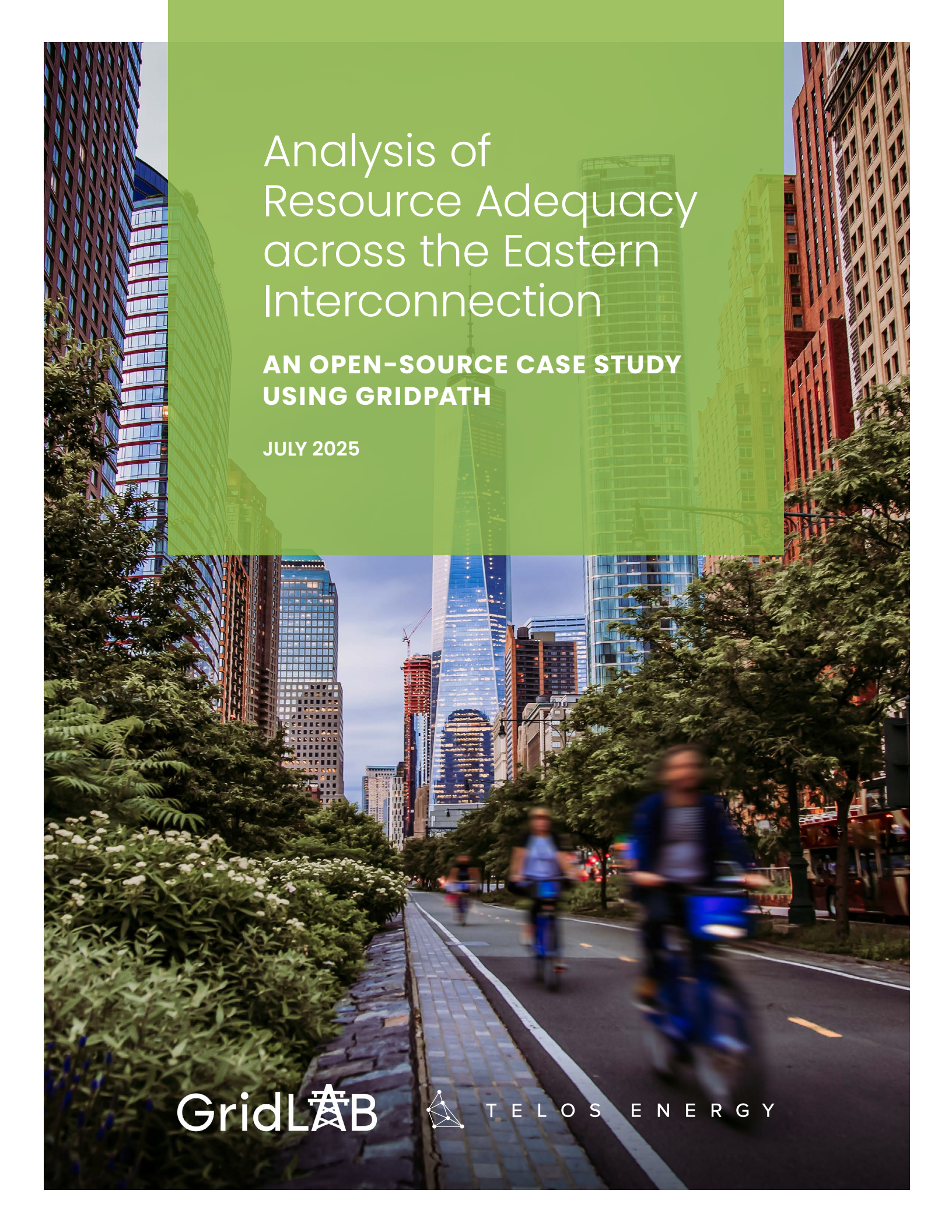




# Analysis of Resource Adequacy across the Eastern Interconnection

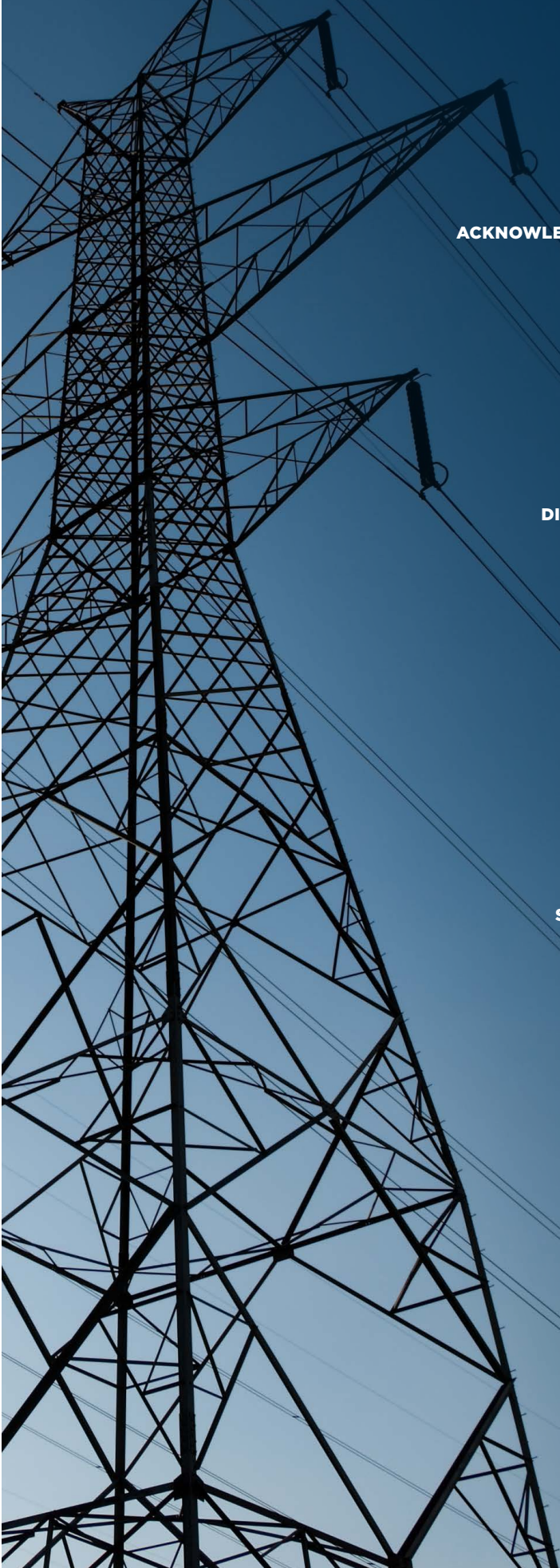
**AN OPEN-SOURCE CASE STUDY  
USING GRIDPATH**

JULY 2025

GridLAB



TELOS ENERGY



#### AUTHORS

Derek Stenclik, Telos Energy  
Sam Hostetter, Telos Energy  
Priya Sreedharan, GridLab

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#### DISCLAIMERS

We would like to acknowledge that this work builds on foundational methods implemented in the North American Electric Reliability Corporation (NERC) *Interregional Transfer Capability Study* and was conducted using concepts and best practices developed by the Energy Systems Integration Group (ESIG) *Redefining Resource Adequacy Task Force on Wide-area Adequacy Assessments*. However, this study was conducted independently of ESIG and NERC.

#### SUGGESTED CITATION

GridLab and Telos Energy, 2025, Analysis of resource adequacy across the Eastern Interconnection: An open-source case study using GridPath, [gridlab.org/publications](https://gridlab.org/publications)

All project materials are available at [www.gridlab.org/GridPath\\_EI](https://www.gridlab.org/GridPath_EI)

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# EXECUTIVE SUMMARY

## Study Objectives

The Eastern Interconnection spans 44 states and provinces, encompassing numerous balancing authorities, utilities, and regional transmission organizations. Each of these entities is responsible for their own resource adequacy, ensuring enough resources to serve load across a wide range of power system uncertainties and weather conditions.

Each planning entity typically evaluates their own resource adequacy independently, subject to their own assumptions about power exchanges outside of their region. However, given the nature of an interconnected electricity system, it is important to conduct an integrated resource adequacy assessment across the entire interconnection. Such an assessment can provide a better understanding of how evolving system conditions affect the likelihood of shortfalls in supply, both within planning entity footprints and across their boundaries. It can be argued that such an assessment is essential to understand resource adequacy from a physical system perspective due to inconsistencies in data sources, assumptions and methodologies across independent resource adequacy studies.

This study assesses resource adequacy across the Eastern Interconnection (“wide-area” assessments) to quantify near-term reliability risks and to evaluate how interregional transmission and market assistance between regions can help mitigate those risks. Unlike traditional planning approaches that focus on isolated systems, this analysis adopts a wide-area probabilistic resource adequacy approach. Building on the GridPath RA Toolkit Study,<sup>1</sup> which offered two methods for assessing weather related risk, we adopt the “weather-synchronized” simulation approach to assess resource adequacy under a range of historically observed weather and grid conditions. Our study year is 2028 and we account for expected changes in load, generator retirements and additions, and the increasing role of variable renewable and energy-limited resources. Scenarios are conducted to assess how varying degrees of interregional transfer capability affect outcomes across the interconnection.

A parallel objective of the study is to make the data, tools, and methods available to power system planners and practitioners to facilitate analysis for the Eastern Interconnection. This study leverages the open-source GridPath modeling tool<sup>2</sup> and methods from the GridPath RA Toolkit study, which analyzed resource adequacy across the Western Interconnection. To support transparency and reproducibility, the study publishes a companion dataset that can be adapted and extended by

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1 Hart, E. and Mileva, A., 2022, *Advancing resource adequacy analysis with the GridPath RA Toolkit: A case study of the Western US*, GridLab report, <https://gridlab.org/gridpathratoolkit/>

2 GridPath, <https://gridpath.io/>



planners, researchers, and regulators.<sup>3</sup>

Finally, this study complements a growing body of work in the industry aimed at addressing interregional resource adequacy challenges. The European Network of Transmission System Operators (ENTSO-E) has developed a standardized, pan-European resource adequacy process (ERAA) that offers valuable lessons on harmonizing input data, sharing assumptions, and coordinating cross-border contributions.<sup>4</sup> In the United States, interregional analysis efforts are gaining momentum. The North American Electric Reliability Corporation's (NERC) recent Interregional Transfer Capability Study<sup>5</sup> and its forthcoming pilot study for ERO Wide Area Energy Assessments represent important steps toward establishing a national framework. In parallel, the Energy Systems Integration Group (ESIG) is leading work to define best practices for conducting and institutionalizing wide-area adequacy assessments across regions.<sup>6</sup>

## Key Findings

The primary finding of this study is that resource adequacy outcomes depend significantly on assumptions about interregional transfers. When regions are evaluated in isolation (i.e., assuming no transmission capability across region boundaries), most areas within the Eastern Interconnection experience some level of reliability risk in 2028 (Figure 1). However, allowing for interregional transfers, either at levels consistent with current ISO practices or at full transfer capabilities,<sup>7</sup> substantially reduces loss of load risk, revealing the critical value of geographic diversity. Certain regions such as SERC Southeast, SERC Florida, and ISO New England are shown to be self-sufficient under most scenarios, while others, including PJM South and the Southwest Power Pool, face persistent risk even when interregional transfers are considered.

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3 GridPath EI GitHub Repository, [https://github.com/Telos-Energy/GridPath\\_RA\\_Toolkit\\_EI](https://github.com/Telos-Energy/GridPath_RA_Toolkit_EI)

4 European Network of Transmission System Operators for Electricity (ENTSO-E), *European Resource Adequacy Assessment*, <https://www.entsoe.eu/eraa/>

5 North American Electric Reliability Corporation (NERC), *Interregional Transfer Capability Study*, December 2024, <https://www.nerc.com/pa/RAPA/Pages/ITCS.aspx>

6 Energy Systems Integration Group, *Wide-Area Resource Adequacy Assessments: Probabilistic RA Planning for Interconnected Grids*, 2025, <https://www.esig.energy/redefining-resource-adequacy/>

7 Full transfer capability takes into account region-to-region available transfer capability and region simultaneous transfer capability.

### Moderate Risk

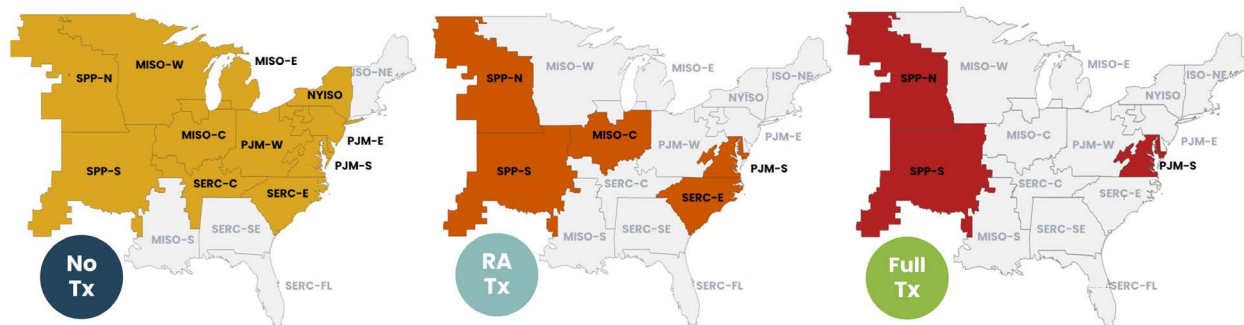
Greater than 0.1 days/year LOLE, but only without interregional transfers

### Elevated Risk

Greater than 0.1 days/year LOLE when using a region's RA import levels

### High Risk

Greater than 0.1 days/year LOLE in all scenarios, even with full transfer capability



**FIGURE 1.** Eastern Interconnection Risk Map by Transmission Scenario

## Top-level findings from the study include the following:

- Most regions exhibit some level of loss of load risk in 2028 assuming significant load growth, generator retirements, and limited generator additions under a case where we exclude any interregional transmission—however, as allowance for interregional transfers increases, loss of load diminishes and most regions resolve any deficiency, relative to a 1-day-in-10-year LOLE standard.
- Loss of load risk is substantially reduced across the system when the analysis mirrors transfer capabilities typically assumed by ISOs or when firm contracts are considered. Only a few areas, including SPP, MISO Central, and PJM South, continue to experience “elevated” LOLE, which means that LOLE exceeds 1 day in 10 years under assumptions of typical ISO market assistance and firm contracts.
- As the analysis considers increasing levels of interregional transfer capability, the frequency and duration of events decline significantly. Under the “Full transmission” scenario, which assumes interregional transmission up to the technical limit, the remaining loss of load events are not only less frequent but shorter in duration, conditions that are well-suited for mitigation through short-duration energy storage or demand-side flexibility.
- While near-term reliability concerns were found in some scenarios, many remaining shortages could be alleviated with efficient solutions such as additional demand response (given many of the events were within 2–4 hours of duration), accelerated deployment of new resources, and improved utilization of existing transmission networks rather than out-of-market interventions to retain aging or uneconomic generation. For context, at the end of 2023 there were 1,100 gigawatts (GW) of generation in the interconnection queues across the Eastern Interconnection.<sup>8</sup> The vast majority of these resources were not included in this study (we only included resources already under construction or have all required regulatory approvals).

<sup>8</sup> Rand J. et al., 2024, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection*, Lawrence Berkeley National Laboratory, <https://emp.lbl.gov/queues>



This study suggests an opportunity for policymakers and system planners to focus on enabling generation and battery storage resource development and enhancing interregional connectivity as the primary strategies to ensure reliability in a changing grid facing fossil-fuel generation retirements.

These results underscore the importance of integrated planning approaches that reflect the electrically connected nature of the Eastern Interconnection. The analysis highlights that surplus capacity in one region can help mitigate shortages in another, provided that transmission infrastructure and market structures enable the transfer. In particular, persistent constraints in subregions like PJM South point to a need for new generation and transmission resources, but results show that this can be mitigated with demand response, targeted clean energy additions, increased interregional transmission capacity, or a combination of these approaches. As such, the study offers important insights into where resource adequacy challenges may emerge, and how strategic investments in generation and transmission can support reliability in a rapidly evolving electric grid.

## Study Limitations

This study provides a wide-area assessment of resource adequacy across the Eastern Interconnection under projected 2028 conditions. While the methodology is rigorous and the insights valuable for regional and interregional planning, the results should be interpreted recognizing these caveats and limitations:

- **Local vs. wide-area focus:** This analysis does not replace ISO- or utility-specific planning studies, nor does it incorporate specific market constructs or procurement processes from local capacity markets. Results will differ from regionally published assessments.
- **Forward projections:** The study evaluates one conceptualization of 2028 conditions, including forecasted load growth, announced retirements, and only resources already under construction. It does not account for potential new resource additions that may be procured, or are in the process of being procured to maintain reliability, or resources that are in interconnection queues.
- **Weather-dependent outages:** The results in this report do not consider temperature-correlated thermal generator forced outages, such as cold-related mechanical failures or natural gas supply constraints. As a result, winter reliability risk may be understated.<sup>9</sup>
- **Limited representation of Canada:** Canadian regions were not modeled in detail due to data limitations. Imports from Canada are included as proxy generation based on historical transfer levels and seasonal constraints.
- **Linkage to other planning studies:** This work was initiated prior to the release of recent policy directives and planning studies. As such, it offers an independent point of reference, grounded in a consistent methodology and an open-source modeling platform.

These caveats and limitations, including the treatment of temperature-dependent thermal outages, expanded future resource scenarios, and Canadian representation are areas of active development and will be addressed in future analysis and data releases.

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<sup>9</sup> Future work is underway to include temperature dependent outage assumptions.

# MOTIVATION

## Background to Resource Adequacy in the Eastern Interconnection

Resource adequacy planning in the Eastern Interconnection faces growing challenges due to rapid changes in the generation mix, load growth, and greater exposure to weather variability. Recent extreme events such as Winter Storm Uri, Winter Storm Elliott, and widespread summer heatwaves have revealed how large-scale weather phenomena can simultaneously affect multiple regions, underscoring the need for a broader view of reliability risk.



Currently, most planning entities<sup>10</sup> evaluate resource adequacy independently, with limited consideration of neighboring systems. When external support is modeled, it is either omitted unless tied to a firm capacity contract, or represented using conservative assumptions about market assistance, often based on historical flows or policy preferences, rather than technical transfer capability. This fragmented approach limits planners' ability to understand the true availability of imports, evaluate the reliability value of interregional transmission, and align capacity accreditation practices across the grid.

This study illustrates how a “wide-area” resource adequacy framework can close those gaps. In the context of this study, we define a wide-area assessment to be one that analyzes an entire interconnection, rather than an individual region within. By modeling the Eastern Interconnection in an integrated fashion, it provides a more accurate assessment of regional interdependence and offers insights into how coordinated planning and shared assumptions can improve reliability outcomes.

## Importance of Wide Area Assessments

While this study focuses on resource adequacy, the broader value of wide-area approaches extends beyond resource adequacy because wide-area resource adequacy assessments offer a framework for improving coordination, transparency, and effectiveness in system planning. The benefits of wide-area assessments<sup>11</sup> include the following:

- **Interregional transmission planning:** Helps identify limitations in current transfer capability and supports the identification of high-value opportunities for new interregional transmission investments for resource adequacy.
- **Scenario consistency:** Promotes the use of harmonized assumptions and scenarios across regions, improving alignment and reducing inconsistencies between neighboring planning efforts.
- **Neighboring system visibility:** Enhances understanding of how changes in adjacent regions, such as shifts in resource mix or demand growth, can influence local reliability outcomes.
- **External assistance evaluation:** Provides a consistent method for comparing reliability outcomes with and without imports, clarifying the degree to which regions rely on external capacity during stressed conditions.
- **Extreme weather event evaluation:** Enables the analysis of geographically widespread events, such as heatwaves and polar vortexes, which can create correlated risks across multiple regions simultaneously.
- **Methodological and metric alignment:** Supports the development of shared modeling practices, input datasets, and performance metrics. This alignment improves transparency and facilitates more consistent accreditation of capacity across regional boundaries.

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<sup>10</sup> In this report, the term “planning entities” is broad and refers to any entity responsible for conducting resource adequacy assessments for a given power system, including independent system operators, utilities, balancing authorities, or states.

<sup>11</sup> Energy Systems Integration Group, *Wide-Area Resource Adequacy Assessments: Probabilistic RA Planning for Interconnected Grids*, 2025, <https://www.esig.energy/redefining-resource-adequacy/>

## Linkage to Policy and Regulatory Discussions

This study is intended to contribute to ongoing policy and regulatory analyses and discussions surrounding the reliability and coordination of the North American electric grid. While the analysis is not designed to replace existing regulatory or planning initiatives, it provides a complementary perspective that can inform and augment those efforts.

The assumptions and inputs used here differ from those in other efforts, enabling a useful point of comparison that can help identify areas of convergence, uncertainty, or methodological advancement. The study also presents a replicable framework that planners and researchers may adopt to strengthen their own assessments. This analysis complements and is relevant to several key industry and regulatory initiatives:

- **NERC interregional transfer capability study (2024):**<sup>12</sup> Provided a system-wide perspective on transfer capability and energy sufficiency during extreme weather conditions. This study utilizes those transfer capabilities and builds on that work by applying a probabilistic resource adequacy framework using a publicly available dataset and open-source tool.
- **Forthcoming NERC energy assessment pilot:** Expected to perform a similar Eastern Interconnection-wide resource adequacy analysis. The present study offers a reference point for methodological comparison and can support refinement of future NERC assessments.
- **FERC Order No. 1920:**<sup>13</sup> Requires that regional transmission plans evaluate projects based on their contribution to resource adequacy. This study directly supports that objective by demonstrating the value of interregional transfer capability under varying system conditions.
- **Potential FERC rulemaking on interregional transmission:**<sup>14</sup> While still under development, the rulemaking process may benefit from the insights presented here, particularly on how interregional flows affect system-level reliability.
- **Executive order (April 8, 2025)**<sup>15</sup> “Strengthening the Reliability and Security of the United States Electric Grid”: Although not conducted in anticipation of this Executive Order, the study is being released at a similar time and offers relevant findings that may support broader reliability objectives. It is intended as a separate resource that operates independent of federal planning efforts.

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12 North American Electric Reliability Corporation (NERC), *Interregional Transfer Capability Study*, December 2024, <https://www.nerc.com/pa/RAPA/Pages/ITCS.aspx>

13 Federal Energy Regulatory Commission, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Docket No. RM21-17-001; Order No. 1920-A, November 21, 2024, <https://www.ferc.gov/media/e-1-rm-21-17-001>

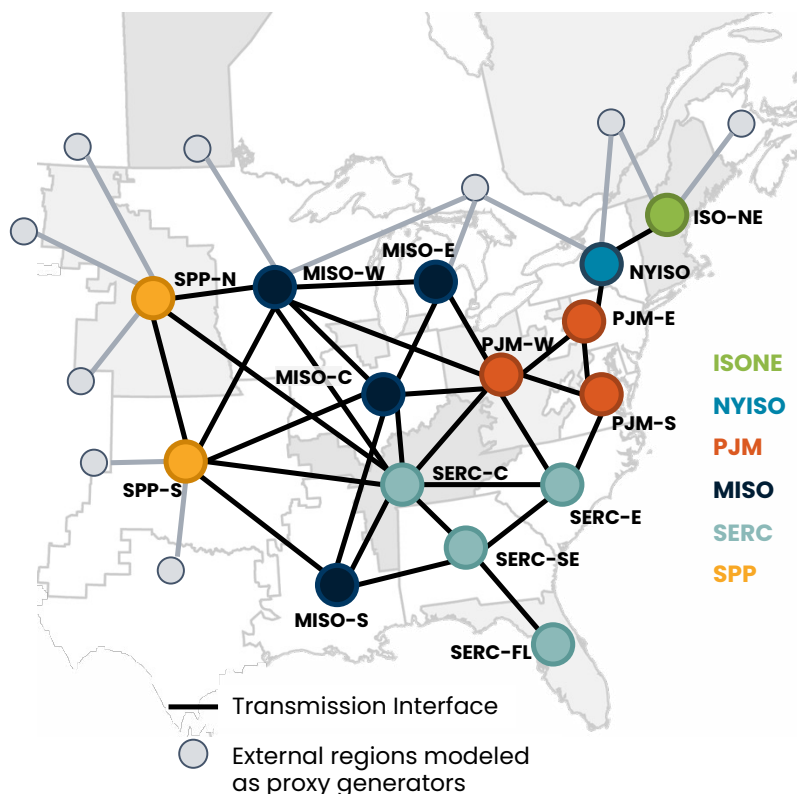
14 Federal Energy Regulatory Commission, *Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements*, Docket No. AD23-3-000.

15 The White House, *Executive Order on Strengthening the Reliability and Security of the United States Electric Grid*, April 8, 2025, <https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/>

## SCOPE AND SCENARIOS

### Study Topology

This study covers the full Eastern Interconnection, encompassing all major organized market regions, such as PJM, MISO, SPP, ISONE, and NYISO, as well as the vertically integrated utilities in the Southeastern United States. The analysis is structured to reflect the actual operational and planning topology across the interconnection. The regional study topology and transfer interfaces (Figure 2) are based on the North American Electric Reliability Corporation (NERC) Interregional Transmission Coordination Study (ITCS) transmission planning regions.<sup>16</sup>



**FIGURE 2.**

Map of Study Topology in the Eastern Interconnection

<sup>16</sup> North American Electric Reliability Corporation (NERC), *Interregional Transfer Capability Study, Transfer Capability Analysis (Part 1)*, August 2024, [https://www.nerc.com/pa/RAPA/Documents/ITCS\\_Part\\_1\\_Results.pdf](https://www.nerc.com/pa/RAPA/Documents/ITCS_Part_1_Results.pdf)

PJM, MISO, and SPP are subdivided into multiple internal sub-regions, each with explicit internal transmission constraints. This level of granularity reflects locations of load, generation, and transmission availability within these large RTOs, but do not align directly with RTO load or capacity market zones.

SERC is divided into four assessment areas: SERC Southeast, Central, East, and Florida. These aggregated regions consist of multiple balancing authorities, utilities, and planning coordinators. While not reflective of each individual entity, this structure allows for aggregated modeling across the Southeast.

ISONE and NYISO are each modeled as single regions but have multiple capacity zones and internal transmission constraints within their footprint.

External connections to Canada, the Western Interconnection, and ERCOT are represented as proxy generating resources. These proxies are defined based on historical transfer levels and are assigned maximum import limits and daily energy budgets consistent with historical observed seasonal flows. While not a full representation of neighboring system's supply and resource balance, these modeled inerties allow for the evaluation of reliability impacts from potential external assistance.

## Transmission Representation and Interfaces

The transmission network in this study is modeled using a regional “pipe-and-bubble” framework that captures transfer capabilities between regions. This approach simplifies the underlying AC power flow into a set of bi-directional transmission interfaces in which the constraints are based on transfer analysis conducted in the NERC ITCS.<sup>17</sup>

The transmission technical limits are composed of two assumptions. The first constraint, called region-to-region transfer interface, characterizes the maximum amount of power flow across an interface given thermal and voltage constraints under N-1 security conditions. Region-to-region transfer interfaces are determined in a non-coincident manner, in which each interface is assessed independently with a single importing “sink” region and a single exporting “source” region. While effective for isolating interface-specific capability, this methodology allows for shared transmission elements across multiple interfaces, potentially leading to overlapping use of the same physical infrastructure.

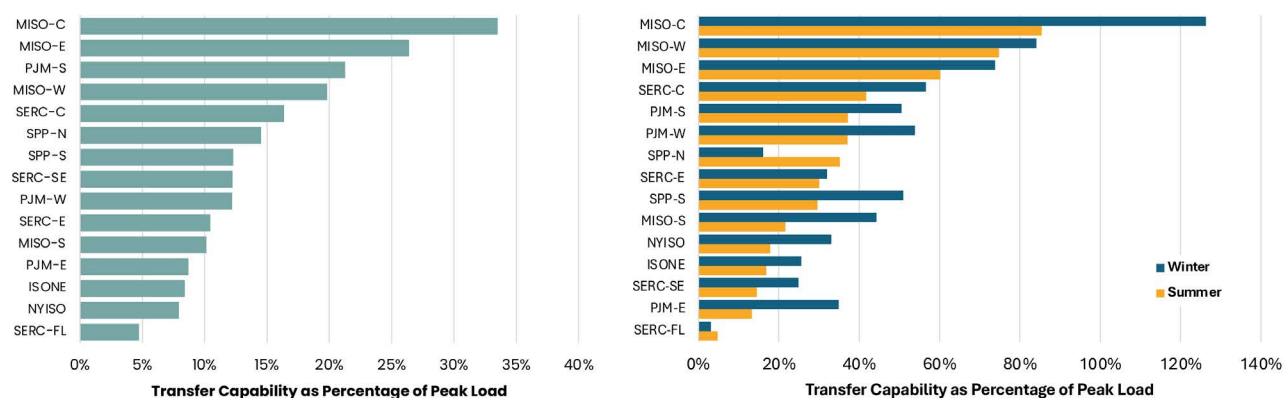
The second constraint, called simultaneous import capability, represents the maximum aggregate inflow the region can receive across all of its importing interfaces at once, while avoiding thermal and voltage overloads in N-1 conditions. This coincident import constraint ensures that the aggregate use of transmission capacity into a region respects technical limitations during system-wide stress events.

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<sup>17</sup> *ibid.*

In summary, each region in the model is characterized by:

- **Region-to-region transfer interface:** A set of bilateral transfer interfaces with adjacent regions, each defined by a directionally limited flow based on region-to-region transfer capabilities, which establish the region's non-coincident transfer capabilities;
- **Total simultaneous import capability:** A regional total import constraint that caps simultaneous inflows from multiple neighboring regions, which caps the region's coincident transfer capability. Consistent with the NERC method, the total simultaneous import interface excludes DC-only ties.



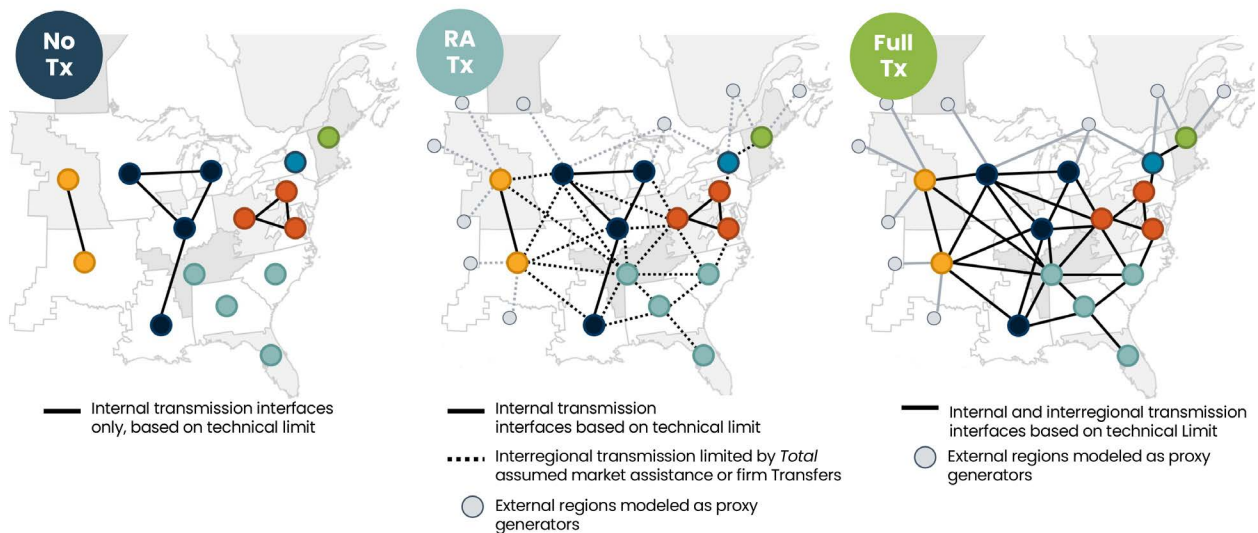
**FIGURE 3.** Coincident (left frame) and Non-Coincident (right frame) Transfer Capability by Region Normalized as a Percentage of Peak Load

A visual representation of these constraints is shown in Figure 3, where each region or sub-region's total import capability (left frame) and the sum of its non-coincident bilateral limits (right frame) are normalized relative to peak load. In all regions, the total import capability represents a fraction of total non-coincident capability. This framework preserves operational realism while maintaining computational efficiency, allowing the model to represent both directional transfers and aggregate system limitations within a probabilistic resource adequacy analysis. Individual transfer capabilities are provided in the data tables found on the project website.

## Scenarios Evaluated

To evaluate the role of interregional transfers in supporting resource adequacy, the study examined a set of transmission scenarios that vary the extent to which each region can utilize the transfer capability described in the prior section. While the underlying transmission topology and transfer capabilities remained constant across scenarios, the degree of permissible flows across regional boundaries was adjusted to isolate the impact of market assistance during periods of loss of load risk.

Each scenario represents a different policy or operational assumption regarding how much external support is accessible to a region during loss of load events. All other modeling inputs, such as resource capacity, load, weather years, and outage sampling, were held constant across scenarios to ensure that differences in results reflect transmission usage alone.



**FIGURE 4.** Interregional Transmission Scenarios Evaluated

## Three transmission scenarios were analyzed as follows:

### NO TRANSMISSION (NO TX)

Regions are limited to internal transfers only. While *intraregional* transfer constraints within an RTO (MISO, PJM, SPP) continue to reflect the technical capability identified in the NERC ITCS, no *interregional* imports from neighboring regions are allowed. This case serves as a reference point for assessing the value of interregional support.

### RESOURCE ADEQUACY TRANSMISSION (RA TX)

This scenario allows limited interregional transfers based on market assistance assumptions used in ISO-specific resource adequacy studies or firm commitments reported in NERC assessments. Interconnections to Canadian regions and the Western Interconnection are modeled as proxy generators, consistent with historical import behavior.

### FULL TRANSMISSION (FULL TX)

Represents the maximum utilization of the transmission network, using the full set of technical interface limits from the NERC ITCS. This scenario evaluates the theoretical benefits of unconstrained interregional support within the technical capabilities of the grid.

In all cases, each region's maximum import capability is bounded by the simultaneous coincident import constraint established in the NERC ITCS, ensuring that system-wide flows remain physically feasible. Interfaces are not modeled seasonally but utilize the interface limit associated with each region's highest risk season.

# ASSUMPTIONS AND METHODOLOGY

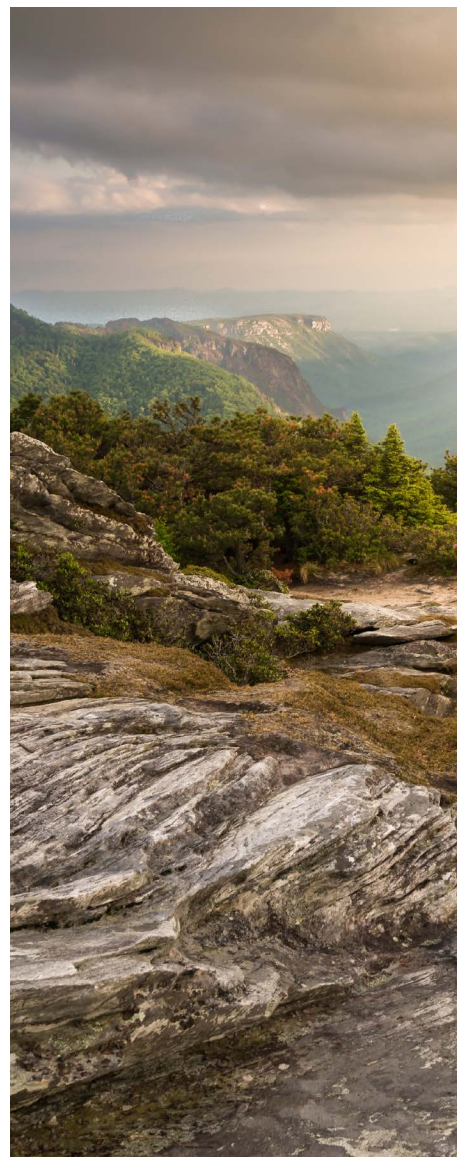
## GridPath

This study leverages GridPath, an open-source power system modeling platform that is developed and maintained by Sylvan Energy Analytics. GridPath is designed to support a range of planning applications, including capacity expansion, production cost simulation, and resource adequacy assessment. For the purposes of this analysis, only the resource adequacy module was used, with a focus on capturing probabilistic reliability outcomes under varying transmission assumptions and weather conditions.

The study methodology builds on a compendium of tools and datasets initially developed for a similar assessment of the Western United States.<sup>18</sup> The code and tools for the GridPath platform is open source and hosted on GitHub,<sup>19</sup> providing a foundation for further collaboration across the industry.

## Weather-synchronized, sequential, Monte Carlo Simulations

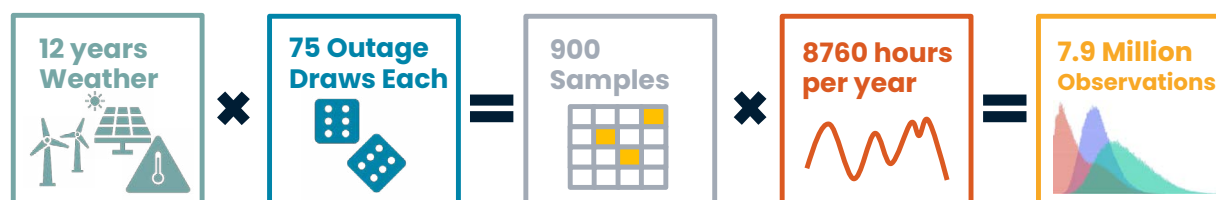
The resource adequacy analysis in this study was conducted using a probabilistic simulation framework designed to account for the chronological and correlated nature of resource availability in a grid with increasing levels of variable renewable energy and energy-limited resources. Specifically, the study employed sequential Monte-Carlo simulations to estimate loss of load risk across a range of system conditions. This approach, which retains unaltered weather years and correlations



<sup>18</sup> Hart, E. and Mileva, A., 2022, *Advancing resource adequacy analysis with the GridPath RA Toolkit: A case study of the Western US*, GridLab report, <https://gridlab.org/gridpathratoolkit/>

<sup>19</sup> Blue Marble Analytics, *GridPath [Computer software]*, GitHub, <https://github.com/blue-marble/gridpath>

with demand and generation profiles, but creates multiple samples of random forced outages, was called the “weather-synchronized simulation” mode in the GridPath RA Toolkit study.



**FIGURE 5.** Weather-synchronized, sequential, Monte Carlo Simulations

A simplified generator dispatch framework was used to schedule available generation on an hourly basis, subject to constraints on transmission flows and storage operation. Storage resources are scheduled to shift energy across time in response to price signals, while ensuring sufficient state of charge is maintained during periods of system scarcity. This outcome is enforced through a high value of lost load (VoLL). Interregional transmission flows are modeled as a resource of last resort, meaning interregional flows only occur after a region has exhausted all available local capacity. This allows the model to isolate flows for reliability and allows for a regional attribution of loss of load events.

At the core of the methodology is a sequential simplified generator dispatch model, which assesses a full year (8,760 hours) of hourly resource availability for each simulation, capturing time-varying changes in load, wind, solar output, generator availability, and storage behavior. This simplified generator dispatch model schedules generation and storage resources to arbitrage hourly reserves and minimize loss of load expectation. Monte Carlo sampling is used to introduce variability in generator unplanned outages, drawing from unit-specific outage rates and repair time distributions to simulate 75 different outage conditions for each weather year, equating to 900 modeled years of simulation.

The model was run across 12 years of historical weather (2007–2013 and 2019–2023), using two different approaches for hourly weather-synchronized load, wind, and solar profiles. This study intentionally preserved chronological weather data across a limited number of historical years rather than utilize a Monte Carlo sampling of weather days that is often performed in other resource adequacy studies.<sup>20</sup> Additionally, year-to-year hydropower variability was not sampled in this study due to its relatively limited contribution to total resource adequacy in the Eastern Interconnection; a median hydro year profile was used.

<sup>20</sup> In many resource adequacy studies, when coherent weather data for wind, solar, and load is limited, Monte Carlo simulation can be used to synthesize many years of random, but plausible, conditions using historical data, grouping similar days together, and resampling. In contrast, this study utilized a weather synchronized simulation approach, preserving the meteorological conditions as they occurred across the Eastern Interconnect in the 12-years evaluated. For more information contrasting the two approaches, refer to: Hart, E. and Mileva, A., 2022, *Advancing resource adequacy analysis with the GridPath RA Toolkit: A case study of the Western US*, GridLab report, <https://gridlab.org/gridpathratoolkit/>

## Peak Demand Forecasts and Hourly Load Profiles

Peak demand forecasts were developed using the regional projections of load in 2028 based on recent forecasts from the ISOs and the NERC Long-Term Reliability Assessment (LTRA) for non-ISO areas. The modeling used gross demand prior to reductions for behind-the-meter solar generation, which was modeled as a supply-side resource. These forecasts incorporate up-to-date assumptions, including significant new data center-driven demand growth in several regions.

Hourly load profiles were constructed for each of the 12 historical weather years. While the study utilized historical weather conditions, all data was applied to a load and resource mix that represents a 2028 future study year. In other words, historical weather observations were applied to a future portfolio, and the study simulated potential future resource availability.

Different processes were used to create weather-correlated load profiles for 2007–2013 and 2019–2023, respectively. The first process used *simulated* data available through the input files of the National Renewable Energy Laboratory (NREL) ReEDS model, which provide hourly load profiles across the country (at a sub-regional level) for different future years and for the 2007–2013 weather years.<sup>21</sup> In order to reconcile the profiles from this source with the NERC LTRA and ISO forecasts, the “NREL-ReEDS” hourly profiles were scaled so that the median peak demand and annual energy across the seven simulated years matched the 2028 NERC LTRA and ISO peak and energy forecasts for each region.

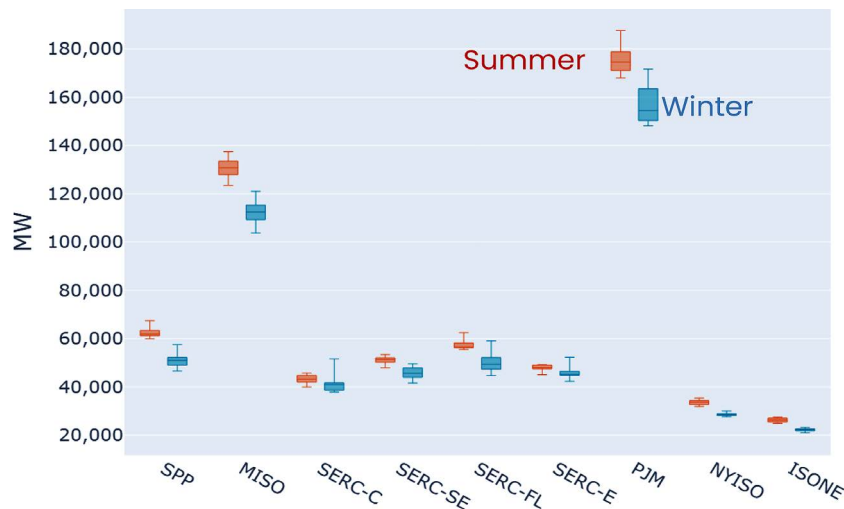
Given the limited number of years available in the NREL-ReEDS input files, additional weather years were included using a second approach to generate weather-correlated load profiles for 2019–2023; this process leveraged *historical observations* from 2019–2023. These five years reflect the most recent data available from the EIA Form 930 dataset, which includes consistent reports for all the balancing authorities in the Eastern Interconnection. The historical data was scaled up to a forecasted 2028 study year such that the median peak and energy across the five years aligned with the forecast, but allowing for variation due to weather. The load scaling methods for both approaches are discussed further in the NERC ITCS.<sup>22</sup>

Both methods were developed to preserve weather-driven variation both in the timing of peak demand within a year, and the magnitude of peak demand across weather years. All regions are modeled as summer-peaking under normal conditions, though several regions (including SERC-C, SERC-FL, SERC-E, and PJM) had dual summer and winter peaks under certain weather conditions. Seasonal peak variation was captured at  $\pm 5$  percent for summer and  $\pm 10$  to 15 percent for winter. Seasonal peak demand for each region is provided in Figure 6, with a range based on the weather year simulated.

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21 Awara, S., et al., 2023, *2023 Standard Scenario Report: A U.S. Electricity Sector Outlook*, National Renewable Energy Laboratory, <https://docs.nrel.gov/docs/fy24osti/87724.pdf>

22 Appendix B, North American Electric Reliability Corporation (NERC), *Interregional Transfer Capability Study*, December 2024, [https://www.nerc.com/pa/RAPA/Documents/ITCS\\_Part2\\_Part3.pdf](https://www.nerc.com/pa/RAPA/Documents/ITCS_Part2_Part3.pdf)



**FIGURE 6.**

Seasonal gross peak demand (MW) by Region

## Hourly Wind and Solar Profiles

Similar to the hourly load profiles, renewable energy profiles were developed using a combination of two approaches to cover the same 12-weather years. In the first approach, simulated data from NREL's Wind Integration National Dataset Toolkits (WIND Toolkit) and National Solar Radiation Database (NSRDB) were used to develop hourly aggregate wind and solar profiles for each region and weather years 2007–2013. A bias correction process was applied to align modeled profiles with observed historical generation from EIA Form-930, ensuring consistency between synthetic and empirical data.

A second approach was used for the 2019–2023 weather years that leveraged historical hourly observations from EIA Form-930 (the same data source that provided load information for the same period). For these weather years, wind and solar profiles were based on reported generation data for each balancing area and converted to hourly capacity factors based on installed capacity of wind and solar during the same time period. These hourly capacity factors were then applied to 2028 projected levels of wind and solar capacities.

## Generator Capacities and Retirements

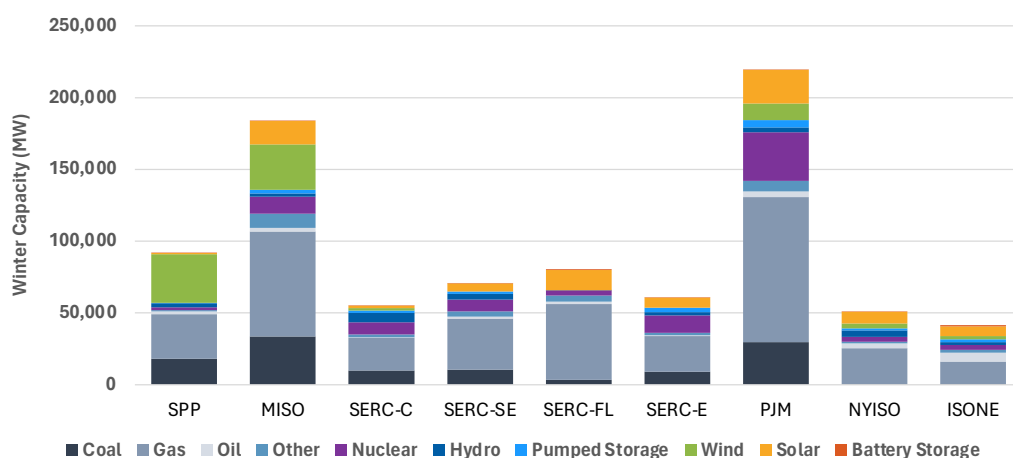
Generation capacity assumptions are based on the U.S. Energy Information Administration (EIA) Form 860 dataset<sup>23</sup> expected to be online by 2028. The analysis intentionally adopts a conservative approach: it includes all announced retirements but limits new builds to only those projects that are under construction or have all required regulatory approvals. The purpose is not to predict the most likely 2028 scenario, but to quantify potential resource adequacy risk under limited new resource deployment. Figure 7 illustrates the capacity by resource type and region for 2028.

Generator data were aggregated to the transmission planning region level, mapped using a combination of state boundaries, balancing authority areas, and manual assignments where

23 U.S. Energy Information Administration, *Form EIA-860 (2023)*, <https://www.eia.gov/electricity/data/eia860/>

necessary. The majority of new capacity is from wind, solar, and storage technologies. Based on unit status codes in the EIA Form 860 dataset, limited new natural gas capacity is assumed, even in regions facing large retirements. In total, the system reflects approximately 30 GW of coal retirements, concentrated in SPP (2.6 GW), MISO (13.4 GW), SERC-C (4.5 GW), and PJM (7.8 GW).

Demand response and behind-the-meter solar PV were modeled as supply-side resources based on data provided by ISO reports where available and supplemented by the NERC Long Term Reliability Assessment when needed.



**FIGURE 7.**

**2028 Capacity by Region, by Resource Type (MW)**

*Note: RTO regions in SPP, MISO, and PJM are aggregated from the transmission topology*

## Generator Outages

Thermal generator outages were modeled using a probabilistic sampling process based on unit-level forced outage factors from the Generating Availability Data System (GADS), differentiated by technology type and unit size. This outage modeling was conducted with the GridPath Data Toolkit (using methods developed in the GridPath RA Toolkit study). We simulated unit-level outage statistics and then aggregated them into fleet-level availability profiles to be used as inputs to the GridPath model.

While no correlation across units or weather conditions was assumed in this version of the model, outages were sampled independently and aggregated by region and fuel type. This represents a key limitation of the current study, as it does not yet capture weather-dependent outage risk or fuel supply constraints, which are areas identified for future enhancement.

## SCENARIO INSIGHTS AND LESSONS

### Key Scenario Findings

The results of this study reveal clear patterns in the geographic and temporal distribution of resource adequacy risk across the Eastern Interconnection under varying transmission assumptions. As shown in the Eastern Interconnect risk map (Figure 8), most regions exhibit moderate to high loss of load risk in 2028 across the different transmission scenarios. This resource adequacy outlook is conservative; the analysis assumes significant load growth that may not come to fruition, announced generator retirements, and limited generation additions (only those generators under construction or that have all required regulatory approvals are included). The value of erring on the side of conservatism is that it provides insight into the value of policy reforms, such as accelerated interconnection processes, a sense of the potential capacity shortfall under conservative assumptions, and the value of interregional and regional coordination. These results will not be relevant for a future with less demand growth.

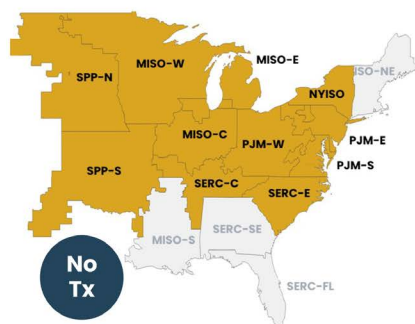
The loss of load risk is highly dependent on the assumed interregional transmission and market assistance available, as loss of load events are unlikely to occur simultaneously across the Eastern Interconnection. As allowance for interregional transfers increases, loss of load diminishes, and most regions resolve any deficiency.



***This resource adequacy outlook is conservative; the analysis assumes significant load growth that may not come to fruition, announced generator retirements, and limited generation additions***

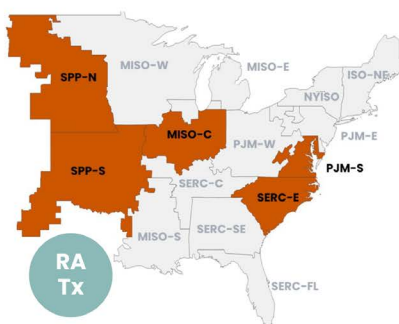
### Moderate Risk

Greater than 0.1 days/year LOLE, but only without interregional transfers



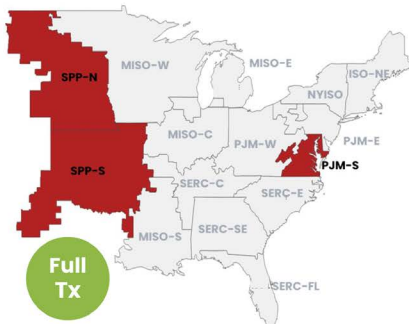
### Elevated Risk

Greater than 0.1 days/year LOLE when using a region's RA import levels



### High Risk

Greater than 0.1 days/year LOLE in all scenarios, even with full transfer capability



**FIGURE 8.** Eastern Interconnection Risk Map by Transmission Scenario

The risk map can be interpreted as follows:

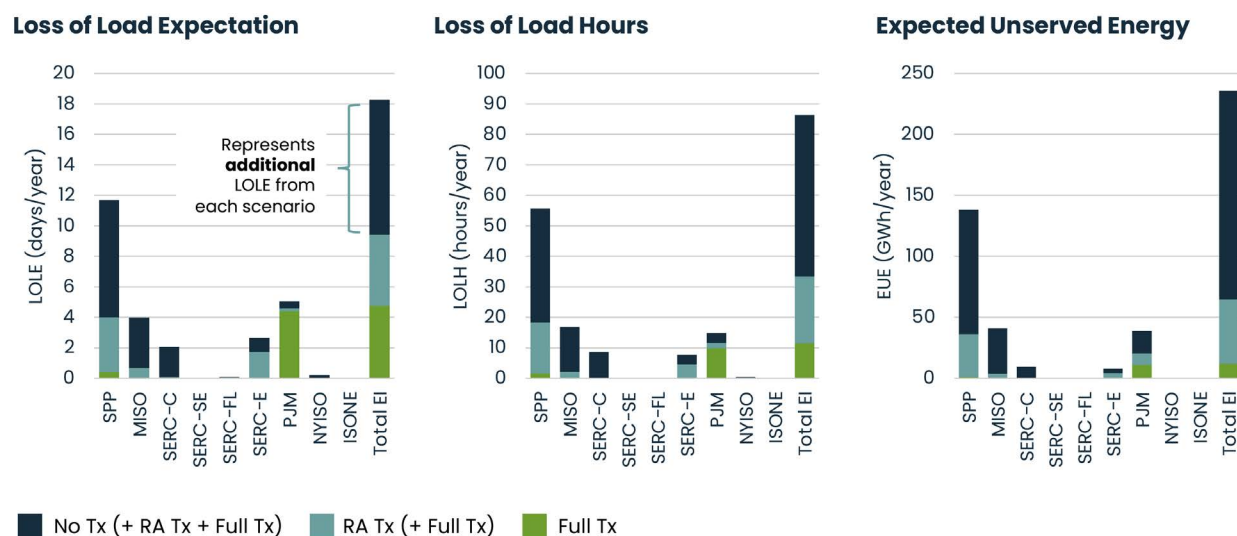
- **Moderate loss of load risk** indicates a region has a loss of load expectation (LOLE) greater than 1-day-in-10-years (0.1 days/year) when evaluated in isolation (No Tx scenario), when interregional transfers are not assumed.
- **Elevated loss of load risk** indicates a region continues to have an LOLE greater than 1-day-in-10-years even when accounting from some, albeit limited, market assistance (RA Tx Scenario) used in ISO studies or firm transfer assumptions.
- **High loss of load risk** indicates the region continues to have LOLE greater than 1-day-in-10-years even when assuming *technical* transfer capability from neighbors and assuming full transfer capability between regions.

Only ISO New England, SERC Southeast, and SERC Florida meet the commonly used reliability criterion of 0.1 days/year loss of load expectation (LOLE) in all transmission scenarios, including the No Transmission (No Tx) scenario. In contrast, under the Resource Adequacy Transmission (RA Tx) scenario, which reflects transfer capabilities typically assumed by ISOs or firm contracts reported in NERC assessments, risk is substantially reduced across the system. Only a few areas, including SPP, MISO Central, and PJM South, continue to experience “elevated” LOLE, which means that LOLE exceeds 1 day in 10 years when assuming typical transfer capabilities and firm contracts.

The Full Transmission (Full Tx) scenario demonstrates the potential benefits of fully utilizing available interregional transfer capability. In this case, nearly all regions meet the reliability standard, with deficiencies persisting only in SPP and PJM South. These remaining gaps could be addressed through additional transmission investment, targeted clean energy additions, or potentially load flexibility.

***Under the “Resource Adequacy Transmission scenario”, which reflects transfer capabilities typically assumed by ISOs or firm contracts, risk is substantially reduced across the entire system. Only SPP, MISO Central and PJM South experience “elevated” LOLE, which we define as a region having more than 1 day in 10 years LOLE when assuming typical transfer capabilities and firm contracts.***

The results in Figure 9 show the loss of load expectation (LOLE) (left frame), loss of load hours (LOLH) (middle frame), and expected unserved energy (EUE) (right frame) for each region. The results are shown in a stacked column chart, showing additional loss of load events as the transmission system assumptions are made more restrictive.



**FIGURE 9.** Summary Statistics of Resource Adequacy by Region, Segmented by Scenario



Table 1 shows the loss of load expectation by region and scenario. We summarize the trends and provide some explanations for the trends in the table.

- **PJM** and **SPP** exhibit the highest levels of loss of load risk across the Eastern Interconnection, particularly when interregional transfers are limited and new resources are not added.
- Within **PJM**, risk is concentrated in the **PJM South** subregion, which faces both transmission constraints, resource retirements, and high load growth driven primarily by new data centers. These localized transmissions constraints limit the ability of surplus capacity from **PJM East**, **PJM West**, and **SERC East** to serve load in **PJM South**.
- **SPP** shows persistent risk in both its northern and southern subregions, split roughly evenly between the two. These risks remain elevated even in the Full Tx scenario, suggesting the need for additional internal resources or external transfer capability.
- The elevated risk in PJM-South and SPP is concentrated in a limited number of historical weather years, particularly during major summer heat events in 2011, 2012, 2022, and 2023.
- In **MISO**, moderate resource adequacy risk is primarily observed in **MISO Central**. While MISO's geographic position and strong interregional ties reduce overall risk in the Full Tx scenario, some vulnerabilities remain under more limited transfer assumptions.
- **SERC regions** show moderate risk in **SERC Central** if imports are not assumed, and elevated risk in **SERC East** when assuming only firm imports. **SERC Southeast** and **SERC Florida** are reliable under all transmission scenarios.
- **NYISO**, when evaluated without interchange to neighbors, has a loss of load expectation of 0.2 days/year, but this is fully mitigated when the RA Tx market assistance from neighbors is included. This allows flows from ISONE, PJM-E, and Canadian regions during risk periods.
- Only **ISO New England**, **SERC Southeast**, and **SERC Florida** demonstrate sufficient resource adequacy in all scenarios evaluated, reflecting robust internal generation and manageable load levels.

**TABLE 1.** Loss of Load Expectation by Region, by Scenario

| Region          | No Tx        | RA Tx      | Full Tx     |
|-----------------|--------------|------------|-------------|
| <b>SPP</b>      | 11.68        | 4.00       | 0.40        |
| SPP-N           | 8.94         | 3.18       | 0.27        |
| SPP-S           | 10.82        | 3.61       | 0.18        |
| <b>MISO</b>     | 3.97         | 0.67       | -           |
| MISO-W          | 1.22         | 0.07       | -           |
| MISO-C          | 3.78         | 0.67       | -           |
| MISO-E          | 2.80         | 0.05       | -           |
| MISO-S          | 0.11         | 0.03       | -           |
| <b>SERC-C</b>   | 2.07         | 0.08       | -           |
| <b>SERC-E</b>   | 2.64         | 1.73       | -           |
| <b>SERC-FL</b>  | 0.08         | 0.06       | -           |
| <b>SERC-SE</b>  | -            | -          | -           |
| <b>PJM</b>      | 5.05         | 4.58       | 4.39        |
| PJM-W           | 0.26         | 0.04       | -           |
| PJM-S           | 5.05         | 4.58       | 4.39        |
| PJM-E           | 0.22         | 0.11       | -           |
| <b>NYISO</b>    | 0.21         | -          | -           |
| <b>ISONE</b>    | 0.01         | -          | -           |
| <b>Total EI</b> | <b>18.26</b> | <b>9.4</b> | <b>4.75</b> |

## Temporal Risk Characteristics

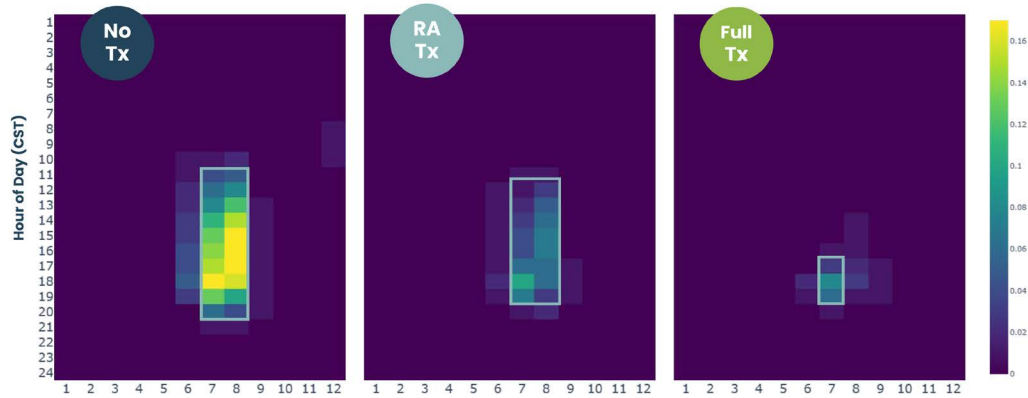
The seasonal breakdown in Figure 10 shows LOLE in days per year (left frame) and EUE (right frame) for the full Eastern Interconnection, segmented by month. The figure shows that risk is concentrated in summer months, primarily July and August, while winter risk is minimal. However, it is important to note that this analysis does not yet account for correlated thermal outages or gas supply constraints, which could increase winter risk. This is especially true for regions like MISO-S, PJM-S, SERC-C, SERC-E, and SERC-SE, which can experience rare, but extreme cold events and have a gas fleet that is less winterized than northern regions. Even without assuming weather dependent outages or fuel supply disruption for thermal resources, a loss of load event occurs under Winter Storm Elliott weather conditions for the scenario that excludes interregional transmission.



**FIGURE 10.**

LOLE (left) and EUE (right) by Month and by Transmission Scenario

Another way to visualize the timing of resource adequacy risk is through the heatmap shown in Figure 11, which displays the percentage of loss of load events by month and hour of the day across the three transmission scenarios. The results clearly show that system risk is heavily concentrated in the summer months, particularly July and August, and from afternoon to evening hours (roughly 14:00 to 20:00). This pattern is most pronounced in the No Tx scenario, when risk is highest. As transfer capability increases across the scenarios (from left to right), the overall frequency and intensity of loss of load events decline, and the window of elevated risk narrows significantly.



**FIGURE 11.** Heatmap of Loss of Load Probability by Month and Hour of Day, by Scenario

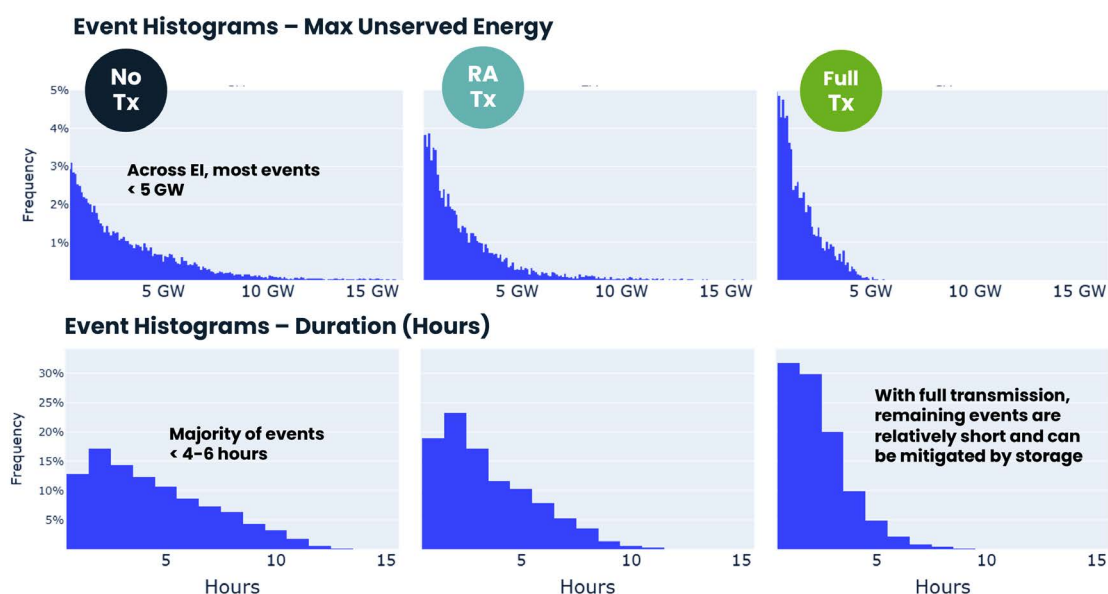
Looking past 2028, as the system continues to integrate higher levels of renewable energy and storage, the timing of risk is expected to evolve. First, the shift of risk will push later into the evening as solar output declines, and eventually expand into the winter season as electrification drives up heating loads and variable renewable energy droughts become more impactful. While winter reliability risk is limited in this analysis, this is due to the exclusion of correlated thermal outages and fuel supply disruptions, which are known drivers of winter resource adequacy events. Future assessments should incorporate these dynamics to fully capture the evolving shape of grid reliability risk.

## Event Characteristics

Figure 12 provides a summary of the maximum magnitude (MW) and duration (hours) of loss of load events across one or more regions in the Eastern Interconnection under each transmission scenario. The top frame illustrates the maximum unserved load for each event, while the bottom frame shows the corresponding duration in hours. These results, which are compiled across all simulations, represent a wide range of system conditions, weather, and loss of load events. Across all scenarios, the vast majority of events are relatively small in scale. Even in the No Transmission case, most events are under 10 GW, with a significant concentration below 5 GW (for reference, the 2028 projected non-coincident peak demand is over 625,000 GW across the Eastern Interconnection).

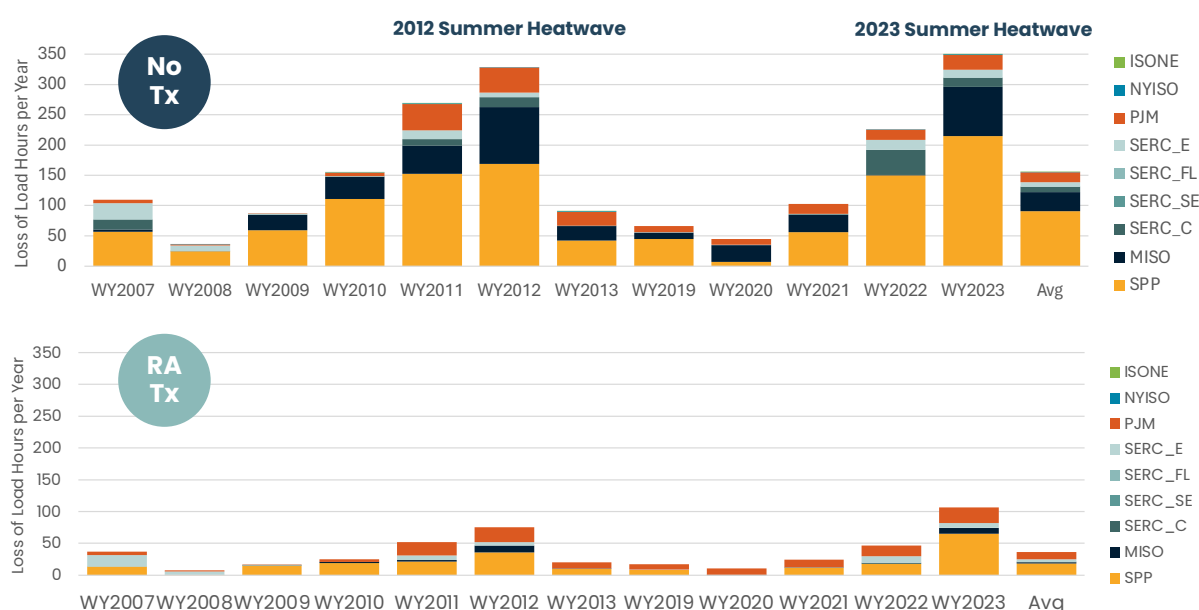
***As the allowed transfers increase across the transmission scenarios, both the frequency and duration of events decline significantly. Under the Full Tx scenario, the remaining loss of load events are not only less frequent but also shorter in duration, conditions that are well-suited for mitigation through short-duration energy storage or demand-side flexibility.***

In terms of duration, most events last less than 4 to 6 hours, particularly in scenarios where interregional transmission is available (RA Tx and Full Tx). As the allowed transfers increase across the transmission scenarios, both the frequency and duration of events decline significantly. Under the Full Tx scenario, the remaining loss of load events are not only less frequent but also shorter in duration, conditions that are well-suited for mitigation through short-duration energy storage or demand-side flexibility.



**FIGURE 12.** Maximum Unserved Energy, MW (top frame) and Event Duration, hours (bottom frame)

Understanding the meteorological drivers of resource adequacy risk is critical to interpreting system reliability patterns. While this study evaluated over 105,000 hours of system operation across 12 historical weather years, the majority of resource adequacy risk is concentrated in a handful of extreme weather events. Figure 13 illustrates the total loss of load hours by weather year, segmented by region, for both the No Transmission (No Tx) and Resource Adequacy Transmission (RA Tx) scenarios. The results show that Weather Years 2012, 2021, 2022, and 2023 account for a disproportionate share of reliability risk, driven primarily by severe summer heatwaves.

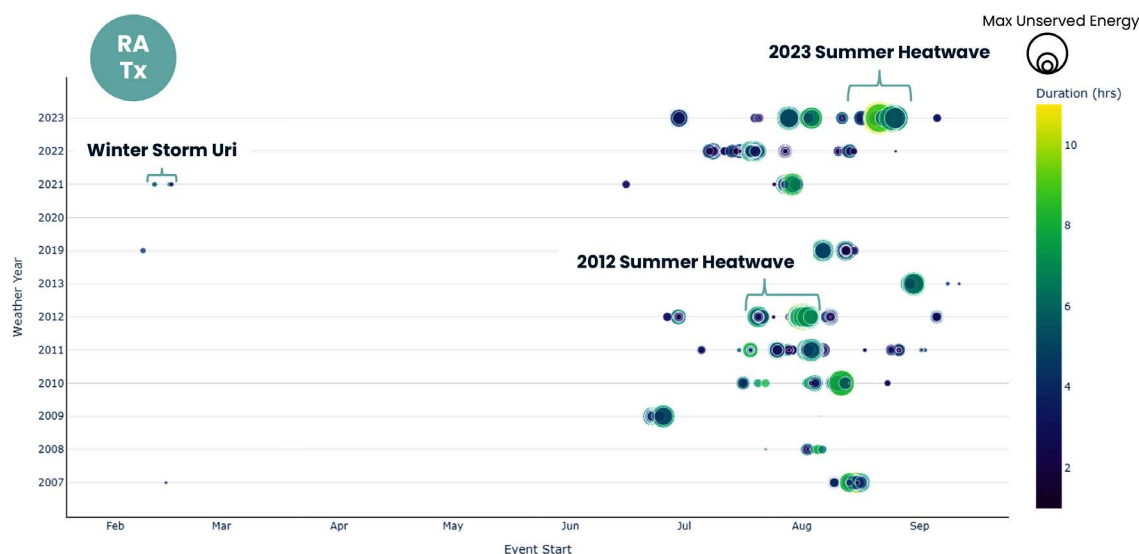


**FIGURE 13.** Loss of Load Hours by Weather Year and Region

The 2012 summer heatwave is particularly noteworthy. Occurring at the end of June and early July, this period marked the hottest weather event in over 40 years for PJM, the first-hottest for SERC, the second-hottest for MISO, and the fifth-hottest for SPP. These conditions triggered significant and large loss of load events in the No Tx scenario. However, with increased interregional transfer capability in the RA Tx scenario, the risk profile changes substantially—while total risk remains elevated during these weather years, the number of affected regions is significantly reduced, demonstrating the role of geographic diversity and transfer capability in mitigating localized capacity shortfalls.

These findings emphasize that while resource adequacy challenges are inherently weather-dependent, strategic use of transmission and planning coordination can significantly reduce the number of regions exposed to risk during even the most extreme events.

Another way to visualize system risk is through the timeline plot shown in Figure 14, which presents each unserved energy event across the Eastern Interconnection in terms of its timing (x-axis), weather year (y-axis), duration (color), and magnitude (bubble size). Small circles represent unserved energy events of less than 1 GWh while the largest circles represent events of greater than 10 GWh. This event-level view offers a complementary perspective to annual summary statistics by providing direct insights into the “when,” “how long,” and “how large” of individual loss of load events.



**FIGURE 14.** Timeline of Resource Adequacy Events

Notably, two periods dominate the risk landscape: the 2012 summer heatwave and the 2023 summer heatwave, both of which are visible in the form of dense clusters of large, long-duration events. These periods align with previously identified reliability stress points, reinforcing the importance of specific weather years in driving system-wide adequacy challenges. The Winter Storm Uri event in early 2021 is also identifiable, though it appears as a short, relatively contained event, presumably due to the exclusion of temperature-dependent thermal generator outages in this analysis.

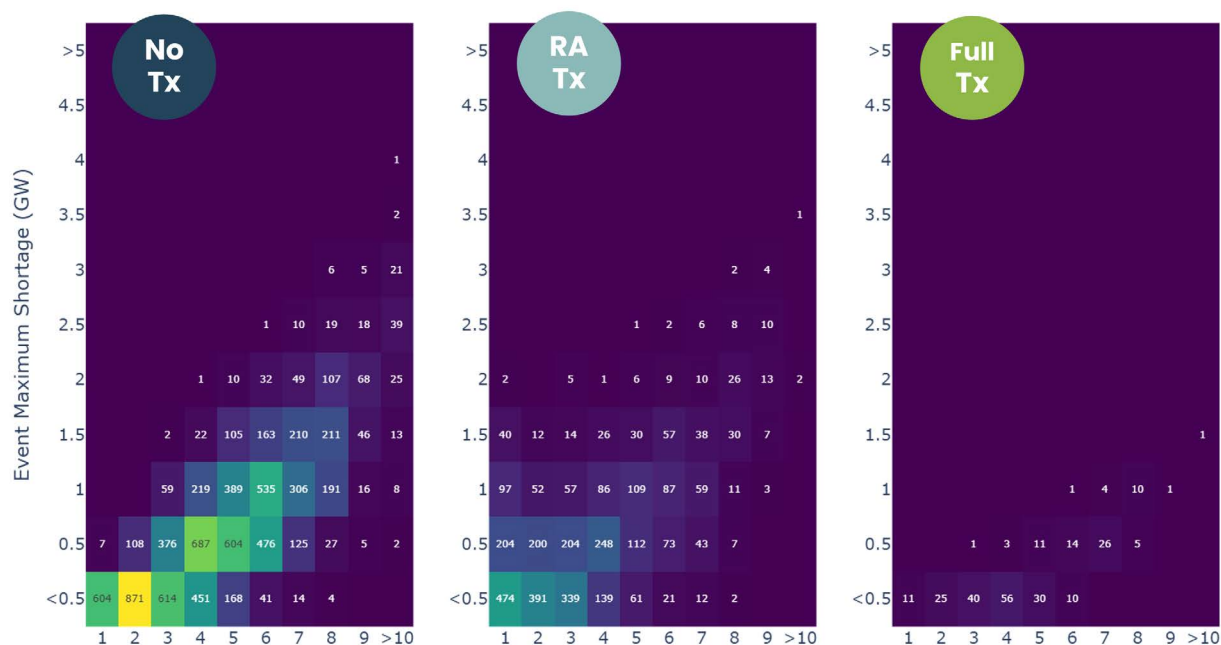
By using this type of visualization, practitioners can move beyond average risk metrics and begin to characterize resource adequacy in terms of event behavior, including size, frequency, duration,

and timing of loss of load events. This enables a more actionable form of planning, where decision-makers can align mitigation strategies with the specific nature of reliability threats rather than relying solely on aggregate indicators.

## Analysis of Risk Mitigation in PJM-South

To explore targeted strategies for mitigating reliability risk in the highest-risk subregion, a sensitivity analysis was performed for PJM-South. This subregion was shown to have the most persistent and elevated loss of load risk across all transmission scenarios. The analysis leveraged the event-level characteristics shown in the previous section to help “right-size” mitigation measures based on actual shortage durations and magnitudes, rather than relying solely on static reserve margin targets.

Figure 15 presents the distribution of unserved energy events by duration and magnitude under each transmission scenario. For PJM-S, most events are relatively short in duration, typically less than six hours, and under three gigawatts in magnitude. This profile suggests that both storage and interregional transfers could be highly effective in managing remaining risk.



**FIGURE 15.** PJM-S Resource Adequacy Risk by Duration (x-axis) and Size (y-axis)

Based on this insight, three sensitivity cases were evaluated:

- **Case A:** Clean Energy Capacity Additions, including 4 GW of battery storage (approximately 33 percent of PJM-S’s interconnection queue), 1 GW of offshore wind (40 percent of the queue), and 3 GW of solar (25 percent of the queue).
- **Case B:** Transmission Expansion, increasing PJM-South’s total simultaneous import limit by 4 GW from 9,580 megawatts to 13,580 megawatts, still below the combined non-coincident capacity of neighboring interfaces.

- **Case C:** Combined Portfolio, applying half of the capacity additions and half of the import increase from the first two cases.

Table 2 summarizes the outcomes across each case. All three approaches effectively reduce PJM-South’s loss of load expectation (LOLE) from 5.05 days per year towards the industry threshold of 0.1 days per year. The combined portfolio performs comparably to the resource only addition portfolio (Case A), confirming the substitutability of clean energy and transmission solutions.

**TABLE 2.** Resource Adequacy Sensitivity Analysis for PJM-South

| PJM-South sensitivity      | LOLE days/yr | LOLH hrs/yr | EUE MWh/yr |
|----------------------------|--------------|-------------|------------|
| Base Case [No Tx scenario] | 5.05         | 14.85       | 36,836     |
| Case A. Resources          | 0.05         | 0.06        | 25         |
| Case B. Transmission       | 0.12         | 0.14        | 107        |
| Case C. Resources + Tx     | 0.06         | 0.07        | 40         |

The key finding is that PJM-South can achieve resource adequacy using less than one-third of its interconnection queue, while meeting the forecasted data center demand, allowing for announced retirements, and without requiring new natural gas capacity. Policy efforts that focus on prolonging the operation of aging resources through reliability-must-run or out-of-market contracts may be less efficient than accelerating clean energy interconnection and enhancing regional transfer capabilities. Load-side solutions, such as flexible demand from data centers or distributed resources, offer additional pathways and should also be explored in future assessments.

## POLICY AND REGULATORY IMPLICATIONS

### Resource Adequacy Risk is Elevated but Solvable

The results of this study indicate that resource adequacy risk across the Eastern Interconnection is elevated in 2028 under scenarios that exclude new resources, interregional transfers or assume limited market assistance. Several regions, particularly those with high load growth and substantial generator retirements, face reliability challenges when modeled in isolation. However, these risks must be viewed in context—the existing transmission network and market structures already provide a significant degree of support across regional boundaries, even in the absence of formal contracts.

***While near-term reliability concerns were found in some scenarios, many of these shortages could be alleviated with efficient solutions such as additional demand response, accelerated deployment of new resources, and improved utilization of existing transmission networks. More than 370 GW of new capacity is in the interconnection queues across the Eastern Interconnection, which were not included in this study.***

Many jurisdictions partially recognize the reliability contributions of neighboring systems through mechanisms such as capacity benefit margins or the incorporation of market assistance in resource adequacy studies. These interregional contributions are implicitly reflected in capacity markets and planning reserve margins. Nevertheless, interregional assumptions are often conservative and do not fully reflect either the technical transfer capability of the grid or the actual historical flow of energy during system stress events. The Eastern Interconnection inherently benefits from geographic diversity and a high degree of interconnectedness, which serve as a built-in reliability buffer.

Even with these benefits, some subregions like PJM South continue to exhibit elevated loss of load risk. Encouragingly, this risk can be addressed with a relatively modest portfolio of new resources. For example, in PJM South, utilizing less than one-third of the currently queued wind, solar, and battery resources would be sufficient to resolve the observed reliability gap. This underscores the value of accelerating the development and interconnection of clean energy resources already in the queue.

New interregional transmission development represents another powerful tool for mitigating risk, though its deployment timeline extends beyond the 2028 horizon evaluated in this study. Still, these findings point to the importance of long-term planning and proactive coordination among regions.

Overall, the study supports the view that while near-term reliability concerns were found in some scenarios, many of these shortages could be alleviated with efficient solutions such as additional demand response (given many of the events were within 2–4 hours of duration), accelerated deployment of new resources, and improved utilization of existing transmission networks rather

than out-of-market interventions to retain aging or uneconomic generation. For context, more than 370 GW of new capacity is in the interconnection queues across the Eastern Interconnection.<sup>24</sup> The vast majority of these resources were not included in this study.

This study suggests an opportunity for policymakers and system planners to focus on enabling resource development and enhancing interregional connectivity as the primary strategies to ensure reliability in a changing grid facing fossil-fuel generation retirements. From a methodology perspective, the study underscores the value of conducting resource adequacy analysis at a wide area scale across multiple system operators and utilities, using a common set of assumptions and methodology. Without methodological advances, any kind of planning effort will be misrepresentative.

## Coordination on Market Assistance is Needed

The analysis clearly demonstrates that interregional transfer capabilities significantly improve system reliability, yet geographic diversity is only partially recognized in current regional planning processes. The degree to which external market assistance is incorporated varies widely across jurisdictions, reflecting differing regulatory philosophies on how much capacity should be sourced locally versus through imports.

This variability is not inherently problematic. It reflects legitimate policy choices, but the current approach is largely ad hoc. Each region applies its own assumptions regarding external support, often without a consistent understanding of evolving conditions in neighboring systems. A structured wide-area resource adequacy framework can provide two important contributions in this context:

- **Visibility Into Neighboring Systems:** By offering insight into how load, resource mix, and risk patterns are shifting across the interconnection, these assessments allow regions to make more informed decisions about how to treat imports and exports in their own planning models.
- **Reliability Back-Check:** Wide-area assessments can serve as a consistent reference point for evaluating the implications of regional decisions within a broader system context, functioning as a cross-regional reliability validation tool.

## Consider Interregional Transfers as a Resource in Planning Activities

This study highlights the role of existing and potential new interregional transmission as a supply-side contributor to system reliability because it provides access to interregional generation resources. In the PJM-South sensitivity case, increasing the region's import capability had reliability benefits comparable to deploying a clean energy portfolio consisting of solar, wind, and battery storage. These findings support the case for exploring regulatory and market approaches that can account for interregional transmission as a resource, possibly through accreditation methods that mirror generation accreditation approaches. For example, incorporating transmission into resource adequacy accreditation would allow planners to evaluate trade-offs between local resource additions and increased access to geographically diverse capacity. It could provide insights, also, into opportunities for cost-effective transmission upgrades.

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<sup>24</sup> Data source from [interconnection.fyi](https://interconnection.fyi), accessed June 2025.

## FUTURE APPLICATIONS AND IMPROVEMENTS

### Enhancements to Resource Adequacy Analysis of the Eastern Interconnection

Through the course of this analysis, several opportunities for improvement have been identified. These include additional scenarios and sensitivities, improvements to the datasets, and methodological improvements. These enhancements will improve the accuracy, flexibility, and applicability of Eastern Interconnection-wide resource adequacy studies.

- **Expanded Clean Energy Portfolios:** Evaluate higher levels of wind, solar, and storage deployment beyond currently announced projects to quantify future resource adequacy needs under clean energy future scenarios and to support well planned, coordinated, and reliable retirement plans.
- **Increased Transmission Scenarios:** Model additional interregional and intraregional transmission expansion to assess how enhanced connectivity can mitigate reliability risks and reduce reliance on local resources.
- **Weather-Dependent Outage Modeling:** Incorporate thermal outage risk driven by cold weather and fuel supply disruptions to improve winter reliability assessments.
- **Longer Historical and Climate-Informed Weather Data:** Extend weather-synchronized datasets to include additional historical years of weather data and potentially include climate-adjusted projections to reflect evolving risk profiles.
- **Expanded Canadian Region Representation:** Improve the modeling of Canadian regions and inerties to better reflect their role in Eastern Interconnection reliability.
- **Ownership and Contract Modeling:** The current modeling framework is based on the physical location of the resource and does not reflect contractual or ownership of resources. Additional model development could layer ownership and contractual relationships onto the physical model to support utility-specific or market-specific planning analysis.
- **Enhanced Computational Efficiency:** Continue optimizing simulation runtimes and scaling methods to support rapid iteration across expanded scenario sets.

## Additional Use Cases for this Tool and Datasets

The methodology and platform developed through this study can support a range of additional applications, including:

- **National or Continental Scale RA Analysis:** As the electric grid evolves toward greater regional interdependence, the absence of a coherent, repeatable framework for assessing resource adequacy at a wide-area scale has become a growing vulnerability. This toolset can be used as a precursor to these future assessments.
- **Transmission Planning:** The toolset can help planners evaluate interregional projects or intra-regional upgrades across capacity zones or load pockets, particularly in the context of their contribution to resource adequacy.
- **Capacity Accreditation:** The toolset can be used to facilitate standardized methodologies and datasets across regions for resource accreditation. This would ensure consistent treatment of all resources, including imports, storage, and transmission.
- **Utility IRP and Future ISO Planning:** The toolset can support local planning by providing local utilities and ISOs with a broader system perspective, enabling more accurate treatment of imports, exports, and potential shared capacity mechanisms.

## CONCLUSION

This study highlights the value of conducting wide-area resource adequacy assessments using a coordinated, transparent, and open-source framework. By evaluating resource adequacy across the Eastern Interconnection using an integrated approach, the analysis reveals both vulnerabilities and opportunities that are not visible through isolated regional studies. It demonstrates that interregional transfers, clean energy additions, and enhanced planning coordination can meaningfully improve reliability outcomes, often with fewer resources than would be required under siloed approaches.

Realizing these benefits will require continued investment in high-quality data, advanced modeling capabilities, and institutional frameworks that support cooperative planning across regions. Open-source tools such as GridPath, and datasets that feed into these tools, are a key enabler of this effort. They allow system planners, regulators, utilities, and researchers to apply consistent methodologies, share insights, and build on one another's work to strengthen grid reliability across jurisdictional boundaries.

This assessment is not intended to be the final word on resource adequacy in the Eastern Interconnection. Rather, it provides a replicable framework and a foundation for continued analysis. The toolset developed through this study is available for further use, offering the broader power system planning community a common platform to address shared challenges in an increasingly interconnected electric grid.

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