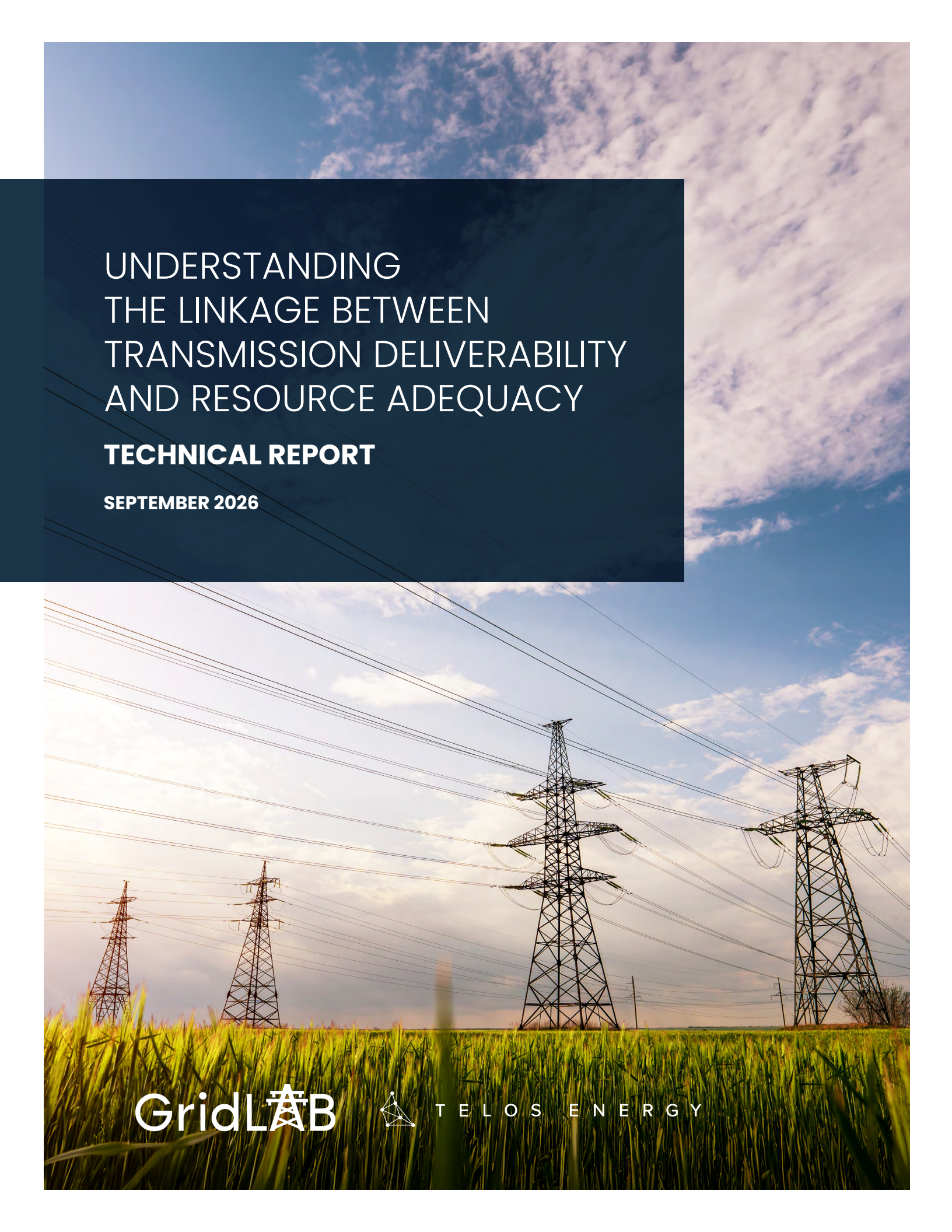




UNDERSTANDING THE LINKAGE BETWEEN TRANSMISSION DELIVERABILITY AND RESOURCE ADEQUACY

TECHNICAL REPORT

SEPTEMBER 2026

GridLAB



TELOS ENERGY

PROJECT TEAM

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ACKNOWLEDGEMENTS

We thank Ric O'Connell, Nikhil Kumar, Casey Baker of GridLab for providing feedback on the concept, analysis, and findings. We also thank Zander Bischof of MN8 for providing a review and discussion of PJM's CIR process; and participants at the GridLab hosted workshop on interconnection for overall feedback on the concepts herein. The authors are responsible for all errors in this report.

SUGGESTED CITATION

GridLab and Telos Energy, 2026, *Understanding the linkage between transmission deliverability and resource adequacy*, Report, www.gridlab.org/publications

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Introduction

Framing and motivation

When a new power plant connects to the grid, in most jurisdictions, it must choose between firm or non-firm interconnection services. In the former, it must go through an interconnection study process that determines how much of its output can be reliably delivered to the broader transmission system. These interconnection studies produce assumptions about each generator's "deliverability" — essentially, how much power it can export under peak load conditions. Those assumptions are then carried forward into resource adequacy analyses and capacity market processes where they determine how much capacity credit a resource receives in a capacity market or resource adequacy program, and how much total capacity the system needs to maintain reliability. Resources that are interconnected through non-firm service are generally ineligible to participate in capacity markets or resource adequacy programs and are often excluded entirely from resource adequacy models.

This study aims to bridge the gap between interconnection studies and resource adequacy assessments, two processes that are deeply interrelated but have historically been treated as separate analytical exercises. Most of the recent attention on generator interconnection has focused on interconnection costs, queue timelines, and transmission cost allocation, while the resource adequacy implications have remained largely unexamined. Despite the central role of deliverability assumptions in resource adequacy assessments, there has been limited research into whether they accurately reflect how resources perform during periods of elevated resource adequacy risk outside of narrowly defined peak-load windows. Inaccurately-assumed generator deliverability can have a large impact on resource adequacy outcomes.

This study was motivated by three objectives:

- Understand how generator deliverability and interconnection study results influence resource adequacy analyses and capacity market outcomes
- Determine whether the deliverability assumptions embedded in current resource adequacy modeling practices appropriately reflect resource availability during the periods that matter most for resource adequacy — specifically, hours of tight system supply and high loss-of-load risk
- Quantify the extent to which these assumptions affect the overall resource adequacy position of the system, and how they alter the capacity accreditation of individual resource types

Despite the central role of deliverability assumptions in resource adequacy assessments, there has been limited research into whether they accurately reflect how resources perform during periods of elevated resource adequacy risk outside of narrowly defined peak-load windows.

ERIS and NRIS interconnection and the linkage to resource adequacy

FERC Order 2003 established two types of generator interconnection service: Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). These categories determine how a generator's connection to the transmission system is studied and, critically, what role that generator can play in ensuring long-term system reliability (Norris et al., 2026¹ and Gorman, W., 2025).²

NRIS is a more stringent interconnection status, which allows a generator to connect to the transmission system and be deliverable during congested grid conditions. NRIS status typically requires more detailed interconnection studies, more extensive transmission upgrades, and a longer time in the interconnection queue. But in return, an NRIS interconnection means the generator can be designated as a capacity resource and contribute to resource adequacy requirements. Despite rigorous transmission studies which quantify generator-specific deliverability, NRIS resources may still be artificially limited by deliverability caps that constrain how much of their output is counted in resource adequacy models.

ERIS, by contrast, allows a generator to deliver its output using existing transmission capacity on an “as available” basis. The benefit of this approach is a more streamlined interconnection process and fewer required transmission upgrades compared to NRIS. ERIS resources are typically eligible to participate in energy markets but are ineligible for capacity market or resource adequacy program participation and receive no resource adequacy capacity value. In each ISO, ERIS resources are, in general, completely ignored in resource adequacy modeling — they do not count toward system capacity needs, and their presence on the system is not reflected when accrediting other resources.

1 Norris, T. et al. Is Energy-Only Interconnection Working? Empirical Evidence from Two Decades of US Market Data, June 2026, <http://dx.doi.org/10.2139/ssrn.6881698>

2 Gorman, W., Energy Resource Interconnection Service (ERIS): A Review of Current Practice and Considerations for its Future, October 2025, Energy Systems Integration Group Fall Workshop, <https://www.esig.energy/attachment/serve/session-3b-energy-resource-interconnection-service-eris-will-gorman>

As shown in Figure 1, NRIS is the primary interconnection service for operational resources across the US (excluding ERCOT). Interconnection requests are trending towards more NRIS in most, but not all, regions. MISO, SPP and the Western US lead in ERIIS interconnections in the operating fleet. New interconnection requests in the Southeast and CAISO are beginning to favor ERIIS. PJM ERIIS remains low for both operating and active requests.

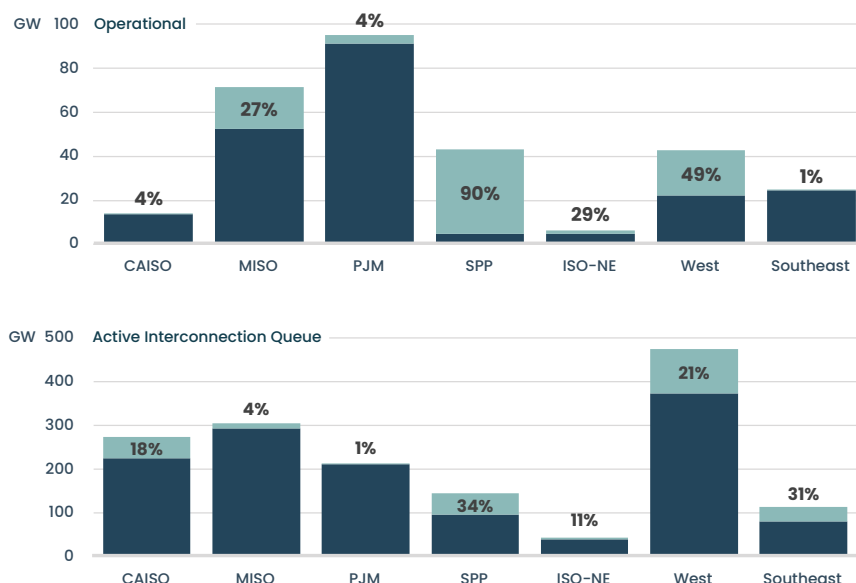
FIGURE 1.

Resource interconnection by ISO, contrasting ERIIS versus NRIS resources

(Source: 2025 LBNL Queued Up³)

Note: Summary data as of the end of 2024 is based on interconnection queue data only. The number of operational and withdrawn projects with available data may be fewer than the total number of operational or withdrawn projects for each entity.)

■ ERIIS
■ NRIS



This NRIS versus ERIIS distinction matters for resource adequacy because it creates a disconnect between how resources operate in real time and how they are represented in resource adequacy planning. Both ERIIS and NRIS generators are dispatched identically in day-ahead and real-time energy markets, yet the capacity contribution of ERIIS resources is often either excluded entirely or limited greatly in resource adequacy models. The resource adequacy models are used, in turn, to determine how much total capacity the system needs (i.e., planning reserve margin) and how much credit each resource receives (i.e., such as through an ELCC estimation). As the share of wind, solar, and storage resources grows, two key practices — limiting NRIS resource output to deliverability caps and the complete omission of ERIIS resources in resource adequacy modeling — have the potential to materially distort resource adequacy outcomes.

Beyond impacting the specific accreditation of ERIIS- and NRIS-designated resources, deliverability assumptions in resource adequacy modeling can

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3 Rand, J. et al. Queued Up: 2025 Edition, Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2024, December 2025, <https://emp.lbl.gov/publications/queued-2025-edition-characteristics>

have secondary effects on the broader system's total capacity need, seasonal risk distribution, and other resource accreditation. For example, if a system has a large portion of "energy only" ERIIS solar resources, which are physically present on the system but omitted from the resource adequacy model, it may show higher loss of load risk during summer afternoon and evening hours than what actually occurs in operations. Not only are these resources not counted as capacity, but it could inflate the total capacity needed in the summer, and have interactive effects on other resource accreditation like storage, wind, or even thermal resources.

Scope and Methodology

The study included three components. First, as summarized in the earlier section, we reviewed how major ISOs and RTOs classify generators as energy-only (i.e., ERIIS) versus capacity-deliverable (i.e., NRIS) within their interconnection processes and how those classifications influence capacity accreditation and market obligations across regions. This analysis drew largely on data from the 2025 LBNL Queued Up report⁴ and related research (Norris et al., 2026 and Gorman, W., 2025)⁵.

Second, using historical PJM pricing data, including nodal LMP and system load during scarcity events and high net-load hours from 2020 to 2025, an evaluation was conducted of whether the deliverability constraints assumed in planning models are consistent with actual generator performance during periods of elevated reliability risk.

Third, a resource adequacy model was developed for PJM to quantify how deliverability assumptions affect both total system capacity needs and individual resource accreditation. The study replicated PJM's ELCC methodology, calibrated to the 2027/2028 Base Residual Auction, and tested the sensitivity of key reliability metrics to the presence or absence of deliverability caps on wind and solar profiles.

PJM case study

PJM was selected as the case study for several reasons. It is the largest organized wholesale electricity market in the United States, with nearly 200 GW of installed capacity. PJM also applies relatively stringent interconnection requirements and embeds deliverability constraints directly into its resource adequacy modeling. Specifically, PJM caps the hourly output profiles of wind and solar resources in its ELCC model based on each resource's Capacity Interconnection Rights (CIRs), with seasonal deliverability limits that vary by resource type and zone. These limits make PJM one of the markets where deliverability assumptions have the most direct and quantifiable effect on capacity accreditation.

The timing is also relevant. PJM has recently undergone significant resource adequacy reforms, including a transition to marginal ELCC-based accreditation across all resource types. These reforms have changed how every class of generation — not just wind and solar — is valued for capacity purposes, driving increased interaction between deliverability assumptions and accreditation methodology.

4 Ibid.

5 Gorman, W., Energy Resource Interconnection Service (ERIS): A Review of Current Practice and Considerations for its Future, October 2025, Energy Systems Integration Group Fall Workshop, <https://www.esig.energy/attachment/serve/session-3b-energy-resource-interconnection-service-eris-will-gorman>

Finally, PJM is experiencing acute capacity constraints driven by accelerating load growth, particularly from data center development concurrent with generator retirements. Recent Base Residual Auctions have cleared at the price cap for consecutive auctions and failed to procure sufficient capacity to meet the most recent reserve margin requirement. When faced with an expensive capacity shortage, modeling assumptions for resource adequacy and accreditation, including deliverability, have heightened financial consequences for load-serving entities and generators alike.

PJM's approach to deliverability in resource adequacy analysis and accreditation

PJM currently incorporates resource deliverability into its resource adequacy analysis for both “unlimited” class resources (e.g., coal, gas, nuclear) and solar and wind class resources. Unlimited resources’ hourly output is capped at their installed capacity (ICAP) rating, which cannot exceed their capacity interconnection rights. Solar and wind resource output is constrained based on “time-of-year” deliverability limits reflecting tested deliverability under three system conditions: Summer, Winter and Light Load. These limits are reflected as caps placed on the hourly wind and solar availability profiles used in the resource adequacy model.

PJM's current approach for incorporating deliverability caps into hourly solar and wind availability profiles is the result of a PJM stakeholder process completed in early 2023.⁶ Prior to reforms introduced through this process, historically observed wind and solar curtailments were represented in the resource adequacy model, which is one metric representative of deliverability constraints. However, PJM argued that this approach was insufficient in the context of growing renewables deployment, and proposed that in addition to reflecting historical curtailments, a resource's hourly output used for accreditation should not exceed its tested transmission deliverability level. Stakeholders also noted that historical wind and solar curtailment may not be a good proxy for those resources' deliverability, since security-constrained economic dispatch would dispatch zero-marginal cost resources at full output despite their tested deliverability, potentially resulting in reduced thermal generation dispatch in the event of network constraints. In other words, wind or solar renewable resources could be running at full output even when transmission constraints are binding. The caps placed on hourly wind and solar availability in the final reform package reflect these considerations, and attempt to better reflect class-specific deliverability constraints in PJM's resource adequacy modeling.

While deliverability caps can help resource adequacy modeling capture transmission-driven constraints absent detailed network representation, they risk introducing artificial energy scarcity in the model and underrepresenting resource capabilities if the caps are misaligned with periods of “headroom” on the transmission system. In PJM's stakeholder process, this

⁶ See PJM Planning Committee's Special Session on Capacity Interconnection Rights (CIR) for ELCC Resources, <https://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue=83aadda8-b6c1-4630-9483-025b6b93fc28>

concern emerged in the context of wintertime solar resource performance, which would be capped at near-zero availability if winter deliverability caps were used for all hours. PJM ultimately reached a compromise with stakeholders capping solar availability based on Summer Light Load (SLL) transmission conditions for the winter mid-day window, allowing solar to be modeled at a higher output level during mid-day hours in winter months, when actual solar output can be meaningful and system headroom is more likely to be available. The resulting deliverability caps are shown in Table 1.

TABLE 1.

Assessed deliverability caps for wind and solar ELCC Classes

(Source: 2025 PJM Effective Load Carrying Capability and Reserve Requirement Study (ELCC/RRS))⁷

ELCC CLASS	ZONE	SUMMER DELIVERABILITY	WINTER DELIVERABILITY MW (AS PERCENT OF ENC)	LIGHT LOAD DELIVERABILITY MW (AS PERCENT OF ENC)
Onshore Wind	MAAC	Max (CIR, Transitional Deliv)	71%	64%
	PJMWEST		84%	80%
	DOM		77%	70%
Offshore Wind	MAAC		95%	88%
	DOM		97%	92%
Solar Fixed	MAAC		5%	51%
	PJMWEST		5%	56%
	DOM		5%	54%
Solar Tracking	MAAC		5%	53%
	PJMWEST		5%	51%
	DOM		5%	58%

Despite the introduction of the light load system condition, PJM's approach for capturing deliverability constraints in its resource adequacy modeling still remains inherently conservative — applying deliverability caps derived from three system condition snapshots across all hours of the year, whether or not those conditions reflect system conditions during the loss-of-load events captured in the modeling.

⁷ See <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2025-pjm-elcc-rrs.pdf>

Historical Congestion Analysis

Historical curtailment and congestion during resource adequacy risk periods

We examined whether transmission constraints have historically limited generator deliverability during the periods that matter most for resource adequacy. The objective was to establish an empirical baseline; if deliverability is a material concern during real-world stress events, it should be observable in historical operational data.⁸

To conduct this analysis, we developed a catalog of resource adequacy “events” in PJM over the 2020–2025 period using two screening criteria. The first screening criteria captured scarcity pricing hours, defined as any hour in which the PJM RTO-wide average real-time LMP exceeded \$500/MWh — a threshold that indicates system-wide supply tightness rather than localized congestion. The second screening criteria captured high net load hours, defined as hours in which PJM system load minus wind and solar generation fell in the top 0.5% of all hours in a given year. To be characterized as a resource adequacy “event,” one of the two criteria would need to be satisfied. Together, these filters identified approximately 60 event-days spanning a range of conditions including summer heat waves, winter cold snaps such as Winter Storm Elliott, and shoulder-season scarcity events.

8 Note that historical hourly curtailment data is not provided by PJM, so curtailment had to be inferred by LMP data.

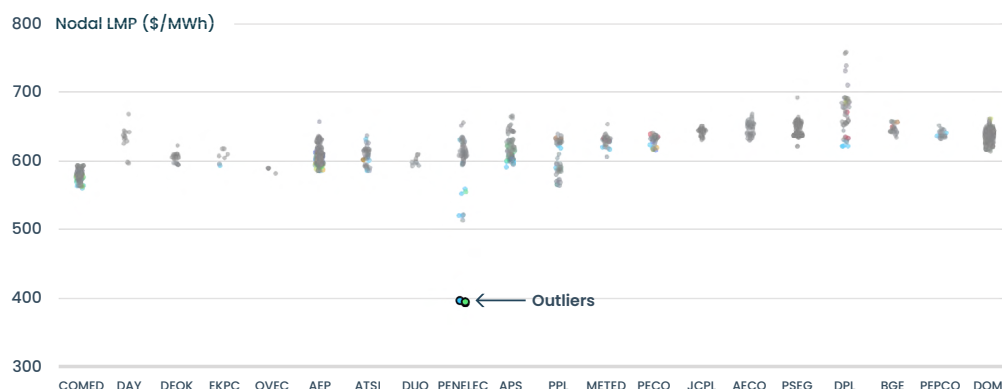


For each identified RA event hour, nodal LMP data was downloaded for every generator in PJM and grouped by transmission zone. The analysis then used a straightforward proxy for deliverability. It assumed that if a resource was unable to fully deliver its output due to transmission constraints during a stress event, its nodal LMP would be suppressed relative to other generators in the same zone; therefore, a suppressed or negative nodal price indicates that the plant had available energy to offer but was constrained by the local transmission network from delivering it to load. This approach was applied across all resource types — thermal, wind, and solar — to determine whether deliverability limitations during RA events were concentrated at specific generators or interconnection types. Although nodal LMP data does not identify whether a specific generator holds ERIS or NRIS interconnection status, this approach still allows us to assess if deliverability constraints may be binding during RA events, regardless of interconnection type.

An example of this analysis (Figure 2) shows the generator LMPs across PJM during the morning of January 13, 2022. This was a major winter storm event and saw prices average \$600/MWh across PJM. But only two locations in northeast Pennsylvania experienced pricing below the rest of the RTO.

FIGURE 2.

Historical pricing analysis during January 13, 2022



Nodal LMPs for additional RA events are shown in the Technical Presentation, which show similar trends — i.e., but for a few outliers, nodal LMPs within the same zone are closely clustered.

Observations and conclusions from historical data

Based on the historical analysis, it does not appear that deliverability has a meaningful impact on resource adequacy, at least not in any way that is observable in market data. The nodal LMP analysis across approximately 60 RA event-days in PJM between 2020 and 2025 did not reveal a systematic relationship between resource type and the likelihood of curtailed or constrained during periods of system stress.

Several patterns emerged from the analysis. First, it was relatively rare for a large number of generator pricing nodes to diverge meaningfully from their zonal average during RA events.

When price separation did occur, it was generally across broad PJM interfaces between zones (consistent with well-known regional transfer constraints) rather than at individual generator interconnection nodes. Second, the outliers that did appear were not systematic. A generator that showed suppressed pricing in one event was not necessarily constrained in subsequent events, suggesting that the congestion was driven by event-specific system conditions rather than persistent deliverability limitations tied to a particular interconnection status. Third, there was no discernible pattern by resource type. Coal, gas, wind, and solar generators all appeared as occasional outliers at roughly similar rates, with no evidence that renewable resources were disproportionately affected.

Based on the historical analysis, it does not appear that deliverability has a meaningful impact on resource adequacy, at least not in any way that is observable in market data.

While the nodal LMP data does not identify whether a specific generator holds ERIS or NRIS interconnection status, the absence of any observable relationship between resource type and curtailment during RA events is notable. If ERIS resources faced materially greater deliverability risk during system stress, one would expect to see that reflected in suppressed nodal pricing concentrated among renewable generators in congested areas. This finding informed the subsequent modeling work, which examines whether the deliverability caps applied in PJM's ELCC model are consistent with the actual transmission constraints observed during the hours that drive reliability risk.

Modeling Approach

The study included developing an independent resource adequacy model designed to closely replicate PJM's ELCC methodology as documented in the 2025 PJM ELCC and Reserve Requirement Study (PJM, 2025).⁹ Our replicated ELCC model, which is a loss of load expectation model uses PJM's published data and assumptions as inputs, including the same installed capacities by resource type used for the 2027/2028 Base Residual Auction, PJM's published hourly profiles for load, wind, solar, and thermal outages across the same set of weather years, and PJM's assumptions around energy-limited resource sequencing and dispatch order. The objective was not to build an alternative model, but to establish a validated baseline from which deliverability assumptions could be isolated and tested.

There were some areas where exact replication was not possible. PJM does not publicly release all data for resources with limited installed capacity, which required some estimation. The replicated model used fewer generator outage samples to improve computational speed. Additionally, PJM's methodology includes a "weather year rotation" process that was not included in the replicated model because it breaks the temporal correlation between load and weather-dependent resource output — an effect that was evaluated separately.

Finally, similar to the PJM ELCC model, our approach mimicked the exclusion of ERIS resources and only included NRIS resources. We did this in order to create a more similar replicated loss of load probability (LOLP) model. We did not have generator-by-generator interconnection designations available; however, we constrained the total solar and wind capacity to the NRIS effective nameplate (MW) levels that were used in the 2027–2028 Base Residual Auction.¹⁰

Despite these differences, the replicated model shows strong alignment with PJM's published results across key reliability metrics and ELCC class ratings. The model matched PJM's target expected loss of load expectation (LOLE) of 0.1 days per year; produced an expected loss of load hours (LOLH) of 0.37 hours per year compared to PJM's 0.35; and expected unserved energy (EUE) of 1,761 MWh per year versus PJM's 1,799 MWh per year.

ELCC class ratings, shown in Figure 3, align within a few percentage points for most resource types, with the largest discrepancies appearing for onshore wind and solar — driven in part by the omission of the weather year rotations. This level of alignment provides confidence that the

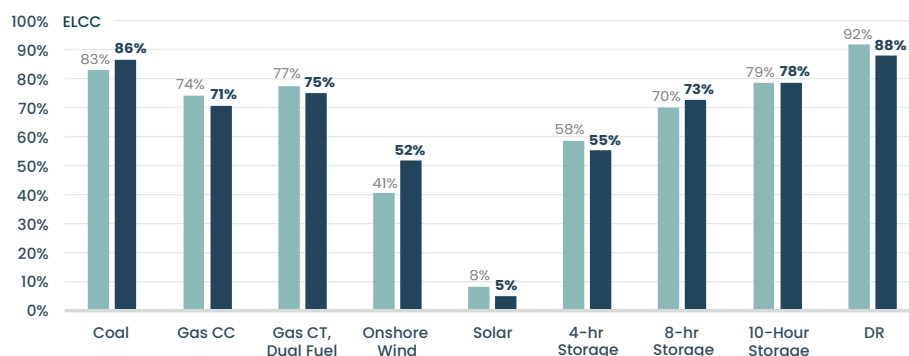
9 PJM, 2025 PJM Effective Load Carrying Capability and Reserve Requirement Study (ELCC/RRS), October 22, 2025, <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2025-pjm-elcc-rrs.pdf>

10 Bruno, J., Installed Reserve Margin (IRM), Forecast Pool Requirement (FPR), and Effective Load Carrying Capability (ELCC) for 2027/2028 BRA, PJM Markets and Reliability Committee, July, 23 2025, <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2025/20250723/20250723-item-04---1-2027-2028-bra-fpr-and-irm---presentation.pdf>

model can be used to meaningfully test how changes in deliverability assumptions propagate through the ELCC framework.

FIGURE 3.

ELCC comparison by resource type between PJM (left) and this study (right)



PJM's approach to modeling capacity injection rights on wind and solar resources

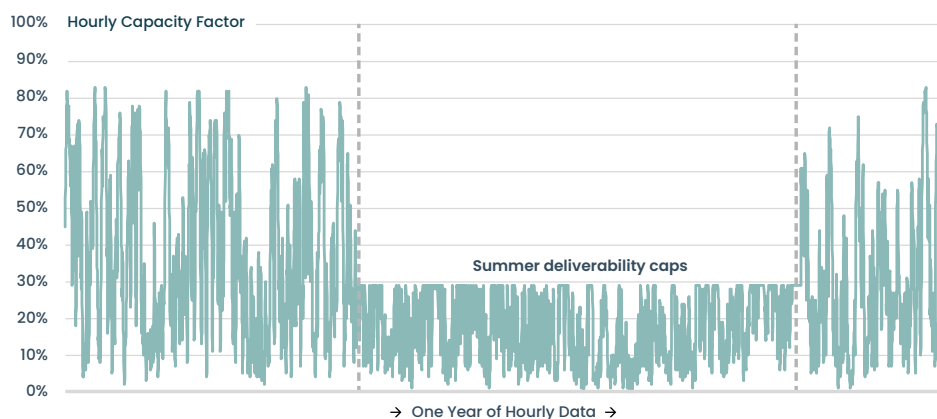
In PJM's ELCC model, wind and solar resources are subject to deliverability caps that limit the hourly output these resources provide based on the resource's Capacity Injection Rights (CIRs). These caps are derived from generator interconnection study results and transmission planning analyses, and they vary by resource type, geographic zone, and season. Specifically, during summer months (June through October and the following May), the hourly output of a variable resource is capped at the greater of its CIRs or its transitional system capability, whichever is higher. During winter months, caps are further differentiated by time of day, with separate limits for winter peak hours and light-load hours (PJM, 2025). These deliverability caps on hourly output apply only to wind and solar resources; thermal generators and energy storage are not subject to the same treatment.

Rather than limiting the maximum capacity a resource can offer into the capacity market, the deliverability caps are applied directly to the hourly input profiles used in the 8,760-hour ELCC simulation. For every hour in which a resource's simulated output exceeds its deliverability rights, the output is truncated to the appropriate deliverability cap value, and the excess energy is effectively discarded in the simulations. Notably, the caps are applied across all hours of the year, not just during resource adequacy risk periods when transmission might actually be constrained (Figure 4). During the vast majority of hours, when the transmission system has ample spare capacity, wind and solar output is still artificially reduced.

This approach also implicitly assumes that all wind or solar resources within a given class and zone are curtailed simultaneously across the entire PJM footprint. In practice, transmission constraints tend to be localized and event-specific, as the historical analysis in this study confirmed. By applying a blanket cap to aggregate resource profiles, the methodology conflates transmission limitations with energy availability limitations, potentially misrepresenting both the timing and magnitude of actual system risk.

FIGURE 4.

Hourly aggregated
PJM-wide wind capacity
factor, including
deliverability caps



Independent development of wind and solar profiles without deliverability caps

PJM publishes hourly wind and solar profiles for use in its ELCC model, but these profiles are aggregated across the entire PJM footprint and already incorporate deliverability caps. Because the caps are embedded in the published data, it is not possible to isolate their effect using PJM's profiles alone. In other words, there is no way to “remove” the deliverability constraint from an already-capped aggregate profile.

To address this, the study developed independent hourly wind and solar generation profiles from the ground up and replaced PJM's profiles. The new hourly profiles were developed both with and without the deliverability caps to ensure an internally consistent analysis. Using the National Laboratory of the Rockies' National Solar Radiation Database (NSRDB) and Wind



Integration National Dataset (WIND) Toolkit, location-specific wind speeds and solar irradiance data were downloaded for every wind project and every solar project in PJM greater than 20 MW from 2012–2024 for solar and from 2015–2023 for wind resources. Each plant’s weather data was then converted into hourly power production profiles using project-specific characteristics, including turbine hub height for wind, and panel tracking type and inverter loading ratios for solar. The profiles were then resampled using the same weather-year and day samples used by PJM to develop a statistical dataset of wind and solar profiles from 2012–2024, correlated to load and thermal outages.

The individual plant profiles were then aggregated on a capacity-weighted basis into PJM-wide profiles under two conditions: one set with deliverability caps applied consistent with PJM’s methodology, and one set without. This approach ensures that when the two cases are compared in the ELCC model, the only variable that changes is the deliverability cap assumption. All other inputs, including load profiles, thermal outage rates, and storage dispatch logic, remain identical. This isolation is what allows the study to quantify the specific effect of deliverability constraints on both total system capacity needs and individual resource accreditation.

Key Findings

Deliverability assumptions and their effects on total capacity needs

To quantify the effect of deliverability caps on system-wide capacity needs, the study ran the replicated PJM ELCC model under two conditions. In the first case, the model used wind and solar profiles with deliverability caps applied, consistent with PJM's current methodology, and was calibrated to meet the standard reliability target of 0.1 days per year LOLE. In the second case, the only change was substituting uncapped wind and solar profiles without the seasonal and hourly output limits imposed by PJM's deliverability methodology. All other model inputs, including load profiles, thermal outage rates, and storage dispatch assumptions, were held constant.

The deliverability caps embedded in PJM's current hourly profiles effectively increase the system's firm capacity requirement by 2,350 MW.

With deliverability caps removed, LOLE dropped from 0.10 to 0.06 days per year, and expected unserved energy was reduced by 44%. To determine the equivalent capacity value of this improvement, additional firm load was incrementally added to the uncapped case until the system returned to the 0.1 days per year LOLE threshold. That break-even point required adding 2,350 MW of firm load — meaning that the deliverability caps embedded in PJM's current hourly profiles effectively increase the system's firm capacity requirement by 2,350 MW. It's worth emphasizing that our ELCC model, similar to PJM's, excludes ERS resources. Given ERS resources are only 4% of total interconnected generators, including ERS generators would likely not have a significant impact, but would serve to further reduce the overall system resource requirement.

In a market where recent Base Residual Auctions have cleared at or near the price cap and the system is projected to move into deficit within a few delivery years, limiting NRS resources to their deliverability caps has direct and material consequences for procurement costs, resource investment signals, and the adequacy of the system as a whole.

Deliverability assumptions and their effects on resource accreditation (ELCC)

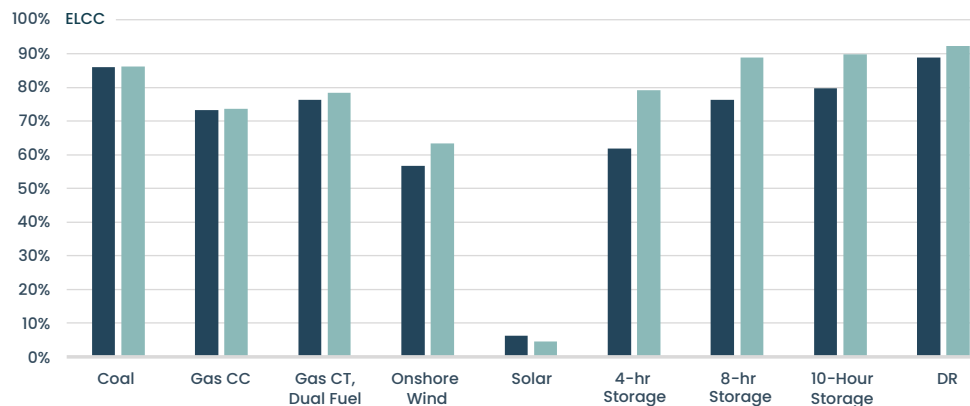
When the ELCC model was run with and without deliverability caps, the effects on individual resource accreditation varied by resource type. Thermal resources, including coal, gas combined cycle, and gas combustion turbines, showed limited or no change in ELCC between

the two cases. This is consistent with expectations, as deliverability caps in PJM’s methodology apply only to wind and solar profiles and do not directly constrain thermal resource output in the model.

FIGURE 5.

ELCC by resource class, with and without deliverability caps

■ Modeled with NLR Profiles Deliverability caps
■ Modeled with NLR Profiles No Deliverability caps



Surprisingly, wind and solar resources saw modest changes to their ELCC values when deliverability caps were removed. Wind accreditation increased slightly, driven by additional output that becomes available during summer peak load hours once the caps are lifted. Solar accreditation showed a smaller effect, and actually decreased. This is because summer risk hours were somewhat mitigated by the increased wind production and because the solar deliverability caps are smaller than the ones applied to wind resources. While removing the caps does increase the total energy these resources can contribute across the year, much of that additional output falls outside of the hours that drive loss-of-load risk, limiting the direct impact on their capacity credit.

The most significant change appeared in energy storage. When deliverability caps were removed, the ELCCs of 4-hour, 8-hour, and 10-hour storage resources increased significantly – 4-hour storage ELCC increased from ~ 60 to 80%, 8-hour storage ELCC increased from ~ 77% to 90%, and 10-hour storage ELCC increased from ~ 80% to 90% (overall, 10–20% increases).

This result reflects a mechanism that is not immediately obvious: deliverability caps constrain wind and solar output not only during risk periods but also during the off-peak hours that precede them. The increase of off-peak renewable generation when deliverability caps are removed has two effects: it shortens the resource adequacy risk periods that storage resources must cover and increases energy availability in hours when storage resources need to charge. Deliverability caps effectively reduce

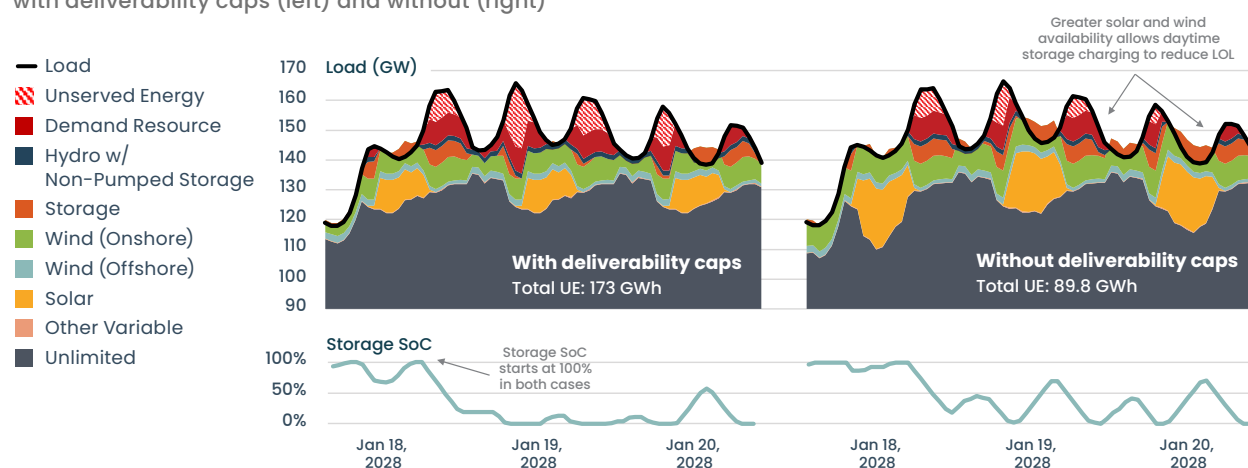
When deliverability caps were removed, the ELCCs of 4-hour, 8-hour, and 10-hour storage resources increased significantly... Deliverability caps effectively reduce the amount of energy that storage can shift into high-risk periods, suppressing storage resources’ capacity contribution in the model.

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This is illustrated during periods of unserved energy, shown in Figure 6. In the case with deliverability caps (left frame), battery state of charge starts the event at 100%, but is diminished during the first RA event. Over the course of the next several days the battery is unable to recharge due to insufficient energy. In the case without deliverability caps (right frame), surplus energy during mid-day, off-peak periods help recharge the batteries to be more available during the evening peak.

FIGURE 6.

Hourly dispatch during unserved energy events, with deliverability caps (left) and without (right)



This finding illustrates that resource adequacy is shaped by both capacity limitations during peak stress hours and energy limitations in the hours leading up to them. Broadly applied deliverability caps tighten the energy balance that storage depends on, an indirect effect that cascades through the ELCC framework and affects accreditation well beyond the resources to which the caps are directly applied.

Policy and Market Design Implications

Improving the linkage between resource adequacy and deliverability

Transmission constraints can and do limit generator deliverability during certain system conditions, and those constraints have real implications for reliability. The question is not whether deliverability matters, but whether the current implementation in resource adequacy models accurately reflects when and how those constraints bind.

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From a policy perspective, there is a reasonable argument for limiting capacity market participation to resources that have been studied for full transmission deliverability. Generators choose their interconnection service level, knowing that their choice carries consequences for their eligibility to provide capacity value. This study does not challenge that basic framework, even if it may be a conservative approach to capacity market participation.

What the results do show, however, is that the modeling treatment of deliverability has effects that extend well beyond the capacity rights of the resources directly subject to the caps. Embedding deliverability constraints in the hourly input profiles of the ELCC model increases total system capacity needs by 2,350 MW and changes the accreditation of resource types — particularly energy storage — that are not themselves subject to any deliverability limitation. These are system-wide effects that flow from assumptions about a subset of resources.

Implications for the interconnection queue and resource adequacy assessments

This study does not call for changes to how interconnection studies are conducted or how transmission upgrade costs are allocated between generators and the broader system. The ERIS/NRIS framework established under FERC Order 2003 serves a legitimate function in determining who pays for network upgrades and what level of transmission service a generator is entitled to. This cost allocation function can continue to operate as designed.



The findings do have implications for how the outputs of those interconnection studies are carried forward into resource adequacy modeling and capacity market processes. In short, the interconnection process and the resource adequacy process are answering different questions. The first asks what transmission investments are needed to ensure a generator can deliver its output under a range of planning conditions. The second asks how much capacity the system needs and how much each resource contributes to reliability. The results of this study suggest that using the answer to the first question as a direct input to the second, without adjusting for the timing, location, and likelihood of actual transmission constraints during risk periods, can distort capacity market outcomes in ways that increase costs for consumers and misrepresent the reliability contribution of the resource fleet.

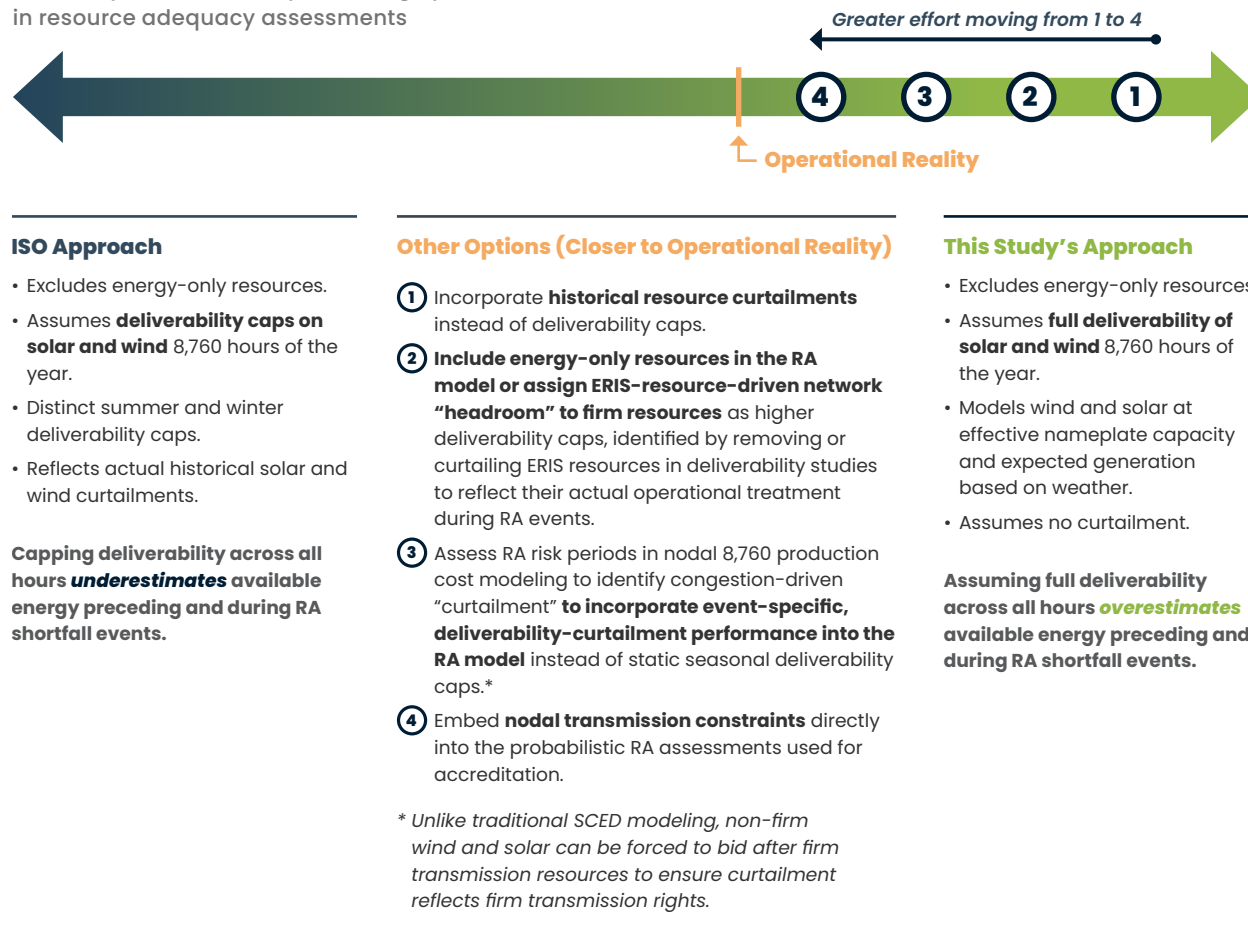
Future options for generator deliverability and resource adequacy

Resource adequacy models should represent deliverability in a way that reflects actual system conditions during the periods that drive reliability risk, rather than applying blanket output reductions across all hours of the year and assuming that an entire fleet of geographically dispersed resources would be curtailed simultaneously. A more targeted approach, one that accounts for when and where transmission is likely to be constrained, rather than treating deliverability as a static annual limitation, would produce capacity requirements and accreditation values that more accurately, and cost-effectively, reflect the physical reliability of the system. There are several ways ISOs could more accurately represent deliverability in their resource adequacy frameworks without abandoning the concept entirely. Figure 7 shows these options within the context of PJM's approach and this study's approach.

There are several ways ISOs could more accurately represent deliverability in their resource adequacy frameworks without abandoning the concept entirely.

FIGURE 7.

Summary of deliverability modeling options in resource adequacy assessments



First, resource profiles used in ELCC modeling should reflect the full operating capability of each resource, incorporating historical curtailment where it has actually occurred, rather than applying blanket deliverability caps across all hours of the year. Historical curtailment captures the real-world interaction between resource output and transmission constraints as they have materialized, while static seasonal caps assume a level of constraint that may not correspond to actual system conditions during the hours that drive reliability risk.

Second, resource adequacy models should reflect the full set of resources that are physically interconnected and operating on the grid, not just those with NRIS or capacity-deliverable status. Energy-only resources generate power and contribute to the supply-demand balance during stress events. Excluding them entirely from RA models produces an incomplete picture of system reliability and can inflate capacity requirements. Alternatively, ERIIS resources can be excluded from the resource adequacy model, but only if transmission capacity traditionally allocated to ERIIS resources in deliverability studies is reallocated to firm resources as higher deliverability caps. This transmission “headroom” could be identified by performing deliverability

assessments that remove or curtail ERS resources to reflect their actual operational treatment during RA events, and comparing results against standard deliverability assessments where ERS resources are included.

Third, where forward-looking estimates of curtailment are needed, particularly for new resources or future system configurations, ISOs should consider using hourly security-constrained production cost models to simulate projected curtailment under realistic operating conditions. This approach captures the locational and temporal specificity of transmission constraints far more accurately than applying a single deliverability value across thousands of hours. It also avoids the implicit assumption that all resources within a class and zone are curtailed simultaneously.

Finally, planners can most closely align deliverability representations in resource adequacy models with operational reality by embedding nodal transmission constraints directly into the probabilistic resource adequacy assessments used for accreditation. While these models traditionally take a copper sheet or zonal approach to network representation, nodal representations would allow for direct consideration of the network constraints that drive deliverability performance in resource adequacy modeling, albeit at a higher computational cost.

If deliverability adjustments are still deemed necessary after consideration of these options, they should be applied to the resulting ELCC values rather than to the input profiles of the resource adequacy model. This could be done by lowering the accredited ELCC value to the resource's capacity interconnection rights (assuming deliverability caps), or by taking a ratio of the generator's capacity interconnection rights versus its installed capacity, and applying that ratio to the ELCC level. Capping the output of a resource in the input profiles distorts the entire simulation — it changes when risk periods occur, decreases surplus energy for storage charging, and affects accreditation for non-capped resource types. Applying a deliverability adjustment to the final ELCC result would preserve the integrity of the underlying reliability simulation while still allowing planners to account for transmission limitations in the capacity value assigned to individual resources.

Next Steps

Future impacts of deliverability with increased wind, solar, and battery storage

Continued research on the interface between generator deliverability and resource adequacy is warranted. The 2,350 MW capacity impact identified in this study reflects the near-term PJM resource mix assumed for the 2027/2028 Base Residual Auction, in which wind, solar, and storage represent a relatively modest share of total installed capacity. As these resource types grow, the volume of capacity subject to deliverability caps will increase, and the system- and accreditation-level distortions introduced by those caps will compound. This applies to other regions as well.

The indirect effect on storage accreditation is particularly important in this context. Storage is expected to play a growing role in maintaining reliability as the resource mix shifts, and its capacity value depends heavily on the availability of surplus energy for charging in the hours before risk periods. If deliverability caps continue to artificially reduce the modeled output of wind and solar resources across all hours, the energy available to storage will be systematically understated, suppressing storage accreditation at precisely the time the system is relying more on these resources.



More broadly, as the generation mix evolves, resource adequacy risk is increasingly driven not just by peak load conditions but by the balance of energy supply and demand across multi-hour periods that include both risk events and the hours leading up to them. It is imperative that resource adequacy simulations accurately represent these dynamics, not only during loss-of-load hours themselves, but also during the periods of relative surplus or deficit that determine whether energy-limited resources like storage can perform when they are needed most.

Remaining questions and future research

The results presented in this study establish that deliverability caps have a material effect on modeled resource adequacy outcomes. However, the resource adequacy model used in this analysis, like PJM's own ELCC model, represents the system as a single zone without nodal transmission constraints. The focus of future analysis will evaluate whether the transmission limitations assumed in the deliverability caps actually bind during the specific conditions that drive reliability risk.

To do this, the study will replicate the resource adequacy risk periods identified in the ELCC model in detailed nodal production cost simulations and AC power flow analyses. These tools model the full transmission network, including individual lines, transformers, and interface limits, allowing the analysis to determine whether specific generators face binding transmission constraints during the hours and conditions that contribute most to loss-of-load risk.

Together, this round-trip analysis, from resource adequacy model to production cost simulation to power flow, will provide a more complete picture of how much transmission constraints could realistically affect generator deliverability during the periods that matter for system reliability, and whether the current resource adequacy modeling approach overstates, understates, or mischaracterizes that risk.



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