2025 TRANSMISSION PLANNING AND DEVELOPMENT REPORT CARD

ASSESSING PROGRESS AND SHORTFALLS AS DEMAND ACCELERATES NATIONWIDE

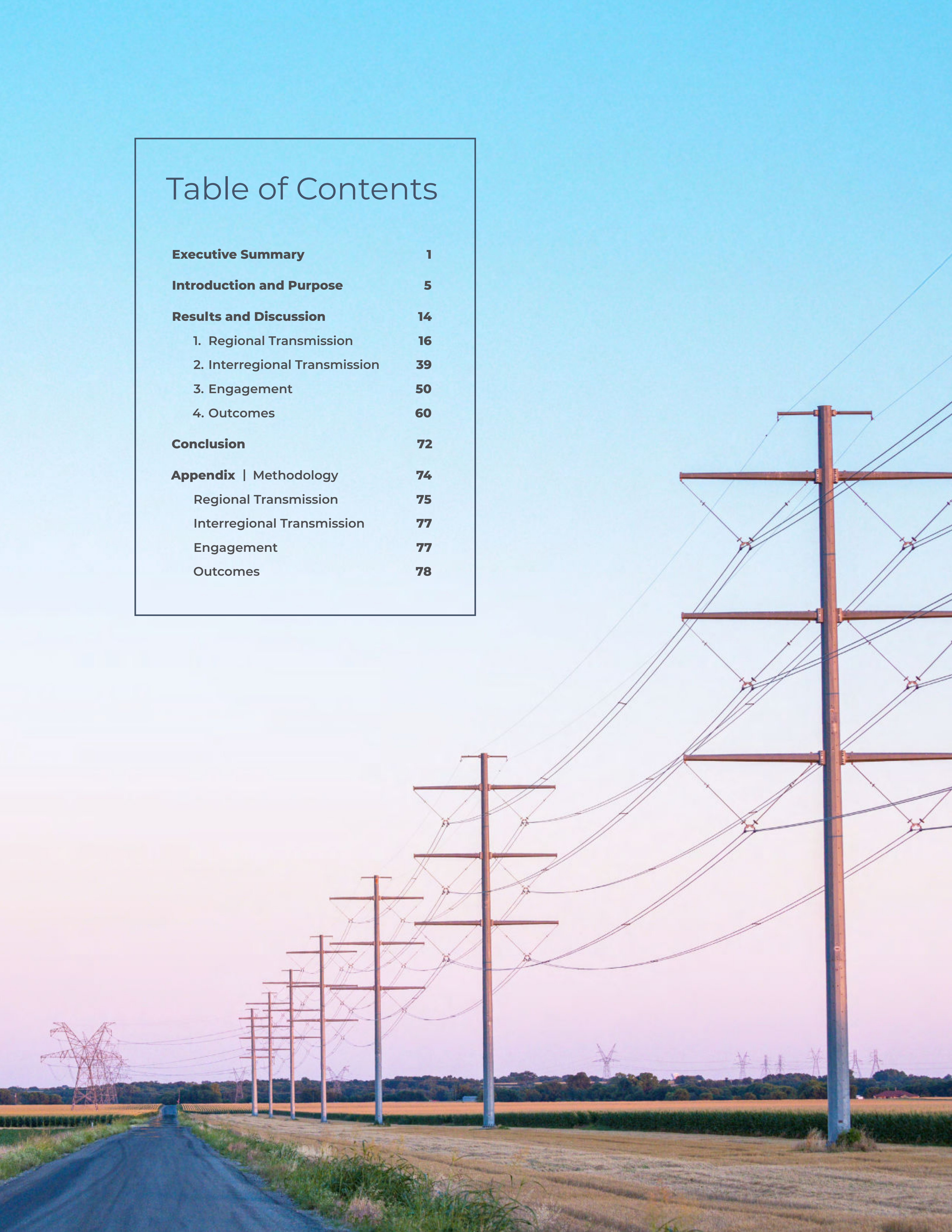
Authors | Zach Zimmerman, Adria E. Brooks, Rob Gramlich, Nathan Shreve, Danish Jamal

GridStrategies

Americans for a Clean Energy Grid

Americans for a Clean Energy Grid (ACEG) is a non-profit broad-based public interest advocacy coalition focused on the need to expand, integrate, and modernize the North American high-capacity grid.

FEBRUARY 2026



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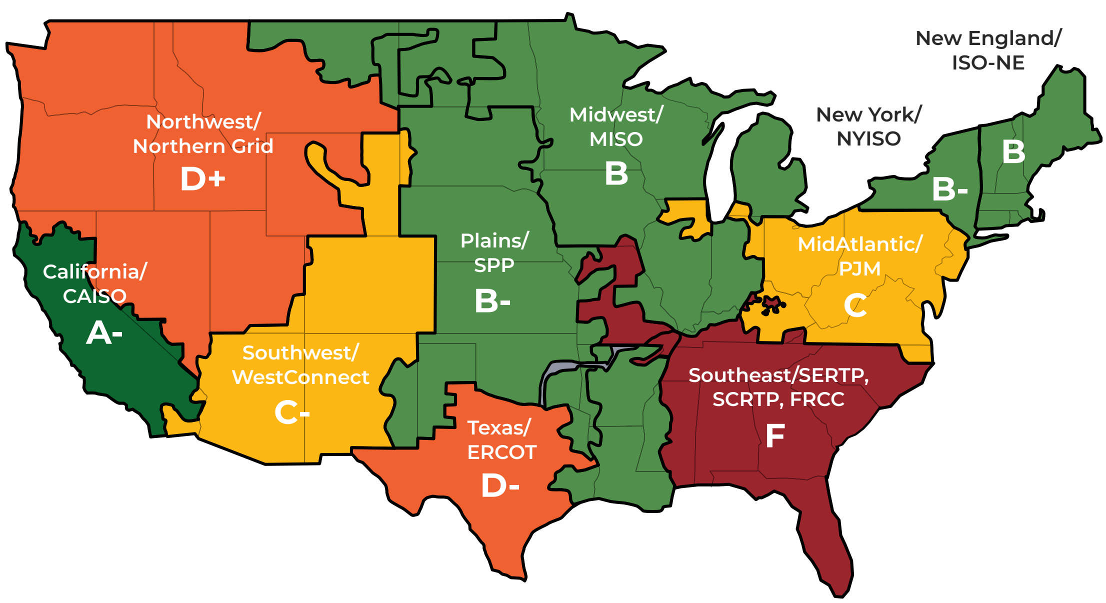
Executive Summary

The 2025 Transmission Planning and Development Report Card provides an updated assessment of U.S. transmission planning and development across ten regions. The first edition of the Report Card was published in 2023. **Overall, this edition of the Report Card shows incremental improvement in transmission planning across most of the regions, driven largely by reforms to regional planning. However, many regions continue to fall well short of best practices, and progress remains uneven relative to the scale and urgency of today's transmission needs.** Accelerating electricity demand — driven by data centers, manufacturing growth, and electrification — is increasing the importance of forward-looking transmission planning, compressing planning timelines, and raising the stakes for regions that continue to rely on incremental or reactive approaches.

The Federal Energy Regulatory Commission's (FERC) Order No. 1920, which requires regions to begin adopting long-term planning best practices, helped drive improvements, particularly in regional planning for a few regions, even before full compliance is finalized. At the same time, widespread compliance extensions for Order No. 1920 mean many of the rule's full benefits may not be realized for years. As a result, current grades should be understood as a snapshot of progress underway rather than an endpoint.

FIGURE ES-1 Summary of overall grades by region



This edition of the Report Card places greater emphasis on interregional transmission planning, reflecting an established body of research demonstrating the significant reliability, affordability, and resilience benefits interregional investments can deliver. While some interregional transmission planning is being conducted through state coordination and voluntary planning efforts and some development is advancing by independent/merchant projects, these efforts remain largely voluntary. Across most regions, interregional coordination relies on reliability-focused studies rather than proactive, scenario-based planning with durable selection and cost-allocation frameworks. As a result, interregional transmission remains one of the weakest elements of the national planning landscape, with planned capacity generally falling short of estimated need.

Regional performance varies across the four metrics evaluated. Several regions — **California**, the **Midwest**, and the **Plains** — continue to demonstrate the benefits of proactive, long-term regional planning. Coupled with developments in interregional transmission planning, these regions' grades continued to improve. Highlighted in this report is the Consolidated Planning Process advanced by the Southwest Power Pool (SPP) in the Plains region, which — once approved by FERC — will be an important and significant reform that merges the region's planning process, including transmission and generator interconnection planning.

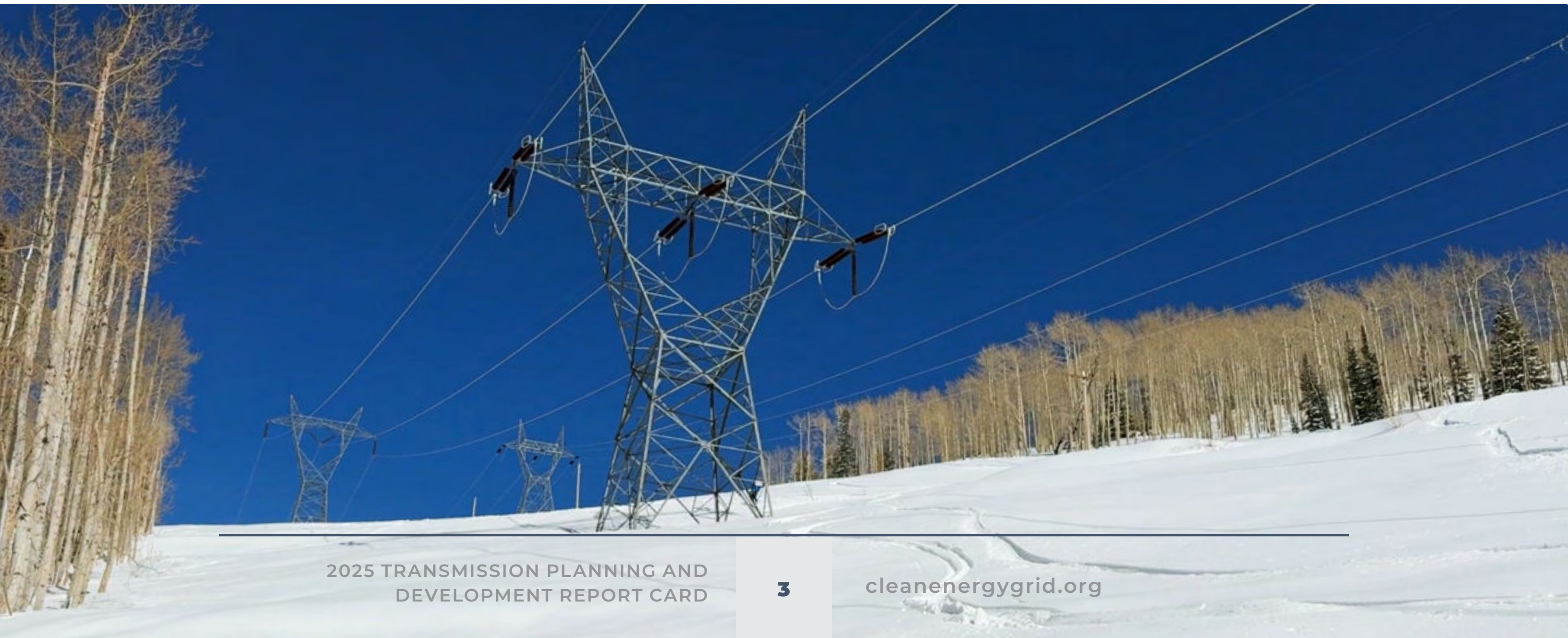
New England and the **Mid-Atlantic** have both shown meaningful improvement, driven by recent long-term regional planning reforms. The Mid-Atlantic improved its regional planning through Order No. 1920-related long-term planning reforms. Most of New England, New York, and some of the Mid-Atlantic have also increased state engagement on interregional transmission planning through the Northeast States Collaborative on Interregional Transmission.

At the same time, many regions — including all of the non-Regional Transmission Organization (RTO) regions — continue to face significant gaps in both regional and interregional planning frameworks. In these regions, transmission development often occurs through individual utility investments or ad hoc coordination rather than durable, region-scale planning processes, limiting the ability to fully capture system-wide benefits. That said, in the West, the **Northwest** and **Southwest** along with California are participating in the Western Transmission Expansion Coalition (WestTEC), a voluntary, west-wide transmission planning process that has broad stakeholder participation and is currently one of the best interregional transmission planning practices in the country.

For the evaluation, the Report Card combines qualitative metrics (regional and interregional planning and engagement best practices) with quantitative outcomes (including recently constructed high-capacity transmission, planned transmission projects, and congestion). The evaluation assesses performance at the regional level rather than assigning responsibility to any single institution. This practice recognizes that outcomes reflect the actions of multiple entities, including regional planning organizations, utilities, states, and other stakeholders. Grades are best interpreted as a benchmark against established best practices rather than a definitive verdict, since any grading framework cannot be completely objective. All grades are provided in Figs. ES-1 and ES-2, including a comparison with grades from the 2023 Report Card.

FIGURE ES-2 Summary of individual grade components for each region

REGION	REGIONAL PLANNING	INTERREGIONAL PLANNING	ENGAGEMENT	OUTCOMES	OVERALL GRADE		2023 GRADE
California	A+	B-	A-	A	A-	↑	B
Northwest	F	C	F	B+	D+	↑	D
Southwest	D+	C	F	B-	C-	↑	D-
Texas	C	F	B	C-	D-	↓	D+
Plains	A	C	B	B-	B-	↑	C+
Midwest	A	B-	B+	C	B	↔	B
Southeast	F	F	F	F	F	↔	F
Mid-Atlantic	B	D+	B	C-	C	↑	D+
New York	B+	C+	A-	C-	B-	↑	C+
New England	B	C	A-	A	B	↑	D+



Regions across the country are generally making progress on planned high-capacity regional transmission, which is encouraging but not yet decisive. Many regions have planned regional transmission capacity broadly consistent with the Department of Energy's (DOE) 2023 National Transmission Needs Study ("Needs Study"). However, load growth projections have risen since that study was released — resulting in lower targets than what will actually be needed if load growth forecasts are correct. Additionally, significant siting, permitting, and implementation challenges remain, particularly for interregional projects, and could affect whether planned investments are ultimately delivered. In all, we believe the 2023 Needs Study provides a conservative target to which we compare regional progress.

To earn an overall "A," regions need to incorporate the following best practices into regional and interregional planning process that considers regional needs holistically: proactive 20-year load and generation forecasts, robust scenario analysis including extreme weather, multi-value benefits analysis, portfolio development, consideration of all business models and Advanced Transmission Technologies, integration with other planning processes, and durable selection and cost allocation frameworks. Regions must also have representation from states and incorporation of state policies, robust engagement with stakeholders, and plan for and build transmission at the necessary pace.

Taken together, the Report Card finds that regional transmission planning reforms related to Order No. 1920 are beginning to take hold, and that early progress is visible in several regions. However, accelerating demand growth and persistent weaknesses in interregional planning mean that incremental improvements alone will not be sufficient. Future Report Cards will be able to assess whether planned projects are built, whether voluntary interregional efforts mature into durable planning frameworks, and whether regions with lower grades are able to translate state and utility-level activity into comprehensive, region-scale outcomes that meet emerging system needs.

Introduction and Purpose

This Report Card is the third installment evaluating the status of transmission planning and development around the country.

In the 2023 Report Card, we established baseline grades for regional transmission planning and development outcomes, laid out best practices, and provided a brief overview of the regulatory context and history of regional planning and its benefits.[1] Our second installment[2] did not update grades, but instead, it offered an interim update as FERC had just issued Order No. 1920 to reform regional long-term transmission planning. Several reforms and initiatives across the regions were also underway but not finalized, so their outcomes remained uncertain. In this third installment, we updated regional planning grades, given the requirements in Order No. 1920, and add a new focus on interregional transmission, engagement with stakeholders, and outcomes.

Co-optimized transmission and generation planning delivers the most system savings to consumers.

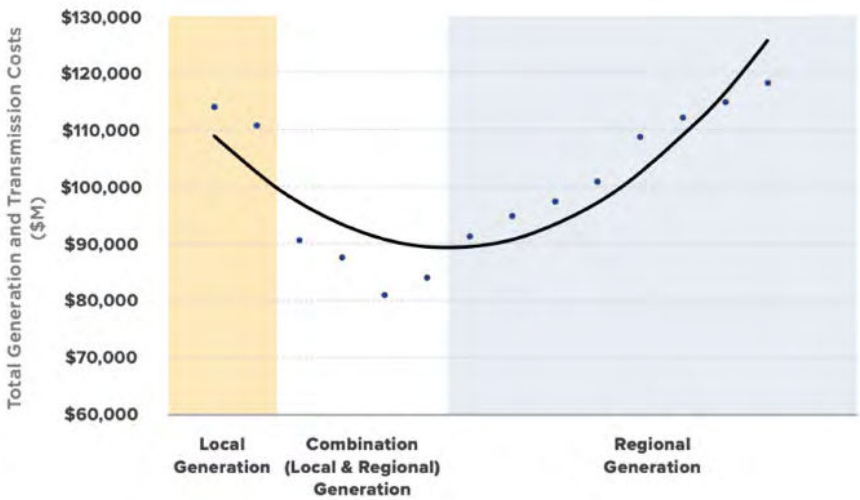
Proactive, holistic planning of large-scale transmission has repeatedly been shown to yield the most efficient investments for consumers. In particular, planning that co-optimizes generation resources and the transmission system delivers the lowest overall power-system costs. In its Multi-Value Planning process, the Midcontinent Independent System Operator (MISO) illustrated this with the 'smile curve' (*see Fig. 1*), which shows that optimizing between local and regional generating resources, together with the transmission needed to connect them, minimizes total system cost while maintaining reliability.[3]

1 *See* Americans for a Clean Energy Grid (ACEG) and Grid Strategies, *Transmission Planning and Development Regional Report Card (Jun. 2023),* https://www.cleanenergygrid.org/wp-content/uploads/2023/06/ACEG_Transmission_Planning_and_Development_Report_Card.pdf ("2023 Report Card").

2 *See* ACEG and Grid Strategies, *2024 State of Regional Transmission Planning (Oct. 2024),* https://cleanenergygrid.org/wp-content/uploads/2024/10/ACEG_2024-State-of-Regional-Transmission-Planning.pdf ("2024 Interim Report Card").

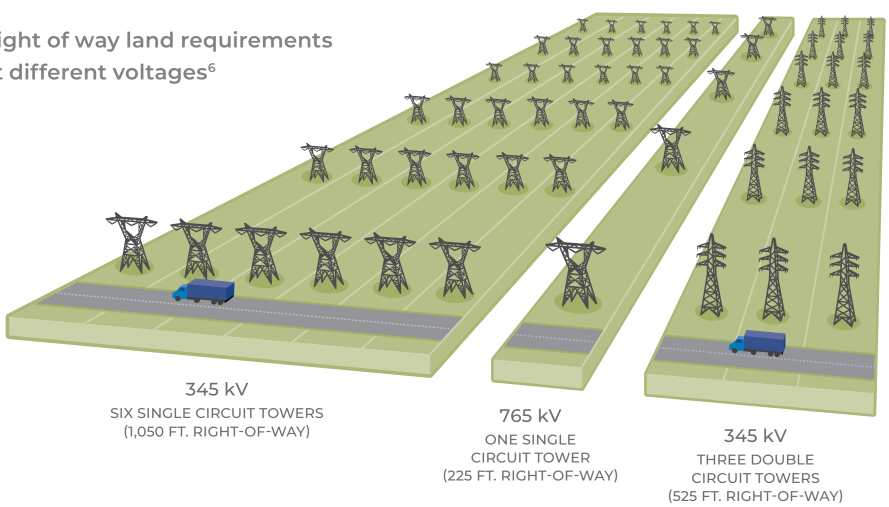
3 MISO, MTEP17 MVP Triennial Review, at 31 (Sept. 2017), https://cdn.misoenergy.org/MTEP17 MVP Triennial Review Report117065.pdf ("MTEP17").

FIGURE 1 Optimizing transmission and generation delivers lowest overall system costs for consumers[4]



Many of these benefits arise from the substantial economies of scale achieved by higher-voltage lines (*see Fig. 2*). Compared with a 230-kilovolt (kV) line, a 765-kV line can deliver roughly six to ten times as much power while requiring only one-fifth the land for a right-of-way. Additionally, a 765-kV line can deliver power at roughly 75% lower cost on a per-unit-of-power-delivered basis than a 230-kV line.[5]

FIGURE 2 Right of way land requirements at different voltages[6]



4 *Id.*

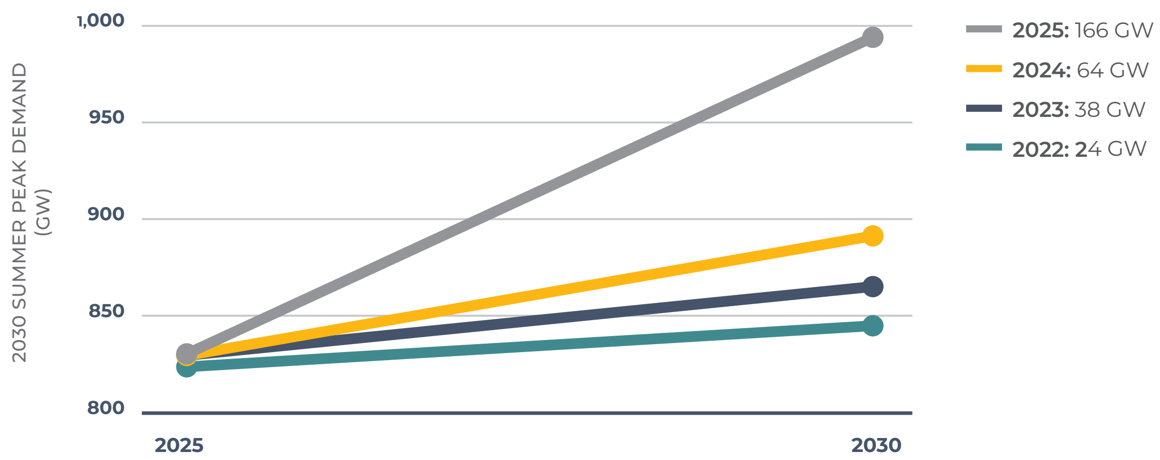
5 See MISO, Transmission Cost Estimation Guide for MTEP24 (May 2024), https://cdn.misoenergy.org/20240501%20PSC%20Item%2004%20MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24632680.pdf ("2024 Transmission Cost Estimation Guide").

6 See 2024 Transmission Cost Estimation Guide; *See also* American Electric Power, "Experience with EHV Transmission Up to 765kV, 3 (Jun. 2023), https://www.ercot.com/files/docs/2023/06/27/7_AEP%20EHV%20Experience_AEP_Wilcox_20230626.pdf.

Load growth is increasing the need for new transmission capacity.

In the first edition of the Report Card, we highlighted multiple drivers of new transmission capacity needs across the country, including an aging grid, building and transportation electrification, more frequent extreme weather, and a backlog of lower-cost generation seeking interconnection. Since then, growth in electricity demand, particularly from data centers and new manufacturing, has emerged as a primary driver of additional transmission needs. Year-over-year load growth expectations continue to rise. Grid Strategies' updated summary of nationwide peak-load forecasts shows that in just three years, the five-year load-growth forecast increased more than sixfold, from 24 GW to 150 GW (*see Fig. 3*).[7]

FIGURE 3 5-year nationwide summer peak load growth[8]



Surging load growth is also beginning to influence transmission construction. According to FERC's 2024 State of the Market Report, load growth was the second-largest driver of new transmission, after reliability needs, with approximately 1,000 miles of new facilities placed in service in 2024 due to load growth.[9] The miles of load-growth-driven transmission energized in 2024 exceeded those added in both 2023 and 2022.[10]

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7 Grid Strategies, *Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers*, 3 (Dec. 2025) https://gridstrategiesllc.com/wp-content/uploads/Grid-Strategies-National-Load-Growth-Report-2025.pdf ("Grid Strategies 2025 Load Growth Report").

8 *Id.*

9 Federal Energy Regulatory Commission (FERC), *2024 State of the Markets, at 32-34 (Mar. 2025)*, https://www.ferc.gov/media/state-markets-report-2024.

10 FERC, *2023 State of the Markets, at 42-44 (Mar. 2024)*, https://www.ferc.gov/media/2023-state-markets-report; FERC, *2022 State of the Markets, at 27-29 (Mar. 2023)*, https://www.ferc.gov/media/report-2022-state-market.

While today's load growth can tempt a crisis-response mindset focused solely on short-term fixes to achieve Speed to Power, it must be balanced with contemporaneous proactive, holistic long-term planning to deliver the highest quality reliability and lowest costs to customers in the long-term.

It captures economies of scale that 'just-in-time' projects miss and enables high-capacity upgrades to come online ahead of demand. By shifting from short-term, crisis-mode additions to comprehensive, multi-value long-term plans, planners can maintain reliability and affordability while building the transmission capacity required for sustained load growth.[11]

Order No. 1920 requires long-term regional planning best practices to be adopted

FERC issued its final rule, Order No. 1920,[12] on long-term regional transmission planning in May 2024 and, in November 2024 and April 2025, modified the requirements through Order Nos. 1920-A and 1920-B, respectively.[13] Order No. 1920 adopts many best practices identified in ACEG's initial Report Card and requires transmission providers to participate in a planning process that is "sufficiently long term, forward-looking, and comprehensive" to identify long-term transmission needs.[14]

The rule also requires several common-sense best practices. Regions must produce a 20-year regional transmission plan at least once every five years.[15] Plans must use the best available data to develop at least three scenarios that reasonably capture future outcomes, include an extreme-weather sensitivity, and incorporate seven inputs, including:

1. federal, federally recognized Tribal, state, and local laws and regulations affecting the resource mix and demand;
2. federal, federally recognized Tribal, state, and local laws and regulations on decarbonization and electrification;

11 Chang, J., et al., "It's all one system: Integrate transmission and interconnection planning to support load growth," Utility Dive (Sep. 2025), https://www.utilitydive.com/news/its-all-one-system-integrate-transmission-and-interconnection-planning-Judy-Chang/761240/.

12 Order No. 1920, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, FERC 187 FERC ¶ 61,068 (May 13, 2024) ("Order No. 1920").

13 Throughout the report, we refer to all three orders collectively as "Order No. 1920." Order No. 1920-A, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, FERC 189 FERC ¶ 61,126 (November 21, 2024) ("Order No. 1920-A"); Order No. 1920-B, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, FERC 191 FERC ¶ 61,026 (April 11, 2025) ("Order No. 1920-B").

14 Order No. 1920 at P 224.

15 Order No. 1920-A at P 237.

3. state-approved integrated resource plans and expected supply obligations for load-serving entities;
4. trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies;
5. resource retirements;
6. generator interconnection requests and withdrawals; and
7. utility commitments and federal, federally recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs.[16]

Factors 4-7 can be discounted by planners, giving regions flexibility in scenario development that best meets their individual needs.[17] Order No. 1920-A required that planners seek input from states on the categories and allowed states to request additional scenarios.[18]

Once the scenarios are developed, planners must evaluate seven distinct benefits to help identify regional transmission portfolios that will efficiently and cost-effectively address long-term reliability and economic transmission needs. These benefits are:

1. avoided or deferred reliability transmission facilities and aging infrastructure replacement;
2. a benefit that can be characterized and measured as either reduced loss of load probability or reduced planning reserve margin;
3. production cost savings;
4. reduced transmission energy losses;
5. reduced congestion due to transmission outages;
6. mitigation of extreme weather events and unexpected system conditions; and
7. capacity cost benefits from reduced peak energy losses.[19]

As part of solutions development and benefits evaluation, planners may take a portfolio approach and must consider right-sizing options and Advanced Transmission Technologies (ATTs) including Dynamic Line Ratings, Advanced Power-Flow Controls, Transmission Switching (or Transmission Topology Optimization), and High Performance Conductors alongside traditional solutions.[20]

16 *Id. at P 248, 409.*
17 Order No. 1920 at P 507, 528, 865.
18 Order No. 1920-A at 344-345.
19 Id. at P 271-277 and 296-313; Order No. 1920 at P 565 & 597.
20 Order No. 1920 at P 8, 1198-1216, 1239-1247; Order No. 1920-A at 598-600.

Orders No. 1920 and 1920-A also require transmission providers to develop a cost allocation methodology for any selected facilities.[21] States may propose their own cost allocation methodology during compliance and can choose whether or not to use it each planning cycle.[22] The rule further adopts transparency requirements for local transmission planning, including three stakeholder meetings that cover assumptions, needs, and solutions for each planned local facility.[23]

Lastly, Order No. 1920-B largely upheld Order Nos. 1920 and 1920-A clarifying that transmission providers are not required to plan for the long-term needs of unenrolled non-jurisdictional providers (though voluntary agreements are allowed), reaffirming requirements that transmission providers must file any Relevant State Entities cost allocation methods and consult with those entities before amending cost allocation. The order also declined to broaden the definition of Relevant State Entities.[24]

Order No. 1920 requires many of the transmission planning practices evaluated in our initial Report Card. However, delays in compliance threaten to slow or even derail progress. Every region in the country has received extensions on its compliance deadlines (*see Fig. 4*), which means that in many regions, facilities or portfolios may not be approved under the Order No. 1920 process until well after 2030.

Nonetheless, regions do not have to wait for formal compliance to begin implementing regional transmission planning best practices set forth in the rule, and indeed, many have begun implementation, such as MISO through its Long-Range Transmission Planning (LRTP) Tranches.

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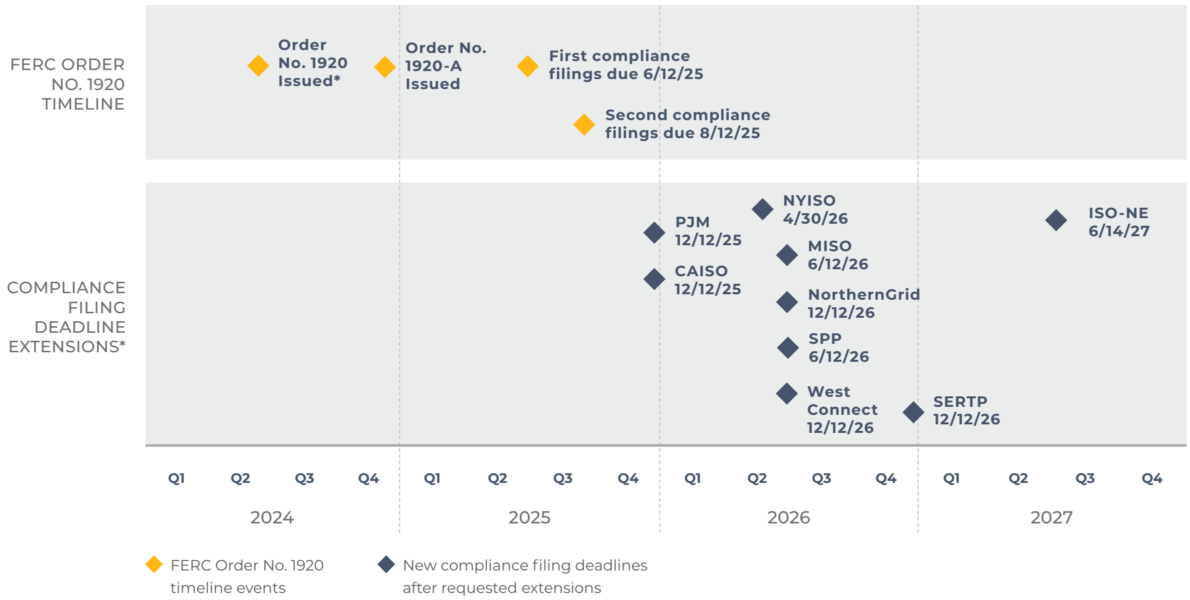
21 Order No. 1920 Section VI "Regional Transmission Cost Allocation"; Order No. 1920-A at 70, 610-793.

22 Order No. 1920-A at P 635-708.

23 Id. at P 804-862.

24 Order No. 1920-B at 21-22 and 152-154.

FIGURE 4 FERC Order No. 1920 regional compliance filing schedule[25]



** FERC Order No. 1920 requires transmission providers to submit two compliance filings. The lower portion of this chart shows deadline extensions granted for the first compliance filing, which encompasses all of Order No. 1920's requirements except for those related to interregional transmission coordination.*

SOURCE: FERC, Order No. 1920 Compliance Filings Schedule (Jun. 2025), https://www.ferc.gov/news-events/news/order-no-1920-compliance-filings-schedule.

Interregional transmission is an added focus this Report Card

Just as students advance to new subjects, this third edition of the Transmission Planning and Development Report Card adds a stronger emphasis on interregional transmission. In the first Report Card, we briefly reviewed interregional planning but focused largely on regional planning and development outcomes.[26] Given the requirements that FERC set out in Order No. 1920, many regions will likely eventually adopt and use the proactive, holistic long-term practices we evaluate here. By contrast, there is no analogous set of planning requirements or standardized benefits for interregional transmission, so a substantial portion of this Report Card's grade now evaluates interregional planning.

25 FERC Order No. 1920 requires transmission providers to submit two compliance filings. The lower portion of this chart shows deadline extensions granted for the first compliance filing, which encompasses all of Order No. 1920's requirements except for those related to interregional transmission coordination. Note that PJM is submitting a two part compliance filing, with the cost allocation portion due June 2026. *See FERC, "Order No. 1920 Compliance Filings Schedule" (Dec. 2025),* https://www.ferc.gov/news-events/news/order-no-1920-compliance-filings-schedule; *See also ACEG, "FERC Order No. 1920 Resources," accessed Jan. 2026,* https://cleanenergygrid.org/policies/ferc-order-no-1920-resources/.

26 2023 Report Card at 19-20.

The need for new interregional capacity is significant. As directed by Congress, the North American Electric Reliability Corporation (NERC) conducted the 2024 Interregional Transfer Capability Study (ITCS), focusing exclusively on reliability, and not economic benefits.[27] Even with that narrow scope, NERC recommended 35 GW of additional interregional transfer capability as prudent to maintain reliability.[28]

Interregional transmission offers some of the highest benefit-cost ratios for consumers. A June 2025 ACEG analysis found that interregional lines can deliver $5 in benefits for every dollar invested.[29] This value is particularly high during stress events. Interregional transmission acts as an insurance policy during extreme weather, mitigating price spikes and enabling power imports from neighboring regions with surplus capacity. In its study of transmission path congestion value (*see Fig. 5*) the Lawrence Berkeley National Laboratory has found that roughly half of a transmission path's value accrues in just 10% of the hours each year.[30] Studies also show that even when one region faces peak demand, neighboring regions often have excess resources. Interregional transmission allows operators to access that capacity, reducing the need for redundant generation and lowering overall system costs.[31]

27 North American Reliability Corporation (NERC), *Interregional Transfer Capability Study (ITCS), v-xvi* (Nov. 2024), https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf ("NERC ITCS").

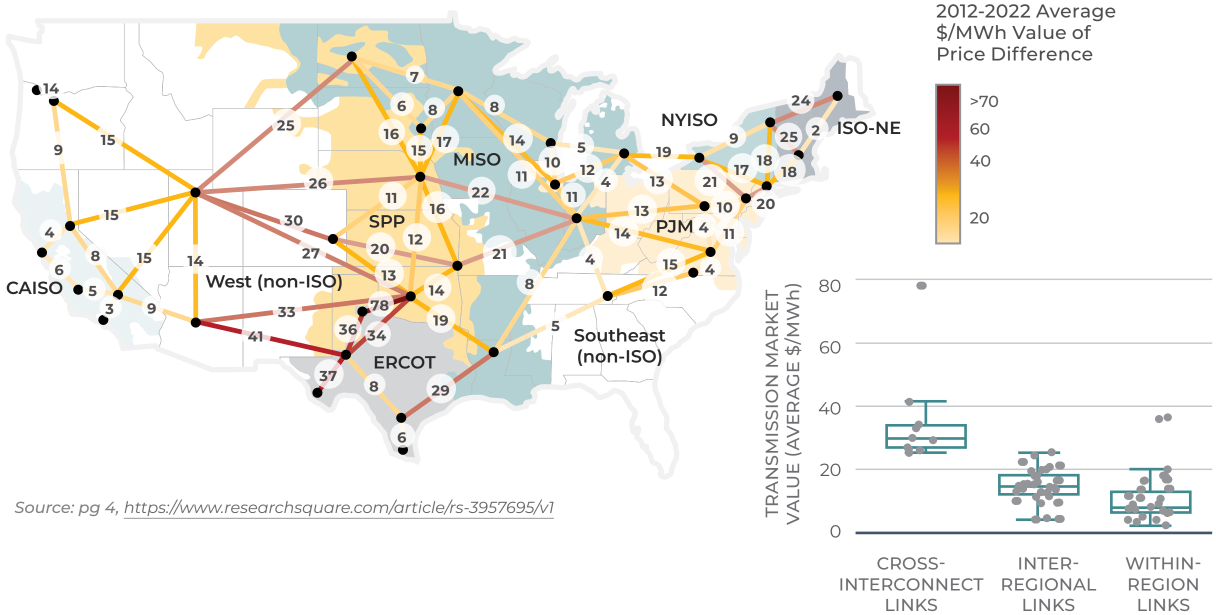
28 *Id.*

29 Transmission saves consumers money at 4.

30 Millstein, D., et al., "The Latest Market Data Show that the Potential Savings of New Electric Transmission was Higher Last Year than at Any Point in the Last Decade" (Feb. 2023) https://eta-publications.lbl.gov/sites/default/files/lbnl-transmissionvalue-fact_sheet-2022update-20230203.pdf.

31 See Brooks, A., et al., *Resource adequacy value of interregional transmission*, Grid Strategies (Jun. 2025) https://cleanenergygrid.org/wp-content/uploads/2025/06/250610_RAValueInterregionalTx_Corrections.pdf.

FIGURE 5 Average market value of interregional transmission (2012-2022)[32]



Source: pg 4, https://www.researchsquare.com/article/rs-3957695/v1

Despite the well-documented value of interregional transmission planning, regions are planning very little interregional transmission. Current rules and planning structures often require a potential interregional line to be identified as needed and approved in both regions and then approved again through a joint evaluation process. This makes projects difficult to advance, particularly when regions' modeling assumptions, identified needs, benefit calculations, and cost-allocation approaches do not align. In addition, FERC's efforts to encourage interregional planning are limited, and there is no formal requirement for regions to conduct proactive, multi-value interregional planning.[33]

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32 Julie Kemp, Dev Millstein, Will Gorman et al. *Electric transmission value and its drivers in United States power markets, 29 March 2024, PREPRINT (Version 1),* https://doi.org/10.21203/rs.3.rs-3957695/v1.

33 For additional discussion of the value and barriers to interregional transmission see Pfeifenberger, J., "The Value of Interregional Transmission: Grid Planning for the 21st Century" (Sep. 2023), https://www.brattle.com/wp-content/uploads/2023/09/The-Value-of-Interregional-Transmission-Grid-Planning-for-the-21st-Century.pdf; See also NARUC and Energy and Environmental Economics, *Collaborative Enhancements to Unlock Interregional Transmission* (Jun. 2024), https://pubs.naruc.org/pub/BACDBB9D-02BF-0090-0109-B51B36B74439.

Results and Discussion

The third edition of the Transmission Planning and Development Report Card combines grades across 1) regional transmission planning and development, 2) interregional transmission planning and development, 3) engagement, and 4) outcomes. This final component quantitatively evaluates transmission constructed, regional and interregional transmission planned, and economic congestion in each region. The sections below provide further discussion on each of the four grade components.

In general, the latest edition of this Report Card saw marginal to significant improvements in grades for many regions. These improvements can be attributed to several factors: recent planning reforms being enacted in light of the issuance of Order No. 1920, a reasonable ad hoc baseline for interregional planning, and overall increase in planned transmission lines due in part to increasing load forecasts. The added emphasis on interregional transmission resulted in different overall grades compared to the first Report Card edition, including a reduction in some regions' grades where strong regional planning is inhibited by little to no interregional planning.

As with the 2023 Report Card, this report grades regions, not specific entities such as RTOs or Order No. 1000 planning authorities, because responsibility for performance extends beyond planning entities to utilities, states, and other stakeholders. This approach extends credits for transmission-related actions, with regional impacts, even when they were not initiated by regional planning entities or advanced through formal regional planning processes. In some cases, often in the non-organized market regions, actions are taken by an individual state or utility outside of regional processes and still have regional significance. In general, most of those actions are captured in the outcomes section. Figs. 6 and 7 summarize the overall grade for each region.

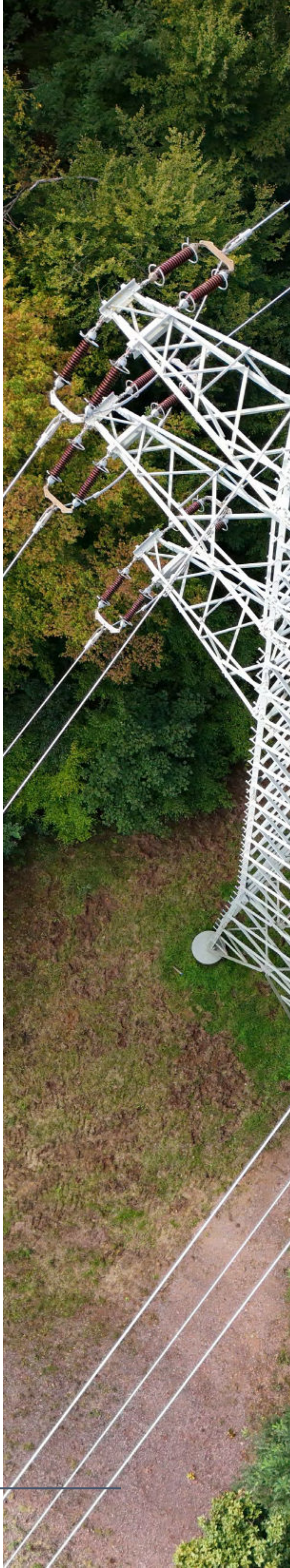


FIGURE 6 Summary of overall grades by region

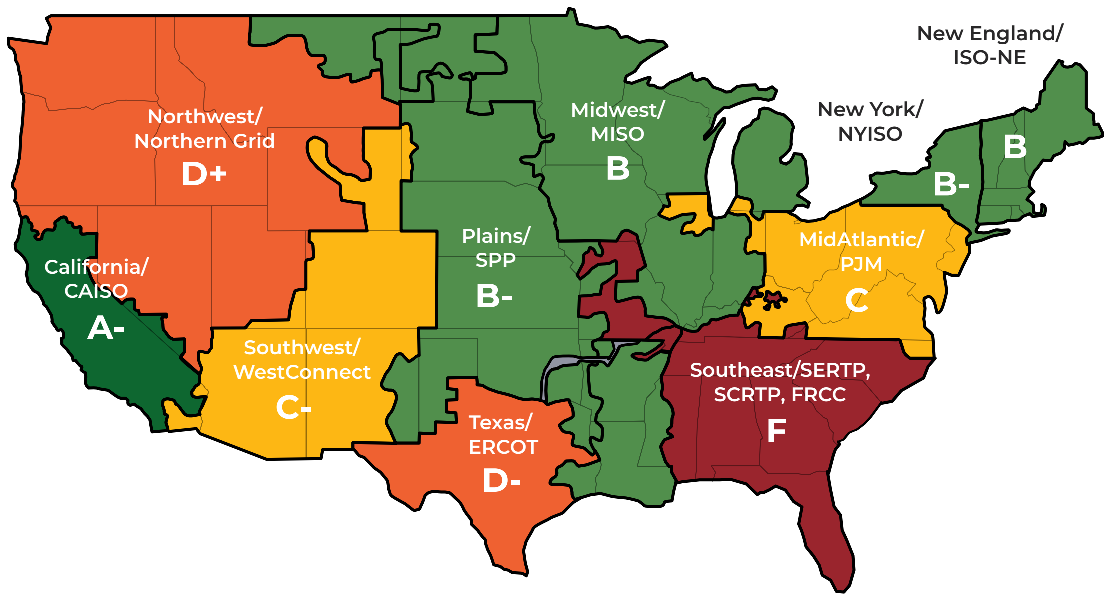


FIGURE 7 Summary of individual grade components for each region

REGION	REGIONAL PLANNING	INTERREGIONAL PLANNING	ENGAGEMENT	OUTCOMES	OVERALL GRADE		2023 GRADE
California	A+	B-	A-	A	**A-**	↑	**B**
Northwest	F	C	F	B+	**D+**	↑	**D**
Southwest	D+	C	F	B-	**C-**	↑	**D-**
Texas	C	F	B	C-	**D-**	↓	**D+**
Plains	A	C	B	B-	**B-**	↑	**C+**
Midwest	A	B-	B+	C	**B**	↔	**B**
Southeast	F	F	F	F	**F**	↔	**F**
Mid-Atlantic	B	D+	B	C-	**C**	↑	**D+**
New York	B+	C+	A-	C-	**B-**	↑	**C+**
New England	B	C	A-	A	**B**	↑	**D+**

1. Regional Transmission

The first grade component is regional planning and development. This component — and the metrics associated with it — remain largely unchanged from the 2023 Report Card. This component is based on best planning practices, including 1) proactive generation and load forecasts, 2) scenario-based planning, 3) portfolio-based planning, 4) multi-value evaluation of transmission solutions, 5) inclusion of alternative transmission technologies or business models (like merchant transmission developers), and 6) transmission planning that is integrated with other planning paradigms. This component makes up 35% of the final grade.

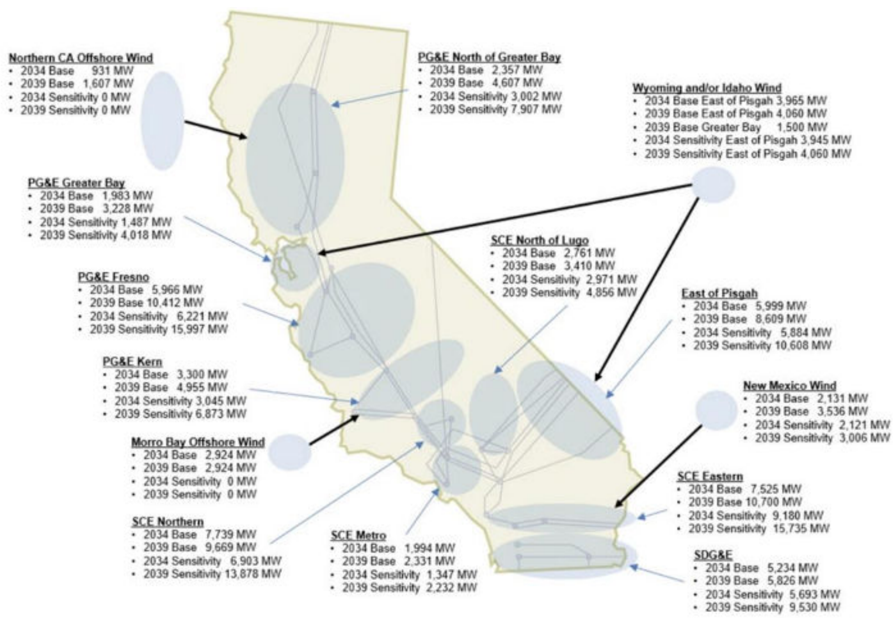
Grades for regional planning have risen marginally across most regions as many have continued to make incremental improvements to their planning. In some cases — notably the **Plains, Mid-Atlantic**, and **New England** — grades have improved drastically as these regions have finalized new long-term planning processes, driven in part by the FERC proceedings leading up to the issuance of Order No. 1920. Many of the specific regional transmission planning and development details are explored in the first edition of this Report Card. Below we highlight significant regional updates that have occurred since the Report Card was first published in June 2023.

California

California has received an A+ and has continued to make incremental improvements, with the state once again taking home the highest grade for regional planning. The California Independent System Operator (CAISO) has largely the same proactive, multi-value, scenario-based regional transmission planning process as two years ago and has continued to make small improvements to the process.[34]

The 2024-2025 Transmissions Plan is the third plan to be adopted after the memorandum of understanding was signed between the California Public Utilities Commission, the California Energy Commission, and CAISO, which tightened the coordination between power and transmission planning, interconnection queuing and resource procurement.[35] The 2024-2025 plan identified 31 new reliability-driven and policy-driven transmission projects[36] totaling $4.8 billion to help accommodate 76 GW of new capacity needed by 2039 to meet policy goals and address load growth, including building, transportation, and other electrification as well as data center growth.[37] CAISO estimates the cost of this portfolio over the lifetime of the projects is approximately 0.5 cents per kWh.[38] The transmission plan is shown in Fig. 8.

FIGURE 8 CAISO's 2024-2025 Transmission plan



34 For a detailed assessment of CAISO's planning methods see 2023 Report Card at 27-29; *See also 2024 Interim Update at 12-17.*

35 *See* "Memorandum of Understanding Between The California Public Utilities Commission (CPUC) And The California Energy Commission (CEC) And The California Independent System Operator (ISO) Regarding Transmission and Resource Planning and Implementation" (Dec. 2022), https://www.caiso. com/Documents/ISO-CEC-and-CPUC-Memorandum-of-Understanding-Dec-2022.pdf ("CPUC, CEC, and CAISO Planning MOU").

36 As discussed in the 2023 Report Card, because CAISO's reliability, policy, and economic planning happen sequentially and transmission optimization largely happens in coordination with the resource buildout in the CPUC's capacity expansion modeling, no economic projects were selected again with this plan. CAISO did identify opportunities for economic projects to relieve congestion but none of the projects showed sufficient economic justification to be included in the ISO's final plan. *See 2023 Report Card at 27-29; See also CAISO, 2024-2025 Transmission Plan, at 28-29, 133-151 (May 2025),* https://www.caiso.com/documents/iso-board-approved-2024-2025-transmission-plan.pdf ("CAISO 2024-2025 Transmission Plan").

37 CAISO 2024-2025 Transmission Plan, at 5-13.

38 *Id.* at 9.

Some additional incremental improvements have come from the increased consideration of ATTs, though planned deployments are still limited. The 2023-2024 Transmission Plan contained a limited, case-by-case analysis incorporating a few ATTs. While the 2024-2025 Transmissions Plan appeared to use a similar case-by-base process, it did identify a broader range of projects. CAISO has the opportunity in the 2025-2026 Transmission Plan, currently underway, to further expand on the use of ATTs in planning because of California bill S.B. 1006, which requires California utilities to provide feasibility studies on cost effective deployments of ATTs on their system in January 2026.[39]

CAISO and PJM (discussed later) were the first two regions to file their Order No. 1920 compliance tariffs. Order No. 1920 has a similar requirement to SB 1006 in evaluating potentially beneficial ATT deployments and traditional upgrades alike.[40] CAISO's Order No. 1920 filing extends the region's 10- and 15-year planning horizon to 20-years, making CAISO's 20-year plan no longer information-only, and transitions its annual transmission planning process to a biennial one to better align timelines.[41]

Northwest

The Northwest received an F for regional planning. The regional planner in the northwest, NorthernGrid, completed its biannual Order No. 1000 regional transmission planning cycle in 2025 as outlined in Attachment K of the Enrolled Parties tariffs. However, its planning practices remain largely unchanged from our initial 2023 Report Card.[42]

In the Attachment K Tariff of its Enrolled Parties, it notes that NorthernGrid's regional plans are not intended to be a construction plan and NorthernGrid does not have the authority to issue construction orders. NorthernGrid's 2024-2025 Regional Transmission plan did not select any lines for regional cost allocation, and consequently the overall planning process remains largely a compilation of the member utilities' local transmission plans.[43] Alongside its biannual transmission planning process, NorthernGrid conducts information-only economic studies at the request of interested parties. Recent planning cycles have included the evaluation of offshore wind in Oregon,[44] pumped storage hydro proj-

39 Id. at 28-29, 195-196; See also CAISO, *2023-2024 Transmission Plan*, 24-27 (May 2024) https://www.caiso.com/documents/iso-board-approved-2023-2024-transmission-plan.pdf; Senator Padilla, California State Senate, S.B. 1006, February 2024, https://leginfo.legislature.ca.gov/faces/billStatusClient.xhtml?bill_ id=202320240SB1006.

40 CAISO, Tariff Amendment - Order No. 1920 Compliance Filing, FERC Docket ER26-704, December 2025, https://www.caiso.com/documents/dec-9-2025-tariff-amendment-order-no-1920-compliance-filing-er26-704.pdf.

41 *Id.* at 19-20.

42 For a detailed assessment of the Northwest's planning methods see 2023 Report Card at 39-40; *See also 2024 Interim Update at 57-59.*

43 *See* NorthernGrid, *Regional Transmission Plan for the 2024-2025 Northern Grid Planning Cycle* (Nov. 2025), https://www.northerngrid.net/private-media/documents/2024-2025_NorthernGrid_RTP.pdf.

44 *See* NorthernGrid, *Economic Study Request Offshore Wind in Oregon* (Jul. 2023), https://www.northerngrid.net/private-media/documents/2022_ESR_OSW_Approved.pdf.

ects in Wyoming and Oregon,[45] an additional pumped storage hydro project in Oregon,[46] and potential congestion impacts of the high-capacity North Plains Connector transmission facility.[47]

The biggest update to planning in the Northwest is potential reforms to Bonneville Power Administration's (BPA) transmission planning. Since 2023, BPA has announced new transmission investments — $5 billion to connect more than 20 GW of new resources in its last few Transmission Service Request planning cycles.[48] This renewed focus on transmission development is primarily due to increased demand for transmission service from new generation and anticipated load growth in the Pacific Northwest over the next decade.[49] Because of the significant increase in requests for transmission service, BPA paused its transmission planning at the beginning of 2025, and then over the summer of 2025 announced it would be undertaking significant reforms to its existing planning processes, called the Grid Access Transformation Project.[50] Under this new process, BPA proposed a six-point solution framework divided between near-term actions to clear bottlenecks and stabilize planning in order to transition to its "Future State" of planning with the stated goal of implementing long-term reforms to enable proactive, scenario-driven transmission planning and execution of service within a 5-6 year delivery window.[51]

As seen in Fig. 9, BPA is currently working on the near term transitional reforms under the TC-27 Tariff proceeding.[52] BPA held its first workshop in December 2025 where it discussed its goal of establishing a commercial expansion delivery pipeline that enables BPA to provide service in 5–6 years or less on a consistent basis and across customer types.[53] While BPA's efforts are much needed, it is still critical that BPA coordinate with other transmission owners on regional planning. This process is still in its early stages but

45 *See* NorthernGrid, *Economic Study Request Pumped Storage Hydro in Wyoming* (Jul. 2023), https://www.northerngrid.net/private-media/documents/2022_ESR_PSH_Approved.pdf.

46 *See* NorthernGrid, *Economic Study Request Pumped Storage Hydro in Oregon* (Apr. 2024), https://www.northerngrid.net/private-media/documents/ESR_OSW_PSH_Final.pdf.

47 *See* NorthernGrid, *Economic Study Request: North Plains Connector* (Jan. 2025), https://www.northerngrid.net/private-media/documents/ESR_NorthPlains_Approved_REport.pdf.

48 Bonneville Power Administration (BPA), "TSR Study and Expansion Process (TSEP) 2022 Cluster Study Results," December 15, 2022, at 6-7, https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/2022-cluster-study-results-overview-customer.pdf; BPA, "TSR Study & Expansion Process (TSEP) Update Summary of the 2023 Cluster Study," February 29, 2024, at 24-27, https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/02-29-24-2023-cs-findings-summary-part1-external.pdf.

49 PNUCC, *Northwest Regional Forecast of Power Loads and Resources*, at 5 (Apr. 2025), https://www.pnucc.org/wp-content/uploads/2025-PNUCC-Northwest-Regional-Forecast-final.pdf; *See also* BPA, *2025 Pacific Northwest Loads and Resources Study*, at 21 (May 2025), https://www.bpa.gov/-/media/Aep/power/white-book/2025-whitebook.pdf.

50 BPA, "Grid Access Transformation Project," accessed Jan. 2026, https://www.bpa.gov/energy-and-services/transmission/grid-access-transformation-project ("GAT Project").

51 *See* BPA, "Grid Access Transformation Workshops" (Jul. 2025), https://www.bpa.gov/-/media/Aep/transmission/Grid-Access-Transformation/Jul-10-TPR-Wrkshp-Presentation.pdf.

52 BPA, "TC-27 Tariff Proceeding," accessed Jan. 2026, https://www.bpa.gov/energy-and-services/rate-and-tariff-proceedings/tc-27-tariff-proceeding.

53 BPA, "Grid Access Transformation Future State Workshop Accelerate Expansion Program" (Dec. 2025) https://www.bpa.gov/-/media/Aep/transmission/Grid-Access-Transformation/12-17-25-GAT-Future-State-Workshop.pdf.

depending on the outcome and coordination with entities in the region, BPA's proactive planning reforms developed for its Future State may help improve the Northwest's regional grade in future Report Cards.

In the Northwest, independent/merchant transmission developers and individual transmission owners are planning and developing significant transmission projects outside of the regional planning processes, but that will have regional impacts. Northwestern transmission owners and stakeholders, though not NorthernGrid itself, are also participating in the west-wide WestTEC transmission planning study. Credit is given and discussion of independent/merchant projects is in the outcomes section and discussion of the WestTEC process is in the interregional planning section below.

FIGURE 9 BPA's proposed Six-Point Solution Framework[54]

Southwest

The Southwest received a D+ for regional planning. The Southwestern transmission planning organization, WestConnect, completed its biannual regional transmission planning cycles in 2025. Like their northern neighbor, their planning practices remain largely unchanged from our initial 2023 Report Card.[55]

As noted in the NorthernGrid section above, transmission owners and stakeholders, though not WestConnect itself, are participating in WestTEC. For the Southwest region, this study represents a potentially meaningful supplement to existing regional planning. We discuss the broader west-wide value of WestTEC further below in the interregional planning section.

54 BPA, "Grid Access Transformation Project," accessed Jan. 2026, https://www.bpa.gov/energy-and-services/transmission/grid-access-transformation-project.

55 For a detailed assessment of the Southwest's planning methods see 2023 Report Card at 45-47; *See also 2024 Interim Update at 59-61.*

The WestConnect 2024-2025 Regional Transmission Study Plan did not identify any regional needs.[56] As discussed in the interim update in 2024, the 2024-2025 Regional Transmission Study Plan did include three new scenarios in its planning, including a decreased facility rating scenario, extreme cold weather scenario, and 20-year increased renewable scenario.[57] The scenarios were for informational purposes only, and the 20-year increased renewable scenario was not completed due to a decision to stop all non-Order No. 1000-mandated activities in early 2025.[58]

The request to stop work came from the remaining WestConnect Enrolled Transmission Owners (ETOs) after FERC ordered the WestConnect ETOs to revise their Open Access Transmission Tariffs (OATTs) to exclude non-jurisdictional "coordinating transmission owners" so that its regional transmission planning process will only identify and plan for the regional transmission needs of enrolled transmission providers (who are FERC-jurisdictional).[59] This effectively removed nine transmission owner members from the WestConnect footprint and caused a mid-cycle reevaluation of study plan activities. Had the scenario-based planning continued, a higher score may have been awarded. We discuss additional impacts of these governance changes at length in the engagement section below.

In the Southwest, much of the transmission planning occurs through states, utilities, or by independent/merchant transmission developers. Interwest Energy Alliance released a two-part report in 2025 on opportunities to evaluate transmission in Integrated Resource Plans (IRPs). The first report details five common methods for evaluating transmission constraints in IRPs and then discusses the range of practices utilities have used and the benefits or drawbacks.[60] The second report evaluates five recent IRPs for Interior West utilities based on how well transmission is incorporated across the five methods, finding that PacifiCorp and the Public Service Company of New Mexico (PNM) ranked the two highest in terms of their approach to evaluating transmission expansion in their IRPs relative to the other utilities evaluated.[61] The report also includes utility-specific recommendations for better evaluation of transmission expansion in IRPs.[62] As an example, in

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56 WestConnect, *Regional Transmission Plan Report: WestConnect 2024-25 Regional Transmission Planning Cycle*, 6 (Dec. 2025), https://doc.westconnect.com/Documents.aspx?NID=21545&dl=1 ("WestConnect 2024-25 Transmission Plan") .

57 *Id.* at 7.

58 *Id.* at 56-64.

59 WestConnect Enrolled Transmission Owners, "Letter to WestConnect on Non-Tariff Activities for the Remainder of 2025" (Jun. 2025), https://doc.westconnect.com/Documents.aspx?NID=21407&dl=1; *See also Order on Remand, 189 FERC ¶ 61,028 at P 19 (2024) & Order Accepting Tariff Revisions and Terminating Section 206 Proceedings, 191 FERC ¶ 61,074 (2025).*

60 *See* Franklin, R. & Fitch-Fleischmann, B., *Evaluating Transmission Opportunities in Integrated Resource Plans Part 1: How to Incorporate Transmission in IRP Models* (Sep. 2025), https://interwest.org/wp-content/uploads/2025/09/Transmission-in-IRP-Part-1.pdf.

61 *See* Franklin, R. & Fitch-Fleischmann, B., *Evaluating Transmission Opportunities in Integrated Resource Plans Part 2: A Review of Interior West Utilities* (Sep. 2025), https://interwest.org/wp-content/uploads/2025/10/Transmission-in-IRP-Part-2.pdf.

62 *Id.* at 35-40.

2025 PNM completed its 20-Year Transmission Outlook where they evaluated numerous conceptual projects to meet carbon-free goals. The study concluded that further work was needed including additional scenarios and evaluation of economic benefits for the conceptual projects.[63] We also discuss in further detail transmission planning and development by the Colorado Electric Transmission Authority, the New Mexico Renewable Energy Transmission Authority and Xcel Energy in the outcomes section.

Texas

Texas received a C for regional planning. In response to House Bill 5066 from the 88th Texas Legislature, the Electric Reliability Council of Texas (ERCOT) developed the Permian Basin Reliability plan to maintain reliability and connect significant new loads in the Permian Basin in west Texas, primarily from new oil and gas and data center loads, as well as address load growth in eastern Texas.[64] The plan was released in July 2024 and identified two options, a 345 kV portfolio and 765 kV portfolio.[65] The Public Utility Commission of Texas (PUCT) approved the plan in October 2024 but delayed a decision on which portfolio to use until April 2025 when it selected the 765 kV transmission plan.[66] Alongside the Permian Basin Reliability Plan, ERCOT released its 2024 annual Regional Transmission Plan (RTP), which included for the first time two transmission plans, a 345 kV portfolio and 765 kV portfolio, called the Strategic Transmission Expansion Plan (STEP).[67] After review by stakeholders, ERCOT's board approved the planned 765 kV projects, which create an eastern Texas 765 kV loop closer to load centers and connect the western ends of the three 765 kV Permian Basin Reliability plan projects (*see Fig. 10)*.[68]

63 *See* Public Service Company of New Mexico, *PNM 20-Year Transmission Outlook* (Sep. 2025), https://www.pnm.com/documents/d/pnm.com/pnm_20-year-transmission-outlook_92025.

64 Electric Reliability Council of Texas (ERCOT), *Permian Basin Reliability Plan Study, July 2024*, at ii-xi, https://interchange.puc.texas.gov/Documents/55718_17_1414013.PDF ("Permian Basin Reliability Plan").

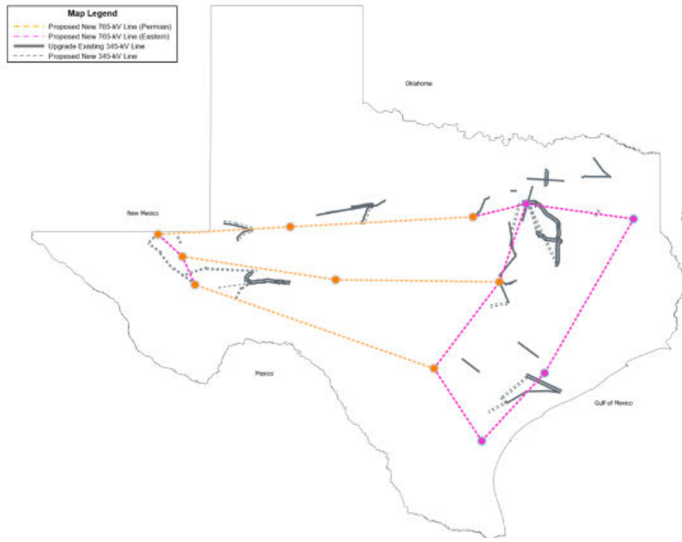
65 *Id.*

66 *See* Public Utility Commission of Texas, "Second Order Approving the Reliability Plan for the Permian Basin Region" (Apr. 2025) https://interchange.puc.texas.gov/Documents/55718_109_1492424.PDF.

67 *See* 2023 Report Card at 48-51 and 2024 Interim Report Card at 50-54 for additional details on ERCOT's transmission planning; *See also* ERCOT, *2024 Regional Transmission Plan (RTP) 345-kV Plan and Texas 765-kV Strategic Transmission Expansion Plan Comparison* (Jan. 2025), https://interchange.puc.texas.gov/Documents/55718_54_1462478.PDF ("ERCOT 2024 RTP").

68 ERCOT, "TOPIC: ERCOT Transmission Planning: 345-kV and TX 765-kV Strategic Transmission Expansion Plan (STEP)" (Dec. 2025), https://www.ercot.com/files/docs/2025/01/28/ERCOT_Trending_Topic_345-kV_vs_765-kV_Transmission.pdf ("ERCOT Trending Topic").

FIGURE 10 ERCOT's 765 kV Permian Basin Reliability Plan, 765 kV STEP projects, and needed 345 kV New Lines and Upgrades[69]



As a part of the 2024 RTP, ERCOT estimated two years (2034 and 2039) for multiple benefits for each portfolio, including production cost savings, system-wide consumer energy savings, reduction in congestion rent, power loss reduction, and reductions in construction related outage costs.[70] In addition, while the 2024 RTP portfolio is designed to accommodate a total of over 150 GW of load forecasted for summer 2030 — representing an approximately 35% increase over the 2029 load forecast in the 2023 RTP — the economic analysis was conducted using the 2024 Long Term System Assessment scenarios, which only estimated peak demand in 2034 as 107 GW.[71] ERCOT also conducted a load sensitivity analysis where roughly 20 GW of load did not materialize and found that significant portions of both 345 kV or 765 kV plans were still needed.

There is significant evidence that 765 kV lines provide the lowest cost delivery of power to consumers and ERCOT's 765 kV STEP plan highlights many of those benefits (*see Fig. 11*). However, ideally, ERCOT would have used a 20-year, scenario-based plan (beyond sensitivities), that proactively plans for generation additions and retirements. In addition, rather than just two years of benefits ERCOT could have expanded the benefits analysis to cover the lifetime of the projects and used their benefits plus the reliability and economic benefits identified in Order No. 1920.[72]

69 *Id.*

70 ERCOT 2024 RTP at 8-21.

71 *Id.* at 18; ERCOT, "Completion of the 2024 Regional Transmission Plan (RTP)" (Dec. 2024), https://www.ercot.com/services/comm/mkt_notices/M-A122024-01.

72 Siemens also conducted a benefit-cost analysis that found more beneficial results than ERCOT but did not expand on the benefits or use of only two years. *See generally* Siemens, "Cost Benefit Analysis of 765-kV Transmission Facilities in ERCOT" (Apr. 2025), https://interchange.puc.texas.gov/search/documents/?controlNumber=55718&itemNumber=107.

FIGURE 11 Comparison of annual 765 kV STEP benefits to 345 kV plan[73]

TX 765-kV STEP	VS	345-kV Plan
1,443 fewer miles *of existing system work*	Existing System Upgrades	-
-	New ROW	**434 fewer miles** *of new ROW*
-	Estimated New Construction Costs	**$2.24B less** construction cost
$890M *less in outage-related construction costs*	Live/Hot Construction to Facilitate Existing Upgrades	-
$229M/year *more consumer energy cost savings (annually)*	Estimated Consumer Energy Cost Savings	-
$28M/year *more production* cost savings *for energy (annually)*	Estimated Production Cost Savings	-
560 GWh/year *less energy losses ($16.2M annual savings)*	Estimated System Loss Reduction	-
600 to 3,000 MW *increases in power transfer capability*	Incremental Transfer Capability	-

While the amount of transmission Texas has planned and approved in the last two years is significant, ERCOT continues to plan most of its projects in a siloed manner. The 765 kV lines arose through a reliability-only planning process. ERCOT's reliability planning process falls short of best practices, including use of a 10-year time horizon and omission of proactively assessed generation additions or retirements outside of the informational-only Long Term System Assessment. In addition, ERCOT did not include multiple portfolios or any assessment of benefits in the 2025 RTP, despite including it in the 2024 RTP. Despite these drawbacks, credit is given for the work done in its reliability plans to address Texas State mandates around reliability in the Permian Basin and addressing large load growth.

There are some signs of improved planning practices in the coming years. Notably, ERCOT intends to change how generation is added in its reliability modeling to meet load growth starting in 2026.[74] The 2025 RTP economic analysis was also the first use of the new congestion cost savings metric, but only looked at 2027-2030.[75] Ideally, those practices would expand and continue.

Plains

The Plains region received an A for regional planning, and has continued to improve its regional transmission planning over the last few years, in particular through load and resource forecasting.[76] These changes have resulted in the region now having one of the highest grades. SPP is facing significant load growth, notably from data centers and oil

73 *See* ERCOT Trending Topics.

74 ERCOT, *2025 Regional Transmission Plan*, iii (Dec. 2025), https://www.ercot.com/mp/data-products/data-product-details?id=pg7-048-m (2025 RTP).

75 *See* 2025 RTP Appendix C.

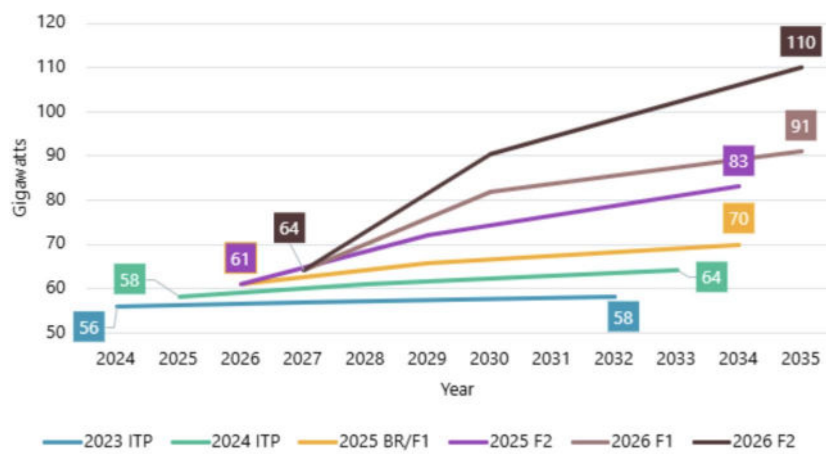
76 For a detailed assessment of SPP's planning methods see 2023 Report Card at 40-42; *See also 2024 Interim Report Card at 38-44.*

and gas developments in New Mexico, Texas, Oklahoma, and North Dakota.[77] This large demand growth helped drive historic investments in their two most recent transmission plans.

SPP's 2024 Integrated Transmission Plan (ITP) includes a historic $7.68 billion investment in transmission with the first 765 kV line planned in the region.[78] The projects are estimated to have a $8.90 to $9.57 in benefits for every dollar invested, resulting in estimated savings on the average retail residential monthly bill of $10.55 to $11.47.[79] The 2024 ITP also included modeling and solution development based on two historic extreme weather events, Winter Storms Uri and Elliot.[80]

As Fig. 12 shows, SPP faced even larger load growth in its 2025 and 2026 planning processes. SPP is forecasting a 35% increase in demand, even under conservative assumptions, and could double in the next 10 years.[81]

FIGURE 12 SPP Load Growth by Study[82]



To address this demand, SPP approved a historic $8.6 billion investment of fifty transmission facilities for the 2025 ITP. This includes four 765 kV lines approved for construction, comprising almost half of SPP's now planned 765 kV regional "backbone" transmission (*see Fig. 13*).[83] In support of its ITP, SPP notes that using 765 kV lines can deliver up to six times the power of 345 kV lines while requiring nearly five times less land.[84]

77 SPP, *2025 Integrated Transmission Planning Assessment Report*, 15-20, (Nov. 2025), https://www.spp.org/media/2429/2025-itp-report-v10.pdf ("2025 ITP").

78 SPP, *2024 Integrated Transmission Planning Assessment Report*, 1-13 (Jan. 2025), https://www.spp.org/media/2229/2024-itp-assessment-report-v10.pdf ("2024 ITP").

79 *Id.* at 184-192.

80 *Id.* at 6-7, 50-56.

81 *Id.* at 1-13.

82 *Id.* at 97.

83 *See* SPP, "SPP board advances regional transmission plan to keep pace with accelerating growth and ensure grid reliability" (November 2025), https://www.spp.org/news-list/spp-board-advances-regional-transmission-plan-to-keep-pace-with-accelerating-growth-and-ensure-grid-reliability/.

84 SPP, "Powering the Future: The 2025 Integrated Transmission Plan," (November 2025), https://www.spp.org/documents/75194/2025%20itp%20fact%20sheet%20final.pdf.

While the plan represents a significant investment, the approved plan omits approximately 1,000 miles of 765 kV lines in its southern footprint. Concerns from some stakeholders of high upfront costs, potential cost overruns, and need led SPP to defer the lines for further analysis in the 2026 ITP.[85] These deferrals could impact SPP's transition to the Consolidated Planning Process, discussed in detail below, as the timing of large portfolio approvals could influence the initial Generalized Rates for Interconnection Development Contribution (GRID-C) rate design.

In addition, SPP is creating the Cost Control and Allocation Review and Evaluation Team to "review, evaluate, assess, and recommend refinements or alternatives to the current transmission cost controls and cost allocation methodologies."[86] The team will "emphasize efficiency and increase transparency into cost formation and decision-making" and is expected to provide a final report and recommendation, which will carry significant weight in October 2026.[87]

The 2025 ITP has the highest benefit-to-cost ratio in the region's planning history with the portfolio overall estimated to provide between $12.10 to $17.60 in benefits for every dollar invested, saving ratepayers between $19.42 to $26.09 dollars annually after accounting for the cost of transmission.[88]

As discussed above, the 2024 ITP added extreme weather scenarios, and the 2025 ITP built on that work creating a new resiliency need. The resiliency need has three categories, peak Locational Marginal Price, transfer capacity within subregions, and load shed reduction during extreme weather. These categories of resiliency needs allow SPP to develop better transmission solutions to improve overall resilience.[89]

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85 2025 ITP at 29-34.

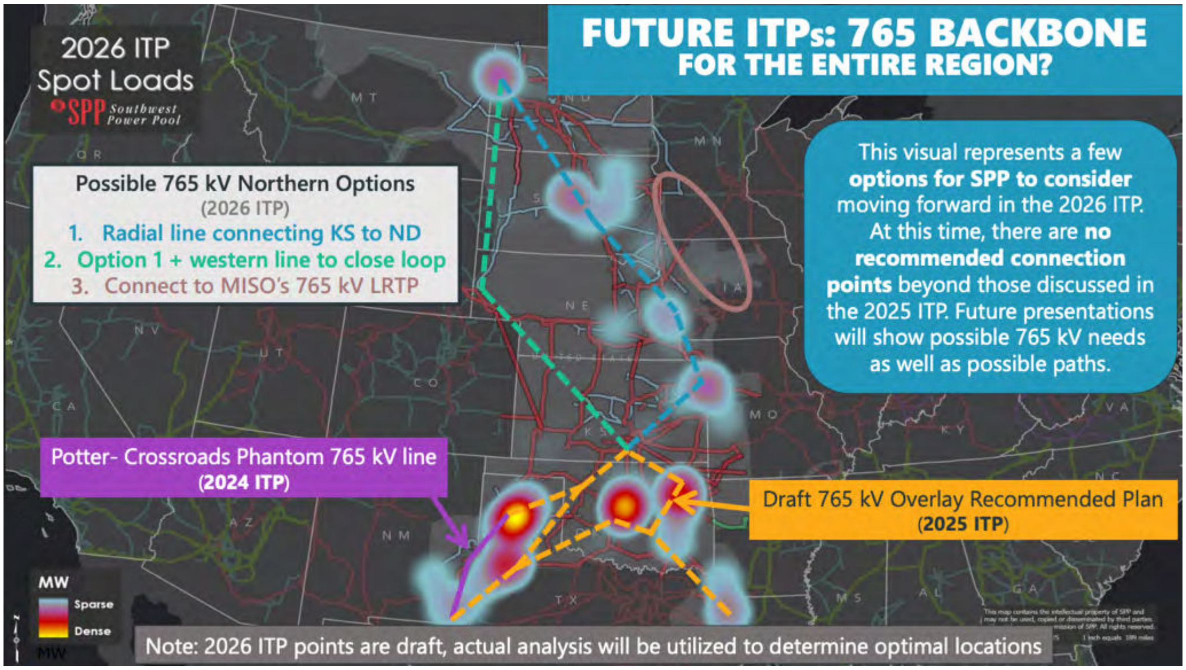
86 SPP, "Cost Control and Allocation Review & Evaluation Team," accessed Jan. 2026, https://spp.org/stakeholder-groups-list/organizational-groups/cost-control-and-allocation-review-evaluation-team/.

87 *See* SPP, "Cost Control and Allocation Review & Evaluation Organizational Group Scope Statement" (Nov. 2025) https://spp.org/Documents/75412/CARE%20Materials%2020251210.zip.

88 2025 ITP at 241-249.

89 *Id.* at 112-119.

FIGURE 13 Potential 765 kV overlay being discussed in SPP[90]



90 SPP, "Special Joint Stakeholder Briefing" 45 (Sep. 2023), https://www.spp.org/documents/74668/25-09-03%20board%20rsc%20joint%20briefing%20materials%20v3.pdf.

SPP Takes Historic Step to Fully Integrate Transmission Planning with Generation and Load Interconnection Planning

Since 2020, SPP has been working to create the Consolidated Planning Process (CPP). The CPP arose in response to a recognition of improvements needed across its planning process. The traditional planning approach handles resource, load, and transmission planning as separate processes which created uncertainty, delays, redundancies, and less efficient transmission solutions. The goal of the CPP is to bring together all of SPP's planning process, combining transmission and generator interconnection planning, helping ensure the optimal transmission upgrades are built at the right time and costs are shared based on benefits.[91]

At a high level, CPP merges SPP's long-term regional transmission planning and generator interconnection into a single, streamlined process designed to identify "multi-driver" transmission solutions that serve both load and generation needs. The CPP is designed as a three-year repeating planning cycle that includes a 20-year planning assessment (CPP-20) and subsequent 10-year planning assessments (CPP-10), which incorporate interconnection studies and a regional planning assessment over a 10-year horizon.[92]

One of the key components of the CPP is the GRID-C. The GRID-C is a flat cost ($/MW) all generation interconnection customers will have to pay to interconnect as a part of the 10-year planning. GRID-C is initially developed based on the CPP-20, which includes a future resource and load forecast as well as needed transmission. Once the GRID-C is determined, the cost is assigned to actual generator interconnection customers within the CPP-10 and paid to load. Ideally, GRID-C will be used to fund more holistic transmission solutions in the CPP-10.[93]

SPP filed its CPP Phase 1 tariff revisions in November 2025 and is hoping for the changes to go into effect in March 2026. In the meantime, SPP is continuing to work on the CPP "transition study," which will be completed by the end of 2026 and determine the initial GRID-C rates. SPP will continue to develop legacy ITPs for 2026 and 2027, with the CPP 10-year assessments beginning in 2028.[94]

91 SPP, "CPP Education Session 1," Slide 18 (May 2025), https://www.spp.org/calendar-list/cpp-education-series-session-1-consolidated-planning-process-cpp-overview-net-conference-20250507/ ("CPP Education Session 1").

92 SPP, Submission of Revisions to the SPP Open Access Transmission Tariff to Implement the Consolidated Planning Process, FERC Docket ER26-414, November 2025, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20251103-5149&optimized=false&sid=7c8ec448-abb4-495d-b95e-f5d1266d32e4.

93 SPP, Submission of Revisions to the SPP Open Access Transmission Tariff to Implement the Consolidated Planning Process, FERC Docket ER26-414, November 2025, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20251103-5149&optimized=false&sid=7c8ec448-abb4-495d-b95e-f5d1266d32e4.

94 CPP Education Session 1 at Slide 36.

Midwest

The Midwest received an A for regional planning. MISO has largely stuck to the transmission planning described in the 2023 Report Card.[95] In December 2024, MISO approved the LRTP Tranche 2.1 portfolio, a $21.8 billion portfolio of 1,800 miles of 765 kV backbone transmission lines and 1,800 miles of 345 kV lines. The portfolio is estimated to provide between $1.80 to $3.50 in benefits for every $1 invested in the projects.[96]

In 2025, MISO did not develop a new LRTP portfolio; instead, it is refreshing its Futures Scenarios, which are the 20-year load, resource, and policy assumptions that underlie the LRTP planning process. A final report is expected in Q1 of 2026 for the refreshed (Series 2) Futures, with Futures 1-3 largely reflecting the assumptions from the first two rounds of Futures development (Series 1/1A). New to this refresh will be a fourth scenario that is intended to test the impacts of supply chain constraints on new resource additions.[97] Fig. 14 shows the major changes of each future between Series 1/1A and 2.

FIGURE 14 Summary of assumptions in each of the four Futures MISO is developing for its Series 2 Futures[98]

Future Scenario Definitions	Lower Load Growth		Stated Policy		Higher Load Growth		Supply Shift
	FUTURE 1		FUTURE 2		FUTURE 3		FUTURE 4
	Series 1 & 1A	Series 2 (New)	Series 1 & 1A	Series 2 (New)	Series 1 & 1A	Series 2 (New)	Series 2 (New)
Footprint Development	In line with 100% of utility IRPs and state legislation; and 85% of utility/state announcements	No Change	Companies/states meet their goals, policies and announcements	No Change	Companies/states meet their goals, policies and announcements	No Change	In line with supply frictions: limits build rate and causes tension with timelines of member plans and goals
Emissions	Minimum 40% reduction from 2005 levels	No Change	Minimum 60% reduction from 2005 levels	No Change	Minimum 80% reduction from 2005 levels	No Change	Minimum 60% reduction from 2005 levels, unless supply friction build rate violated
Load Growth	Consistent with current trends (0.35% CAGR)	Consistent with low-end projections (1.1% CAGR)	30% energy increase (0.8% CAGR)	Consistent with anticipated values (1.6% CAGR)	50% energy increase (1.1% CAGR)	Consistent with high-end projections (2.1% CAGR)	Consistent with anticipated values (1.6% CAGR) – additional Demand Response if needed
Generation Retirements	Age-based and member planned generation retirements	No Change	**Accelerated** age-based and member planned generation retirements	No Change	**Advanced** age-based and member planned generation retirements	No Change	No age-based generation retirements – delayed retirements if needed

At the end of 2025, MISO also approved its annual transmission plan, the 2025 MISO Transmission Expansion Plan (MTEP), consisting of 432 projects and representing over a $12 billion investment (*see Fig. 15).*[99] Similar to the MTEP24, new large loads are a significant driver of many projects, in particular 49 expedited projects totaling more than $4 billion,

95 *See* 2023 Report Card at 31-34 and 2024 Interim Report Card at 22-25 for additional details on the Midwest's transmission planning.

96 MISO, "Long Range Transmission Planning," accessed Jan. 2026, https://www.misoenergy.org/planning/long-range-transmission-planning/.

97 *See* MISO, "Futures Redesign Project Status & Schedule" (Dec. 2025) https://cdn.misoenergy.org/20251217%20Futures%20Workshop%20Items%2001%20%2002%20Presentation732081.pdf.

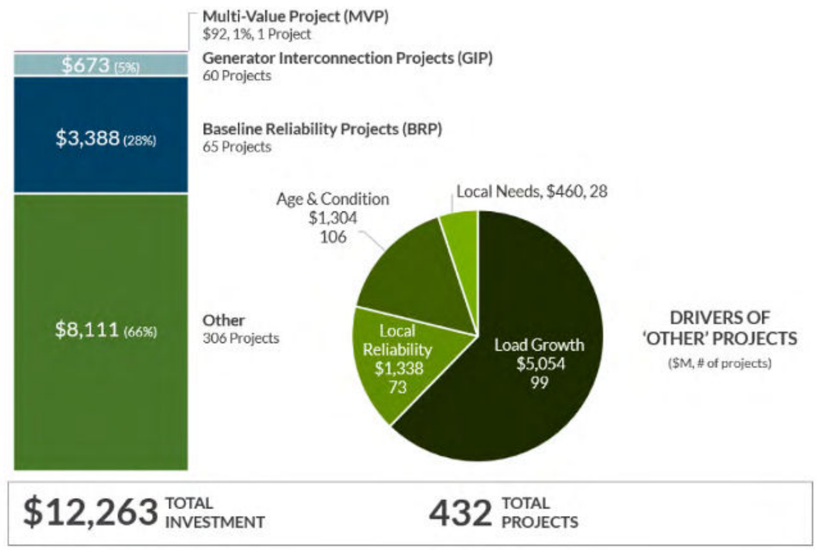
98 *Id.* at 13.

99 MISO, *MTEP25 Transmission Portfolio*, 36 (Dec. 2025), https://cdn.misoenergy.org/MTEP25731615.zip ("MTEP25").

with an estimated 11.6 GW being supported by MTEP25 projects.[100]

In October 2025, FERC also ordered MISO to describe how it will integrate merchant high-voltage direct current (HVDC) transmission projects into its transmission planning.[101] FERC's Order was in response to a complaint by Invenergy, the developer of the HVDC Grain Belt Express project, that MISO's process was unfair and creating duplicative transmission projects by not properly accounting for proposed merchant HVDC lines.[102] As required, MISO revised its tariff to include HVDC and filed it with FERC in January 2026.[103]

FIGURE 15 MISO's MTEP 25 Investment Summary[104]



As discussed in the previous Report Cards, MISO's grades are impacted by its MISO South region, which includes parts of Arkansas, Mississippi, Louisiana, and Texas and has not participated in any proactive planning practices. To date, MISO South has not had a successful transmission project with regional cost allocation. This lack of proactive planning in MISO South has increasingly become a problem as the utilities have advanced significant investments in new transmission capacity through the local transmission planning process and MISO's reliability and expedited project review processes ("other" projects), largely considered less efficient than regional planning.

For example, Louisiana and southeast Texas comprised $3.9 billion of the $9 billion MTEP23 projects,[105] and in MTEP 24, projects in MISO South made up almost $2 billion

100 *Id.*

101 FERC, Order on Complaint, 193 FERC ¶ 61,033 (Oct. 2025), https://www.ferc.gov/media/e-3-el22-83-000 ("Order on Complaint").

102 Complaint of Invenergy Transmission LLC vs. Midcontinent Independent System Operator, Inc. under EL22-83, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20220808-5195&optimized=false.

103 MISO, OATT Tariff Attachment FF revisions, available: https://cdn.misoenergy.org/EL22-83%20-%20Att%20FF%20Compliance%20Revisions%20-%2001-12-2026735542.pdf.

104 MTEP25 at 34.

105 MISO, *MTEP23 Transmission Portfolio*, 25 (Dec. 2023), https://cdn.misoenergy.org/MTEP23650305.zip.

of the $6.7 billion.[106] Louisiana has the most investment of all MISO states in MTEP 25, at more than $3.4 billion in reliability projects and projects needed to meet load growth, with MISO South accounting for $4.7 billion overall.[107] However, the region's grade could see improvement in future Report Cards as MISO is expected to begin its South LRTP planning in 2026. MISO has said it will use the Series 2 Futures for the South LRTP planning but will start with a more limited "South Load Pocket Risk Assessment."[108]

Southeast

The Southeast received an F for regional planning. For the 2023 Report Card, we reviewed three Order No. 1000 regional planning entities in the Southeast: Southeastern Regional Transmission Planning (SERTP), South Carolina Regional Transmission Planning (SCRTP), and Florida Reliability Coordinating Council (FRCC). However, with the issuance of Order No. 1920, SCRTP has announced they will be joining SERTP and retiring the SCRTP Order 1000 process.[109]

SERTP has continued to not select any public policy scenarios for study in both the 2024 and 2025 planning cycle, and no regional projects have ever been selected.[110] SERTP and FRCC continue to essentially "roll up" the local transmission plans from their member utilities and have not made changes to their existing regional transmission planning processes.[111] In addition, SERTP's plan relies on incomplete or inconsistently reported data from the SERTP sponsors.[112] The process continues to lack transparency, stakeholder involvement is often limited, both of which are discussed further in the Engagement section.

Despite these planning realities, there is a clear need for additional transmission capacity in the Southeast. The 2024 NERC ITCS showed a need for transmission to maintain reliability and the Southeast is projecting some of the largest load growth over the next five

106 MISO, *MTEP24 Transmission Portfolio*, 180 (Dec. 2024), https://cdn.misoenergy.org/MTEP24720395.zip.

107 MTEP25 at 36.

108 *See* MISO, "Reliability Imperative: Transmission Evolution" (Sep. 2025), https://cdn.misoenergy.org/20250916%20System%20Planning%20Committee%20of%20the%20BOD%20Item%2005%20Reliability%20Imperative_Transmission%20Evolution717558.pdf.

109 South Carolina Regional Transmission Planning, "Home," accessed Jan. 2026, https://www.scrtp.com/.

110 *See* SERTP, *Regional Transmission Plan & Input Assumptions Overview* (Nov. 2024), https://www.southeasternrtp.com/docs/general/2024/2024_Regional_Transmission_Plan_and_Input_Assumptions.pdf; *See also* SERTP, *Regional Transmission Plan & Input Assumptions Overview* (Nov. 2025), https://www.southeasternrtp.com/docs/general/2025/2025%20Regional%20Transmission%20Plan%20and%20Input%20Assumptions.pdf.

111 *See* 2023 Report Card at 42-45 and 2024 Interim Report Card at 45-49 for additional details on the Southeast's transmission planning.

112 In a 2025 report The Brattle Group found that Southeast "utilities have identified the need for over 80 GW of new power generation, but the regional plan only accounts for 12% of that growth. This mismatch could lead to a system that is ill-prepared for the coming changes and result in bottlenecks on the grid and delays in bringing new power online." Haggerty, J.M., *Modernizing Southeast Grid Investments: How Enhanced Regional Transmission Planning Supports a Growing Economy*, The Brattle Group, 8 (Apr. 2025), https://carolinasceba.com/wp-content/uploads/2025/04/SERTP-Report-Summary_FINAL.pdf.

years.[113]

However, as in the Northwest and Southwest, this need for transmission is showing up in the Southeast at the state level and in individual Transmission Owner transmission plans. The Georgia utilities' ten-year transmission planning process currently has almost 500 miles of new 500 kV transmission lines planned to go in-service by 2033. These lines are being developed to bring in new resources to accommodate load growth and maintain reliability.[114]

In the Carolinas, Duke Energy has almost completed its first round of Multi-Value Strategic Transmission planning. This process is an attempt to create a more proactive, multi-value local transmission plan.[115] The process has good participation from interested parties and does include some improvements, including scenario-based planning based on Duke's recent IRP and stakeholder input along with production cost modeling to quantify benefits for proposed projects.[116] However, there are concerns that may prevent Duke from achieving its stated goals. The first Multi-Value Strategic Transmission study cycle used a 10-year planning horizon, which will likely prevent longer lead time projects from being identified and built, and the study did not include economic drivers for transmission needs.[117] The study has not yet been finalized, but draft results suggest a more narrow focus, which may have removed high-capacity solutions from consideration, even though higher-capacity solutions can provide larger economies of scale.[118]

Looking to the future, compliance with FERC Order No. 1920 should improve the Southeast's grade for regional transmission planning. That said, the SERTP sponsors have pushed their Order No. 1920 compliance filing to December 2026, meaning the first projects selected under Order No. 1920 planning process, if any, will not be until 2031. This date is too late to accommodate the exponential near-term load growth the SERTP sponsors are expecting.[119]

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113 *See* NERC, *Interregional Transfer Capability Study (ITCS): Strengthening Reliability Through the Energy Transformation*, xvi (Nov. 2024), https://www.nerc.com/globalassets/initiatives/itcs/itcs_final_report.pdf; Grid Strategies 2025 Load Growth Report at 22.

114 Georgia Power, *2025 Integrated Resource Plan*, 120 (Jan. 2025), https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/2025-Integrated-Resource-Plan.pdf.

115 *See* Carolinas Transmission Planning Collaborative (CTPC), "Multi-Value Strategic Transmission Planning" (Apr. 2024), https://carolinastpc.org/static/ctpc/Multi-Value-Strategic-Transmission-Planning-Process.pdf.

116 *See* CTPC, "2024 Multi-Value Strategic Transmission (MVST) Study," August 16, 2024, https://carolinastpc.org/media/reference/2024/08/19/2024_CTPC_MVST_Study_Scope_08_16_2024_Clean.pd.

117 *See* Carolinas Transmission Planning Collaborative (CTPC), "2024 Multi-Value Strategic Transmission (MVST) Study" (Aug. 2024), https://carolinastpc.org/media/reference/2024/08/19/2024_CTPC_MVST_Study_Scope_08_16_2024_Clean.pdf; *See* "Joint Comments on MVST Study Proposals," (Aug. 2024), https://carolinastpc.org/media/reference/2024/09/24/Aug_26_2024__Joint_Comments_on_MVST_Scenarios.pdf.

118 *See* SELC, NCSEA, SACE, and Sierra Club, "Comments on Preliminary MVST Solutions and Proposed Alternatives" (Sep. 2025), https://carolinastpc.org/media/reference/2025/09/18/SELC_NCSEA_SACE_Sierra_Club_Solutions_Comments_9.15.25.pdf.

119 Notice of Extension of Time, FERC Docket No. RM21-17 (Oct. 2025), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20251017-3019&optimized=false&sid=025f19da-8026-45b8-b93b-b8e01ef260b3.

Mid-Atlantic

The Mid-Atlantic received a B for regional planning, and experienced one of largest regional planning grade improvements since the 2023 Report Card. The Mid-Atlantic RTO, PJM Interconnection (PJM), has been working on reforms for more than two years to incorporate longer term planning into its regional transmission planning process.[120] In December 2025, PJM filed its Long Term Regional Transmission Planning (LTRTP) process, adopted to comply with Order No. 1920. PJM has also approved new, significant investments through its annual Regional Transmission Expansion Plans (RTEP).

PJM is facing some of the largest load growth in the county, largely driven by the rapid expansion of data centers and some new manufacturing facilities. Consistent with those trends, the 2024 RTEP approved new projects totaling nearly $6 billion, with most of the investment concentrated in two 765 kV projects that would extend PJM's extra-high-voltage backbone across West Virginia, Virginia, and Maryland. The 2024 transmission planning cycle also included more than $9 billion in supplemental projects.[121]

Early indications suggest the 2025 RTEP could be larger still. In December 2025, PJM previewed an approximately $11.6 billion transmission package expected to be considered for approval in Q1 2026 as part of the 2025 RTEP. The preliminary results reflect a substantial buildout, including more than 1,000 miles of 500 kV and 765 kV facilities through a mix of new greenfield lines, upgrades, and network reinforcements, with total costs exceeding $10 billion. Key drivers include continued load growth, particularly in Northern Virginia, and changes to previously planned projects. In particular, the New Jersey State Agreement Approach — which was intended to facilitate the interconnection of offshore wind — has been paused, increasing the need to move power from west to east to serve coastal demand that would otherwise have been met by offshore generation.[122] Major elements of the preliminary package include a new 765 kV line from West Virginia to central Pennsylvania, upgrades to portions of the 765 kV and 345 kV systems in Ohio, and a new 185-mile underground HVDC line in Northern Virginia (*see Fig. 16*).[123]

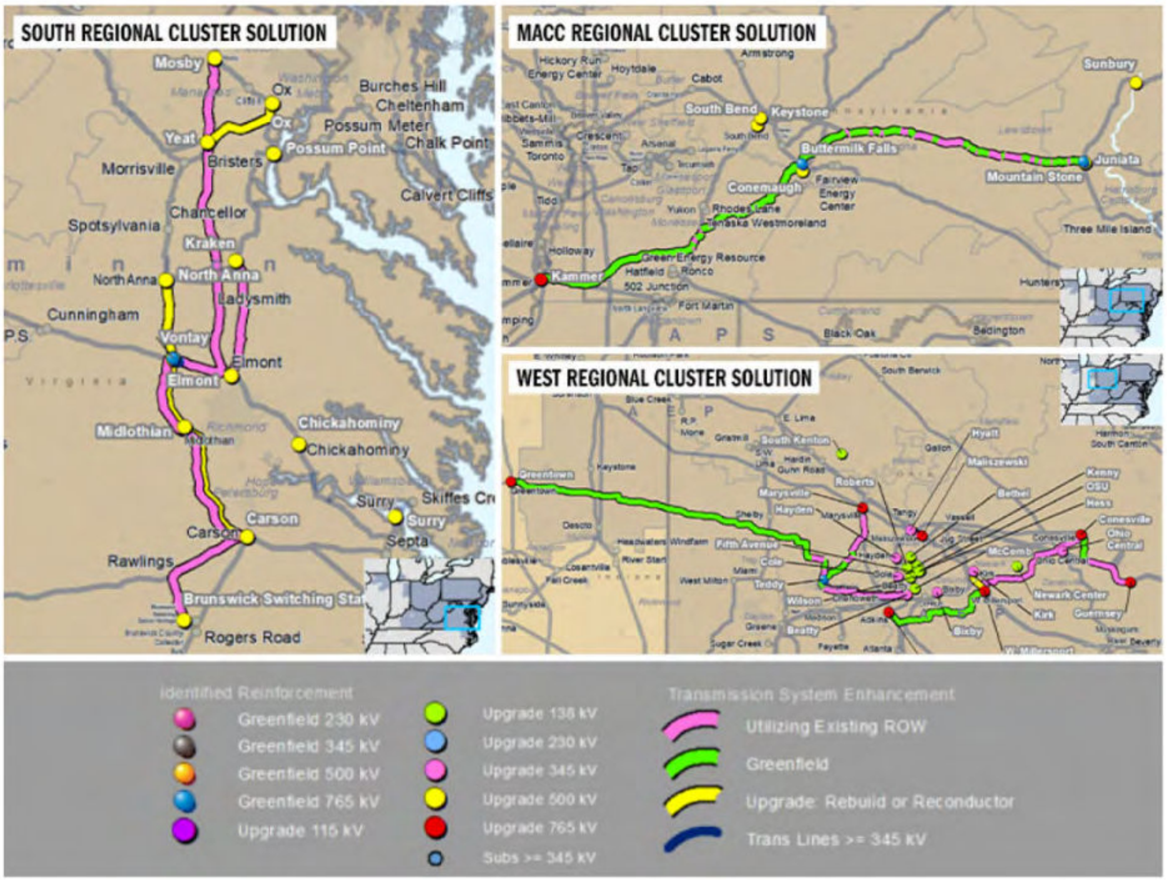
120 *See* 2023 Report Card at 29-31 and 2024 Interim Report Card at 18-21 for additional details on PJM's transmission planning.

121 PJM, *RTEP 2024* (Apr. 2025), https://www.pjm.com/-/media/DotCom/library/reports-notices/2024-rtep/2024-rtep-report.pdf.

122 PJM, "New Jersey SAA Update" (Sept. 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250909/20250909-item-01---new-jersey-saa-update.pdf.

123 PJM, *Reliability Analysis Report: 2025 RTEP Window 1* (Jan. 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2026/20260106/20260106-2025-rtep-window-1-reliability-analysis-report.pdf.

FIGURE 16 Preliminary Recommended Solutions by PJM Cluster[124]



The biggest improvement in PJM's grade compared to our last Report Card comes from their Order No. 1920 compliance filing. Our assessed grade assumes approval by FERC without significant changes to PJM's filing. The filing is intended to make tariff changes to codify PJM's LTRTP reforms and Order No. 1920 requirements. The new LTRTP process would add a 20-year planning horizon and capacity expansion modeling using at least three scenarios based on Order No. 1920's seven required factors. If implemented well, these changes will be a major improvement over PJM's current, more limited RTEP planning process, though additional action will still be required on the cost allocation funding due later in 2026.[125]

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124 Leith-Yessian, D., " PJM Considering $11.6B Transmission Expansion Plan," RTO Insider (Dec. 2025), https://www.rtoinsider.com/121587-pjm-considering-11-6-b-transmission-expansion-plan/.

125 PJM, Order Nos. 1920, 1920-A, and 1920-B Compliance Filing of PJM Interconnection, L.L.C. and Request for Extension of Comment Period, Docket No. ER26-751-000 (Dec. 2025), https://www.pjm.com/pjmfiles/directory/etariff/FercDockets/9298/20251212-er26-751-000.pdf (Compliance Filing).

After developing and modeling the scenarios, PJM will parse the identified long-term transmission needs in two categories: Core Long-Term (LT) Needs and Additional LT Needs. Core LT Needs are designed to maintain system reliability, though they could address other drivers (such as economic congestion and public policy drivers). Additional LT Needs are any remaining needs that are identified but are not specific to maintain system reliability. PJM will identify which of these needs can be met by upgrading "right-sizing" existing facilities, and will open a competitive window to solicit new project proposals for any remaining needs in these two categories.

From the submitted and right-sized projects, PJM will develop a "Core Plan," comprised of the selected projects which will resolve the Core LT Needs. Transmission projects selected to address Core LT Needs will be evaluated on a portfolio basis to ensure they have a benefit-to-cost ratio great than or equal to one. PJM will then select additional transmission projects to address any Additional LT Needs that remain following selection of the Core Plan. Projects addressing Additional LT Needs must have an individual benefit-to-cost ratio of at least 1.25. Although full details are not yet available, PJM's proposed compliance includes the opportunity for states to opt-out of cost allocation for projects that only address Additional LT Needs.[126] Conversely, states and other parties will have the opportunity to voluntarily fund Additional LT Need projects that were not selected by PJM. PJM will then optimize the final plan based on the Core Plan and projects selected to address Additional LT Needs, which have not lost State support via the opt-out provision or those that are voluntarily funded, to create the All-In-One Plan, for approval by the PJM board.

The difference between the two planning categories is meant to show the incremental costs and benefits associated with developing projects beyond those needed just for reliability purposes (i.e. needed to meet Additional LT Needs). The incremental projects designed to address Additional LT Needs are not subject to the same mandatory selection criteria and must demonstrate a higher benefit-to-cost ratio on an individual project basis. The inequity and siloed nature of project selection based on need category is one reason PJM's new long-term planning approach did not score higher. However, the strength of PJM's process will be highly dependent on how PJM evaluates the factors and categorizes needs and solutions, and this grade may be revised in the future if the process is less siloed than it appears to be on paper. PJM will apply its existing RTEP criteria along with the required Order No. 1920 benefits to select projects in either plan.[127]

126 The language for the opt-out and voluntary funding will be included in the June 2026 cost allocation filing.

127 *See* Compliance Filing.

New York

New York received a B+ for regional planning, and their regional planning grades remain largely unchanged from the 2023 Report Card as their proactive and holistic planning process remains in place under the New York Independent System Operator's (NYISO) Public Policy Transmission Planning Processes.[128] However, over the past year New York has faced some headwinds in its transmission planning, which could be cause for concern if prolonged. In July 2025, NYISO and the NY Public Service Commission (NYPSC) canceled its 2022-2023 Public Policy Transmission Planning Process, which was being used to develop the transmission needed to deliver new offshore wind resources to New York City.[129] In 2025, NYPSC also denied Clean Path Transmission's petition to be granted status as a priority transmission project,[130] a status available to the New York Power Authority and co-developers. The denial came after a termination of the contract with NYSERDA to develop associated generation via a renewable energy certificate at the end of 2024.[131] The project was designed to deliver 1,300 MW of power from new generation resources in upstate New York to New York City using an underground HVDC transmission line to help New York meet its state policy goals.[132]

As discussed in the 2024 Interim Update, NYISO completed its second biannual System & Resource Outlook ("Outlook") as part of its economic transmission planning.[133] For the second iteration, NYISO broadened the study to better inform the Coordinated Grid Planning Process (CGPP) by adding new scenarios and by flagging zones where congestion is likely to constrain renewable development. The Outlook also incorporated significant load growth assumptions, including a shift toward a winter peaking system in the mid-2030s, with large loads driving near-term growth before electrification of buildings and transportation becomes the larger driver later in the decade.[134] The Outlook is primarily informational, but it feeds into some local transmission solution and need determinations. NYISO is currently conducting the 2025-2044 Outlook, with preliminary results expected in early 2026.[135]

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128 *See 2023 Report Card at 36-38 and 2024 Interim Report Card at 32-37 for additional details on New York's transmission planning.*

129 New York Public Service Commission (NYPSC), "Commission Decision Avoids Premature Ratepayer Costs as a Result of Federal Uncertainty Decision Positions New York for Smarter, Faster Offshore Wind Growth When Federal Policies Improve" (Jul. 2025) https://dps.ny.gov/news/commission-acts-protect-ratepayers-federal-offshore-wind-permitting-stalls.

130 See NYPSC, "Order Denying Petition," Case 20-E-0197, 2-3 (Aug. 2025) https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={10A1A998-0000-C42B-B3B8-0AB5C401EF82}&DocTitle=Order%20Denying%20Petition.

131 *Id.* at 7.

132 *Id.*

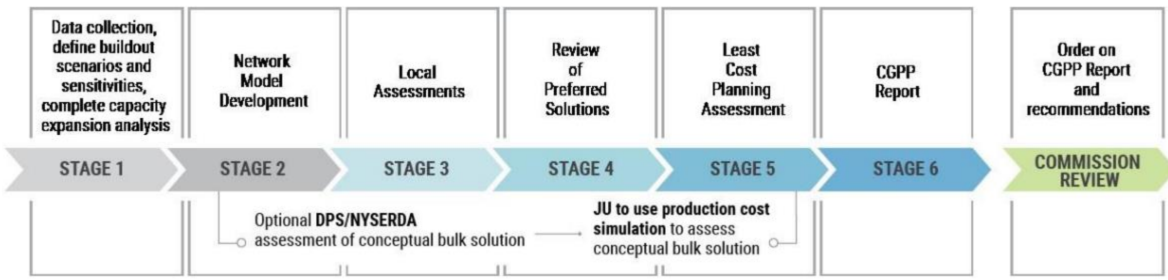
133 *See* NYISO, *2023-2042 System & Resource Outlook (The Outlook)* (Jul. 2024), https://www.nyiso.com/documents/20142/46037414/2023-2042-System-Resource-Outlook.pdf/8fb9d37a-dfac-a1a8-8b3f-63fbf4ef6167?t=1721752637474 ("2023-2042 System Outlook").

134 *Id.* at 13.

135 NYISO, "2025-2044 System & Resource Outlook Update," 4 (Dec. 2025), https://www.nyiso.com/documents/20142/55862442/2025-2044_System_Resource_Outlook_Update_12182025.pdf/80ef8110-1093-f1a7-cb31-9209e38faf44.

New York launched the CGPP in 2023 to better align utility local transmission planning with NYISO transmission planning and interconnection processes. The process follows a six-stage framework and is expected to culminate in an initial set of recommended investments for NYPSC consideration (*see Fig. 17).*[136] The first cycle timeline has slipped from late 2025 to May 2026.[137] Additionally, the NYPSC has already made process reforms to the CGPP based on stakeholder feedback, including moving to a two-year planning cycle.[138]

FIGURE 17 Coordinated Grid Planning Process Timeline[139]



Within the CGPP, the NYPSC established the Advanced Technology Working Group (ATWG) to evaluate options such as Dynamic Line Ratings, Advanced Power Flow Control devices, and energy storage, with a 2024 NYPSC order directing the ATWG to consider a wider set of technologies and to allow submissions from interested parties.[140] In January 2025, the ATWG released its 2024 Annual Report summarizing the efforts from the previous year, mainly evaluating concept papers.[141] In 2025 the ATWG also took steps to more closely align with the CGPP and support the next planning cycle, including by developing screening criteria for each advanced transmission technology for the CGPP to apply to Stage 3 of the planning process.[142] The ATWG accepted another round of concept papers

136 System Outlook at 25; *See* also NYPSC, "Order Approving a Coordinated Grid Planning Process," Case 20-E-0197, August 17, 2023, at 24-25, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={101C058A-0000-C45D-9CD3-A87E49DF7A99}&DocTitle=Order%20Approving%20a%20Coordinated%20Grid%20Planning%20Process.

137 NYPSC, "Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act," Case 20-E-0197 (Dec. 2025), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={F039379B-0000-CE3A-87EF-F5D1DD596792}&DocTitle=Ruling%20on%20Extension%20Request.

138 *See* NYPSC, "Order Modifying Coordinated Grid Planning Process" (Nov. 2025), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={10517E9A-0000-C96B-B373-B6256DBE4622}&DocTitle=Order%20Modifying%20Coordinated%20Grid%20Planning%20Process.

139 2023-2042 System Outlook at 25.

140 *See* NYPSC, "Order Establishing Procedures for the Advanced Transmission Technologies Working Group," Case 20-E-0917, January 19, 2024, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={B0E0228D-0000-C413-8A45-E2317EA6E16D}.

141 *See* Joint Utilities of New York, *Advanced Technology Working Group 2024 Annual Report* (Jan. 2025), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={D047BD94-0000-CC11-AA01-95CA3727E1FA}&DocTitle=2024%20ATWG%20Annual%20Report.

142 Joint Utilities of New York, "Advanced Technology Working Group (ATWG) 2025 October Webinar," 16-17 (Oct. 2025) https://jointutilitiesofny.org/sites/default/files/Fall%202025%20Stakeholder%20Webinar%20Presentation%20(10.21.2025).pdf.

in late 2025 and is expected to release its second annual report in early 2026.[143]

New England

New England received a B for regional planning, improving with the finalization of the Longer-Term Transmission Planning (LTTP) process, which was detailed in the 2024 Interim Report Card. The LTTP process was developed in two stages, which culminated in tariff changes that were approved by FERC in 2024.[144] The LTTP process is a proactive, holistic planning process that in its first study looked out to 2050 to address public policy transmission needs. The LTTP process also includes a broader set of benefits, though not the full Order No. 1920 set, and if the benefit-to-cost ratio was less than one, it allows for a state or a group of states to pay the difference.[145]

The process also includes the ability for states to solicit solutions to needs that are identified in the study. ISO New England (ISO-NE) and its states initiated that RFP process in 2024 with the first RFP window closing September 2025. The LTTP procurement requires proposals to increase the capacity of the Maine-New Hampshire interface to 3,000 MW and the Surowiec-South interface to 3,200 MW as well as support the interconnection of at least 1,200 MW of new resources in Northern Maine.[146] ISO-NE reported that there were six submissions to the RFP, three alternating current and three direct current projects, ranging between $962 and $4.04 billion, though these estimates will likely change as corollary upgrade cost estimates associated with the proposals are updated.[147] ISO-NE is in the process of evaluating the submissions, and project selection is expected in the second half of 2026.[148] ISO-NE has indicated additional RFPs may follow. In December 2025, the Maine Public Utility Commission, in collaboration with Connecticut, Massachusetts, Rhode Island, and Vermont, issued a related RFP to procure at least 1,200 MW of new transmission capacity to connect new generation in Northern Maine with ISO-NE. The Maine RFP project is expected to tie into the northern end of the ISO-NE LTTP RFP line, with in-service dates expected in the early 2030s.[149]

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143 *Id.* at 21.

144 *See* ISO New England, Inc. (ISO-NE), "ISO New England Inc. submits tariff filing per 35.13(a)(2)(iii): Revisions to the Attachment K Longer-Term Transmission Planning Process to be effective 7/9/2024 under ER24-1978," May 9, 2024, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240509-5064&optimized=false.

145 *See* 2023 Report Card at 34-36 and 2024 Interim Report Card at 26-31 for additional details on New England's transmission planning.

146 *See NESOE, "Transmission Needs for a Longer-term Transmission Planning RFP" (Dec. 2024),* https://www.iso-ne.com/static-assets/documents/100018/a05_2024_12_18_pac_transmission_needs_for_a_longer-term_transmission_planning_rfp_final.pdf.

147 *See* ISO-NE, "Longer-Term Proposals Summary" (Dec. 2025), https://www.iso-ne.com/static-assets/documents/100030/2025_lttp_rfp_proposal_summaries_rev1_clean.pdf.

148 ISO-NE, "2025 Longer-Term Transmission Planning Request for Proposals (2025 LTTP RFP)" (Nov. 2025), https://www.iso-ne.com/static-assets/documents/100029/a03_pac_2025_lttp_rfp_longer_term_summary_presentation.pdf.

149 *See* Maine Public Utilities Commission, "Request for Proposals for Renewable Energy Generation and Transmission Projects Pursuant to the Northern Maine Renewable Energy Development Program," Docket No. 2025-00361 (Dec. 2025), https://www.maine.gov/mpuc/regulated-utilities/electricity/rfp-awarded-contracts/2025-00361.

2. Interregional Transmission

The second grade component is interregional planning and development. This component — and the metrics associated with it — are based on very similar best planning practices to the regional transmission planning and development grade, including proactive generation and load forecasts, scenario- and portfolio-based planning, multi-value evaluation of transmission solutions, inclusion of alternative transmission technologies or business models (like merchant transmission developers), and interregional transmission planning that is integrated with other planning paradigms. This component also makes up 35% of the final grade.

As discussed in the introduction, there are very few formal requirements for interregional transmission planning. However, since the issuance of Order No. 1000, FERC has recommended stronger interregional transmission planning[150] and has held multiple workshops in 2016 and 2022 on the benefits of interregional transmission.[151] Additionally, in 2024, as discussed in the interim report card, NERC completed the Interregional Transfer Capability Study. The study was directed by Congress and focused solely on interregional transmission capacity additions needed for reliability.[152] NERC filed the study with FERC, where the public had an opportunity to comment. FERC must file the report plus its recommendations to Congress in early 2026,[153] but has not yet moved to take action on its own.

As such, many regions' interregional planning process consist solely of affected systems studies, which determine whether a neighboring transmission plan could impact the operational reliability of another system and would therefore be responsible for "do no harm" payments. Affected system studies are generally reliability-focused power flow models and do not include proactive, multi-value, scenario-based planning. Each regional discussion below considers whether regions are undertaking interregional transmission planning studies beyond the expected affected system studies.

California

California received a B-, one of the highest grades for interregional transmission planning. While the region's formal interregional planning is limited, the region has taken some proactive measures to develop interregional transmission. For example, CAISO's recent

150 ScottMadden, "FERC Order No. 1000: Five Years On," 6 (Jun. 2016), https://www.scottmadden.com/content/uploads/2016/06/ScottMadden_FERC_Order_1000_2016_0601.pdf.

151 See FERC, "Staff-Led Workshop on Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements," Docket AD23-3-000 (Dec. 2022), https://www.ferc.gov/news-events/events/technical-conference-regarding-competitive-transmission-development-rates-docket; *See also* FERC Competitive Transmission Development Technical Conference," Docket AD16-18-000 (Jun. 2016), https://www.ferc.gov/news-events/events/staff-led-workshop-establishing-interregional-transfer-capability-transmission.

152 NERC ITCS at xix, 11.

153 "Notice of Request for Comments," FERC Docket No. AD25-4-000 (Nov. 2024), https://www.ferc.gov/sites/default/files/2024-11/20241125-3020_AD25-4-000-NERC%20ITCS%20Notice.pdf.

regional transmission plans have explicitly included estimates of out-of-state resources needed to help meet load growth and state policy goals, while maintaining reliability. The 2024-2025 CAISO Transmission Plan called for the "the import of over 9 GW of out-of-state wind generation from Idaho, Wyoming and New Mexico, by enhancing corridors from the ISO border in southeastern Nevada and from western Arizona into California load centers."[154]

In the 2023 Report Card, we noted that CAISO had initiated the Subscriber Participating Transmission Owner (PTO) model as an innovative way to integrate out-of-state resources that California load-serving entities had procured. The Subscriber PTO model allows CAISO to develop transmission lines outside of its footprint and creates a cost recovery mechanism for developers. FERC approved the Subscriber PTO model in March 2024.[155] CAISO has approved two new transmission facilities under this model: TransWest Express and SunZia.[156] In January 2025 FERC approved a development agreement between CAISO and the Southwest Intertie Project (SWIP) North, where CAISO funds nearly 80% of the transmission project (Idaho Power will fund the remaining amount)[157] in exchange for assuming operational control of SWIP North and related One Nevada line.[158] In its 2024-2025 Transmission Plan, CAISO noted many of the challenges it is facing as it seeks to integrate out-of-state resources beyond the three lines above. The ISO highlighted that there are no interregional projects in development in the West seeking to deliver to CAISO, suggesting a lack of developer interest.[159] CAISO also notes the challenges of coordinating interregional transmission planning and cost allocation under the current formal interregional planning process, and has relied instead on the Voluntary Agreement Framework, outlined by FERC in 2018.[160]

However, CAISO also continues to participate in the Order No. 1000 interregional planning processes with NorthernGrid and WestConnect, despite no projects identified through those interregional processes.[161] In addition, CAISO is participating in an extensive West-wide transmission planning process, known as Western Transmission Expansion Coali-

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154 CAISO 2024-2025 Transmission Plan at 7.

155 See Order Accepting Proposed Tariff Revisions re California Independent System Operator Corporation under ER23-2917, FERC Docket No. ER23-2917-001, March 12, 2024, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240312-3078&optimized=false.

156 CAISO 2024-2025 Transmission Plan at 127.

157 Idaho Power, "SWIP-North," accessed Jan. 2026, https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/current-projects/swip-north/.

158 *Id.*; See also Order Accepting Project Development Agreement, 190 FERC ¶ 61,034 (Jan. 2025), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250121-3068&optimized=false&sid=fa23f5ce-e93a-44aa-a547-d512ed245570; *See also* Order on Transmission Incentives and Accepting Transmission Owner Tariff and Formula Rate, 193 FERC ¶ 61,083 (Oct. 2025), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20251031-3043&optimized=false&sid=cf779238-bd14-4f6b-86c8-939199233962.

159 *CAISO 2024-2025 Transmission Plan* at 128.

160 CAISO, "2025-2026 Transmission Planning Process," 30-39 (Sep. 2025), https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-2025-2026-TransmissionPlanningProcess-Sep2525.pdf.

161 *Id.* at 157-158.

tion, discussed further below, and continues to explore mutually-beneficial transmission opportunities with other western utilities.

Northwest & Southwest

The Northwest and Southwest both received a C for interregional planning. Many of the transmission owners, states, and stakeholders from the NorthernGrid and WestConnect footprints — though, unlike in California, not the planning organizations themselves — are participating in WestTEC. WestTEC is a West-wide transmission planning study that emerged, at least in part, due to a lack of coordinated regional planning in the Western regions. The study has identified numerous interregional needs and upgrades and is one of the most robust interregional transmission planning processes in the country. Broad participation in WestTEC improved both regions' overall interregional transmission planning grades above what was earned by the limited, reliability and operational Order No. 1000 required interregional processes performed by NorthernGrid, WestConnect, and CAISO which has not identified any interregional needs.

WestTEC Planning Process

The WestTEC process is a proactive, scenario-based multi-value 10- and 20-year West-wide transmission plan, described in more detail in our 2024 Interim Report Card.[162] The WestTEC process is the only interregional transmission planning process that considers ATTs of any kind, though it has limited ATTs to only reconductoring with High Performance Conductors.[163]

The WestTEC planning process is on track to publicly release its 10-year transmission plan in Q1 of 2026 and has preliminarily identified 104 upgrades across the West (*see Fig. 18*). The upgrade list includes both new projects and some currently in development, all of which improve reliability, enhance interregional transfers, and/or provide congestion relief.[164] WestTEC plans to release the related 20-year transmission plan at the end of 2026.[165]

WestTEC process is currently informational only without a path to development of the project. There is no formal cost allocation or requirement for project selection, but there are some other efforts underway in the West. For example, the Committee on Regional Electric Power Cooperation Transmission Collaborative is working on an Order No. 1920

162 *See* 2024 Interim Report Card at 55-56 for additional details on the WestTEC's transmission planning process.

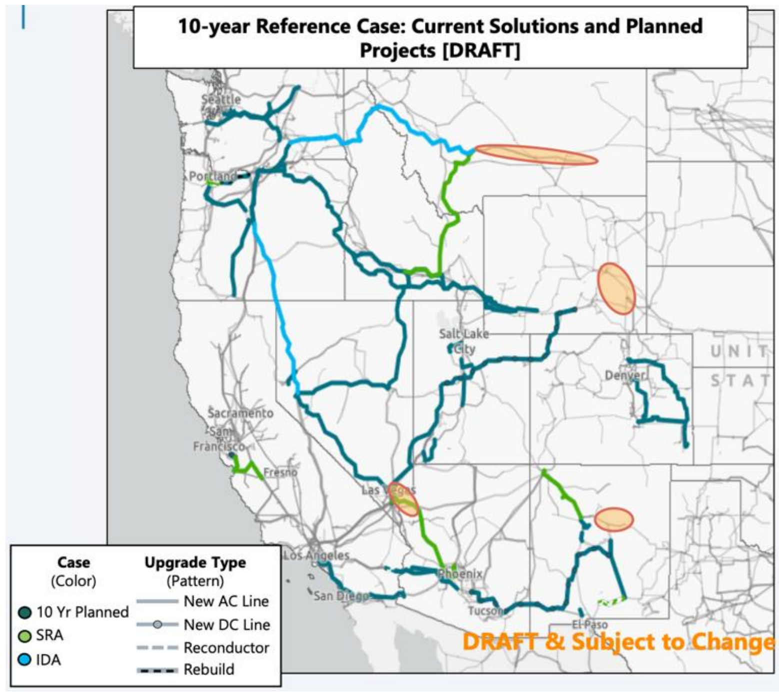
163 WestTEC, "Western Transmission Expansion Coalition," at 22-25 (Nov. 2025), https://www.westernpowerpool.org/private-media/documents/ES_REC_Update_-_251113.pdf.

164 *Id.* at 2.

165 *Id.*

cost allocation framework.[166] In addition, there is the Western Transmission Consortium composed of utilities and independent developers, which is aimed at developing bilateral, collaborative interregional or interjurisdictional transmission.[167] Both are positive developments, but neither is associated with WestTEC, and are unlikely to produce planning or create cost allocation functions in the same way a formal RTO would.

FIGURE 18 WestTEC Preliminary 10-year Initial Transmission Plan[168]



Texas

Texas received an F for interregional planning. The region is a separate electrical interconnection from the Eastern and Western United States and the grid operator, ERCOT, does not conduct regular interregional planning. ERCOT has jurisdictional independence, and its electricity is not considered interstate commerce under the Federal Power Act.[169] To avoid impacting ERCOT's jurisdictional status, any future interconnection must be specially built pursuant to a case-specific declaratory order from FERC, further complicating the process of developing interregional transmission. As was discussed in the 2023 Report Card, ERCOT, the Public Utility Commission of Texas, and the Texas legislature in the past have contemplated expanding or upgrading interregional transmission capacity with adjacent regions, but to date have not taken action.[170] There are a few re-

166 *See* Energy Strategies, *State Exploration of Western Transmission Cost Allocation, prepared for Western Interstate Energy Board & Committee on Regional Power Cooperation Transmission Collaborative* (Nov. 2024), https://www.westernenergyboard.org/wp-content/uploads/CREPC-TC-Cost-Allocation-Frameworks-White-Paper-FINAL-11-26-24.pdf.

167 Western Transmission Consortium, "The Western Transmission Consortium," accessed Jan. 2026, https://www.westerntransco.com/.

168 WestTEC, "Western Transmission Expansion Coalition," at 7.

169 Cottonwood Energy Co., LP, 118 FERC ¶ 61,198 (2007); Sharyland Utilities, LP, 121 FERC ¶ 61,006 (2007); Cross Texas Transmission, LLC, 129 FERC ¶ 61,106 (2009).

170 2023 Report Card at 50.

cently proposed merchant interregional lines to connect the Texas Interconnection with the rest of the country, but those have not arisen through a formal interregional planning process.[171] At this point, ERCOT earns the lowest grade for interregional planning.

Plains

The Plains region received a C for interregional planning. The Plains is bordered by Canada, the Mid-Atlantic, Midwest, Northwest, Southwest, and Texas and to date has concentrated most of its interregional planning with efforts with the Midwest. The Plains and the Midwest continue to move forward with their Joint Targeted Interconnection Queue (JTIQ) portfolio through MISO and SPP planning. The regions have agreed to a Joint Operating Agreement and cost allocation methodology, which has been filed at FERC.[172] However, not all parties in MISO and SPP were supportive of the cost allocation structure, which proposes to allocate costs solely to developers.[173] The JTIQ portfolio was also awarded $464 million in the first round of DOE's Grid Resilience and Innovation Partnerships Program funding announced in October 2023. As of the end of 2025, the funding appears to still be in play; however, its long-term status is uncertain due to shifting administration priorities.[174]

The regions are moving forward assuming JTIQ will be built. In July 2025, FERC approved a MISO filing to allow the 2023 queue cycle to use the JTIQ process. That queue cycle began in September 2025. Additionally, the first cycle of MISO's Expedited Resource Addition Study kicked off in September. Interconnection requests in both MISO's Expedited Resource Addition Study and SPP's Definitive Planning Phase 2023 cycle have been identified as eventual projects that will fund the JTIQ portfolio once they enter into a Generator Interconnection Agreement and the appropriate JTIQ agreements.[175]

Both regions have indicated there will likely be a second round of planning. As discussed in the original report, this is a good step forward in aligning processes to work on joint planning and will facilitate the connection of nearly 30 GW of new generation. But the process falls short of true, optimized interregional planning, which would consider a more holistic set of transmission benefits beyond simply easing the interconnection process.

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171 *See* Pattern, "Southern Spirit Transmission," accessed Jan. 2026, https://patternenergy.com/projects/southern-spirit-transmission/; *See also*, Grid United, "Pecos West," accessed Jan. 2026, https://pecoswest.com/.

172 *See generally* tariff revisions and Joint Operating Agreement filings from SPP and MISO in FERC Docket Nos. ER24-2797-000, ER24-2798-000, ER24-2871-000, ER24- 2825-000, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240826-5149&optimized=false.

173 *See generally* Protest of the Clean Energy Associations to the 08/16/2024 filings of Southwest Power Pool Inc. et al. under ER24-2797, et al., https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240919-5161&optimized=false.

174 GDO, "Joint Targeted Interconnection Queue Transmission Study Process and Portfolio" (Oct. 2023); Durish Cook, A., "MISO Says JTIQ Tx Portfolio Stands — for Now," RTO Insider (Oct. 2025), https://www.rtoinsider.com/116917-miso-says-jtiq-tx-portfolio-stands-for-now/.

175 MTEP25 at 30.

MISO and SPP also attempted to conduct a new, enhanced Coordinated System Plan (CSP), which would incrementally enhance interregional transfer capabilities at their seam (*see Fig. 19*). The study was intended to identify near-term upgrades that incrementally enhance transfer capability, similar to the MISO-PJM study, but may also allow for the identification of transmission projects with multiple benefits.[176] As a part of the study, MISO and SPP requested a Joint Operating Agreement waiver, which was denied by FERC.[177] Despite the denial, MISO and SPP moved forward with the voluntary CSP study, which includes 10- and 15-year blended models of both operators' transmission systems based on MISO's Series 1A Future 2 and SPP's Future 2 models.[178] The final study model will include MISO's large load expedited project requests, Expedited Resource Addition Study generation additions, and SPP's reliability only future load.[179]

FIGURE 19 MISO-SPP CSP Study Solutions Areas of Focus[180]

Based on the CSP modeling results, MISO opened a solicitation window and received 31 solutions, which were evaluated. From those 31 solutions, MISO and SPP down selected to 14 solutions, which received additional analysis using the updated blended models. Next steps for MISO and SPP are to finalize the business case methodology to demonstrate the multiple benefits of interregional transmission. The goal is to develop a methodology

176 SPP & MISO, "SPP-MISO Interregional Planning Stakeholder Advisory Committee," 6-12, (Dec. 2025), https://cdn.misoenergy.org/20251219%20MISO-SPP%20IPSAC%20Meeting732572.pdf ("SPP-MISO IPSAC").

177 *See* Petition of the Midcontinent Independent System Operator, Inc., and Southwest Power Pool, Inc. for Waiver of Tariff Provision, Docket No. ER25-943 (Jan. 2025), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250115-5170&optimized=false&sid=4b18f9da-543c-467a-b0a6-19050e7a220a; Order Denying Waiver Request, 192 FERC ¶ 61,004 (Jul. 2025), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250702-3095&optimized=false&sid=4b18f9da-543c-467a-b0a6-19050e7a220a ("Order Denying Waiver Request").

178 SPP-MISO IPSAC *at 6-12.*

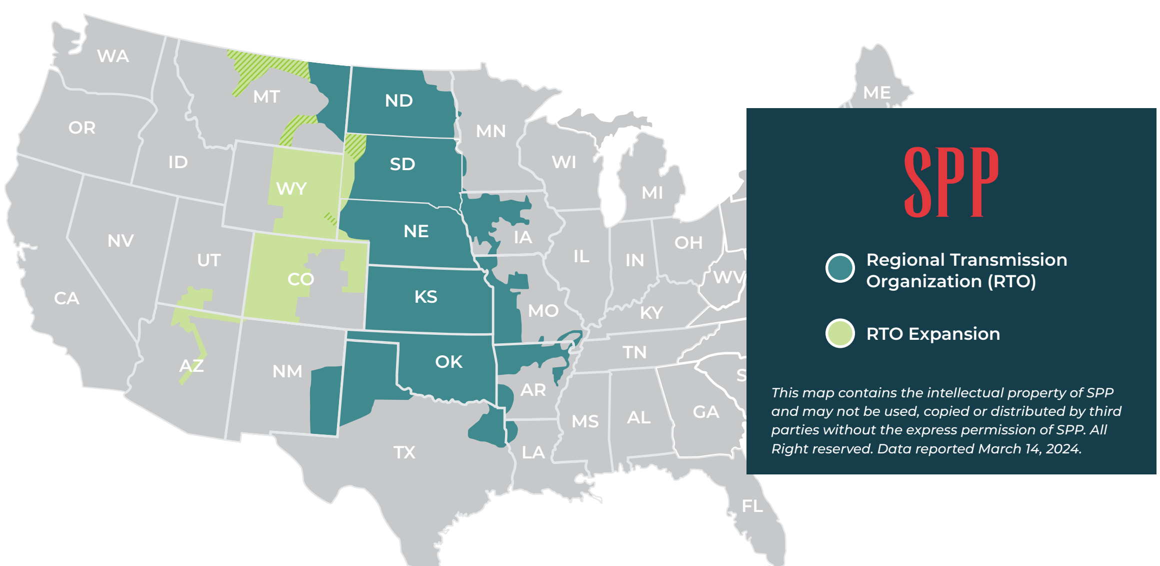
179 *Id.* at 8-9.

180 *Id.* at 16.

aligned with the seven economic and reliability benefits in Order No. 1920. A draft report including solution recommendations is expected in March 2026; after which, SPP and MISO may decide to further develop the CSP projects requiring the new interregional cost allocation and Joint Operating Agreement changes, which would have to be filed with and approved by FERC.[181]

In 2025, FERC also approved SPP's expansion under its RTO West plan (*see Fig. 20*). The plan will expand the RTO's footprint into the Western Interconnection effective in the first half of 2026. As of now, the Eastern Interconnection region and Western Interconnection region of SPP will be connected by three DC interties totaling just over 0.5 GW.[182] Depending on how transmission planning is executed with the expansion, it could lead to interregional transmission expansion with the non-RTO west and could improve the grade in future Report Cards.

FIGURE 20 Expansion of the SPP RTO[183]



Midwest

The Midwest received a B- for interregional planning. The Midwest is bordered by Canada, the Mid-Atlantic, the Northwest, the Plains, the Southeast regions, and Texas. The

181 *Id.* at 7.

182 SPP, "SPP first RTO to operate in both interconnections with tariff approval" (Mar. 2025), https://www.spp.org/news-list/spp-first-rto-to-operate-in-both-interconnections-with-tariff-approval/.

183 SPP, "Expansion of the SPP RTO" (Nov. 2020), https://www.spp.org/documents/63373/spp%20rto%20west%20expansion%2020201111%20announcement%20v2.png.

Midwest has taken steps to improve interregional transmission planning and increase interregional transfer capacity, both through its regional planning process and existing interregional planning, in particular with the Plains and Mid-Atlantic.

MISO's LRTP Tranche 2.1 includes several 765 kV transmission lines that will connect with PJM's existing 765 kV system. PJM is currently conducting an affected systems study for the Tranche 2.1 portfolio. Preliminary results indicate there are just over $120 million in reinforcement upgrade costs (*see Fig. 21*).[184] MISO is currently negotiating a universal construction, cost allocation, and funding agreement with the constructing PJM transmission owners, which will be filed with FERC. An update is expected in the first quarter of 2026.[185] More on the interregional transmission planning efforts initiated by MISO are covered in its neighbors' sections — the Plains and Mid-Atlantic.

FIGURE 21 Preliminary PJM Identified Upgrades for MISO's Tranche 2.1[186]

ComEd Transmission Zone	Total cost: $34.5 M
▪ **Zion-Lakeview 345 kV (8.8-mile transmission facility) –** Required thermal upgrades to improve capability (line trap and re-sag)	$3 M
▪ **Short-circuit upgrades –** Replace nine 345 kV breakers.	$31.5 M

FirstEnergy (ATSI) Transmission Zone	Total cost: $86.57 M
▪ **Morocco-Allen 345 kV (terminal equipment)**	
▪ **Lakeview-Greenfield 138 kV** (14.5 miles add second circuit to Greenfield – Lakeview 138 kV Line, 6.1 miles of new line construction)	
▪ **Lakeview-Ottawa 138 kV** (2.7 miles of reconductor)	
▪ **No short-circuit requirements**	

TOTAL PJM DO NO HARM REQUIRED REINFORCEMENT COST = $121.07 M

- **AEP/DEOK have T2.1 physical connections;** however, no PJM or local TO requirements were required.
- **Costs are preliminary** and subject to further review by the PJM TOs.

Southeast

The Southeast received an F for interregional planning. The region performs affected systems studies with its neighboring regions and also participates in the Eastern Interconnection Planning Collaborative (EIPC), which includes all Eastern Interconnection regions (New England, New York, the Midwest, Mid-Atlantic, Plains, and Southeast).[187] The EIPC performs Interregional Transfer Capability studies to identify constraints and evalu-

184 PJM & MISO, "MISO Tranche 2.1 Evaluation Update," 4 (Dec. 2025), https://cdn.misoenergy.org/20251205%20MISO-PJM%20IPSAC%20Item%2002%20Tranche%202.1%20Update730296.pdf.

185 *Id.* at 5.

186 *Id.* at 4.

187 Eastern Interconnection Planning Collaborative (EIPC), accessed Jan. 2026, https://eipconline.com/.

ate how regional transmission plans mesh to maintain the reliability of the bulk electric system. These studies are not intended to identify specific transmission projects to increase transfer capability.[188] At the end of 2024, Southern Company, Santee Cooper, and Dominion Energy South Carolina did announce a joint study to determine “efficient and cost-effective projects to increase interregional transfer capability” and to accommodate resource changes. However, there have been no updates on the study, and it is not clear if any developments have arisen.[189] In general, the interregional studies that the Southeast is involved in are focused solely on regional reliability impacts, and to the best of our knowledge, there is little proactive interregional transmission planning occurring. The results of these studies may warrant a higher grade in the future, but there is little transparency into their current processes or interim results.

Mid-Atlantic

The Mid-Atlantic received a D+ for interregional planning. The Mid-Atlantic is bordered by New York, the Midwest, and the Southeast. Currently, the Mid-Atlantic is doing little to no proactive, scenario-based interregional transmission planning with the Southeast or New York.

However, in conjunction with the Midwest, the Mid-Atlantic initiated a new, limited — but innovative — joint Interregional Transfer Capability Study (MISO/PJM ITCS). The goal of the study is to identify projects near the MISO-PJM seam that can incrementally enhance interregional transfer capabilities. The MISO/PJM ITCS study used a blended model that reflected proactive transmission, load, and resource additions for both regions. However, the MISO/PJM ITCS only included contracts for existing generators sending power across the seam and did not model expanded cross-seams generation sales or transfers. This significantly limits the amount of transmission that could be modeled or built. The transmission topology also included merchant HVDC facilities with executed Interconnection and Facilities Construction Agreements.[190] Based on the blended model, MISO and PJM then conducted a reliability, transfer, economic, and extreme weather analysis identifying 22 issues that arose across all areas of analysis. MISO solicited conceptual projects from stakeholders, which included upgrades and new corridors (*see Fig. 22).*[191] In part, PJM did not also solicit projects because their sponsorship model constrains solution

188 EIPC, *EIPC Interregional Transmission Transfer Capability Study Report*, 8-10 (Sep. 2025), https://eipconline.com/s/EIPCITCSTUDYREPORT-FINAL9-10-25-1.pdf.

189 SERTP, “4th Quarter Meeting Annual Transmission Planning Summit & Assumptions Input Meeting,” 209 (Dec. 2024), https://www.southeasternrtp.com/docs/general/2024/2024_SERTP_4th_Qtr_Presentation.pdf.

190 The study relied on PJM’s LTRTP Workshop Policy Study 2032 model and MISO’s Series 1A Futures Report. *See* PJM & MISO, “PJM/MISO Interregional Transfer Capability Study,” 5 (Jun. 2025), https://cdn.misoenergy.org/20250625%20MISO-PJM%20IPSAC%20Item%2002%20ITCS%20Update704126.pdf (“PJM/MISO ITCS”).

191 *Id.* at 18-19.

development until after final needs are identified and posted.

Both PJM and MISO recognized neither organization has a project category, nor an associated cost allocation methodology, to capture the full suite of benefits provided (i.e. economic, reliability, and transfer capability) by the solutions evaluated in the MISO/PJM ITCS process.[192] The next step for these regions is to develop an interregional transmission benefits evaluation methodology in the first half of 2026 and then an RTO-RTO cost allocation methodology.[193]

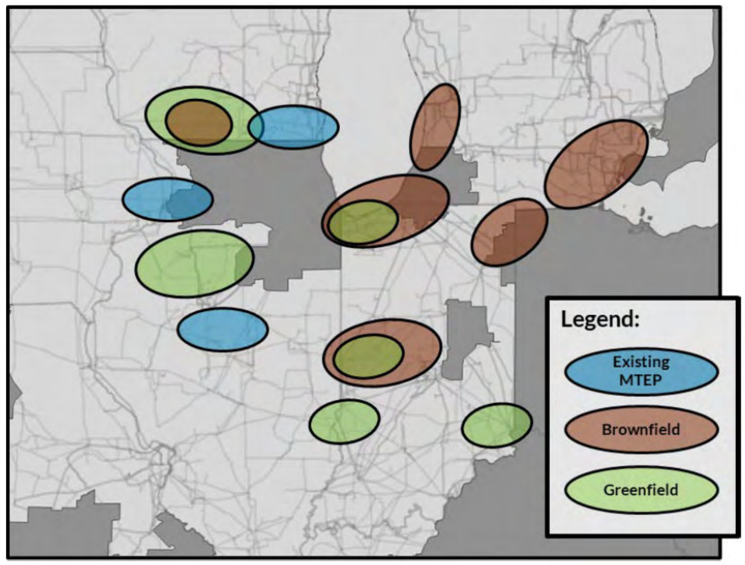


FIGURE 22 Target areas of conceptual solutions submission and alternatives that MISO recommends for further evaluation in the MISO/PJM ITCS[194]

New York & New England

New York received a C+ and New England received a C for interregional planning. The regions are neighbors bordered by Canada and the Mid-Atlantic. New York and New England are both active in interregional transmission planning, including the Northeast Grid Planning Forum, which recently released the Eastern Canada-NE US Interregional Planning Roadmap.[195]

Both NYISO and ISO-NE consider different import scenarios in their regional planning processes, the Outlook and LTTP studies, respectively. In its 2032-2042 Outlook, NYISO conducted a limited evaluation of potential resource exports to determine if New York can achieve its policy goals.[196] ISO-NE considers both HVDC imports from Canada and

192 PJM & MISO, "PJM/MISO Interregional Transfer Capability Study," at 30-35 (Dec. 2025), https://cdn.misoenergy.org/20251205%20MISO-PJM%20IPSAC%20Item%2003%20ITCS%20Update730297.pdf.

193 PJM/MISO ITCS at 2-5.

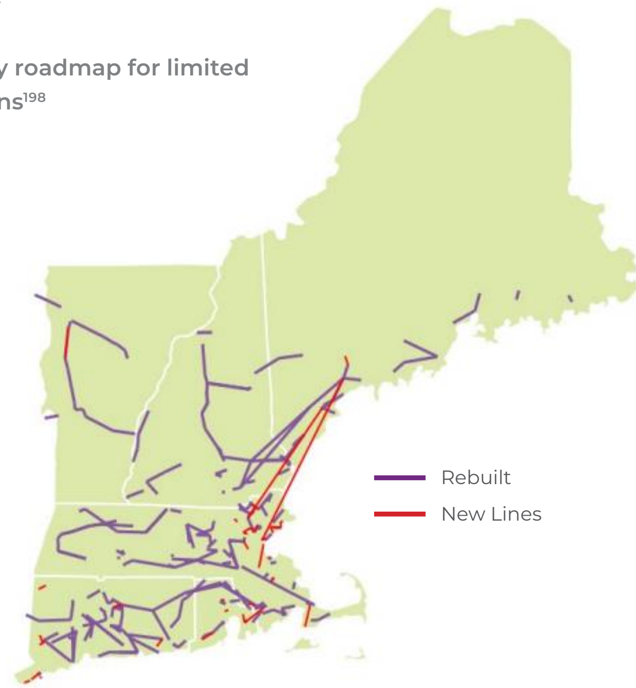
194 MTEP25 at 28.

195 *See* Power Advisory, *Eastern Canada-NE US Interregional Planning Roadmap, prepared for Northeast Grid Planning Forum* (Aug. 2025), https://acadiacenter.wpenginepowered.com/wp-content/uploads/2025/09/Eastern-Canada-Northeast-U.S.-Interregional-Transmission-Planning-Roadmap_25.08.07.pdf.

196 2023-2042 System Outlook at 67-71; *See also*, NYISO, *2023-2042 System & Resource Outlook: Appendix I: Transmission Congestion Analysis* (Jul. 2024) https://www.nyiso.com/documents/20142/46037616/Appendix-I%20-Transmission-Congestion-Analysis.pdf/a3a7beed-1e4b-125d-eb42-442f1a1189d4.

additional connections with NYISO as a part of its 2050 Transmission Study (*see Fig. 23).*[197] However, these scenarios are generally information only or do not have any associated selection mechanism or cost allocation.

FIGURE 23 **ISO-NE 2050 Transmission study roadmap for limited interregional and HVDC additions**[198]



Both regions do allow for significant independent interregional transmission lines to be planned and developed, with several lines connecting to Canada expected to be energized in 2026.[199] Financial support for independent interregional transmission development is often sourced from New York and the northeastern States, which require interregional transmission development to accomplish state legislative aims.

Momentum for interregional transmission has been growing in NYISO and ISO-NE in recent years. For example, in July 2024, nine states, including New York, most New England states, and some PJM states, announced they would participate in the Northeast States Collaborative on Regional Planning.[200] The states signed a Memorandum of Understanding which "establishes a non-binding framework to coordinate enhanced interregional transmission planning and development."[201] A key component of this memorandum is better coordination on the planning and development of transmission to support offshore wind generation. The states developed a strategic action plan, published in April

197 ISO-NE, "2050 Transmission Study" (Feb. 2024), https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf.

198 *Id.* 33 & 44.

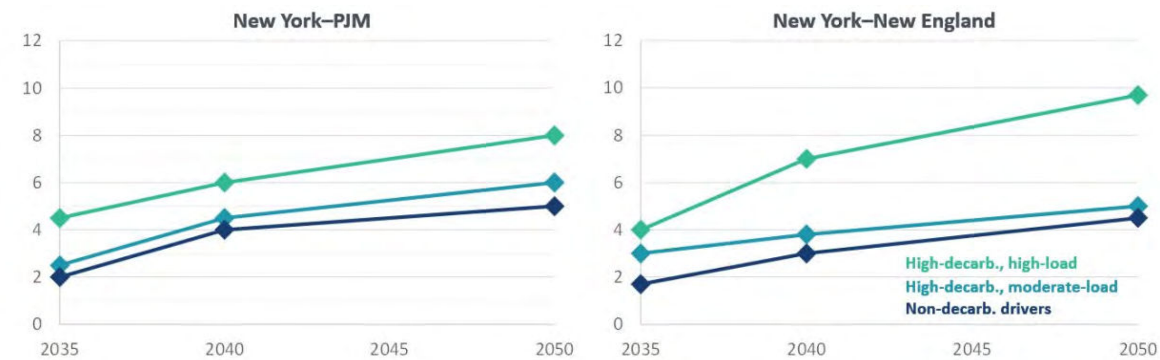
199 New England Clean Energy Connect was energized in Jan. 2026, Avangrid, "Avangrid's New England Clean Energy Connect Project Is Complete and Energized" (Jan. 2026), https://www.avangrid.com/w/avangrid-s-new-england-clean-energy-connect-project-is-complete-and-energized; *See also* New England Clean Energy Connect, accessed Jan. 2026, https://www.necleanenergyconnect.org/; See also Champlain Hudson Power Express, accessed Jan. 2026, https://chpexpress.com/.

200 Johns Hopkins, "Northeast States Collaborative on Interregional Transmission," accessed Jan. 2026, https://energyinstitute.jhu.edu/northeast-states-collaborative-on-interregional-transmission/.

201 Northeast States Collaborative on Interregional Transmission, "Memorandum of Understanding," 1 (Jul. 2024), https://energyinstitute.jhu.edu/wp-content/uploads/2024/07/MOU-Northeast-States-Collaborative-on-Interregional-Transmission.pdf.

2025, which estimated their interregional transmission expansion needs (*see Fig. 24*).[202] Following this release, the collaborative released an RFI seeking interregional projects that would increase transfer capacity between at least two of the regions involved.[203]

FIGURE 24 Estimated range of low-regret interregional transmission expansion needs (GW)[204]



A negative development related to interregional planning for New England, New York, and the Mid-Atlantic was the decision by ISO-NE to pause its study to find solutions to increase ISO-NE's 1,200 MW loss of source limit with NYISO and PJM.[205] The study, initiated by ISO-NE, was narrowly focused on ISO-NE's 1,200 MW loss of source limit. ISO-NE concluded that it was not currently feasible to raise the loss of source limit to 2,000 MW and found that upgrades were required along the New York and New England interface, though more study is required.[206] Abandoning this study and foregoing identification of transmission upgrades needed to raise the loss of source limit potentially impacts the viability of future HVDC projects that would likely benefit from a higher limit.

3. Engagement

The third grade component is engagement. This component, and the metrics associated with it, are based on stakeholder engagement, transparency, the role for states and their regulators, and effective cost allocation for regional and interregional transmission development. This component makes up 15% of the final grade.

202 *Id.* at 3; See The Brattle Group, *Strategic Action Pan*, prepared for Northeast States Collaborative on Interregional Transmission (Apr. 2025), https://energyinstitute.jhu.edu/wp-content/uploads/2025/04/Strategic-Action-Plan-Final.pdf.

203 *See* Northeast States Collaborative on Interregional Transmission, "Request for Information on State-Led Interregional Transmission Projects" (Jun. 2025), https://energyinstitute.jhu.edu/wp-content/uploads/2025/06/Northeast-States-Collaborative_RFI_FINAL-6_20_25.pdf.

204 *Strategic Action Plan* at 3.

205 ISO-NE, "Letter to Joint ISO/RTO Planning Committee (JIPC)" (Mar. 2023), https://www.iso-ne.com/static-assets/documents/2023/03/jipc_loss_of_source_limit_final.pdf; JIPC, "JIPC Response to ISO New England's Request for Raising ISO New England's Minimum Loss of Source Value" (Aug. 2023), https://www.iso-ne.com/static-assets/documents/2023/08/2023_08_23_jipc_response_to_iso_letter.pdf.

206 ISO-NE, "Interregional Study Update: Increasing New England Loss of Source Limit" (Dec. 2025), https://www.iso-ne.com/static-assets/documents/100030/a02_2025_12_05_ipsac_iso_loss_of_source.pdf.

California

California received an A- on Engagement, and is a single-state region, which means there is a clearer relationship between California state entities and regional planners at CAISO. There is extensive coordination between CAISO's transmission planning processes and California state agencies, including the California Energy Commission and the California Public Utilities Commission.[207] The Commission hosts numerous stakeholder advisory committees that support the state and CAISO in its transmission planning processes. CAISO uses a public stakeholder initiative process to develop new policy, beginning with an issue paper which goes through several stakeholder revisions until a final proposal is presented to for CAISO Board of Governors approval.[208] Stakeholders submit written comments and participate in meetings at each stage, but there is no formal sector voting; instead, staff considers comments and elevates a recommendation. Final decisions to adopt market or tariff changes rest with the CAISO Board, which determines whether to proceed with a regulatory filing.[209] For regional transmission projects, CAISO utilizes an effective postage stamp cost allocation method where costs are allocated on load ratio basis.[210] CAISO's cost allocation also includes the Subscriber PTO model, which was approved by FERC in March 2024, and allows CAISO to develop transmission lines outside of its footprint and creates a cost recovery mechanism for developers.[211] See further discussion of the Subscriber PTO model in the interregional planning section.

Northwest

The Northwest received an F on Engagement. The Northwest transmission owners created NorthernGrid to conduct Order No. 1000 regional planning. NorthernGrid includes investor-owned FERC-jurisdictional utilities and publicly owned utilities that are not FERC-jurisdictional and voluntarily participate. NorthernGrid's planning process is largely driven by its members. NorthernGrid does have a limited role for state regulators through the Enrolled Parties Planning Committee and States Committee. State regulators are provided a vote in the planning process via the Committees but are not allowed to modify the tariff. Non-utility stakeholders can participate in public meetings and provide com-

207 *See generally* CPUC, CEC, and CAISO Planning MOU.

208 FERC, "Understanding and Participating in California ISO (CAISO) Processes," accessed Jan. 2026, https://www.ferc.gov/understanding-and-participating-california-iso-caiso-processes.

209 CAISO, "Policy initiatives and stakeholder process," accessed Jan. 2026, https://stakeholdercenter.caiso.com.

210 Kahrl, K. et al, *Transmission Cost Allocation Practices, Lawrence Berkeley National Laboratory*, 3 & 20 (May 2025), https://eta-publications.lbl.gov/sites/default/files/2026-01/transmission_cost_allocation_brief_final_v2.pdf ("Transmission Cost Allocation Principles").

211 *See* Order Accepting Proposed Tariff Revisions re California Independent System Operator Corporation under ER23-2917, FERC Docket No. ER23-2917-001, March 12, 2024, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240312-3078&optimized=false.

ments on plans.[212] Though as discussed in the regional planning section, NorthernGrid regional plans are not intended to be construction plans.[213] The region has yet to develop a regional or interregional line using the NorthernGrid planning and cost allocation process.[214]

The Northwest also includes BPA, which owns 75% of the region's high-voltage transmission system. Historically, despite not being subject to FERC oversight, BPA voluntarily adopted FERC open access and tariff standards.[215] However, in 2013 FERC denied BPA "safe harbor reciprocity status," and in 2016 BPA decided that rather than make further changes to its OATT to align with FERC requirements, it would drop its safe harbor reciprocity status.[216] BPA remains a voluntary participant with a significant role in NorthernGrid given the size of its transmission system, but does not have to comply with FERC Orders No. 2023 and 1920. However, in recent years, BPA has recognized the increasing need for transmission and need to reform many of its planning processes. BPA has begun to develop a limited number of transmission projects through its Grid Expansion and Reinforcement Portfolio.[217] BPA has also held initial workshops in preparation for a formal tariff revision process that will reform how BPA conducts cluster studies of customer transmission service requests and is hosting a series of workshops as a part of its Grid Access Transformation project to determine the future of its transmission planning.[218]

In the non-market regions states do not have the same formalized regional state committees with dedicated staff. And while it is no substitute, the West does have numerous bodies outside of the region that provide some staff support and technical expertise to states including the Western Interstate Energy Board, which also supports the Committee on Regional Electric Power Cooperation, the Western Interconnection Regional Advisory Body, the Western Energy Imbalance Market Body of State Regulators, and the Western Resource Adequacy Program Committee of State Representatives.[219]

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212 Northwestern, "Attachment K Transmission Planning Process," 83-95 (Jan. 2022), https://www.northerngrid.net/private-media/documents/Att_K_-_Transmission_Planning_Process_ROdZrBy.pdf.

213 *Id,* at 28.

214 *See* 2023 Report Card at 38-40.

215 NIPPC and Renewable Northwest, "'Appropriate and Required': BPA and Building the Grid the Northwest Needs," 15-17 (May 2023), https://renewablenw.org/sites/default/files/Reports-Fact%20Sheets/BPA%20Tx%20Whitepaper%2005.03.2023.pdf.

216 *Id.*

217 BPA, "Grid Expansion and Reinforcement Portfolio (GERP)," accessed Jan. 2026, https://www.bpa.gov/energy-and-services/transmission/grid-expansion-and-reinforcement-portfolio.

218 BPA, "Grid Access Transformation Project," accessed Jan. 2026, https://www.bpa.gov/energy-and-services/transmission/grid-access-transformation-project; *See also* BPA, "TC-27 Tariff Proceeding," accessed Jan. 2026, https://www.bpa.gov/energy-and-services/rate-and-tariff-proceedings/tc-27-tariff-proceeding.

219 Concurrence by Commissioner Christie and Commissioner Rosner to the Order Accepting Proposed Tariff, Subject to Condition, 190 FERC ¶ 61,030 (Jan. 2025), https://www.ferc.gov/media/e-1-er24-1658-000.

Southwest

The Southwest received an F on Engagement. The Southwest regional transmission planning process occurs on a two-year cycle, through WestConnect, and evaluates a 10-year planning horizon. WestConnect is the Order No. 1000 regional planning entity and includes FERC-jurisdictional utilities (Enrolled Transmission Owners) for the purposes of cost allocation under Order No. 1000. The WestConnect regional transmission planning process is largely driven by its ETOs. All committees in WestConnect report to the Planning Management Committee. The Planning Management Committee does include roles for State Regulatory Commissions and Key Interest Groups. In the 2023 Report Card, those seats were vacant but have since been filled, which is an improvement.[220]

WestConnect has three Subregional Planning Groups: the Southwest Transmission Planning Group, the Sierra Subregional Planning Group, and the Colorado Coordinated Planning Group. The ETOs participate within these groups, but the Subregional Planning Groups do not perform any of the regional planning functions. The ETOs develop the base cases for the regional transmission study by reviewing and updating WECC base case models. WestConnect has yet to develop a regional or interregional line using its regional planning and cost allocation processes.[221]

Since the 2023 Report Card, litigation surrounding WestConnect's Order No. 1000 planning has been resolved.[222] In response to a court decision, FERC ordered WestConnect to remove the Coordinating Transmission Owner framework from their OATT, which was a unique framework that allowed nonpublic utility members to participate in the regional transmission planning process. This is because once projects are selected in a regional plan, the Coordinating Transmission Owners could choose to not pay for the costs of the projects they would be allocated, which was determined to be incompatible with cost causation principles. In April 2025, FERC accepted the ETOs' amended OATT, which revised WestConnect's regional transmission planning process to only conduct regional transmission planning for enrolled transmission providers because they are subject to binding cost allocation.[223]

While the removal of non-jurisdictional transmission owners was mandated by FERC, the result has undermined the effectiveness of regional planning in the Southwest as West-

220 WestConnect, "Regional Planning: Planning Management Committee Members," accessed Jan. 2026, https://regplanning.westconnect.com/pmc_members.htm.

221 *See 2023 Report Card* at 45-47.

222 El Paso v. FERC (2023), https://www.ca5.uscourts.gov/opinions/pub/18/18-60575-CV0.pdf; *See also* Order on Remand, 189 FERC ¶ 61,028 at P 19 (2024) & Order Accepting Tariff Revisions and Terminating Section 206 Proceedings, 191 FERC ¶ 61,074 (2025).

223 WestConnect Enrolled Transmission Owners, "Letter to WestConnect on Non-Tariff Activities for the Remainder of 2025" (Jun. 2025), https://doc.westconnect.com/Documents.aspx?NID=21407&dl=1.

Connect's planning footprint now includes substantial gaps. WestConnect's 2024-2025 regional plan only identified transmission needs affecting multiple participating entities, and unless the region develops other ways to collaborate on planning, future planning cycles will not identify potential regional needs between FERC-jurisdictional utilities and federal power agencies, municipal utilities, or cooperative utilities.

Texas

Texas received a B on Engagement, and is a single-state region, which means there is a clearer relationship between Texas state entities and regional planners at ERCOT. Texas is also different because ERCOT operates a separate electrical interconnection from the rest of the U.S. that is intrastate and not subject to FERC jurisdiction for market rules. Ultimate approvals occur under Texas oversight via the ERCOT Board and the Public Utility Commission of Texas.[224] Texas' stakeholder process in ERCOT is centered on the Protocol Revision Subcommittee and the Technical Advisory Committee. It uses segment-based voting (generators, transmission/distribution utilities, retail electric providers, consumers, municipals/co-ops, and others). Thresholds vary by body, and recommendations move to the ERCOT Board who has ultimate approval.[225] For regional transmission projects ERCOT utilizes a postage stamp cost allocation method. As discussed in the 2024 Interim Report Card, limitations to the economic planning test mean almost all projects arise through reliability planning.[226] In addition, Senate Bill 6, which passed in 2025, directed the Public Utility Commission of Texas to evaluate existing transmission cost allocation and recovery methods.[227] The PUCT's process kicked off in August 2025.[228]

Plains

The Plains received a B on Engagement. The region has balanced regional stakeholder and state engagement through SPP and a significant stakeholder process, which includes multiple committees and working groups, such as the Strategic Planning Committee, the Transmission Working Group, the Economic Studies Working Group, the Cost Allocation Working Group, the Regional State Committee, and the Markets and Operations Policy Committee.[229] SPP's process is notably stakeholder-driven with working

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224 *See* ERCOT, "Stakeholder Process Overview" (Jan 2021), https://www.ercot.com/files/docs/2021/01/05/05.__Stakeholder_Process_Overview_010721.PPTX.

225 ERCOT, "Governance," accessed Jan. 2026, https://www.ercot.com/about/governance; ERCOT, "Committees and Groups," accessed Jan. 2026, https://www.ercot.com/committees.

226 *Transmission Cost Allocation Principles* at 3.

227 89th Tex. Leg., R.S., Senate Bill 6, § 6 (effective June 20, 2025).

228 *See generally* Public Utility Commission of Texas, Project Number 58484, accessed Jan. 2026, https://interchange.puc.texas.gov/search/filings/?UtilityType=A&ControlNumber=58484.

229 FERC, "An Introductory Guide for Participation in Southwest Power Pool Processes," accessed Jan. 2026, https://www.ferc.gov/introductory-guide-participation-southwest-power-pool-processes.

groups developing recommendations that move to the Markets and Operations Policy Committee. Markets and Operations Policy Committee often uses sector or weighted voting with supermajority thresholds before forwarding items. Both the Regional State Committee (RSC) and the SPP Board must approve major changes, and the Board decides what to file with FERC.[230] While SPP's RSC has no full-time independent staff, the RSC is a formal committee with the Section 205 filing rights for both cost allocation and resource adequacy.[231]

SPP also has an effective cost allocation methodology for regional transmission planning, utilizing a type of regional postage-stamp cost allocation methodology, called the Highway/Byway cost allocation method, which allows SPP to regionally allocate the costs for transmission facilities at or above 300 kV.[232]

In 2025, MISO and SPP attempted to get a waiver to their Joint Operating Agreement to conduct a more robust interregional Coordinated System Plan with MISO but were denied the waiver by FERC. Both regions have indicated that it will likely pursue tariff changes for interregional cost allocation and project selection with MISO.[233]

Midwest

The Midwest received a B+ on Engagement. The region has regional stakeholder and state engagement through MISO, which has three main stakeholder committee groups that participate in transmission planning, including several sub-regional planning committees, the Planning Subcommittee, and the Planning Advisory Committee.[234] MISO uses a comprehensive planning process that involves many stakeholders. Participation is organized through working groups and subcommittees that feed into the Advisory Committee. The Advisory Committee uses sector-based voting in which sectors cast positions and forward recommendations to the MISO Board. These recommendations are influential but advisory; the Board ultimately determines what is filed with FERC.[235]

MISO's RSC is known as the Organization of MISO states (OMS) and exists outside of the RTO with a few full-time staff. OMS does not have "jump-ball" filing rights but does have complementary Sec. 205 filing rights for transmission cost allocation. This means MISO

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230 *See* Exeter Associates, Inc., *Governance Structure and Practices in the FERC-Jurisdictional ISOs/RTOs, prepared for NESCOE* (Feb. 201), https://nescoe.com/wp-content/uploads/2021/02/ISO-RTOGovernanceStructureandPractices_19Feb2021.pdf ("Governance Structure and Practices").

231 Clements, A., "Making Sense of Potential Western ISO Governance Structures: The Role of the State," 4 (Jun. 2016), https://www.nrdc.org/sites/default/files/potential-western-iso-governance-structures-ib.pdf ("Making Sense of Potential Western ISO Governance").

232 Sw. Power Pool, Inc., 131 FERC ¶ 61,252 (2010) (Highway/Byway Order), reh'g denied, 137 FERC ¶ 61,075 (2011).

233 *See* Order Denying Waiver Request.

234 FERC, "Participation in Midcontinent Independent System Operator (MISO) Processes," accessed Jan. 2026, https://www.ferc.gov/participation-midcontinent-independent-system-operator-miso-processes.

235 *See Governance Structure and Practices.*

can develop, amend, or review changes to regional cost allocation methodology. IF OMS can obtain a supermajority, it can request that MISO file alternative or modified cost allocation proposal with FERC. However, MISO does not have to make the filing but must provide a written explanation as to why it did not.[236]

MISO has developed a Multi-Value Project cost allocation methodology, which it uses for its LTRP process, and as discussed above, MISO has indicated that it will likely pursue tariff changes for interregional cost allocation with PJM as well as with SPP after FERC denied MISO and SPP's joint waiver request earlier in 2025.[237]

Southeast

The Southeast received an F on Engagement. In the Southeast, a key hurdle for regional transmission planning is the lack of access to information and transparency. SERTP, SCRTP, and FRCC's opaque processes limit the effectiveness of stakeholder engagement in transmission planning. In FRCC, for example, most published information is behind a password-protected website, and there is very limited opportunity for stakeholder engagement or influence. SCRTP does include a list of their planned projects with costs for everything above $2 million, but for everything else a nondisclosure agreement or Critical Energy Infrastructure Information clearance is needed to access nearly all transmission planning outcomes. In SERTP, for the 2025 planning cycle, transmission owners did provide limited access to cost estimates, though access required a nondisclosure agreement, like most of the planning assumptions and details, and the cost information was not allowed to be used elsewhere. In SERTP and SCRTP, state regulators and stakeholders also have little influence or ability to participate in the planning process or outcomes.[238] Similar to the Northwest and Southwest regions, states in the Southeast do not have the same formalized regional state committees with dedicated staff as in organized markets. However, unlike the Northwest and Southwest, the Southeast does not have numerous bodies that provide support and technical expertise to the states.

Mid-Atlantic

The Mid-Atlantic received a B on Engagement. The region conducts regional transmission planning predominantly through the PJM Transmission Expansion Advisory Committee.[239] In PJM, transmission planning is governed by the PJM Operating Agreement

236 Gardner, J., "RTO Governance Models: The Role of States," 11 (Apr. 2019), https://westernenergyboard.org/wp-content/uploads/2019/04/04-17-19-eim-bosr-gardner-rto-governance-models-role-of-states.pdf; *See also "Making Sense of Potential Western ISO Governance" at 3-4*.

237 *See* MISO, *Attachment FF - Transmission Expansion Planning Protocol* (Jan. 2026), https://docs.misoenergy.org/miso12-legalcontent/Attachment_FF_-_Transmission_Expansion_Planning_Protocol.pdf; See also Order Denying Waiver Request.

238 *See 2023 Report Card* at 42-45.

239 PJM, "Transmission Expansion Advisory Committee," accessed Jan. 2026, https://www.pjm.com/committees-and-groups/committees/teac.

which keeps some section 205 filing rights with PJM's Transmission Owners, such as transmission cost recovery and rate design.[240] As a part of the Operating Agreement, to make changes to transmission planning, PJM must get approval from the PJM Members Committee, which uses a sector-weighted model in which each sector casts one vote, and supermajority support is typically required for endorsement.[241] However, the PJM board, if it believes part of the Operating Agreement is "unjust, unreasonable, or unduly discriminatory," can file a complaint under section 206 of the Federal Power Act asking for FERC to make a change.[242]

This process is currently playing out in FERC and the courts. In 2024, PJM made a filing under Federal Power Act Section 206 to transfer transmission planning from the Operating Agreement to the OATT, where the PJM board, rather than the members, would have the authority to amend the regional transmission planning rules through FPA section 205 filings.[243] These changes were jointly filed with amendments to the Consolidated Transmission Owners Agreement filed by PJM's Transmission Owners. FERC rejected both filings,[244] and that decision has been appealed by PJM's Transmission Owners in court.[245]

PJM's regional state committee, the Organization of PJM States, is a formal, incorporated non-profit with a few full-time positions that serves in an advisory role, including regular meetings with PJM's board, but it is one of the only committees not to have complementary Section 205 filing rights.[246] However, with the issuance of Order No. 1920, states were given limited Section 205 filing rights for long-term transmission planning cost allocation that can be agreed to by the Relevant State Entities.[247] In PJM, the PJM Area Relevant State Entities Committee (PARSEC), a part of Organization of PJM States is conducting this process, and is expected to file its Order No. 1920 cost allocation in June 2026.[248]

PJM conducted extensive stakeholder processes around Order No. 1920. PJM held over

240 PJM, Operating Agreement, accessed Jan. 2026, https://agreements.pjm.com/oa/4541.

241 PJM, "Committees & Groups FAQs," accessed Jan. 2026, https://learn.pjm.com/pjm-structure/member-org/committees-groups-faqs/sector-weighted-voting.aspx.

242 PJM, *Open Access Transmission Tariff*, accessed Jan. 2026, https://agreements.pjm.com/oatt/3897.

243 *See generally* Docket No. EL24-119-000; Docket Nos. ER24-2338-000 and ER24-2338-001.

244 PJM TOs' Amendments to the Consolidated Transmission Owners, Docket No. ER24-2336 (Jun. 2024), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240621-5058&optimized=false&sid=bdf63b82-eb33-445d-9717-10812d470f7e; Order Rejecting Consolidated Transmission Owners Agreement Amendments and Denying Complaint, 189 FERC ¶ 61,181 (Dec. 2024), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20241206-3052&optimized=false&sid=bdf63b82-eb33-445d-9717-10812d470f7e.

245 The PJM Transmission Owners submit Petition for Review filed in the US Court of Appeals for the District of Columbia Circuit, Docket No. ER24-2336 (Feb. 2025), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250214-5234&optimized=false&sid=bdf63b82-eb33-445d-9717-10812d470f7e.

246 Western Resource Advocates, "RTO Governance Models: The Role of States," 12 (Apr. 2019), https://westernenergyboard.org/wp-content/uploads/2019/04/04-17-19-eim-bosr-gardner-rto-governance-models-role-of-states.pdf.

247 Order No. 1920-A at P 651.

248 PJM Area Relevant State Entities Committee (PARSEC), "Charter," OPSI (Oct. 2025), https://opsi.us/wp-content/uploads/2025/10/2025.10.21_Relevant-State-Entities-Committee-Charter.pdf.

36 meetings with the states collectively in a span of 16 months to discuss Order No. 1920 compliance, plus dozens of other meetings with individual states, and 16 public meetings with stakeholders through the Transmission Expansion Advisory Committee (TEAC). PJM integrated some comments in response to the feedback received in these meetings and did obtain the unanimous support of the states for its compliance filing.[249] PJM also holds regular meetings on its RTEP process but, under the current rules outlined above, neither PJM nor the transmission owners are required to respond to any stakeholder comments. PJM's board approves the plan based on staff recommendations.

As discussed in the interregional planning section, PJM does engage with state entities across the northeastern and midwestern U.S. in interregional planning processes although there is currently no mechanism for PJM to act on the results of those processes.

New York

New York received a A- on engagement, and is a single-state region, which means there is a more clear relationship between New York state entities and regional planners at NYISO. New York's transmission planning processes are well integrated between NYISO and other New York state agencies, such as formal determination by the NYPSC as to which public policy requirements should be used in NYISO's planning studies.[250] As discussed in the interregional planning section, NYISO, similar to CAISO, has successfully developed and paid for some interregional transmission, though the Northeast State Collaborative on Interregional Transmission suggests there is room to improve the process with in the ISO. The NYISO stakeholder process for transmission planning happens in the Transmission Planning Advisory Subcommittees with a diverse membership that includes consumer interests, but ultimately the Board approves plans. Governance is shared across the NYISO Operating Committee, Business Issues Committee, and Management Committee. The Management Committee takes sector-weighted votes — each sector voting as a bloc — to advance market design and tariff proposals. These votes are advisory to the NYISO Board of Directors, which has final authority to approve proposals for FERC filing. NYISO's planning documents are transparent and include comprehensive information for stakeholders.[251] For regional public policy transmission projects, NYISO utilizes an effective postage stamp cost allocation method where costs are allocated on load ratio basis.[252]

249 *See* Comments of the PJM Area Relevant State Entities Committee, FERC Docket No. ER26-751-000, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260121-5169&optimized=false&sid=9c4515e6-099b-4b87-afdb-8db7b7132db2.

250 *See* FERC, "An Introductory Guide for Participation in New York ISO Processes" (Sep. 2023), https://www.ferc.gov/media/introductory-guide-participation-new-york-iso-processes.

251 *See* Governance Structure and Practices.

252 *Transmission Cost Allocation Practices* at 19-20.

New England

New England received an A- on Engagement. The region New England has a robust stakeholder process in ISO-NE, driven by the New England states (*see discussion in the regional planning section*). Stakeholders engage through the Planning Advisory Committee, technical committees, and the Participants Committee, which takes sector-weighted advisory votes. Sectors cast collective votes that signal support or opposition to proposed changes, often with supermajority thresholds for endorsement. Votes guide — but do not bind — the ISO.[253] ISO-NE (or, in specific instances, participating transmission owners) retains Section 205 filing rights and decides whether to file a proposal with FERC.[254] Transmission planning happens in the Planning Advisory Committee, where stakeholders have an advisory to ISO-NE.

New England's RSC is known as the New England States Committee of Electricity (NESCOE). NESCOE exists outside of ISO-NE and has several full-time staff. NESCOE can sponsor proposals in the New England Power Pool and also has complementary Sec. 205 filing rights where if NESCOE secures 60 percent support for an alternative market proposal that differs from what ISO-NE is advancing, ISO-NE must file their proposal at FERC with sufficient detail that FERC can choose between the two filings. This is commonly referred to as the "jump-ball" provision.

ISO-NE continues to move forward with its Asset Condition Reviewer initiative. Costs associated with asset condition projects, which are transmission upgrades identified by transmission owners to address wear and tear, aging, and end-of-life replacement for existing transmission infrastructure, have been rising in recent years, and the ISO is working with stakeholders and transmission owners to develop a role which is intended to improve transparency and review of local transmission projects, but as of now will be advisory only.[255]

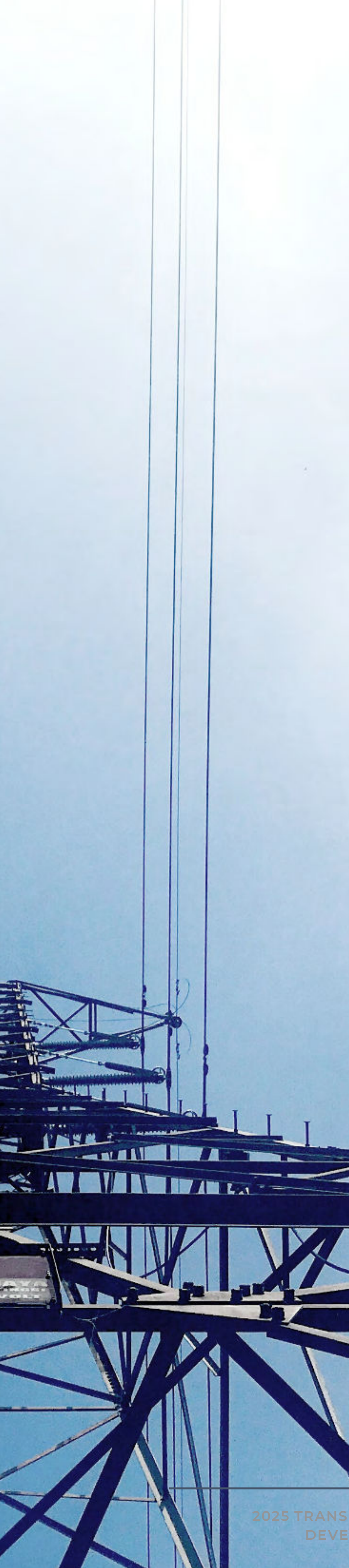
ISO-NE does recover network transmission costs based on the entire ISO-NE portfolio, utilizing postage stamp cost recovery, and also filed an updated cost allocation methodology with its LTTP process that allows states to fund individual projects.[256] In addition, as discussed in the regional planning section, ISO-NE created a new cost allocation pathway for states where if a project identified in the LTTP does not have a benefit-to-cost ratio greater than one, one or more states may voluntarily elect to fund the portion of the costs

253 FERC, "An Introductory Guide for Participation in ISO New England Processes" (Apr. 2025), https://www.ferc.gov/introductory-guide-participation-iso-new-england-processes.

254 *See* Governance Structure and Practices.

255 *See generally* ISO-NE, "Asset Condition Reviewer Key Project," accessed Jan. 2026, https://www.iso-ne.com/committees/key-projects/asset-condition-reviewer.

256 *See* ISO-NE, 178 FERC ¶ 61,137 (2022), https://www.iso-ne.com/system-planning/transmission-planning/longer-term-transmission-studies; See also FERC, "Order Accepting Tariff Revisions, Subject to Condition, and Directing Compliance," Docket No. ER24-1978-000 (Jul. 2024), https://www.iso-ne.com/static-assets/documents/100013/er24-1978-000.pdf.



that do not meet the benefit-to-cost ratio of one.[257]

4. Outcomes

The final grade component quantifies real-world "outcomes." This grade — and the metrics associated with it — are based on four different subcomponents. The four subcomponents are planned future regional transmission, planned future interregional transmission, transmission constructed in recent years, and recent historic economic congestion. Given the reliance on quantitative metrics to determine the outcome score, this section is organized differently than the previous sections. Here we discuss each subcomponent individually instead of each region.

The first three subcomponents are compared to regional estimates of transmission needs by 2035 from the DOE's 2023 Needs Study.[258] While the Needs Study is not necessarily a perfect representation of regional and interregional transmission need, we believe it is a reasonable benchmark to guide our evaluation. The Needs Study takes into account regional variation in load, generation, and transmission capacity. This means that some regions need to add much more transmission capacity, relative to other regions, so on a relative basis some regions may be building or planning more, but each grade is determined relative to the region's progress toward the DOE's estimate for that region.

The outcomes component makes up 15% of the final grade. Within the outcomes metric, planned regional and interregional lines are weighted more heavily than congestion or recent transmission construction to tie more closely to the planning outcomes evaluated in the section above. We provide additional details on our methodology for each outcome evaluated in the Appendix. Fig. 25 shows detailed grades for each quantitative subcomponent.

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257 *Transmission Cost Allocation Practices* at 3 & 7.

258 U.S. Department of Energy, *National Transmission Needs Study* (2023), https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf ("Needs Study").

FIGURE 25 Outcome component grades by region

REGION	PLANNED REGIONAL LINES (30%)	PLANNED INTERREGIONAL LINES (30%)	MILES CONSTRUCTED (20%)	CONGESTION (20%)	OVERALL GRADE
California	Grade	A	A	D-	**A**
Northwest	A	A	D-	F	**B+**
Southwest	B+	A	F	F	**B-**
Texas	C	C	D-	C	**C-**
Plains	B+	A	F	F	**B-**
Midwest	C	B+	F	C	**C**
Southeast	D-	F	F	F	**F**
Mid-Atlantic	B+	D-	D-	D-	**C-**
New York	A	F	A	B+	**C-**
New England	A	B+	A	B+	**A**

OUTCOME | Planned regional transmission

For the first subcomponent, we compared the carrying capacity of planned transmission tracked by Yes Energy (formerly the C Three Group)[259] to the additional transmission capacity needs identified in the Needs Study for the middle scenario group.[260] This subcomponent counts toward 30% of the outcomes grade to provide a more forward looking view and tie more closely to the regional planning grades.

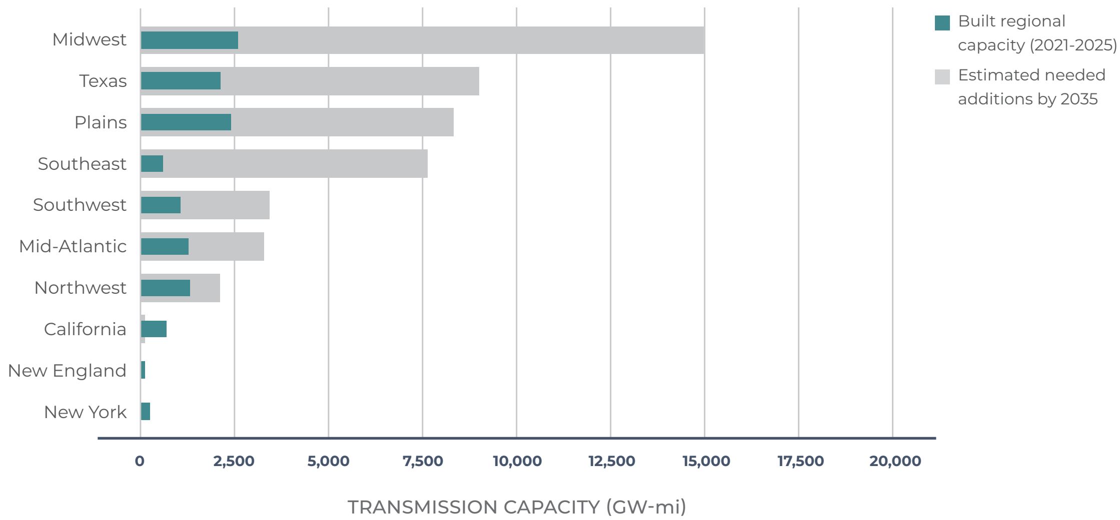
Fig. 26 compares the planned within-region transmission capacity to the DOE's estimated need. Regional transmission is measured in terms of power capacity density (gigawatt-miles).[261]

259 YesEnergy (2025) "Infrastructure Insights: Electric Transmission and Distribution Database," https://www.yesenergy.com/power-grid-projects-in-our-electric-transmission-distribution-database.

260 The middle scenario group in the Needs Study is called the "mid load and high clean energy" group.

261 Gigawatt-miles is a common unit used in U.S. energy planning and modeling to measure required electrical transmission capacity by multiplying the lines power (Gigawatts) by its length (miles) which allows for assessment and comparison of transmission projects and grid expansion plans.

FIGURE 26 Regional transmission (≥100kV) capacity planned to be operating by 2035 compared to the expected need.



Data Sources: Yes Energy (2025) & DOE (2023)

The spread of planned regional transmission lines varies across the regions, but generally regions appear to be planning transmission that would address their projected needs. Three of the ten regions (**California, New England, New York**) are currently planning enough transmission capacity to meet the estimated transmission need identified by the Needs Study.

While it is good to see regions are planning transmission at rates above what was estimated in the Needs Study, these results likely show the shortcomings (and potentially dated results) from the Needs Study, as there is still clearly a demonstrated need for transmission in those regions. As an example, in **New England**, the ISO-NE 2050 Transmission Study demonstrated the need for additional transmission capacity in the region through 2050.[262] Additionally, the transmission capacity targets from the Needs Study used for comparison are likely on the low end of what will be needed given the current load growth paradigm.

Unsurprisingly, the regions that have some of the best planning grades for regional and interregional planning also appear to be planning for a large capacity of transmission additions. For example, both **California** and **New York** have the highest planning component grades and these data show both regions are planning sufficient transmission relative to DOE's estimated need.

262 2050 Transmission Study at 26, 34, 37, and 44.

On the other hand, some regions like the **Midwest** and **Plains** are planning even higher near-term regional and interregional transmission deployment (in absolute terms) than **California** and **New York**, but their need is so much higher that they do not score as highly as regions with both good planning processes and lower needs.

As discussed in the regional planning section, **California**, the **Midwest**, and the **Plains** produce annual regional transmission plans, which in recent years have included significant amounts of new, planned regional transmission. Over the past three transmission plans, CAISO has approved over $18 billion in regional transmission investments. In 2022 and 2024, MISO approved two long-range multi-value transmission portfolios totaling over $30 billion and almost 4,000 miles of 345 kV lines and 1,800 miles of 765 kV lines. While none of this planning has yet to translate to a multi-value portfolio in MISO South, the need is becoming increasingly clear as MISO approved several 500 kV lines in its Southern footprint as a part of MTEP25. In its 2024 ITP, SPP approved its first 765 kV line, and in the 2025 ITP another almost 1000 miles of 765 kV lines were approved for construction, totaling over $16 billion approved.

In the **Mid-Atlantic** recent construction of new high-capacity transmission has been limited, but this will likely change in future Report Cards. Fig. 26 indicates that in recent years PJM has planned and approved significant investments in regional transmission. As discussed in the regional planning section, the 2024 RTEP included a nearly $6 billion investment, with most of the investment going to two 765 kV projects that would extend PJM's extra-high-voltage backbone across West Virginia, Virginia, and Maryland.[263] PJM also presented a preliminary $11.6 billion transmission package for the 2025 RTEP including more than 1,000 miles of 500 kV and 765 kV facilities through a mix of new greenfield lines, upgrades, network reinforcements, and an HVDC line.[264] The preliminary 2025 RTEP lines are not included in the totals in this report as they have not yet been approved. The 2023 RTEP also included some significant 500 kV investments.

In the non-market regions, individual utilities and states are planning and developing significant amounts of transmission that, despite not arising through a regional planning process, will likely have a regional impact. As previously stated, neither NorthernGrid nor WestConnect's transmission planning processes have ever identified any regional or interregional transmission lines for development. Instead, individual utilities and independent/merchant developers are what is primarily contributing to the grades in these two regions.

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263 PJM, *RTEP 2024* (Apr. 2025), https://www.pjm.com/-/media/DotCom/library/reports-notices/2024-rtep/2024-rtep-report.pdf.

264 PJM, *Reliability Analysis Report: 2025 RTEP Window 1* (Jan. 2026), https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2026/20260106/20260106-2025-rtep-window-1-reliability-analysis-report.pdf.

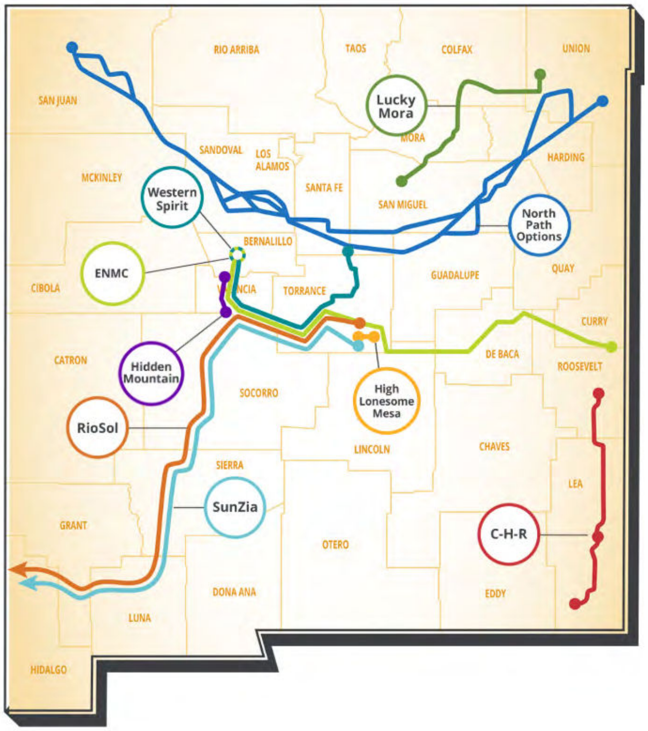
In the **Northwest**, PacifiCorp and NV Energy have both undertaken the planning and development of substantial high-voltage transmission projects. PacifiCorp has been working on its Gateway Transmission Projects, which expand over a utility service territory larger than some of the other regions. To plan projects, PacifiCorp utilized proactive generation and load forecasting. Additionally, NV Energy has been developing its Greenlink projects to access new renewable energy zones. Berkshire Hathaway Energy utilities, like PacifiCorp and NV Energy, are unique in their geographic size and scope, and unlike most utilities in the country, can build high-capacity long haul transmission within their footprints — including cost allocation and recovery.

In the **Southwest**, states, utilities, and merchant developers are planning and developing significant amounts of transmission in the region. For example, in Colorado, Xcel is currently constructing the Colorado Power Pathway projects, an approximately $2 billion investment with almost 600 miles of high voltage lines that is expected to help Colorado meet its goals by interconnecting 5.5 GW of resources. The state of Colorado also completed a Transmission Capacity Expansion Study in 2025, based on 2023 legislation, to identify needed transmission capacity expansion in the state by 2045. The study results found an additional $4-$8 billion in transmission was likely needed over the next 20 years to meet state policy and load growth while maintaining reliability.[265] In New Mexico, the Renewable Energy Transmission Authority (NM RETA) is supporting the development of nine high-capacity transmission projects, two of which are operational, and at least one is under construction (*see Fig. 27*). These projects are expected to interconnect most than 15 GW of new generation and represent over 2,200 miles and tens of billions in investment in the state.[266]

265 CETA, "Transmission Capacity Expansion Study for Colorado," accessed Jan. 2026, https://www.cotransmissionauthority.com/transmission-study.

266 NMRETA, "RETA Projects Overview," accessed Jan. 2026, https://nmreta.com/reta-projects/#.

FIGURE 27 Transmission Projects Supported by New Mexico RETA[267]



In the **Southeast**, as briefly discussed in the regional planning section, individual transmission utilities or groups of utilities are driving plans for significant new high-capacity transmission investment. A majority of the high-capacity transmission investment is in Georgia and will bring online new generation resources to accommodate large load growth and maintain reliability. Georgia Power and the other Georgia utilities, in their ten-year Integrated Transmission System plan have proposed to construct nearly 500 miles of new 500 kV transmission lines, which are intended to be in-service by 2033 (*see Fig. 28*).[268]

Beyond the projects under development in Geogia, there is resistance to building large, high-voltage transmission. One example, discussed above, is Duke's transmission planning process. In both the Multi-Value Strategic Transmission process and Carbon Plan Duke has not identified or selected any greenfield 500 kV transmission projects.

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267 *Id.*

268 Georgia *Power, 2025 Integrated Resource Plan*, 120 (Jan. 2025), https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/2025-Integrated-Resource-Plan.pdf.

FIGURE 28 Our Grid Future map of planned 500 kV transmission lines included in the Georgia 10-year transmission plan[269]

OUTCOME | Planned interregional transmission

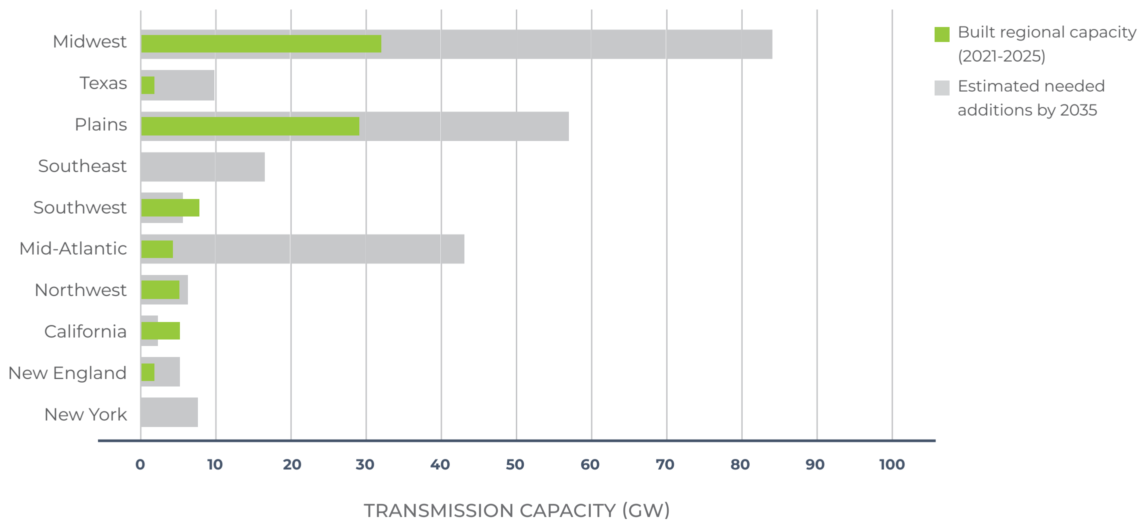
Similar to the planned regional transmission subcomponent, we compared the carrying capacity of planned interregional transmission tracked by Our Grid Future[270] against the additional capacity needs identified in the Needs Study. This subcomponent also makes up 30% of the outcomes grade. Fig. 29 compares the planned interregional transmission capacity in each region to DOE's estimated need. Interregional transmission is measured in terms of power capacity (gigawatt).

For planned interregional transmission the results are a little more mixed, and in most regions independent transmission developers are driving planned interregional capacity. Fig. 29 shows that most regions are likely to fall short of planning for the necessary interregional transmission capacity needed to meet the Needs Study estimates. These results demonstrate the shortcomings of today's ad-hoc interregional transmission planning landscape. While many regions recognize the need for and benefits of interregional transmission and are taking creative steps in its planning, the reality is no formal processes exist to ensure its construction. This is likely contributing to most regions falling short of their projected needs.

269 Abramson, E., Ramsay, E., McFarlane, D., Prorok, M., *Our Grid Future Planned Transmission Projects National Database, Horizon Energy Systems*, December 2025. Available: http://www.ourgridfuture.org ("Our Grid Future").

270 *Id.*

FIGURE 29 Interregional transmission (≥100kV) capacity planned in each region to be operating by 2035 compared to the expected need.



The Midwest and Plains regions score high for planned interregional transmission. As discussed in the interregional planning section, MISO and SPP continue to move forward with their JTIQ portfolio, despite the uncertainty associated with federal funding. The JTIQ projects are good step forward in developing interregional transmission capacity and will facilitate the connection of 28-53 GW of new generation. The Midwest and Plains regions also have several independent/merchant interregional transmission lines under development, such as Grain Belt Express and SOO Green, that are "shovel-ready" according to ACEG's 2023 Ready-to-Go Transmission Projects report.[271] As we explained above, incorporation of these projects into MISO and SPP's transmission planning processes will improve the development chances for these projects.

California, the **Northwest**, and **Southwest** also score high in this subcomponent. WestTEC, despite not having cost allocation, has proven to be a significant west-wide planning exercise, identifying 104 upgrades across the West in the 10-year plan. These upgrades consist of newly identified projects as well as some that have been under development by utilities or transmission developers. Independent developers are planning some significant interregional transmission projects in the West. For example, the North Plains Connector transmission facility (developed by Grid United, Allete, and Pattern) is one of several under development transmission facilities that would connect the Eastern and Western Interconnects. Additionally, several new transmission lines are being developed

271 Zimmerman, Z., et al., *Ready-to-go transmission projects, ACEG and Grid Strategies*, 4 (Sep. 2023) https://cleanenergygrid.org/wp-content/uploads/2023/09/ACEG_Transmission-Projects-Ready-To-Go_September-2023.pdf.

by independent developers to better interconnect the Northwest with its neighbors, including the Cascade Renewable Transmission Project (PowerBridge, Sun2o Partners, and NextEra Energy Transmission) and the Western Bounty Transmission System (Engie North America).[272]

Independent/merchant development between **Texas** its neighbors has boosted the region's grade for planned interregional transmission capacity, despite ERCOT having no interregional planning process. Independent/merchant transmission developers, in particular Pattern and Grid United, are developing interregional transmission projects that would increase transfer capacity between Texas and the Eastern and Western Interconnects.[273]

Notably, planned transmission is not always constructed. So, the inclusion of high-capacity lines in planning does not guarantee that the projects will get built or the anticipated future need will be met. This caveat is potentially more applicable to interregional transmission, as many of the planned interregional transmission lines are being developed by independent merchant developers and may not have a clear path to regional approval or cost recovery. Additionally, many of the lines discussed in this report are substantial multi-state projects that would benefit from additional streamlining in federal siting and permitting processes.

OUTCOME | Transmission Constructed

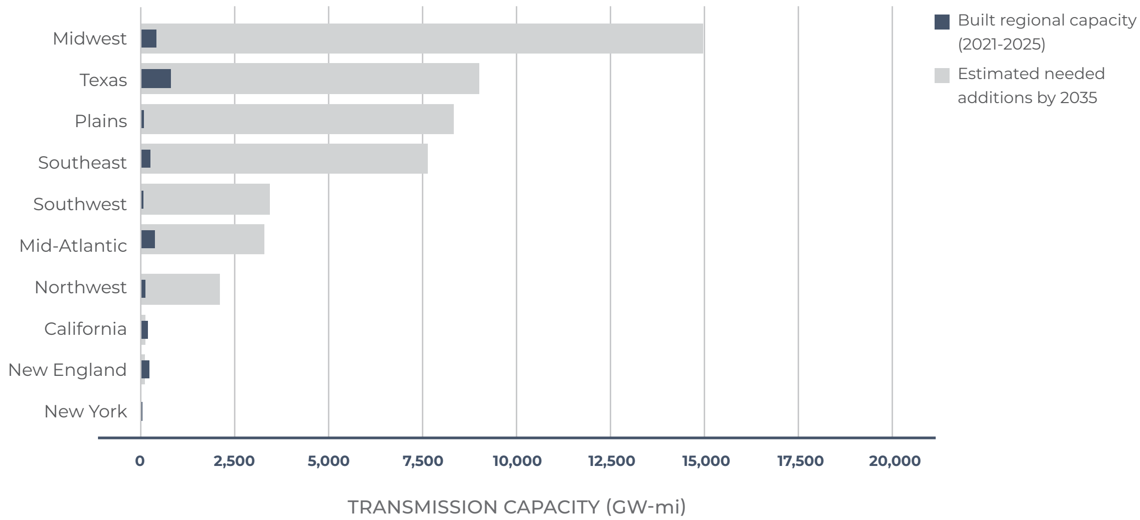
The third subcomponent evaluates miles of recently constructed high-capacity transmission lines (100 kV and up). Using data from Yes Energy, our analysis compares the total capacity of transmission energized between 2021 and 2025 to the estimated transmission capacity addition needs identified for each region from the DOE's 2023 Needs Study.[274] Fig. 30 shows the total new transmission constructed in each region compared to the estimated regional need in terms of power capacity and length as measured in gigawatt-miles. This subcomponent counts toward 15% of the outcomes grade.

272 See "Cascade Renewable Transmission Project," accessed Jan. 2026, https://www.cascaderenewable.com/; See also "Western Bounty Transmission System," accessed Jan. 2026, https://www.engie-na.com/wp-content/uploads/Flyer_Western_Bounty_Transmission_System.pdf.

273 *See* Southern Spirit and Pattern.

274 *See* DOE Needs Study.

FIGURE 30 Transmission (≥100kV) capacity constructed in each region between 2021 and 2025 compared to the 2035 expected need.



Data Sources: Yes Energy (2025) & DOE (2023)

As with the first edition of this Report Card, most regions are still not constructing new high-capacity transmission at the rate required to meet anticipated need. A few regions, however, have constructed a significant number of new miles of high-capacity transmission. Sometimes those regional grades are boosted by a singular, large project that spent numerous years in development and has finally been constructed.

Almost 900 miles of new high-voltage transmission were constructed nationwide in 2024. These miles can be attributed to just a handful of high-capacity projects, most with long development timelines. For example, the 125-mile Ten West Link project, which was energized in 2024, was first approved by **California** in 2013. And the 102-mile Cardinal-Hickory Creek project was approved in the **Midwest** in 2011 as part of MISO's Multi-Value Projects portfolio. Lastly, the Energy Gateway South line in the **Northwest** — originally announced by PacifiCorp in 2007 and partially completed in 2015 — was finally energized in 2024 after the last segment of construction was completed.[275]

The regional construction targets used here from the Needs Study reflect median outcomes in a range for the mid-scenario (mid-load growth and mid-clean energy deployment). These regional targets, in all likelihood, are at the low end of needed future transmission given the current high-load growth paradigm we find ourselves in. Some regions

275 ACEG and Grid Strategies, *Fewer New Miles: Strategic industries held back by slow pace of transmission Rev. 1*, 6-10 (Jul. 2025), https://cleanenergygrid.org/wp-content/uploads/2025/07/ACEG_Grid-Strategies_Fewer-New-Miles-2025_Rev-1.pdf.

— **New York, New England**, and **California** — are constructing transmission in excess of these targets, proactively preparing their regions to keep up with high load growth. For example, in 2023, New York completed its Public Policy Transmission Segments A and B, also known as the Central East Energy Connect and New York Energy Solution, adding approximately 150 miles of 345 kV transmission line to help New York meet its state policy goals.[276]

While not a part of the grade because of lack of data, one other important note on recent high-capacity construction is the challenges related to construction. Regions do have variance analyses for projects that may have significant cost overruns.[277] Order No. 1920 also included additional cost containment measures,[278] but there can be limited transparency on the underlying causes of longer construction timelines. One observation is that performance appears to vary by transmission owner even within regions, and it is not clear whether there are good reasons for variation in performance across transmission owners, or whether certain transmission owners need to adopt different practices.

OUTCOME | Congestion

The final subcomponent, congestion, reflects a representative snapshot of each region's available transmission system capacity, which, in turn, informs consumer impacts as greater congestion equates to higher energy delivery costs and limits the opportunity for desired generation resources to add power to the grid. Generally, lower congestion is associated with adequate capacity on a high-capacity transmission system to meet today's load and generation. However, a good grade does not necessarily mean the region is prepared for future needed capacity additions. As with the previous metrics, robust, proactive regional transmission planning occurring in a region would increase transmission capacity and could help reduce congestion. This subcomponent counts toward 15% of the total outcomes grade for a region.

For the evaluation, economic congestion was adjusted for the annual load in each region, so the final congestion number is the total dollars of congestion per total MWh of load in the region (*see Fig. 31*). Regions scored high in the congestion category if their absolute annual congestion for years 2021, 2023, and 2024 were low and trending downwards. We

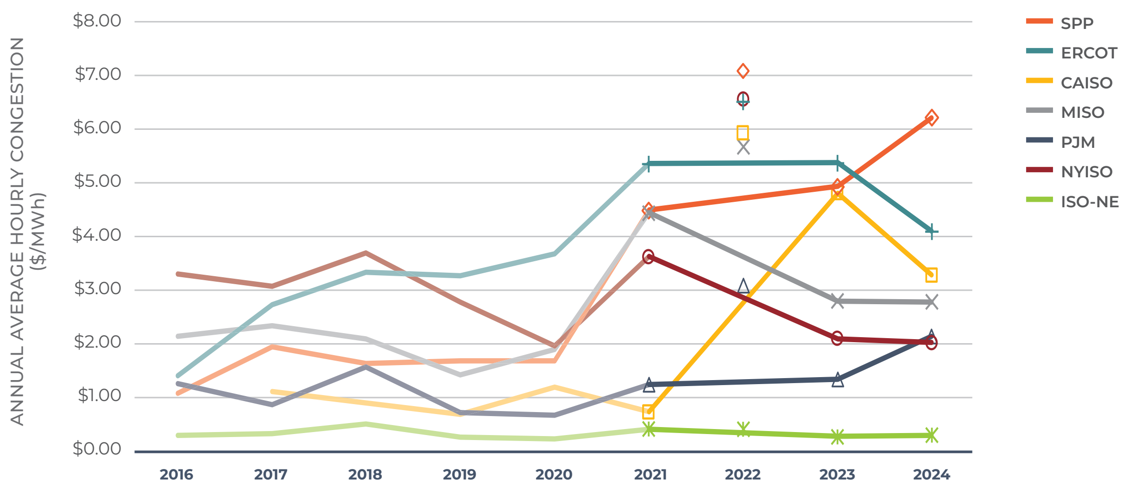
276 *See* New York Governor Kathy Hochul, "Governor Hochul Announces Completion of Central East Energy Connect Transmission Line" (Dec. 2023), https://www.governor.ny.gov/news/governor-hochul-announces-completion-central-east-energy-connect-transmission-line; *See also* New York Transco, "New York Transco Announces Energization of New York Energy Solution Clean Energy Transmission Project" (Aug. 2023), https://static1.squarespace.com/static/5d31dc252528ec000193dbb3/t/64dd36df8ebe51596be41849/1692219103967/NYES+News+Release.8.16.23_updated.pdf.

277 *See* Wilson, J., et al., *Independent Transmission Construction Monitor* (Nov. 2024), https://gridstrategiesllc.com/wp-content/uploads/Independent-Construction-Monitor-Grid-Strategies-Nov-2024.pdf.

278 *Id.*

omitted congestion data across all regions for year 2022 as several variables — Russia's invasion of Ukraine, significant winter storms — inflated congestion pricing across the entire U.S. that year. Even with the omission of 2022, congestion continues to rise across many regions. Congestion data was sourced from Annual Market Monitor Reports for each region, and a summary of sources can be found in Grid Strategies' *Transmission Congestion for 2024* report.[279]

FIGURE 31 Historic annual load-weighted congestion prices in each region. With the omission of year 2022, the most recent three years (2021, 2023, 2024) are highlighted.



Across the country, several regions, the **Midwest**, **New England**, and **New York**, have seen a downward trend in load-weighted congestion since 2021 (excluding 2022 as discussed above). **Texas** has also seen load weighted congestion trend downward, though the region has the second highest overall average level of congestion over the past three years. **California** and the **Plains** have seen some of the largest jumps in load weighted congestion since 2021, which is reflected in the highest and third highest average load-weighted congestion respectively. The **Mid-Atlantic** saw a slight upward trend in congestion over the past three years, but their average load weighted congestion has stayed relatively constant since 2016.

There is little transparency or congestion data available in the non-organized markets in the **Northwest**, **Southwest**, and **Southeast**, so grades were assigned as zeros. Given that on average congestion across the country in the 2020s is rising compared to pre-2020, we believe it is safe to assume similar trends also apply in the three non-organized market regions.

279 *See*, Shreve, N., et al., *Transmission Congestion for 2024, Grid Strategies* (October 2025), https://gridstrategiesllc.com/wp-content/uploads/GS_Transmission-Congestion-for-2024.pdf ("Transmission Congestion for 2024").

Conclusion

The 2025 Report Card shows marked improvement in regional and interregional planning processes, engagement, and real-world transmission development outcomes across ten regions. Grades differ across regions based on actions by the regional planning entity as well as state and individual utility actions within each footprint. Although region-specific recommendations are beyond the scope of this report, we provide some basic guidance on what "good" transmission planning and development entails across the four scored categories; additional detail is provided in the methodology section.

Across both regional and interregional planning, regions can improve by implementing six core elements:

1. Proactive, 20-year planning for generation and load;
2. Scenario-based planning that extends beyond sensitivities and includes extreme weather beyond a 1-in-10 standard;
3. Multi-value planning across needs and benefits;

4. A portfolio approach;
5. Consideration of all business models and Advanced Transmission Technologies; and
6. Integration with related planning processes (including resource adequacy and regional/interregional efforts).

Because regional and interregional planning are the most heavily weighted categories, improvements here will have the greatest impact on overall grades.

For engagement, regions can improve by strengthening transparency and formal stakeholder representation, ensuring meaningful state representation and incorporation of state policies, and adopting cost allocation approaches that enable both regional and interregional projects. For outcomes, improvement can be achieved by reducing congestion and planning for and constructing transmission development at a pace consistent with the capacity goals articulated in DOE's Needs Study.

No metric is perfect, and some subjectivity is unavoidable. Even so, the grades are intended as a benchmark against best practices, and we hope this report catalyzes an urgent conversation among policymakers, planners, and stakeholders about the improvements needed in transmission planning and development to ensure the United States has the infrastructure required to meet evolving reliability and affordability needs while meeting growing energy demands.

Appendix
Methodology

Similar to the first Report Card, this third edition relies on both qualitative and quantitative metrics.[280] The qualitative metrics generally evaluate planning best practices. The quantitative metrics are based on real-world outcomes related to constructing large-scale transmission ("putting steel in the ground") to determine whether a region's planning processes are delivering results.

This Report Card is intended to provide an update on regional transmission planning and initiate a constructive conversation around the state of interregional transmission planning practices across the U.S. given the numerous studies highlighting the need and value of interregional transmission. The Report Card discusses differences in planning processes and the impact that those differences are having on real-world outcomes.

The grades are assigned based on objective measures, with a stated basis for each one, so that others may try to replicate the grading. Because there can be subjectivity in the weighting given to various factors and the interpretation of data, reasonable people can disagree on individual grades or grading scales chosen. Additionally, individual metrics can be interpreted differently and may not represent a region's comprehensive performance. While no grade is sacrosanct, we feel a region's overall grade reflects a fair representation of how each region performs compared to well-established best practices.

For this Report Card, we evaluated ten regions total. The regions generally follow FERC Order No. 1000 planning borders and ERCOT (*see* Fig. A-1). For the Southeast we combined SERTP, SCRTP, and FRCC. It is important to note that in some regions — particularly those in the non-RTO areas — regional and interregional transmission planning often occurs more at the utility-level. While our grades generally reflect the actions of the regional planning entities, we do also credit regions for best practices occurring at the state or utility level, which can materially influence outcomes. Where these actions affect a grade, we note that in the report.

For the assessment of this metric, practices were evaluated on a scale from 0 to 5. The following sections provide further details on each metric being used to evaluate whether

280 The second edition, released in 2024, functioned as a progress updated and did not include updated grades.

regions incorporate planning best practices in their transmission planning processes and how that impacts real-world outcomes.

FIGURE A-1 FERC Order 1000 Planning Regions[281]

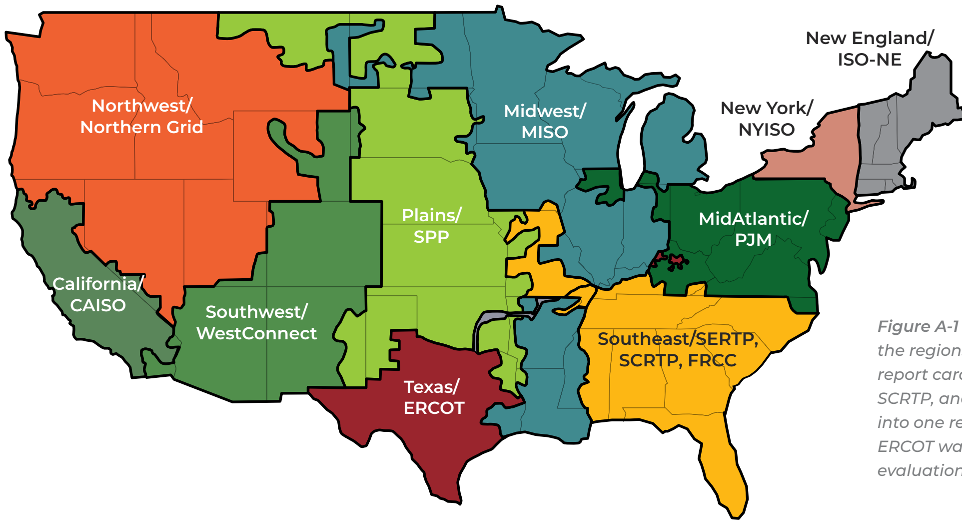


Figure A-1 *shows the borders of the regions used for grading in the report card. In the Southeast, SERTP, SCRTP, and FRCC were combined into one region, the Southeast. ERCOT was also included in the evaluation and is indicated in gray.*

Regional Transmission

For the regional transmission planning grade, we reviewed the most recent planning cycle, tariff provisions, and any relevant state or utility actions. Our tests focus on whether the region uses transparent inputs, evaluates a wide range of futures, and selects portfolios that minimize total system cost while maintaining reliability.

The grade for regional transmission planning reflects performance across established best practices. This metric accounts for 35% of the overall Report Card. The weighting is lower than in the initial Report Card because this edition places added emphasis on interregional transmission. However, regional planning remains a major contributor to the final grade because proactive and holistic planning signals a region's ability to deliver the lowest-cost power system for consumers while reliably addressing load growth.

We assessed whether each region's methods align with the best practices listed below. The regional planning grade assesses whether a region's planning processes are incorporating best practices. As discussed elsewhere, these practices broadly align with requirements in Order No. 1920.

281 FERC, "Regions Map Printable Version Order No. 1000," November 9, 2021, https://www.ferc.gov/media/regions-map-printable-version-order-no-1000.

Each best practice is scored on a 0–5 scale. Five means that best industry practices are used consistently. Three indicates partial adoption of best practices with gaps in documentation or scope. Zero indicates the practice is absent or only nominally present.

The list below summarizes the criteria used to evaluate whether regions incorporate these best practices into their transmission planning processes.

1. Proactive planning for future generation and load
    a. Forecast the likely future resource mix
    b. Reflect customer and utility commitments that affect supply and demand
    c. Estimate load levels and profiles over the investment life
        i. Include end-use electrification
        ii. Include extreme weather effects
    d. Account for expected resource retirements
2. Scenario based planning
    a. Evaluate a broad set of plausible futures (i.e. beyond singular power flow models and NERC reliability cases)
    b. Include extreme weather scenarios
    c. Favor a least-regrets outcome across scenarios
3. Multi-value planning
    a. Consider projects that resolve multiple categories of need (i.e. reliability and economic)
    b. Quantify a set of benefits equal to or better than the benefits required in Order No. 1920
4. Utilization of a portfolio approach
    a. Evaluate how candidate facilities interact and optimize the system
5. Consideration of all transmission business models (i.e. merchant developer and non-developer proposals) and Advanced Transmission Technologies
    a. Evaluate benefits from reasonable non-incumbent developer transmission plans
    b. Incorporate Grid Enhancing Technologies (e.g., Dynamic Line Ratings, Advanced Power Flow Controls, Topology Optimization) and High Performance Conductors (e.g., carbon fiber and composite conductors and superconductors)
6. Integrated Planning
    a. Evaluate if the regional planning process, including inputs, assumptions, and outputs is aligned with other planning processes (e.g., resource adequacy assessments)

Interregional Transmission

Similar to regional transmission planning, we reviewed the most recent planning cycle (if any), tariff provisions, and any relevant state or utility actions for the interregional transmission planning component. Our evaluation is based on performance across best practices similar to the regional planning metric.

Interregional transmission planning also accounts for 35% of the overall grade for the Report Card. Each best practice is scored on a 0–5 scale. With one exception, we used identical criteria to those outlined in the regional transmission planning methodology section above. We also considered if each region's interregional planning processes are aligned with the interregional planning processes, schedule, input assumptions, and benefits of their neighbors.

Engagement

Good stakeholder and state engagement along with balanced governance improves the quality of plans and the durability of decisions. We evaluate representation, transparency, and opportunities for stakeholders to shape assumptions and alternatives.

Engagement accounts for 15% of the overall grade. We evaluate whether a region's structure includes meaningful roles for load and generation customers, representation for non-utility companies and transmission developers, and participation from non-governmental organizations (NGOs) and consumers. Diverse participation improves innovation, transparency, and accountability in transmission planning. State participation also increases the likelihood of broad support for regional plans and alignment with policy objectives.

Engagement also includes evaluation of cost allocation for both regional and interregional transmission projects. If the region has a broad-based cost allocation methodology that quantifies the benefits defined above and allows for the selection and construction of regional or interregional projects, the region scores higher.

Each best practice is scored on a 0–5 scale. Below are additional details on the metrics used to evaluate engagement in regional transmission planning processes.

1. Are non-utility entities and/or transmission companies represented?
2. Are states or their policies represented in any formal way?
3. Are consumers and NGOs represented in the voting?
4. Does the region have effective cost allocation for the development of regional and interregional projects

Outcomes

This report includes four quantitative metrics that are 15% of the overall grade and evaluate real-world outcomes related to planning and constructing large-scale transmission to determine whether a region's planning processes are delivering results. The outcomes metric includes four subcomponents which are weighted to reflect the connection between regional and interregional planning. The four subcomponents are a) regional transmission constructed (20%), b) planned regional transmission (30%), c) planned interregional transmission (30%), and d) congestion (20%). The methodology for each section is described in detail below.

Recently Constructed Transmission

The first quantitative metric evaluated was recently built transmission lines. Grades compare the annual average miles constructed over the past three years, from Yes Energy data[282] with the annual average transmission need for each region from the DOE's 2023 Transmission Needs Study.[283] Below are the steps we took to arrive at the grades.

i. **Data sources:** We evaluate new high-capacity transmission placed in service during 2021 through 2024 using data from Yes Energy. The carrying capacity of transmission lines are from MISO's Transmission Cost Estimation Guide.[284] Target transmission capacity addition rates for each region are the estimates from DOE's Needs Study of the gigawatt-miles required by 2035 to meet new electricity demand. The comparison values chosen are the median results of the middle scenario from the DOE Needs Study.

ii. **Evaluation:** The power capacity (in GW-miles) of recently constructed lines was calculated by multiplying the carrying capacity of any facility (in mega-volt amperes) energized between 2021 and 2025 by the number of circuits and by the facility length (in miles). If this facility was a reconductored or upgraded line and not a greenfield project, then the final capacity was derated to only 20% of this calculation to represent a marginal improvement of carrying capacity to the overall system. When the developer-identified carrying capacity of the line was not available, we estimated the carrying capacity of each voltage classification using the per circuit power rating of each voltage class from MISO's MTEP Transmission

282 Data from Yes Energy is summarized in FERC's monthly "Energy Infrastructure Updates." See FERC, Staff Reports and Papers, accessed October 2025, https://www.ferc.gov/staff-reports-and-papers.

283 DOE, *National Transmission Needs Study*, at 123-124 (Oct. 2023), https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf.

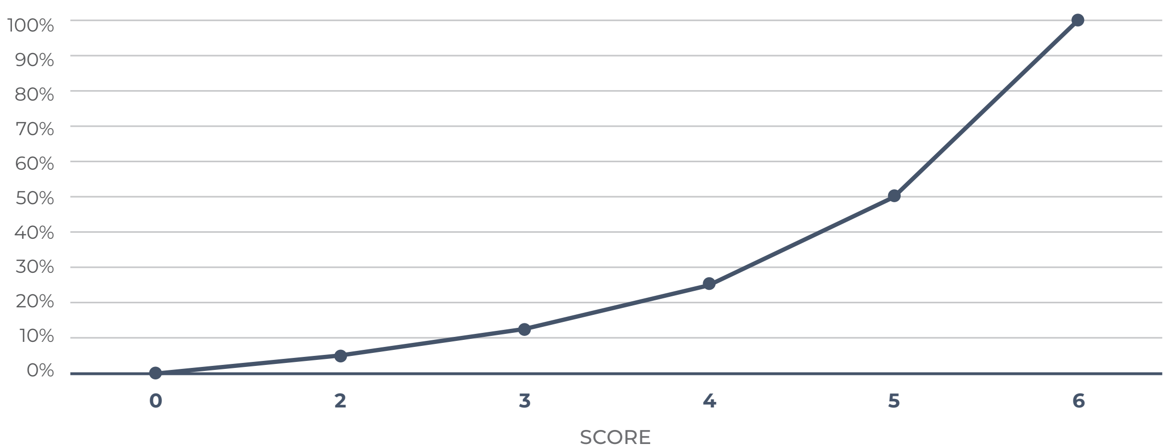
284 MISO, *Transmission Cost Estimation Guide for MTEP24*, 33 (May 2024), https://cdn.misoenergy.org/20240501%20PSC%20Item%2004%20MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24632680.pdf.

Cost Estimation Guide.[285] The sum of all power capacities in each region were then compared to the anticipated 2035 regional need from the DOE Needs Study.

iii. **Scoring:** Each region was scored on a 0–5 scale based on the percentage of regional needs from DOE Needs Study that were met from the recently added projects. A score of zero reflects negligible additions. One reflects progress below 5% of the benchmark need. Two reflects progress between 5-12.5%. Three reflects progress between 12.5%-25%. Four reflects progress between 25%-50%. Five reflects progress above 50%. These scores are shown in Figure A-2.

FIGURE A-2 **Numeric score assigned to outcomes**

Numeric score assigned based on percentage of 2035 needs met in each category



Planned regional and interregional transmission

The second and third quantitative metrics we evaluated were planned regional and interregional transmission projects. For planned regional projects, the methodology is identical to that described in the recently constructed lines, only applied for transmission facilities that are in development instead of those already energized. We included all active U.S. projects of at least 100kV nominal voltage within the Yes Energy database with a target in service date of 2035 or earlier, regardless of whether they are in advanced, early, or conceptual development stages.

For planned interregional transmission lines, which we defined as planned transmission lines between the Order No. 1000 planning regions, the methodology is slightly different. Following the steps outlined for the constructed regional transmission, we used the

285 *Id.*, "Table 3.1-5" at 33.

same methodology to calculate an interregional grade. Data used for interregional transmission came from Our Grid Future[286] as we noticed gaps in the interregional data available in other sources. To align with the DOE Needs Study, we calculated carrying capacity in GW instead of calculating carrying capacity of planned transmission in GW-miles. The same carrying capacities for voltage classes were used, but without regard for transmission facility length.

Congestion

The final metric, congestion, reflects a representative snapshot of each region's available transmission system capacity which, in turn, informs consumer impacts as greater congestion equates to higher energy delivery costs and limits the opportunity for desired generation resources to add power to the grid.

Generally, lower economic congestion is associated with adequate capacity on the high-capacity transmission system to meet each day's load and generation. However, a good grade does not necessarily mean the region is prepared for future needed capacity additions. As with the previous metrics, robust, proactive regional transmission planning would increase transmission capacity and help reduce congestion.

Congestion was normalized by annual load in each region, representing total dollars of congestion per total MWh of load in the region. The congestion data was sourced from Annual Market Monitor Reports for each region, and a summary of sources can be found in a recently released Grid Strategies report.[287]

Each region was scored on a 0–5 scale. The grade for each region is a combination of the average load weighted congestion (3 out of 5 points) and the congestion trend (2 out of 5 points) for the last three years (2021-2024), excluding 2022 because much of the increase in transmission congestion that year was due to extreme weather and gas price spikes caused by Russia invading Ukraine. For the average load weighted congestion, 0 reflects an average load weighted congestion higher than $5 per MWh and an upward trend in congestion. One reflects an average load weighted congestion between $3 and $5 per MWh and no change in congestion trends. Two reflects a downward trend in congestion and load weighted congestion between $1 and $3 per MWh. Three reflects load weighted congestion less than $1 per MWh. A four or five reflects a combination of a constant or downward trend in congestion and an average load weighted congestion between $1 and $3 per MWh or $3 and $5 per MWh.

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286 Our Grid Future.

287 Transmission Congestion for 2024.