Transmission Congestion for 2025

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Grid Strategies

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KEY FINDINGS

In 2025, U.S. grid congestion costs are estimated to exceed $17 billion, up from $12 billion in 2024.[1] High grid congestion is not a temporary blip caused by one bad year of weather or high gas prices, but rather a trend that has emerged in the 2020s. Prior to 2021, annual congestion costs had never exceeded $8 billion, but for the last five years, congestion costs nationwide have been over $12 billion. Even after adjusting for inflation, average annual congestion costs rose from roughly $9.2 billion for 2016-2020 to $16.1 billion for 2021-2025, almost doubling. In 2025, rising congestion costs were driven by:

1. **Limited expansion of the transmission grid.** New transmission build has not kept up with the expanding needs of the grid, largely driven by load growth and new generation resources.
2. **Extreme weather events.** While in the past extreme cold has led to the most grid congestion, in 2025 extreme summer heat was the dominant factor.
3. **Natural gas prices.** Natural gas remains the marginal fuel, setting electricity prices in many areas. Higher gas prices widen the gap between low-cost and high-cost areas on the grid, adding to the cost of congestion.

A combination of solutions that expand the capacity of the grid and make the best use of existing infrastructure could reduce congestion costs. These solutions are:

1. **Expanding regional and interregional transmission capacity.** Building new transmission lines increases the grid's ability to move power from low-cost regions to high-cost regions. Increasing transfer capacity between regions increases reliability by allowing power to flow across a wider footprint, reducing the impact of localized congestion and extreme weather events.
2. **Deploy Advanced Transmission Technologies (ATTs) and battery storage.** ATTs and storage allow grid operators to get more capacity from existing transmission. ATTs can also be deployed in months to expand transmission capacity, helping to reduce grid congestion.

Without expanded transmission capacity through new lines and ATTs, the U.S. grid will continue to face constraints that add costs for customers and complicate response to extreme weather.

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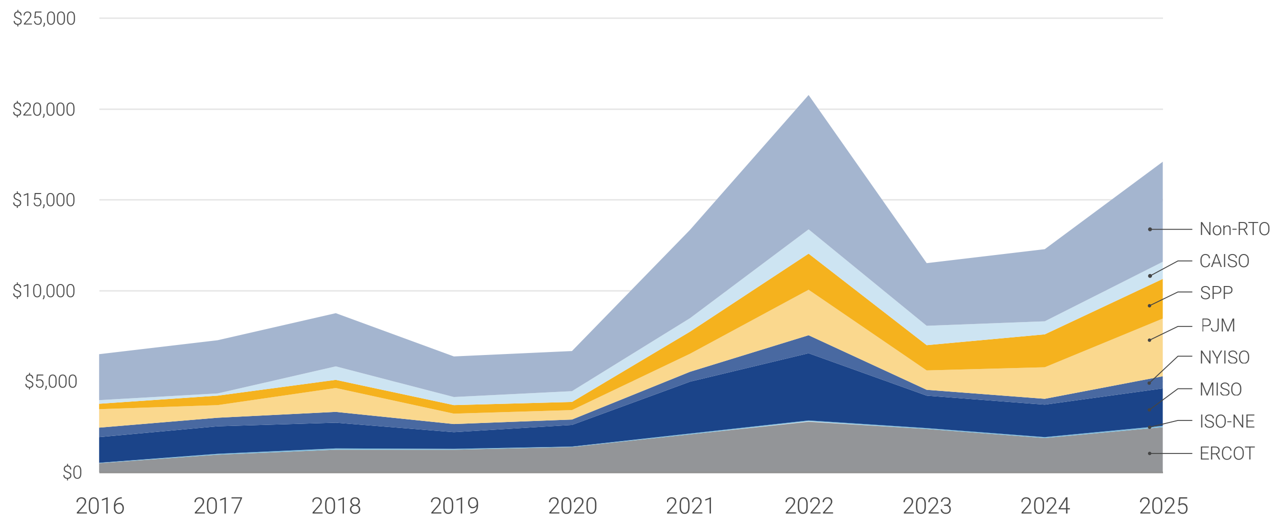
1 A detailed description of congestion and our assumptions can be found in the appendices. Congestion costs are generally only transparent within regions with an organized wholesale market, meaning those with a regional transmission organization (RTO) or independent system operator (ISO). To estimate national congestion cost including non-RTO regions, this report scales the known RTO congestion costs in Table C1 in Appendix C according to the peak load of the same regions when compared to total U.S. load.

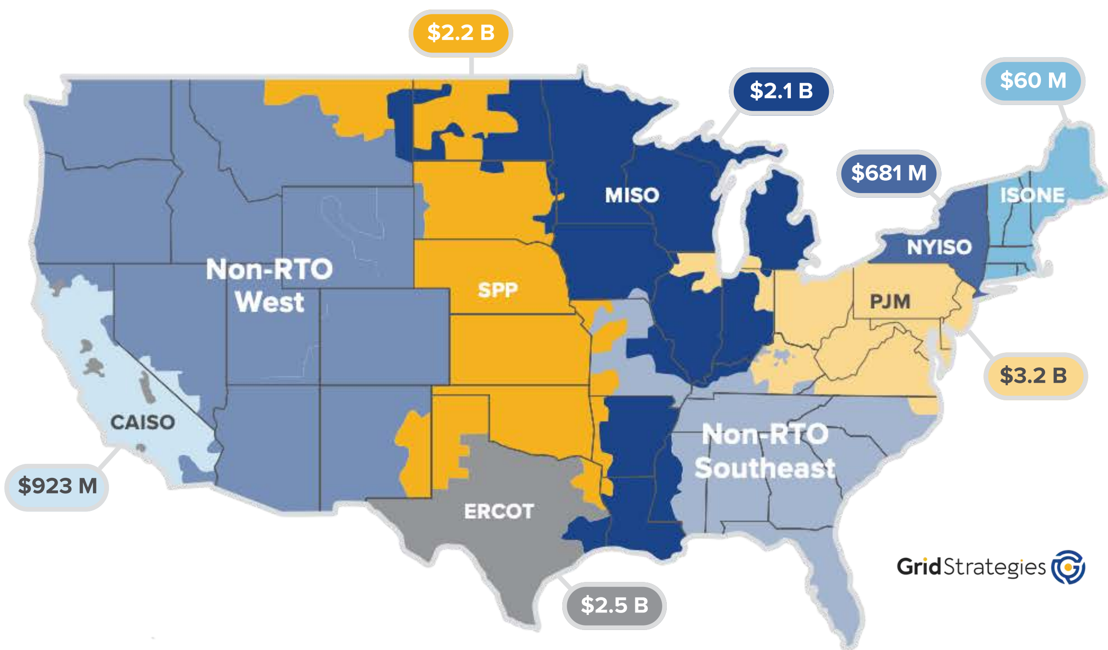
Figure 1. Estimated transmission congestion costs for the contiguous U.S., scaled based on costs reported across all RTOs, 2016-2025 ($M)

Estimated total transmission congestion costs in 2025 across the contiguous United States are slightly higher than those in 2024.[2]



Source: Market monitor reports; see Appendix

Figure 2. Transmission congestion costs by RTO, as reported by the internal and independent market monitors, 2025



2 Note that electricity congestion costs spiked in 2022, largely due to surging natural gas prices caused by the onset of the war in Ukraine.

DRIVERS OF CONGESTION PATTERNS

Congestion costs in 2025 were driven by a mix of factors including limited transfer capacity, extreme weather events, increasing fuel prices, and generation and transmission outages that added to existing constraints.

Limited transfer capacity

Congestion arises when generation cannot be delivered to demand centers due to limited capacity. The Electric Reliability Council of Texas (ERCOT) provides a clear example. The Panhandle in the north has abundant output from low-cost generation but is export-constrained, while the Permian Basin in the west has seen growth in demand but is import-constrained. This dynamic shows up in congestion prices, with congestion increasing in the West zone by 27% from 2024 to 2025,[3] and 2025 prices roughly 13% above the ERCOT-wide average.[4] Additional transmission between both regions would reduce the price spread, and ERCOT has approved significant transmission investments, which will likely help alleviate congestion in the West zone.

While some drivers of congestion may change, demand in the Permian Basin is not projected to slow down. Average load in the West zone grew over 12%,[5] largely due to cryptomining operations and oil and gas activity in the Permian Basin. The result is that the West zone has become ERCOT's largest contributor to an increase in intrazonal congestion prices, with congestion costs increasing in the region by 27% from 2024 to 2025.[6] This has reversed a three-year trend of declining system-wide congestion costs and pushed real-time congestion costs up 32% year-over-year across all of ERCOT.[7] The solution to reduce costs and enable growth is either to increase transmission capacity or build local, lower-cost generation. Given the abundance of cheap electricity in the Panhandle, ERCOT has planned a significant grid expansion, discussed in the Congestion Mitigation section of this report.

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3 Potomac Economics, *2025 State of the Markets Report for the ERCOT Electricity Markets* (May 2026), at 72, https://www.potomaceconomics.com/wp-content/uploads/2026/06/2025-State-of-the-Market-Report-for-ERCOT.pdf (ERCOT State of the Markets Report).

4 *Id.* at 1.

5 *Id.* at 15.

6 *Id.* at 72.

7 *Id.* at v.

Extreme weather

Although winter storms have been highlighted as primary congestion drivers in past iterations of this report, the PJM Interconnection (PJM)'s 2025 congestion cost increases stemmed largely from record demand overwhelming transfer capability during summer heat waves. In June and July 2025, high loads due to extreme summer heat prompted PJM to declare maximum generation conditions across ten days.[8] During peak demand periods of late June (June 22–26) and mid-to-late July (July 14–17 and 23–30),[9] limited transmission transfer capacity from low-cost generation located in the west reduced PJM's ability to meet cooling demand in major eastern load centers, such as Dominion.[10] PJM was forced to dispatch out of merit, resulting in severe price divergence between regions. This heat-driven stress drove congestion prices in PJM to a peak of $608.9 million in July.[11]

Natural gas price increases

High fuel prices pushed congestion costs higher across the eastern half of the country. Rising natural gas prices were a dominant driver in increasing congestion costs across the Midcontinent Independent System Operator (MISO) in 2025.[12] The all-in price of electricity, a measure of the total cost of power to serve load, rose 67% in MISO markets in 2025 to an average of $53/MWh.[13] Cost of energy rose 43% as natural gas prices climbed 53% at Chicago CityGates and 58% at Henry hub,[14] the two benchmark hubs for MISO's gas fleet. This increase in fuel costs contributed directly to increased congestion costs since gas-fired resources set the marginal price the majority of the time in MISO. As a result, real-time congestion costs grew 23% year-over-year to $2.2 billion,[15] while day-ahead congestion rose 27% to $1.6 billion.[16] MISO's market monitor notes that congestion

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8 Monitoring Analytics, *2025 State of the Market Report for PJM* (Mar. 2026), at 297, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025/2025-som-pjm-vol2.pdf.

9 *Id.* at 303.

10 *Id.* at 75.

11 *Id.* at 74.

12 Potomac Economics, *2025 State of the Market Report for the MISO Electricity* Markets (Jun. 2026), at 6, https://www.potomaceconomics.com/wp-content/uploads/2026/07/2025-State-of-the-Market-Report.pdf (MISO State of the Market Report).

13 *Id.* at i.

14 *Id.* at 4.

15 *Id.* at ii.

16 *Id.* at x.

costs tend to scale with gas prices as higher-cost gas generation is required to serve load in transmission constrained areas.[17]

Transmission and generation outages

Simultaneous transmission and generation outages also drove congestion cost increases. $625 million, or 28%, of the increase in MISO congestion year-over-year was driven by simultaneous transmission and generation outages.[18] In one notable example, widespread tornadoes and wind damage combined with planned and forced transmission and generation outages caused two load-shed events in MISO South. Planned and unplanned outages along the MISO and Southwest Power Pool (SPP) seam on April 2 resulted in several reliability violations, causing MISO to direct 100 MW of load shedding in SPP and 27 MW of load shedding in MISO. Congestion in MISO South totaled $10 million on this day alone.[19]

In New York, regional transmission outages continue to be a driver of rising congestion costs in 2025. In New York City, day-ahead congestion costs surged by 195% from $52 million in 2024 to over $150 million in 2025, largely driven by two major outages along Gowanus-Greenwood facilities and Astoria Annex–E.13th St. lines.[20] On Long Island, congestion increased 27% from the previous year, driven by line outages on Shore Road-to-Lake Success and Valley Stream-to-Stewart Ave lines.[21]

Weather-related outages and planned maintenance are an unavoidable part of grid operation, but they can be mitigated. Most RTOs[22] lack robust workflows for reducing the economic impacts of grid outages, even though low-cost operational or technical interventions, such as Grid Enhancing Technologies, can often address them. For examples, ISO New England uses Transmission Topology Optimization to manage outage-related congestion.[23]

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17 *Id.* at 52.

18 MISO State of the Market Report at 73.

19 *Id.* at 12.

20 Potomac Economics, *2025 State of the Markets Report for the New York ISO Markets* (May 2026), at 71, https://www.potomaceconomics.com/wp-content/uploads/2026/05/NYISO-2025-SOM-Report__5-19-2026-final.pdf.

21 *Id.*

22 Although there are independent system operators (ISOs) that are not RTOs, this report uses RTOs for simplicity, unless specific reference to ISOs is needed.

23 Massachusetts Department of Public Utilities, *Report on Advanced Transmission Solutions* (Sept. 2025), https://www.mass.gov/info-details/dpu-report-on-advanced-transmission-solutions.

MITIGATING CONGESTION

Expanding transmission capacity

The United States must invest in well-planned, high-capacity transmission to unlock the greatest savings for consumers. In 2025, 411 miles of new, high-capacity transmission were completed in the U.S., far short of the approximately 5,000 miles of new, high-capacity transmission needed each year to reliably and affordably serve growing demand.[24] A draft version of the U.S. Department of Energy (DOE)'s *2026 National Transmission Needs Study* highlights this need, noting that a significant investment into regional and interregional transmission is necessary to address congestion across the United States.[25]

Recent and planned expansion of the ERCOT grid highlights how investment in high-capacity transmission can relieve congestion. In ERCOT, congestion declined significantly in the Houston area after the completion of transmission upgrades to resolve constraints that had made it the highest congested zone in the state in prior years.[26] ERCOT and the Public Utility Commission of Texas, through its *Strategic Transmission Expansion Plan*, have also approved a significant 765 kV backbone transmission plan to serve, in part, oil and gas-related demand growth in the Permian Basin, comprising several thousand new miles of transmission and representing nearly $33 billion in investment.[27] While not expected to come online until the early 2030s, these projects should also help with congestion in ERCOT West.

Expanding interregional transmission

Studies have repeatedly shown that interregional transmission is among the most valuable transmission investment. But interregional transmission remains underbuilt and undervalued, in part because interregional congestion costs are not currently measured. New case studies from the Southeast and from SPP's recent western expansion show the value of interregional transmission in practice. However, current transmission planning processes are not structured to prioritize interregional planning to capture this value.

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24 Grid Strategies, *Fewer New Miles Rev. 1* (July 2025), https://cleanenergygrid.org/wp-content/uploads/2025/07/ACEG_Grid-Strategies_Fewer-New-Miles-2025_Rev-1.pdf; *See also* forthcoming report from Grid Strategies on miles of high-capacity transmission constructed in 2025.

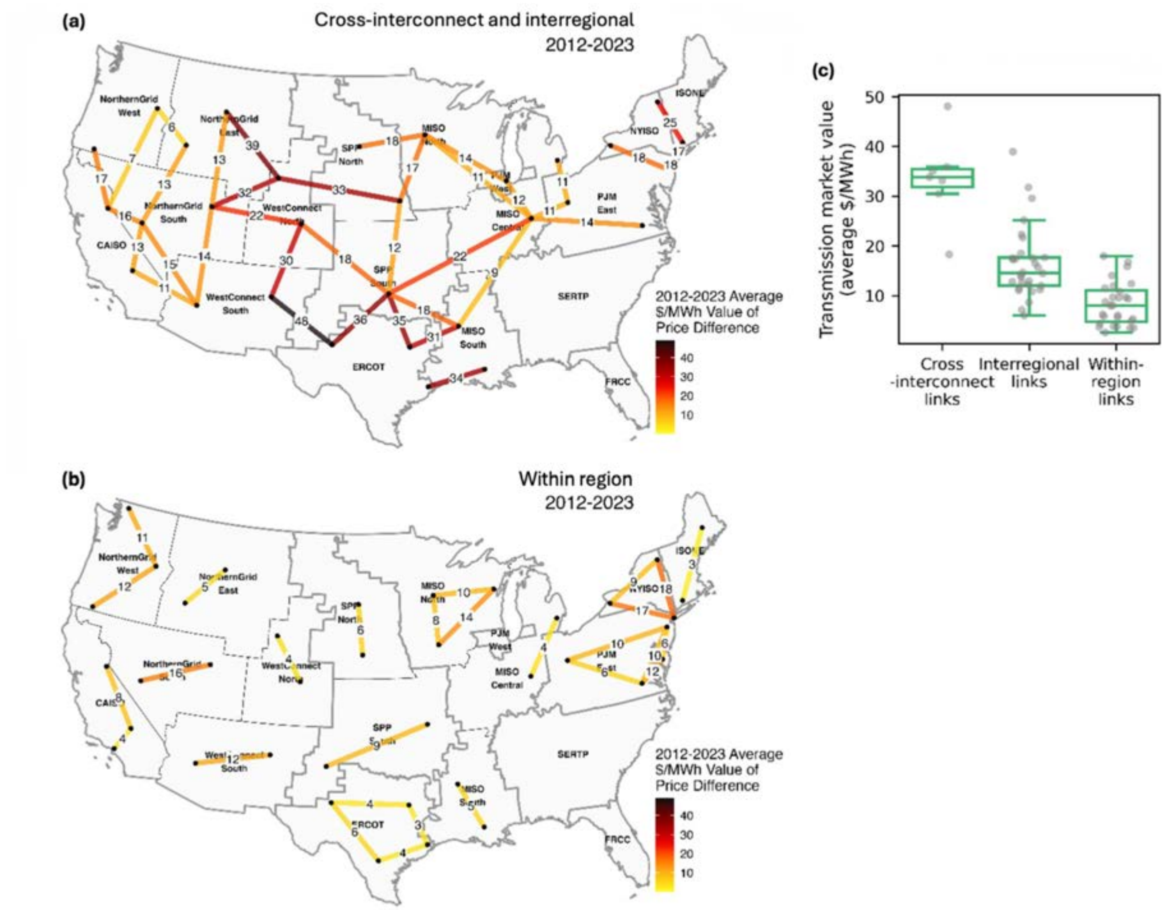
25 U.S. Department of Energy, *National Transmission Needs Study: Draft for Consultation and Public Comment* (July 2026), at vii, https://www.energy.gov/documents/national-transmission-needs-study-draft-july-2026 (Draft Needs Study).

26 *Id.* at 46.

27 ERCOT, *2024 Regional Transmission Plan (RTP) 345-kV Plan and Texas 765-kV Strategic Transmission Expansion Plan Comparison* (Jan. 2025), https://www.ercot.com/files/docs/2025/01/27/2024-regional-transmission-plan-rtp-345-kv-plan-and-texas-765-kv-strategic-transmission-expans.pdf.

The *National Transmission Needs Study* highlights interregional transmission as the single highest-value tool for relieving congestion.[28] Likewise, Lawrence Berkeley National Lab (LBNL)'s analysis found that interregional transmission lines consistently provide the most valuable connections. Cross-interconnect connections have potential value at or above $30/MWh, versus just $17-$18/MWh for the highest valued intraregional links (New York City to the rest of the New York ISO).[29] With roughly half of all congestion concentrated in 5% of hours,[30] interregional lines are also best positioned to relieve congestion during extreme weather events, resulting in billions of savings annually.

Figure 3. The maps of the mean marginal transmission market values for the analyzed links are divided into (a) cross-interconnect and interregional links and (b) within-region links. The graphic indicated by (c) is the distribution of mean marginal transmission market values across the set of 65 analyzed links (real-time market).[31]



28 Draft Needs Study at v.

29 *Id.* at 38 and 39.

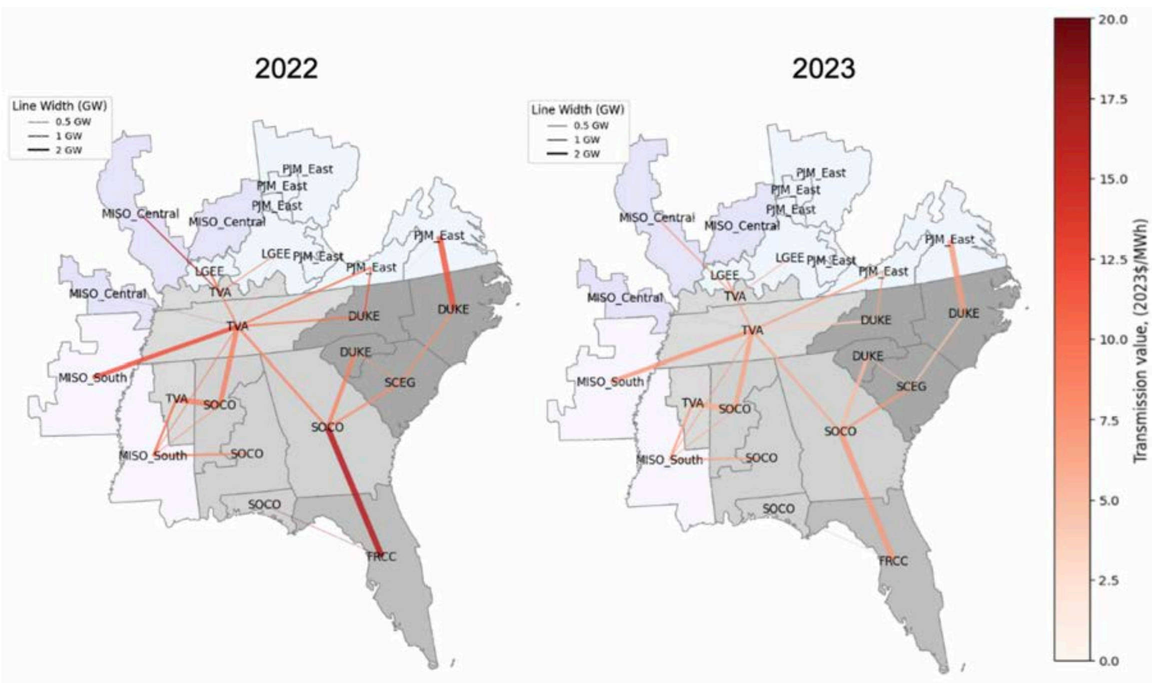
30 *Id.* at iv.

31 LBNL, *Electric transmission value and its drivers in United States power markets*, (Aug. 2025), https://eta-publications.lbl.gov/sites/default/files/2025-09/task_1_empricalvalue_and_drivers_formatted.pdf.

New studies and real-world evidence show the value of interregional transmission in the Southeast and West

Congestion in the Southeast is difficult to measure due to the lack of an organized market and public wholesale power pricing data, but a new analysis from LBNL and the National Laboratory of the Rockies (NLR) shows significant intra- and interregional congestion in the Southeast and how interregional transmission may help alleviate it. Using production cost modeling, the national labs found that the Southeastern Regional Transmission Planning (SERTP) region's links to its neighbors averaged $8.14/MWh and the Florida Reliability Coordinating Council (FRCC)-SERTP link averaged $7.98/MWh, with 2022 the highest year in per MW congestion costs due to elevated gas prices.[32]

Figure 4. Map of transmission congestion value for interregional and intraregional links in the U.S. Southeast derived from locational marginal prices extracted from a production cost model[33]



SPP's western expansion provides an excellent example of the value of gaining visibility into the cost of interregional transmission congestion. In April 2026, SPP completed its expansion into the Western Interconnection, becoming the first RTO to operate wholesale markets across both the Eastern and Western Interconnections. The expansion added nine utilities across seven states, extending SPP into 17 states total.[34] The physical

32 Draft Needs Study at 41.

33 *Id.* at 43.

34 SPP Market Monitoring Unit, *State of the Market 2025* (May 2026), at 28, https://www.spp.org/documents/76798/2025_annual_state_of_the_market_report.pdf.

capacity between the SPP's new West balancing authority area (BAA) and the existing East BAA remains limited—two systems with a combined capacity of 310 MWs.[35] Since market launch, the West BAA has experienced significant congestion, leading to two emergency energy declarations due to inability to transfer energy between the West and East BAAs. The new level of price transparency offered by the market will make it easier to track the cost of the limited transfer capacity and potentially help justify new transfer capacity in the future.

Formal interregional planning processes are needed

Despite the clear value of interregional transmission, changes are needed to establish a formal interregional transmission planning process. DOE's *National Transmission Needs Study* candidly notes that interregional transmission is structurally under-planned and under-valued.[36] Federal Energy Regulatory Commission (FERC) Order Nos. 1000 and 1920 mandate regional transmission planning processes, but leave interregional planning as a secondary process, achieved largely through coordinating studies instead of formal planning processes.

Battery storage and generation resources

Strategically-sited battery storage can help alleviate congestion and is faster to deploy than traditional transmission upgrades. Batteries can relieve congestion by acting as both load and generation at the same location, or they can be deployed on either side of a transmission constraint. Batteries absorb power, often at a negative price when generation would otherwise be curtailed, and then discharge when prices are high, potentially reducing the impacts of grid constraints.

The ERCOT market monitor notes Energy Storage Resources (ESRs) are "particularly effective at managing congestion when they are located at key locations where they can influence power flows in both directions by charging or discharging."[37] In ERCOT, constraint violations fell to 64 constraint-hours in 2025, a record low and a drastic reduction from the previous low of 271 constraint-hours in 2016.[38] This decline is in part due to ERCOT's rapid installation of battery capacity, which increased by around 80% in 2025 to 17 GW.[39] While batteries are an important tool in the congestion management toolkit, they are not a substitute for broader transmission expansion in reducing congestion. Despite a record low of constraint-hours in ERCOT, congestion still

35 *Id.* at 29

36 *See* Draft Needs Study at v, viii, 38-39, 54-62.

37 ERCOT State of the Markets Report at vi.

38 *Id.* at 63.

39 *Id.* at ii.

rose in 2025, reversing a three-year declining trend. Batteries are effective at relieving local constraints but cannot solve the problem of congestion caused by region-wide transmission shortfalls.

Local generation resources coming online can also reduce grid congestion costs. Congestion can be a useful signal to generation developers for where more power is needed, and they are rewarded for building where real-time prices are high. However, congestion also indicates that low-cost power is already available on the system, just not in the right place. Transmission capacity is the efficient solution to optimize delivery of available resources.

Advanced Transmission Technologies

Grid operators have tools available today which can be quickly deployed to relieve congestion or act as a bridge while more permanent solutions are being planned and built. ATTs include Grid Enhancing Technologies (GETs), such as Dynamic Line Rating (DLR), Advanced Power Flow Control, and Transmission Topology Optimization, along with High Performance Conductors (HPCs), which include Composite Core Conductors and Superconductors.

GETs deliver value quickly and work alongside existing and new transmission infrastructure. They can free up more than 20% of capacity on lines that already exist and can cut congestion costs in half.[40] Studies have shown that GETs can pay for themselves in savings within six months to two years and sometimes even faster.[41] In 2022, PPL Electric Utilities deployed DLR for less than $1 million, compared to $20 million for reconductoring and $40–$60 million for rebuilding transmission. The project was operational in less than 1 year with no outages, compared to 2 to 3 years with outages for reconductoring and 3 to 5 years with extended outages for rebuilding transmission. The deployment saves $20–$60 million in congestion costs yearly, and the extra capacity from DLR was noted for avoiding redispatch during Winter Storm Elliot by PJM.[42]

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40 The Brattle Group, *Building a Better Grid: How Grid Enhancing Technologies Complement Transmission Buildout* (Apr. 2023), https://www.brattle.com/wp-content/uploads/2023/04/Building-a-Better-Grid-How-Grid-Enhancing-Technologies-Complement-Transmission-Buildouts.pdf (Building a Better Grid).

41 The Brattle Group, *Unlocking the Queue with Grid Enhancing Technologies* (Feb. 2021), https://watt-transmission.org/wp-content/uploads/2021/02/ Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf; U.S. Department of Energy, *Grid Enhancing Technologies: A Case Study on Ratepayer Impact* (Feb. 2022), https://www.energy.gov/sites/default/files/2022-04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf.

42 Building a Better Grid at 14; WATT Coalition, *Grid Enhancing Technologies Could Unlock More Reliable, Affordable, Clean Energy in PJM* (Feb. 2024), https://watt-transmission.org/wp-content/uploads/2024/02/2.15.2024-Grid-Enhancing-Technologies-Could-Unlock-More-Reliable-Affordable-Clean-Energy-in-PJM.pdf.

Reconductoring with HPCs also offers grid operators an option to address congestion, with a solution that can alleviate congestion in less time and at a lower cost than building new transmission lines. HPCs can be used to reconductor existing lines, doubling their capacity without needing a new right-of-way.[43] In addition, significantly increasing grid capacity and connecting large amounts of new generation resources to serve growing load will create new congestion on the underlying grid. This reality will require swift action to relieve the congestion and avoid stifling development of needed generation resources. Reconductoring on the underlying system with HPCs is a solution that can more quickly alleviate congestion.

Dynamic Line Ratings are quickly deployable. MISO's market monitor shows how much opportunity is left on the table when utilities fail to deploy these low-cost solutions. In MISO, the market monitor estimates that consistent use of Ambient-Adjusted Ratings (AARs) and emergency ratings could have avoided over $300 million in congestion costs in 2025, representing roughly 15% of the overall real-time congestion costs. Notably, roughly two-thirds of the savings are concentrated in 23 facilities, suggesting that targeted deployment can capture most of the value available rather than system-wide implementation.[44] Despite these estimated savings, and a requirement in FERC Order 881 (issued 2021) to implement AARs, MISO has yet to comply and filed for an extension to 2028 in March 2025, citing software delays.[45]

RTOs save hundreds of millions with Transmission Topology Optimization. MISO implemented a limited Economic Reconfiguration Request Process in 2023. In 2026, the process achieved $95 million in market benefits between January and August with only 5 implemented reconfigurations.[46] In response to this success, SPP proposed a similar process, which was approved by FERC on August 19, 2026.[47]

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43 AMP Coalition, Grid Strategies LLC & ACORE, *Unlocking the Grid: A Playbook on High Performance Conductors for State and Regional Regulators and Policymakers* (Oct. 2024), https://acore.org/wp-content/uploads/2024/10/Unlocking-the-Grid-A-Playbook-on-High-Performance-Conductors-for-Stateand-Regional-Regulators-and-Policymakers.pdf.

44 MISO State of the Market Report at 69.

45 *Id.* at xi.

46 MISO Reliability Subcommittee, *Topology Optimization Top Ten Constraints and Economic Reconfiguration Update* (Formerly Reconfiguration for Congestion Cost Update) (Aug. 2026), https://cdn.misoenergy.org/20260818%20RSC%20Item%2002d%20Top%20Ten%20Constraints%20and%20Economic%20Reconfiguration%20Update%20(Formerly%20Reconfiguration%20for%20Congestion%20Cost%20Update)774850.pdf.

47 FERC, *Letter order accepting Southwest Power Pool, Inc.'s 05/21/2026 filing of revisions to Attachment AE of its Open Access Transmission Tariff etc. under ER26-2592*, https://elibrary.ferc.gov/eLibrary/filelist?_sp=ea126f61-cefd-4f9f-84b4-b5878c494296.1787340098456&accession_number=20260819-3087&optimized=false&sid=efb5b84c-9ceb-4428-9616-f67f98166a8e.

CONCLUSION

In 2025, nationwide congestion costs rose to $17 billion, with no signs of slowing down. This was the fifth year in a row that congestion costs surpassed $10 billion, driven by increasing demand, slow transmission expansion, extreme weather events, and outages. Reversing this trend will require expanding transmission capacity, and expanding the use of proven solutions like ATTs, battery storage, and planning for interregional transmission. Adopting these solutions would lower the rising cost of congestion and ease the financial burden on consumers while making the system more reliable, helping securely deliver more affordable electricity for all Americans.

APPENDIX A

Explanation of transmission congestion

When the grid cannot deliver the lowest-cost generation to load, more expensive generation is dispatched instead, raising prices. This cost is reported as "transmission congestion" in organized wholesale markets administered by RTOs. While in some cases these costs can be hedged through financial instruments, they provide a measure of how inadequate transmission capacity raises power prices for customers. Grid congestion costs reveal where the system is constrained and can signal the need to build additional transmission infrastructure.

Note that FERC requires transmission planners to conduct a robust evaluation of potential transmission projects, using multiple measures of the benefits of new transmission, before a transmission planner can move a project forward. One of those metrics is the value of new transmission for relieving costly congestion. This report focuses on congestion rents, which represent the difference in market prices between two locations multiplied by the amount of power flowing between them. Congestion rents are the most common—and often the only—metric reported by RTO market monitors for quantifying and comparing congestion across the grid.

Non-RTO regions do not have transparent congestion data, but the factors that drive congestion in these regions are similar to RTO regions. If anything, non-RTO regions may experience even higher relative costs driven by grid constraints because those regions are not able to benefit from the operational scale, greater resource and load diversity, and regional transmission planning in the RTO regions. FERC has recognized this issue and proposed new data reporting requirements for non-RTO regions to increase transparency as part of its consideration of new rules around transmission line ratings.[48]

This report does not include interregional congestion costs in our aggregated estimate. Our national congestion estimate is based on market monitor data that measures intraregional congestion only and therefore does not quantify interregional congestion costs. However, other sources show very high costs and opportunities for consumer savings if addressed. The difference in wholesale energy prices between two regions is a way to approximate interregional congestion costs. Like regional congestion, interregional wholesale price differences reflect the added cost to consumers when cheaper power cannot reach demand centers.

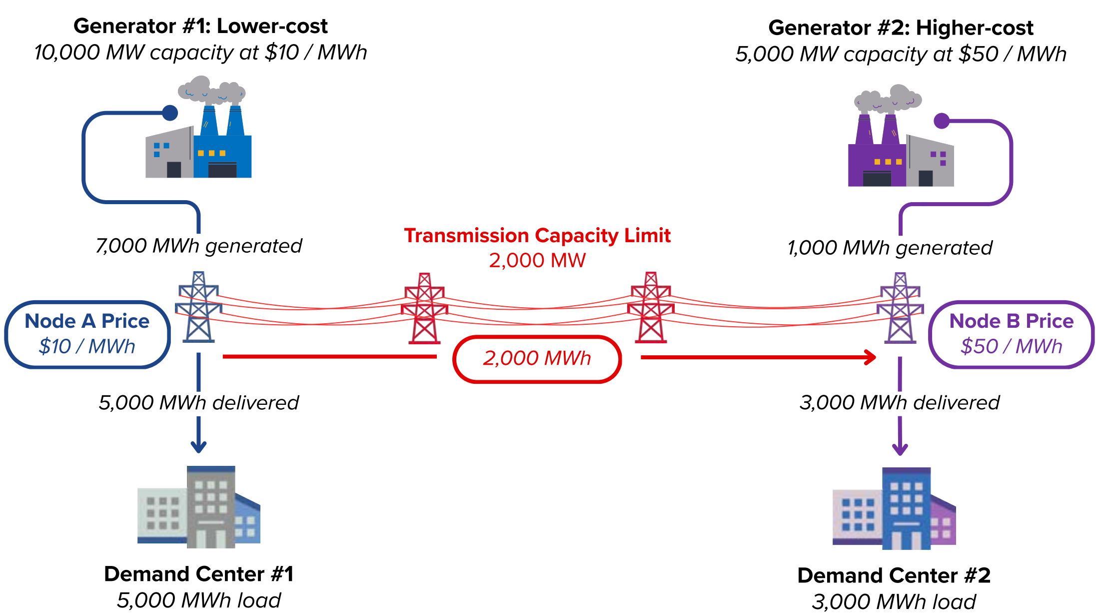
48 *Implementation of Dynamic Line Ratings*, 187 FERC ¶ 61,201 (2024) (issuing an advance notice of proposed rulemaking that proposes potential reforms to enhance data reporting practices related to congestion in non-RTO regions, among other proposed reforms).

How expanding transmission capacity reduces congestion

Congestion occurs when lower-cost generation cannot be fully delivered to load because transmission lines are operating at their physical or safety limits. When this happens, the line is said to be a binding constraint, and the system operator must dispatch higher-cost generation located within the constrained area to meet demand. This is called dispatching out of economic merit order, which is the order of pricing offers by all generators, from lowest to highest. The result is that the price of energy in the constrained area is higher than in the unconstrained area. This idea is illustrated in the two figures below.

Assume an isolated, simplified system in Figure 5. The transmission line in red has a capacity limit of 2,000 MW. Generator #1 is the cheaper generator, producing energy at $10 / MWh, and can meet the entire load at Demand Center #1, resulting in a nodal price at Node A of $10 /MWh. However, Generator #1 cannot fully serve Demand Center #2, since the transmission line connecting the two can only carry 2,000 MW. The remaining load from Demand Center #2 must be met by Generator #2, which produces energy at $50 / MWh. As a result, the price of energy at Node B rises to $50 / MWh, even though part of this energy is imported from the lower cost Generator #1. The congestion cost equals the price difference between the two nodes multiplied by the flow on the constrained line, which in this case is $80,000.

Figure 5. Limited transmission capacity constrains dispatch of lower-cost generation



$$\text{Total congestion cost} = \left(\frac{\$50}{\text{MWh}} - \frac{\$10}{\text{MWh}} \right) \times 2{,}000\ \text{MWh} = \mathbf{\$80{,}000}$$

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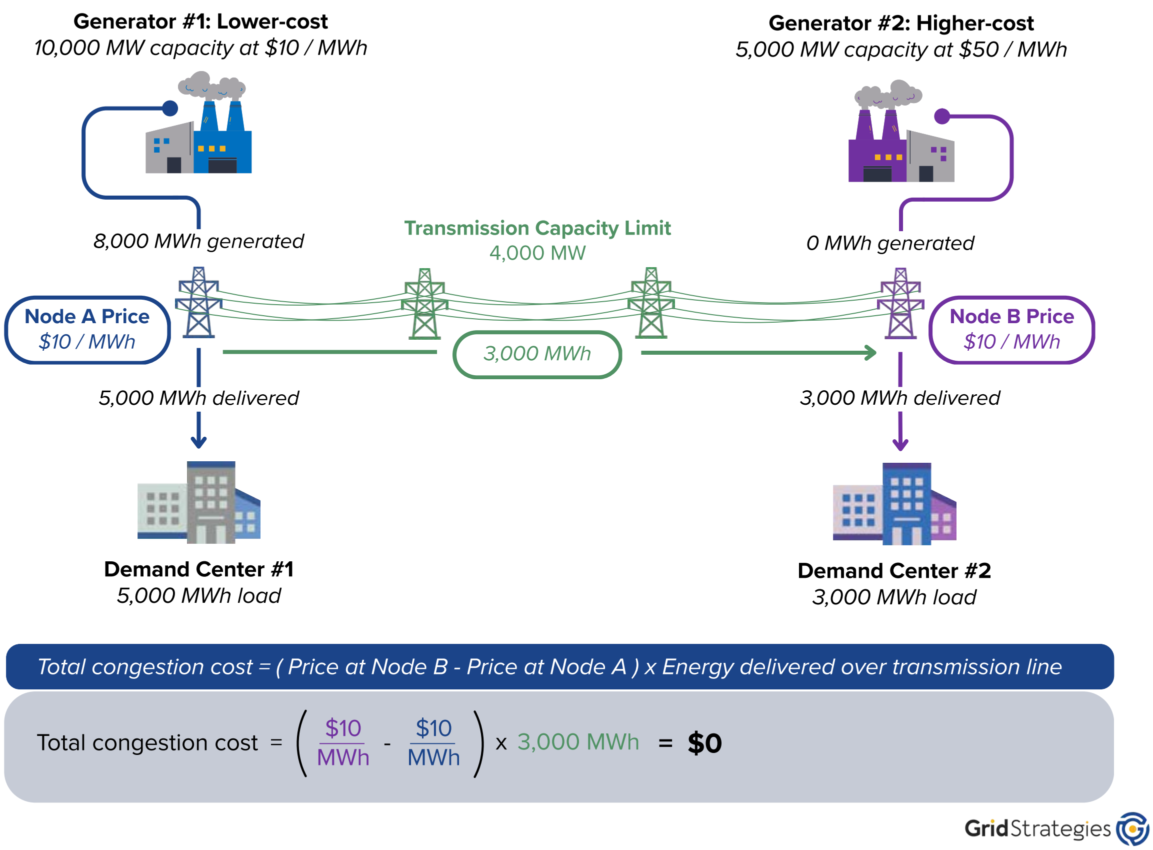
Assume an isolated, simplified system in Figure 6. The transmission line in red has now doubled in capacity to 4,000 MW. This additional capacity allows Generator #1 to supply all energy needed to meet total system load from both demand centers. Because the line is no longer a binding constraint, the system can dispatch generation in merit order, and Generator #2 does not dispatch energy. The price of energy at both nodes is therefore \$10 / MWh. With no price difference between nodes, the congestion cost falls to zero.

Figure 6. Additional transmission capacity allows for increased dispatch of lower-cost generation



APPENDIX B

Note on congestion rents

Congestion rents offer insights that can guide transmission investment. Geographic differences in short-term marginal prices, reflected in congestion rents, result from physical constraints on the transmission system and the need to dispatch higher-cost local generation when lower-cost remote resources are undeliverable due to congestion. Those higher production costs are borne by consumers and are a direct measure of the societal value of congestion.

Market data available from RTOs includes congestion rents, but not production costs incurred due to transmission congestion. Thus, congestion rents serve as a valuable available metric to assess congestion. Any other metric would be based on modeling rather than actual system and market data. Congestion rents are not a direct measure of the value of expanding a specific transmission element or path. Transmission expansion planning requires a holistic evaluation of the multiple reliability and economic benefits of new transmission.

Furthermore, high observed congestion costs do not always translate directly into higher costs borne by load. Consumers may be hedged against congestion through mechanisms such as Financial Transmission Rights, Auction Revenue Rights, or Congestion Revenue Rights. These instruments redistribute congestion rents, potentially mitigating the direct cost impact on some market participants. Nevertheless, congestion rents remain an important indicator of the underlying physical and economic inefficiencies on the system that transmission expansion can alleviate.

APPENDIX C

RTO/ISO regional analysis

Table C1. Total congestion costs by RTO/ISO, 2016–2025 ($M)

RTO/ISO	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
ERCOT	497	976	1,260	1,260	1,400	2,100	2,800	2,400	1,900	2,499
ISO-NE	39	41	65	33	29	50	51	32	37	60
MISO	1,402	1,518	1,409	934	1,181	2,849	3,700	1,800	1,800	2,054
NYISO[49]	529	481	596	433	297	551	1,000	311	306	681
PJM	1,024	698	1,310	583	529	995	2,500	1,068	1,754	3,174
SPP	280	500	450	457	442	1,200	2,000	1,400	1,800	2,192
CAISO[50]	197	138	745	451	605	760	1,323	1,049	734	923
TOTAL	**3,968**	**4,352**	**5,835**	**4,151**	**4,483**	**8,505**	**13,374**	**8,060**	**8,331**	**11,582**

Table C2. Estimated nationwide congestion costs, 2016–2025 ($M)

Region	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
U.S.	6,501	7,266	8,776	6,379	6,686	13,353	20,777	11,521	12,295	17,092

49 The New York ISO (NYISO)'s market monitor does not report both real-time and day-ahead congestion values in its annual state of the market report. These numbers are, therefore, based on day-ahead market congestion only.

50 The California ISO (CAISO) does not have a region-specific congestion metric. However, DOE's *National Transmission Needs Study* used a proxy by combining Day Ahead Congestion with Real Time Congestion Imbalance Offset Charges as reported by CAISO's market monitor. *See* U.S. Department of Energy, *National Transmission Needs Study* (Oct. 2023), at 65, https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf. This report replicates DOE's method, using CAISO's *Annual Reports on Market Issues and Performance* for the relevant years.

APPENDIX D

Internal and independent market monitor reports cited

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