4] *See* Section V.B, *supra*.
[5] *See* Section VI, *supra*.
[6] *See 2026 Draft Needs Study* at ii–iii, 5-6; *see also* 16 U.S.C. § 824p(a)(1)–(4).

emergency conditions, or reliability violations rather than limiting its analysis to areas already experiencing these issues. A national transmission-needs assessment should help policymakers and planners identify the infrastructure that will be required before those conditions become acute.

The final Needs Study should better characterize the extent to which recent transmission investment has expanded the high-voltage, high-capacity regional and interregional grid, including through metrics such as voltage level, incremental transfer capability, and the geographic scope of new facilities. Relying primarily on aggregate historical circuit-mile additions risks overstating the extent to which recent investment has increased the grid's ability to move large amounts of power over longer distances.[7] The final Needs Study should also provide a quantitative, forward-looking assessment of the need for additional transmission expansion, comparable to the analysis in the 2023 Needs Study.[8] Such an assessment should evaluate how much additional regional and interregional transmission capability may be needed to serve projected load growth, maintain reliability and resource adequacy, reduce congestion, and accommodate changes in the generation mix. Finally, DOE should build on the Draft's findings regarding the substantial potential value of interregional transmission[9] by identifying the limitations of existing interregional planning processes and recommending improvements that

[7] *See id*. at 26 (reporting historical transmission additions in aggregate circuit miles while showing that only a relatively small share of additions were at the highest voltage levels); *see also* U.S. Dep't of Energy, Office of Electricity, *DOE's Office of Electricity Publishes 2026 Draft National Transmission Needs Study to Strengthen America's Grid* (July 9, 2026) (noting that substantial additional transmission infrastructure remains necessary notwithstanding recent transmission investment).
[8] *Id.* at vi–vii, 79–83.
[9] *Id*. at 37–39, 54–56 (finding that interregional and cross-interconnection links can provide substantial congestion and resource-adequacy value, including at interfaces such as ISO-NE–NYISO and NorthernGrid–WestConnect).

would allow planners to more consistently identify, evaluate, select, and allocate the costs of projects whose benefits cross regional boundaries.[10]

The final Study should retain the findings that are well supported by the record and strengthen the analysis where the Draft remains incomplete. Specifically, DOE should retain its broad definition of transmission need; make load growth a distinct category of need in the Executive Summary; restore a quantitative, forward-looking assessment of regional and interregional transmission need; revise its characterization of recent transmission development to distinguish lower-voltage and replacement activity from additions that materially expand transfer capability; more fully assess the need for high-capacity regional and interregional transmission; expand its treatment of advanced transmission technologies (ATTs); strengthen the analysis of severe weather, resilience, and resource adequacy; identify the institutional barriers that continue to impede interregional development; strengthen its discussion of Tribal participation in transmission planning, and correct several technical issues discussed below.

II. DOE's Broad, Forward-Looking Definition of Transmission Need is Well Founded and should be Included in the Final Needs Study[11]

The Draft properly defines a transmission need as the existence of a present or expected electric transmission capacity constraint or congestion that could be alleviated through a

---

[10] *See Transmission Planning & Cost Allocation by Transmission Owning & Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, PP 393, 399 (2011) (requiring neighboring regions to identify and jointly evaluate interregional facilities that may more efficiently or cost-effectively address needs identified in their respective regional planning processes, but not requiring an interregional transmission plan); *Southwest Power Pool, Inc.*, 150 FERC ¶ 61,037, PP 92–93 (2015) (explaining that Order No. 1000 does not require interregional planning to identify transmission needs at the interregional level, but instead builds on needs identified separately in each region). *See also* FERC, *FERC Accepts Order No. 1000 Interregional Filings by SPP, MISO* (Feb. 19, 2015) (explaining that Order No. 1000 "does not require an interregional transmission plan or interconnection-wide planning," but instead requires neighboring transmission planning regions to identify and jointly evaluate interregional transmission facilities that may provide more efficient or cost-effective solutions to regional transmission needs).

[11] This section responds to the Draft Needs Study's Executive Summary (p. ii), Section I (pp. 1–2), and Section III.b, "Transmission Needs" (pp. 9–11).

transmission solution.[12] DOE further explains that such solutions may improve reliability and resilience, alleviate congestion and unscheduled flows, increase transfer capability between neighboring regions, deliver cost-effective generation to demand, or meet projected future generation, electricity-demand, or reliability requirements.[13] As DOE indicates, the benefits of such solutions can lead to economic benefits for consumers in the form of reduced electricity prices, and can result in increased employment and tax revenues and other economic development benefits.[14] This conception of need is consistent with section 216(a) of the Federal Power Act, which directs DOE to study electric transmission capacity constraints and congestion, including constraints that are expected to arise in the future.[15]

PIOs strongly support this approach. Transmission planning necessarily operates on a longer time horizon than many of the conditions it is intended to address. Major transmission projects require years of planning, regional approval, permitting, siting, procurement, and construction. If DOE were to identify a need only after a constraint has become chronic, the Study would be of limited value to planners attempting to avoid future reliability problems and unnecessary consumer costs.

A forward-looking definition is particularly important given the projected rapid increase in electricity demand from data centers, advanced manufacturing, large industrial facilities, and other major new loads. Historical congestion may say little about whether a system that experienced relatively flat demand over the last decade will have sufficient transfer capability to serve several gigawatts of concentrated new load. Likewise, a region that has historically

---

[12] *See 2026 Draft Needs Study*, *supra* note 1, at 7 (defining a "transmission need" as "the existence of a present or expected electric transmission capacity constraint or congestion in a geographic area that could be alleviated through the construction, modification, or operation of electric transmission facilities").
[13] *Id.* at ii, 2.
[14] *Id.* at 8.
[15] 16 U.S.C. § 824p(a)(1)–(2).

maintained adequate reserves may face materially different resource-adequacy conditions if demand growth outpaces additions of generation and transmission. The final Study should therefore retain the Draft's broader analytical framework and make clear that credible evidence of a foreseeable capacity constraint can establish transmission need even before historical operations show persistent congestion or reliability violations.

III. DOE Appropriately Identifies Demand as a Major Driver of Transmission Need, but Should Make the Link Between Load Growth and Transmission Expansion More Explicit

A. Projected Rapid Load Growth is Creating Transmission Needs that Historical Data Cannot Fully Capture[16]

The Draft correctly identifies rapidly increasing electricity demand as a major driver of transmission need. DOE states that regional planners are seeing future transmission needs primarily driven by load growth and recognizes that transmission planning must account for anticipated future requirements because of the lengthy timelines associated with transmission development.[17] The Draft also reports substantial projected increases in electricity consumption and identifies data centers, expanding domestic manufacturing, and large industrial loads as important contributors to that growth.[18]

The final Study should build on those findings by making the relationship between load growth and transmission expansion more explicit. Adding generation alone cannot reliably serve rapidly growing load where the transmission system lacks sufficient capability to deliver that generation to the locations and hours in which it is needed. Additional transfer capability can provide access to a broader pool of resources, reduce the risk that concentrated new demand

[16] This section responds to Section VI.e, "Drivers of Future Transmission Needs" (pp. 79–81), including the Draft's discussion of projected data-center and other large-load growth.
[17] *2026 Draft Needs Study*, *supra* note 1, at vi–vii, 78–83.
[18] *Id*. at iii, 79–81; U.S. Dep't of Energy, *DOE's Office of Electricity Publishes 2026 Draft National Transmission Needs Study to Strengthen America's Grid* (July 9, 2026).

must be met through expensive local generation, and allow system operators to respond more effectively when expected resources are unavailable.

DOE should also emphasize the significance of geographic concentration. National demand growth may appear manageable in aggregate while still creating substantial local and regional transmission needs where multiple data centers, manufacturing facilities, or other large loads locate in the same constrained area. The North American Electric Reliability Corp. (NERC) has noted that individual large loads can create a rapid and substantial increase in electricity demand within a particular geographic area on a relatively short timeline, and that data-center-driven growth is especially pronounced in regions such as PJM, ERCOT, and parts of the Western Interconnection.[19] Existing utility forecasts and regional plans may therefore fail to capture the timing, magnitude, or location of emerging demand. The final Study should encourage planners to use multiple plausible load scenarios, including high-load and geographically concentrated cases, and to evaluate the consequences if load materializes faster than expected.

Because transmission facilities often require many years to develop, uncertainty is not a reason to defer analysis. Scenario-based planning allows decision-makers to distinguish investments that are valuable across a range of futures from those that depend on a single forecast.[20] DOE should encourage that approach so that planners do not wait until new demand

---

[19] *See* N. Am. Elec. Reliability Corp., *2025 State of Reliability* 10–11 (2025) (explaining that individual large-load facilities can produce a rapid and substantial increase in the load forecast for a geographic area, often within a two-year period, and create uncertainty for generation and transmission planning); N. Am. Elec. Reliability Corp., *2025 Long-Term Reliability Assessment* 20–23 (2025) (identifying particularly rapid data-center and large-load growth in Texas, PJM, and portions of the Western Interconnection); Elec. Power Rsch. Inst., *Powering Intelligence 2026* (2026) (explaining that clusters of new data centers and other large loads are driving renewed regional load growth).

[20] *See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068, P 967 (2024) (explaining that transmission providers may use a "least-regrets" approach to evaluate transmission facilities across Long-Term Scenarios and thereby minimize the risks of overbuilding and undersizing).

produces immediate reliability violations, interconnection delays, or costly emergency upgrades before identifying needed transmission.

Accordingly, PIOs recommend that the following text be added in Section VI.e, "Drivers of Future Transmission Needs," on page 81, immediately after the paragraph discussing the range of projected data-center demand growth:

> Given uncertainty regarding the timing and location of major new loads, planners should evaluate multiple plausible demand futures, including higher-load and geographically concentrated scenarios. Scenario-based analysis can identify transmission investments that remain valuable across a range of futures and reduce the risk that needed infrastructure is identified only after new demand creates acute reliability or interconnection problems.

B. Future Load Growth Should be a Separate Need Category in the Executive Summary[21]

The Executive Summary should more clearly communicate the importance of load-driven transmission needs. Figure ES-5 currently summarizes regional needs using four principal categories: reliability and resilience, within-region congestion, transfer-capability limits between neighboring regions, and resource adequacy through interregional transfer capability.[22] Yet the Draft itself repeatedly identifies projected demand growth as a central driver of future transmission requirements.[23]

DOE should therefore add "meeting projected future load growth" as a fifth category of transmission need in Figure ES-5 and the accompanying discussion. That would align the Executive Summary with the Study's own discussion of rising demand and would make clear that a region can face significant transmission needs even before those needs show up in

---

[21] This section responds specifically to the Executive Summary's four-category regional-needs framework and Figure ES-5 (p. viii), read together with its discussion of load growth as the principal driver of future transmission needs (pp. vi–vii).

[22] *2026 Draft Needs Study*, *supra* note 1, at viii & fig. ES-5.

[23] *See id*. at vi–viii, 64–71, 74–76, 79–83 (July 2026) (repeatedly identifying load and demand growth as a principal driver of future transmission needs, including projected growth from data centers, manufacturing, other large loads, and electrification, and describing regional transmission investments planned to accommodate that growth).

historical congestion or reliability data. Because the Executive Summary and its graphics are likely to shape how policymakers, states, regional entities, and other stakeholders understand the Study, they should capture the Study's forward-looking findings as well as existing constraints.

Accordingly, PIOs recommend that DOE revise Figure ES-5 and the accompanying Executive Summary text to add a fifth category of transmission need: "Meeting projected future load growth." Further, PIOs recommend that DOE explain that projected rapidly increasing and geographically concentrated demand can create significant transmission needs before those needs appear in historical congestion or reliability metrics.

C. DOE Should Restore a Quantitative Assessment of Future Transmission Need[24]

The 2023 Needs Study provided quantitative estimates of the magnitude of additional regional and interregional transmission that could be required under alternative future scenarios.[25] The 2026 Draft instead reviews national modeling studies and concludes that they collectively indicate a need for significant transmission investment over the next two decades, but it does not translate those results into an updated quantitative assessment of regional and interregional expansion.[26]

That omission materially reduces the usefulness of the Study. A statutory assessment of current and expected transmission constraints should help decision-makers understand not merely that more transmission may be needed, but approximately how much additional capability may be required, where it is likely to be most valuable, and over what time horizon. DOE need not identify a single deterministic buildout. It can present ranges that reflect

---

[24] This section responds to Section VII, "Future Transmission Needs Assessment through Review of National Modeling Studies" (pp. 82–83) which synthesizes national modeling results but does not provide an updated quantitative estimate of regional and interregional expansion needs comparable to the 2023 Study.
[25] U.S. Dep't of Energy, *National Transmission Needs Study* 130–43 (Oct. 2023) [hereinafter *2023 Needs Study*].
[26] *2026 Draft Needs Study*, *supra* note 1, at 82–83.

uncertainty in load growth, resource development, retirements, fuel prices, technology costs, and other major drivers.

At a minimum, the final Study should synthesize quantitative results from NERC's Interregional Transfer Capability Study, DOE's National Transmission Planning Study, NREL's Standard Scenarios, relevant national resource-adequacy studies, and current regional plans reflecting the recent acceleration in load growth.[27] The final Study should identify the amount, approximate location, timing, and type of transmission capability likely to be needed across plausible futures and should explain where approved or planned projects leave a material gap.

IV. DOE Should Revise Its Characterization of Recent Transmission Development

A. Aggregate Circuit-mile Figures Obscure the Limited Development of High-capacity Infrastructure[28]

The Draft Study relies on several characterizations of recent transmission development that obscure the trends most relevant to assessing congestion and interregional transmission needs. Its reliance on aggregate circuit-mile figures and broad characterization of the pace of transmission development provide little insight into whether recent investment has actually increased transfer capability or relieved significant regional and interregional constraints. DOE should revise the Study to provide greater granularity regarding the geographic distribution of

---

[27] *See, e.g.*, N. Am. Elec. Reliability Corp., *Interregional Transfer Capability Study: Final Report* 3 (Nov. 2024) (conducting the first comprehensive assessment of transfer capability between adjacent transmission planning regions and evaluating whether additional transfer capability is needed to maintain reliability under a range of conditions, including extreme weather); U.S. Dep't of Energy, *National Transmission Planning Study: Executive Summary* 3–5 (Oct. 2024) (finding that substantial regional and interregional transmission expansion would reduce system costs and improve reliability and that aggregate U.S. interregional transfer capability increases substantially across modeled futures); Pieter Gagnon et al., Nat'l Renewable Energy Lab., *2024 Standard Scenarios Report: A U.S. Electricity Sector Outlook* 1–4 (2024) (presenting 61 forward-looking scenarios of the U.S. electricity sector through 2050 designed to capture a broad range of potential futures and uncertainties); N. Am. Elec. Reliability Corp., *2025 Long-Term Reliability Assessment* 8–9 (2025) (finding that projected peak-demand and energy growth over the next decade have risen to their highest levels in two decades, with summer peak demand forecast to increase by more than 224 GW and winter peak demand by 245 GW, driven substantially by data-center growth).

[28] This section responds to Section IV, "Historical Transmission Investment" (especially pp. 26, 31–32 and Figure IV-3), which reports aggregate circuit-miles and the voltage distribution of new, upgraded, and rebuilt facilities.

new transmission, distinguish newly constructed lines from upgrades and repairs to existing facilities, identify changes in interregional transfer capability, and report the voltage and ratings of transmission facilities placed in service. This information is essential to evaluating whether recent transmission development is occurring where it is most needed and whether it is meaningfully increasing the grid's ability to relieve congestion and move power between regions.

The Draft states that significant investments were made in transmission between 2016 and 2024 and reports approximately 85,000 circuit-miles of new, upgraded, or rebuilt facilities rated 69 kV or above.[29] But that figure combines very different types of transmission activity and therefore says relatively little about the extent to which the nation's high-capacity transmission backbone actually expanded. In particular, it does not distinguish new transmission from upgrades or rebuilding of existing facilities, identify where those investments occurred, or indicate how much additional regional or interregional transfer capability they provided.

DOE itself finds that approximately 66 percent of the circuit-miles added during that period were rated at only 69 or 138 kV, while just 4 percent were rated at 500 kV or above.[30] The 85,000-mile figure also combines newly constructed facilities with rebuilt and upgraded existing lines. Lower-voltage investments and asset replacement can provide substantial local reliability benefits, but they are not equivalent to constructing new regional backbone facilities capable of moving large quantities of power over long distances or across regional seams.

The final Study should therefore (1) distinguish new facilities from rebuilt or upgraded facilities; (2) disaggregate mileage by voltage class; (3) report incremental megawatts of transfer capability where available; (4) distinguish local projects from regional and interregional projects;

[29] *2026 Draft Needs Study*, *supra* note 1, at 26.
[30] *Id*. at 26, 31–32.

(5) identify facilities that materially expand interregional transfers; (6) distinguish replacement of aging infrastructure from expansion intended to serve new system needs; and (7) present comparable data across multiple years so that changes in the pace and character of transmission development are readily apparent. DOE should also consider using metrics such as gigawatt-miles or incremental transfer capability so that the Study better reflects what transmission investment enables the grid to do, rather than simply how many circuit-miles were constructed, rebuilt, or upgraded.

B. The Draft Highlights the Limited Development of Interregional Lines[31]

As discussed in more detail below in Section VI.A, one of the Draft's strongest findings is that interregional and cross-interconnection links show some of the highest potential value for relieving transmission congestion. Yet the Draft's own data indicates an especially significant shortfall in interregional development. Table IV-1 reports an average of only approximately 150 circuit-miles of interregional transmission per year between 2016 and 2024, compared with approximately 9,400 circuit-miles per year nationwide.[32] That figure, if accurate, demonstrates that only a very small share of recent transmission activity has expanded connections across regional boundaries.

Moreover, the Draft identifies transmission needs throughout 20 regions of the country and bases its analysis of interregional transmission on transmission connecting two of those 20 regions. However, the electric industry plans regional transmission based on the 11 planning regions created pursuant to FERC's Order No. 1000 and considers interregional transmission as transmission that connects two neighboring Order No. 1000 planning regions. Therefore, the

---

[31] This section responds to Section IV, "Historical Transmission Investment" (especially p. 30 and Table IV-1), which separately reports average annual interregional circuit-miles.
[32] *2026 Draft Needs Study*, *supra* note 1, at 30 tbl. IV-1.

final Study should provide a more policy-relevant interregional analysis based on the larger Order No. 1000 planning regions, rather than relying exclusively on the Study's more granular twenty-region framework.[33] An Order No. 1000-region comparison would more closely align with how the electric industry plans regional and interregional transmission and help show whether the bulk power system is becoming meaningfully more interconnected across the planning seams where institutional and cost-allocation barriers are most significant.

DOE should also measure actual increases in transfer capability, rather than merely counting lines that cross a regional boundary. A short line or localized upgrade may technically be interregional without materially improving the ability of neighboring systems to exchange power during high-value or high-risk hours. For each major seam, the final Study should identify existing transfer capability, capability added during the Study period, the voltage and capacity of new facilities, utilization and binding constraints, projects under development, and the remaining gap between planned capability and modeled need.

C. DOE Should Reconsider Its Conclusion that Transmission Investment has Maintained a Steady Pace[34]

The Draft states that transmission investment has maintained a steady pace since 2016, while also reporting that annual circuit-mile additions fell to approximately 3,600 miles in 2024 after ranging from roughly 8,700 to 12,500 miles annually between 2016 and 2023.[35] DOE should explain this characterization and reconcile it with the 2023 Needs Study's finding that transmission investment "decreased during the second half of the 2010s."[36]

---

[33] *Id*. at 12–14, 27 n.36 & fig. III-2.
[34] This section responds to Section IV, "Historical Transmission Investment" (pp. 26–31), which state that transmission investment maintained a steady pace while reporting annual circuit-mile additions through 2024.
[35] *2026 Draft Needs Study, supra note 1,* at 27, 30–31; *see 2023 Needs Study, supra* note 25, at 20–22 (discussing longer-term transmission-investment trends).
[36] *2023 National Transmission Needs Study*, *supra* note 25, at 21–24.

More fundamentally, the final Study should distinguish a steady pace of all transmission activity from the pace at which the country is adding high-capacity facilities that materially increase regional and interregional transfer capability. A system can spend substantial sums replacing aging assets while still failing to expand the transfer capability necessary to serve new load, relieve persistent congestion, and share resources across regions.

Accordingly, PIOs make the following suggestions. First, DOE should revise page iii of the Executive Summary which begins "Transmission investments have maintained a steady pace since 2016" to read: "Overall transmission investment and circuit-mile additions maintained a relatively steady pace from 2016 through 2023, although these measures include new, upgraded, and rebuilt facilities across voltage classes and therefore do not by themselves indicate the extent to which high-capacity regional and interregional transfer capability increased." Second, on page 30, after the paragraph discussing the 85,000 circuit-miles energized between 2016 and 2024 and the relatively steady pace of annual circuit-mile additions through 2023, DOE should add the following text:

> These measures describe the overall level of transmission development activity but do not necessarily indicate the extent to which the transmission system's regional or interregional transfer capability has expanded. The data include newly constructed, upgraded, and rebuilt facilities rated 69 kV and above, and therefore encompass lower-voltage investments and replacement or rehabilitation of existing infrastructure as well as new high-capacity facilities. Accordingly, a relatively steady level of capital investment or circuit-mile additions should not be interpreted as demonstrating a comparable increase in the Nation's high-capacity regional or interregional transmission capability. Additional metrics, including voltage class, whether facilities are new or rebuilt, and changes in transfer capability, are necessary to provide important context regarding the functional expansion of the transmission system.

V. DOE Should Retain and Strengthen its Congestion Analysis

A. The Nationwide Congestion Findings are Important and Should be Retained[37]

The Draft estimates nationwide transmission congestion costs of approximately $11 billion in 2023 and $12 billion in 2024.[38] It further finds that approximately half of the potential congestion value of transmission occurs during just 5 percent of hours and that these high-value periods frequently coincide with forecast error, high net load, cold weather, severe weather, and other periods of stress on the bulk power system.[39]

Those findings are important and should be retained prominently in the final Study. The concentration of congestion value in a small number of hours does not diminish the importance of the problem. It instead demonstrates that additional transmission capability may provide its largest consumer and reliability benefits precisely when the system is most constrained and prices are highest. Annual averages can obscure this value because they dilute a small number of very consequential hours across the entire year.

The final Study should therefore supplement annual congestion-cost metrics with measures that better capture stress-period value, including avoided scarcity prices, emergency actions, reserve shortages, expected unserved energy, fuel constraints, generator outages, and performance during extreme-weather events. A facility that produces moderate savings during ordinary hours but prevents severe price spikes or reliability emergencies during a handful of critical periods may be highly valuable even if annual average congestion appears modest.

---

[37] This section responds primarily to Section V.a, "National and Interregional System Congestion and Transfer Capabilities" (pp. 37–43), including the findings on national congestion costs and the concentration of transmission value in a small number of high-value hours.
[38] *2026 Draft Needs Study*, *supra* note 1, at 37–38.
[39] *Id*. at iv, 43–44.

B. DOE Should Retain and Expand the Southeast Congestion Analysis[40]

The Draft's analysis of congestion in the Southeast is an important improvement and should be preserved. Because the Southeast does not have an RTO- or ISO-operated energy market with publicly available locational marginal price data, DOE has developed alternative approaches for assessing congestion and identifies meaningful transmission value, including high-value interregional links involving Southern Company and FRCC, Duke and PJM, and TVA and MISO South.[41]

The absence of transparent market prices should not be interpreted as an absence of transmission constraints or economic need. Nor should data limitations place non-RTO regions outside a national transmission-needs assessment. The final Study should retain this work, identify remaining methodological limitations, and continue developing approaches that allow policymakers to compare the economic and reliability consequences of constrained transfer capability across all regions of the country.

DOE should also encourage greater public transparency regarding available transfer capability, flowgate constraints, transmission loading relief, curtailments, interchange, production-cost results, and the assumptions used in regional and interregional planning. Better data would improve future Needs Studies and allow states, utilities, consumers, and other stakeholders to independently assess whether existing planning processes are identifying the most cost-effective solutions.

Accordingly, PIOs recommend that DOE add the following language in Section V.a, "National and Interregional System Congestion and Transfer Capabilities," under the subsection

---

[40] This section responds to Section V.a (pp. 41–43) and related regional discussion in Section V.b, which develop alternative methods for estimating congestion in the Southeast where public LMP data are limited.
[41] *2026 Draft Needs Study*, *supra* note 1, at vi, 42–43.

"Non-RTO/ISO Regions," on page 49, immediately after the paragraph ending "Congestion in Hawaii is not discussed because no congestion information is available.":

> Future Needs Studies would benefit from greater public availability of information concerning available transfer capability, flowgate and other transmission constraints, transmission loading relief events, curtailments, interchange, production-cost modeling results, and key assumptions used in regional and interregional transmission planning. Greater transparency regarding these data and assumptions would improve DOE's ability to assess and compare transmission needs across regions and would allow states, consumers, and other stakeholders to independently evaluate whether existing planning processes are identifying cost-effective transmission solutions."

VI. DOE Should Make the Need For Interregional Transmission a Central Finding of the Final Study

A. DOE Should Expressly Retain its Finding that Interregional Links Offer Especially High Value[42]

One of the Draft's strongest findings is that interregional and cross-interconnection links show some of the highest potential value for relieving transmission congestion. DOE identifies high-value links between NorthernGrid and WestConnect, ISO New England and NYISO, ERCOT and neighboring regions, and the Eastern and Western Interconnections.[43]

The Draft also recognizes that interregional transmission can support resource adequacy by allowing regions with different weather conditions, load profiles, generation mixes, and outage patterns to share resources. National studies summarized by DOE likewise show that interregional expansion can improve resource adequacy and mitigate the consequences of severe weather and other disruptions.[44] These benefits are distinct from ordinary energy market congestion savings and should be evaluated separately rather than treated as incidental.

---

[42] This section responds to Section V.a, "National and Interregional System Congestion and Transfer Capabilities" (pp. 37–43), which identify especially high potential congestion value at several interregional and cross-interconnection links.
[43] *2026 Draft Needs Study*, *supra* note 1, at v, 38–39.
[44] *Id*. at 54–56, 82–83.

Additional interregional capability can allow neighboring regions to share capacity and reserves, take advantage of non-coincident peaks, access geographically diverse resources, respond to generation and transmission outages, reduce exposure to localized fuel constraints, and provide emergency assistance.[45] Interregional lines can also reduce the amount of duplicative capacity each region must independently maintain for rare but consequential system conditions.[46] Those benefits can accrue in both directions over time, which is why interregional projects should not be evaluated under a simplistic assumption that one region is permanently the exporter and the other the beneficiary.[47]

B. DOE Should Expand its Assessment of the Resource-Adequacy Value of Interregional Transmission[48]

The Draft Study recognizes that interregional transmission can improve resource adequacy by allowing neighboring regions to share power during periods of system stress. It looks at overlap in each region's highest net-load and highest-price hours as indicators of when that value may be greatest, but it also acknowledges that this analysis does not show how much

---

[45] *See 2023 National Transmission Needs Study*, *supra* note 35, at 130–31 (explaining that interregional transfer capability strengthens reliability and resilience by providing geographic and resource diversity, allows regions to import electricity when local generation is insufficient, and provides operational benefits from resource diversification); U.S. Dep't of Energy, *National Transmission Planning Study: Executive Summary* 14–15 (Oct. 2024) (finding that interregional transmission enables regions to coordinate to meet resource-adequacy requirements, permits external resources to support local adequacy needs, and substantially reduces the cost of maintaining adequate capacity); *see also* U.S. Dep't of Energy, *National Transmission Planning Study* chs. 2–3 (Oct. 2024) (finding that transmission is used bidirectionally across regional interfaces to support resource adequacy and enables regions to share resources across diverse weather, load, and generation conditions).

[46] *See* U.S. Dep't of Energy, *National Transmission Planning Study Chapter 2: Long-Term U.S. Transmission Planning Scenarios* at 55 (explaining that, absent interregional resource-adequacy sharing, each planning region must meet its resource-adequacy needs solely with resources within its own borders, and finding that allowing regions to rely on interregional transmission and excess resources in neighboring regions substantially reduces total system costs).

[47] *See id*. at 53 (finding that interregional transmission used for resource adequacy frequently carries power in both directions and observing several interfaces with roughly 50/50 to 60/40 directional flows; further noting that even SPP, although predominantly an exporter to PJM, imports from PJM during hundreds of hours when needed to meet its own resource-adequacy needs).

[48] This section responds to Section V.c, "Resource Adequacy and Resilience Benefits of Transmission" (pp. 54–63), particularly the peak-net-load and price-overlap analyses used to assess interregional resource-adequacy and resilience value.

additional transfer capability is needed or whether power could actually be delivered during those periods.[49] The final Study should therefore strengthen this analysis in two respects. First, it should evaluate deliverability by considering generator outages, fuel constraints, transmission outages, reserve shortages, and severe weather when assessing the resource-adequacy value of additional interregional transmission. Second, consistent with the quantitative, forward-looking assessment recommended above, it should estimate the additional interregional transfer capability needed to address identified resource-adequacy needs.

State regulators have underscored the critical connection between interregional transfer capability and resource adequacy. In July 2026, the National Association of Regulatory Utility Commissioners (NARUC) adopted Resolution EL-2, *Resolution Supporting the Use of Interregional HVDC Transmission to Address Resource Adequacy, Reliability, and Electricity Affordability*. The resolution recognizes that accelerating electricity demand, projected peak load growth, extreme weather risks, and generation permitting and interconnection bottlenecks are placing severe strain on resource adequacy. The resolution highlights that interregional High Voltage Direct Current (HVDC) transmission provides bi-directional, flexible transfer capabilities that allow planning regions and load-serving entities to access diverse external generation resources and non-coincident load profiles without requiring duplicative local generation construction within each footprint. NARUC expressly encourages Regional Transmission Organizations (RTOs), Independent System Operators (ISOs), transmission providers, utilities, and federal policymakers to incorporate interregional HVDC transmission

[49] *2026 Draft Needs Study*, *supra* note 1, at 54–56 (explaining that interregional transmission can support resource adequacy by allowing regions to share power during periods of system stress; analyzing the 100 highest net-load and highest-price hours in each region as proxies for periods of resource-adequacy stress; and acknowledging that the analysis does not determine the optimal amount of interregional transmission or account for whether existing interregional capability could deliver power during peak periods).

into resource planning and resource adequacy strategies, and to update regulatory frameworks to properly reflect and value these facilities. Incorporating this state commission-supported framework into the final Study would align DOE's analytical approach with state regulatory priorities for affordable and resilient capacity sharing.

In addition, NERC's Interregional Transfer Capability Study provides one important source because it specifically examines existing and potential future interregional transfer capability and its relationship to reliability.[50] DOE should incorporate its quantitative findings more directly into the final Study and supplement them with probabilistic resource-adequacy studies where available. Metrics such as loss-of-load expectation and expected unserved energy can reveal reliability value that annual congestion calculations or historical peak-overlap proxies may miss.

This is particularly important for interfaces such as ISO-NE and NYISO, as set forth in more detail in the next section. The Draft identifies substantial congestion value between the regions but may understate the resource-adequacy value of additional transfer capability if it relies heavily on historical similarity in net-load patterns.[51] A more complete analysis should test multi-day winter fuel constraints, correlated generation outages, internal deliverability limitations, emergency assistance, and extreme-weather conditions in which the ability to import from a neighboring region can have disproportionate value.

C. DOE Should Revisit the Assessment of the ISO-NE–NYISO Interface[52]

[50] N. Am. Elec. Reliability Corp., *Interregional Transfer Capability Study* (2024).
[51] *2026 Draft Needs Study*, *supra* note 1, at 39, 54–55. The Draft identifies the ISO-NE–NYISO link as having relatively high congestion value and reports that NYISO shared 72% of its peak net-load hours with ISO-NE.
[52] This section responds to Section V.a, "National and Interregional System Congestion and Transfer Capabilities" (especially p. 39), the ISO-NE regional congestion discussion in Section V.b (including p. 47), and Section V.c's peak-net-load analysis (pp. 54–55).

The Draft Study's congestion analysis identifies the ISO-NE–NYISO interface as one of the nation's higher-value interregional links and recognizes that substantial winter price differences can arise when constraints on New England's natural-gas infrastructure increase generation costs.[53] At the same time, its resource-adequacy analysis finds substantial overlap between New York and New England's highest net-load hours, which could be read to suggest comparatively limited resource-adequacy diversity.[54]

DOE should clarify that this simplified overlap analysis does not establish that additional New York–New England transfer capability has little reliability value. As the Draft Study acknowledges, the analysis cannot determine how much interregional transmission would be optimal or whether additional capability is needed, and it does not account for the ability of existing interregional transmission to deliver power during neighboring regions' highest net-load periods.[55] A comparison of historical net-load hours also does not capture whether existing interregional transmission can actually deliver power during neighboring regions' periods of highest net load.[56]

Rather than rely principally on the net-load overlap metric, DOE should incorporate existing regional studies that examine these issues in greater detail. Most directly, the Northeast Power Coordinating Council's 2025 Review of Interconnection Assistance Reliability Benefits evaluates the reliability value that neighboring systems and their interconnections provide to

[53] *2026 Draft Needs Study*, *supra* note 1, at v, 39, 47.
[54] *Id*. at 54–55.
[55] *Id*. at 55.
[56] *Id*.

resource adequacy across the Northeast. That analysis provides a stronger basis for assessing the ISO-NE–NYISO interface than coincidence of historical peak hours alone.[57]

DOE should also consider NPCC's Northeast Gas/Electric System Study, which examined New York and New England together under extreme and prolonged winter conditions, including natural-gas supply and pipeline constraints and gas- and electric-system contingencies. The study is particularly relevant because it evaluates stresses that can affect both regions during winter but may not be reflected in a simple comparison of net-load peaks.[58]

Finally, ISO-NE's probabilistic energy-adequacy work provides a useful complement. Its Probabilistic Energy Adequacy Tool evaluates the risk of energy shortfalls under extreme weather and other stressful conditions, including multi-day events.[59] The final Study should synthesize these existing analyses and explain how interregional transmission can provide reliability value during prolonged fuel constraints, outages, reserve shortages, internal deliverability constraints, and periods when neighboring systems can provide emergency assistance.[60]

D. Order No. 1920 Does Not Eliminate the Interregional Planning Gap[61]

The final Study should also recognize that the existing planning framework does not reliably produce interregional transmission. FERC's Order No. 1920 substantially reforms long-

---

[57] Northeast Power Coordinating Council, 2025 Review of Interconnection Assistance Reliability Benefits (Mar. 23, 2026).
[58] Northeast Power Coordinating Council, Northeast Gas/Electric System Study Summary Report (Jan. 21, 2025).
[59] *See* ISO New England, *Operational Impacts of Extreme Weather Events* (explaining that ISO-NE developed the Probabilistic Energy Adequacy Tool ("PEAT") to assess operational energy-security risks associated with extreme weather events); *see also* N. Am. Elec. Reliability Corp., *Evolving Planning Criteria for a Sustainable Power Grid* 13 (July 2024) (explaining that PEAT stress-tests the New England system under extreme-weather conditions and evaluates its ability to manage disruptions in energy demand and supply over a 21-day period).
[60] ISO New England, ISO-NE's Study of Energy Shortfall Risks Produces Innovative Tool for Assessing Energy Adequacy (Dec. 11, 2023).
[61] This section responds to Section III.b's discussion of interregional coordination and Order No. 1920 (pp. 11–12) and Section VI.d, "Regional Transmission Planning and Coordination" (pp. 64–78), which review existing regional and interregional planning practices.

term regional transmission planning, including scenario development, evaluation of a broad set of benefits, consideration of certain advanced transmission technologies, and ex ante cost allocation for selected Long-Term Regional Transmission Facilities.

Its interregional reforms, however, are considerably more limited.[62] Order No. 1920 requires neighboring regions to improve coordination by sharing information concerning long-term transmission needs and potential facilities and by jointly evaluating certain proposed interregional projects. But it does not create a parallel interregional long-term planning regime with the same mandatory scenario development, benefit analysis, portfolio evaluation, selection, and cost-allocation framework that applies within regions. As a result, many of the longstanding procedural and cost-allocation barriers at regional seams remain unresolved.

DOE should therefore make clear that the limited number of interregional projects reflected in current regional plans does not, by itself, demonstrate an absence of interregional transmission need. Existing regional planning processes can systematically understate interregional value where each region evaluates investments largely from its own perspective, applies different assumptions or benefit metrics, or lacks a recurring process for jointly identifying a portfolio of cross-border solutions. For example, Order No. 1000 requires neighboring planning regions to coordinate, exchange information, and jointly evaluate proposed interregional facilities, but it does *not* require an interregional transmission planning process.[63] As explained in more detail below, MISO and SPP, for example, have relied on discrete coordinated studies such as their Coordinated System Plan to examine congestion and other

[62] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068, PP 150–152, 1751–1754 (2024), order on reh'g, Order No. 1920-A, 189 FERC ¶ 61,126 (2024), order on reh'g, Order No. 1920-B, 191 FERC ¶ 61,030 (2025).

[63] *See Transmission Planning & Cost Allocation by Transmission Owning & Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, PP 396–398 (2011); Fed. Energy Regul. Comm'n, *FERC Accepts Order No. 1000 Interregional Filings by SPP, MISO* (Feb. 19, 2015) (explaining that Order No. 1000 "does not require an interregional transmission plan or interconnection-wide planning").

issues along their seam, illustrating both the value of joint analysis and the absence of a single recurring interregional portfolio-planning process comparable to regional planning.

Accordingly, PIOs recommend that DOE insert the following language in Section VI.d, page 79, "Regional Transmission Planning and Coordination," after the region-by-region discussion of regional transmission plans and before the discussion of transmission needs on Tribal lands:

> The absence of an identified interregional project in current regional transmission plans should not be interpreted as evidence that no interregional transmission need exists. Existing regional planning and interregional coordination processes may not employ common scenarios, comparable benefit metrics, recurring portfolio analysis, or durable cost-allocation mechanisms. As a result, current regional plans are likely to systematically under-identify transmission projects whose costs and benefits extend across regional boundaries.

E. DOE Should Encourage Regular Joint Seam Planning and Portfolio Comparisons[64]

The final Study should recommend that neighboring regions conduct recurring joint planning using common or compatible scenarios, exchange comparable planning data, identify shared reliability and resource-adequacy needs, use standardized or mutually recognized benefit metrics, evaluate interregional portfolios, and develop durable mechanisms for project selection and cost allocation. These studies should occur on a predictable cycle rather than only when a particular project sponsor or short-term issue prompts a one-off analysis.

The Draft Study also does not assess whether identified regional transmission needs could be addressed more efficiently through alternatives that include additional interregional transfer capability. Without such a comparison, the Study cannot determine whether a series of separate local or regional upgrades would be more costly, less flexible, or provide fewer

[64] This section responds to Section I.a, "How to Use This Study" (pp. 2–3), which encourages holistic portfolio evaluation, and Section VI.d, "Regional Transmission Planning and Coordination" (pp. 64–78), which surveys regional and interregional coordination practices.

reliability benefits than a coordinated interregional solution. This analytical gap is particularly important where neighboring regions are simultaneously planning for load growth, severe weather, generator retirements, or resource-adequacy needs that stronger interregional ties could help address.

F. MISO-SPP Initiatives Demonstrate Both the Potential and the Limitations of Current Seam Planning[65]

Recent MISO-SPP initiatives provide useful examples of what more coordinated seam planning can accomplish. Through the Joint Targeted Interconnection Queue process, MISO and SPP jointly studied transmission constraints limiting generator interconnections along their shared seam and identified a five-project portfolio estimated at approximately $1.6 billion to facilitate generator interconnection. MISO states that the portfolio is expected to enable approximately 28.6 GW of generation to interconnect, and both RTO boards approved the portfolio in December 2024.[66]

The 2024-2025 MISO-SPP Coordinated System Plan likewise provides a useful model. Its study scope calls for coordinated analysis of transmission needs and solutions, including reliability and economic issues and interregional transfer capability, followed by evaluation of solutions and discussion of interregional cost allocation.[67] The process illustrates the value of studying the seam as a system rather than relying entirely on two independent regional processes.

DOE should cite these initiatives as evidence that joint seam studies can identify valuable transmission solutions that may not emerge through traditional regional planning alone. At the

---

[65] This section responds to Section III.b (pp. 11–12) and Section VI.d (pp. 64–78), which discuss MISO-SPP interregional coordination and identify JTIQ as an example of joint seam planning.
[66] Midcontinent Indep. Sys. Operator, Inc., *Generator Interconnection: Joint Targeted Interconnection Queue (JTIQ) Portfolio—Approved December 2024* (stating that the five-project, approximately $1.6 billion portfolio is expected to enable approximately 28.6 GW of generation to interconnect); see also Midcontinent Indep. Sys. Operator, Inc., *MISO Board Approves Historic Transmission Plan to Strengthen Grid Reliability* (Dec. 12, 2024).
[67] Midcontinent Indep. Sys. Operator, Inc. & Sw. Power Pool, Inc., *SPP-MISO 2024–25 Coordinated System Plan Study Scope* 7–9 (Mar. 2025).

same time, their specialized or episodic character underscores the need for a more durable and regularly recurring interregional planning framework. JTIQ demonstrates that joint analysis can identify portfolio solutions across a seam, while also illustrating that such solutions currently tend to emerge through specialized processes rather than a recurring process that evaluates the full range of reliability, economic, resource-adequacy, and public-policy needs. The final Study should draw both lessons: coordinated analysis can work, and the nation still lacks a sufficiently routine mechanism for doing it.

VII. DOE Should More Fully Address Severe Weather, Resilience, and Resource Adequacy[68]

The Draft Study appropriately recognizes that severe-weather events expose limitations in the existing transmission system. It discusses emergency conditions associated with events such as Winter Storm Uri and Winter Storm Elliott and acknowledges that power systems must be prepared for increasingly severe and widespread disruptions.[69] The final Study should preserve this framing but strengthen the underlying analysis so that transmission needs driven by extreme-weather and resilience risks are not understated or overlooked. A more robust assessment would also make the Study more useful to planners and decisionmakers evaluating where additional transmission could reduce vulnerability to widespread or prolonged system stress.

DOE's regional reliability and resilience classification relies heavily on NERC's 2024 Long-Term Reliability Assessment.[70] NERC's assessment is an important source, but it should not be the principal or exclusive basis for identifying transmission-related reliability needs

[68] This section responds to Section V.c, "Resource Adequacy and Resilience Benefits of Transmission" (pp. 54–63), including its discussion of energy emergencies and severe-weather events, as well as the Executive Summary's reliability-and-resilience category (p. viii).
[69] *2026 Draft Needs Study*, supra note 1, at 56–59.
[70] *Id*. at viii & fig. ES-5; *see id*. at 59–68.

nationwide. The final Study should supplement it with other analyses, including FERC-NERC-Regional Entity assessments of major extreme-weather events, such as Winter Storm Uri, Winter Storm Elliott, and the January 2025 Arctic weather events; regional resource-adequacy studies such as the OMS-MISO Resource Adequacy Survey; and regional extreme-weather and seasonal reliability assessments.[71] These sources can identify risks associated with fuel constraints, correlated generator outages, changing load patterns, and extreme weather that may not be fully captured in a single annual adequacy assessment.

The final Study should also evaluate transmission needs under realistic multi-day and multi-region stress events. Scenarios should include extreme heat and cold; drought and hydrological constraints; wildfire and smoke; hurricanes and coastal storms; fuel-delivery disruptions; correlated generator outages; multiple transmission outages; forecast error associated with large-load growth; and compound events affecting several parts of the energy system simultaneously.

The Draft itself recognizes that severe weather can simultaneously increase demand and disrupt generation and transmission infrastructure.[72] DOE should apply that principle to its own analysis and quantify, where practicable, both the transmission need revealed by these events and the reliability and consumer value of additional transfer capability. A line may provide only

---

[71] *See, e.g.,* Fed. Energy Regul. Comm'n, N. Am. Elec. Reliability Corp. & Regional Entities, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 2021) (examining widespread generator outages, fuel-supply constraints, and system conditions during Winter Storm Uri); Fed. Energy Regul. Comm'n, N. Am. Elec. Reliability Corp. & Regional Entities, *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott* (Nov. 2023) (examining widespread generator outages, natural-gas constraints, and system conditions during Winter Storm Elliott); Fed. Energy Regul. Comm'n, N. Am. Elec. Reliability Corp. & Regional Entities, *January 2025 Arctic Events: A System Performance Review* (Apr. 2025) (evaluating bulk-power-system performance during successive periods of extreme cold and the effectiveness of measures adopted following earlier winter events); Org. of MISO States, Inc. & Midcontinent Indep. Sys. Operator, Inc., *2024 OMS-MISO Resource Adequacy Survey* 1–2 (June 2024) (identifying seasonal capacity risks, rapidly growing large loads, and the effects of extreme weather and resource accreditation on resource adequacy); ISO New England, Inc., *Operational Impact of Extreme Weather Events* (Dec. 2023) (evaluating energy-shortfall risks under stressful weather and operating conditions in 2027 and 2032).

[72] *2026 Draft Needs Study*, supra note 1, at 56–59, 81–82.

moderate benefits during ordinary conditions but exceptionally large reliability and consumer benefits during a system emergency or other period of grid stress. Planning methods that rely primarily on annual averages or normal-weather conditions can therefore systematically undervalue this insurance function.[73]

DOE should also emphasize that resilience benefits may be inherently interregional. Severe weather does not affect all regions identically or at the same time. Stronger interregional ties can allow power to move from areas with available generation and lower demand to areas experiencing outages, fuel constraints, or unexpectedly high load. That geographic diversity is one of the principal reasons the final Study should integrate its severe-weather analysis with its assessment of interregional transfer capability rather than treating the two issues separately.

VIII. DOE Should Expand the Study's Treatment of Advanced Transmission Technologies[74]

The Draft appropriately recognizes Advanced Transmission Technologies (ATTs) including dynamic line ratings (DLRs), advanced conductors and reconductoring, advanced power flow control devices, and transmission switching or topology optimization as part of the transmission solution set. These technologies can increase the usable capacity of existing facilities, relieve congestion, improve operational flexibility, and in some cases defer or reduce the need for more costly conventional upgrades. DOE specifically notes that DLRs can allow

---

[73] *See* U.S. Dep't of Energy, *National Transmission Needs Study* 41 (Oct. 2023) (finding that, in the median case, the top 5% of hours account for approximately half of transmission congestion value and that designated extreme events account for 10%–20% of total value; explaining that properly representing extreme weather, fuel-price volatility, generation and load uncertainty, and other challenging grid conditions is "critical" to accurately accounting for the value of transmission investments, and that failing to do so can produce transmission plans that do not address the adverse effects of congestion and constraints over time); *see also* U.S. Dep't of Energy, *National Transmission Planning Study* ch. 5 (Oct. 2024) (evaluating transmission-system performance during approximately week-long extreme heat and cold events through resource-adequacy and production-cost modeling).

[74] This section responds to the Draft's treatment of grid-enhancing technologies in Section I (p. 2) and Section V.b, "Regional Congestion Management" (including the DLR example at p. 48), as well as its broader discussion of transmission solutions and regional planning.

resources to connect more quickly and at lower near-term cost and cites PPL's reported DLR pilot savings.[75] These examples are useful, but the final Study should include ATTs more systematically throughout the analysis rather than primarily as discrete examples.

DOE should address DLRs, advanced conductors and reconductoring, advanced power flow control devices, topology optimization or transmission switching, and advanced monitoring and control technologies by explaining where these technologies can increase usable capacity on existing infrastructure, reduce congestion, accelerate generation and load interconnections, improve operational flexibility, and reduce or defer conventional upgrades.

The final Study should also encourage planners to evaluate ATTs early and alongside conventional solutions. DOE need not independently model every potential deployment. Instead, it could draw on existing utility, RTO/ISO, national laboratory, and FERC studies to identify representative opportunities for DLRs, advanced conductors, advanced power flow control devices, and topology optimization/switching.[76] Where the record permits, the final Study should summarize the additional transfer capability these technologies can provide, typical deployment timelines, congestion or production-cost savings, reliability benefits, and the types of constraints that still require new transmission. Order No. 1920's requirement that planners consider DLRs, advanced power flow controls, advanced conductors, and transmission switching in specified planning contexts reinforces the importance of systematic evaluation.[77]

---

[75] *2026 Draft Needs Study*, supra note 1, at 48.
[76] *See, e.g.*, U.S. Dep't of Energy, *Advanced Transmission Technologies* 1–3, 19–35 (Dec. 2020) (examining opportunities for dynamic line ratings, advanced power flow control devices, topology optimization, and other advanced transmission technologies to increase transmission-system efficiency, capacity, reliability, and resilience); *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068, P 1198 (2024) (requiring transmission providers to consider dynamic line ratings, advanced power flow control devices, advanced conductors, and transmission switching in regional transmission planning).
[77] Order No. 1920, 187 FERC ¶ 61,068, PP 1198–1248 (requiring consideration of specified alternative transmission technologies in long-term regional transmission planning).

At the same time, DOE should avoid suggesting that ATTs eliminate the need for new high-capacity regional or interregional facilities. Many constraints are geographic, stability-related, voltage-related, or simply too large to be resolved by optimizing existing facilities alone. The appropriate comparison is among portfolios of solutions. In many locations the least-cost approach will combine better utilization of existing infrastructure with reconductoring, uprating, and construction of new high-capacity lines.

IX. DOE Should Address HVDC Supply Chain Constraints[78]

Supply chain constraints for high-voltage transmission equipment are becoming a significant bottleneck to the development of beneficial regional and interregional transmission. A recent analysis found that prices and wait times for transformers and cables have nearly doubled since 2021,[79] with even greater challenges for specialized equipment such as HVDC cables and converter-station components. These constraints are exacerbated by a market concentrated among a relatively small number of global suppliers whose manufacturing and engineering capacity is often committed years in advance. Individual transmission projects may also lack the scale or certainty needed to secure production slots, support new manufacturing investment, or reduce costs through larger and more predictable orders.

DOE has previously identified strategies for addressing transmission supply chain constraints, including in its 2022 report on securing clean-energy supply chains.[80] But market conditions have changed substantially since that report was issued. DOE should revisit and

---

[78] This section responds to Section VI's discussion of anticipated future transmission needs and development across regions (pp. 64–81), including barriers affecting the timely development of needed regional and interregional transmission infrastructure.

[79] International Energy Agency, *Building the Future Transmission Grid: Strategies to Navigate Supply Chain Challenges* (Feb. 2025).

[80] U.S. Dep't of Energy, *America's Strategy to Secure the Supply Chain for a Robust Clean Energy Transition* (Feb. 2022).

update those recommendations, including by identifying actions the federal government can take to expand domestic manufacturing capacity, improve procurement certainty, and reduce supply chain risks for HVDC and other critical transmission equipment.

Recent analysis also identifies a need for further evaluation of the feasibility, costs, and policy incentives associated with attracting U.S.-based converter and cable manufacturing.[81] Potential measures include domestic-content or Buy America requirements, tax incentives, workforce-development support, and other policies that could create sufficient long-term demand to support new manufacturing investment. DOE is well positioned to evaluate these options and coordinate federal efforts. DOE should identify supply-chain constraints that could impede timely development of transmission needed to address the needs identified in the Study and identify existing or potential federal tools for mitigating those constraints. The Final Study should therefore include a discussion of transmission supply chain bottlenecks and recommendations for using DOE's authorities and other federal policy tools to help address them.

X. DOE Should Cite Specific Processes to Illustrate How Identified Needs Can Be Addressed and This Report Can be Used[82]

The final Study would be more useful if it connected the categories of transmission needs it identifies with representative examples of transmission efforts and solutions already being planned or developed. DOE need not endorse individual projects or processes, nor determine that a particular planning effort is the only appropriate solution to overcome a barrier to transmission

[81] POINTS Consortium, *Procurement and Contracting Strategies* (June 2026).
[82] This section responds to Section I.a, "How to Use This Study" (pp. 2–3), the Executive Summary's examples of recently approved portfolios and JTIQ (pp. vii–viii), and Section VI's review of regional planning reports (pp. 64–81).

deployment. But case studies of ongoing efforts and processes can demonstrate that the needs identified in the Study are technically actionable rather than abstract.

Appropriate examples could include processes that incentivize or enable the expansion of transfer capability across regional seams, service of rapidly growing load, resolution of recurring reliability constraints, congestion reduction, increase of generator-interconnection capability, use of ATTs, or provision of multiple categories of benefits. JTIQ is particularly relevant because it demonstrates a joint regional process focused on a constrained seam and a portfolio solution designed to address multiple interconnection limitations.[83]

DOE should also identify, where appropriate, the federal financing, funding, or technical-assistance programs that can help move projects from identified need to construction. The purpose should not be to predetermine outcomes, but to make clear how the Needs Study can inform practical steps by federal agencies, states, utilities, regional planners, and private developers. Financing programs like the Transmission Facilitation Program reduce developer risk on longer-distance, high-voltage lines that can deliver the benefits put forth in this Study.

DOE can also identify permitting tools and efforts aimed at reducing barriers to deploying transmission lines. For example, DOE could highlight ongoing permitting efforts and processes that do not yet amplify and incorporate interregional transmission benefits found in this Study but could incorporate and leverage the Study's findings. For example, the Federal Permitting Improvement Steering Council ("Permitting Council") is developing memoranda of understanding (MOU) with states to align federal and state transmission permitting

[83] *See 2026 Draft Needs Study*, *supra* note 1, at 12; Midcontinent Indep. Sys. Operator, Inc., *Generator Interconnection: Joint Targeted Interconnection Queue (JTIQ) Portfolio—Approved December 2024*.

processes.[84] The potential for future MOUs with more states increases the opportunity for the Permitting Council to discuss and share benefits of greater transmission connections between these states and the regions in which they sit. These MOUs could begin to incorporate or consider opportunities to, where relevant and in cooperation with states, develop and streamline interstate and interregional permitting processes to unlock benefits.

Across the West, this Study could also be an important input to and validator of efforts like the Western Transmission Expansion Coalition (WestTEC) and the Permitting Alignment and Coordination Task Force (PACT). A bipartisan group of Western governors signed the PACT agreement to find opportunities to improve transmission permitting processes across their states. A more coordinated permitting framework across the West could unlock transmission with reliability, resiliency, and affordability benefits illustrated by this Study.

XI. DOE Should Strengthen Its Discussion of Tribal Participation in Transmission Planning[85]

In Section VI.d. of the Draft 2026 National Transmission Needs Study, DOE discusses anticipated future transmission needs and development across different regions of the country. As part of that discussion, DOE recognizes that Tribal Nations have a wide range of energy needs and goals and that additional analysis focused specifically on Tribal lands could help identify opportunities for transmission development.[86] DOE also identifies transmission needs on

[84] *See* Fed. Permitting Improvement Steering Council, *Permitting Council Announces Two New Federal-State Agreements to Streamline Permitting* (July 23, 2026), https://urldefense.com/v3/__https://www.permitting.gov/newsroom/press-releases/permitting-council-announces-two-new-federal-state-agreements-streamline.
[85] This section responds to Section VI.d of the *2026 Draft Needs Study*.
[86] *See 2026 Draft Needs Study*, *supra* note 1, at 64.

or near Tribal lands, noting that additional investment could support continued energy development and improve reliability, security, and resilience for Tribal communities.[87]

At the same time, DOE acknowledges that planning, siting, permitting, and constructing transmission on Tribal lands "can be a challenging process that spans multiple jurisdictions and types of land ownership and requires building trust between Tribal governments and transmission planners, owners, and operators."[88] Given these complexities, DOE should expand this discussion to expressly recognize Tribal sovereignty and the importance of ensuring that Tribal Nations have meaningful and sustained representation in transmission planning processes that may affect their lands, resources, or communities.

The 2026 National Laboratory of the Rockies report on *Tribal Engagement in Transmission Planning*, which DOE cites, provides important context. The report explains that the Constitution expressly recognizes Indian Tribes in the Commerce Clause and that Tribes possess a distinct sovereign status under federal law.[89] It further emphasizes that Tribes are not simply utilities or other stakeholders in transmission-planning processes; they are sovereign governmental entities with a unique government-to-government relationship with the United States.[90] DOE should reflect that distinction in the final Study and encourage transmission planners to engage Tribal Nations early and meaningfully, including in the identification of needs, development of alternatives, evaluation of impacts and benefits, and consideration of projects affecting Tribal lands and interests.

---

[87] *Id.* at 79.
[88] *Id.*
[89] D. J. Hurlbut et al., National Laboratory of the Rockies, *Tribal Engagement in Transmission Planning* 8 (Feb. 2026), https://docs.nlr.gov/docs/fy26osti/97009.pdf.
[90] *Id.*

Accordingly, PIOs recommend that DOE insert the following language in Section VI.d, page 79, immediately after DOE's discussion of the challenges associated with planning, siting, permitting, and constructing transmission on Tribal lands:

> Tribal Nations occupy a distinct role in transmission planning because they are sovereign governmental entities, not merely utilities or stakeholders participating in a planning process. Transmission planning that may affect Tribal lands, resources, or communities should therefore provide for early, meaningful, and sustained Tribal engagement consistent with this sovereign status. Such engagement should occur throughout the planning process, including in the identification of transmission needs, development and evaluation of alternatives, assessment of project impacts and benefits, and consideration of projects that may affect Tribal lands or interests. Early engagement can also help identify opportunities for transmission development that advance Tribal energy goals while avoiding or addressing potential impacts before project decisions are substantially complete.

XII. The Executive Summary Should Accurately Communicate the Study's Most Important Findings[91]

The Executive Summary is likely to be the portion of the Study most frequently read and cited by policymakers and stakeholders. It should therefore accurately communicate the principal national transmission needs rather than requiring readers to identify critical findings buried in individual regional discussions.

In particular, DOE should revise the Executive Summary and Figure ES-5 to reflect projected future load growth, existing within-region congestion, transfer-capability limitations between regions, the resource-adequacy and resilience benefits of interregional transmission, limited recent development of high-capacity regional transmission, and limited recent interregional construction. A region should not appear to have no significant transmission need

[91] This section responds directly to the Executive Summary (pp. ii–viii), especially Figure ES-5 (p. viii), which summarizes regional needs using four categories derived from the Study's historical congestion, transfer-capability, and resource-adequacy analyses.

merely because an emerging need driven by future load growth or resilience is not captured by one of the existing summary indicators.

DOE should likewise ensure that findings it considers important enough to support future regional or federal action are visible in the summary materials. The body of the Study may appropriately contain methodological nuance, but the high-level presentation should not inadvertently erase a significant transmission need simply because it does not fit neatly within one historical metric.

XIII. Additional Technical Corrections[92]

PIOs recommend several narrower technical and presentational corrections. DOE should update Figure III-8 and its accompanying discussion to reflect current SPP Western expansion and reliability-coordination arrangements.[93] More generally, where the Study depicts transmission-planning boundaries, DOE should ensure that the figures clearly distinguish its analytical regions from the 11 Order No. 1000 transmission planning regions used for regional and interregional transmission planning.

Finally, DOE should clarify the units reported in Table IV-1. Because the table presents a nine-year average of annual circuit-mile sums, the unit should be expressed as circuit-miles per year rather than simply circuit-miles.[94] This correction would make the table easier to interpret and reduce the risk that readers mistake an annualized value for total mileage over the full study period.

---

[92] Responds to Section III.c, "Transmission Regions" (pp. 12–17), Figures III-2 and III-8 (pp. 14 and 23), and Section IV's Table IV-1 (p. 30), which are the specific figures and table addressed by the technical corrections below.
[93] *Id*. at 23 fig. III-8.
[94] *Id*. at 30 tbl. IV-1.

XIV. Conclusion

The Draft 2026 National Transmission Needs Study contains several important findings that DOE should preserve and strengthen. DOE correctly identifies projected rapidly increasing electricity demand as a principal driver of transmission need, demonstrates substantial congestion throughout the country, provides valuable new analysis for the Southeast, and finds that interregional and cross-interconnection transmission can offer especially significant economic, reliability, and resource adequacy value.

The final Study should make those conclusions more useful for decision-makers by quantifying future need, adding load growth to its principal summary of regional needs, distinguishing routine and lower-voltage investment from high-capacity regional and interregional expansion, and more fully addressing interregional planning, severe weather, resource adequacy, and advanced transmission technologies. It should also make clear that the amount of historical transmission activity reflected in circuit-mile statistics does not answer the central planning question: how much additional usable transfer capability the system needs, and where, to reliably and economically serve future demand.

A stronger final Study would provide states, regional planners, utilities, federal agencies, and consumers with a clearer picture of where transmission capability is insufficient today, how much additional capability may be needed in the future, where that capability is most valuable, and which categories of solutions should be evaluated. That is particularly important now, when rapid load growth and increasingly consequential system-stress events make delayed transmission development both more expensive and more difficult to remedy. PIOs therefore urge DOE to retain the Draft's strongest findings and adopt the revisions described above.

Respectfully submitted,

/s/ Cullen Howe
Cullen Howe
Senior Attorney
Natural Resources Defense Council
40 West 20th Street
New York, NY 10011
chowe@nrdc.org

/s/ John Moore
John Moore
Director
Sustainable FERC Project
1125 15th Street NW, Suite 300
Washington, DC 20005
Moore.fercproject@gmail.com

/s/ Nick Fitzmaurice
Nick Fitzmaurice
Energy Transition Engineer
Montana Environmental Information Center
P.O. Box 1184
Helena, MT 59624
nfitzmaurice@meic.org

/s/ Jacob Richardson
Jacob Richardson
Senior Transmission Policy Advisor
Western Resource Advocates
307 West 200 S #2000
Salt Lake City, UT 84101
jacob.richardson@westernresources.org

s/ Nicholas J. Guidi
Nicholas J. Guidi
Senior Attorney
/s/ Katherine L. Rogers
Katherine L. Rogers
Associate Attorney
Southern Environmental Law Center
500 New Jersey Ave. NW, Suite 600
Washington, DC 20001
nguidi@selc.org
krogers@selc.org

/s/ Kavya Niranjan
Kavya Niranjan
Senior Markets & Transmission Policy Manager
Renewable Northwest
421 SW 6th Ave, Suite 1400
Portland, OR 97204
kavya@renewablenw.org

/s/ Nicole Pavia
Nicole Pavia
Director, Clean Energy Infrastructure Deployment
Clean Air Task Force
114 State Street, 6th Floor
Boston, MA 02109
npavia@catf.us

/s/ Phelps Turner
Phelps Turner
Senior Attorney
Environmental Defense Fund
257 Park Avenue South
New York, NY 10010
pturner@edf.org