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Transmission Planning for Long-term Reliability: Literature and Gaps Analysis

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Final Report

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Acronyms and Abbreviations

ATT	advanced transmission technologies
BAA	balancing authority area
CAISO	California Independent System Operator
CBM	Capacity Benefit Margin
CBOT	Capacity Benefit of Ties
CETL	capacity emergency transfer limit
CPP	Consolidated Planning Process
CVaR	conditional value-at-risk
ELCC	Effective Load Carrying Capability
ERAA	European Resource Adequacy Assessment
EUE	expected unserved energy
FCA	Forward Capacity Auction
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
GET	grid-enhancing technology
HVDC	high-voltage direct current
ICR	Installed Capacity Requirement
IRM	Installed Reserve Margin
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	ISO New England
IRH	Interconnection Rights Holder
ITCS	interregional transfer capability study
ITP	integrated transmission plan
LOLE	loss of load expectation
LRTP	long-range transmission planning
LSE	load serving entities
LTTP	longer-term transmission planning
MARS	Multi-Area Reliability Simulation
MIC	maximum import capability
MISO	Midcontinent Independent System Operator
MTEP	MISO's transmission expansion plan
NERC	North American Electric Reliability Corporation

nEUE	normalized expected unserved energy
NPCC	Northeast Power Coordinating Council
NRECA	National Rural Electric Cooperative Association
NYISO	New York Independent System Operator
PJM	PJM Interconnection
ppm	parts per million
PPTPP	Public Policy Transmission Planning Process
PPTN	Public Policy Transmission Need
PRM	planning reserve margin
PRMR	planning reserve margin requirement
RNA	Reliability Needs Assessment
RPP	Reliability Planning Process
RRS	Reserve Requirement Study
RSP	regional system plan
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
SAA	State Agreement Approach
SENS	system efficiency needs scenario
SPP	Southwest Power Pool
STEP	SPP's transmission expansion plan
Tri-State	Tri-State Generation and Transmission Association
TO	transmission owner
VaR	Value-at-Risk

Executive Summary

Capturing the contributions of electric transmission to resource adequacy holds the potential to make power grids across the United States more reliable and affordable. In general, current planning paradigms separately consider resource capacity planning relative to regional resource adequacy needs and transmission capacity planning relative to regional grid reliability needs. In addition to reinforcing existing transmission systems in case of equipment failure, new transmission can also enhance grid reliability by reaching more resources in uncertain periods of grid stress. If such contributions of transmission to resource adequacy are incompletely considered, supply and demand-side resources may be over-built, causing added costs for end-users that are unnecessary from a system needs perspective.

This work provides a review of the literature and industry practice around: (i) regional transmission planning, (ii) interregional transmission planning, and (iii) valuation of transmission for resource adequacy. These findings subsequently informed a gap analysis, conducted in concert with the formation and repeated engagement of an industry working group with expertise in system planning. Through the review of the reasons why transmission is not presently planned for resource adequacy, opportunities were categorized under either regional, interregional, or valuation gaps.

Three gaps stand out after a review of **regional** planning practices:

- **There are misalignments between planning processes for transmission and resources (for resource adequacy needs) in terms of planning horizons and objectives.** Resource planning typically looks ahead 10–20 years and considers non-location specific loads and capacity additions to develop a least-cost resource portfolio. Transmission planning, on the other hand, typically anticipates peak reliability needs over a 5 to10-year horizon, and includes only mature generation projects with a high degree of locational certainty. The disparity in objectives between these planning processes poses a philosophical and process challenge in leveraging transmission for resource adequacy.
- **There are misalignments between planning processes for transmission and resources (for resource adequacy needs) in terms of modeling methods.** Resource planning abstracts the transmission system, missing important aspects of transmission in meeting resource adequacy needs and creating a least-cost resource portfolio. Transmission planning often is focused solely on reliability needs and overlooks the conditions critical to resource adequacy modeling including temporal resolution of supply and demand patterns, generator outages and de-rates, storage conditions, contracted transmission rights, resource cost impacts, and other factors.
- **There are misalignments between planning processes for transmission and resources (for resource adequacy needs) in terms of data inputs.** Access to and stewardship of the fundamental input data are critical to both planning processes, and all necessary information for better integration or co-optimization of these planning processes is not consistent among resource and transmission planners, particularly not across multiple regions.

From an **interregional** planning perspective, three additional gaps are noted:

- **Fixed, administrative caps on external assistance during resource adequacy events limit opportunities for new non-firm transmission in most areas.** Almost every region evaluated was shown to impose non-technical caps on allowable (assumed) non-firm assistance, neglecting any resource adequacy benefits of additional interregional transmission.
- **Where recognized, the resource adequacy benefits of non-firm energy imports over uncommitted, interregional transmission are commonly socialized, failing to incentivize alternative business models**. In nearly every region surveyed, the modeled resource adequacy benefit of non-firm assistance is applied as a reduction to the system-wide resource adequacy requirement, which means the benefits accrue to all loads. This socialization of resource adequacy benefits, common practice within regions, fails to incentivize valuable, interregional participant-funded or merchant projects, in which an intertie is funded by a subset of loads. Alternative models could reduce regional resource adequacy payments only for the loads funding the intertie or enable capacity market participation with non-firm transmission.
- **In the independent system operator (ISO), transmission system operator (TSO), or transmission owner (TO) planning processes, there is generally no active exploration of how interregional transmission expansion can reduce total system costs, which limits the opportunity for new transmission investment.** Interregional transmission projects for resource adequacy conceivably could emerge if interregional expansion was motivated by total system cost savings, despite the gaps between resource and transmission planning. This total system-wide cost reduction approach, spanning multiple regions, has not been implemented to date.

The final gap highlighted in this assessment pertains to the **valuation** of the resource adequacy contribution of transmission assets:

- **There is a need to establish best practices for the valuation of the resource adequacy value of transmission, via planning reserve margin (PRM) reduction, accreditation, or other mechanisms.** The literature indicates that resource adequacy contributions of transmission can be valued implicitly or explicitly in both (i) the planning processes of regulated, vertically integrated utilities and (ii) restructured capacity markets or resource sharing constructs. However, differences in resource adequacy definitions or import conditions stand as a friction to the amount of resource adequacy contribution which transmission assets can deliver, even in cases when the trade of capacity enabled by the transmission would offer an economic benefit.

Based on this literature review and gaps analysis, a foundation has been established for the development of approaches and methods—and their associated demonstrations—to capture the contributions of transmission to resource adequacy and thereby improve the affordability of reliable electricity systems. Future work will develop solutions to these gaps, while seeking input from industry on the challenges inherent to implementing and updating industry practice.



1.0 Introduction

As a pillar of power system reliability, resource adequacy is satisfied when supply- and demand-side assets are coordinated to serve the need for electrical power throughout the transmission system at any time within an acceptable likelihood of success (North American Electric Reliability Corporation 2011). Ensuring sufficient resources to cover uncertainty in supply and demand has been achieved by system planners despite fundamental changes to resources and recent, significant demand growth projections, through recurring resource adequacy assessments as a component of resource planning. These assessments consider weather variations, affecting both electrical supply and demand, scheduled maintenance of equipment, the possibility of forced outages of generation or transmission equipment, and may take probabilistic or deterministic approaches.

Today, typical transmission planning processes across the United States focus on addressing national and regional reliability criteria, but do not fully account for long-term resource expansion or resource adequacy needs. Resource planning paradigms generally consider planning for resource expansion relative to resource adequacy needs (California Public Utilities Commission 2025b; Midcontinent Independent System Operator 2025). These processes often overlook the opportunity to identify the potential for a reduction in resource adequacy requirements that could be provided by efficiently designed transmission assets that increase supply- and demand-side diversity. Consequently, without full consideration of unlocking resource potential, today's design of transmission facilities misses the synergistic benefits transmission could provide for both economic resource expansion and ensuring resource adequacy.

Further, given that transmission has limited recognition for its resource adequacy benefits, some potential revenue streams associated with resource adequacy may be limited. This literature review and gaps analysis seeks to summarize the state of academic and industry practice to inform forthcoming work identifying methods of overcoming these planning inefficiencies.

This report is organized around answering two main questions about the relationship between transmission and resource adequacy. First: ***Do regional planning processes identify transmission's contributions to resource adequacy?*** Here, a *region* generally refers to a single transmission planning area or ISO/RTO. Through the lens of transmission and resource adequacy, this section examines how relevant existing regional processes currently interact, including transmission planning, resource planning (and capacity markets where applicable), resource interconnection queues, deliverability assessments, and others. Because the processes vary across the country and are well represented and best documented by ISO/TSOs, all restructured markets in the U.S. are examined in detail and compared.

The second question addresses interregional coordination: ***What considerations in current planning practices evaluate or identify contributions from interregional transmission to resource adequacy?*** Interregional transmission is examined here for the same regions considered in the first question with distinction highlighted for resource imports on firm and non-firm transmission across different regions. Lastly, a generic modeling approach is abstracted from the reviews of restructured regions to support gap identification and future solution development.

After an overview on resource and transmission planning, which includes a review and examples of implicit and explicit approaches to valuation of transmission for resource adequacy benefits, including Federal Energy Regulatory Commission (FERC) Order 1920 impacts, each of these questions is examined through a review of literature (studies and reports from academia, government agencies, consultants, and non-governmental organizations) and industry practice (materials from ISOs/RTOs, developers, and related industry entities).

The report concludes with an analysis of gaps identified in order to set the stage for potential process and accounting improvements. The gap analysis is conducted based on the expertise of study authors and that of system planners, researchers, and regulators convened through a project working group. Context with which to best understand these gaps begins with an overview of the main elements of electrical power system planning in the United States.

2.0 Resource and Transmission Planning

There are two primary domains of power system planning as depicted in Figure 1: resource planning, including resource adequacy assessments, and transmission planning. Traditionally these two processes are conducted largely independently of one another, with limited linkages and flow of information, data, assumptions, and results between the planning processes. This is due to several factors, including regulatory and governance structures, software tool limitations, engineering skillsets, and corporate structures.

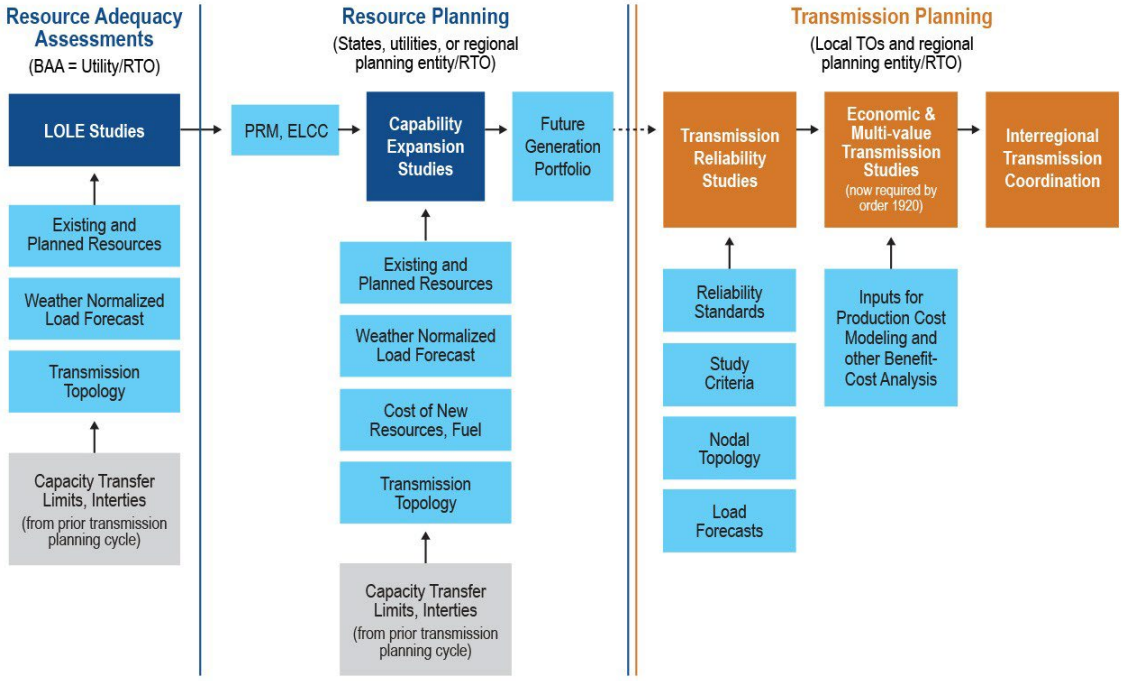


Figure 1. Conventional Interaction of Resource and Transmission Planning

Resource adequacy assessments are conducted by utilities or transmission operators and consider existing and planned generation projects (based on past planning cycles and project development maturity and including any relevant retirements), load projections, weather variability, assumed outages, and capacity transfers from neighboring regions. The outcome of these resource adequacy studies are recommendations for PRM, which establishes the total system need for firm capacity needed to meet resource adequacy requirements and accreditation of capacity value, through metrics such as Effective Load Carrying Capability (ELCC), which measures the contribution of each individual resource or resource class to meet that need.

Resource planning efforts aim to produce a least-cost set of resources to meet future demand, subject to engineering constraints and policy requirements of states and regulators. The planning process often considers the potential energy production profile and cost of existing and planned resources and assumes a representation of future transmission. In restructured market regions, this planning exercise sometimes includes a capacity market mechanism to identify resource needs and securing resources. In most cases, the resource planning process considers candidate

additions and retirements of generator capacity or demand side resources but often does not include options for new transmission resources to be selected.

Finally, transmission planning responsibility falls to utilities, transmission operators or regional planners and considers projects to meet North American Electric Reliability Corporation (NERC) and regional reliability standards, provide economic benefits, interconnect new generation resources, and support public policy. To accomplish this task, rather than comprehensively evaluating the resources considered in resource planning, transmission planners often only assume projects which are advanced sufficiently that they can be located on the transmission system.

Thus, transmission is largely decoupled from resource adequacy assessments and resource planning processes in terms of the personnel involved and the timing of these processes. As a result, inconsistencies often arise between the various planning processes, and challenges are encountered in co-optimizing the results across various studies.

2.1 Transmission Planning Processes

Transmission planning consists of reliability, economic, and multi-value planning processes alongside interregional coordination. In these planning processes, system reliability is evaluated by standardized contingency analysis defined by NERC. Most transmission investments are made to meet NERC transmission reliability standards and other local or regional reliability needs. A variety of entities engage in transmission planning processes, including incumbent transmission owners (local planning), the transmission planning regions (RTO/ISO, etc.), and interregional coordination entities (e.g., the Interregional Planning Stakeholder Advisory Committee).

Generally, transmission planning uses several distinct processes for identifying and developing new or upgraded facilities. Local transmission planning seeks to interconnect loads and meet reliability needs which are unaddressed by other planning steps. The generator interconnection process reinforces the transmission system to facilitate the transmission of new generation to load. Transmission service requests are also made to a transmission operator to reserve transmission capability to enable power trade or market participation. At the regional level, reliability planning identifies projects which address violations of NERC or other regional reliability criteria. These four reliability-focused planning processes drive most U.S. transmission investments. They are also typically focused only on a few snapshots of challenging future reliability conditions over up to the next 10 years, such as summer peak and winter peak under certain transmission and generation outage scenarios, with just enough foresight to be able to build new transmission lines.

Regional economic, public policy, and multi-value planning processes seek to improve market efficiency (e.g., reduce congestion), implement policies of states or regulators, and identify projects that produce multiple benefits, respectively. These types of economic transmission planning analysis tend to look 5–10 years out, tend to analyze generation dispatch cost on an hourly basis for selected future years, and attempt to estimate the “benefits” (i.e., system wide cost savings) offered by the considered transmission solutions.

Lastly, coordination also occurs between regions to address cross-border impacts of generator interconnections and regional planning, and to identify if an interregional solution could more efficiently address needs of each neighboring region than projects within regions. As described further in Section 4.0, this form of interregional coordination has been largely ineffective for advancing interregional transmission projects to date.

These planning processes are shown in Figure 2.

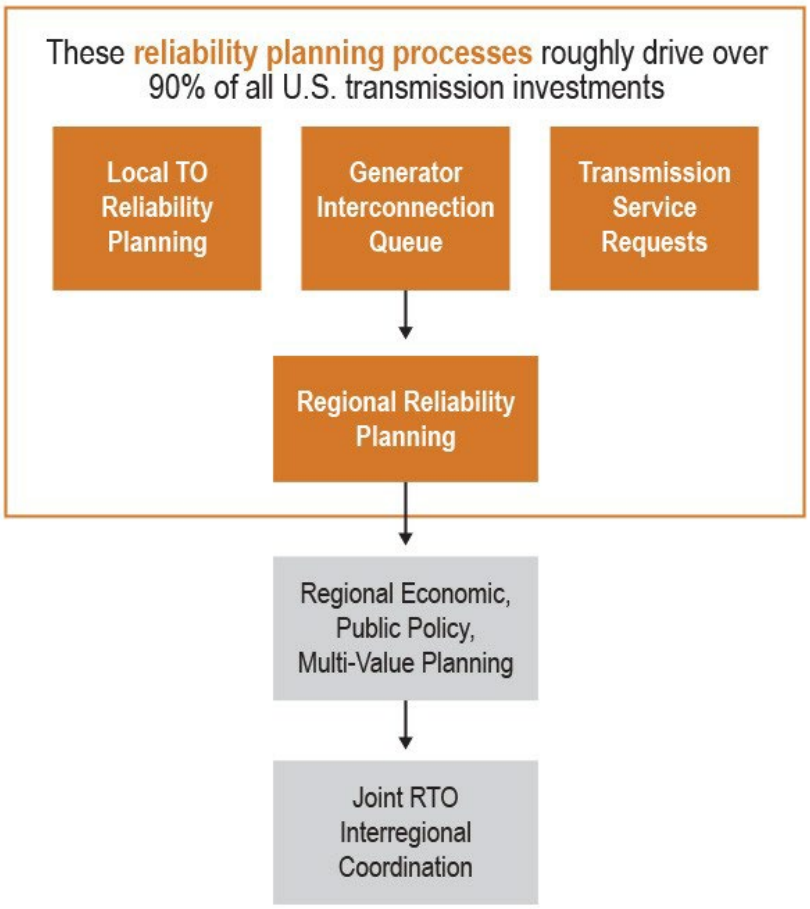


Figure 2. Transmission Planning Process Overview

2.2 Types of Transmission in Planning Processes

Transmission is planned and constructed for a variety of reasons. Figure 3 provides an overview of the various types of transmission between and within two hypothetical planning regions, regions A and B. T_{Load} and T_{Gen} serve to interconnect new load and generation within a region, respectively. $T_{CapTrans}$ permits capacity transfers within a region and T_{Other} serves a variety of other reliability needs. On the interregional front, T_{CapImp} represents transmission for capacity imports to a region contractually secured including through the necessary firm transmission rights. Finally, T_{Uncom}

corresponds to transmission imports which are not contractually secured. These are typically economically motivated imports of power which may fluctuate by hour.

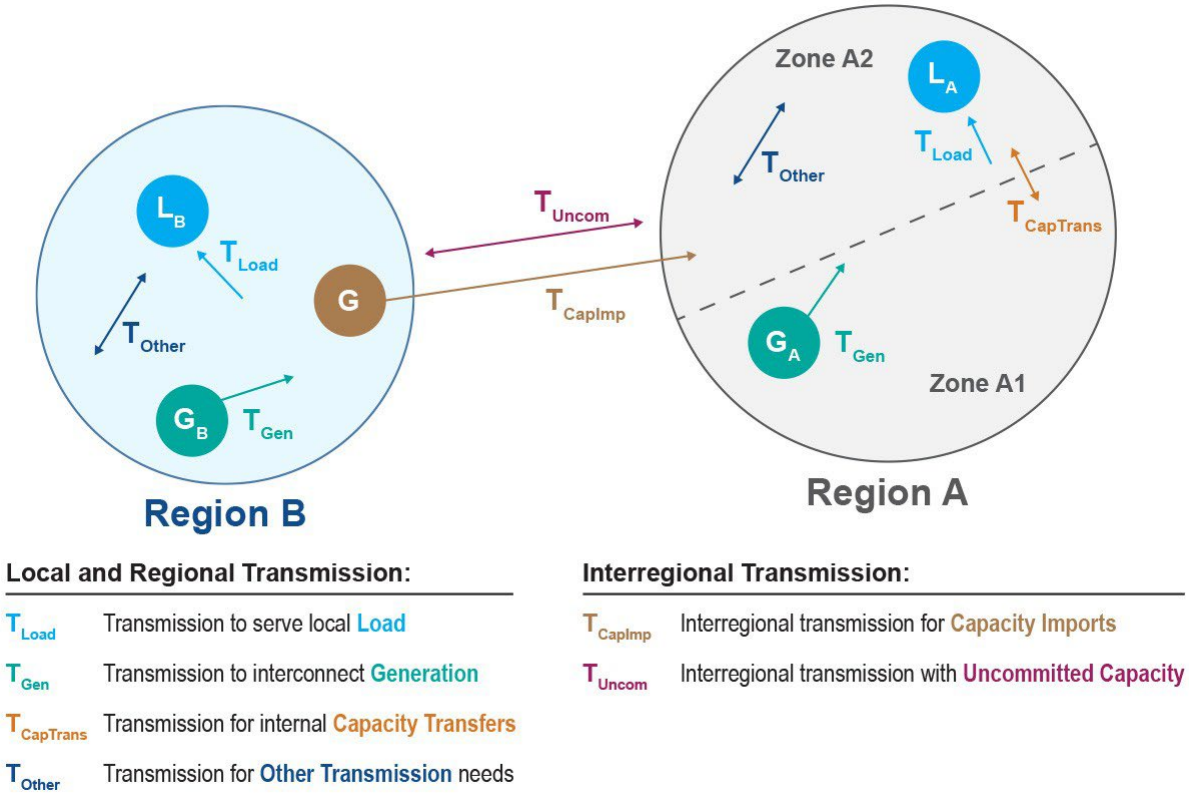


Figure 3. Classification of Transmission Across Local, Regional, and Interregional Levels

2.3 Link between Transmission Planning and Resource Adequacy Planning

The various types of transmission described in Figure 3 impact resource adequacy requirements in various ways, as described in Figure 4. T_{Gen} and T_{CapImp} primarily contribute to today's resource adequacy needs, by interconnecting online generators and enabling firm capacity imports. T_{CapImp}, or firm capacity imports, can take the form of radial gen-ties, switchable capacity, or firm capacity contracts on existing transmission contract paths (i.e., the portion of interties with "committed" capacity, or committed interties). Within a region, $T_{CapTrans}$ enables further capacity trade to reduce the need for more expensive, local capacity. T_{Uncom}, the portion of interregional interties that is not committed to capacity imports, is rarely fully accounted for in regional resource adequacy studies. For resource adequacy objectives, $T_{Uncom,}$ is the portion of interregional transmission that is most unrecognized in terms of its resource adequacy value and least addressed in current planning practice.

	Type of transmission	Resource Adequacy Value of this type of transmission
Local & Regional	T_{Load}	Connects loads that create RA requirements
	T_{Gen}	Connects new generation needed **to meet zonal/regional RA requirements**
	$T_{CapTrans}$	Enable cross-zonal capacity transfers within region, **reducing RA requirement and costs**
	T_{Other}	Other transmission needed to reliably (and effectively) deliver generation to serve load
Interregional	T_{CapImp}	Enables resource-specific **capacity imports** from neighboring regions to meet RA requirements
	T_{Uncom}	Non-firm imports over uncommitted capacity reduce regional RA requirements due to interregional load and resource diversity

Figure 4. Resource Adequacy Value of Transmission Types

2.4 Resource Adequacy Assessments and Planning

Resource adequacy assessments often take the form of probabilistic loss of load expectation (LOLE) studies, which evaluate the probability that a system will have insufficient generation to meet its load. Planners perform this analysis across a series of simulations incorporating varying weather patterns (e.g., by evaluating 30 weather years), installed or planned generation capacity, generator outages, variable generation, load projections, zonal and interregional capacity import capability (in some cases), and more. Based on the common industry LOLE criterion[1] of one loss of load event-day[2] in 10 years, the LOLE studies yield the resource adequacy requirement, the associated PRM necessary to meet the LOLE standard, and the ELCC of different resource types to measure contribution towards the PRM. The PRM and ELCC information can then be used in the generation expansion models that are used for resource planning, or in capacity market auctions. These probabilistic resource adequacy assessments and associated planning practices do not typically consider how resource requirements (i.e., the amount of new generation needed) can be planned most efficiently or minimized through expansion of transmission capacity between zones. Instead, existing or projected transmission capabilities are simply an input into the resource adequacy assessment or generation expansion process.

Probabilistic resource adequacy planning criteria are evolving, and they differ by region. The literature indicates movement from probability-of-occurrence metrics alone to quantification of event duration and severity (ESIG 2021; Hart and Mileva 2022; U.S. Department of Energy 2024b).

[1] In most North American jurisdictions, planners use a criterion of 0.1 days/year LOLE—often summarized as "1 day in 10 years"—as the acceptable risk threshold evaluated in planning studies. While this is not a national reliability standard, it remains the prevailing criterion and provides a consistent anchor for translating modeled risk into capacity needs.

[2] Here the unit of "event-day" groups loss of load events that happen within a 24-hour period as a single event. Though commonly referred to as "1 day in 10 years," assessments often rely upon event-days.

The method used to procure the generating capacity necessary to meet resource adequacy requirements also differs across regions. Some regions rely on resource development facilitated by capacity markets while other regions impose the resource adequacy requirement on load serving entities (LSE), who then develop or procure the necessary generation. Where LSEs are the responsible entities, LSEs' resource development is often based on state-mandated Integrated Resource Plans (IRPs). These IRP efforts typically include a load forecast, information on the existing generation mix, cost assumptions for new resources, and (at best) a highly simplified transmission topology (such as assumptions about a utility's total imports from neighbors). The IRPs identify the least-cost portfolio of resources to meet projected future loads and anticipated resource adequacy requirements. Given the relative lack of granularity in how transmission expansion is modeled in these processes (if at all), any resource adequacy benefit of an expanded transmission system will only be captured incidentally—that is, the resource adequacy benefit of an existing transmission facility would be captured, but a transmission facility would not be designed to maximize (or create, where economic) resource adequacy benefits. As a result, there is generally no attempt to optimize the combination of new generation and transmission capacity.

In other regions, generator capacity additions to meet resource adequacy needs are not determined through centralized planning processes, but rather through capacity markets and economic incentives. In this context it is further challenging to coordinate planning of both resource and transmission resources due to the uncertainty in resource additions and the decentralized decision-making process.

The extent to which an LSE's IRP or regional capacity expansion modeling is used as an input to transmission planning also varies across regions and transmission planning processes. Most reliability-driven transmission planning processes will look less than 10 years out and consider only announced retirements and firmly-planned additions. The generation expansions and retirements needed for longer-term transmission studies may be informed by regional capacity expansion modeling (possibly with zonal granularity) or simply be based on assumptions and stakeholder inputs. Only in rare cases will regional transmission planners use zonal generation expansion simulations that co-optimize the generation expansion with regional (inter-zonal) transmission expansion. Outside of conceptual studies by U.S. Department of Energy (DOE) labs and universities, there is no evidence of any transmission planning effort informed by generation expansion simulations that would also consider the expansion of interregional transmission capacity in their optimization.

2.5 Bridging Resource Adequacy Assessments with Resource Procurement

Resource adequacy studies quantify system risk under uncertainty, measuring resource adequacy risk with probabilistic metrics such as LOLE to determine the resource adequacy requirement which is often expressed as a PRM. Procurement then occurs through a capacity mechanism to achieve the required total system capacity necessary to achieve the PRM. The capacity procurement mechanism is either an organized capacity market, a utility procurement, or bilateral

capacity purchase often handled in an IRP. The objective is to make these procurement decisions in a resource-agnostic way, selecting portfolios that collectively satisfy the resource adequacy criterion at least-cost in advance of the projected need to maintain adequacy. The frequency and time horizon for capacity procurements vary by entity. In an organized capacity market, procurement signals may be provided seasonally, one year in advance, or several years into the future. In an IRP framework, analyses are typically done every two to three years with a 10–20-year horizon (e.g., a 2025 IRP covering 2025–2045) to determine the least-cost resource mix that can meet the required PRM.

The PRM or capacity requirement provides the bridge between the probabilistic resource adequacy assessment and procurement (Figure 5). In this workflow, planners (i) model the system across varying chronological weather, load, and generator outage conditions; (ii) "tune" total effective capacity until the target LOLE is achieved; and (iii) use the resulting requirement to inform market clearing or IRP selections that can meet the PRM. The same LOLE study is often used to develop capacity accreditation for different resource types. Capacity accreditation enables allocating the share of the planning reserve margin or capacity requirement provided by different resources or resource classes on a consistent basis. These methods support resource-neutral, least-cost procurement while preserving alignment with system risk.

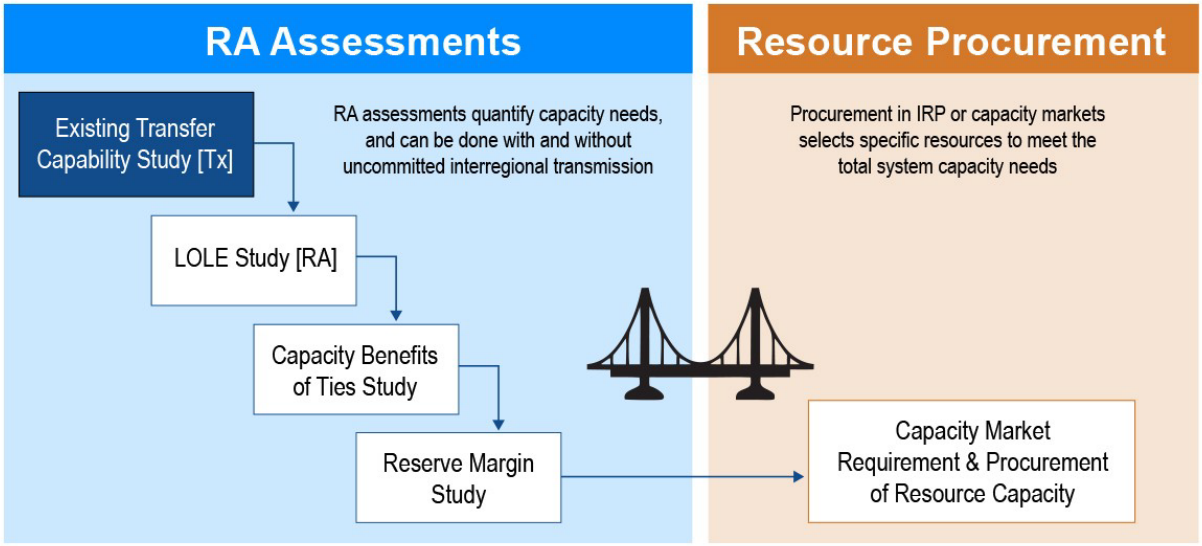


Figure 5. Bridging Resource Adequacy Assessments with Resource Procurement

In resource adequacy models, transmission is often represented with a zonal "pipe and bubble" topology. A total transfer capability (TTC) determines the amount of power that can flow between regions based on the underlying physics of the transmission topology. When represented, this transmission limit (T_{CapImp}) can be identified as either reducing or increasing LOLE.

When non-committed (non-firm) interregional transfers are present (T_{Uncom}), an extra step is needed: planners must quantify the expected contribution of external assistance during scarcity conditions and reflect this benefit in the requirement. Common practice is to calculate the capacity benefits of ties (or tie benefits) from the resource adequacy model and socialize that

benefit as a reduction in the system's capacity requirement or PRM for the relevant region or capacity zone. Under this construct, the assistance is not offered as a discrete supply-side product; rather, it reduces the amount of capacity that must be procured from specific resources to meet the LOLE target which in turn reduces the planning reserve margin or capacity requirement.

This bridge, from a resource adequacy study to capacity requirement to procurement, applies across market designs. Whether the region relies on a wholesale capacity market or vertically integrated IRP processes, the same logic holds—probabilistic resource adequacy studies define "how much" capacity is needed, accreditation defines "which (resource) counts for how much," and procurement acquires the resulting quantities. For interregional transmission, the modeling-to-procurement translation is typically represented as an adjustment to internal capacity requirements rather than asset-level offers. Emerging accreditation proposals for controllable High Voltage Direct Current (HVDC) facilities may potentially change this paradigm as they could enable attribution of asset level accreditation or reserve margin benefits to specific transmission assets, as discussed further in Section 6.0.

2.6 Valuation and compensation of transmission providing system-wide benefits to resource adequacy

Transmission contributes to resource adequacy through distinct mechanisms that raise different valuation and compensation questions. One common construct is transmission enabling a specific generating resource to qualify for deliverable capacity to meet resource adequacy obligations. In this scenario, a generator typically pays for transmission rights or upgrades needed for its capacity to be recognized at the delivery point. A different case arises when transmission itself provides a broader system-wide resource adequacy benefit- for example, by increasing access to a diverse pool of resources, enabling emergency assistance between regions, relieving deliverability constraints, or reducing the amount or cost of capacity the system must otherwise procure to satisfy a reliability standard.

These benefits may exist independently of any individual generator's capacity commitment and may accrue broadly to load across the system. This section focuses principally on this latter category, including examples from literature and industry practice of how system-wide resource-adequacy benefits associated with a transmission project may be calculated, allocated, and compensated.

2.6.1 Valuation of transmission for resource adequacy

There are several ways to value transmission's system-wide contributions to resource adequacy, and in this section literature is presented before RTO planning processes are cross-examined in Section 3.0. A transmission project may result in improvements in resource adequacy criteria, including loss of load probability, expected unserved energy or loss of load timing and duration for a given system under average and extreme conditions (Hart and Mileva 2022; ESIG 2021).[3] These

[3] The Northwest Power and Conservation Council protects against extreme shortfall in 39 out of 40 years through a 97.5th Value-at-Risk (VaR) construct, which includes event duration, peak unserved demand, and unserved energy aggregation

improvements may be translated to reductions in the amount of capacity that otherwise would need to be procured in resource planning to meet a relevant resource adequacy criterion. This step is often referred to as capacity accreditation, and capacity metrics like ELCC or others may be employed.[4] Accreditation methods vary by planning entity or market operator and may incorporate deterministic or probabilistic, prospective or retrospective, and average or marginal techniques, each with potential extensions from resource to transmission application (ESIG 2023). The following examples of this accreditation approach are among the numerous found in the literature:

- A stream of work by the Energy Systems Integration Group (ESIG) systematically contributed to the concept of valuating transmission's contributions to resource adequacy and specifically examined accrediting the capacity value of transmission. In a 2021 report (ESIG 2021, 22, 25) on resource adequacy metrics, the group identified as a principle that "neighboring grids and transmission should be modeled as capacity resources" and that "transmission assets should be evaluated as a capacity resource if they allow additional flow to enter into a capacity- and transmission-constrained region." A subsequent study of multi-value transmission (ESIG 2022) quantified these principles, with a model case study of an interregional line between ERCOT and Southern Company wherein resource adequacy benefits made up the majority of the potential monetary benefits, even when accounting for significant other benefit categories like production cost savings and capital cost savings. In a subsequent study of capacity accreditation across multiple asset types, the group found that transmission is rarely considered for accreditation and that challenges include representation of forced transmission outages and figuring out whether transmission or the resources it connects should receive the accreditation (ESIG 2023). The report also pointed out the advantages of probabilistic capacity metrics like ELCC while noting their computational challenges. The report also notes that if transmission with capacity accreditation participates in regional capacity markets it will take on certain obligations (such as mandated energy market participation) and is also likely to face non-performance penalties and risks that could create challenges for this compensatory framework.

- In a study of capacity and transmission expansion for SPP, Pfeifenberger et al. (2025) modeled the resource adequacy value of non-firm interregional transmission ties with SPP's neighboring regions and calculated "proxy ELCC" values for many interties averaging around 40%, with certain ties reaching almost 100%, during the 100 highest resource adequacy risk hours. These values were termed "proxy ELCC" because the model relied on simplified representations of neighboring zones and resource adequacy challenges. This approach has been borrowed from resource-focused applications (e.g., Frew et al. 2017; Novacheck and Schwarz 2021).

thresholds for its upcoming 9th Power Plan (Jensen 2025). A more demanding extension of VaR is the conditional value-at-risk metric which averages durations, peak demand and energy shortfalls of *all* shortfall events greater than the 97.5th percentile of observations (ESIG 2024b).

[4] There are various alternatives to ELCC such as the Marginal Reliability Improvement method (Olson et al. 2025), Equivalent Firm Capacity or Equivalent Conventional Power (EPRI 2024), Associated System Capacity Contribution (Northwest Power and Conservation Council 2021; Douville et al. 2023), and Direct Loss of Load method (MISO 2024). All of these methods could be applied for resource adequacy accreditation of transmission just as ELCC has been.

- The ELCC values of two proposed merchant transmission projects—The North Plains Connector and the Three Corners Connector—have recently been modeled in two studies using a consistent methodology (Astrape Consulting 2024; PowerGEM 2024). The ELCC calculation in these studies involved: (i) generating a model of the future resource mix of each region, (ii) calibrating the baseline reliability of the modeled regions to a LOLE of approximately 0.1 days/year, (iii) adding the transmission connector to the model, causing a reduction in the LOLE, and (iv) adding load to the regions on both ends of the connector until the LOLE returned to approximately the baseline value. The studies note that because the process is iterated across multiple regions, a precise determination of ELCC is difficult to achieve. Both studies involved simulating 43 historical weather years combined with multiple generator outage scenarios resulting in over a thousand 8,760-hour simulations (4,300 simulations for the Three Corners Connector and 1,290 for the North Plains Connector).

- Brooks et al. (2025) compiled a report focused directly on the resource adequacy value of interregional transmission. The report identified 18 transmission facilities in the US and abroad, including the North Plains Connector and the Three Corners Connector the two merchant projects described immediately above, with assigned or modeled capacity accreditation. The report also found that all surveyed regions include firm transmission imports in their resource adequacy assessments, but non-firm transmission is not consistently included. Furthermore, across the surveyed regions, there is not a consistent method to calculate and accredit capacity value to these transmission assets.

- As emphasized by Brooks et al. (2025), Astrape Consulting (2024), and PowerGEM (2024), by providing capacity in both directions to meet varying peak load events occurring at different times over the course of a year, interregional transmission has the potential to achieve ELCC values that (when summed up in both directions) exceed rated capacity. The Three Corners Connector is modeled to provide 715 MW accredited capacity on for imports to one region connected by the line while also providing 1362 MW accredited for imports to the other region, in the other direction. This is possible because each region's resource adequacy need occurs at different times throughout the year (though often only days or hours apart). The total accredited capacity in both directions of 2077 MW exceeds the line rating of 1800 MW by 15% (PowerGEM 2024). Similarly, the North Plains Connector, which connects WECC, SPP, and MISO, is modeled to have accredited capacity exceeding line capacity by 18%. These results highlight the potential value of interregional transmission in particular to provide significant capacity benefits.

These avoided capacity investments manifest in cost savings which can be carried through the planning process in two main ways. Most commonly, this value is spread across the system. In centrally planned systems, where new transmission reduces the potential for LOLE, planners will reduce the PRMs utilized within the capacity expansion optimization steps. Alternatively, in markets or sharing programs, the resource adequacy benefits could manifest as lower overall

capacity requirements for these programs to secure. [5] Though such reductions in planned capacity for an entire system do not require the capacity accreditation of transmission assets, it is done in some planning processes such as in those of ISO-NE, for example. Without accreditation however, some questions arise such as whether planners will identify high priority resource adequacy driven transmission builds or simply stack incidental benefits on top of existing predominantly reliability-driven transmission planning practices. The literature includes the following prominent examples of this system-wide cost savings:

- Early work on this topic included a study by Pfeifenberger et al. (2013) who modeled a hypothetical "study RTO" and three hypothetical neighboring RTOs to demonstrate the resource adequacy effects of varying levels interregional transmission. Model cases that allowed for exchange with neighbors reduced the planning reserve margin and reliability-related costs in the study RTO significantly, compared to an island case with no interregional transmission.

- In a roadmap of transmission planning practices, Pfeifenberger et al. (2021b) identified reduced loss of load probability and reduced PRM as measurable resource adequacy benefits of transmission. These benefit categories were gleaned from industry studies in several regions including MISO, SPP, and PJM.

- Reduced loss of load probability and reduced planning reserve margin were subsequently identified in FERC Order 1920 (Federal Energy Regulatory Commission 2024a) among the seven benefits that planners must evaluate in long-term regional transmission planning. While FERC Order 1920 recognizes the inherent resource adequacy value of transmission and requires its evaluation, questions remain on how transmission will be valued and whether transmission plans will optimize for all 1920 benefits.

An alternative to spreading the benefit of avoided costs for capacity procurement across the system, is to share the benefit with transmission owners and thus serve as an incentive for transmission development. Allocating this benefit to specific transmission owners instead of spreading it across an entire system will require some form of capacity accreditation of the relevant transmission project(s). However, there are only limited examples of such incentives in current practice.

[5] Note, the potential exists for alternate valuations outside of these approaches in restructured regions which do not operate forward capacity markets today. Both the Alberta Electric System Operator (AESO) and the Electric Reliability Council of Texas (ERCOT) instead incentivize capacity through spot energy and ancillary services markets with scarcity pricing mechanisms. Through transmission cannot participate directly in these markets, it enables the ability of resources to participate in these systems to access energy scarcity revenue. The access enabled by transmission could be valued as a method to capture value (from market participants) or hedge the system against extreme events (by the market operator).

2.6.2 Compensation of transmission providing system-wide benefits to resource adequacy

Mechanisms for compensating transmission assets that provide system-wide benefits to support resource adequacy are evolving in literature and industry practice. Often, when a transmission line or set of lines is recognized for its system-wide value to resource adequacy (if it is recognized at all) there is often no direct compensation for transmission owners. Instead, the benefit of lower procurement costs is socialized across ratepayers, whether through centralized planning, a capacity market, or a resource adequacy sharing program. An example of this structure is found in the MISO transmission planning processes documented in Section 3.2.4.

Examples of more direct compensation structures have also been found recently in ISO-NE and NYISO. In one case, ISO-NE ascribed the capacity value of a transmission line via Hydro-Quebec Interconnection Capability Credits (HQICC) to interconnection rights holders (IRHs), which relieved these entities of their capacity obligations—as required in their respective installed capacity requirements (ICRs)—based on the proportion of their ownership stake in the transmission project (ISO-NE 2025). While the treatment of HQICC Phase I/II HVDC transmission facilities is unique due to their status as legacy assets (arrangements existed prior to the formation of ISO-NE), the effect of the capacity value due to the interconnection enabled by the HVDC intertie is recognized and calculated. These ICR credits for the IRHs differ from direct payments to a transmission owner corresponding to capacity. The entities with ownership in the project were able to monetize the credits because of their existing capacity obligations. Questions arise about the broad applicability of this arrangement (e.g., for merchant transmission development) and whether the credits could be transferred among entitles with or without capacity obligations.

Additionally, the Champlain Hudson Power Express (CHPE) HVDC transmission project in NYISO is an example of a transmission-specific mechanism for directly monetizing resource adequacy value. NYISO awarded the project Unforced Capacity Deliverability Rights, which allows CHPE to directly participate in NYISO's Installed Capacity Market and receive capacity payments for its incremental contribution to resource adequacy (NYISO 2023c; Orelowitz 2026). Foreshadowing this development, Brooks et al. (2025) highlighted the need to develop valuation and compensation strategies that could apply to both regulated and merchant interregional transmission. Without new procurement methods, merchant participation in non-firm, interregional and regional transmission, would not be able to monetize resource adequacy value, as in the case of CHPE.

2.6.3 Commercial considerations

Whether and how regions value and compensate the resource adequacy value of transmission holds commercial implications directly relevant to attracting participation and securing benefits. Details of the compensation signal are impactful. In the case of purely socialized benefits across a system, resource adequacy benefits are likely to be incidental to transmission plans designed for reliability first rather than optimized with resource adequacy as a core objective. In cases in which transmission ownership can offset firm resource requirements of LSEs, a strong incentive can established for regulated transmission development, but merchant developers may be unable to access the resource credit. Conversely, if procurement for resource adequacy benefit of

transmission can be planned such that transmission owners are directly compensated for capacity benefits, a stronger signal still will be established to encourage transmission contributions.

In addition, MISO's recent 2025 HVDC Impact Assessment notes that HVDC projects may offer specific resource adequacy considerations that valuation and compensation mechanisms are still evolving to consider (MISO 2025a). Of note, MISO indicated that high priority work is needed on how external resources enabled by firm HVDC transmission are considered and accredited for resource adequacy. Lastly, the whitepaper identified remaining challenges with explicitly accounting for the resource adequacy value of transmission by placing low priority on incorporating transmission lines, or interfaces, into resource adequacy modeling.

An analysis by Goggin et al. (2025) quantified one stream of economic benefits associated with the interregional transmission expansion recommended in NERC's ITCS. The report assumed a range for the value of lost load using estimates for MISO and ERCOT of $10,000/MWh and $35,000/MWh, respectively, and found that preventing loss of load through ITCS expansions would result in $1.1–$3.9 billion in benefits. However, the authors acknowledge that NERC's ITCS only attempted to mitigate loss of load events and that it did not consider neighbor-of-neighbor ties or the potential to reduce planning reserve margins by preventing load loss, and thus their analysis is likely an underestimation of the potential economic benefits. This type of valuation based on value of lost load, is not unfamiliar to system planners, and could be similarly leveraged toward compensation structures in planning regions.

3.0 Transmission Identification: Do regional planning processes identify transmission's contributions to resource adequacy?

Regional planning processes generally do not integrate—and certainly do not co-optimize—resource adequacy, generation expansion, and transmission planning processes. Notably, NERC transmission planning standards, which drive transmission reliability needs (including T_{Gen}, T_{Load}, and T_{Other} as shown in Figure 3), do not require transmission providers to consider transmission in resource adequacy planning (other than for reliably interconnecting new regional generation and for reliably delivering that regional generation to load). Similarly, NERC standards do not guide or require regional planners to maintain or develop a minimum transfer capability within or between regions. Most transmission investments identified through traditional transmission planning processes therefore have an incidental impact on resource adequacy needs. This distinction will be key in the section that follows.

This chapter identifies processes in regions that consider resource adequacy benefits of proposed transmission projects but fall short of maximizing resource adequacy benefits through co-optimization of transmission design with future resource adequacy needs. That is, neither the "need for" nor the "design of" transmission solutions are focused on their direct resource adequacy benefits, even if those benefits result from the construction of the reliability-driven

projects. [6] The resource adequacy value provided by transmission projects is not a core objective of transmission planning and is instead sometimes identified as an incidental "benefit" in market-efficiency or multi-value planning processes.[7] However, while various national and regional studies have documented resource adequacy benefits and their role in improving reliability and reducing total system costs (e.g., U.S. Department of Energy 2024b), no regional transmission planning processes exist that would determine the optimal amount of inter-zonal transmission necessary to create the lowest overall system costs by efficiently co-optimizing generation and transmission investments through an endogenous consideration of the resource adequacy value. While some regional planning entities have documented that there is an optimal combination of transmission and generation (such as through the "smile" chart of the Midcontinent Independent System Operator (MISO) Regional Generation Outlet Study from 2010 (MISO 2010, 30)), this type of co-optimization has not been used in the multi-value processes that identify and approve specific regional transmission projects for development and cost recovery. (Given the absence of interregional transmission planning processes, that gap is even larger for interregional transmission, as discussed in the next section of this report.)

Looking ahead, the FERC Order 1920 provides initial guidance to planners on long-term regional planning processes, in-part by ensuring that resource adequacy benefits of transmission will be recognized as a benefit that helps reduce generation investment costs. Order 1920 sets out minimum requirements for long-term transmission planning processes, including a set of seven categories of benefits that must be considered in the evaluation of long-term transmission facilities. Notably, the second category includes the requirement to consider the resource adequacy benefit of long-term transmission facilities (Federal Energy Regulatory Commission 2024a, 2024b). This benefit category implements the Commission's finding that "investments in transmission capacity can reduce the system-wide planning reserve margin requirement or the reserve margin requirement within individual resource adequacy zones of a transmission planning region, which can reduce the need for generation capital expenditures" (Federal Energy Regulatory Commission 2024a).

However, Order 1920 does not require transmission planners to identify the optimal amount of transmission that would maximize overall benefits (including resource adequacy benefits), so the plan results in the lowest overall total (transmission and generation) cost to customers. Instead, in an approach similar to MISO's long-term planning process (as discussed further below), the resource adequacy benefit of potential transmission projects would be identified and accounted for within the benefits case to support the selection of the long-term transmission project, to ensure that benefits exceed costs (Federal Energy Regulatory Commission 2024b). While resource adequacy benefits of proposed transmission must be quantified, the transmission planning process does not need to identify potential projects based on resource adequacy objectives as a

[6] T_{Gen} and T_{Load} are typically planned for deliverability of resources to loads, ensuring the capability of the wires to carry needed power under varying system conditions. However, while resource adequacy requires resource deliverability, not all deliverable resources offer adequacy contributions, and these sources are not targeted for adequacy contributions.

[7] For example, MISO's LRTP Tranche 2.1 evaluation identified $16b in savings associated with the extent to which the increase in interzonal transmission capabilities provided by Tranche 2.1 projects reduces regional resource adequacy requirements (by reducing the applicable planning reserve margin).

"driver" or "need." This poses a risk of planners never evaluating the most valuable projects due to the siloed nature of the requirement.

In addition, the underlying structure supporting development of long-term planning scenarios is intended to assess the various "drivers of Long-Term Transmission Needs, including changes in transmission reliability needs, demand, and supply (such as the generation resource mix) that, in turn, affect what transmission facilities will be required going forward" (Federal Energy Regulatory Commission 2024b, 139). Specific choices made in ongoing compliance proceedings by transmission providers, including the methods of developing the design of proposed long-term transmission projects, will determine the overall effectiveness of future long-term planning processes under Order 1920.



3.1 Literature Survey

The role of transmission in providing resource adequacy has been recognized in the literature mostly in the general sense that resource adequacy necessitates having a transmission system to deliver electricity at the right time and place, a concept sometimes referred to as transmission adequacy (Bose 2024). This concept was raised in relatively early studies considering the economic value of reliability (Carden et al. 2011; Pfeifenberger et al. 2013), energy market

operations (Chao and Simaan 2009), and the integration of variable energy resources (Ibanez and Milligan 2012).

A recent review of resource adequacy assessments in the United States (Carvallo et al. 2023) found that although the importance of transmission in resource adequacy is acknowledged, as discussed below, the representation of transmission is often simplified, with many regional studies, "generally assuming a copper-plate model with no transmission constraints." Carvallo et al. (2023) note that this simplification does not allow for representation of transmission failures, and this can lead to a systematic overestimation of system reliability contributions from transmission within a region. Carvallo et al. (2023) also point out that some regional deliverability assessments—which evaluate if new resources can be reliably delivered via transmission—are not holistically considered in resource adequacy evaluations and planning processes.

3.2 Regional Transmission Planning Processes that Consider Resource Adequacy

Some regional planning processes do consider elements of resource adequacy benefits in transmission planning though significant opportunities exist to fully realize the potential. This section summarizes the regional planning process of the major ISOs as it relates to achieving resource adequacy.

3.2.1 ISO New England

The regional system plan (RSP) of ISO New England (ISO-NE) includes planning for economically justified transmission projects under the system efficiency needs scenario (SENS) process. The benefit metrics used in this process currently do not consider resource adequacy (or avoided generation capacity) savings. Under ISO-NE's recently developed longer-term transmission planning (LTTP) process, the ISO collaborates with states in identifying and developing long-term transmission needs (ISO-NE 2024b), which may include the need to expand inter-zonal transfer capabilities. In December, 2024, the New England states submitted their first request through the LTTP process, seeking to address north-south transfer capabilities to enable more power flows from northern Maine to southern New England (NESCOE 2024). The evaluation of projects submitted to the LTTP process considers both the avoided investments in local capacity enabled by capacity transfer across zones, as well as the reduction in expected unserved energy (ISO-NE 2024a).

3.2.2 New York ISO

New York ISO (NYISO) relies on a relatively well-integrated transmission planning framework which considers a limited set of emerging resource adequacy needs as part of its Reliability Planning Process (RPP). Unlike other regions (with processes that yield resource adequacy benefits of reliability projects mostly incidentally), NYISO includes both transmission reliability and resource adequacy studies directly within the RPP, enabling the resulting plan to identify solutions to resource adequacy and transmission reliability needs that are projected to emerge during the study

horizon (NYISO 2023b, 2024).[8] Transmission identified within the RPP addresses emerging transmission reliability or local resource adequacy needs in a piecemeal fashion. That is, the RPP does not identify new transmission to address projected resource adequacy challenges or identify cost-saving opportunities for net beneficial inter-zonal capacity transfers. In fact, NYISO's "market efficiency" planning process does not even allow for the consideration of resource adequacy benefits (NYISO 2025).

Only New York's Public Policy Transmission Planning Process (PPTPP), initiated upon request of the New York Public Service Commission, allows the benefits of expanding transmission between NYISO resource adequacy zones to be considered and only when a Public Policy Transmission Need (PPTN) is identified by the Public Service Commission. While these PPTN-triggered planning efforts are not part of the regular NYISO planning processes (i.e., only initiated upon identification of a PPTN), they have yielded several projects that also offer resource adequacy benefits. For instance, NYISO selected the Segment A and Segment B PPTN in 2019 which sought to improve the ability for the system to move power from upstate into New York City (NYISO 2019). Similarly, a PPTN need was issued to resolve inter-zonal export constraints likely to be faced between Long Island and New York, with the selection of the Propel NY Project (NYISO 2023a).

3.2.3 PJM Interconnection

PJM's mostly reliability-driven regional planning process integrates local transmission upgrades planned by transmission owners with additional PJM-identified regional transmission needs.

PJM participants can also propose specific transmission projects in response to a PJM-identified market efficiency, which can be approved if the proposal is found to be cost-effective. Market efficiency projects proposed for PJM's consideration in the Regional Transmission Expansion Plan (RTEP) are therefore generally designed to maximize value, including by providing a benefit through relieving zonal transfer constraints within PJM's capacity market (PJM 2021). Specifically, the PJM-calculated capacity market benefits for a proposed market efficiency project proposal assesses the value of reducing future capacity market clearing costs and load capacity payments based on the difference in cleared zonal megawatts in the capacity market auction with and without the economic transmission project (PJM 2021). Market efficiency project proposals providing such capacity benefits alongside other production cost benefits are more likely to be determined by PJM to be net beneficial and ultimately be selected in the RTEP (though market efficiency projects are rarely selected). However, the approach PJM uses to estimate capacity market clearing-price benefits does not consider the extent to which transmission may reduce the overall quantity of resource adequacy needs (even though PJM may realize such resource adequacy quantity-related benefits incidentally in its subsequent determination of resource adequacy requirements).

However, the vast majority of transmission approved by PJM are regional reliability projects—which provide only incidental benefits to resource adequacy as they are focused instead on separate

[8] The 2024 RNA identifies a zonal resource adequacy shortfall, driving a reliability need within New York City (ultimately canceled). NYISO explains that "the reliability need could be met by combinations of solutions including new generation, retention of planned generation retirements, transmission, energy efficiency, demand response measures, or changes in operating protocols" (NYISO 2024).

system needs. Only in unique circumstances, reliability upgrades can be reactively triggered to address zonal resource adequacy import limitations as such limitations emerge. Specifically, projects may be triggered if a locational deliverability area has a significant shortfall in the emergency resource adequacy transfer limit (i.e., where the area's capacity emergency transfer limit [CETL] must be improved to meet a region-wide LOLE standard of 1 in 25). These CETL values (indicating the ability of a resource adequacy zone to import capacity from other areas) serve as inputs into PJM's capacity market auction, creating the previously discussed link between transmission planning and capacity market benefits for economic efficiency projects. Public policy projects in PJM currently use the State Agreement Approach (SAA), which when applied on behalf of New Jersey also sought to evaluate capacity market benefits of the proposed projects, but found these to be immaterial (Pfeifenberger et al. 2022).

3.2.4 Midcontinent ISO

Neither MISO's reliability planning process nor market efficiency benefit metrics account for the resource adequacy value of transmission projects (MISO 2025b). However, MISO's annual transmission expansion plan (MTEP) includes multi-value projects planned under the long-range transmission planning (LRTP) process through several "tranches" of planning efforts. While the ability to reduce resource adequacy needs is not an explicit driver in designing new projects, the "capacity savings due to reductions in the overall planning reserve margins resulting from transmission expansion" are included in the evaluation criteria and the ultimate business case supporting the selection of multi-value projects as noted earlier (MISO 2025b attachment FF, Section II.C). These multi-value projects make up the majority of recent transmission investment in MISO (MISO 2025b, attachment FF-7).

3.2.5 Southwest Power Pool

Southwest Power Pool (SPP) recently approved a transition to a new regional transmission planning process, the Consolidated Planning Process (CPP). The CPP seeks to enable more efficient development of transmission by proactively identifying transmission solutions that address multiple needs. Similar to the processes in the California ISO (CAISO) and MISO, future generation needs will inform the design of transmission projects, improving the likelihood that future transmission projects will provide resource adequacy value.

Uniquely, the CPP provides SPP an even higher degree of flexibility, coordinating various system needs within regularly-sequenced 10- and 20-year studies, where zonal transfers are explicitly considered within the modeling architecture (SPP 2025b). The CPP projects are ultimately approved within SPP's transmission expansion plan (STEP). In the legacy integrated transmission plan (ITP) process (which remains alongside the new CPP), however, resource adequacy benefits of transmission are not specifically considered (SPP 2025a).[9] Other transmission projects may have incidental benefits for resource adequacy, but those benefits are not considered in project design and selection.

[9] Generating capacity cost savings were considered only due to reduced on-peak transmission losses in the evaluation of economic projects.

3.2.6 California ISO

Several types of transmission in CAISO also directly or indirectly provide recognized resource adequacy benefits. Economic projects are explicitly evaluated for the benefits of avoided local capacity by increasing import capabilities into the ISO or into a local capacity zone (e.g., CAISO 2025). Other aspects of CAISO's transmission planning process also link resource planning and transmission planning, including by proactively building generator interconnection capacity and by prioritizing generators in the interconnection queue that align with the goals of the California Public Utilities Commission (CPUC). Uniquely, California's integrated resource planning process includes both resource adequacy evaluations and capacity expansion planning to meet those requirements, enabling the CPUC to align the identification of resource needs (and the procurement of those resources by LSEs) with CAISO's transmission plan (California Public Utilities Commission 2025a). As in other regions, reliability-driven transmission upgrades can incidentally benefit resource adequacy, though these benefits do not impact the design or approval of reliability projects.

3.3 Summary of Regional Transmission Planning Processes Considering Resource Adequacy

RTOs' regional planning processes vary widely, including the extent to which they assess the resource adequacy value of transmission. Despite most regions' processes at least partially accounting for resource adequacy benefits, few projects have been designed co-optimizing transmission and future resource adequacy needs. The overall focus of transmission planning remains on transmission only designed to meet NERC reliability criteria. For example, between 2015–2024, PJM approved only 11 market efficiency projects while over 3,600 reliability-based projects were placed into service (LLC 2025). There is no formal established process to optimize resource adequacy contributions of regional transmission.

In practice therefore, RTO transmission planning processes are rarely focused on or driven by the potential resource adequacy contribution of transmission facilities, despite many processes' direct or indirect consideration of capacity market or broader resource adequacy benefits in the evaluation of market efficiency, public policy, multi-value, or regional reliability projects. Table 1 summarizes the ways in which planning processes across the United States account for resource adequacy contributions.

Table 1. Treatment of Resource Adequacy within Regional Transmission Planning Processes

	ISO-NE	NYISO	PJM	MISO	SPP	CAISO
Relevant Planning Process	Regional System Plan (RSP) developed on annual basis to identify reliability and system efficiency projects along with longer-term transmission study (LTTS) to inform the region's future transmission needs	Comprehensive System Planning Process (CSPP) covering public policy projects, economic efficiency projects, network upgrades for resource integration, and reliability planning	Either: 1) Market Efficiency project with resource adequacy (RA) benefit through RTEP; or 2) RTEP reliability, Network Upgrade, or Public Policy projects with incidental RA benefit	MTEP mostly focused on meeting transmission reliability standards but also includes market efficiency, multi-value, market participant funded, and transmission delivery service projects	New Consolidated Planning Process (CPP) results in STEP that covers network upgrades, local reliability, economic projects	RA assessments and long-term resource planning is undertaken by the CPUC and CAISO plans transmission through transmission Planning Process (TPP) on annual basis for CPUC plan. Covers reliability, policy, and economic projects
Notes	RA discussion in RSP but focus on generator interconnection, not how transmission can support RA; economic projects do not consider capacity benefits in evaluation criteria; LTTS can identify transmission for increasing inter-zonal transfer capabilities, reductions in local capacity and expected unserved energy considered in evaluation of LTTS project benefits	RA considered in reliability needs assessment as part of CPP but not explicitly quantified in benefits assessment for economic efficiency; public policy projects consider $/MW for cost effectiveness comparison and provide opportunity for transmission that enables beneficial capacity transfer within NYISO zones when initiated by Public Service Commission	Market efficiency project benefits criteria includes reductions in capacity costs but not overall RA needs; RA benefit of added import capability into capacity market zones (mostly an incidental result of reliability planning processes) is considered in PJM's zonal RA requirements and capacity market clearing; any such benefits also noted for specific projects in RTEP	MVP analysis for long term planning through LRTP has explicitly quantified RA benefits through "avoided capital costs of local resource investments" but MVPs are not designed to target RA benefits; RA not valued in criteria for economic projects	Capacity cost savings due to reduced on-peak transmission losses are considered in the evaluation of economic projects but is not a quantification of RA benefits and those are not considered in current SPP metrics	RA informs TPP as public policy projects driven by enabling deliverability of CPUC resource planning portfolios both within and across regions; generators in interconnection queue prioritized for alignment with CPUC resource planning; economic projects explicitly evaluated for the benefits of avoided local capacity by increasing import capabilities into the ISO or local capacity zone
# of Capacity Zones	4 zones	11 localities	16 Locational Deliverability Areas	10 Local Resource Zones	62 LREs, each with planning reserve margin	10 local capacity areas for LSEs to meet local RA needs along with system level RA need
Import Limits for Capacity Zones	Yes, determined by ISO-NE through local sourcing requirement (LSR) and maximum capacity limit (MCL) from external zones	Minimum Installed Locational Capacity Requirement (LCR) % target for each Locality. Import limit = 100% - LCR	Defined through capacity emergency transfer limit (CETL) which is updated prior to each capacity market auction	Defined through zonal import and export limits (ZIA/ZEA), Capacity Import Limits (CIL), and Capacity Export Limits (CEL), determined by MISO seasonal transfer analyses	Considers zonal RA implications of zonal capacity import limits in its multi-zonal LOLE simulations	CAISO estimates intraregional capacity transfer limits

4.0 Interregional Coordination: *What considerations in current planning practices evaluate or identify contributions from interregional transmission to resource adequacy?*

In contrast to regional transmission planning where resource adequacy benefits are often incidental to reliability-driven projects, interregional transmission is more often reviewed in literature, though not necessarily in practice, within the context of its resource adequacy potential (Astrape Consulting 2024; Brooks et al. 2025; PowerGEM 2024). However, even when there are means to value transmission for resource adequacy, planning processes do not proactively identify transmission for this value. The resource adequacy value of interregional transmission deserves particular attention given the significant, demonstrated benefits created by the geographic variation in both generation and load, enabling beneficial exchange of energy between regions, even during grid conditions (such as extreme weather events) that drive resource adequacy risks. This section sharpens this focus by exploring the question of how resources are shared between regions through (i) a brief review of literature, (ii) a review of industry practice, and (iii) a description of a generic modeling approach, which encompasses current practices.

4.1 Literature Survey

There is substantial literature on the barriers to developing interregional transmission, with several studies identifying challenges relative to resource adequacy, specifically. In a report on improving interregional transmission planning, Pfeifenberger et al. (2021b) identified that benefits analyses used to evaluate interregional projects are often narrowly focused on production cost benefits; other benefits (like resource adequacy) are often not considered or not quantified because the methods for estimating these values are lacking (Pfeifenberger et al. 2021a). Though there has been recent research to improve the valuation of transmission resource adequacy benefits (ESIG 2022), inconsistent or incompatible valuation among regions is a barrier echoed in several subsequent sources (e.g., Homer et al. 2025; Pfeifenberger et al. 2023), with Pfeifenberger et al. (2023) furthermore identifying that some regional processes understate or ignore the resource adequacy value of interregional transmission.

When regions do consider the resource adequacy value of interregional transmission, it can sometimes be incorporated into existing capacity market frameworks, as is the case for ISO-NE. While inclusion of transmission resource adequacy benefits in capacity markets (or other mechanisms such as reduced planning reserve margins), marks an improvement, Tsoukalis et al. (2025) identified that incompatible accreditation methodologies of some regional processes also create barriers to capacity trading even between regions that do quantify benefits from interregional transmission.

Numerous studies suggest opportunities for overcoming barriers to interregional transmission development. Many recommend variations on planning and regulatory reform (Pfeifenberger et al. 2021a; Homer et al. 2025; Schulte and Wahle 2024; Macey and Emmerick 2025; Gavan and

Gramlich 2021). Relative to resource adequacy, specifically, opportunities suggested in the literature include: development of sharing frameworks for resource adequacy and capacity (ESIG 2021; Simeone and Rose 2024), intertie optimization (Pfeifenberger et al. 2023; Tsoukalis et al. 2025), and using a consistent capacity estimation methodology like ELCC for interregional transmission (Homer et al. 2025). Homer et al. (2025, 26) specifically suggest that, "by calculating the effective load-carrying capability of interregional transmission and giving it access to capacity markets, RTOs/ISOs can help incentivize interregional transmission development, ensure revenue adequacy for interregional transmission, and help their member utilities manage risk." Each of these studies reviews different barriers and potential solutions to improving the representation of interregional transmission and its specific resource adequacy benefits better in various planning and market frameworks.

The literature also echoes strong themes around the opportunities for interregional coordination through national studies, quantification of the impact of interregional transfer capacities, wide-area assessments, consideration of HVDC transmission, and the inclusion of resilience benefits. These themes are explored further in Appendix A. They are also supported to varying degrees within current industry practice, which is reviewed in the next section.

4.2 Industry practice for valuing interregional transmission for resource adequacy

Though studies consistently find significant potential benefits of increased interregional transmission, recent real-world additions remain relatively limited (Astrape Consulting 2024; Brooks et al. 2025; PowerGEM 2024). This can be attributed, in some part, to how current industry practice incorporates interregional transmission in existing resource adequacy processes. This section reviews these industry practices and explains how each ISO and RTO considers the contribution of interregional transmission towards meeting resource adequacy requirements.

4.2.1 Defining External Assistance and Non-Firm Transfers

Before diving into practices across ISO/RTOs, the distinction between firm capacity imports and non-firm other imports must be established. In this report, "external assistance"—or "non-firm imports"—refers to the ability to import power over existing AC or DC interfaces during tight system conditions without a corresponding capacity contract on the other side. It is distinct from firm imports, which are backed by a capacity commitment.

- **Firm Capacity Imports:** a resource that clears in the host region's capacity market, a remotely owned generator with firm transmission rights into the region, or a gen-tie resource that electrically locates the unit within the region despite its physical siting outside.
- **Non-firm imports:** also referred to as "external assistance," "tie benefits," "capacity benefits of ties," or "market assistance." Non-firm imports recognize that some level of market-based transfers are likely to be available and can be imported during a region's scarcity conditions. This resource adequacy value can be quantified probabilistically for planning purposes.

A major distinction between firm and non-firm imports is that in all resource adequacy planning practices, firm imports are treated as part of the regional supply mix and accounted for in meeting planning reserve margin or capacity requirements.

For non-firm imports, regions decide whether to include non-firm at all, and if they do include them, how to quantify their contribution to resource adequacy. A region's choice to account for non-firm imports is based on governance and market design, but the modeling building blocks are consistent: transfer capability is first quantified from power flow studies and then probabilistic resource adequacy studies quantify how often and how much non-firm assistance is likely available during high-risk hours. The resulting contribution to resource adequacy is either set to zero (firm-only approach) or translated into a requirement reduction (tie-benefit approach). Whether a region selects the firm-only or tie-benefit approach directly affects the amount of regional and local capacity needed to meet resource adequacy requirements. The following subsections summarize how each of the six U.S. ISO/RTOs implements these concepts today.

4.2.2 ISO New England

ISO-NE quantifies the contribution of non-firm external assistance through an annual "Tie Benefits Study" used to set the Installed Capacity Requirement (ICR) for each Forward Capacity Auction (FCA). First, ISO-NE conducts a probabilistic resource adequacy study with GE's Multi-Area Reliability Simulation (MARS) model. This model includes not only the ISO-NE region, but also regions in the Northeast Power Coordinating Council (NPCC), such as Quebec, Maritimes, and New York. Through coordination with NPCC the interconnected system representation includes granular assumptions on load, resource, and interface models rather than coarse proxies. ISO-NE uses NPCC's common load shapes (most recently from 2021) to preserve interregional load correlations, and it models both external interfaces and key internal New England interfaces (ISO-NE 2023a).

The resulting tie benefits, as shown in Table 2, are applied as a system-wide reduction to the ICR that must be procured in the capacity market. For FCA 18 (2027–2028), the study produced a total of 2,115 MW of tie benefits, with contributions of 1,041 MW (HQ Phase II), 544 MW (Maritimes), 394 MW (NY-AC), 136 MW (Highgate), and 0 MW (CSC) (ISO-NE 2023c, 2023b). These amounts vary slightly from year to year, as changes in the resource mix, load profiles, and modeling approaches of the interconnected system change in the probabilistic resource adequacy studies.

Table 2. ISO-NE Tie Benefits by Interconnection used in Forward Capacity Auction 18

Interconnection	Description	Capacity Market (FCA 18) Tie Benefits Amount (MW)
Maritimes	AC Ties	544
HQ Phase II	DC tie to Quebec	1,041
Highgate	DC tie to Quebec	136
New York AC Ties	AC Ties	394
Cross Sound Cable (CSC)	DC tie to Long Island	0
Total Tie Benefits		**2,115**

Methodologically, ISO-NE first establishes a loss of load expectation of New England with all ties connected and again with New England electrically isolated. The isolated case results in a higher loss of load expectation due to the assumed lack of external assistance during resource adequacy events. The capacity difference between these cases defines the total tie-benefit amount.

> *Tie benefits shall be calculated using a probabilistic multi-area reliability model, by comparing the LOLE for the New England system before and after interconnecting the system to the neighboring Control Areas. To quantify tie benefits, firm capacity equivalents shall be added until the LOLE of the isolated New England Control Area is equal to the LOLE of the interconnected New England Control Area (ISO-NE 2023a).*

ISO-NE then prorates that total tie benefits to individual interfaces by conducting several modeling permutations that "turn off" different ties, or combinations of ties, to compare the relative capacity contributions of the different interfaces (Table 3) (ISO-NE 2023c). The ISO then adjusts the capacity benefits by subtracting out firm capacity imports that are offered into the market separately. At the conclusion of the process, total tie benefits are used as an input into the FCA to reduce the total required capacity procured for the remaining load.

Table 3. Equivalent Capacity of ISO-NE Interties

	Description	Interconnection Status					LOLE	Equivalent TB (MW)
		Maritimes	Ph II	Highgate	NY-AC	CSC		
1	Cut All	X	X	X	X	X	0.61603	0
2	Cut None	✓	✓	✓	✓	✓	0.10065	2115
3	Cut MT	X	✓	✓	✓	✓	0.14926	1615
4	Cut Ph II	✓	X	✓	✓	✓	0.21701	1175
5	Cut Highgate	✓	✓	X	✓	✓	0.11103	1975
6	Cut NY-AC	✓	✓	✓	X	✓	0.12066	1875
7	Cut CSC	✓	✓	✓	✓	X	0.10065	2115
8	Cut MT & Ph II	X	X	✓	✓	✓	0.35420	620
9	Cut MT & Highgate	X	✓	X	✓	✓	0.16598	1495
10	Cut MT & NY-AC	X	✓	✓	X	✓	0.19436	1305
11	Cut MT & CSC	X	✓	✓	✓	X	0.14926	1615
12	Cut Ph II & Highgate	✓	X	X	✓	✓	0.23989	1055
13	Cut Ph II & NY-AC	✓	X	✓	X	✓	0.30832	770
14	Cut Ph II & CSC	✓	X	✓	✓	X	0.21701	1175
15	Cut Highgate & NY-AC	✓	✓	X	X	✓	0.13759	1700
16	Cut Highgate & CSC	✓	✓	X	✓	X	0.11103	1975
X – disconnected ✓ – connected								

Notes:
"TB" = Tie Benefits, "MT" = Maritimes, "Ph II" = Phase 2 intertie between Hydro Quebec and Massachusetts
"Highgate" = Highgate intertie between Hydro Quebec and Vermont
"NY-AC" = AC interties between New York and New England
"CSC" = Cross Sound Cable between Connecticut and Long Island, New York



4.2.3 New York ISO

In New York, the contribution of non-firm external assistance is incorporated through two parallel modeling processes: the Reliability Needs Assessment (RNA) and the Installed Reserve Margin (IRM) Study. The former assessment is used for long-term, reliability-based transmission planning, while the latter is used to determine the total amount of capacity necessary to meet resource adequacy needs.

Both studies rely on the GE MARS probabilistic resource adequacy tool and include detailed representations of neighboring control areas, including PJM, ISO-NE, Ontario (IESO), and Hydro-Québec. While each of these regions is modeled with their own load shapes, resource mixes, and transfer capabilities, they are further adjusted to ensure that NYISO is not overly reliant on non-firm imports. For example:

> *…the probabilistic model used in the RNA to assess resource adequacy employs a number of methods aimed at preventing the NYISO's overreliance on support from the external Control Areas. These include imposing a limit of 3,500 MW to the total emergency assistance from all neighbors, modeling simultaneous five peak days (changed from 3 days to further limit reliance), and modeling the long-term purchases and sales with neighboring control areas. Furthermore, the external Control Areas are kept within a LOLE range of 0.10 to 0.15 event days/year throughout the study period (NYISO 2024).*

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The IRM Study goes a step further, quantifying how this non-firm, external assistance affects New York's capacity requirements (Table 4). Emergency assistance from neighboring systems is included in the IRM simulations, but with additional constraints intended to prevent over-reliance. The constraints include a cap on external assistance that is below the technical capability of interregional transmission, depending on the assumed load level. While previous IRM studies used a static 3,500 MW limit for emergency assistance, new methods for the 2025–2026 IRM instead use a range from 1,470 MW to 3,500 MW depending on the load forecast uncertainty bin used in the probabilistic resource adequacy sample (New York State Reliability Council 2024b, 2024a). It should be noted that "such topology limitations do not reflect the real constraints on the transmission system, but rather, represent an estimate of the neighboring area's ability to provide support to the NYCA at [Emergency Operating Procedure] steps during the GE-MARS simulation" (New York State Reliability Council 2024b, 2024a).

Table 4. Assumed external assistance used in NYCA Installed Reserve Margin Study (New York State Reliability Council 2024a)

Area	Bin 1	Bin 2	Bin 3	Bin 4	Bin 5	Bin 6	Bin7
IESO	550 MW	60 MW	750 MW	860 MW	No additional limits (1950/2100 MW)		
ISONE	50 MW	540 MW	1,000 MW	1,530 MW	No additional limits (1804 MW)		
PJM	580 MW	1,110 MW	No additional limits (1412 MW)				
HQ	No additional limits (280/1162 MW)						
Total	1,470 MW	2,600 MW	No additional limits (3500 MW)				

When calculating the total installed reserve margin requirement, the New York State Reliability Council includes various sensitivities to calculate what the reserve margin requirement would be with and without the external assistance assumption (Table 5). These results quantify that external assistance reduces the IRM by approximately 5.5%, or nearly 2,000 MW, under standard assumptions. This is a larger change to the IRM than if all internal transmission constraints within NYISO were resolved.

While IESO and ISO-NE are the main providers of assistance under normal scenarios, under the most severe conditions the modeling shifts that reliance toward PJM. Non-firm external assistance from Hydro-Québec is capped at 280 MW, reflecting that much of the existing HVDC transmission capacity is already allocated to firm, contracted imports. NYISO continues to refine these assumptions annually, in coordination with the New York State Reliability Corporation and neighboring ISOs, and recent analysis suggests that neighboring systems may be modeling more conservative tie-benefit assumptions than New York itself—an insight that is spurring further review of the EA treatment and its policy implications (New York State Reliability Council 2024a).

Table 5. NYSRC Installed Reserve Margin Sensitivity Cases with and without External Assistance

Case	Description	IRM (%)	NYC (%)	LI (%)	IRM (%) Change from Base	LOLH (hrs/yr)	EUE (MWh/yr)
0	2025–2026 IRM Final Base Case (FBC)	24.40	75.58	107.30	-	0.374	216.980
These are the Base Case technical results derived from knee of the IRM-LCR curve							
1	NYCA Isolated	29.87	79.42	112.41	5.47	0.341	198.973
Track Total New York Control rea (NYCA) Emergency Assistance (EA) – NYCA system is isolated and receives no emergency assistance from neighboring areas (New England, Ontario, Quebec, and PJM). Unforced Capacity Deliverability Rights (UDRs) are allowed							
2	No Internal NYCA transmission constraints	22.55	74.28	105.56	−1.85	0.364	326.999
Track level of NYCA congestion with respect to the IRM model – eliminates internal transmission constraints and measures the impact of transmission constraints on statewide IRM requirements							

4.2.4 PJM Interconnection

PJM accounts for the contribution of neighboring systems through a combination of probabilistic modeling and limits on external assistance. In its Reserve Requirement Study (RRS), PJM uses the probabilistic reliability index study model (PRISM) tool and a two-area loss-of-load probability model that divides the system into the PJM RTO (Area 1) and the "Outside World" (Area 2), which includes adjacent regions like NYISO, TVA (Tennessee Valley Authority), VACAR (Virginia-Carolinas), and MISO (excluding MISO South). This external region is modeled in aggregate to simulate emergency assistance during system stress conditions, rather than on a zonal basis. The modeling captures probabilistic variability in generation and load, with forced outages, derates, and demand patterns derived from historical data and weather years (PJM 2023).

Two values govern PJM's reliance on this non-firm, uncommitted transmission capacity: the Capacity Benefit Margin (CBM) and the Capacity Benefit of Ties (CBOT). The CBM represents a hard cap on the amount of emergency assistance the model is allowed to draw from neighbors, currently set at 3,500 MW. This ensures that the model does not overly rely on external resources that may not be available in coincident stress events. The CBOT, by contrast, is the actual contribution of external assistance that results from the simulation and is used to adjust the Installed Reserve Margin (IRM) (PJM 2025b). It is currently set at 1.5% of PJM peak load, or about 2,400 MW (PJM 2025a). In effect, this 1.5% tie benefit lowers the total amount of capacity PJM must procure to meet its planning reserve margin based on the one-day-in-10-year LOLE criterion.

The IRM is calculated as the difference between the required installed capacity (to meet the simulated LOLE target) and the forecasted peak load, minus the CBOT. This formulation embeds the value of neighboring support as a system-wide requirement reduction, rather than a tradable supply-side product. The CBOT value is reviewed with stakeholders annually as part of PJM's ELCC and RRS process. Notably, while the CBOT captures measurable reliability contributions, it is

limited by the CBM ceiling to maintain consistency with contractual deliverability and policy constraints (PJM 2025b).

4.2.5 Midcontinent ISO

In contrast to some ISOs that model neighboring systems in more detail, MISO employs a statistical proxy to represent non-firm external assistance in its probabilistic loss-of-load expectation studies. These studies are then used to calculate the planning reserve margin requirement (PRMR) that load serving entities are required to meet.

For example, in the 2025–2026 Planning Year, MISO did not model the generation or load characteristics of adjacent regions (e.g., PJM, SPP, Manitoba Hydro, SERC). Instead, it created a synthetic external region containing 12,000 MW of perfect generation, connected to the MISO system through a constrained interface. Non-firm external imports were then modeled with a seasonal probabilistic distribution between 9 MW and 9,197 MW without identifying specific neighboring resources or interfaces. Instead, the MISO Strategic Energy Risk Valuation Model (SERVM) draws random values from a non-firm support distribution during each hour of the simulation (MISO 2025c).

The non-firm support distribution was derived from a three-year average of seasonal Net Scheduled Interchange (NSI) data during emergency pricing hours. This historical data reflects actual imports into MISO during tight conditions, net of any exports and subtracting out firm imports already accounted for at the resource level. The seasonal values are provided in Table 6, including the distribution probabilities that are used in the resource adequacy simulation.

Table 6. MISO Assumed Non-Firm External Import Distribution During Emergency Pricing Hours (MW)

	Summer	Fall	Winter	Spring
p5	1,138	525	9	1,384
p10	1,440	903	288	1,626
p25	2,959	1,749	1,223	2,283
p50	4,260	2,601	3,292	3,717
p75	5,198	3,632	5,785	4,987
p90	5,921	4,935	8,097	6,221
p95	6,520	5,748	9,197	6,497

This approach ensures that MISO's resource adequacy requirement reflects historical patterns of assistance while remaining conservative about the future availability of non-firm transfers. The probabilistic modeling of imports provides a capacity benefit, reducing the amount of internal generation required to meet the planning criterion (0.1 days/year LOLE), but without assuming perfect availability of external support. Importantly, MISO does not allocate or accredit these non-firm transfers to any specific entities and the benefit is socialized across the footprint as a

downward adjustment to the total PRM, rather than as a supply-side contribution in the capacity accreditation process.

MISO also does not provide the results of a counter-factual simulation that quantifies the change in loss of load expectation when the non-firm imports are not included in the model. Thus, it is unknown the extent to which the planning reserve margin is reduced by the non-firm import assumption.

4.2.6 Southwest Power Pool

In the SPP, only firm contractual imports are considered in the probabilistic resource adequacy analysis. SPP uses the SERVM model to conduct its LOLE studies but does not model the load or generation characteristics of neighboring systems, nor does it represent any form of non-firm or emergency external assistance. Instead, external support is included solely through proxy capacity units that reflect firm contractual transactions reported in the Resource Adequacy Workbook submissions. For the 2025 study cycle, this includes approximately 2,200 MW of firm imports, which are modeled as perfect-capacity generators within the appropriate LOLE zones. These units are not assigned forced outage rates and are treated equivalently to fully accredited supply-side resources.

4.2.7 California ISO

In California, the resource adequacy framework is governed by CPUC for the state's investor-owned utilities (PG&E, SCE, and SDG&E). Operational coordination and wholesale market functions are administered by CAISO. Both CAISO and CPUC use probabilistic models to evaluate resource adequacy across the Western Interconnection, with modeling frameworks that include imports from neighboring regions within the Western Electricity Coordinating Council (WECC).

The CPUC uses the SERVM model to conduct system-level resource adequacy analysis. This model represents California and neighboring regions in a zonal format, with six internal zones for California and seven external zones for adjacent parts of the WECC. These zones correspond roughly to balancing authority areas and reflect transmission constraints, flow limits, and hurdle rates between zones. External resources are modeled currently based on the WECC 2032 Anchor Data Set (ADS). While CAISO has a total import capability of over 11,000 MW, the resource adequacy studies cap external resource adequacy imports at 5,500 MW, applied specifically during high-risk summer evening hours (June–September, hours ending 17–23) (California Public Utilities Commission 2024).

While the modeling of the 5,500 MW does not include individual resources, it is fully subscribed by firm imports. These are typically either resource-specific resource adequacy imports (e.g., tie-line generators like Palo Verde and Hoover) or generic block imports contracted by LSEs, typically in 8-hour or 16-hour daily blocks, including transmission rights. Given that most of the 5,500 MW limit is met by these contracts, the modeling assumes negligible non-firm market assistance from the broader WECC regions. The structure of the state’s resource adequacy program, which requires all

LSEs to contract for capacity, including external resources, ensures that only firm, deliverable imports are counted toward meeting reliability criteria.

4.2.8 Summary Table of Current RTO/ISO Approaches

As discussed, each ISO and utility takes a different approach to quantifying and valuing the contributions of non-firm external assistance in their resource adequacy studies and capacity mechanism. Specific implementations for all ISO/RTOs are summarized in Table 7.

Table 7. Summary of Interregional, Non-firm Market Assistance for Resource Adequacy

ISO/RTO	RA Tool(s)	Non-firm reliance allowed?	How neighboring systems are modeled in RA	Policy/assumption limiting non-firm assistance	Assumed non-firm imports available in the RA model (MW)	RA contribution/ avoided capacity due to non-firm imports (MW)
ISO-NE	GE MARS	**Yes** (tie benefits)	Full co-modeling with NPCC neighbors in GE MARS; ties constrained by interface limits; annual "Tie Benefits" study allocates benefits to interfaces, after removing firm capacity contracts.	No single statewide cap; benefits allocated by running with/without ties and prorating by interface. The benefits assumed subject to review by the Northeast Power Coordinating Council.	Not a hard cap (interface-limited; varies by topology and neighbor conditions).	FCA-18 total Tie Benefits = **2,115 MW**
NYISO	GE MARS	**Yes** (emergency assistance, EA)	GE MARS with four Outside World areas (HQ, IESO, ISO-NE, PJM); NE & PJM modeled as multi-area with internal constraints. Firm imports (UDR) modeled separately.	Global EA cap 3,500 MW, alongside load forecast uncertainty bin limits (1,470 / 2,600 / 3,500 MW) and per-area limits; also forces 5 coincident peak days and keeps neighbors within LOLE 0.10–0.15. Tie benefits assumed subject to review by the Northeast Power Coordinating Council.	**1,470–3,500** MW depending on LFU bin; plus per-area limits	IRM reduction of 5.5% of peak demand, **~2,000** MW
PJM	PRISM	**Yes** (capacity benefit of ties, CBOT)	Two-area PRISM model (Area 1 = PJM, Area 2 = "World" neighbors).	Capacity Benefit Margin (CBM) 3,500 MW (max EA allowed)	**3,500 MW** (CBM cap)	CBOT reduces IRM by 1.5%, **≈ 2200 MW** in the 2023 study
MISO	SERVM	**Yes** (statistical proxy)	Includes an added "External region" proxy (12,000 MW perfect gen); non-firm support modeled as a **probabilistic** distribution derived from historical Net Scheduled Interchange; firm imports modeled separately.	6500 MW summer, 9200 MW winter; stochastic draws each hour from seasonal distributions (separate from firm PRA imports).	**Stochastic** (e.g., p5 ≈ 1,033 MW, p50 ≈ 4,351 MW, p95 ≈ 7,657 MW)	Unknown; embedded in PRM/LOLE results rather than published as a single MW credit.
SPP	SERVM	**No** (non-firm excluded)	No explicit modeling of neighbor load/generation; only **firm** DC-tie and external capacity transactions modeled as hourly "generators"	No non-firm assistance represented in LOLE model.	**0 MW**	**0 MW**
CAISO / CPUC RA	PLEXOS (CAISO) SERVM (CPUC)	**Effectively no** (firm/ showing only)	CPUC runs a zonal model of WECC neighbors; CAISO RA import accounting limits external RA that can be shown; modeling assumes up to 5,500 MW of **firm** RA imports in peak summer evenings; non-firm assistance not credited.	External RA limited by RA import capability and contracted showings; non-firm WECC assistance not assumed for PRM.	**0 MW** non-firm (imports reflected via shown RA up to ~5,500 MW, which are firm contracts).	**0 MW**

4.3 A Generic Modeling Approach for Valuing Interregional Transmission for Resource Adequacy

While practices are not uniform, most ISOs and utilities presented in Table 7 follow a broadly similar workflow to represent interregional transfers in resource adequacy analysis and incorporate the effect of interregional transfers into a local capacity procurement requirement. This section summarizes the common attributes of how many ISOs and utilities model the contributions of non-firm external assistance for resource adequacy and turns them into a generic six-step process. These six steps represent a high-level, broadly applicable method to help distill the varied approaches discussed in Section 4.1 into a common framework.



Step 1: Establish transfer capabilities between zones and regions.
In this step, transmission planners develop both internal and external transfer capabilities that can be used in a zonal resource adequacy model. These limits are typically derived from power-flow and stability studies and capture key constraints (thermal, voltage, stability) using interface ratings or a transfer matrix. Where relevant, limits reflect simultaneous import constraints (i.e., nomograms), seasonal ratings, and distinctions between AC and controllable HVDC ties. This can be developed both for the existing transmission infrastructure but can also be modified to evaluate increased transfer capability attributed to new transmission projects. The output of this step is a set of transfer limits by direction and, if available, by season or operating condition, that the resource adequacy simulation will enforce.

Step 2: Develop the probabilistic resource adequacy model.
The resource model simulates the balance of load and available resources across many weather years, different load conditions, and hundreds or thousands of generator outage draws, allowing transfers between zones subject to the Step-1 limits.

Step 3: Calculate the total capacity needed to meet the reliability criterion.
Planners conduct model runs to determine how much capacity is needed to meet the target resource adequacy criterion (commonly 0.1 days/year LOLE). This "tuning" can be done by either adding firm load (constant across all hours), scaling the load profile, or adding/retiring specific capacity resources.

Step 4: Isolate the resource adequacy contributions of non-committed transmission.
To isolate the resource adequacy contribution of interregional transmission, this step is performed both with transfers enabled and with transfers disabled (or constrained to firm-only). The difference in required capacity to meet the 0.1 days/year LOLE criterion is attributed to the capacity benefit of ties (i.e., the contribution of non-firm external assistance). This step is not always required for the capacity mechanism but is a useful reference point for the utility or ISO to quantify the total amount of capacity that is being relied on from non-firm, external assistance.

Step 5: Set the capacity requirement.
The required capacity identified in Step-3 becomes the planning target for the upcoming delivery year(s). If tie benefits are recognized, the requirement is reduced accordingly for the region or capacity zone. Depending on market design, this target may be expressed as a total system PRM, a zonal requirement, or both. Most jurisdictions apply guardrails or caps on how much non-firm assistance can offset the requirement.

Step 6: Procure resources to meet the obligation.
Finally, capacity is acquired through the applicable mechanism, either an organized capacity market or IRP solicitation, using the requirement from Step-5 and the region's accreditation rules. In most implementations, non-firm external assistance is not procured as a discrete supply offer; instead, its modeled contribution is already embedded as a requirement reduction, and procurement focuses on accredited resources needed to close the remaining gap.

At a high level, these generic modeling steps and the ISO/RTO specific analyses described are all focused on how to account for the resource adequacy benefits of existing interregional transmission and interregional transfer capabilities. Incorporating at least some benefit of interregional transmission (firm or non-firm) is standard practice in the United States, even in regions where administrative caps or other types of regulations limit the contribution of non-firm imports to resource adequacy analyses. Therefore, reviewing the current methods for quantifying the resource adequacy value of individual transmission assets (or portfolios of assets) is important for evaluating current industry practice and where practices can evolve to better reflect existing benefits and enable future benefits as transmission expansion continues.

5.0 Preliminary Gaps Analysis

This section identifies initial gaps or barriers that may be the subject of further work or improvement in practice. The identified gaps include those that are stated explicitly in literature and those inferred from the foregoing assessment of literature and industry practice. They were refined and prioritized through the feedback of an advisory group of subject matter experts convened around this topic in mid-2025.

To understand the nature of these gaps, a crosscut through resource and transmission planning processes provides context. The identification, valuation, and development of four types of regional transmission and two classes of interregional transmission, described earlier and portrayed in Figure 3, are supported through the various planning processes shown in Figure 6. These processes have different goals that interact with planning objectives for securing resource adequacy in different ways. The degree to which various planning practices have potential to support transmission identification and development for resource adequacy can be summarized in three tiers:

1. **No support**: Planning processes remain generally ineffective in identifying transmission to support adequacy. This is particularly evident in: (i) the case for transmission to transfer capacity between reliability zones within a region or support system-level resource adequacy, $T_{CapTrans}$, and (ii) non-firm transmission between regions, T_{Uncom}.

2. **Reliability-driven, incidental support**: Local and regional reliability planning commonly and explicitly accounts for transmission to serve load, T_{Load}, and other transmission projects, T_{Other}, which reinforce system performance under various contingency failures of generators or transmission lines, per NERC transmission planning standards. These projects may ultimately support regional resource adequacy but are not planned with improving resource adequacy in mind.

3. **Unit-by-unit, generator-optimized support**: T_{Gen} and T_{CapImp} primarily contribute to today's resource adequacy needs by interconnecting online generators and enabling firm capacity imports, respectively. T_{Gen} is supported primarily through generator interconnection and interregional coordination around identification, through affected system studies, of transmission needed to address interconnections of specific generating facilities (e.g. pseudo ties in CAISO). T_{CapImp} is primarily driven by transmission service requests and there are some examples of development due to interregional coordination. However, these processes improve resource adequacy only slowly on a unit-specific basis and do not co-optimize transmission for resource adequacy benefit. Similarly, both transmission service requests and regional economic and public policy planning may support T_{Other} to provide resource adequacy contributions on a case-by-base basis.

The gaps presented in this section primarily reside within the first and third tiers in the list above, though multi-value assessments of transmission could also improve the co-identification of reliability-driven projects.

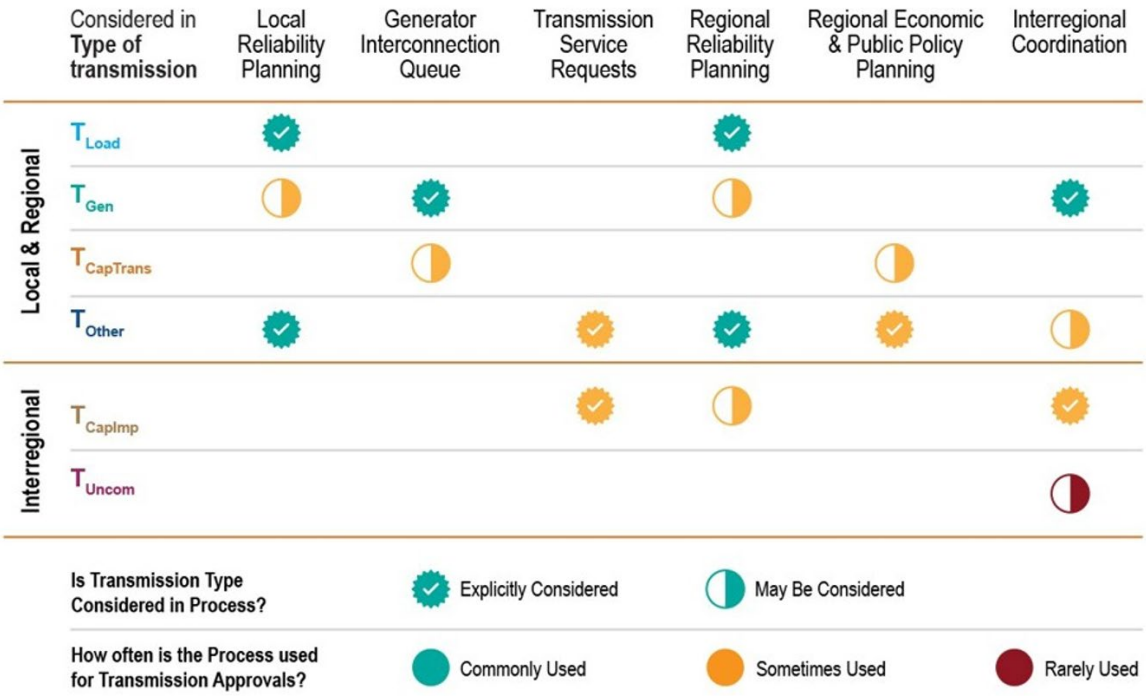


Figure 6. Link Between Planning Processes and Transmission Types

Note: *Circles in the figure are a combination of the first and second rows of the legend. For example, a half full red circle indicates that the transmission type May be Considered in the process, but the process is Rarely Used for transmission approvals*.

5.1 Regional Planning

Siloed planning processes mean transmission is not co-optimized with generation for resource adequacy needs. Within most regional planning processes, transmission is planned distinctly from the processes through which resources are identified for resource adequacy. In other words, resources are often selected through integrated resource plans, forward capacity auctions, or other resource planning processes and the regional planners determine the amount of resources (generation capacity and demand resources) needed to meet a 1-day-in-10-year loss of load expectation or alternative resource adequacy criterion. A separate, and often subsequent, transmission planning process uses the pre-determined resource mix—one that already meets the region's resource adequacy criterion—to determine transmission needs that may be required to deliver power to load.

Alternatively, when co-optimized with the resource planning process, transmission offers the opportunity to unlock access to lower-cost resources which could provide alternate, and potentially more cost-effective, pathways to meet resource adequacy standards while potentially

decreasing the total need (or local need) for new resources. Note that within this section, resource planning is taken to refer to a subset of the practice, in which resources are identified to meet resource adequacy standards. This overarching gap may be split into three main threads.

There are misalignments between planning processes for transmission and resources (for resource adequacy needs) in terms of planning horizons and objectives.

Centralized resource planning looks ahead 10–20 years. In this context, resource planning will consider generic, or non-location specific capacity expansion additions to resources that may be selected to meet the resource adequacy or other planning requirements. It relies heavily on scenario-based planning to bracket uncertainty. In non-centrally planned areas, market procurements to meet resource adequacy needs typically consider one to five years in the future.

Most existing reliability-based transmission planning processes, on the other hand, anticipate a five-to-ten-year horizon. Historically rooted in NERC contingency-based planning standards, transmission planning typically only includes generation projects further along in the development process (i.e., named projects that are under construction or have full regulatory approvals) and that have a high degree of locational certainty. The disparity in planning objectives between these planning processes poses a philosophical and process challenge to leverage transmission for resource adequacy.

Even within the resource side, a practical challenge of bridging resource adequacy assessments and resource planning and procurement is the mismatch in timing among these processes. LOLE studies and any associated capacity benefit of ties analysis are typically refreshed on an annual or biennial cycle and focus on near-term system conditions, which means changing load, weather, and fleet characteristics can shift resource accreditation and the modeled contribution of transmission between study vintages.

These staggered timelines complicate the planning framework that represents both resources and transmission on a consistent basis, since the planning reserve margin derived from short-term probabilistic studies is not naturally aligned with long-lead transmission investments that would alter future adequacy risk.

Additionally, most transmission planning processes do not establish resource adequacy as a core transmission objective. With exception of generator integration and firm capacity import requests, the resource adequacy benefits of transmission upgrades that are planned through the existing processes are mostly an incidental result of transmission additions and the planning process.

There are misalignments between planning processes for transmission and resources (for resource adequacy needs) in terms of modeling methods.

Inconsistent, incompatible, or incomplete resource adequacy methodologies hinder the initial identification of assets, capacity sharing across regions, and investment signals that may facilitate efficient reliability (Pfeifenberger et al. 2021a; Homer et al. 2025; Brooks et al. 2025; Tsoukalis et al. 2025). Generally, resource planning is focused on generation additions while transmission is

abstracted. That is, resource planning processes often treat transmission as a fixed input into the model, such as through existing transfer limits between zones. Additions to transmission which may improve the system's resource adequacy or lower total resource capacity needs are, in most cases, not considered.

Resource planning processes also feature varying resolutions in their representations of transmission components. Even when neighboring regions are represented, the spatial fidelity of models is likely to vary across regions. Many analyses use zonal or pipe-and-bubble models for the primary system of interest, and they either extend this resolution to neighbors or aggregate neighboring regions into less resolved zones (California Public Utilities Commission 2024; Carden et al. 2023). Without representing nodal transmission details, down to specific line or flow gate capacity by hour, representation of transmission capacity may be hampered. These may take the form of power flow limits due to contingency or dynamic stability concerns rather than transmission line rated capacities, some of which are represented in flow-based limits of the ERAA (European Network of Transmission System Operators for Electricity 2025). They could also be weather-dependent thermal de-rates (Douville et al. 2023; Hart and Mileva 2022). Transfer capabilities may be calculated using power flow modeling tools and limited snapshot analyses that may not represent the range of conditions where transfer capabilities are most important for resource adequacy. Without resource adequacy analyses sufficiently representing the system conditions corresponding to resource adequacy events, contributions from transmission to resource adequacy are left unquantified.

There are also differences in the types of transmission evaluated in the resource adequacy analysis. In some cases, only valuations of whole existing interfaces—groups of lines connecting regions or zones—are considered. In others, individual transmission projects may be in focus. Still in others, portfolios of transmission projects are modeled collectively, rather than evaluating single projects.

Identification of new transmission is commonly focused on NERC contingency-based planning standards. In other words, transmission planning is mostly based on power flow models to ensure generation can meet load reliably during specific and acute peak demand periods rather than conditions which drive resource adequacy needs more broadly. These conditions commonly are not modeled because transmission planning practice does not sufficiently resolve the following necessary elements:

1. Spatial and temporal granularity of demand and weather
2. Generator outage modeling and renewable generation levels
3. Battery storage conditions
4. Contracted transmission rights.

Failing to consider resource adequacy value of transmission also leads to planners undercounting benefits created by extreme weather events, which are under-appreciated by conventional transmission planning. Efforts to consider the role of transmission in these high-impact low-probability events have been limited (EPRI 2023). Transmission planning cases for 90th percentile

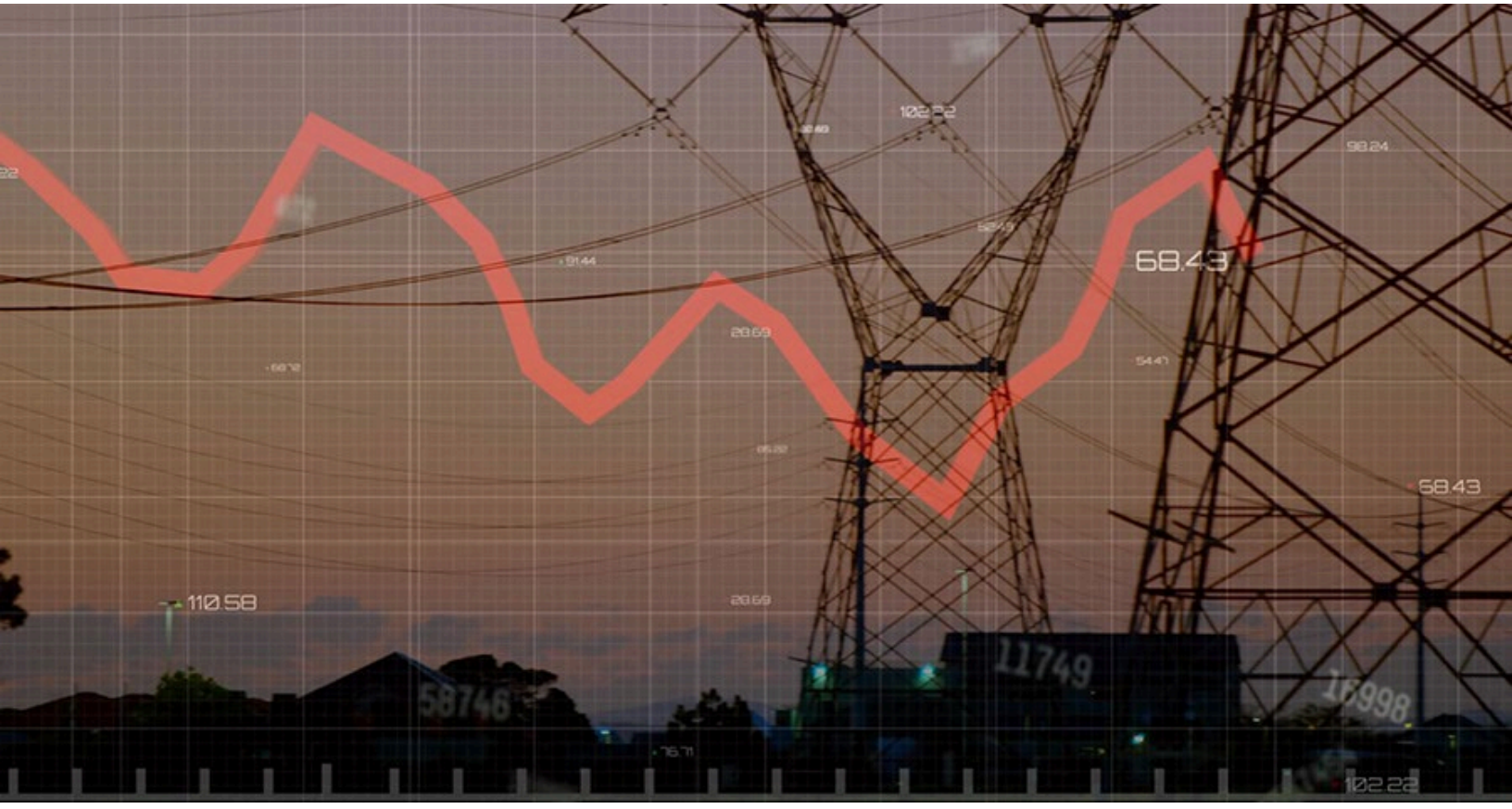
conditions are inadequate for representing resource adequacy events where weather and load conditions may be 99th percentile or above.

Finally, the lack of probabilistic planning for transmission and joint scenario planning for both transmission and resources create further challenges in fully integrating transmission and resource adequacy studies.

There are misalignments between planning processes for transmission and resources (for resource adequacy needs) in terms of data inputs.

Access to and stewardship of the fundamental input data are critical to both planning processes and such information has not been fully available to resource and transmission planners. Because the planning of resources is distinct from the planning of transmission, the assumptions of transmission capability often do not match those of resource planning and the assumptions of the generation fleet in transmission planning are typically misaligned with resource planning (EPRI 2023).

Resource planning commonly includes only a limited representation of transmission, which typically only considers zonal or copper-sheet representation of the underlying transmission system. Transmission planning commonly lacks long-term resource information. Consolidated transmission planning cases (e.g., NERC MOD32 and FERC 715 power flow cases) do not always represent long-term (10 years or longer) generation plans because specific locations of new



resources are required. This reduces their capability to expand detailed transmission analysis for resource adequacy uses. This gap links to the decoupling of resource adequacy with other planning activities (EPRI 2023). The bar for generation assets to be included in an IRP is lower than what it takes to be included in a transmission model because locational specificity is not required. There are also instances in which resources in the transmission planning cases are missing from related IRPs. Until data and common scenarios can be fully shared across planning frameworks, the value of transmission for resource adequacy will not be fully realized.

5.2 Interregional Planning

Despite recognition that transfers can materially reduce resource adequacy risk, current interregional planning practices remain patchwork and largely policy or regulatory-driven decisions. The following gaps and limitations highlight where today's methods can mute investment signals, weaken performance accountability, and under-credit the resource adequacy contributions of transmission.

Fixed caps on external assistance limit opportunities for new non-firm transmission in most areas.

System operators establish what types of resources and transmission may qualify for capacity markets or capacity contracts, and almost every region evaluated was shown to impose non-technical caps on allowable non-firm assistance (Table 7). Even if new transmission is built, these caps can prevent any incremental resource adequacy benefit from being recognized. In some cases, non-firm transmission is precluded from resource adequacy contributions, despite studies which have concluded potential adequacy contributions. Brooks et al. (2025) also found that current U.S. planning practices account for the resource adequacy contributions of firm transmission interties, but do not consistently account for the contributions of non-firm transmission interties.

Where recognized, the resource adequacy benefits of non-firm energy imports over uncommitted, interregional transmission are commonly socialized, failing to incentivize alternative business models.

In nearly every region surveyed, the modeled resource adequacy benefit of non-firm assistance is applied as a reduction to the system-wide resource adequacy requirement, which means the benefits accrue to all loads. This may be appropriate for transmission planned by a utility incumbent, but participant-funded or merchant transmission offerings may warrant different treatment.

Because socialized benefits are not tied to an individual transmission resource there is limited incentive to develop new participant-funded or merchant projects, in which an intertie in question is paid for by a subset of loads. Alternative models could reduce regional resource adequacy payments only for the loads who funded the intertie or enable capacity market participation with non-firm transmission. In the case of capacity markets, market design would need to consider the

obligations and penalties for non-performance during scarcity events appropriate for non-firm energy imports over uncommitted, interregional transmission.

There is generally no active exploration of how interregional transmission expansion can reduce total system costs, such as reducing the cost of meeting resource adequacy requirements.

Interregional transmission projects for resource adequacy conceivably could emerge if interregional expansion was motivated by total system cost savings, despite the gaps between resource and transmission planning. Interregional planning coordination established by FERC Order 1000 has been ineffective, given the only limited requirements for *coordination,* and not interregional *planning*. FERC Order 1920 added interregional coordination requirements but did not require planning processes to identify or develop new interregional transmission.

There are methodology and data components to this gap as well. Neighboring transmission networks are inconsistently represented in models and information around a neighboring region's resource mix and transmission capabilities may be limited. In the study of SPP by Pfeifenberger et al. (2025), this gap meant that only "proxy ELCC" values could be calculated for interregional transmission connections. This gap is especially important in the context of the emerging theme in the literature of wide area assessments, which call for evaluating resource adequacy and transmission of a given region and its neighboring regions—and even neighbors' neighbors—simultaneously (North American Electric Reliability Corporation 2024). The ESIG (2024a, ix) found that, "system planners often model their own region in a high degree of detail, while incorporating limited or even no representation of neighboring regions."

5.3 Valuation

The third overarching category of identified gaps applies to both the regional and interregional transmission types and concerns how capacity contributions are valued and compensated. Differences in capacity definitions stand as a friction to the amount of resource adequacy contribution which transmission assets can deliver, even in cases when the trade of capacity enabled by the transmission would offer an economic benefit.

There is a need to establish best practices for the valuation and compensation of transmission for its resource adequacy contributions.

Though there is significant literature on commercial barriers and opportunities for transmission in general, there is comparatively limited literature on the monetization of transmission's contributions to resource adequacy, specifically. Brooks et al. (2025) presents advanced work on this topic by identifying avenues for providing investment signals for transmission projects. However, there appears to be significant room for further development. Homer et al. (2025, 26) make a link between valuation and investment in their suggestion that, "by calculating the effective load-carrying capability of interregional transmission and giving it access to capacity markets, RTOs/ISOs can help incentivize interregional transmission development."

There is not a standardized method for allocating the capacity value of new transmission between generation, transmission, and ratepayers. In their review of capacity accreditation methods across resource types, the Energy Systems Integration Group (2023, 40) found that when explicitly (i.e., on the supply-side) accrediting resource adequacy value of transmission, a key challenge is determining "whether the capacity accreditation should be awarded to the transmission line or to the resources located at the other end of the line."

Additional challenges arise when attempting to credit resource adequacy value over AC interties while accounting for loop flow. In the case of interregional capacity contributions, there are times when energy delivery creates "loop flows" which travel through third-party systems. It is unclear how a method to account for capacity contributions from one region to another may acknowledge these flows (North American Electric Reliability Corporation 2024). Explicit capacity valuation also encounters challenges in ensuring that capacity is not double counted by two neighboring regions.

Distinct regional rules for valuing capacity imports create barriers for trading capacity across regions. Without an established best practice for valuation, the trading of resource adequacy value across regions may be constrained, even when it would otherwise be economic. For example, if one ISO acknowledges the resource adequacy contribution of an HVDC facility but a neighboring ISO does not, such resource adequacy contribution could not be acknowledged by the neighbor even if it could reduce costs to ratepayers.

Further refinement of methodologies is necessary to capture value unique to specific technologies. One potential refinement could be for differentiating HVDC from alternating current transmission, as HVDC has attributes that may provide additional resource adequacy value (Manz et al. 2022; Stenclik 2025b, 2025a). Another potential refinement would be to probabilistically account for transmission outage rates when valuating resource adequacy value to transmission itself. Brooks et al. (2025) notes that high-voltage transmission availability is generally "near 100%." Carvallo et al. (2023, 37, 34) reviewed resource adequacy practices and found that "ELCC can be applied to…transmission to account for weather derates" and identifies as a frontier practice "enhanced representation of failure rates by modeling transmission lines with weather-dependent stochastic failures." The resource adequacy contribution of grid-enhancing technologies (GETs) may also warrant specific treatment, as GETs increase transmission capacity and thus can increase a region's ability to import power. NERC's ITCS recommended increasing transfer capability through transmission upgrades including reconductoring, dynamic line ratings, and advanced power flow controls. In addition, Tsuchida et al. (2025) demonstrated that advanced transmission technologies (ATTs) can provide reliability benefits including reduced loss of load probability or lower reserve margin. However, it is unclear which valuation methods may be compatible with current planning practices. In addition to uncertainty over which valuation method to adopt, it is also unclear if transmission developers would want to take the non-performance risks associated with participating in capacity markets, as well as exposure to the high variance in expected renumeration from these markets, that can come from rapidly changing assessments of resource adequacy.

6.0 Conclusions

Transmission planning in the United States has been largely successful in delivering electrical power to an increasing pool of end consumers with limited disruptions. The industry accomplished this feat despite several major transitions over the previous decades. First, nearly from their inception, as regional grids grew in scale, a reliance upon increasingly higher-voltage transmission infrastructure was fully embedded into the system. Next, various rounds of consolidation and market restructuring changed how systems were planned, built, and operated. More recently, significant changes in where and when electricity is generated and consumed have only increased the importance of transmission to deliver electricity reliably and affordably, both within and between planning regions.

Though reliability has been a consistent objective of system planners, today's U.S. transmission planning processes do not identify or design transmission facilities to most efficiently address long-term resource capacity expansion or the resource adequacy needs of customers. Current planning paradigms generally consider planning for resource capacity expansion relative to resource adequacy needs and transmission capacity planning relative to grid reliability needs. Consequently, the design of transmission facilities does not capture the benefits efficiently designed transmission could provide towards ensuring least-cost resource adequacy.

A review of the literature and industry practice regarding: (i) regional transmission planning, (ii) interregional transmission planning, and (iii) valuation of transmission for resource adequacy, as compiled in this report, reveals the two fundamental reasons for this inefficiency. First, transmission and resource planning processes are siloed within regions which effectively precludes co-optimization of the generation and transmission components. Secondly, interregional transmission planning is constricted by existing regional planning procedures and limited federal involvement beyond interregional coordination processes. After consulting with industry experts, the following seven gaps were extracted out of these planning misalignments:

- There are misalignments between planning processes for transmission and resources (for resource adequacy needs) in terms of planning horizons and objectives.
- There are misalignments between planning processes for transmission and resources (for resource adequacy needs) in terms of modeling methods.
- There are misalignments between planning processes for transmission and resources (for resource adequacy needs) in terms of data inputs.
- Fixed, administrative caps on external assistance limit opportunities for new non-firm transmission in most areas.
- Where recognized, the resource adequacy benefits of non-firm interregional transmission are commonly socialized, failing to incentivize alternative business models.
- There is generally no active exploration of how interregional transmission expansion can reduce total system costs, such as reducing the cost of meeting resource adequacy requirements.

- There is a need to establish best practices for the valuation of the resource adequacy value of transmission, via PRM reduction, accreditation, or other mechanism.

Based on this literature review and gaps analysis, a foundation has been established for the development of approaches and methods, and their associated demonstrations, to capture the contributions of transmission to resource adequacy and thereby improve the affordability of reliable electricity systems. From this foundation, improvements to planning practice may be best pursued through sustained industry engagement and refinement of approaches to reflect the realities of planning and operations.

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Appendix A

Additional Considerations Relevant to Interregional Transmission

Numerous studies have highlighted the general potential benefits of interregional transmission, but only a subset of these also consider resource adequacy benefits. Several recent national studies have quantified the resource adequacy contributions of interregional transmission. Enhanced interregional transfer capabilities have been examined in recent work of FERC and NERC as well. This Appendix briefly summarizes these studies, and identifies emerging themes in wide-area assessments, HVDC transmission, and resilience.

A.1 National Studies

The value of interregional coordination of electricity flows has been a recurring theme in national transmission studies by researchers, regulators, and planners for the past five years. Bloom et al. (2021) modeled increased interregional transmission capacity along the seam of the Eastern and Western Interconnections in the United States. The study enforced a consistent resource adequacy requirement across the 32 simulations conducted and used a nodal transmission model with hourly resolution for matching supply and demand for select scenarios. The study examined several high-load periods including a three-day summer period when both the Eastern and Western Interconnections reached peak load. Though mechanisms for capacity sharing consistently drove favorable benefit-cost ratios for increased cross-seam transmission across study scenarios, the resource adequacy value was not isolated.

More recently, the U.S. Department of Energy (DOE) National Transmission Planning study (U.S. Department of Energy 2024b) used the ReEDS model and a resource adequacy target of 10 parts per million (ppm) nEUE for the entire United States and found that interregional coordination lowered resource adequacy costs by $170–380 billion through 2050. The benefits of resource adequacy due to interregional transmission were determined by restricting transmission flows from counting towards subregional (FERC Order 1000 region) planning target. Preventing interregional transmission from counting towards meeting resource adequacy criteria raised total system costs through 2050 by requiring all subregions to meet resource adequacy criteria with only local resources and intraregional transmission. Benefits were calculated as the delta in net present value of total system costs while meeting the resource adequacy criteria. The study additionally examined high opportunity transmission interfaces, which were identified as expansions to interregional transfer capabilities that showed up in 75% or more of the sensitivity cases and ranged from 1 to 25 GW increases in transfer capabilities across subregional boundaries.

Concurrently, U.S. Department of Energy (2024a) highlighted resource adequacy contributions to offshore transmission links between the Carolinas, PJM, NYISO, and ISO-NE . Winter peaking regions to the north were assisted by transmission imports of excess generation from the south. To quantify equivalent firm capacity over seven weather years, load was incremented in all cases until supply insufficiencies of 0.1 event-days per year LOLE and less than 10 ppm nEUE. An interregional

backbone was then shown to supply 29%–31% of firm capacity relative to aggregated transmission line ratings. The study yielded this capacity value in a constrained eastern seaboard, without additional onshore buildout of interregional transmission. In contrast, an ensuing study (Douville et al. 2025) nearly doubled onshore transmission builds across the Western Interconnection from 2035 to 2050 by reflecting mature projects and interconnecting more than 300 GW of new generation. Given this baseline, ELCCs of additional offshore interregional transmission builds were negligible across more than 900 historical weather year combinations of supply and demand. This sensitivity to onshore transmission is reinforced by noting the Associated System Capacity Credit of 28% for a similar offshore backbone concluded by Douville et al. (2023) in a more constrained system.

Sergi et al. (2024) also advanced the case that transmission is a cost-effective resource adequacy asset. The study employed a multi-criteria capacity expansion and resource adequacy assessment using EUE, NEUE, and LOLP to identify least cost solutions while ensuring resource adequacy metrics were met. The acknowledged shortcomings of the study included potentially insufficient zonal representation of load profiles and the assumption that seasonal peaks are coincident, an assumption that likely overlooks temporal complementarity and the additional potential benefits that transmission could provide. Notwithstanding study limitations, when transmission expansion was constrained, the annual system costs for meeting a target NEUE shifted up. The increase in system costs when transmission expansion is limited reinforces that transmission expansion can be a key part of a region's least-cost resource adequacy solution.

A.2 Interregional Transfer Capability

In 2022, FERC convened a staff-led workshop to discuss whether and how the Commission could establish a minimum interregional transfer capability requirement (Federal Energy Regulatory Commission 2022). The workshop explored the value of setting a minimum requirement, as well as the objective, drivers, methodology, and the potential cost allocation considerations accompanying such a requirement. Following the workshop, Goggin et al. (2023) demonstrated that a minimum interregional transfer capability requirement could be based on objective historical data. Using publicly available hourly electricity supply and demand data from the last decade, Goggin et al. (2023) determined that 20%–25% of peak load can be considered a conservative requirement. The report contends that it is ideal to apply a minimum transfer capability requirement uniformly to all regions rather than region-specific approaches given the uncertainty associated with key inputs and the challenges associated with regions using different methodologies and assumptions.

In 2024, NERC conducted an interregional transfer capability study (ITCS) for NERC transmission planning regions across the US and their interfaces with Canada (North American Electric Reliability Corporation 2024). The study first modeled the current transfer capabilities between regions for summer and winter peaks, finding that current interregional transfer ranges from 1% to

92% of planning region peak load. The study next defined and examined prudent additions[10] of transfer capacity for 2033, finding 35 GW of prudent additions across regional seams across the country, with ERCOT identified as having the greatest prudent transfer capacity addition. The study provided methodological innovations that have served as the basis for subsequent research, such as a national assessment of adequacy by planning regions under potential generator retirement, capacity addition, and load growth futures (U.S. Department of Energy 2025).

It is important to note that many of the national-level studies above model transmission paths in a general sense and do not identify specific transmission projects to support the modeled flows. Several observers caution that studies like these do not consider the transmission system in sufficient detail to answer questions of transmission adequacy and cannot be a substitute for the detailed transmission planning needed to identify specific transmission projects (Pfeifenberger et al. 2021a; Bose 2024). NERC cautioned that although the ITCS used large hourly datasets and multiple weather years, it did not implement probabilistic resource adequacy analysis and the prudent transmission additions should not be interpreted as accreditations arising from a resource adequacy assessment.

[10] Rather than isolate additions to meet a specific resource adequacy target, the recommended additions sought more generally to: (i) strengthen reliability, (ii) serve load under extreme conditions and (iii) not create unintended reliability concerns (North American Electric Reliability Corporation, 2024).



A.3 Wide-Area Assessments

There is an emerging theme of "wide-area assessments" in the literature on transmission and resource adequacy, which is most relevant to interregional transmission. The central idea of this theme is using transmission to exploit differing load and generation profiles across geographic areas that extend beyond the geographic limits of influential weather patterns, such as heat domes or winter storms.

NERC's ITCS foreshadowed a need to "conduct wide-area energy assessment and scenario development" (North American Electric Reliability Corporation 2024, xxi). In its description of this need, the study highlighted the importance of a methodology that allows regions to plan in coordination, such that a region does not plan to rely on neighboring regions during an extreme event when the neighboring regions may also be strained. This concept is later echoed by Brooks et al. (2025, 21), where wide-area assessments are described as identifying "capacity that can be shared across both internal and interregional zones."

The European Resource Adequacy Assessment (ERAA) serves as a current example of a wide-area assessment incorporating national and regional electricity grid data into a single probabilistic resource adequacy analysis (European Network of Transmission System Operators for Electricity 2025). Through the use of a common modeling framework, metrics, and scenarios centrally collected from member states, the methodology provides a standard set of input data and reliability metrics for member states to consider relative to their local criteria. This type of wide-area analysis also improved the resolution and understanding of cross-border capacity and introduced flow-based market coupling for more accurate modeling of interregional transfers. As a result, the ERAA provides a supplementary, 10-year overview of adequacy for regional planners and promotes cooperation across Europe by using existing analytical methods across a wider geographic scope under a common dataset.

Building on the example of the benefits to performing multi-region resource adequacy analyses used in the ERAA, ESIG (2025) outlined a list of important motivations of these wide-area assessments. The group identified that wide-area assessments improve resource adequacy analysis through:

- more consistent scenarios with respect to load growth and generator additions and retirement
- enhanced visibility of neighboring systems and how they are likely to change in time due to generation mix changes, load growth, public policies, and transmission planning
- isolation of the value of external contributions to reliability
- improved modeling of large-scale, extreme weather patterns which affect multiple regions simultaneously
- uniformity of methods and metrics for consistency.

Given the importance of existing interregional transmission in maintain reliability in the United States and the diverse analytical methods used to evaluate transfers between neighbors, wide-area resource adequacy assessments may be needed. These analyses could perform an important

function by improving national visibility into resource adequacy benefits by expanding interregional transmission. Furthermore, these studies could provide the necessary datasets and modeling frameworks to align utilities and market operators across the country on methods and metrics needed to provide investment signals or regulatory approvals.

A.4 High-Voltage Direct Current Transmission

Many of the transmission assets with significant potential for providing resource adequacy benefits are HVDC facilities. At least 11 of the 18 facilities identified by Brooks et al. (2025) are HVDC. The power transfer efficiency of HVDC over HVAC explains why this technology is often superior for long-distance interregional transmission which spans weather patterns. Several studies point out the necessity and value of HVDC for transferring power across asynchronous seams, like the seams between the Eastern Interconnection, Western Interconnection, and ERCOT (Schulte and Wahle 2024; Bloom et al. 2021). Additional capabilities provided by HVDC, such as the ability to efficiently transmit power long distances, quickly change the direction of power flow, and easily measure capacity injections at a point of interconnection, are advantageous for resource adequacy applications (Grid United 2024; Stenclik 2025b, 2025a).

A.5 Resilience

The coupling of resource adequacy and system resilience is a topic of active debate within the planning community (ESIG 2024b). Several references present a distinction between transmission's contribution to resource adequacy and its contribution to resilience (ESIG 2022, 2024a). FERC Order 1920 lists "mitigation of extreme weather events and unexpected system conditions" separately from the resource adequacy-related benefits in the list of seven benefits that transmission planners must evaluate.

Despite these distinctions, studies on this topic demonstrate that interregional transmission may contribute to resilience in much the same way that it can contribute to resource adequacy (i.e., by exploiting geographic differences in load and generation profiles). Numerous studies have examined extreme weather events and found significant potential benefits from additional interregional transmission (ESIG 2024a; Manz et al. 2022; Botterud et al. 2024; Goggin et al. 2023; Goggin 2021). While these studies support the resilience value of interregional transmission, there are also additional vulnerabilities that arise from outages or tripping when very long-distance transmission assets are relied on and experience a wider range of extreme events due to their geographic spread. Noting the core resource adequacy objective of limiting loss of load events across frequency, size, and duration, resilience benefits that improve these metrics during extreme conditions may fall within the scope of resource adequacy planning and be well characterized through multi-metric criteria.

However, historical weather databases may be insufficient to incorporate resilience events in probabilistic resource adequacy assessments due to the most extreme events exhibiting low frequency and multiple high impact failures, including on the transmission system, at once. Assigning probabilities to these events is inherently challenging. Furthermore, if included in

probabilistic assessments, the severity of the risks can be masked in aggregated resource adequacy metrics.

Another point worth stressing is that typical probabilistic resource adequacy analyses represent extreme events as solely driven by weather (e.g., temperature, humidity, irradiance, etc.), which is primarily driven by temperature relationships between load, generator outages, and renewable generation. Existing probabilistic methods have not looked to evaluate other extreme events such as wildfires or hurricanes. Evaluating other extremes could illustrate how interregional transmission provides substantial benefits to mitigate risks due to extreme events not considered in resource adequacy analysis. In this case, some planners have supplemented their probabilistic analysis with discrete and deterministic stress testing for relevant extreme events. These analyses often encompass renewable droughts, heat waves, winter storms, or wildfires which exceed those in the historical record, for instance. If these supplementary assessments result in an unacceptable unserved energy magnitude or duration, planners could trigger additional generation or transmission investments or defer retirements, regardless of the adequacy indicated by the primary, probabilistic analysis. For example, Tri-State Generation and Transmission Association (Tri-State) implements a Level 1 and Level 2 analysis framework for resource adequacy (ESIG 2024b). The first level is probabilistic and uses a multi-metric criterion including LOLE, EUE, and reserve margin targets. The second level considers stress tests around specific extreme weather events, and measures success by limiting loss of load hours to less than three hours per event and ensuring unserved energy does not exceed 20% of load in any hour. This supplementary, deterministic analysis may yield non-generation solutions such as transmission, that probabilistic analysis has been less likely to consider through conventional planning.

So far, the distinction between resource adequacy and resilience remains grey. This is in part due to industry trends towards multi-metric resource adequacy criteria which encompass potential resilience metrics such as mitigating loss of load magnitude. Placing caps on magnitude and duration of loss of load events is necessarily making a system more resilient while the analysis that develops those caps is firmly rooted in probabilistic resource adequacy studies. For additional discussion of resilience metrics and their intersection with resource adequacy metrics, see *Metrics to Evaluate Effectiveness of Resilience Strategy Deployment* (EPRI 2025). Despite this uncertainty, the resilience benefits of transmission can remain distinct and complementary to resource adequacy benefits by evaluating events that have not occurred in the historical record and are substantially extreme beyond the events covered under resource adequacy analyses.



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