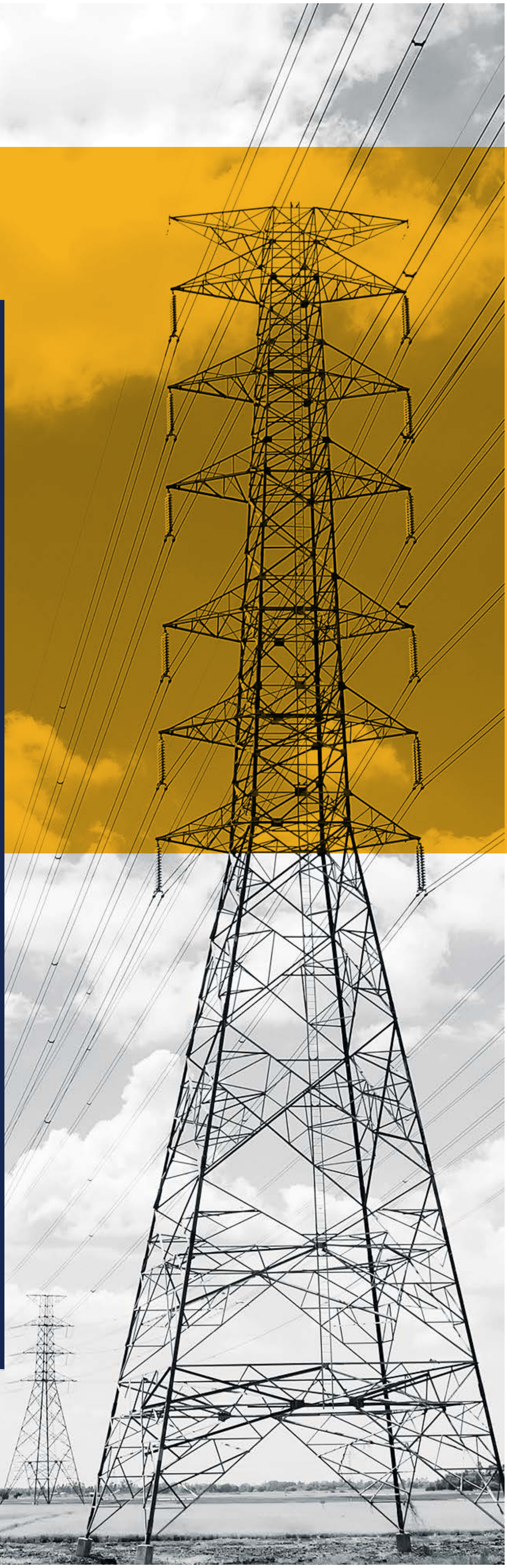

RESOURCE ADEQUACY VALUE OF INTERREGIONAL TRANSMISSION

Rev. 1

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Report Organization

This report is organized into three parts. Part I reviews resource adequacy assessments generally, and the role that capacity imports enabled by interregional transmission can play in supporting resource adequacy specifically. Part II examines specific methodologies and examples of how to include the capacity value of interregional transmission into resource adequacy assessments and capacity procurement processes. Finally, a review of the resource adequacy practices of each U.S. planning region, with particular focus on how imports and interregional transmission are incorporated, is provided in the Appendix. Parts I through III are heavily are heavily informed by the current practices reviewed in the Appendix, but are discussed generally.

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FIGURES & TABLES

EXECUTIVE SUMMARY

To reliably meet significant load growth across the country, all means of capacity expansion should be enabled. Interregional transmission supports resource adequacy (RA) in similar ways to other resources and can help system planners efficiently and reliably meet supply targets, complementing the contributions of other resources.

Interregional transmission offers resource adequacy value because neighboring regions have differing resource mixes and times of peak load, so may have excess capacity to share when a neighbor needs it. Interregional transmission allows capacity resources to be shared between regions with noncoincident demand. The interregional transmission assets themselves tend to be available nearly 100% of the time. Consumers benefit from this sharing of reserves, both in terms of improved reliability and reduced costs. These reliability and economic benefits are heightened during grid stress events. Reliability authorities have confirmed this value, as demonstrated by the North American Electric Reliability Corporation (NERC) Interregional Transfer Capability Study (*see* Figure ES-1, which shows that load and generation availability differed across U.S. regions during Winter Storm Elliot).

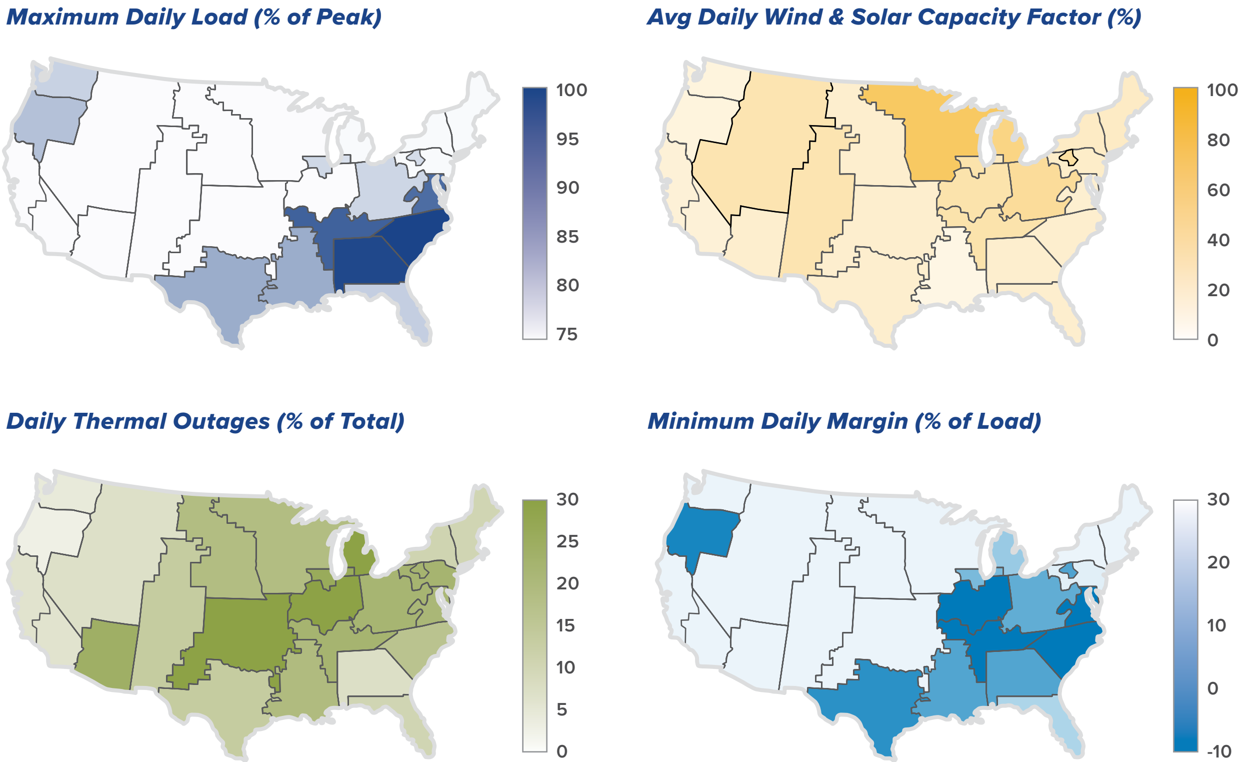


FIGURE ES-1 | Average regional diversity in load, generation, and energy margins on 12/24/2022 during Winter Storm Elliot. These maps show that neighboring regions had excess resource capacity which could have been imported to prevent load shed in regions where load exceeded available supply (blue in lower right panel). *Source: NERC, "Interregional Transfer Capability Study" (2024), with modifications*

But the electric industry has not yet adopted a consistent method to calculate the capacity value of interregional transmission that enables resource sharing. Without a calculation of capacity value that system planners can easily integrate into their resource adequacy assessments, they will likely fail to attract and retain this capacity, and lose some of the associated reliability and economic benefits.

The capacity value of interregional transmission can be calculated using standard industry methods. System planners are increasingly using the effective load carrying capability (ELCC) method to accredit a capacity value to supply resources. ELCC considers the difference in loss of load expectation (LOLE)—or any other RA metric—for the system with and without the supply resource and calculates how much additional load the resource can serve to return the system to the standard LOLE baseline of 1-day-in-10-years. This method has been successfully applied in several recent transmission facility or resource adequacy studies to derive the capacity value of several interregional transmission lines both in the United States and abroad (*see* **Table ES-1** for relevant values for 73 facilities / paths, grouped by importing region).

Incorporating the capacity value of interregional transmission into RA assessments is not new or foreign to system planners. Regional transmission organizations and independent system operators (RTOs/ISOs) already have a multi-year history of calculating the capacity

value of interregional transmission. While not many system planners have calculated the LOLE reduction from an individual transmission facility and converted it to a capacity value, most system planners have calculated the reduction in LOLE associated with the fleet of interregional ties that currently exist between regions, albeit in different ways and using different names. System planners refer to these fleet-wide RA contributions by many names, such as "external assistance," "tie benefits," or "firm and non-firm imports." *See* **Table ES-2** for each region's import assistance levels and the associated reduction in RA metrics.

System planners could account for the capacity contribution of interregional transmission in various ways, such as planning for a lower reserve margin or converting LOLE reductions to ELCC values. Both interregional transmission accounting methods are based in current industry practice. These RA crediting methods are similar to the benefits that the Federal Energy Regulatory Commission (FERC) requires transmission planning regions to consider as part of long-term intraregional planning under Order No. 1920 in the form of either reduced loss of load probability or planning reserve margin. But in the interregional case, there is also the option of assigning the value directly to the asset, enabling market sales of that transmission capacity as a capacity resource in an RA regime.

Given the meaningful capacity value attributable to interregional transmission, system planners should develop procurement and valuation methods for these capacity resources. Without a benefit to load-serving entities associated with their RA obligations (which indirectly provides value to transmission developers), or direct compensation to transmission developers for the RA contributions of their assets, there is less incentive to build these vital resources. Valuation and compensation methodologies can apply to both regulated (planned and rate-based) assets and merchant (independently owned with cost recovery through voluntary subscriptions) interregional transmission, or hybrids of the two.

System planners must work with stakeholders to find solutions that work best for their region. This report demonstrates the resource adequacy value and proposes quantification methods to incorporate that value into capacity procurement constructs. Additional discussion of the resource adequacy value of interregional transmission should continue with system planners to develop methods that work best for their circumstances.

TABLE ES-1 | Capacity value and associated resource adequacy of interregional transmission facilities. While calculable, U.S. electricity planners rarely fully incorporate the capacity value of transmission facilities into resource adequacy assessments and/or resource procurement processes.

Transmission Facilities	Accrediting region	Number of associated facilities	Nameplate capacity (MW)	Accredited capacity (MW)	Reported reduction in LOLE (day/yr)	Capacity Value (accredited / nameplate)
North Plains Connector	WECC	1	3,000	1,800	0.088	**60%**
	SPP			1,350	0.087	**45%**
	MISO			400	0.070	**13%**
Three Corners Connector	PSCo	1	1,800	715	0.09	**40%**
	SPP			1,362	0.054	**76%**
Grain Belt Express Phase 1	MISO	1	2,500	2,116	0.06	**85%**
	SPP			450		**18%**
Boardman to Hemingway	Idaho Power	1	750	700	0.006	**93%**
CAISO Interties	CAISO	45	39,923	16,148		**40%**
NS-NB Reliability Intertie Project	Nova Scotia	1	300 (est.)	200		**67%**
North Sea Link	NESO	1	1,400	1,316		**94%**
NESO - Ireland Interties	NESO	3	1,500	1,050		**70%**
NESO – France Interties	NESO	3	4,000	2,680		**67%**
Nemo Link	NESO	1	1,000	800		**80%**
Viking Link	NESO	1	1,400	1,204		**86%**
BritNed	NESO	1	1,000	840		**84%**
ISONE - Maritimes	ISONE	2	980	770	0.469	**78%**
ISONE - HQ Phase II	ISONE	1	1,400	1060	0.556	**76%**
ISONE - HQ Highgate	ISONE	1	200	160	0.137	**80%**
ISONE - NYISO Ties	ISONE	8	1,400	730	0.454	**52%**
Soo Green	ComEd	1	2,100	2,016	0.1	**96%**
Champlain Hudson Power Express	NYISO	1	1,250	1,250	0.008	**100%**

Notes | Because transmission lines can be accredited differently in multiple directions, the importing capacity is listed for the named entity in the Accrediting region column. Blank cells indicate the calculation was not performed, not reported, or cannot be estimated from reported information.

TABLE ES-2 | Capacity value and associated resource adequacy contributions of firm and non-firm imports used in regional planners' RA assessments. Reduction in reserve margins is not a reduction in system reliability, but rather a reduction in the amount of capacity needed to maintain resource adequacy.

Region	Import type	Nameplate capacity (MW)	Accredited capacity (MW)	Reported reduction in RA metric	Reduction in reserve margin	Equiv. capacity value (accredited / nameplate)
Tennessee Valley Authority	Non-firm		4,750		8%	
Southern Company	Non-firm		2,714		1.75%	
Desert Southwest (APS, AEPCO, EPE, PNM, SRP, TEP)	Non-firm		1,379	LOLE: 0.04 day/yr NEUE: 0.34 ppm		
Public Service Colorado	Non-firm		390		4.70%	
Idaho Power	Non-firm	100	14			14%
MISO	Firm	1,986	1,935		1.60%	97%
	Non-firm	12,000	4,351		3.50%	36%
SPP	Firm	2,255	2,255		3.60%	100%
CAISO	Firm		1,700		3.80%	
PJM	Firm	1,485	1,269		1.10%	85%
	Non-firm		2,937		1.50%	
NYISO	Firm		1,600		5.1%	
	Non-firm		3,500 (max)	LOLE: 0.42 day/yr		
ISO-NE	Firm	1,936	1,870		6.0%	97%
	Non-firm	3,980	2,175	LOLE: 0.724 day/yr	7.0%	55%

Notes | Unless otherwise stated, all capacity value calculations are estimated by the authors using industry reported information. Blank cells indicate the calculation was not performed, not reported, or cannot be estimated from reported information.

Recommendations for system planners and regulators:

1. **System planners that do not already include the contribution of transmission-enabled imports in their resource adequacy assessments should do so.**

   This can be done through LOLE reduction, planning reserve margin reduction, or wide area assessments. Importantly, reductions to planning reserve margins are not a reduction in system reliability, but rather a reduction in the amount of capacity needed to maintain resource adequacy. Best practices for non-firm imports include measuring this contribution for each neighbor individually and during times of grid stress. A probabilistic treatment of available non-firm imports helps prevent over-reliance on this resource. Consideration of the historic performance of firm and non-firm imports is important to validate that the resources are available when they are needed most.

2. **System planners should determine the capacity value of major interregional transmission facilities by measuring the change in resource adequacy (e.g., LOLE or expected unserved energy) with and without the facilities given resource availability on the other end of the facility.**

   When calculating the capacity value, it is best practice to consider seasonal accreditation and peak load diversity with specific neighboring regions, rather than average annual accreditation and average diversity with all neighbors in aggregate.

   FERC might consider directing regional system planners to expand upon the NERC *Interregional Transfer Capacity Study* with a deeper investigation of the potential capacity values of new interregional transmission.

3. **Regulators and system planners should foster the development of interregional transmission that directly contributes to resource adequacy.**

   Such efforts could include establishing an interregional transmission planning process with transmission rate-base cost recovery, enabling merchant transmission development with the capacity value assigned either to the asset or to load-serving entities through a reduction in their capacity obligations (i.e., RA requirements), or some other means.

   Regulatory oversight of capacity procurement decisions may be needed to ensure utilities make decisions which benefit ratepayers most.

PART I

The role of transmission in supporting resource adequacy

Transmission is a critical piece of the resource adequacy (RA) puzzle. To set the stage, Part I of this report introduces the concept of resource adequacy and how system planners evaluate it. It then reviews the role interregional transmission in delivering capacity to resource constrained regions and explains how the benefits of interregional transmission align with resource adequacy needs.

Overview of resource adequacy and capacity accreditation

Resource adequacy is a part of overall power system reliability. The definitions of resource adequacy provided by reliability authorities are very similar. NERC defines it as: "the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses)."[1] MISO defines it as: "the availability of sufficient resources over the planning horizon to meet demand during real-time operations considering uncertainties in generation performance, weather and load."[2] In other words, resource adequacy ensures customers get the power they need, when and where they need it. Electric system operators must confirm there will be sufficient generation available to supply those needs, including in ordinary times and under system stress (e.g., hot summer and cold winter days). In reality, the concept is far more complex.

If the planning reserve margin is too low, there could be inadequate capacity to meet demand, particularly during stress events. Conversely, if the planning reserve margin is too high, ratepayers could be paying too much for more capacity than is needed to meet demand.

System planners run resource adequacy assessments to determine how much supply is needed to keep load

1 North American Electric Reliability Corporation (NERC), Standard BAL-502-RFC-02 "Planning Resource Adequacy Analysis, Assessment and Documentation," https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-502-RFC-02.pdf

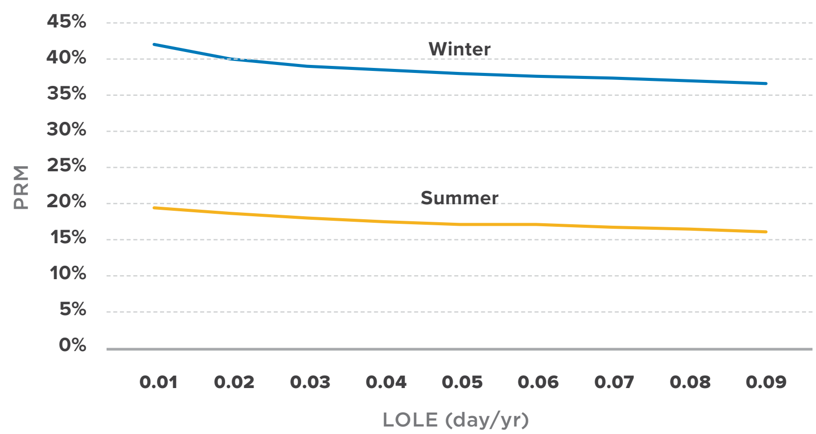
2 Midcontinent Independent System Operator (MISO), "Resource Adequacy Metrics and Criteria Roadmap: A Reliability Imperative Roadmap" (2024), https://cdn.misoenergy.org/Resource%20Adequacy%20Metrics%20and%20Criteria%20Roadmap667168.pdf

loss events under a target threshold. The target threshold most widely used is a loss of load expectation (LOLE) of no more than one event or day every ten years.[3] The 1-in-10 criterion was an industry practice starting in the 1950s that became the de facto standard across the country. Importantly, the LOLE metric only measures the frequency of load loss events, not the duration of the event or the magnitude of how much load is lost. Alternative metrics which planners can use instead of or in addition to LOLE in their RA assessments to capture these dynamics are discussed in more detail elsewhere.[4,5]

Resource adequacy assessments then consider if there will be adequate resource capacity to meet the target threshold—whether a 0.1 day/yr LOLE or otherwise—given the forecasted future load and other system constraints. A planning reserve margin (PRM) defines the percentage of excess ability to produce electricity (i.e., the capacity) in the studied area relative to the expected peak demand. The relationship between LOLE and PRM in SPP for the 2025/26 operating year is shown in Figure 1.[6] If the planning reserve margin is too low, there could be inadequate capacity to meet demand, particularly during stress events. Conversely, if the planning reserve margin is too high, ratepayers could be paying too much for more capacity than is needed to meet demand. To find the balance between capacity and cost, planners reduce the PRM to the lowest value necessary to maintain resource adequacy below the loss of load event threshold.

FIGURE 1 | **Relationship between planning reserve margin and LOLE in SPP for 2025/26 operating year**

Source: SPP,[7] with modifications



If insufficient resources exist to meet the required planning reserve margin, then planners must procure additional capacity resources. Many load serving entities and utilities self-supply capacity or rely on bilateral contracts with capacity owners to meet their resource adequacy needs. Other load serving entities can purchase capacity in forward capacity markets operated by the independent system operators or regional transmission organizations (ISOs/RTOs) of which they are apart. In forward capacity markets, owners of generation and demand-side capacity bid in to a forward auction for the supply that will be needed for the region, selecting

3 An LOLE of 1-day-in-10-years has a value of 0.1 day/yr

4 Carvallo, J.P., et al., "Guide for improved resource adequacy assessments in evolving power systems" (Lawrence Berkeley National Laboratory [LBNL], 2023)

5 Stenclik, D., et al., "New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements" (Energy Systems Integration Group [ESIG], 2024), https://www.esig.energy/wp-content/uploads/2024/03/ESIG-New-Criteria-Resource-Adequacy-report-2024a.pdf

6 Southwest Power Pool (SPP) Resource Adequacy, "2024 Loss of load expectation study report" (2025)

7 *Id.*

the lowest supply bid and each incrementally higher bid until enough capacity has been selected to meet the planning reserve margin and the required capacity "clears" in the market. The basic physical metrics described above (such as LOLE and expected unserved energy) are used to establish the planning reserve margin and ensure resource adequacy regardless of the prevailing market regime.

The following factors are usually taken into account when conducting RA assessments:

- **Peak load forecast.** Utilities assess load growth forecasts given general economic growth in the area, growth by sector, energy efficiency, load shape, and both peak (in MW) and energy (in MWh) trends. The regional planner then rolls up each utility's forecast to establish a regional planning reserve margin.
- **Load forecast error.** Recognizing that load forecasts are imperfect, utilities build in some cushion to address uncertainty, including weather and climatic variability.
- **Firm load.** Planners focus on resource adequacy for only for firm load, subtracting out interruptible load.
- **Operating reserves requirements.** System operators must retain some amount of capacity to serve as operating reserves in the event of an emergency.
- **Intrazonal transmission constraints.** Transmission system congestion that limits deliverability of generating capacity from sources to major loads are considered.
- **Installed capacity.** Planners consider the installed capacity of generating and demand response resources on their system, including expected retirements and planned additions.
- **Generator outages.** Generators operate at a level below their installed capacity, given planned (e.g., maintenance) and forced outages, which must be considered. Expected and forced outages are used to calculate the accredited capacity of a resource.
- **Imports from other regions.** More imports from neighboring regions can reduce the required planning reserve margin within a planning footprint.

These last three factors are a large focus of this report.

Capacity value

Not all resources contribute to resource adequacy equally, and they must be derated based on availability during times of grid stress. How much any one resource contributes to the planning reserve margin is its capacity value, defined here as the ratio of the expected output of the resource (its accredited capacity) and its nameplate or installed capacity.[8]

At a minimum, most planners accredit the capacity of a resource based on its outage rate and/or historical performance during times of peak demand. Outage rates alone miss several other important derate factors, risking an overestimate of the capacity value of different resource

8 Others may refer to *capacity value* as "capacity credit" or "effective credit." A key concept that is often confused is "capacity value" versus "capacity factor." Capacity factor is the amount of electricity produced over the course of some time period, such as a year, as a ratio of the maximum possible output. In contrast, capacity value is the amount of electricity expected to be produced at times of peak system need. For example, a natural gas peaker (i.e., a plant designed for use at peak system demand) might have a very low 10% capacity factor since it is only used when needed for reliability, but might have a high 90% capacity value because it is highly likely to be available when needed. All generation types have different capacity factors and capacity values; the capacity value is incorporated into each system planner's resource adequacy methodology. Transmission can also be assigned a capacity value.

types. Additionally, resource performance at the hour of peak demand may differ from its performance during times of grid stress, when resource adequacy is most at risk. A recent report from the Energy Systems Integration Group details several best practices for capacity accreditation methods and concludes that capacity accreditation should be applied similarly and transparently across resource types, robust to future uncertainty, and reliably capture behavior during scarcity events.[9]

Additional best practices for capacity accreditation include:

- **Adjustments to capacity value for correlated outages:** Resources of the same type in the same geographic area often experience correlated failures due to a single event. If resource adequacy assessments assume full statistical independence of facility outages, they will overstate the available capacity. The same issue arises for all types of generators: coal piles can freeze from the same storm; nuclear cooling water can be limited by drought in the same months; gas delivery is constrained during cold weather; diurnal and seasonal variability can affect a fleet of solar units at the same time; and wind patterns can affect geographically close wind units at the same time.
- **Capacity valuation to reflect generation portfolios:** Capacity values are a function of a resource's share of the overall generation portfolio, particularly when the resource type has significant correlation within the fleet, as is the case with renewable generators. As the penetration of renewable generation has risen in some regions, the marginal capacity value of those generators has begun to fall. As the generation mix changes, grid planners must continue to re-assess and refine capacity accreditation.
- **Seasonality of capacity value:** Seasonality is becoming a more important issue today than in past resource adequacy evaluations. In the past, many systems experienced peak demand in the summer or winter—with little to no scarcity risk in the spring and fall—and capacity resources were optimized for that season only. In recent years, the risk of shortages is rising across the year due to changes in weather patterns, the resource mix, and regional load profiles (e.g., growing electrification). The capacity value of resources must be considered in each season where shortfall risk exists.

Many regional planners have experience using the effective load carrying capability (ELCC) method for calculating the capacity value of resources, though other accreditation methods exist. ELCC is derived directly from the same modeling that system planners use to establish the planning reserve margin given LOLE assessments. ELCC measures the incremental amount of demand that can be met by adding the resource type to the grid. Many apply ELCC only to intermittent resources, but it was originally designed to apply to all resource types. Importantly, an ELCC value can also be applied to imports enabled by interregional transmission.

ELCC can be calculated for a single asset (e.g., a nuclear plant), but it is more commonly determined for types of resources (e.g., wind or solar or gas combustion turbines) or the entire portfolio of assets in a region or system. ELCC calculations are time- and context-specific. Solar

9 Stenclik, D., et al., "Ensuring Efficient Reliability: New Design Principles for Capacity" (ESIG, 2023), https://www.esig.energy/wp-content/uploads/2023/02/ESIG-Design-principles-capacity-accreditation-report-2023.pdf

plants, for example, have higher output and availability in the summer than in winter, and natural gas deliveries are more problematic in winter than in summer. And ELCCs for a technology type depend on how much of that asset type is already on the system. For example, higher proportions of natural gas generation on a system increase its vulnerability to natural gas pipeline and delivery disruptions, diminishing the gas fleet's ELCC.

Non-firm imports are a vital resource to the system, allowing operators to keep customers' lights on even when there are no more internal resources to call on for support. However, these imports are not consistently incorporated into resource adequacy assessments. This omission may result in the over-procurement of capacity resources internal to the planning region to meet the planning reserve requirement, raising costs for ratepayers.

Transmission-enabled imports

All regions we surveyed include firm imports from neighbors in their resource adequacy assessments, but only a handful also consider the contribution of non-firm imports. Those that do incorporate non-firm imports rarely accredit the interregional transmission which enables non-firm imports with a capacity value for their contribution to resource adequacy. The inclusion of imports in resource adequacy assessments lowers the amount of in-region capacity that must be supplied by utilities to meet their planning reserve margins.

Firm imports have both firm power supply contracts for the sale of energy at specific times and amounts, and firm transmission capacity and delivery priority unencumbered by transmission constraints to assure delivery of the energy to load. Non-firm imports are the resources shared by a neighbor with excess capacity to a region experiencing a scarcity event and are at risk of shedding load. They often occur under spot market purchases or interruptible contracts and do not have firm transmission rights. Some regions evaluate historical imports and transmission path usage patterns to determine how much firm and non-firm imports can be assumed to be available in future times of need to include in resource adequacy assessments.

Non-firm imports are a means to quantify the net load diversity between regions, as occurs when one region is experiencing a scarcity event and a neighbor may have surplus capacity to share. This is the resource adequacy value of interregional transmission. Table 1 summarizes the firm and non-firm imports that are included in each planning region's resource adequacy assessments for the 2025/26 operating year. Imports considered in RA assessments make up no more than 17% of any planning region's peak demand.

Non-firm imports are a vital resource to the system, allowing operators to keep customers' lights on even when there are no more internal resources to call on for support. However, these imports are not consistently incorporated into resource adequacy assessments. This omission may result in the over-procurement of capacity resources internal to the planning region to meet the planning reserve requirement, raising costs for ratepayers. These concepts are discussed more in Part II.

TABLE 1 | Imports included in resource adequacy assessments for the 2025/26 operating year.

Region	Peak Demand (MW)	Max Historic Coincident Imports[a] (MW)	Imports included in RA Assessment (MW)	RA Imports to Peak Demand Ratio	RA Imports to Historic Imports Ratio
CAISO [b]	44,885	12,600	Firm: 1,700 Non-firm: 0	3.8%	13.5%
ISONE [c]	28,891	4,380 [d]	Firm: 1,870 Non-firm: 2,175	14.0%	92.4% [d]
MISO [e]	123,576	16,100	Firm: 1,935 Non-firm: 4,351	5.1%	39.0%
NYISO [e]	31,650	5,000	Firm: 1,600 [g] Non-firm: 1,900	11.1%	70.0%
PJM [h]	153,883 [i]	11,800	Firm: 1,485 Non-firm: 2,937	2.9%	37.5%
SPP [j]	58,028	4,000	Firm: 2,100 MW Non-firm: 0	3.6%	52.5%

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(a) Deyoe, R., et al. "Interregional Transmission for Resilience: Using regional diversity to prioritize additional interregional transmission" (ESIG, 2024), 13, https://www.esig.energy/wp-content/uploads/2024/06/ESIG-Interregional-Transmission-Resilience-methodology-report-2024.pdf

(b) September load (peak month) for 2026. Source: California Public Utility Commission, "Loss of Load Expectation Study for 2026 Including Slice of Day Tool Analysis" (2024), docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M536/K273/536273741.PDF

(c) Peak demand is 90/10 expectation since this value used in RA assessments, and not the 50/50 expectation. Firm imports are cleared "import capacity resources" and non-firm are remaining "tie benefits." All values for ARA 3 capacity auction across all ties for the 2025/26 summer. Source: Saarela, H., "Installed Capacity Requirement (ICR) and related values calculations assumptions for the Annual Reconfiguration Auctions (ARAs) to be conducted in 2025 rev.1" (2024), https://www.iso-ne.com/static-assets/documents/100014/a03_annual_reconfigurationauction_icr_related_values_development.pdf

(d) Deyoe, R., et al. only evaluated domestic imports (1,800MW for ISONE), not the imports ISONE receives from Canadian provinces. This max transfer capability is calculated as the sum of max domestic imports from Deyoe, R., et al. and the nameplate capacity of the international ISONE ties (see Table 3 of this report). This is likely an underestimate of total maximum coincident imports for ISONE, resulting in an overestimated RA imports to historic imports ratio in the last column. Source: Bringolf, M., "Tie Benefit Values: For Reconfiguration Auctions to be Conducted in 2025" (2024)

(e) Peak load is summer coincident peak demand for 2026. Firm imports are the unforced capacity and non-firm imports are 50% probability of availability, all for summer. Source: MISO, "Planning Year 2025-2026 Loss of Load Expectation Study" (2024)

(f) Peak demand is summer baseline coincident peak for 2025 planning year. Non-firm imports are the "external assistance simultaneous import limit" (3,500 MW) less the firm imports, representing the maximum possible and not the actual input of external assistance used in the LOLE calculation. Source: NYISO, "2024 Long-Term Resource Adequacy Assessment for NYSRC" (2025)

(g) Firm imports are capacity purchases from external areas over fleet of interregional ties. Source: NYISO 2024 "Gold Book" Available: https://www.nyiso.com/documents/20142/2226333/2024-Gold-Book-Public.pdf/170c7717-1e3e-e2fc-0afb-44b75d337ec6

(h) Firm imports are the ICAP value of imports and non-firm imports are the product of CBOT (1.5%) and ICAP for generation (195,831 MW) for 2025/2026 Base Residual Auction. Source: PJM, "2025/26 Base Residual Auction Report" (2024), 9-12, www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.pdf

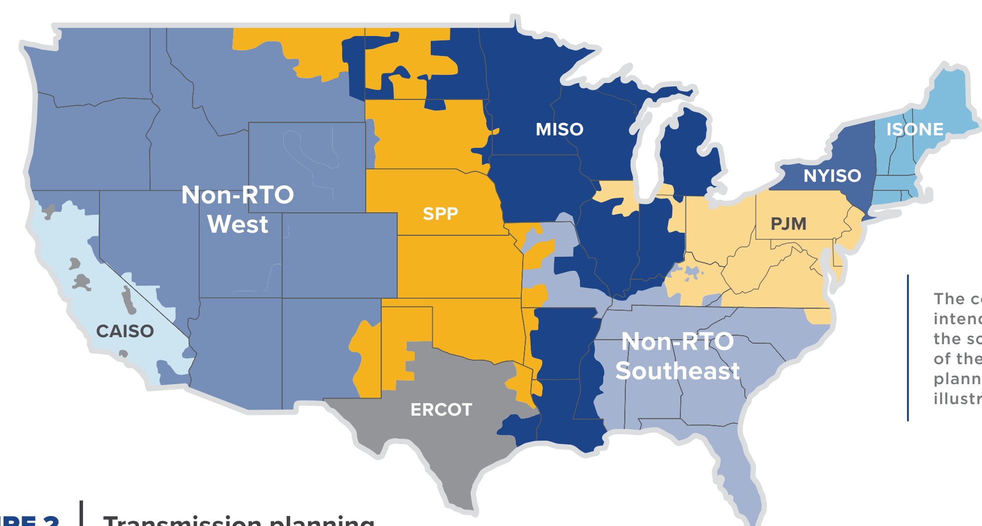
(i) Source: PJM, "2025/2026 Base Residual Auction Planning Period Parameters" (2024)

(j) Non-coincident peak demand and firm external imports for summer 2026. Source: SPP Resource Adequacy, "2023 Loss of load expectation study report" (2024)

Interregional transmission benefits align with resource adequacy needs

Interregional transmission connects utility system planning regions, whether aligned along RTO/ISO boundaries or otherwise. Typically, when system planners talk about regions, they are referring to the 11 transmission planning regions formed to comply with FERC Order No. 1000 (*see* **Figure 2**).[10] These regions are comprised of multiple transmission owners that came together as a "region" to conduct coordinated transmission planning. These same regions frequently examine resource adequacy across the regional footprint, benefiting from the broader system rather than basing resource adequacy only on those resources contained within a single utility footprint. These broad regional system benefits include load and generation diversity, enabled by a strong regional transmission network.

In many cases there is more generation and load diversity between regions than within regions, meaning there is more likely to be excess energy available to flow in times of need. Interregional transmission also provides substantial resilience value by bridging weather-related differences between regions. Demand does not peak in every region across the country at the same time. A grid that is "bigger than the weather"—be it a polar vortex or cloud cover—enables power to be shared from a region that is not peaking into a region that is, lowering consumers' costs in both regions.[11] Interregional transmission can provide greater diversity in both load and generation across greater distances as well.[12] Despite the larger resilience benefits between regions than within regions, system planning between regions has been less systematic than that within regions.



The colored areas are intended to approximate the scope and location of the transmission planning region but are for illustrative purposes *only*.

FIGURE 2 | **Transmission planning regions used in this report**

Source: FERC,[13] with modifications

10 "Order No. 1000 Transmission Planning and Cost Allocation," Federal Energy Regulatory Commission, last modified November 9, 2021, https://www.ferc.gov/electric-transmission/order-no-1000-transmission-planning-and-cost-allocation

11 NERC, "Interregional Transfer Capability Study: Final Report" (2024), xiii, https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf

12 Millstein, D., et al. "Empirical Estimates of Transmission Value using Locational Marginal Prices" (LBNL, 2022), 20, https://eta-publications.lbl.gov/sites/default/files/lbnl-empirical_transmission_value_study-august_2022.pdf

13 "Regions Map Printable Version Order No. 1000," Federal Energy Regulatory Commission, last modified November 9, 2021, https://www.ferc.gov/media/regions-map-printable-version-order-no-1000

Transmission and deliverability to load are necessary for generation resources to contribute their capacities to system resource adequacy and, thus, to qualify as capacity resources. Resource curtailment occurs when the grid operator must enforce limits on transmission paths and there is too much generation seeking to use the same transmission path. The limited transmission capacity means that not all generation can be delivered, so the operator cuts some generation off. More transmission increases the amount that can be delivered and reduces curtailment, allowing more of that generation to serve loads.

Demand does not peak in every region across the country at the same time. A grid that is "bigger than the weather"—be it a polar vortex or cloud cover—enables power to be shared from a region that is not peaking into a region that is, lowering consumers' costs in both regions.

Interregional transmission can increase generator availability by reducing vulnerability to localized impacts. Weather and fuel supply can impair generators in the same area, whereas generators farther away are likely to face different fuel supply and weather conditions. Outages resulting from the same event are common mode failures, and to the extent they occur, they violate the basic assumption of independent forced outage rates. Planners are starting to recognize and characterize these common failure modes and incorporate them into resource planning.[14] Regions across the country have experienced multiple events in which many generation types have been forced offline by fuel supply limitations or other interruptions.[15]

Analysis using historical generator forced outage rates demonstrates that conventional generators experience correlated outages many times more frequently than is predicted under the assumption that individual plant outages are uncorrelated independent events.[16] The data shows that correlated forced outages have affected coal, nuclear and gas thermal generators, with gas generators experiencing some of the highest correlated outage rates.[17] NERC has noted that correlated outages are a major risk, particularly for gas generators.[18,19]

Diversity of resource types and fuel sources tends to increase resource adequacy and transmission enables access to a wider selection of resources and types. Given the varied outputs of different generation resources, a diverse resource mix can yield a combined capacity value that is larger than the sum of its parts. **Figure 3**[20] illustrates the individual accredited capacity of 2 GW of solar and 4 GW of batteries with a combined capacity of 7 GW.

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14 NERC, "ERO Reliability Risk Priorities, RISC recommendations to the NERC Board of Trustees" (2015), 3, https://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO_Reliability_Risk_Priorities_RISC_Recommendations_to_the_Board.pdf

15 Goggin, M., et al. "Fleetwide Failures: How Interregional Transmission Tends to Keep the Lights on When There Is a Loss of Generation" (Grid Strategies, 2021), https://gridstrategiesllc.com/wp-content/uploads/2024/05/fleetwide-failures-how-interregional-transmission-tends-to-keep-the-lights-on-when-there-is-a-loss-of-generation.pdf

16 Murphy, S., et al., "Resource adequacy risks to the bulk power system in North America" (Carnegie Mellon University, 2018), 29, https://www.sciencedirect.com/science/article/pii/S0306261917318202

17 *Id., 26–27.*

18 NERC, "Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System" (2020), https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf

19 NERC, "Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System" (2017), 3, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf

20 Schlag, N., et al. "Resource Adequacy in the Desert Southwest" (E3, 2023), 3, https://www.ethree.com/wp-content/uploads/2022/02/E3_SW_Resource_Adequacy_Final_Report_FINAL.pdf

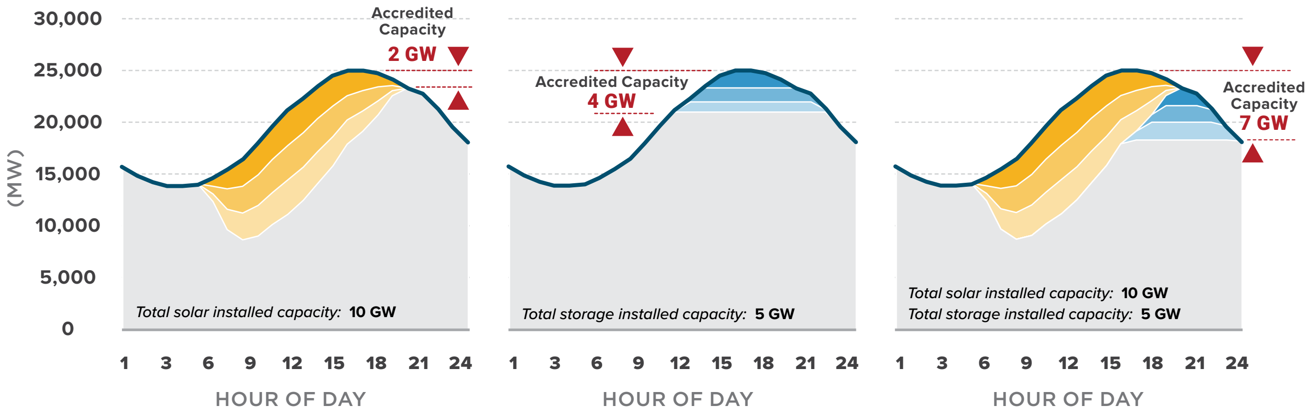

FIGURE 3 | **Illustrative resource diversity benefit, where combined resources have higher accredited capacity than the sum of the individual accredited capacities.** *Source: E3,[21] with modifications*

Loads in neighboring utility systems have always had some amount of diversity, meaning imperfect correlation such that the utilities' peaks do not occur at the same time. For example, if one utility reaches a peak of 10 GW on one afternoon and the other reaches its peak of 15 GW on a different day, the combined peak load is not 25 GW but rather might be 22 GW or some other lower amount. This "coincident peak" is calculated, reported, and used when utilities unite for resource adequacy purposes. Combining three or more systems creates further efficiencies, such that the aggregate coincident peak is lower when calculated together than if they remain separate. Interregional transmission enables many systems to be integrated together, reducing the whole combined system's coincident peak.

Interregional transmission also mitigates the impacts of load growth uncertainty. Consider two neighboring systems, one where the 10-year load forecast was too high by 1 GW, and one where it was low by 1 GW. If interregional transmission can deliver 1 GW each way, then both systems can be in balance by leveraging flows between the two regions. Such transmission is an insurance policy against load forecast error. Given the full suite of resource adequacy, energy, resilience, and flexibility benefits of interregional transmission, interregional transmission is often a cheaper option than overbuilding generation in each region.[22]

Many resource adequacy assessments are performed assuming normal weather conditions, although this practice is changing. Recent weather events have raised load and impaired generation beyond that predicted by traditional resource adequacy assessments. Because interregional transmission offers the benefits of reduced deliverability constraints, reduced correlated outages, and increased resource and load diversity, it is particularly valuable during severe weather events.[23] NERC adopted this approach in their recent *Interregional Transfer Capability Study.*[24] **Figure 4**, from the NERC study, illustrates these benefits by showing the load, resource, and reserve margin diversity of several subregions during Winter Storm Elliot.

21 *Id.*

22 U.S. Department of Energy, "National Transmission Planning Study: Executive Summary" (2024), 2-4, https://www.energy.gov/sites/default/files/2024-10/NationalTransmissionPlanningStudy-ExecutiveSummary.pdf

23 Deyoe, R., et al. "Interregional Transmission for Resilience: Using regional diversity to prioritize additional interregional transmission" (ESIG, 2024), 31-36, https://www.esig.energy/wp-content/uploads/2024/06/ESIG-Interregional-Transmission-Resilience-methodology-report-2024.pdf

24 NERC, "Interregional Transfer Capability Study", 1-3 and 74

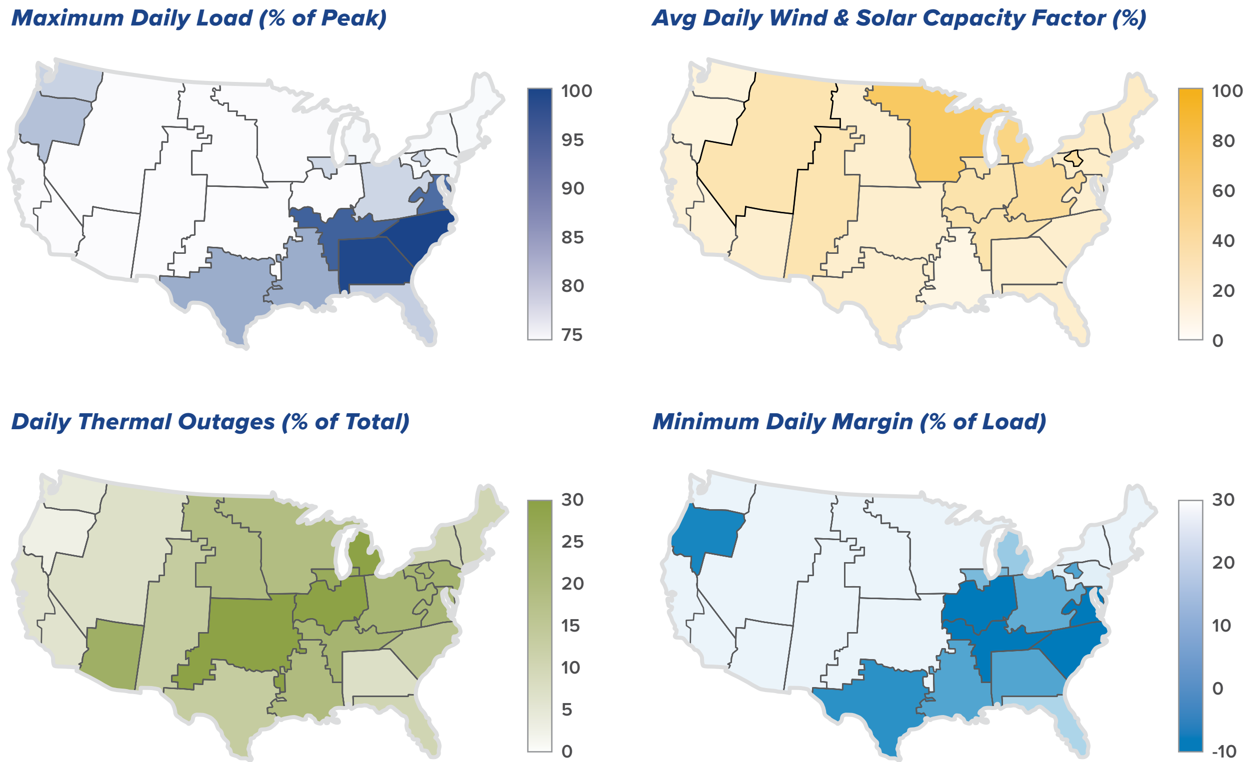

FIGURE 4 | Average regional diversity in load, generation, and energy margins on 12/24/2022 during Winter Storm Elliot. The source study defines a margin (bottom right panel) as the measure of the available internal resources to meet regional load, as a percentage of load calculated every hour of the day. It is a composite metric made up of hourly load and generation availability (shown in the other three panels). A negative margin (bottom right) indicates that load has exceeded available internal resources, and imports are necessary to prevent load shed. *Source: NERC,[25] with modifications*

In another example, Figure 5 demonstrates the net load diversity between regions during multiple recent severe weather events.[26] Each row in the figure shows regional net load during the same hour of a severe weather event, as a percentage of the maximum regional net load across all nine years of the analysis. Regions at or near 100% (shown in red) were experiencing their maximum shortfall in resource supply, while regions with low percentages (shown in green) had abundant spare capacity during that hour. Interregional transmission exploits this resource and load diversity by enabling the transfer of surplus capacity to regions experiencing shortfalls during each of the extreme weather events (rows) shown.

25 *Id., 83*

26 Goggin, M., Zimmerman, Z., Sherman, A., "Quantifying A Minimum Interregional Transfer Capability Requirement" (Grid Strategies, 2023), 4, https://gridstrategiesllc.com/wp-content/uploads/2023/05/GS_Interregional-Transfer-Requirement-Analysis-final54.pdf

	ERCOT	SPP	MISO S	TVA	MISO N	PJM	NYISO	ISO-NE	Carolinas	SOCO	Florida
1/17/2014 7 AM ET	58%	60%	74%	86%	75%	100%	68%	64%	88%	87%	60%
1/17/2018 10 AM ET	60%	67%	100%	81%	61%	70%	61%	63%	56%	85%	61%
1/18/2018 6 AM ET	58%	50%	65%	76%	55%	66%	51%	55%	63%	100%	79%
2/15/2021 10 AM ET	100%	99%	83%	61%	69%	63%	56%	59%	58%	68%	55%
12/23/2022 6 PM ET	68%	87%	88%	99%	86%	85%	60%	56%	88%	91%	65%
12/24/2022 6 AM ET	63%	87%	87%	91%	77%	85%	49%	50%	100%	95%	66%

FIGURE 5 | Regional net load during recent extreme weather events, as a percentage of that region's maximum net load across all nine years. *Source: Grid Strategies*[27]

> **Utilizing interregional transmission to share resources across regions reduces the cost of building the power system, as less power plant capacity is needed to reliably meet peak demand in any individual region.**

These regional diversity benefits tend to be high, offsetting the cost of the transmission investment. One study based on NERC's interregional transfer capacity assessment found: "Each $1 invested in the transmission expansion recommended in NERC's [study] would yield benefits of $4.30 to $5.80, with a payback period of less than three years."[28] Looking at Winter Storm Uri, we concluded in a prior report that a 1 GW transmission line—costing approximately $700 million—between ERCOT and the Southeast could have imported enough energy into ERCOT to save Texas consumers nearly $1 billion just during that single storm;[29] in the next year, during Winter Storm Elliott, reversing flows on the same line could have saved Southeast consumers nearly $95 million.[30] These savings quickly exceed the cost of the transmission investment. In its 2024 National Transmission Planning Study, DOE found that "[a]ccelerated transmission expansion leads to national electricity system cost savings of $270–490 billion through 2050," and that such transmission investments "are more than compensated for by reduced electricity system costs for fuel, generation and storage capacity, and other costs."[31]

Finally, utilizing interregional transmission to share resources across regions reduces the cost of building the power system, as less power plant capacity is needed to reliably meet peak

27 *Id.*, 4

28 Goggin, M., Zimmerman, Z., Ammann, D., "NERC's Recommended Grid Expansion Would Save Consumers Billions" (Grid Strategies, 2025), https://gridstrategiesllc.com/wp-content/uploads/GS_NRDC_NERCs-Recommended-Grid-Expansion-Report54.pdf

29 Goggin, M. and Schneider, J. "The One-Year Anniversary Of Winter Storm Uri: Lessons Learned And The Continued Need For Large-Scale Transmission" (Grid Strategies, 2022), https://gridstrategiesllc.com/wp-content/uploads/the-one-year-anniversary-of-winter-storm-uri-lessons-learned-and-the-continued-need-for-large-scale-transmission.pdf

30 Goggin, M. and Zimmerman, Z., "The Value of Transmission During Winter Storm Elliott" (Grid Strategies, 2023), 2, https://acore.org/wp-content/uploads/2023/02/ACORE-The-Value-of-Transmission-During-Winter-Storm-Elliott.pdf

31 U.S. Department of Energy, "National Transmission Planning Study: Executive Summary" (2024), 2

demand in any individual region. Many regions, as reviewed in the Appendix of this report, have each documented how transmission enables them to take advantage of diversity in load patterns across their large footprints, saving billions of dollars per year in capital and fuel costs. Importing capacity from a neighboring region extends that diversity benefit and the associated savings even further.

Interregional transmission between regions with load and resource diversity has substantive, quantifiable benefits for resource adequacy and energy adequacy. But interregional transmission and interregional imports don't occur by chance—they require parties tasked with the responsibility to plan, coordinate and communicate carefully, accepted methods for cost allocation for new local and interregional transmission, acquisition of firm transmission capacity for future imports, and a willingness to pay for the resource and reliability value that transmission-enabled imports offer.

PART II

Capturing the value of interregional transmission for resource adequacy

Regions receive support from neighbors during resource scarcity events over interregional transmission lines. These imports leverage *existing* generation, storage and demand reduction capacity in neighboring regions, especially those regions with net load diversity from the importing region. However, resource adequacy practices often do not account for these flows, and resource planners do not often work actively to create such opportunities. By omitting this vital resource, resource adequacy assessments will ignore an important contributor to resource adequacy; that error may lead to overly high planning reserve margins charged to consumers or lower reliability. Furthermore, when the resource procurement process does not recognize and pay for the value of interregional transmission to deliver support during scarcity events, transmission developers are not incentivized to increase interregional transfer capability between regions.

Including transmission-enabled imports in RA assessments

All regions incorporate firm imports into their resource adequacy assessments (albeit in inconsistent ways), but non-firm imports are not always included. This ignores the benefit of net load diversity and resource mix diversity (discussed in Part I) with neighbors to reduce loss of load events and, therefore, planning reserve margins.

Several entities calculate net load diversity between themselves and neighbors using historic load data (*see* an example of PJM's net load diversity calculation in **Figure 6**), while others[32,33,34] calculate net load diversity between all regions during extreme events using modeled data for future systems. All RA assessments should include measures of diversity to recognize and capture potential imports from regions with less coincidence of peak load or stress events.

32 NERC, "Interregional Transfer Capability Study"

33 Deyoe, R., et al. "Interregional Transmission for Resilience"

34 Goggin, M., Zimmerman, Z., Sherman, A., "Quantifying A Minimum Interregional Transfer Capability Requirement"

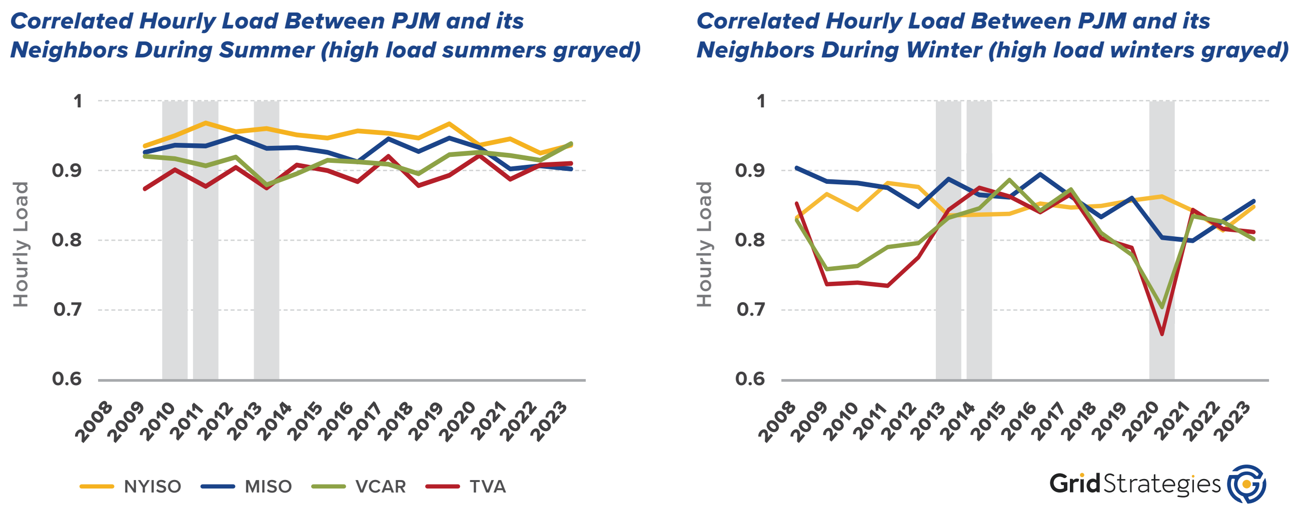

FIGURE 6 | How hourly load correlated between PJM and each of its neighbors during summer (left) and winter (right) over 15 years. High load summers and winters are grayed. *Data Source: PJM*[35]

Consideration of individual neighboring regions or zones in RA assessments can better identify and prioritize imports from neighbors with the most diverse load and resource mix relative to the planner's home region, as demonstrated by the Energy Systems Integration Group.[36] PJM, for example, directly reduces their planning reserve margin using the "capacity benefit of ties," but does not estimate that benefit for each neighboring region individually. Many regions like PJM border multiple neighbors with significantly different climates and power systems. As seen in Figure 4, regions with many neighbors will have more diversity with some over others. By calculating the RA contribution of all neighbors in aggregate, the planner may miss the potential strategic value of imports from a specific region.

The diversity between neighbors matters most during times of grid stress, when diversity offers more resource adequacy value, whether calculated using historical data or modeled for a future system. If the diversity factor is based on annual peak load instead of concentrated during times of grid stress, then this diversity factor should be calculated for each season individually to provide more granular resource adequacy information.

At its simplest, planners can look at historic imports to determine the amount and timing of non-firm imports to be included in LOLE studies. Considering historic imports during different seasons, as demonstrated by NYISO and CAISO (*see* Appendix), or only imports that materialized during previous capacity-tight periods, provides additional confidence that external support will be available in the future.

A more sophisticated method for this would identify and include the full distribution of possible non-firm imports in LOLE studies. Probabilistic RA assessments use numerous scenarios of possible resource outages and load levels to calculate the loss of load expectation for a future

35 Rocha-Garrido, P., "Capacity Benefit of Ties (CBOT) Update" (PJM, 2024), 4-8, www.pjm.com/-/media/DotCom/committees-groups/subcommittees/raas/2024/20241104/20241104-item-2---cbot-related-update.pdf. Figure created by authors using data available in the source documentation.

36 Deyoe, R., et al. "Interregional Transmission for Resilience"

system. Availability of non-firm imports based on historic import distributions can be added to these probabilistic assessments. MISO has demonstrated a version of this method by including distributions of historic imports during resource deficient events to calculate its seasonal LOLE values.[37] Figure 7 shows the likelihood that MISO will receive non-firm support from its neighbors in different seasons of the year.

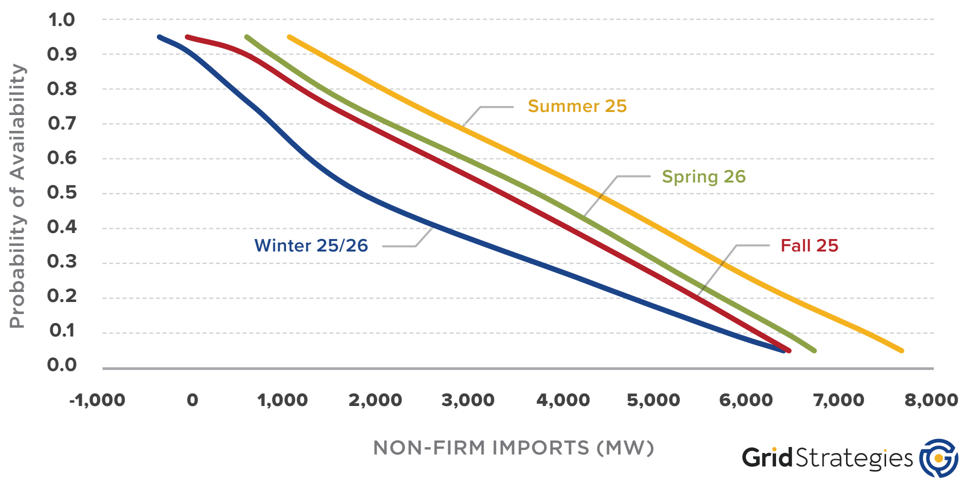

FIGURE 7 | **Likelihood (y-axis) that MISO received at least this much support from its neighbors (x-axis) during times of grid stress using historical import data.** *Data Source: MISO[38]*

Planners already recognize within-region transmission constraints in RA assessments to optimize the amount of capacity that can be shared internally across zones, minimizing the amount of new capacity needed to serve load locally. Performing a resource adequacy assessment which also includes the transmission constraints and resource portfolio of its neighboring regions—known as a wide-area RA assessment—takes this concept a step farther. Wide-area assessments identify capacity that can be shared across both internal and interregional zones, further minimizing the amount of new capacity needed to serve load locally. Ideally, such resource adequacy analyses would lead to integrated consideration of whether new interregional and intraregional transmission is needed to complement potential new supply and demand resources.

The National Energy System Operator (NESO) of Great Britian performs wide-area assessments for all of the European neighbors with which it has interconnecting ties.[39] NESO simulates grid stress events for both itself and its neighbors to determine the amount of external support it could expect from neighbors in the future. With knowledge of its neighbors' transmission systems, resource mixes, load profiles, and resource adequacy needs, NESO is able to calculate the amount of expected imports to maintain its own resource adequacy.

37 MISO, "Planning Year 2025-2026 Loss of Load Expectation Study" (2024)

38 *Id.*, 33. Figure created by the authors using the inverse cumulative distribution function of non-firm external support values from Table 3-10 of the source documentation.

39 National Energy System Operator (NESO), "Electricity Capacity Report 2024" (2025), 12-20, emrdeliverybody.nationalenergyso.com/IG/s/article/2024-25-CM-Auction-Guidelines-and-Parameters

Some U.S. regions are taking steps toward wider area assessments. MISO, ISO-NE, and NYISO include zonal representations of neighboring systems in their LOLE (*see* **Appendix**). studies. ISO-NE includes its neighbors' resource capacity, load profiles, and import capabilities (including the import capability of its neighbors' neighbors) in its LOLE study.[40] When modeling potential non-firm support, NYISO's model ensures that all neighbors are also able to maintain an RTO-wide LOLE of 0.1 day/yr when exporting into NYISO.[41]

Even those RTOs which include multi-area modeling in their RA assessments may not have a full representation of the transmission system and/or weather patterns across all regions, which have large implications for whether excess supply is available and can be shared with neighbors. Wide-area RA assessments require coordination between all modeled regions to be useful, as single-region RA models are overly simplistic. More on the importance of wide-area RA assessments and proposed methods to do them well are available in ESIG (2025).[42]

Accrediting the capacity value of interregional transmission

Though most regional planners have a method to incorporate transmission-enabled firm and non-firm imports in their RA assessments, there is no consistent method to calculate the capacity value of the interregional transmission that enables resource sharing. Without a measure of capacity value that can be easily integrated into resource adequacy assessments and capacity procurement processes, this value may be underrecognized, unaccredited and uncompensated.

Fortunately, most system planners already have experience calculating how much an individual resource contributes to resource adequacy for the system as a whole. These methods often rely on the historical performance, outage rates, weather-dependency, and marginal impact of increasing the penetration of a resource type to determine accreditation ratings. Transmission facilities are similarly impacted by forced outages, routine maintenance, weather-dependency (e.g., both high temperatures and low winds decrease transmission throughput) and marginal impact with increasing resource penetration. When accounting for these outage sources, high voltage transmission still maintains very high, near 100%, availability. The same industry standard accreditation methods used to rate generation, storage, and demand-side capacity resources can be applied to transmission lines to capture these dynamics.

Many planners use a resource's historic outages to determine its accredited capacity while others use a combination of the influencing factors noted above. Planners are becoming increasingly familiar with the effective load carrying capability method, though it is applied inconsistently across resource classes.[43] ELCC calculates the difference in loss of load expectation for the system without (baseline) and with the resource, specifically quantifying how much additional load the resource can support to return the system to the baseline LOLE.

40 ISO-NE, "Tariff Section III Market Rule 1 Standard Market Design, FERC Docket No. ER25-456-000, effective 2/28/2025" (2025), https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf

41 NYISO, "2024 Long-Term Resource Adequacy Assessment for NYSRC" (2025)

42 Stenlick, D. et al. "Wide Area Resource Adequacy Assessments: Probabilistic RA planning for interconnected grids" (ESIG, 2025)

43 Caravallo, J.P. et al., (2023)

Several regions have calculated the accredited capacity of firm and/or non-firm imports used in their LOLE studies, but these are performed for the entire *fleet* of transmission ties and potential imports, often without regard to which neighbor is exporting. **Table 2** shows the estimated capacity value of imports using reported accredited and installed capacities from several planning regions and utilities.

It is also possible to calculate the capacity value of individual high-capacity transmission facilities for delivering non-firm imports. NESO calculates this value for each of the interties to neighboring countries given knowledge about the availability of non-firm exports from each country. Nova Scotia recently evaluated the long-term ability of a proposed 345kV AC intertie with New Brunswick to offset the need for new generators (the equivalent of negative load in ELCC studies). And the ELCC method has been used to derive the capacity value of several individual high-voltage transmission lines in the United States.

One such line is the North Plains Connector HVDC transmission line (3,000 MW nominal rating) proposed between WECC, SPP, and MISO. The addition of the line lowered the baseline LOLE in all three regions significantly, by up to 84% (*see* **Figure 8**). The resulting accreditation of the line in each RTO was 400 MW in MISO, 1,350 MW in SPP, and 1,800 MW in WECC.[44] These values represent capacity values of 60% in WECC, 45% in SPP, and 13% in MISO. Collectively, the accreditation across all three regions sums to 3,550 MW, or 118% of the line's nominal rated capacity.

Accreditation above nameplate is possible for transmission lines because lines can be accredited separately in both directions, exploiting differing load and generation profiles on either end of the line. In the case of the North Plains Connector, the maximum capacity value of the East-to-West direction occurs in the winter, while West-to-East flows have highest value in the summer. Importantly, the line's capacity value does not include any new generation in either system. That value is created entirely by the load and generation diversity between the regions, which enables non-firm imports during scarcity events.

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44 Astrapé Consulting, "North Plains Connector (NPC) Evaluation: Final Report" (2024), 6-7

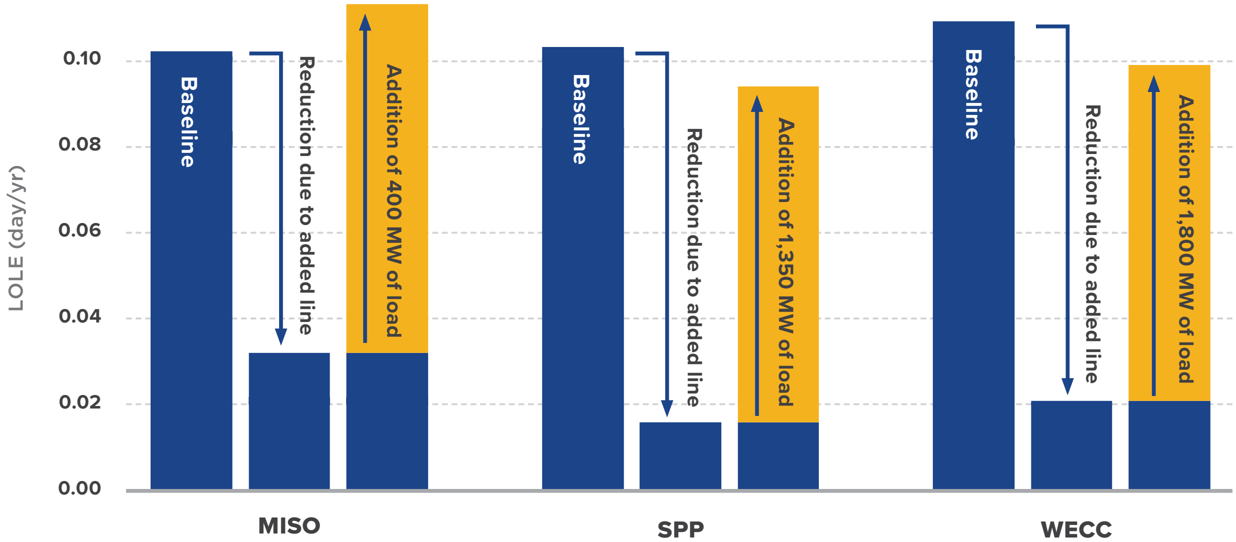

FIGURE 8 Demonstration of ELCC accreditation of the 3,000 MW North Plains Connector, which terminates in MISO, SPP, and WECC. Columns show the baseline loss of load expectation (LOLE) in each planning region, reduced LOLE (increased reliability) due to the addition of the transmission line, and the additional new load added to each region to return to the baseline LOLE. The associated capacity values of the transmission line are 60% in WECC, 45% in SPP, and 13% in MISO. *Source: Astrape Consulting,[45] with modifications*

In addition to having capacity values across multiple regions that exceed 100%, transmission lines can also contribute to resource adequacy and earn capacity accreditation in regions to which they are not directly connected. One example is the Three Corners Connector, a 1,800 MW transmission line that connects Public Service Company of Colorado (PSCo) and load zone 5 in SPP. The addition of the transmission line reduces the LOLE of both PSCo and SPP zone 5 to nearly 0 day/yr. The line has an ELCC contribution of 715 MW (40% capacity value) in PSCo and 1,362 MW (76% capacity value) in SPP zone 5.[46] The addition of the line also reduces the baseline LOLE of neighboring utilities in WECC and other load zones in SPP. While the ELCC contribution of the line in these areas was not reported, they could be calculated. Figure 9 demonstrates the LOLE reduction in all utilities and SPP zones from the addition of the line, and the ELCC calculation for PSCo and SPP zone 5. The capacity value of the North Plains Connector, Three Corners Connector and other domestic and international transmission facilities are summarized in Table 3.

45 *Id.*, 6-7. Figure created by authors given data in Fig.1 of source documentation.
46 Astrapé Consulting, “Three Corners Connector Project Evaluation: Final Report” (2024), 5-6

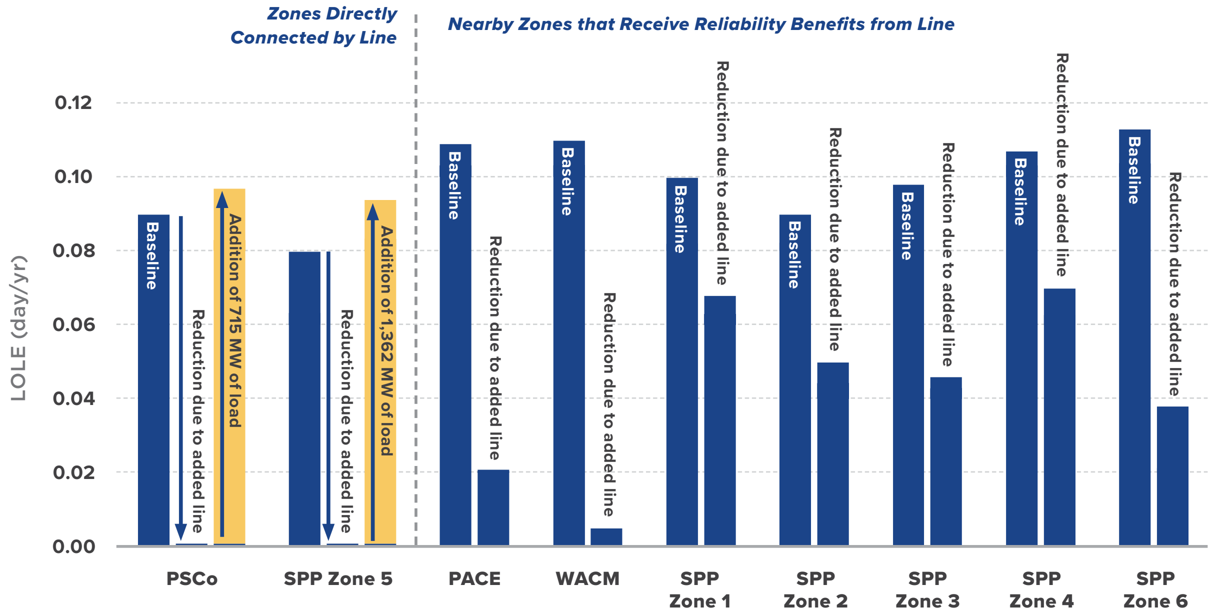

FIGURE 9 | Demonstration of ELCC accreditation of the 1,800 MW Three Corners Connector, which terminates in Public Service Company of Colorado (PSCo) and zone 5 of SPP. The reduction in baseline LOLE is also shown for neighboring SPP zones and WECC utilities (PacifiCorp East [PACE], Rocky Mountain region of Western Area Power Administration [WACM]). Columns show the baseline LOLE in each planning region, reduced LOLE (increased reliability) due to the addition of the transmission line, and the additional new load added to each region to return to the baseline LOLE. The associated capacity values of the transmission line are 40% in PSCo and 76% in SPP zone 5. *Source: Astrape Consulting,[47] with modifications*

Capacity value from interregional transmission can be expected to decline when there is more interregional transmission and excess generation in neighboring regions, just like with any other resource. But at this stage of the industry's evolution, where interregional transmission has experienced several decades of under-investment,[48] capacity values are likely to be very high between many systems.

47 *Id.*, Figure created by authors given data in Figs.1 and 9 of source documentation.
48 U.S. Department of Energy, "National Transmission Needs Study" (2023), 20-24, https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf

TABLE 2 | Capacity value and associated resource adequacy contributions of firm and non-firm imports used in regional planners' RA assessments. Reduction in reserve margins is not a reduction in system reliability, but rather a reduction in the amount of capacity needed to maintain resource adequacy.

Region	Import type	Nameplate capacity (MW)	Accredited capacity (MW)	Reported reduction in RA metric	Reduction in reserve margin	Equiv. capacity value (accredited / nameplate)
Tennessee Valley Authority (a)	Non-firm		4,750		8%	
Southern Company (b)	Non-firm		2,714		1.75%	
Desert Southwest (APS, AEPCO, EPE, PNM, SRP, TEP) (c)	Non-firm		1,379	LOLE: 0.04 day/yr NEUE: 0.34 ppm		
Public Service Colorado (d)	Non-firm		390		4.70%	
Idaho Power (e)	Non-firm	100	14			14%
MISO (f)	Firm	1,986	1,935		1.60%	97%
	Non-firm	12,000	4,351		3.50%	36%
SPP (g)	Firm	2,255	2,255		3.60%	100%
CAISO (h)	Firm		1,700		3.80%	
PJM (i)	Firm	1,485	1,269		1.10%	85%
	Non-firm		2,937		1.50%	
NYISO	Firm (j)		1,600		5.1%	
	Non-firm (k)		3,500 (max)	LOLE: 0.42 day/yr		
ISO-NE	Firm (l)	1,936	1,870		6.0%	97%
	Non-firm (m)	3,980	2,175	LOLE: 0.724 day/yr	7.0%	55%

Notes | Unless otherwise stated, all capacity value calculations are estimated by the authors using industry reported information. Blank cells indicate the calculation was not performed, not reported, or cannot be estimated from reported information.

(a) Summer max imports and "island" market imports sensitivity results. Source: Tennessee Valley Authority, "Integrated Resource Plan 2025" (2024), D-5 to D-7

(b) Summer values reported. Total fleet of installed transfer capability not reported. Source: E3 Consulting, "2024 Public Service Company of Colorado Resource Adequacy Study: Analysis of Planning Reserve Margin Requirements & Effective Load Carrying Capability" (2024)

(c) Accredited non-firm imports measured as difference between regional support and base case effective capacity surplus values. Source: Schlag, et al., "Resource Adequacy in the Desert Southwest" (E3, 2023), 86

(d) Results of the "islanded system" sensitivity found that removing all firm imports increased the reserve margin associated with a 1 in 10 LOLE threshold from 25.75% to 27.50%. Source: Southern Company, "An Economic and Reliability Study of the Target Reserve Margin for the Southern Company System" (2025)

(e) 100MW of shared resources via WRAP found to offset 14MW of perfect generation capacity in Idaho Power's LOLE studies. Source: Idaho Power, "2023 Integrated Resource Plan Appendix C: Technical Report" (2023), 91-92, docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2023/2023-appendix-c-final.pdf

(f) Summer values are reported. Firm installed capacity is reported ICAP value and accredited capacity is UCAP. Non-firm installed capacity is modeled perfect capacity available from the outside world and accredited capacity is the 50% probability of summer imports. Reduction in PRM calculated as difference in PRM UCAP of all available resources without and without each import type. Source: MISO, "Planning Year 2025-2026 Loss of Load Expectation Study" (2024), 33

(g) Reduction in reserve margin calculated with and without firm external imports for the 2029/30 planning year in summer. Source: SPP Resource Adequacy, "2024 Loss of load expectation study report" (2025)

(h) Reduction in reserve margin calculated as difference in PRM with and without modeled 1,700 MW of firm interchange. Source: California Public Utility Commission, "Loss of Load Expectation Study for 2026 Including Slice of Day Tool Analysis" (2024), docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M536/K273/536273741.PDF

(i) Firm imports are the ICAP value of imports and non-firm imports are the product of CBOT (1.5%) and ICAP for generation (195,831 MW) for 2025/2026 Base Residual Auction. Source: PJM, "2025/26 Base Residual Auction Report" (2024), 9-12, www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.pdf

(j) Firm imports are capacity purchases from external areas over fleet of interregional ties. Source: NYISO, "Gold Book" (2024), https://www.nyiso.com/documents/20142/2226333/2024-Gold-Book-Public.pdf/170c7717-1e3e-e2fc-0afb-44b75d337ec6

(k) Non-firm import change in LOLE difference between steps 8 and 9 for addition of external assistance in LOLE calculation. Source: NYISO, "2024 Long-Term Resource Adequacy Assessment for NYSRC" (2025), https://www.nysrc.org/wp-content/uploads/2025/02/A.3-R2-2024-NY-Long-Term-Resource-Adequacy-Assessment.pdf

(l) Accredited firm imports are cleared imports in the ARA 3 capacity auction across all ties for the 2025/26 summer. Nameplate capacity of firm imports calculated using reported EFORd of 3.7%, average for all ISO-NE ties. Reduction in reserve margin calculated using Net Installed Capacity Requirement formula assuming an additional load carrying capacity of 4,138 MW. Source: Saarela, H., "Installed Capacity Requirement (ICR) and related values calculations assumptions for the Annual Reconfiguration Auctions (ARAs) to be conducted in 2025 rev.1" (2024), https://www.iso-ne.com/static-assets/documents/100014/a03_annual_reconfigurationauction_icr_related_values_development.pdf

(m) Accredited non-firm import values are the adjusted tie benefit calculations for the entire fleet of ISO-NE ties. Nameplate values are the sum of import capacity of each tie, including both firm and non-firm imports. Reduction in reserve margin calculated using Net Installed Capacity Requirement formula assuming an additional load carrying capacity of 4,138 MW. Source: Bringolf, M., "Tie Benefit Values: For Reconfiguration Auctions to be Conducted in 2025" (2024), https://www.iso-ne.com/static-assets/documents/100015/a03_review_of_2025_2026_ara_3_tie_benefits_study_results.pdf

TABLE 3 | Capacity value and associated resource adequacy of interregional transmission facilities. While calculable, the capacity value of transmission facilities is rarely fully incorporated into resource adequacy assessments and/or resource procurement processes of planners in the United States.

Transmission Facilities	Accrediting region	Number of associated facilities	Nameplate capacity (MW)	Accredited capacity (MW)	Reported reduction in LOLE (day/yr)	Capacity Value (accredited / nameplate)
North Plains Connector [a]	WECC	1	3,000	1,800	0.088	**60%**
	SPP			1,350	0.087	**45%**
	MISO			400	0.070	**13%**
Three Corners Connector [b]	PSCo	1	1,800	715	0.09	**40%**
	SPP			1,362	0.054	**76%**
Grain Belt Express Phase 1 [c]	MISO	1	2,500	2,116	0.06	**85%**
	SPP			450		**18%**
Boardman to Hemingway [d]	Idaho Power	1	750	700	0.006	**93%**
CAISO Interties [e]	CAISO	45	39,923	16,148		**40%**
NS-NB Reliability Intertie Project [f]	Nova Scotia	1	300 (est.)	200		**67%**
North Sea Link [g, h]	NESO	1	1,400	1,316		**94%**
NESO - Ireland Interties [g, i]	NESO	3	1,500	1,050		**70%**
NESO – France Interties [g, j]	NESO	3	4,000	2,680		**67%**
Nemo Link [g, k]	NESO	1	1,000	800		**80%**
Viking Link [g, l]	NESO	1	1,400	1,204		**86%**
BritNed [g, m]	NESO	1	1,000	840		**84%**
ISONE - Maritimes [n]	ISONE	2	980	770	0.469	**78%**
ISONE - HQ Phase II [n]	ISONE	1	1,400	1060	0.556	**76%**
ISONE - HQ Highgate [n]	ISONE	1	200	160	0.137	**80%**
ISONE - NYISO Ties [n]	ISONE	8	1,400	730	0.454	**52%**
Soo Green [o]	ComEd	1	2,100	2,016	0.1	**96%**
Champlain Hudson Power Express [p]	NYISO	1	1,250	1,250	0.008	**100%**

Notes | Because transmission lines can be accredited differently in multiple directions, the importing capacity is listed for the named entity in the Accrediting region column. Blank cells indicate the calculation was not performed, not reported, or cannot be estimated from reported information.

(a) Specifically accredited capacity value of line via ELCC method. Source: Astrapé Consulting, “North Plains Connector (NPC) Evaluation: Final Report” (2024), 6-7

(b) Specifically accredited capacity value of line via ELCC method. Load was only added to SPP Zone 5, the eastern termini of the line, but the reduction in LOLE and accredited capacity for the entire RTO is reported. Source: Astrapé Consulting, “Three Corners Connector Project Evaluation: Final Report” (2024), 5-6

(c) Combined annual average accreditation of non-firm (Scenario 3) and firm (Schedule 53) generation resources associated with the transmission facility. Firm and non-firm generation contribute to capacity value in MISO but only non-firm contributes in SPP. LOLE reduction in MISO from Scenario 3. Source: Collins, S., Smith, N., and Carden, K., "Grain Belt Express Phase 1 Capacity Accreditation" (PowerGEM, forthcoming), 16-18 and 21-23.

(d) Idaho Power is allocated 750 MW of West to East import capacity and assumes between 400 (winter) and 700 MW (summer) of accredited capacity will be imported from the line. A comparison of two scenarios with and without the B2H showed an increase in LOLE in 2027, the first year that the line was fully operational. Additional resources were added to the “without B2H” scenario to make up for energy shortfall, so the LOLE reduction from the addition of B2H is not isolate to the line alone. Source: Idaho Power, “2021 Integrated Resource Plan: Appendix C” (2021), 24, 82, and 100.

(e) Equivalent capacity value of fleet of 45 interregional paths is ratio of Operating Transfer Capability (OTC) and Maximum Import Capability for all import paths used in 2025 RA analysis. Capacity values could be calculated for each path individually. Source: CAISO, “Maximum RA Import Capability for Year 2025” (2024)

(f) Nameplate capacity for intertie not provided, so set equal to import limit of sister intertie. Production cost modeling through 2050 found this facility offset need for two 100MW “perfect capacity” generation units. Sources: Energy + Environment Economics, “Evaluation of NS-NB Reliability Tie Project Benefits Modeling: Report to the Wasoqonatl Transmission Inc.” (2025) and Wasoqonatl Transmission Inc., “NS-NB Reliability Intertie Project Application” (Nova Scotia Energy Board, 2025)

(g) Tie “derate factors” between countries determined for 102 tightest resource hours using 34 historic weather years; aligned with LOLE target of 3 hours per year. Nameplate capacity of individual facilities provided in additional citations. Source: National Energy System Operator, “Electricity Capacity Report 2024” (2025), 12-20

(h) HVDC between Great Britian and Norway, nameplate capacity from National Grid. Source: “North Sea Link,” National Grid, accessed May 19, 2025, https://www.nationalgrid.com/national-grid-ventures/interconnectors-connecting-cleaner-future/north-sea-link

(i) Three HVDC interties (East West Interconnection, Moyle, and Greenlink) between Great Britain and Ireland island (both Northern Ireland and Republic of Ireland) are each rated 500 MW. Source: “Interconnection,” EirGrid, accessed May 19, 2025, https://www.eirgrid.ie/industry/interconnection

(j) Three HVDC interties between Great Britain and France include the 1000 MW ElecLink, 1000 MW IFA, and the 2000 MW IFA2 lines. Sources: Enerdata, “IFA2 power transmission line (France-UK) enters commercial operations,” (2025), https://www. enerdata.net/publications/daily-energy-news/ifa2-power-transmission-line-france-uk-enters-commercial-operations.html and Sharpe, L., “ElecLink awards Channel Tunnel interconnector construction contract” (Engineering and Technology 2017), https://eandt.theiet.org/2017/02/24/eleclink-awards-channel-tunnel-interconnector-construction-contract

(k) Tie between Great Britain and Belgium. Source: EliaGroup, “The Nemo Link interconnector celebrates its fifth anniversary” (2024), https://www.eliagroup.eu/en/press/2024/02/20240131_5th-anniversary-nemo-link

(l) Tie between Great Britain and Denmark. Source: “Viking Link,” National Grid, accessed May 19, 2025, https://www.nationalgrid. com/national-grid-ventures/viking-link

(m) Tie between Great Britain and Netherlands. Source: “BritNed,” TenneT, accessed May 19, 2025, https://www.tennet.eu/projects/britned

(n) LOLE reduction measured as difference between baseline system with no ties (cut 1) and each set of ties added individually (cuts 29-32 vs. cut 1). Accredited capacity is equivalent tie benefit from each LOLE scenario “cut” and nameplate capacity is assumed interface import capability. Source: Bringolf, M., “Tie Benefit Values: For Reconfiguration Auctions to be Conducted in 2025” (2024), https://www.iso-ne.com/static-assets/documents/100015/a03_review_of_2025_2026_ara_3_tie_benefits_study_results.pdf

(o) Soo Green line is estimated to drop the LOLE in ComEd service territory (PJM East area) to 0 day/yr in 2030 and to 0.01 day/yr in 2040. ELCC analysis provides a capacity value of 96% in 2030 and 92% in 2040. 2030 values presented in the table. Source: Illinois Power Agency, “2024 Policy Study Draft for Public Comment. Prepared pursuant to P.A. 103-0580” (2024), vii, https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/ipa-2024%20-draft-policy-study-22-jan-2024.pdf

(p) Firm imports for Champlain Hudson Power Express using the “Delayed CHPE” scenario 2026 summer LOLE results. Source: NYISO, “2024 Long-Term Resource Adequacy Assessment for NYSRC” (2025), https://www.nysrc.org/wp-content/uploads/2025/02/A.3-R2-2024-NY-Long-Term-Resource-Adequacy-Assessment.pdf

Fostering interregional transmission development and accounting for its capacity value

Load serving entities on either end of an interregional transmission facility could realize significant resource adequacy contributions from the transmission facility, even without firm generation associated with the facility. The resource adequacy contribution can be incorporated in at least two ways that provide appropriate transmission investment incentives: reducing the LSE's capacity obligation or accrediting and compensating the transmission line owner. In either case, the LSE could make an economic choice between local generation, local demand response, firm imports, and non-firm imports enabled by interregional transmission. Both approaches put interregional transmission on an equal footing with other contributors to resource adequacy, creating an additional incentive for transmission developers to increase interregional transfer capability. Regulatory oversight of associated decisions may be necessary as vertically integrated utilities often lack an incentive to procure less-expensive external resources even though it would lower costs for ratepayers.

Whoever receives the capacity credit (LSE or line owner) should be eligible to submit new transmission facilities or upgrades into capacity procurement processes. Winning bids would be compensated for their capacity value. Such compensation mechanisms have been considered in MISO.[49,50,51] In isolated capacity procurement processes, developers could choose if they would rather be compensated for supplying capacity or participate in the transmission planning process and receive rate recovery.[52]

In linked resource adequacy and transmission planning processes, new or upgraded transmission facilities evaluated for their energy, resilience, economic, and public policy benefits could also be tested for their capacity benefits in the resource adequacy framework. Any capacity value identified would be added to the reliability, economic congestion, and/or public policy benefits that facility provides to the transmission system. This would increase the benefit-to-cost ratio of the facility, prioritizing facilities that improve resource adequacy in addition to other metrics considered in the transmission planning process.

49 Kowalczyk, A., "Capacity Accreditation for External Resources facilitated by HVDC Transmission" (MISO 2024), https://cdn.misoenergy.org/20240710%20RASC%20Item%2005%20New%20Issue%20-%20Capacity%20Accreditation%20for%20External%20Resources%20facilitated%20by%20HVDC%20Transmission633062.pdf

50 "Capacity Accreditation for External Resources facilitated by HVDC Transmission RASC-2024-5," MISO, modified July 23, 2024, https://www.misoenergy.org/engage/MISO-Dashboard/capacity-accreditation-for-external-resources-facilitated-by-hvdc-transmission/

51 Grid United, "The Need for HVDC Intertie Accreditation" (MISO, 2025), https://cdn.misoenergy.org/20250429%20HVDC%20Workshop%20Item%2002a%20Need%20for%20HVDC%20Intertie%20Accreditation693665.pdf

52 Stenclik, D., "Transmission as a Capacity Resource" (Telos, 2025), https://www.telos.energy/post/transmission-as-a-capacity-resource

PART III

Recommendations

This report discusses the resource adequacy contribution of interregional transmission, highlighting current industry practices and needed improvements. We identify several recent studies which quantify the value of 17 transmission facilities (*see* **Table 3**) using industry-standard LOLE and/or ELCC methods. But until interregional transmission planning is conducted consistently and in a coordinated fashion across multiple regions, the many potential benefits of new interregional transmission projects across the entire nation may never be realized.

To fully capture the resource adequacy value of transmission-enabled imports:

1. **System planners that do not already include the contribution of transmission-enabled imports in their resource adequacy assessments should do so.**

   This can be done through LOLE reduction, planning reserve margin reduction, or wide area assessments. Importantly, reductions to planning reserve margins are not a reduction in system reliability, but rather a reduction in the amount of capacity needed to maintain resource adequacy. Best practices for non-firm imports include measuring this contribution for each neighbor individually and during times of grid stress. A probabilistic treatment of available non-firm imports helps prevent over-reliance on this resource. Consideration of the historic performance of firm and non-firm imports is important to validate that the resources are available when they are needed most.

2. **System planners should determine the capacity value of major interregional transmission facilities by measuring the change in resource adequacy (e.g., LOLE or expected unserved energy) with and without the facilities given resource availability on the other end of the facility.**

   When calculating the capacity value, it is best practice to consider seasonal accreditation and peak load diversity with specific neighboring regions, rather than average annual accreditation and average diversity with all neighbors in aggregate.

   FERC might consider directing regional system planners to expand upon the NERC *Interregional Transfer Capacity Study* with a deeper investigation of the potential capacity values of new interregional transmission.

3. **Regulators and system planners should foster the development of interregional transmission that directly contributes to resource adequacy.**

   Such efforts could include establishing an interregional transmission planning process with transmission rate-base cost recovery, enabling merchant transmission development with the capacity value assigned either to the asset or to load-serving entities through a reduction in their capacity obligations (i.e., RA requirements), or some other means.

   Regulatory oversight of capacity procurement decisions may be needed to ensure utilities make decisions which benefit ratepayers most.

APPENDIX

Current resource adequacy and transmission accreditation practices

This report suggests improvements to how imports are modeled and incorporated into regional resource adequacy assessments, and how to accredit capacity value to the interregional transmission which enables these imports. This Appendix summarizes the existing resource adequacy and capacity accreditation practices of all U.S. transmission planning regions. While this Appendix reviews regional resource adequacy and resource procurement practices at a high level, more details on these general and evolving practices can be found in published regional guidelines and industry literature.[53,54,55]

While every region approaches resource adequacy using slightly varying reliability criteria and widely varying rules and methodologies, all of the regions studied conduct their reliability planning using some common assumptions:

1. All regions rely on interregional transmission (*see* **Figure 2**) imports to some degree, whether very limited (1-4% of peak demand) or moderate (10-15% of peak) to meet their reliability goals (*see* **Table 1**).
2. Every region has a formal process for counting and accrediting firm import availability subject to transmission constraints.
3. Regions that use capacity markets let firm imports qualify to bid as capacity for the upcoming reliability periods.
4. Imports—whether interregional, as between MISO and PJM, or intraregional, as between Georgia and Florida—reduce the amount of in-region capacity needed to attain reliability goals such as planning reserve margin (PRM) or loss of load expectation (LOLE), and thus reduce how much in-region (or sub-region) customers need to pay for additional generation investments.
5. As energy adequacy issues increase with rising renewables and energy storage penetrations,

53 Stenclik, D., et al., “Ensuring Efficient Reliability”

54 Stenclik, D., et al., “New Resource Adequacy Criteria for the Energy Transition”

55 Carvallo, J.P., et al.

energy trades between regions enhance regional flexibility and lower energy costs on both sides of the trade.

6. Most regions value imports particularly to improve resilience against extreme weather events, which raise demand as they exacerbate weather-correlated fuel delivery problems and generation forced outages.
7. Most of the RTO-managed regions coordinate or integrate their transmission and resource planning with reliability and energy adequacy planning.

There are several inconsistencies and gaps in how regional planners conduct RA assessments and capacity accreditation as they relate to interregional transmission and imported capacity. These include:

1. Many planners do not include non-firm imports in their resource adequacy assessments, potentially missing opportunities to increase system reliability and reduce the need for new internal capacity.
2. Only a couple of regional planners consider the historical performance of imports to validate that accredited imports will be available at the time of grid need. Historical performance is a good indicator of capacity value across all capacity resource types, including firm and non-firm imports.
3. Few planners are considering how import potential varies between individual neighbors. Similarly, very few planners are evaluating the RA contribution of firm and/or non-firm imports during times of grid stress. These practices ignore valuable information about which neighbors may have correlated scarcity events during extreme events. By considering neighbor-specific imports during scarcity events, regions can better prioritize imports which provide the most benefit.
4. Few planners in our survey are assigning a capacity value less than 100% to firm imports, and none are assigning capacity values to the transmission facilities which enable non-firm imports.[56] Capacity values can be assigned to interregional transmission facilities using existing probabilistic capacity accreditation methods already used by planners today.
5. Although all regions recognize that transmission-enabled imports have value for meeting resource adequacy and reliability goals, not all regions are actively trying to build new interregional transmission capacity to increase future import capabilities.

CAISO

Resource Adequacy Assessment

The California state agencies and CAISO have developed a highly detailed process for resource adequacy and transmission planning. CAISO's transmission and resource adequacy planning processes are closely integrated and use assumptions and forecasts developed by the California

56 Given the nature of non-firm imports, the generator facilities supplying energy cannot be easily accredited in resource adequacy planning, but the transmission facilities which deliver the capacity can be.

Public Utility Commission's (CPUC) Integrated Resource Planning process[57] and the California Energy Commission's Integrated Energy Policy Report.[58] The state agencies and CAISO issue a set of unified planning assumptions and study plan covering the entire transmission planning process.

The CPUC conducts a Loss of Load Expectation Study at least once every two years for consideration in the CPUC's RA proceeding.[59] The assessment uses an RA threshold of 0.1 day/yr LOLE to determine an adequate planning reserve margin level, which is recommended to the CPUC for adoption.[60] For the 2025 planning year, the PRM was set to 17%.[61] The LOLE Study for the 2026 planning year initially recommended an RTO-wide PRM of 18.5%,[62] but was later revised to 23.5% for half of the year and to 26.5% for the other half[63] to accommodate RA framework and modeling changes.[64]

The CPUC introduced a new resource adequacy framework, called the Slice of Day Framework, to be implemented in 2025.[65] It is intended to address the LSEs' hourly capacity requirements and hourly energy sufficiency needs given the increasing penetration of energy-limited energy sources. The framework lays out how to calculate an LSE's hourly resource adequacy needs based on its gross load profile plus a planning reserve margin (for excess energy) on the "worst day" of each month.

California's resource adequacy framework contains three sets of RA requirements covering different operational scales. First, a system RA requirement obligates each LSE to cover its load forecast plus the CPUC determined planning reserve margin. Second, a local RA requirement is calculated for each LSE individually given the unique energy needs and system constraints of that LSE. Finally, a flexible RA requirement is calculated using the largest 3-hour ramp expected in each month, which obligates LSEs to procure quick- ramping resources in order to support steep increases in hourly load.[66]

The CPUC issued annual Resource Adequacy Reports meant to review RA performance from previous years through 2022 (last issued in May 2024),[67] but with the extensive changes to the RA process those reports will change in future years.

57 "Integrated Resource Plan and Long Term Procurement Plan (IRP-LTPP)," California Public Utilities Commission (CPUC), accessed May 10, 2025, https://www.cpuc.ca.gov/irp/

58 "2025 Integrated Energy Policy Report," California Energy Commission (CEC), accessed May 10, 2025, https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2025-integrated-energy-policy-report

59 CPUC, "Fact Sheet on the proposed decision in Track 2 of the RA Proceeding" (R.23-10-011), (Dec 2024)

60 CPUC, "Loss of Load Expectation Study for 2026 Including Slice of Day Tool Analysis: Recommendation for the Slice of Day Planning Reserve Margin" (R.23-10-011), (2024), docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M536/K273/536273741.PDF

61 CPUC (2023), "Fact Sheet on Resource Adequacy Decision in D.23-06-029, Decision in Phase 3 of the Implementation Track in the Resource Adequacy (RA) Proceeding," (R.21-10-002).

62 CPUC, "Loss of Load Expectation Study for 2026 Including Slice of Day Tool Analysis"

63 CPUC, "Appendix A to Loss of Load Expectation Study for 2026: Revised Slice of Day Tool Analysis (R.23-10-011), (2024), docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M539/K203/539203368.PDF

64 CPUC "Fact Sheet on the proposed decision in Track 2 of the RA Proceeding"

65 CPUC, "2025 Resource adequacy and slice of day filing guide" (2024), https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/guides-and-resources/2025-ra-slice-of-day-filing-guide.pdf

66 *Id.*

67 CPUC, "2022 Resource Adequacy Report" (2024), https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2022-ra-report_05022024.pdf

Resource accreditation and procurement

The California PUC has placed a resource procurement burden on each of the load serving entities in CAISO. LSEs must enter into bilateral capacity contracts with generating facilities directly. All facilities must participate in CAISO's day-ahead and real-time energy markets to be eligible to meet the resource adequacy obligation.[68] Additionally, resources must be deliverable (i.e., have firm transmission) to provide resource adequacy.

LSEs are required to make annual and monthly compliance filings showing they can meet the system, local, and flexible RA requirements. While compliance rules differ for individual LSEs, in general LSEs are required to show that they can meet 90% of the annual RA requirements and 100% of the monthly requirements.[69]

CAISO applies a non-uniform capacity accreditation methodology to different supply resources. Non-intermittent, dispatchable resources are accredited based on their maximum capability. Non-intermittent, non-dispatchable resources are accredited based on either their historic performance or previous bids into the day-ahead market. Intermittent resources are accredited based on the effective load carrying capability method.[70]

Consideration of intraregional transmission

The local RA requirement portion of an LSE's total capacity obligations is meant to account for transmission constraints that may limit the transfer of resource output between LSEs.[71] Load areas that are transmission-constrained may need to procure more RA capacity within their zone until additional transfer capacity can be built. CAISO calculates the intraregional transfer capability limits between zones considering the complete CAISO transmission topology and major outages that could occur to the transmission system.[72]

The CAISO conducts a 20-year transmission outlook plan, to serve load and interconnect resources in alignment with the state's greenhouse gas and renewables policy targets and the load forecasts. California anticipates using extensive buildouts of land-based and offshore wind, solar, and batteries to meet its policy goals and resource adequacy requirements. CAISO has identified major upgrades needed to its existing bulk transmission footprint (up to $11.5 billion cost) and new lines (up to $36.5 billion).[73]

Consideration of interregional transmission and neighboring support

CAISO is import-dependent and therefore transmission-dependent. By 2045, CAISO expects to meet at least 10% of its resource adequacy needs from imports and will need to spend at least $15 billion on new high voltage transmission lines to import resources from Wyoming, Idaho and New Mexico. Three new interregional transmission lines—SWIP-North, SunZia, and TransWest

68 *Id.*

69 CPUC, "2022 Resource Adequacy Report"

70 *Id.*

71 CAISO, "Local capacity technical study: final report and study results" (Apr 2024), stakeholdercenter.caiso.com/RecurringStakeholderProcesses/Local-capacity-requirements-process-2025

72 *Id.*

73 CAISO, "2024 Twenty-year transmission outlook" (2024), https://www.caiso.com/documents/2024-20-year-transmission-outlook-jul-31-2024.pdf

Express—have been approved and allocated to import 5.7 GW of new resources into CAISO.[74]

CAISO includes firm imports in its resource adequacy assessments, but not non-firm imports. There are two types of firm imports allowed for RA, resource-specific and non-resource specific. Resource-specific are tagged generation facilities outside of the CAISO control area. Non-resource-specific imports are not tied to a specific generator but must be supported by a bilateral contract with an entity that sources resources outside of the control area. Like all resources, both resource- and non-resource-specific imports must self-schedule or bid into the energy markets to be eligible to meet RA obligations. [75] In 2022, most LSEs used more resource-specific imports rather than non-resource-specific to meet their RA obligations. Still, non-resource-specific imports still accounted for up to 7.2% of capacity used to meet LSE's RA obligations in that year.[76]

CAISO explicitly considers interregional transmission when accrediting firm imports. CAISO calculates the maximum import capability of all existing interties and will determine available import capability by accounting for existing contracts and transmission ownership rights.[77] CAISO assumes that full transfer capability will be used by firm imports in its annual resource adequacy plans. CAISO reviews historic imports by each transmission allocation holder and line to determine whether the transmission holder used its full import capability allocation in preceding years. Then it develops a 10-year forward-looking advisory estimate of future resource adequacy import capability for each import path. The equivalent capacity value of all CAISO interties are shown in **Table 2** as a fleet, though the capacity value could be calculated for all individual paths from the source documentation.

Usually in resource adequacy assessments, proxy generation will be added or removed from an area to determine the amount of reserve necessary to maintain a target loss of load expectation. In the CPUC 2026 LOLE Study, however, simultaneous import capability was used as the lever to determine the planning reserves necessary to meet the LOLE threshold. The 0.1 day/yr LOLE threshold for CAISO was found by reducing the simultaneous import constraint from 4,000 MW to 2,500 MW, implying a 1,500 MW surplus exists between all planned resources and the forecasted peak demand for the 2026 planning year.[78]

Non-RTO West

Resource Adequacy Assessment

Individual balancing authorities in the Western Interconnection are largely responsible for their own resource adequacy. Unlike in the Eastern Interconnection, the majority of utilities in the Western Interconnection do not fully participate in an RTO. While an RTO performs resource adequacy modeling and can aid in capacity procurements across its entire footprint, these

74 *Id.*

75 CPUC, "2025 Resource adequacy and slide of day filing guide"

76 CPUC, "2022 Resource adequacy report"

77 CPUC, "2025 Resource adequacy and slide of day filing guide"

78 CPUC, "Loss of Load Expectation Study for 2026 Including Slice of Day Analysis" (2024), www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/slice-of-day-compliance-materials/2026_lole_final_report_07192024.pdf

responsibilities fall to individual LSEs outside of RTO frameworks.

The non-RTO West includes a patchwork of organizations with resource adequacy in their mandates. Most utilities are obligated to determine the amount of generating reserves required to meet resource adequacy, the threshold for which may be determined by state law or regulations.[79] Most western utilities use a single expectation metric to quantify the acceptable frequency of load loss events (usually a 1-day-in-10-years loss of load expectation). The Northwest Power and Conservation Council (NWPCC), which recommends transmission plans for the Bonneville Power Administration (BPA) system in the Pacific Northwest, uses multiple probabilistic metrics to quantify the frequency, magnitude and duration of load loss events.[80] Carvallo, J.P., et al. reviews the RA thresholds that many western utilities use to calculate their reserve margins.

Resource Accreditation and Procurement

Methods to accredit resources for providing resource adequacy vary significantly across the western utilities. Many use the effective load carrying capability method for intermittent and battery storage facilities and the unforced outage capability for thermal, nuclear, and pumped hydro storage. Others are applying ELCC to all supply resources, regardless of resource type. Schlag, N., et al.[81] review the resource accreditation methods used by many western utilities.

Utilities procure supply to meet their load and reserve needs by building utility-owned generation, purchasing power from independent power producers, or through bilateral agreements to trade power with neighboring utilities. Some of these transactions use firm transmission commitments while others use non-firm transmission as available. In bilateral transactions, a specific amount of power trade is established contractually with each supply source, instead of relying on a pool of producers across a wider region to provide generation.

The Western Power Pool has established a new program—the Western Resource Adequacy Program (WRAP)—to help coordinate power trading for resource adequacy.[82] WRAP uses an RA threshold of 1-day-in-10-years LOLE across the entire Western Interconnection footprint to calculate each subregion's planning reserve margin.[83] Participating utilities will be assigned individual reserve requirements in order to meet the region-wide requirement.[84] During actual emergencies, WRAP operators will identify any utilities with excess reserves in real-time and coordinate the transfer of that power to utilities experiencing shortfalls subject to transmission availability.[85]

Centralized coordination of trading should speed the response of transfers between utilities and help maintain resource adequacy across the non-RTO West. The non-RTO West has good resource diversity across a very large footprint. Load in the Pacific Northwest peaks in the

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79 Carvallo, J.P., et al.

80 Gai, D.H.B., "Memorandum Western Resource Adequacy Program Update" (2024)

81 Schlag, N., et al.

82 WRAP has delayed binding resource commitments and trading operations from 2025 to 2029, extending the transition period for participating utilities to gain more comfort with the program. Source: Roy, R., "Western Resource Adequacy Program" (Northwest Power and Conservation Council, 2024)

83 Western Power Pool (WPP), "Western Resource Adequacy Program Business Practice Manual 102 Forward Showing Reliability Metrics, rev. 1.0" (2024)

84 *Id.*

85 WPP, "Western Resource Adequacy Program Tariff" (2025)

winter months and in the summer for the rest of the West.[86] As an indication of the value of coordinated reserves, Idaho Power tested participation in the Western Resource Adequacy Program to see how much benefit they would receive from sharing resources during grid stress events. They found that utilizing shared resources via WRAP on six recent highest-risk days could have offset 14MW of perfect generation capacity, demonstrating the value of coordinated reserves.[87]

The 2021 Integrated Resource Plans of the several desert southwest utilities demonstrated adequacy through 2033.[88] These plans became less sufficient, however, given load growth of even 3% more than what was anticipated in 2021.[89] Northwestern utilities face a similar outlook. The Pacific Northwest has adequate resources under the plan developed by NWPCC through 2029 in their reference case but is short of necessary reserves in high load cases,[90] an increasingly likely future given the recent proliferation of data centers.

Consideration of intraregional transmission

Utilities in non-RTO regions frequently overlook the impact of transmission constraints in IRP and RA assessments. Utilities may focus on ensuring generation meets load plus reserves, but they may not examine how that could cause congestion or curtailments on their own transmission system.[91] In bilateral trading markets between service territories, utilities must reserve transmission service rights ahead of the trade to ensure that transmission lines are not dangerously overloaded by the movement of additional power.

Transmission service rights are contractual obligations defining which entities, supply resources or load-serving utilities are allowed to send and receive power over the transmission system. Transmission service rights are assigned to entities on a scale from firm to non-firm, which establishes a priority order of which entities are less likely to be curtailed over others should any transmission paths on the system be at risk of overloading.[92]

Consideration of interregional transmission and neighboring support

Entities that do include interregional transmission investments in their system plans find that greater transmission and import capability enables them to maintain resource adequacy with a lower internal reserve margin. Idaho Power's 2021 Integrated Resource Plan, for example, included an assessment of resource adequacy both with and without the 290-mi, 500-kV Boardman to Hemingway transmission line, scheduled to be energized in 2027. The presence of Boardman to Hemingway reduced Idaho Power's firm capacity requirement five-fold.[93] A 2021 assessment of the desert Southwest's resource adequacy similarly found that increased imports

86 Northwest Power and Conservation Council (NWPCC), "Pacific Northwest Power Supply Adequacy Assessment for 2029" (2024)

87 Idaho Power "2023 Integrated Resource Plan Appendix C: Technical Report" (2023), 91-92, docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2023/2023-appendix-c-final.pdf

88 Schlag, N., et al.

89 *Id.*

90 NWPCC

91 Carvallo, J.P., et al.

92 Hart, E., "Toward a more holistic and adaptive treatment of BPA transmission rights in Northwest utility planning and procurement processes" (GridLab, 2025), https://gridlab.org/portfolio-item/renewables-transmission-rights/

93 Carvallo, J.P., et al.

from neighboring utilities effectively eliminated all risk of loss of load events in 2025.[94]

The NWPCC explicitly considers external imports in their RA assessments for the BPA system. In their 2029 assessment, they found that load growth scenarios consistently relied on imported generation, referred to as *market reliance*, to maintain system adequacy.[95] The need for imports did fluctuate depending on the availability of hydroelectric power and increases in demand, though not necessarily in predictable ways. For example, additional market reliance sometimes fell in the off-peak spring season, even when winter loads were high.[96] This highlights the value of interregional transfer capability to meet shortfalls that could occur at any time of year. Given the large impact of imported energy on internal reserve requirements, the NWPCC is currently considering revisiting the import limits it sets for its resource adequacy assessments.[97]

SPP

Resource Adequacy Assessment

The Southwest Power Pool (SPP) uses a 1-day-in-10-years loss of load expectation metric as their RTO-wide resource adequacy threshold. A planning reserve margin for the system is set based on the forecasted load and generation information supplied by load serving entities and generation owners in SPP's footprint. The SPP-calculated PRM is uniformly assigned to all LSEs, who are responsible for complying with the resource adequacy requirement[98] in SPP's Tariff within their individual service territory. SPP has assessed the PRM biennially and modification to the PRM has historically been on a near-term basis (less than 2 years of advance notice for load serving entities). However, recent resource adequacy improvements have been adopted to assess the PRM more frequently and establish it longer in advance of the effective season.[99]

SPP has made many changes to their resource adequacy assessments and procedures in recent years. Recent LOLE studies have been updated to report expected unserved energy in addition to LOLE metrics, consider both summer and winter LOLE separately (*see* **Figure 1**), assess longer planning horizons, include more historic weather data, include the weather-forced and unplanned outages of thermal generators, and address zonal transmission limitations.[100,101,102]

These changes are being made to keep up with declining reserve margins seen across the SPP footprint, driven by large load growth and declining total installed capacity.[103] Additionally, these changes reflect increased risk in the winter months.[104]

Through 2025, SPP assigned a uniform 15% PRM to all LSEs,[105] which easily met or exceeded

94 Schlag, N., et al.
95 Gai, D.H.B. and Ollis, J., "2029 Adequacy Assessment: Final Results" (2024)
96 *Id.*
97 Gai, D.H.B., "Final Adequacy Criteria Recommendation for the 9th Power Plan" (2025)
98 SSP, "Open Access Transmission Tariff: Attachment AA Resource Adequacy" rev. 6 vol. 1 (2024), https://sppviewer.etariff.biz/tariff
99 SPP, "Long-Term PRM Policy Paper" (2024)
100 *Id.*
101 SPP, "2023 Loss of load expectation study report" (2024)
102 SPP, "2024 Loss of load expectation study report" (2025)
103 SPP, "Long-Term PRM Policy Paper"
104 SPP, "2024 Loss of load expectation study report"
105 LSEs whose capacity mix included at least 75% hydropower resources were assigned a planning reserve margin of 9.89% instead of 15%. Source: SPP, "Resource Adequacy Workbook Instruction Manual" (2024)

that reserve level.[106] Beginning in 2026, the SPP-wide PRM will increase and be set for the summer and winter seasons separately.[107] For the 2026/2027 delivery year, the PRM will be set to 16% (summer) and 36% (winter) and to 17% (summer) and 38% (winter) beginning in 2029/2030.[108] These higher PRM values reflect an LSE submitted increase (forecast comparisons from 2023 to 2024) in forecasts of 5% in non-coincident peak demand and 10% in annual energy needs.

Resource Accreditation and Procurement

SPP has updated its resource accreditation methods in recent years. SPP will begin accrediting thermal and hydropower facilities using historic forced and incremental cold weather outage rates.[109] SPP will begin using an effective load carrying capability method in 2026 to accredit the installed capacity of solar, wind, and battery resources.[110]

SPP does not run a capacity market for its members. Instead, all individual LSEs are required to procure enough supply capacity to meet their individual peak demand plus their assigned planning reserve margin.[111] Failure to comply with this requirement would result in a deficiency payment. Much like non-RTO regions, this is commonly done through self-supply or bilateral contracts.

Consideration of intraregional transmission

SPP includes transfer capability limits on power flow between the six load zones in their LOLE studies. These limits take transmission congestion within the SPP footprint into account. SPP is proposing to modify their 2025 Integrated Transmission Plan to look at *resiliency needs*, which considers the value of increased transfer capability between the load zones to more easily share reserves.[112]

Consideration of interregional transmission and neighboring support

SPP does not consider interregional imports or net load diversity with its neighbors in a comprehensive way when calculating resource adequacy. Individual LSEs can accredit capacity purchases from external suppliers when meeting their individual resource adequacy requirements.[113] These capacity purchases are only eligible if they are backed by firm transmission service. Any non-firm capacity agreements or firm capacity agreements with non-firm transmission rights are ineligible to meet resource adequacy obligations. In the LOLE Study, these firm imports are considered as perfect generation within the LSE's service territory.[114] In

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106 SPP, "2024 SPP Resource Adequacy Report" (2024), https://www.spp.org/documents/71804/2024%20spp%20june%20resource%20adequacy%20report.pdf

107 Crawford, A., "Recommendation Report 622 –Planning Reserve Margin" (2024), https://www.spp.org/spp-documents-filings/?document_name=RR622+planning+reserve+margin&docket=&start=&end=&filter_filetype=&search_type=filtered_search

108 Payne, B., "Recommendation Report 664 – 2029 Planning Reserve Margin" (2025)

109 SPP, "2023 Loss of load expectation study report"

110 *Id.*

111 SPP, "Resource Adequacy Workbook Instruction Manual" (2024)

112 Henderson, N., "Value of Resiliency in Transmission Policy" (2025)

113 SPP, "Resource Adequacy Workbook Instruction Manual"

114 SPP, "2023 Loss of load expectation study report"

the 2024 LOLE Study, a total 2,255 MW of firm imports were modeled when assessing the PRM for the SPP footprint.[115]

For the 2025 LOLE Study, submitted imports by load serving entities will include firm capacity transactions across the DC ties between SPP and the Western Interconnection.[116] Since SPP will be operating on the east and west side of the DC ties, the 2025 LOLE Study clarifies the assumption of importing these firm capacity transactions to the east side of the ties specifically for the LOLE Study. There are seven ties between the two Interconnections, four of which are owned by utilities participating in SPP's Western Energy Imbalance Service Market.[117] The combined 660 MW of full potential import capacity can increase total imports load serving entities use to meet SPP's resource adequacy obligations and may continue to increase as more utilities join the Western Energy Imbalance Service Market.

MISO

Resource Adequacy Assessment

The Midcontinent Independent System Operator (MISO) uses an annual 1-day-in-10-years loss of load expectation as its resource adequacy threshold. MISO calculates how much additional unforced (accredited) capacity is needed above coincident peak demand to maintain a 0.1 day/yr LOLE threshold RTO-wide for the planning year.[118] MISO then looks at the resulting RTO-wide LOLE values for each season. MISO will adjust the modeled unforced capacity in its footprint—increasing proxy load if LOLE values are too low and increasing proxy supply capacity if LOLE values are too high—so that only one season has a value of 0.1 day/yr and all remaining seasons have a value of 0.01 day/yr.[119] With these adjustments, MISO will calculate seasonal RTO-wide planning reserve margins, which defines the percentage of combined adjusted internal supply capacity and external imports above coincident peak demand.[120] Because MISO uses coincident peak demand instead of non-coincident peak demand to define its planning reserve margin, diversity between load serving entities within MISO will result in a reduced need for capacity resources.

A similar method is applied to each local resource zone individually to calculate zonal PRMs. The amount of unforced capacity above a zone's coincident peak demand sets the resource adequacy obligation, known as the local reliability requirement, that must be met by LSEs in that zone.[121] MISO has a process of accrediting capacity to resources in each zone to take zonal transmission limitations into account. The value of sharing of resources to serve load across zones is therefore determined in resource procurement.

States have the regulatory authority to establish resource adequacy parameters within their

115 SPP, "2024 Loss of load expectation study report"

116 *Id.*

117 SPP, "DC Tie Proposal RTO West ver. 1" (2022), https://spp.org/documents/68648/rto%20west%20dc%20tie%20proposal%20final.pdf

118 Midcontinent Independent System Operator (MISO), "Planning Year 2025-2026 Loss of Load Expectation Study" (2024), 33-35

119 Equivalent to a loss of load expectation of 1-day-in-100-years. Source: *Id.*

120 *Id.*

121 *Id.*

jurisdiction. If a State within MISO's footprint establishes a planning reserve margin that differs from MISO's, then MISO will only assign resource adequacy obligations to LSEs within that State in accordance with the State-established reserve margin.[122]

In the 2025-2026 Planning Year, the summer season reached the riskiest RTO-wide LOLE of 0.1 day/yr. However, only half of the ten zones in MISO, predominantly those in the upper Midwest, also had summer LOLE values nearing 0.1 day/yr. The other zones experienced more loss of load risk either in the winter or across multiple seasons.[123]

Resource Accreditation and Procurement

MISO currently uses historic unforced outage rates to accredit capacity from thermal and non-intermittent resources.[124] Intermittent resources, namely wind and solar, are accredited using an effective load carrying capability method.[125] Approved by FERC on October 2024, MISO will move to a direct loss of load (DLOL) accreditation method for all resources in the 2028/29 planning year.[126] This method combines forward-looking resource availability with historical performance. It considers the future availability of resources during high-risk hours when the system is most stressed.[127]

Load serving entities in MISO must meet their requirements through self-supply, bilateral contracts with suppliers, or via the MISO capacity market.[128] MISO operates a voluntary forward capacity market, known as the Planning Resource Auction, in which its members can buy and sell capacity resources to meet their planning reserve margin requirements ahead of the operating year. LSEs that do not participate in the capacity market must prove they can meet their MISO-assigned resource adequacy obligations. Procuring resource capacity from a generator in a different MISO zone is allowed, but only up to certain capacity import and export limits. Bilateral contracts with or capacity market bids from suppliers external to the MISO footprint are permitted.[129] LSEs which do not meet their obligations pay a fee to MISO for the deficit.

Consideration of intraregional transmission

MISO does not consider individual transmission constraints within its footprint when calculating the RTO-wide or zonal planning reserve margins.[130] Instead, it considers the transfer limits between local resource zones, updated annually to reflect upgrades in the transmission system.[131] The lowest seasonal capacity export limit calculated between zones for the 2025/26 planning year was 2,000 MW and the highest was 7,400 MW, both occurring in the winter.[132]

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122 MISO, "Business Practice Manual No. 011: Resource Adequacy rev. 31" (2025), 29
123 *Id.*, 34
124 MISO, "Planning Year 2025-2026 Loss of Load Expectation Study"
125 *Id.*
126 Organization of MISO States (OMS), "Recent RA Changes – Going Forward" (2025), 17, slides presented at OMS Resource Adequacy Committee on Jan 17, 2025
127 *Id.*, 17
128 Judd, S. and Larangeira, G., "ISO-NE Tie Benefits Methodology" (ISONE, 2023)
129 MISO, "Business Practice Manual No. 011," 25-26
130 MISO, "Planning Year 2025-2026 Loss of Load Expectation Study", 34
131 *Id.*, 36
132 *Id.*, 5

The local resource zones are designed to reflect the jurisdictional and electrical boundaries of LSEs within a geographic location.[133] These zones inherently have less transmission congestion within them but may have significant congestion between them. The modeling decision to only represent transmission congestion between zones saves computational burden while approximating the true system.

The capacity import and export limits on sharing resources between zones are enforced in the resource adequacy assessment but are relaxed during capacity market clearing to procure resources.[134] A seasonal feasibility test is run to ensure that all resources initially cleared by the capacity market can be delivered to load. If the feasibility test fails because capacity import and export limits have been violated, then resources are redispatched. If redispatch of resources within the load zones does not resolve the transferability constraints, then the capacity import and export limits are adjusted.[135]

Consideration of interregional transmission and neighboring support

As it does for intraregional transmission, MISO models interregional transmission constraints in resource adequacy assessments and during resource procurement. MISO includes both firm and non-firm imports when calculating planning reserve margins. Firm import procurement can be contracted by a MISO LSE directly or bid in the forward capacity market.

MISO includes all known contracted firm imports, and the equivalent of market-offered[136] imports from the previous year's capacity market when calculating its needed seasonal planning reserve margins.[137] In the 2025/26 Planning Year LOLE Study, there were between 1,900 MW (summer) and 2,600 MW (winter) of accredited capacity from external resources.[138] This accounted for between 1.5% and 2.1% of the total RTO-wide PRM requirement.

MISO models a zonal representation of the Eastern Interconnection in addition to its own transmission system in its forward capacity market to assess the feasibility of resource delivery.[139] MISO updates their transmission topology annually with any known changes to neighbors' transmission system. Imports from any external resources that LSEs procure outside of the capacity market must have firm transmission rights to deliver their capacity.[140] Depending on the structure of the power purchase agreement between an LSE and an external resource, the accredited capacity of the resources may be further reduced by anticipated transmission losses during delivery.[141]

Historically, during times of grid stress neighboring regions have provided MISO with support that was not scheduled in the capacity. MISO uses three years of historical net scheduled

133 MISO, "Business Practice Manual No. 011"
134 MISO, "Business Practice Manual No. 011," 114-117
135 *Id.*
136 Starting in the 2026-2027 Planning Year LOLE Study, MISO will only count the quantity of imports which cleared previous capacity markets instead of the amount offered into past markets. This will lower the quantity of imports considered in LOLE studies. Source: MISO, "Planning Year 2025-2026 Loss of Load Expectation Study", 22
137 MISO, "Planning Year 2025-2026 Loss of Load Expectation Study", 20
138 *Id.*, 9
139 MISO, "Business Practice Manual No. 011," 113-114
140 *Id.*, 43
141 *Id.*, 49

interchange data to quantify the non-firm external support in LOLE.[142] Seasonal distributions of the amount of additional support MISO is likely to receive from its neighbors are produced using this data. MISO's resource adequacy model draws random combinations of possible non-firm support from these distributions to calculate the seasonal LOLE.[143] thereby lowering the planning reserve margins needed to meet load. The non-firm support represents imports that are likely to be available to MISO in times of need given net load diversity with neighbors.

The seasonal distributions used in the 2025/26 Planning Year LOLE study are shown in **Figure 7** for each season.[144] These plots show the likelihood that at least an amount of total non-firm imports is available to MISO during emergency hours in each season. For example, at least 1,370 MW of non-firm imports will be available 90% of the time during the summer season, while 4,350 MW of non-firm imports will only be available 50% of the time this summer. MISO expects higher amounts of non-firm imports in the summer, with lowest amounts available in the winter.

MISO updates the historical interchange data used to calculate the non-firm support every year as part of its annual LOLE study.[145] This ensures the most recent import data is used to calculate the following year's planning reserve margin needs. The non-firm import data update for the 2025/26 planning year LOLE Study resulted in a -0.1% to 0.6% difference for the seasonal RTO-wide planning reserve margins calculated in the previous year's LOLE Study.[146] These changes are small but important to accurately estimate future resource adequacy needs. MISO is continuously improving its resource adequacy assessments, including how it models external assistance in its LOLE studies.[147]

Non-RTO Southeast

Resource Adequacy Assessment

SERC, the regional reliability coordinator for the Southeast, performs an annual long-term reliability assessment[148] and seasonal summer[149] and winter reliability assessments.[150] Demand within SERC is expected to grow rapidly, which will push several subregions' reserve margins below the NERC 15% target reserve margin during the ten-year assessment period. Reserve margin projections are determined using on-peak capacity rather than net peak, and resources include operating units with firm transmission and anticipated resources with firm capacity transfers, less retirements. SERC uses historically based ELCC weightings for some generation resources.

SERC conducts a probabilistic assessment for regional resource adequacy that examines both

142 MISO, "Planning Year 2025-2026 Loss of Load Expectation Study", 33
143 *Id.*, 33
144 *Id.*, 33
145 *Id.*, 14
146 *Id.*, 11-13
147 OMS
148 SERC, "2024-2034 SERC Annual Long-Term Reliability Assessment Report," https://serc1.org/docs/default-source/program-areas/reliability-assessment/reliability-assessments/2024-2034-long-term-relilability-assessment.pdf
149 SERC, "2024 SERC Summer Reliability Assessment Report," https://www.serc1.org/docs/default-source/program-areas/reliability-assessment/reliability-assessments/2024-serc-regional-summer-assessment-final-copy.pdf
150 SERC, "2024-2025 Winter Reliability Assessment Report," https://serc1.org/docs/default-source/program-areas/reliability-assessment/reliability-assessments/2024-2034-long-term-relilability-assessment.pdf

a base case and regional cold weather sensitivity scenario. The last such report covered the 2024-2034 operating years.[151] It evaluated loss of load hours, loss of load expectation and expected unserved energy. It found that planning reserve margins begin to fall below NERC's 15% reference planning reserve margin during the study period in half of the subregions due to growing demand, coal plant retirements, replacements by natural gas, renewables and battery resource, and extreme cold weather. The analysis found that SERC East and SERC FL-Peninsula face the greatest reliability risks. NERC also found growing resource adequacy risk in SERC East (Virginia) due to growing demand and generation retirement.[152]

The utilities within SERC's subregions conduct their own load and resource forecasting using Integrated Resource Planning methods. These use cost-based resource expansion planning tools with some scenario analysis for load, resource and cost variations, followed by transmission plans to serve those plans to meet the planning reserve margin targets (as set by the associated State regulator). Most of these analyses are not resource adequacy assessments (although Georgia Power and Duke do use advanced probabilistic modeling techniques in their IRPs). The SERC subregions use a 1-day-in-10-years LOLE reliability criteria dictated by their state regulators related to the NERC-recommended 15% PRM target, but these reference margin levels are not required nor binding.

Resource Accreditation and Procurement

The Southeastern region contains vertically integrated utilities that have historically met their resource needs by building their own generation and transmission. Although the various utility IRPs occasionally lead to RFPs for new energy contracts (primarily for renewables), most of the utility plans indicate the intention to build their own new thermal plants as needed. In general, most of these utilities and their regulators want to be able to serve their loads with nearby generation, often self-owned.

Consideration of intraregional transmission

There are limited transmission connections between the utilities and regions and limited transmission from the subregions on the edges of SERC to other utilities in PJM (from Dominion) and MISO.[153]

Many SERC utilities are members of the Southeastern Regional Transmission Planning (SERTP) consortium, developed to comply with FERC Orders 890 and 1000. SERTP rolls up the local transmission projects planned by member companies, conducts economic expansion studies and looks at whether there might be other projects that are more effective or cost-efficient.[154] Observers have commented that SERTP uses a very narrow definition of transmission benefits and has not to date identified a transmission project that would be more efficient than the

151 SERC, "2024-2034 SERC Annual Long-Term Reliability Assessment Report," 16-19

152 NERC, "2024 Long-Term Reliability Assessment"

153 SERC's geographic scope is larger than NERC's definition of the Southeast. SERC includes three subregions – MISO-Central, MISO-South and the southern portion of PJM -- that NERC includes in other regions. Therefore, what SERC considers as potentials transfer of power between SERC subregions, others would consider as interregional electricity flows. However, SERC's analysis shows that while the border subregions have the potential to import additional energy from their external neighbors, those flows into and between subregions are relatively small and net out.

154 SERTP, "2024 Regional Transmission Planning Analyses" (2024), https://www.southeasternrtp.com/docs/general/2024/2024_SERTP_Regional_Transmission_Planning_Analyses_Summary.pdf

regional expansion and upgrade projects that members proposed.[155]

Consideration of interregional transmission and neighboring support

The SERC analyses include member utilities' local transmission projects but rarely mention potential imports between subregions or interregional imports into the Southeast as potential reliability or resilience resources. SERC warns that potential imports from MISO and PJM are subject to available transmission and Regional Directional Transfer Limits.[156] Several of the resource plans and reliability reports note that Southeastern utilities were unable to import much energy during Winter Storm Elliott in 2022 because neighboring regions were also facing generation failures and high demand and had no excess energy to share, so they assume that they will be unable to obtain future emergency transfers.[157] Subregional transmission or IRP plans often indicate that transmission import limits constrain potential new imports[158] but never propose solutions to remove or ease those limits.

SERC worked with NERC and industry members on the NERC Interregional Transfer Capability Study, filed with FERC in December 2024. The ITCS identified three SERC subregions for "prudent additions" to interregional transfer capacity: 4,100 MW into SERC East, 1,200 MW into SERC FL-Peninsula, and 600 MW into SERC MISO-South.[159]

PJM

Resource Adequacy Assessment

The PJM Interconnection plans for system resource adequacy of no more than one load loss event in ten years. PJM determines if the 0.1 day/yr LOLE requirement is met in future years by considering the likelihood that the available resource mix can meet anticipated load given tens of thousands of future outage scenarios.[160] The LOLE requirement is converted to loss of load hours (LOLH, measuring the duration of lost load) and expected unserved energy (EUE, measuring the magnitude of lost load) for reporting purposes. By reporting the LOLE, LOLH, and EUE, PJM considers both the frequency and magnitude of load loss events. The resource adequacy parameters for the 2026/27 operating year are 0.1 day/yr LOLE, 0.397 hr/yr LOLH, and 1,963.3 MWh/yr EUE.[161]

PJM determines the necessary amount of resource capacity (in MW) that must be procured to meet its 0.1 day/yr resource adequacy requirement. The installed reserve margin defines the amount of additional capacity above peak demand that is needed to meet customer demands

155 Hagerty, J.M., et al., "Modernizing Southeast Grid Investments: How Enhanced Regional Transmission Planning Supports a Growing Economy" (Brattle 2025), https://www.brattle.com/wp-content/uploads/2025/04/Modernizing-Southeast-Grid-Investments-How-Enhanced-Regional-Transmission-Planning-Supports-a-Growing-Economy.pdf

156 SERC, "2024-2034 Long Term Reliability Assessment Report," 24, warning also that, "Tie lines infrequently limit transfers between areas. Rather, the limiting elements are often internal to the entities' systems."

157 For instance, Duke Carolinas' 2023 Resource Plan comments, "Emergency import assistance can no longer be automatically assumed to be available during winter extreme weather events…. This fact is underlined by the experience of having firm purchases curtailed into the Companies and other utilities … on December 24, 2022." (Appendix M, p. 24, at https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/appendix-m-reliability-and-operational-resilience.pdf?rev=7b27fa4bef4a49f5852f8367ea729d9f)

158 SERC, "2024-2034 Long-Term Reliability Assessment Report," 23-24

159 NERC, "Interregional Transfer Capability Study," 98

160 PJM Interconnection (PJM), "Manual 20A: Resource Adequacy Analysis rev. 0" (2024)

161 Bruno, J., "Installed reserve margin (IRM), forecast pool requirement (FPR), and effective load carrying capability (ELCC) for 2026/2027 BRA" (PJM, 2025), 6

in the event that demand is higher than expected, higher levels of supply become unavailable, or other challenges tighten the excess of supply over demand under grid stress conditions.[162]

PJM is seeing a growing need for more capacity reserves in future years. PJM's need for more reserves is driven in large part by demand growth, especially in winter months when demand is increasingly high, and some resources do not perform as well as they do in summer months.[163] PJM estimates they may be short on capacity as soon as the 2029/30 delivery year, when the anticipated future resource portfolio can reliably serve an annual peak load *below* PJM's forecasted peak load.[164]

Resource Accreditation and Procurement

In previous resource adequacy studies, PJM calculated the installed reserve margin using forced outage rate for many thermal resources and ELCC for intermittent and energy storage resources.[165] Starting in 2025, PJM accounts for the contribution of all supply resources to provide resource adequacy using effective load carrying capability tailored to each type of resource.[166] The marginal ELCC metric provides a consistent measure of generating resources' ability to serve load. Both existing and new capacity are procured through PJM's capacity market.

PJM operates a capacity market for load serving entities to procure capacity resources. The market has a major auction three years ahead of the operating year to procure base resources, and three incremental auctions in the following years to make capacity procurement adjustments.[167] Load serving entities can opt out of the market and procure their own resources via self-supply or bilaterial contracts if desired.[168] The market takes into account summer and winter seasonal needs.

Consideration of intraregional transmission

PJM separates its system into zonal load deliverability areas for those areas of the grid known to have transmission constraints[169] and calculates unique resource adequacy requirements for each zone. The zonal resource adequacy requirements are set to 40% of the RTO-wide expected unserved energy (determined using the RTO-wide 0.1 day/yr LOLE threshold), adjusted to the proportion of annual energy in each respective zone.[170] PJM calculates the transfer limits between zones to understand how much capacity can be shared between zones. The zonal transfer limits are updated regularly to include any changes to the PJM transmission system.[171]

162 PJM, "Manual 20A"

163 Bruno, J., "Installed reserve margin (IRM), forecast pool requirement (FPR), and effective load carrying capability (ELCC) for 2026/2027 BRA" (PJM, 2025)

164 Rocha-Garrido, P., "Supplementary information about ELCC class ratings calculated for DY 2027/28 – DY 2034/35" (2024)

165 PJM, "Manual 18: Capacity Markets" rev. 59 (2024), 236-237 & 246 for "UCAP"

166 PJM, "Manual 20A: Resource Adequacy Analysis rev. 0," 20-21

167 PJM, "Manual 18: Capacity Markets," 12-13 & 16

168 PJM, "Manual 18: Capacity Markets," 13-14

169 PJM, "2025/2026 Base Residual Auction Report" (2024), www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.pdf

170 PJM, "Manual 20A: Resource Adequacy Analysis rev. 0," 9

171 PJM, "2023 PJM Reserve Requirement Study" (2023)

Consideration of interregional transmission and neighboring support

External resources largely do not participate in PJM's procurement processes. They may participate as firm resources if they are procured directly by load serving entities or had cleared the capacity market prior to May 2017.[172] Firm imports purchased from generators in neighboring regions directly decrease the amount of internal capacity PJM needs to meet its resource adequacy requirements. Firm imports must prove available transmission service to the PJM border, including firm transmission service and/or pseudo-tire requirements, to be accredited.[173] Only 1,270 MW of firm imports cleared the 2025/26 capacity market.[174] This is less than 1% of PJM's estimated peak load of 158,883 MW for the 2025/26 delivery year.[175]

PJM calculates the contribution of non-firm imports from neighboring regions—NYISO, MISO, Tennessee Valley Authority (TVA), and the Virginia - Carolinas subregion (VACAR)—to reserve margins. The contribution of any non-firm imports from PJM's neighbors to planning reserve margin is calculated as the capacity benefit of ties (CBOT, unitless). PJM and its neighbors have net load diversity, meaning that each region's demand has historically peaked on different seasons, days and hours, enabling these regions to export power to PJM during its peak load periods. The CBOT is calculated assuming a 3,500 MW maximum simultaneous import limit from all neighboring control areas.[176] PJM uses a CBOT value of 1.5% to reduce the reserve margin needed to maintain resource adequacy in future years.[177] For example, the capacity benefit of ties reduced the final installed reserve margin from 19.2% to 17.7% for delivery year 2025/2026.[178]

In 2025 PJM estimated future installed reserve margins out through 2035 to understand how reserve margins could change over the coming decade.[179] Installed reserve margins are estimated to hit 35.1% by the 2034/2035 delivery year,[180] requiring a nearly 2% increase of generation and storage capacity every year over the next eight years. Notably, PJM assumed the capacity benefit of ties remained constant at 1.5% during this study period instead of allowing the CBOT to vary with varying load diversity with neighboring regions.

The reliability planning team at PJM is currently investigating the load and generation outage diversity of their neighbors at the times of greatest stress on the PJM system.[181] This evaluation will help PJM estimate the amount of interregional support that could be available to PJM in times of need. **Figure 6** demonstrates the net load diversity between PJM and all its neighbors, both in aggregate and individually, for years 2008-2023.[182] While net load diversity has remained constant for many regions, the diversity between PJM and MISO has grown in recent

172 PJM, "Manual 18: Capacity Markets," 59-63

173 *Id.*

174 PJM, "2025/2026 Base Residual Auction Report," 7

175 PJM, "2025/2026 Base Residual Auction Planning Period Parameters" (2024), www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-planning-period-parameters-for-base-residual-auction-pdf.pdf

176 PJM, "2023 PJM Reserve Requirement Study," 10

177 PJM, "Manual 20A: Resource Adequacy Analysis rev. 0"

178 PJM, "2023 PJM Reserve Requirement Study"

179 These estimated future reserve margins are meant for informational purposes only. The official installed reserve margin values used in for capacity procurement are calculated annually as part of the PJM Reserve Requirement Study.

180 Rocha-Garrido, P., "Supplementary information about ELCC class ratings calculated for DY 2027/28 – DY 2034/35"

181 Rocha-Garrido, P., "Capacity Benefit of Ties (CBOT) Update" (PJM, 2024), www.pjm.com/-/media/DotCom/committees-groups/subcommittees/raas/2024/20241104/20241104-item-2---cbot-related-update.pdf

182 *Id.*

years, which would be reflected in an increasing CBOT. Importantly, most diversity between regions occurs in the winter months, when PJM is most likely to experience stress conditions and need imports from neighboring regions.

The capacity benefit of ties is currently under debate in PJM.[183] Some stakeholders want to remove it from the reserve margin calculation.[184] PJM's Board of Directors has asked PJM reliability planners to explore the capacity benefit of ties in more detail to better assess its value to resource adequacy but has not yet removed it from use.[185] The inclusion of CBOT in resource adequacy assessments reduces the amount of capacity necessary to maintain system adequacy, reducing costs for PJM customers. Furthermore, the suggestion to remove the CBOT comes at a time when PJM anticipates growing electric demand and an increased need for reserves moving forward.

NYISO

Resource Adequacy Assessment

The New York Independent System Operator (NYISO) has a comprehensive system planning process for reliability and system planning. NYISO conducts several near- and long-term reliability assessments to quantify the impact of changing demand, generation, transmission, and markets. Reliability assessments include the quarterly Short-Term Assessment of Reliability report which evaluates a five-year planning horizon with a focus on needs in the first three years, the biennial Reliability Needs Assessment which focuses on needs in the four- to ten-year horizon, and the biennial Comprehensive Reliability Plan which proposes solutions to any reliability needs arising in the previous two reports in its ten-year reliability plan. The various reports include many reliability criteria assessments in addition to resource adequacy, such as transmission system security. The resource adequacy results of all three reports are summarized in the biennial Long-Term Resource Adequacy Assessment submitted to the New York State Reliability Council.[186]

NYISO uses a 1-day-in-10-years loss of load expectation criteria to assess resource adequacy, as required by the Northeast Power Coordinating Council, one of the six NERC regional reliability entities. NYISO reports loss of load hours and expected unserved energy metrics in addition to LOLE. The 2024 Reliability Needs Study identified an LOLE that exceeded the 0.1 day/yr threshold in New York City in year 2034, with high demand presenting resource adequacy challenges across the footprint as early as 2032.[187] A 2025 update to NYISO base case as part of the Comprehensive Reliability Plan corrected the LOLE violation in New York City, but narrowing reliability margins still pose a risk.[188] The risk for shortfalls is worse in the summer

183 PJM, "Problem/Opportunity Statement: Capacity Market Enhancements – Resource Adequacy Analysis Enhancements" (2024)

184 LS Power and Calpine, "Issue Charge: Capacity Market Enhancements – Resource Adequacy Analysis Enhancements" (PJM, 2024)

185 Takahashi, M., "Board Letter Substantive Direction" (PJM Board of Managers, 2023), September 27, 2023 letter to Stakeholders outlining decision IN Critical Issue Fast Path-Resource Adequacy (CIFP-RA).

186 New York Independent System Operator (NYISO), "2024 Long-Term Resource Adequacy Assessment for NYSRC" (2025), https://www.nysrc.org/wp-content/uploads/2025/02/A.3-R2-2024-NY-Long-Term-Resource-Adequacy-Assessment.pdf

187 NYISO, "2024 Reliability Needs Assessment (RNA)" (2024), 3 & 28, https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf

188 Altman, J., "2025-2034 Comprehensive Reliability Plan: Key Topics" (NYISO, 2025), 5-8, https://www.nyiso.com/documents/20142/51270164/CRP_KeyTopics_TPAS_050625.pdf/2c8b0041-f925-a50b-c2f5-64be0cebe743

than the winter, but that switches in 2034 given resource retirements.[189] This is the first time that shortfalls due to decreased system flexibility have been observed in the Reliability Needs Assessment.[190]

The NY State Reliability Council adopts reliability rules and goals, including the annual minimum installed reserve margin that NYISO must maintain for statewide resource adequacy.[191] The installed reserve margin was set to 22% in 2024 and 24% in 2025.[192]

Resource Accreditation and Procurement

NYISO uses the installed reserve margin to calculate state-wide and locational minimum capacity requirements.[193] The four locations—Long Island, New York City, Lower Hudson Valley, and the rest of Upstate New York—reflect areas of the state with differing deliverability concerns. Finally, these minimum capacity requirements are divided up between the load serving entities of the state. NYISO facilitates a capacity market for LSEs to procure capacity in order to meet their requirements.

Prior to 2014, NYISO used an unforced capacity method to determine how much capacity any individual or class of generation resources will be accredited to meet the minimum capacity requirements, including a consideration of historical resource performance.[194] Unforced capacity is the probability that the generator can supply load after accounting for forced outages. Beginning in May 2024, NYISO assigns capacity accreditation factors to all resources based on their marginal contribution to resource adequacy requirements using LOLE,[195] similar to the ELCC method. Separate probabilities are calculated for the summer and winter seasons and for each capacity zone of the wider RTO.[196] Suppliers can then offer their accredited unforced capacity into the market for bid by LSEs.

Consideration of intraregional transmission

NYISO considers transmission in its modeling of both resource adequacy assessment and resource procurement. Local transmission owners in-state and imports from neighboring regions are explicitly modeled in all reliability base cases. In its 2024 resource adequacy assessment, NYISO increased the transfer capability between internal zones, notably those around Long Island, by over 6 GW to reflect new transmission capability coming online in 2030.[197] Transmission expansion internally or interregionally has a positive impact on resource adequacy.[198]

189 NYISO, "2024 RNA,", 20-22

190 NYISO, "2024 Long-Term Resource Adequacy Assessment for NYSRC"

191 NYISO, "Reliability Planning Process Manual" (2023), https://www.nyiso.com/documents/20142/2924447/rpp_mnl.pdf/67e1c2ea-46bc-f094-0bc7-7a29f82771de

192 NYISO, "2024 NY Long Term resource adequacy assessment for NYSRC"

193 NYISO, "Manual 04: Installed Capacity Manual" V. 13.0 (2025), 4 https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338

194 *Id.*, 65-67

195 *Id.*, 197 - 202

196 NYISO, "Updated final capacity accreditation factors for the 2024-2025 capability year" (2024), 1-2, https://www.nyiso.com/documents/20142/41593818/Final-CAFs-for-the-2024-2025-capability-year.pdf/3efc1e06-c1b0-72d6-f736-22721709c157

197 NYISO, "2024 Long-Term Resource Adequacy Assessment for NYSRC," 13

198 *Id.*

Consideration of interregional transmission and neighboring support

NYISO's reliability assessments include firm and non-firm imports from four neighboring regions: ISO New England, PJM, IES Ontario, and HydroQuébec. Potential non-firm imports from the four neighboring regions are included in NYISO's loss of load expectation calculations as emergency assistance, which quantifies the upper limit of energy NYISO could import from any individual neighbor. Emergency assistance from neighboring regions plays a very important role in NYISO's ability to meet resource adequacy, especially during extreme events and emergency conditions. New York would not have adequate resources for the years 2025-2034 if not for imports from neighbors.[199] Non-firm imports lowered NYISO's LOLE by 0.42 day/yr for planning year 2025/26.[200]

The New York State Reliability Council has requested that NYISO reduce its reliance on emergency assistance from neighboring regions,[201] leading to numerous changes in response. To limit external assistance, NYISO has imposed a 3,500 MW limit on the total simultaneous imports it can receive from all regions to support a single loss of load event. This artificial limit reduces the risk of export unavailability from neighbors, rather than arising from transmission operating constraints. The policy maintains pressure to grow internal New York resources to increase self-reliance and ability to meet its own needs under normal and emergency conditions. Export availability is further reduced in direct proportion to what is needed for each neighboring control area to maintain an LOLE value of 0.1 day/yr, providing a limit on neighbors' exports when they are also experiencing a resource deficiency event.[202]

The availability of firm imports improves the importer's LOLE and reduces the amount of unforced capacity that must be built in-state to meet reserve requirements. Some individual projects which import from neighboring regions, such as the Neptune project from PJM to Long Island in NYISO, are granted a specific amount of unforced capacity deliverability rights.[203] These projects directly reduce the associated locational minimum installed capacity requirements that load serving entities must meet.

External resources without deliverability rights can bid into the capacity market to help LSEs meet their installed reserve margin requirements,[204] but are not used to reduce the requirements directly. Suppliers from external control areas must calculate the equivalent of unforced capacity using NYISO's prescribed method, demonstrate that their capacity is deliverable to the New York Control Area, and confirm that the capacity will not be curtailed or recalled to serve its own internal control area load.[205] External suppliers are subject to the individual and total simultaneous imports as described in the emergency assistance calculations above.

199 NYISO, "2023-2032 Comprehensive Reliability Plan" (2023), https://www.nyiso.com/documents/20142/2248481/2023-2032-Comprehensive-Reliability-Plan.pdf

200 Calculated as the difference between steps 7 and 8 for the addition of external assistance in LOLE calculation on page 23. Source: NYISO, "2024 Long-Term Resource Adequacy Assessment for NYSRC," 22-23

201 New York State Reliability Council (NYSRC), "New York Control Area Installed Capacity Requirement For the Period May 2025 to April 2026" (2024), https://www.nysrc.org/wp-content/uploads/2024/12/2025-IRM-Study-Technical-Report_Final_12062024_clean.pdf

202 NYSRC

203 NYISO, "Manual 4"

204 *Id.*

205 *Id.*

In 2023, total scheduled firm imports—from both individual projects with deliverability rights and capacity market purchases—were about 2,600 MW during peak hours, serving 14% of NYISO load during the peak period.[206] There was 36% reduction in scheduled net imports from 2022 (3,100 MW) to 2023 during peak hours, mostly due to lower exports from Québec and Ontario due to expansive Canadian wildfires that year and higher NY exports to New England.[207] In summer 2024, NYISO's import capability fell further to about 5% of peak load.[208]

Imports from Québec are scheduled to increase in 2026 when the 1,250 MW HVDC Champlain Hudson Power Express (CHPE) transmission line is energized.[209] The Champlain Hudson line has significant resource adequacy impacts for New York City specifically and New York State generally. New York City will be energy deficient in 2026[210] and the State will fall short of its 0.1 day/yr LOLE threshold in 2034 if the line is not energized.[211]

ISO New England

Resource Adequacy Assessment

ISO New England (ISO-NE) performs annual resource adequacy assessments. They use a 1-day-in-10-years loss of load expectation threshold to determine if adequate resources exist in the region. ISO-NE determines resource adequacy requirements, known as installed capacity requirements with units of MW, needed to maintain the 0.1 day/yr LOLE threshold RTO-wide. Additionally, ISO-NE reports the annual RTO-wide loss of load hours and expected unserved energy to characterize the length and magnitude of resource adequacy events in addition to frequency.[212] The region is currently updating its resource adequacy assessment to include seasonal LOLE targets, which will better assess winter risk.[213]

ISO-NE uses a 90/10 odds of occurrence load forecast in their LOLE studies[214] to capture higher load projections than the average load projection. Load forecasts include the potential impact of future extreme weather.[215] Internal supply resources, demand response, and firm and non-firm imports from external regions are all considered in determining the zonal resource adequacy requirements to meet future projected load.[216]

Resource Accreditation and Procurement

Resources are accredited for capacity based on their historical performance during emergency

206 Patton, D., et al., "2023 State of the Market Report for the New York ISO Markets" (Potomac Economics, 2024), https://www.potomaceconomics.com/wp-content/uploads/2024/05/NYISO-2023-SOM-Full-Report__5-13-2024-Final.pdf

207 *Id.*

208 NYISO, "2024 Reliability Needs Assessment (RNA)"

209 NYISO, "Power Trends 2024" (2024), https://www.nyiso.com/documents/20142/2223020/2024-Power-Trends.pdf

210 NYISO, "2024 Reliability Needs Assessment"

211 NYISO, "2024 Long-Term Resource Adequacy Assessment for NYSRC"

212 Wong, P. and Zeng, F., "Installed Capacity Requirement Development Webinar" (ISONE, 2019), https://www.iso-ne.com/static-assets/documents/2019/12/icr-development-workshop.pdf

213 Zeng, F., "RAA Model and capacity requirements under RCA: Review of proposed Resource Adequacy Assessment (RAA) process for the Resource Capacity Accreditation (RCA) project" (ISONE, 2024), Slides presented to the NEPOOL Reliability Committee on March 19, 2024

214 V. Rojo, "[ISO-NE] 2025 Final Forecasts – Energy and Seasonal Peak Forecasts" (ISONE, 2025), https://www.iso-ne.com/static-assets/documents/100022/a02_2025_04_29_pac_celt_2025_final.pdf

215 Zeng, F., "RAA Model and capacity requirements under RCA"

216 Wong, P. and Zeng, F.

hours. Historic forced and maintenance outages are included to calculate a derate value for accrediting non-intermittent generators and firm imports. The historical output of intermittent generators during reliability hours is used to calculate a derate value for each resource class.[217]

Load serving entities in ISO-NE use a forward capacity market to procure resources to meet the zonal resource adequacy requirements. The forward capacity market is run annually to procure resources three years ahead of the operating period. There are three capacity market auctions for each operating period, run to reconfigure the necessary resource procurements each year leading up to the operating year.[218] In 2025 there were three reconfiguration auctions run: the third annual reconfiguration auction for the 2025-2026 operating year, the 2026-2027 second annual reconfiguration auction, and the 2027-2028 first annual reconfiguration auction. However, ISO-NE has proposed changes to its forward capacity market, to transition the capacity market from a three-year forward auction to a seasonal prompt auction that runs shortly before the capacity commitment period, also modifying the resource adequacy contributions accreditation process. These changes are targeted for 2025-2027.[219,220]

Consideration of intraregional transmission

Intraregional transmission constraints play a key role in ISO-NE's annual resource adequacy assessments. Internal transmission constraints are not modeled in the determination of the resource adequacy requirements, except between capacity zones.[221] A transmission interface model defines the capacity transfer capability between zones. Resource adequacy requirements are informed by the ability to import or export capacity between the different capacity zones.

Zones are considered import-constrained if they do not have enough internal capacity to meet zonal load requirements. The ability to import additional capacity to meet load will be important for these zones. Conversely, export-constrained zones have surplus capacity to meet their internal load requirements.[222] Given zonal import and export limits, it may be more valuable to incentivize additional capacity in the import-constrained zones. ISO-NE evaluates internal and external transfer capability limits annually to assess where the most valuable capacity should be placed.[223]

Consideration of interregional transmission and neighboring support

ISO-NE is a net importer and relies on capacity from neighboring regions to serve load. The region has thirteen ties to neighboring regions: two to Québec, two to New Brunswick, and nine to New York. ISO-NE considers both firm and non-firm imports in its resource adequacy

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217 *Id.*

218 Saarela, H., "Installed Capacity Requirement (ICR) and related values calculations assumptions for the Annual Reconfiguration Auctions (ARAs) to be conducted in 2025 rev.1" (2024), https://www.iso-ne.com/static-assets/documents/100014/a03_annual_reconfigurationauction_icr_related_values_development.pdf

219 Johnson, E. and Winne, M., "ISO New England Overview and Regional Update to the Maine Legislature" (2025), 16, https://www.iso-ne.com/static-assets/documents/100021/iso_overview_regional_update_maine_eut_committee_2025_03_12.pdf

220 Geissler, C., "Capacity Auction Reforms – Overview of Prompt Capacity Market" (2025), 22, https://www.iso-ne.com/static-assets/documents/100021/a03_mc_2025_03-11-12_prompt_iso_presentation.pdf

221 Saarela, H.

222 Wong, P. and Zeng, F.

223 Zeng, F., "RAA Model and capacity requirements under RCA"

assessments.

Unlike many other regions, ISO-NE derates the accreditation of firm imports based on historic performance during reliability hours in both the winter and summer seasons.[224] New firm capacity import requests will be derated based on the type of request, with consideration of whether delivery is via AC or DC transmission lines and the available transfer capability remaining on those lines.

ISO-NE additionally includes non-firm imports, known as tie benefits, in its resource adequacy assessments to account for external assistance from other regions. Tie benefits are evaluated by comparing the RTO-wide LOLE calculated for a fictional, isolated ISO-NE system (assuming no interregional transmission exists) against the LOLE calculated for the system interconnected to its neighbors.[225] Non-firm imports, like firm imports, directly reduce the resource adequacy requirements determined for the region.[226] A total of 1,870 MW of firm and 2,175 MW non-firm summer import capacity was accredited in the third 2025/26 capacity reconfiguration auction.[227] This is 14% of the region's projected 28,900 MW peak demand.

In calculating the tie benefits, ISO-NE models both its and its three neighbors' resource capacity, load profiles, import limits of its neighbors' regions,[228] and the historic imports across its thirteen interregional ties.[229] ISO-NE is careful to remove firm imports and account for available interregional transfer capability across its ties during this calculation.

ISO-NE recently re-evaluated its calculation of tie benefits.[230,231] Enhancements include calculating the contribution of non-firm imports during both summer and winter seasons.[232] The distinction between winter and summer non-firm imports is important because load diversity between New England and its Canadian neighbors diminishes in the winter, resulting in lowered tie benefits. In 2023, ISO-NE estimated that winter tie benefits are less than half that of summer benefits.[233] Additionally, ISO-NE attempted to evaluate the benefit of non-firm imports during past emergency events. Fortunately, ISO-NE has not experienced many deficiency events (only 3 hours out of 60,600), so there was not enough data for the results to be statistically relevant.[234]

ERCOT

This study does not address the reliability value of interregional transmission in the Electric

224 Wong, P. and Zeng, F.

225 ISO-NE, "Tariff Section III Market Rule 1 Standard Market Design"

226 Wong, P. and Zeng, F.

227 Saarela, H., 15

228 For example, ISO-NE models the import limits between NYISO and PJM even though ISO-NE does not directly neighbor PJM.

229 Bringolf, M., "Tie Benefit Values: For Reconfiguration Auctions to be Conducted in 2025" (2024), www.iso-ne.com/static-assets/documents/100015/a03_review_of_2025_2026_ara_3_tie_benefits_study_results.pdf

230 ISO-NE, "Tie Benefits Evaluation Update. Memo to NEPOOL Reliability Committee (RC) and Power Supply Planning Committee (PSPC)" (2024), www.iso-ne.com/static-assets/documents/100012/final_tie_benefits_evaluation_memo_6_26_2024.pdf

231 Judd, S. and Larangeira, G.

232 Zeng, F., "RAA Model and capacity requirements under RCA"

233 Zeng, F., "Resource Capacity Accreditation in the Forward Capacity Market: Seasonal Tie Benefits" (ISONE, 2023), https://www.iso-ne.com/static-assets/documents/100006/a03_b_rca_seasonal_tie_benefits.pdf

234 ISO-NE, "Tie Benefits Evaluation Update"

Reliability Council of Texas (ERCOT) interconnection, which serves 90% of the Texas customer load. This is because ERCOT is effectively an electrical island, with very little interregional transmission capacity. There are four DC ties connecting ERCOT to the Eastern Interconnection, with a total summer-rated import capability of 850 MW. These ties have short-term emergency ratings near 1,200 MW.[235] ERCOT's total installed resource base now exceeds 103,000 MW to serve over 85,000 MW of peak load. Although ERCOT and state policymakers are currently studying whether to approve additional interregional transmission projects, at present ERCOT does not assume any substantive energy imports in its resource adequacy planning.

Revision Notes

The initial publication of this report included capacity accreditation values for the generation associated with the Grain Belt Express transmission facility derived from preliminary results.[236] Revision 1 of this report includes updated capacity accreditation values for the firm and non-firm capacity of the facility as conducted by PowerGEM, which was finalized after initial publication of this report. Additional modifications include correcting a typo in Table 3, moving the accreditation of the Champlain Hudson Power Express facility from Table 2 to Table 3, and replacing "N/A" with blank cells in all tables.

235 Judd, S. and Larangeira, G.

236 Invenergy, "Interregional HVDC: PRMR and DLOL Beneits for MISO" (MISO, 2025), 6, https://cdn.misoenergy.org/20250429%20HVDC%20Workshop%20Item%2002b%20Interregional%20HVDC%20DLOL%20and%20PRMR%20Benefits%20for%20MISO%20DRAFT693698.pdf

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