September 8, 2026

Submitted electronically via NeedsStudy.Comments@hq.doe.gov

Office of Electricity
United States Department of Energy
1000 Independence Ave., SW
Washington, DC 20585

Public Power Comments on Draft 2026 National Transmission Needs Study

The American Public Power Association (APPA) and Large Public Power Council (LPPC) appreciate the opportunity to comment on the Department of Energy's (DOE or Department) draft 2026 National Transmission Needs Study (Draft Study).

The final 2026 National Transmission Needs Study (Final Study) will inform DOE's designation of National Interest Electric Transmission Corridors (NIETCs) and its coordination of federal transmission financing and permitting authorities. Because the Final Study's findings will be cited in consequential proceedings, APPA and LPPC urge the Department to take care that the Final Study is precise about what it does—and does not—conclude. We therefore ask that the Final Study do three things: (1) state plainly that it identifies needs rather than solutions; (2) explain what its economic and reliability findings do not establish; and (3) state that affordability must govern how the study's identified needs are met.

The affordability of transmission, however, does not rest on the Final Study alone. In Section III, APPA and LPPC offer broader considerations for DOE as it exercises the transmission authorities the Final Study informs.

I. About the American Public Power Association and Large Public Power Council

APPA is the voice of not-for-profit, community-owned utilities that power 2,000 towns and cities nationwide. Public power utilities are in every state except Hawaii. They collectively serve over 55 million people in 49 states and five U.S. territories, and account for 15 percent of all sales of electric energy (kilowatt-hours) to end-use consumers.

LPPC represents 29 of the nation's largest state and locally owned, not-for-profit public power systems, serving 30.5 million Americans across 23 states and territories. LPPC's members include the larger, asset-owning members of the public power community and account for approximately 90 percent of the transmission assets owned by public power. LPPC members are also members of APPA.

Public power utilities are load-serving entities, with the primary goal of providing the communities they serve with safe, reliable electric service at the lowest reasonable cost, consistent with good environmental stewardship. This orientation aligns the interests of the utilities with the long-term interests of the residents and businesses in their communities.

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II. COMMENTS ON THE DRAFT STUDY

II.A. The Final Study should state plainly that it identifies needs, not solutions.

The Draft Study's Executive Summary states that its purpose "is not to prescribe particular solutions to issues faced by the nation's power sector, but rather to assess need in order for industry and the public to suggest the best possible solutions."[1] And in its section explaining how the study is to be used, the Draft Study asserts that it "is not meant to displace" existing planning processes or reliability standards.[2] APPA and LPPC wholeheartedly agree with both those statements.

But after expressing those foundational limits in the prefatory text, the Draft Study does not repeat either statement alongside the findings it qualifies, nor does it elaborate on the implications of each statement. A reader who begins with the key findings—as many will—would encounter the study's conclusions about need without DOE's own explanation of the conclusions' limits. We ask that the Final Study restate its "no solutions" and "no displacement" caveats in the body of the study,[3] and elaborate on four necessary implications of those limitations: (1) that transmission may not be the most cost-effective solution to an identified congestion or reliability need; (2) that no uniform, national prescription for regional or interregional transmission is justified; (3) that existing planning processes be used to identify any transmission projects, portfolios, locations, or corridors that will meet the needs identified by the Final Study; and (4) that DOE's own use of the study, including any NIETC designation, will respect the same limitation.

[1] Draft Study at iii.
[2] Draft Study at 2.
[3] For example, at the outset of Chapter V.

First, an identified need does not establish that transmission is the best way to meet it. The Draft Study contemplates that a need may be addressed not only by building new transmission, but also by upgrading or uprating an existing facility, deploying grid-enhancing technologies, or other alternative solutions.[4] APPA and LPPC support that framing. But the Draft Study goes no further: it does not compare the cost of new transmission against retaining existing generation, building new generation, or managing demand. That, of course, is not a defect; it is a deliberate limitation of the study's scope. The Final Study only needs to describe it. We therefore ask DOE to state expressly that it has not made that comparison, and that an identified need is best met by whichever solution proves most cost-effective in the region where the need arises.[5] Moreover, an identified need in the Final Study does not create—and should not be construed as—an obligation on any particular transmission provider to address that need.

Second, the Final Study should state that no uniform national prescription follows from its findings. DOE's own data show why. Between 2016 and 2024, ERCOT and MISO North energized 6.2 and 5.1 circuit-miles per terawatt-hour of annual load, while NorthernGrid South, NorthernGrid West, PJM West, and the Southeast each energized fewer than 1.2.[6] Over the same period, average annual capital expenditures were highest in PJM East, at $3.5 billion, while ERCOT spent only $2.1 billion for nearly double the number of circuit-miles.[7] A study that documents variation of this magnitude should say expressly that its findings support no one-size-fits-all approach to transmission expansion, and that the scale and character of any solution must be determined region by region.[8]

Third, the logical extension of the Draft Study's "no solutions" and "no displacement" limitations is that existing planning processes are the most appropriate forum to determine whether any particular project or portfolio of projects is the most cost-effective solution to identified needs. The essential step between identification of need and the selection of a solution is precisely the domain of the existing planning processes that DOE says it is not displacing. As the Draft Study recognizes, those existing regional and interregional planning processes are overseen by the Federal Energy Regulatory Commission (FERC), which prescribes rigorous protocols for evaluating, selecting, and allocating costs of transmission projects.[9] We therefore ask that the Final Study emphasize that identifying particular projects, portfolios, locations, and corridors remains the province of those processes.[10]

Finally, we ask that the Final Study state that the "no displacement" principle will extend to further DOE actions that are informed by the study, most notably the designation of any NIETCs. Designation is consequential: it enables DOE and FERC to use federal financing and permitting

[4] Draft Study at 1-2.
[5] Such a statement would be appropriate, for example, in Sections I and V.a of the Draft Study.
[6] Draft Study at 26.
[7] *Id*.
[8] Such a statement would be appropriate, for example, in Sections IV, VI, and VII.
[9] Draft Study at 11-12 (describing the FERC-approved processes under Order 1000 and Order 1920).
[10] Such a statement would be appropriate, for example, in Sections I, II, VI.e, and VII.

tools within the designated area, and the Department has said it will consider the results of the Final Study when issuing any designation report. Where the planning entities in a region, through their FERC-approved processes, have identified and selected solutions to the needs the Final Study describes, those solutions—and the geographic areas they occupy—should be DOE's starting point in considering whether and where to designate a corridor. This alignment will advance the national objective of building cost-effective transmission to meet future needs; conversely, if the Department were to designate NIETCs disconnected from the FERC-approved processes, transmission projects within those corridors would likely face substantial hurdles and uncertainty over cost recovery, which is provided for under FERC's Order 1920 regional planning protocols for projects selected under that framework. We therefore ask that the Final Study state that solutions selected through existing planning processes will inform DOE's consideration of any corridor, and that it will explain its reasoning should it consider a corridor those processes have not identified. Grounding designation in the regional record strengthens it. A designation traceable to solutions that states, planners, and load-serving entities have already vetted is more durable than one that is not.

II.B. The Final Study should explain what its economic and reliability findings do not establish.

The Draft Study's economic and reliability findings are its most quantified, and those quantified findings are most readily quoted. But without full context, the study's numerical findings can be misconstrued. We therefore urge DOE to state explicitly the limits of its findings. Specifically, four findings warrant that treatment: the Draft Study's calculation of the savings available from increased transfer capability; its use of historical congestion costs to indicate future value; its use of fixed-in-time regional analyses; and its identification of resource adequacy benefits from transmission.

First, the Draft Study reports the savings available from increased transfer capability without reporting what achieving that capability would cost.[11] Those benefit figures standing alone invite the inference that the benefit is worth having. But that inference does not follow. A full cost-benefit analysis requires quantification not just of benefits, but also of the costs of preferred and alternative solutions.[12] The Draft Study does not do so; and APPA and LPPC do not suggest that it should. But the Final Study should state that its transfer capability findings identify potential value, not net benefit, and do not establish that any particular investment to capture that value would be cost-effective.[13]

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[11] Draft Study, Section V.a.

[12] *See, e.g.,* OMB Circular A-4, Regulatory Analysis at 2 (Sept. 17, 2003) (sound analysis requires "an evaluation of benefits *and costs*—quantitative and qualitative—of the proposed action and main alternatives.") (emphasis added).

[13] The Draft Study acknowledges this fact in Section III.d: "In actual cases, these benefits, intrinsically, might or might not be sufficiently large and recurrent to warrant the investment." But that admission should be repeated alongside the actual findings in Section V.

Second, historical congestion is an imperfect proxy for future value. The Draft Study derives much of its analysis from historical locational marginal prices and observed congestion patterns.[14] Those patterns reflect the resource mix, load profile, fuel prices, and outage history of the years measured, and each of those inputs is changing. The Draft Study itself demonstrates the sensitivity: MISO's congestion costs fell by half in a single year not due to new transmission, but rather through "the decline in natural gas prices and the decrease in overall wind output."[15] A congestion value calculated on historical data measures what a constraint cost under conditions that obtained, not what relieving it will be worth under conditions to come. The Final Study should say as much where those figures appear.

Third, the Draft Study's regional findings are a snapshot of planning documents that their authors continue to revise. For example, the Draft Study reports that Salt River Project's 2023 Integrated System Plan identified a need for up to 380 miles of new or upgraded 500 kilovolt (kV) and 230 kV transmission and twelve new 500/230 kV transformers over the next decade.[16] Salt River Project's 2025 ISP Action Progress Report has since updated those figures, based on additional studies and stakeholder input, to 565 miles of new 500 kV transmission and fourteen new 500/230 kV transformers by 2035.[17] We offer this example to highlight how a study that reviews more than 120 published reports necessarily captures each of them as of a date, and DOE cannot be expected to track every subsequent revision. The point is that the regional planning entities on which the Draft Study relies are continuously refining their own assessments and will do so repeatedly before the next triennial study, particularly as utilities face historic and difficult-to-predict load growth. The Final Study should state that its regional findings reflect the planning record as of publication and that the most current regional plans, not this study, are the authoritative source for any region's transmission needs.

Fourth, the resource adequacy findings identify avoided harm, not net benefit. The Draft Study documents real and serious events—Winter Storm Elliott, the August 2020 Western heat wave, the 2019 Swan Lake fire—and cites analyses estimating what additional transfer capability would have been worth during them.[18] These are the right questions to ask, and APPA and LPPC do not dispute the findings. But an estimate of harm avoided during a discrete event is not a measure of the value of the infrastructure that would have avoided it, which must be paid for every year, including the years no such event occurs. Moreover, the Draft Study does not

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[14] We also note that, outside organized markets, the Draft Study admits that its methodological limitations can contribute to over- or underestimation of congestion. Draft Study at 40, n. 38. This further limits the conclusions that can be drawn from the study's data.
[15] Draft Study at 47 (citing Potomac Economics, 2024d).
[16] Draft Study at 75. *See also* Salt River Project, 2023 Integrated System Plan, pg. 117, *available at* https://azure-na-assets.contentstack.com/v3/assets/bltefc1fc708dcc94e7/bltbadf8fd7923f3abe/SRP-2023-Integrated-System-Plan-Report.pdf.
[17] Salt River Project, Integrated System Plan Actions Progress Report 2025, pg. 9, *available at* https://azure-na-assets.contentstack.com/v3/assets/bltefc1fc708dcc94e7/bltd708f9227acdf57e/SRP-2025-ISP-Actions-Progress-Report.pdf.
[18] Draft Study at 59, 60-61, 63.

evaluate the extent to which operational constraints—interchange rules, scheduling and tagging requirements, and market seams—limited transmission flows during those extreme events. Nor does the Draft Study compare transmission against other means of achieving the same resilience. The Final Study should state that its resource adequacy analysis quantifies the consequences of particular past events and does not establish the cost-effectiveness of any transmission investment relative to alternatives.

II.C. The Final Study should state that identified needs must be met at the lowest reasonable cost to consumers.

Congress made consumer cost a criterion of the authority this study informs: in determining whether to designate a NIETC, the Secretary may consider whether the corridor is constrained by a lack of "adequate or reasonably priced electricity" and whether the designation "would result in a reduction in the cost to purchase electric energy for consumers."[19] Two of the eight statutory considerations are price considerations. The Draft Study likewise defines transmission need in part by reference to the delivery of "cost-effective generation to meet demand."[20] APPA and LPPC ask that the Final Study carry that principle through to its conclusions: all needs identified in this study should be addressed at the lowest reasonable cost to consumers.

The Draft Study's own analysis shows why this cannot be assumed. ISO-New England averaged $0.37 per megawatt-hour in congestion costs from 2021 to 2023, a fraction of the average in other RTO markets.[21] The Draft Study attributes that result to significant transmission investment over the past decade—investment that also produced a transmission rate of approximately $22 per megawatt-hour in 2023, more than twice the average rate in other RTO markets.[22] The region's market monitor concluded that additional transmission investment there is unlikely to be economical in the near term.[23] Low congestion and low consumer cost are not the same measure, and a region can achieve the first without achieving the second.

This is particularly true as the ultimate price of transmission continues to exceed original estimates.[24] For example, the Draft Study reports that MISO approved eighteen projects at a cost of $10.3 billion for its Tranche 1 portfolio.[25] But MISO's latest report shows that the portfolio's estimated cost has increased to $11.7 billion, with only one project having commenced construction.[26]

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[19] 16 U.S.C. § 824p(a)(4)(A), (H); *see also* Draft Study at 5 n.10 (quoting the statutory criteria).
[20] Draft Study at 2.
[21] Draft Study at 46.
[22] Draft Study at 46-47.
[23] Draft Study at 47.
[24] *See infra* Section III.C.
[25] Draft Study at 67.
[26] MISO, Multi-Value Project Dashboard – Tranche 1 Portfolio (June 30, 2026), *available at* https://cdn.misoenergy.org/Tranche 1 Dashboard732077.pdf?v=20251215143928.

We therefore urge DOE to emphasize the importance of affordability in the Final Study, consistent with the Department's congressional mandate and the President's executive orders.

III. Affordability Considerations for DOE's Related Transmission Authorities

While our requests in Section II are directed at the Final Study, the affordability of transmission does not rest on the study alone. DOE and other federal entities exercise several authorities that bear directly on what transmission costs and how quickly it can be built. In this section, APPA and LPPC offer three suggestions on how federal policy can support transmission affordability.

III.A. Federal policy should adopt infrastructure-neutral permitting reform.

Long permitting timelines increase total costs before lines enter service. Delays caused by permitting, litigation, and approvals increase total project costs before a single megawatt is delivered. Those costs are borne by customers regardless of whether the delay produced any offsetting benefit. APPA and LPPC support infrastructure-neutral federal permitting reform, supported by judicial reforms, increased digitalization, interagency information sharing, and sustained funding and training for agencies involved in federal reviews and permits.

III.B. Federal policy should expand opportunities for load-serving entities to jointly own new transmission.

Federal policy should favor projects whose developers have offered load-serving entities, including public power utilities, a meaningful opportunity to take an ownership share. Joint ownership reduces costs while increasing local benefits and support for infrastructure projects. Public power utilities finance transmission at lower cost than investor-owned counterparts and do not earn a return on equity, and joint ownership passes that advantage through to the customers who pay for the line. Joint ownership also aligns the entities bearing a project's cost with the entities deciding to build it—the accountability DOE identifies as essential to sound planning.

Specifically, we urge policymakers to condition any transmission incentives for investor-owned utilities and any federal transmission funding on a demonstration that the investor-owned utility has made a meaningful offer to load-serving entities for joint ownership. We also recommend that joint ownership by not-for-profit, community-owned utilities be considered a positive factor in selecting regional and interregional projects.

III.C. Federal policy should address the supply chain constraints raising transmission costs and delaying projects.

Many APPA and LPPC members developing new generation and transmission projects are experiencing challenges with procurement of major equipment, notably circuit breakers, switchgear, transformers, and turbines. Limited manufacturing capacity and material constraints constrain the electric industry's ability to execute projects in a timely fashion. Members report two problems: delays and price changes. Some suppliers have told members that ordered equipment will be delayed for months or even years. In addition, delivery timelines for certain equipment are now double (or even longer) what they were just a couple of years ago, requiring members to enter into large long-term contracts to secure delivery priority multiple years out. There are various reasons for the much longer production times to manufacture the equipment, but one noteworthy factor is limited access to critical raw materials. These delays disrupt project timelines.

Other suppliers are increasing the cost of equipment: multiple members reported cost increases in the range of 15 to 20 percent from the time of a preliminary quote to the time of the order; others have reported price increases even after orders are completed. DOE should coordinate within the administration to establish a centralized vetting authority to strengthen oversight and alignment on critical electric equipment and materials.