

THE STORAGE GAP

Deployment Challenges
in the East

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GridLAB



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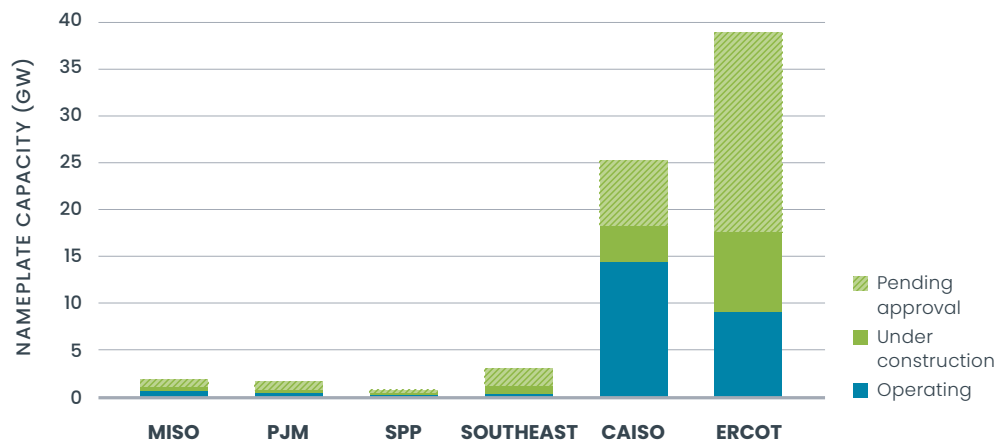
Executive Summary

Battery energy storage system (BESS) deployment has accelerated over the past decade, with global investment surpassing \$60 billion in 2024 and U.S. installed capacity exceeding ~40 GW in 2025. Installations remain highly concentrated in Texas and California, where unique interconnection processes and supportive policies enabled scale. In contrast, Eastern markets like PJM, MISO, and SPP lag despite growing demand and reliability pressures.

Our investigation validates the initial hypothesis that this lag is primarily attributable to systemic, regulatory, and market design limitations rather than a lack of developer interest or technological viability. Enhancements to policy factors including market design, interconnection processes, and procurement practices, and planning and modeling approaches may very well determine the future of BESS across these regions.

Current Deployment

The deployment of battery storage in CAISO and ERCOT far outpaces that seen in PJM, MISO, SPP, and the Southeast. The vast majority of battery storage operating, under construction, or pending approval in the United States is in ERCOT and CAISO. ERCOT alone has deployed nearly ten times more storage than PJM, MISO, SPP, and the Southeast combined:



Value Proposition

The economic viability of utility-scale battery storage hinges on the ability to generate multiple revenue streams, a strategy known as “revenue stacking”. The three major components of the energy storage revenue stack are (1) energy arbitrage, (2) capacity value and resource

adequacy, and (3) ancillary services, which have each provided unique value in each market over time. In the early phases of deployment, ancillary services have been the dominant revenue source in nearly every U.S. market. As energy storage achieves greater penetration, these ancillary markets saturate and the value proposition for storage becomes more reliant on energy, and capacity or resource adequacy payments.

While revenue stacking describes the economic mechanism for BESS participation, a significant portion of its system value is associated with operational flexibility relative to traditional generation, including fast ramping, bidirectional operation, high-precision dispatch, and the ability to respond to system conditions across multiple timescales, attributes that remain incompletely reflected in wholesale market compensation.

Unlike thermal power plants, which face long development cycles, BESS offers one of the fastest speed-to-power pathways to developers and operators. Modular, containerized systems can often be permitted, commissioned, and brought online within 6 to 12 months in favorable jurisdictions. This allows utilities and developers to respond to rapid load growth or reliability gaps within a single planning cycle, materially reducing forecast risk and de-risking long-term infrastructure decisions. Recent extreme weather events have highlighted the resilience advantages of grid scale storage. During periods of severe cold and heat, batteries have often exhibited higher operational availability than many thermal resources, which are often constrained by fuel supply disruptions or temperature related derates.

BESS provides geographical and siting flexibility that traditional assets cannot match. Because they produce no local emissions and offer high power density and modularity, large-scale storage can be deployed on relatively small footprints near dense urban load centers or on brownfield sites where combustion-based generation is unviable. Through fast (sub-second frequency response and exceptionally accurate signal following) inverter-based controls, BESS can emulate much of the behavior of synchronous machines and provide higher-quality frequency control than many aging thermal assets, particularly in systems with high renewable penetration.

ERCOT's early battery storage growth reflects strong ancillary service markets and arbitrage opportunities, while CAISO growth was driven by state-led procurement and resource adequacy structures. In Eastern markets (PJM, MISO, SPP), capacity and resource adequacy offer high potential, but accreditation uncertainty remains a challenge. Theoretically, battery storage could also add value through deployment as a transmission asset. However, due to concerns associated with simultaneous operation of energy storage as both a cost-regulated transmission asset and a competitive market supplier, U.S. grid operators, including PJM, MISO, and SPP, have limited storage as transmission to certain narrow situations where battery storage acts only as a transmission asset and does not simultaneously provide other value streams. This prevents BESS developers from "stacking" this value, and limits storage-as-transmission deployment to a small subset of cases.

Challenge 1 | Market Design

Market design and revenue certainty drive developer economics and timing, and market rule adjustments can materially change profit outcomes. Gaps in market products, price formation, and capacity accreditation that underestimate or obscure storage value can reduce the viability of battery storage projects. Current market rules impose limitations that inaccurately reflect costs or reduce efficiency.

Ancillary Services

- Restrictions in dynamic cost offers for ancillary services pose a significant barrier for BESS because ancillary services often account for a substantial portion of total revenue.
- Pricing mechanisms for ramping products ignore “lumpy” costs, such as start-up costs, creating \$0/MWh pricing for these services, understating the system value of BESS.

Energy Markets

- Restrictions on energy market offers prevent dynamic adjustments, misaligned with battery opportunity costs, which vary on a sub-hourly basis.
- Market software fails to price opportunity costs that resources incur when directed to save energy for future intervals, which can lead to inefficient price outcomes.

Capacity Markets

- Uncertainty around capacity and resource adequacy valuation restricts capacity market reliance. Uncertainty is driven by (1) a lack of transparency regarding system characteristics and (2) frequent methodological changes.
- Capacity accreditation methods may ignore certain flexibility parameters (ramp rates, start-up times) but include others (energy limits), which limits the reflected value of BESS.

Challenge 2 | Interconnection Processes

Long, uncertain study timelines and restudies result in major cost allocation shifts. This increases risk exposure in crowded queues, delays commissioning, and raises contract negotiation friction. While the Federal Energy Regulatory Commission’s (FERC) Order No. 2023 provided for incremental improvement to interconnection processes, it did not address underlying factors driving delay and uncertainty in interconnection. This misalignment is particularly acute for battery energy storage systems: although BESS has among the shortest construction and commissioning timelines of any grid-scale resource and offers a clear speed-to-power advantage in reliability-driven deployments, interconnection timelines frequently dominate project schedules. As resources that both inject and withdraw from the system, BESS face unique challenges to grid integration.

- PJM and MISO did not fully implement Order No. 2023's directive to study energy storage using more assumptions that match the resource developer's planned operations. MISO proposed to instead use a "fuel dispatch methodology" which FERC approved over the objection of BESS developers who argue it overestimates impact on the transmission system. PJM initially declined to implement this reform entirely, but later proposed fuel dispatch assumptions similar to MISO's approach after FERC rejected its initial proposal.
- In the face of inefficient interconnection, Eastern Regional Transmission Organizations (RTOs) have implemented one-time expedited mechanisms that allow certain resources to move ahead in the queue, using methods that may disadvantage various technologies, including storage.
- RTOs frequently require battery storage developers to submit transmission service requests in addition to interconnection requests. Some, such as PJM, offer a pathway to market participation without requiring transmission service that gives the RTO dispatch control whereas MISO and SPP generally do not.

Challenge 3 | Procurement Design

Procurement mechanisms are built for conventional generation technologies, and often fail to capture multi-service capabilities, resulting in mispriced offerings, constrained contracting pathways, and lost opportunities for transmission deferral. By moving beyond existing procurement structures and toward those that explicitly value all services or targeted needs, utilities can strengthen the portfolio of newly deployed resources.

- Procurements that acquire capacity on a strict dollar per firm MW basis disadvantage battery storage and fail to capture all system benefits. All-source procurements may appear resource-neutral while structurally favoring certain technologies.
- Procurement structure and evaluation requirements may favor incumbents and disfavor battery storage. Procurements which allow multiple contract structures and flexible terms strike a better balance between rewarding proven capability and enabling market entry.

Challenge 4 | Planning and Modeling Limitations

Resource planning tools and practices risk inadequate representation of storage performance, duration, and fast-response attributes, leading to underinvestment in BESS.

- Appropriate assessment of battery storage technologies depends on rigorous and up-to-date modeling of all resources and requires careful attention to relative impacts.
- Models may not appropriately reflect the full range of storage technologies and project structures or include up-to-date assumptions on cost and accreditation.
- Dynamic dispatch and sub-hourly price dynamics are critical to energy storage value, but difficult to capture in models and still evolving.

Conclusion

No single reform will close the gap on its own, but improvements in each of these areas could reduce uncertainty, provide revenue commensurate with value, and hasten deployment of BESS in lagging regions (PJM, MISO, SPP, & SERC). The key paths forward include:

Market Design

- Pay storage for flexibility through **dynamic offers, lookahead dispatch, and cost-reflective reserve bids**.
- Improve **ramping & AS price formation and advance nodal reserve pricing**. Nodal reserve pricing extends Locational Marginal Pricing (LMP) to ancillary services, assigning a unique value to reserves at each specific node. For BESS, this provides a granular revenue signal that rewards “locational value”.
- Transition market design toward **dynamic state of charge treatment** and evolve beyond static blanket duration rules. Instead, adopt temporal accreditation frameworks, such as slice-of-day accreditation that value storage based on its ability to deliver energy and reserves during specific, reliability critical periods, rather than assuming uniform value across all hours.
- Strengthen capacity markets with accurate, predictable, **performance-based accreditation that values flexibility adequately**.
- Move towards **long-term capacity agreements** to stabilize revenue certainty.

Interconnection

- **Reduce speculative queue volume**.
- Shift toward **deliverability focused, proactive planning**.
- Expand **fast track and Surplus Interconnection** pathways suited to BESS.
- Use tailored studies to rapidly **pair BESS with large load demand** without waiting for full market-wide studies.

Procurement

- Modernize procurement to **value multi service capabilities and targeted system needs**.
- Increase **transparency into bid evaluation criteria and valuation models** to ensure weighting clarity and consistent scoring.
- Allow **flexible contract structures** to broaden participation.
- Use **state mandates** where market signals are insufficient.

Planning & Modeling

- Use realistic assumptions for **technologies, durations, hybrids, and costs**.
- Incorporate **subhourly dynamics** and nontraditional use cases.



Introduction

Battery Energy Storage Systems (“BESS”) are no longer a nascent technology. More than \$60 billion globally was invested into BESS in 2024, approaching the total level of global investment in gas-fired power generation.¹ In the US, installed capacity has grown 50-fold in the last 10 years, with over 40 GW of capacity now in operation. Yet deployment of BESS in the United States thus far has been concentrated in only two regional markets. In Texas’ deregulated market, where grid interconnection is processed more quickly than other US regional markets and BESS revenues are determined primarily by market forces rather than administrative determinations, BESS deployment has soared to over 9 GW as of 2025. California has achieved even higher deployment numbers with over 14.5 GW as of 2025 via 15 years of policy and market support, representing nearly 38% of its recent peak demand (~44.4 GW), a level of penetration that allows storage to frequently become the grid’s largest power source during the evening net peak. Meanwhile, Texas has rapidly scaled to ~14.5 GW of BESS capacity against a peak demand of 85.6 GW, meaning batteries can now cover approximately 17% of total peak load. By comparison, PJM, MISO and SPP have deployed only 40 MW, 62 MW, and 13 MW respectively. Deployment lags even as the Eastern Interconnection faces a convergence of rising demand, accelerating retirements, gas plant supply chain constraints, and increasing renewable penetration—all of which underscore the urgent need for utility-scale BESS.

While market fundamentals partially explain the relatively higher deployment of BESS in California and Texas due to factors that affect the business case, such as grid constraints and penetration of variable renewable energy resources, that does not provide the full picture. **Differences in regulatory approach also play a critical role in determining energy storage deployment outcomes.** These include market design, interconnection processes, and in many regions procurement and integrated resource planning (IRP) practices.

¹ IEA, World Energy Investment 2025, at 24, available at <https://iea.blob.core.windows.net/assets/1b241aed-501c-4612-947e-8b4ad0d234a0/WorldEnergyInvestment2025.pdf>.

Renewable penetration plays a central role in shaping these revenue opportunities. CAISO and ERCOT both benefit from high levels of renewables that create deep and predictable price spreads. By contrast, while PJM, MISO, and SPP are seeing growing renewable additions, their wind and solar penetration remains far below CAISO and ERCOT. As a result, they experience shallower price spreads and lower volatility, limiting arbitrage value despite increasing capacity needs.

This report examines deployment trends for battery energy storage in the Eastern Interconnection. It examines the value proposition of energy storage resources, and delves into how that value is realized through wholesale energy markets and procurement. We identify wholesale market and interconnection barriers that may be inhibiting the ability of energy storage resources to achieve its potential in the Eastern markets, especially PJM, MISO, and SPP. In addition, we discuss challenges in procurement and planning that render deployment of energy storage more challenging in these regions, as well as in the Southeast.

Our findings are nuanced. There is no single regulatory “silver bullet” that will expand BESS deployment in these regions to the levels seen in California (CAISO) and Texas (ERCOT). However, a range of reforms at both the RTO and state level could meaningfully reduce barriers and improve the investment environment for storage. Importantly, even where wholesale market mechanisms do not allow energy storage to fully capture its value, state regulators can spur deployment through better procurement and planning practices. As wholesale markets continue to be refined to allow storage resources to deliver their value, this will enhance the value of resources procured pursuant to state-regulated mechanisms.

Deployment Trends

While recent market volatility exists, long term analyses show utility scale battery storage costs continue to decline. Over the past decade, the deployment of large-scale battery storage in the United States has undergone a dramatic transformation due to a combination of technological maturation and evolving market dynamics. Between 2015 and 2025, installed battery capacity saw a fifty fold increase, reaching approximately 15 GW of cumulative capacity. This growth was not linear; rather, from 2020 on, annual additions more than doubled year-over-year, demonstrating a new stage in operators' capability to bring storage online.²

This rapid growth in storage however hasn't been distributed equally across all geographies. In fact, the proliferation of battery storage was highly concentrated, with the bulk of capacity additions in the CAISO (California Independent System Operator) and ERCOT (Electric Reliability Council of Texas) footprints. These regions emerged as national leaders in battery deployment thanks to a combination of market, policy and grid incentives, all of which we discuss throughout this paper. In both CAISO and ERCOT, operators report that the storage systems they built are primarily used for revenue stacking across key services like energy arbitrage and ancillary services, functions that leverage the fast-response capabilities of standard lithium-ion grid-scale systems.³

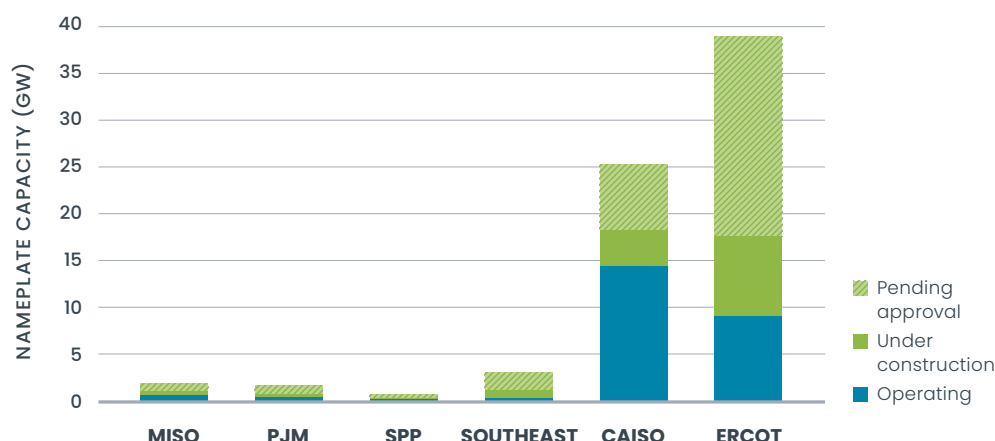
Arbitrage and ancillary services such as regulation are primary storage functions across all regions, but CAISO operators also report high use for other functions such as peak shaving and meeting resource adequacy requirements. This difference is largely attributed to CAISO's market and the state's policy design, which spur a more complex operating landscape for battery storage systems, where a wider array of their grid services have value.

² (EIA 2025)

³ *Id.*



FIGURE 1. Nameplate Capacity of Storage Projects by Region and Status⁴



By contrast, deployment in Eastern regions has lagged significantly. This paper focuses on headwinds to BESS deployment in MISO, PJM, SPP, and the Southeast — all regions that have yet to see battery markets flourish. Despite some growth, these areas lag far behind CAISO and ERCOT in terms of installed capacity, both cumulative and relative to system demand. As of 2024, the combined battery capacity across MISO, PJM, SPP, and major Southeast utilities totaled just 1.52 GW of combined battery storage capacity online (as compared to 14.48 GW and 9 GW in CAISO and ERCOT respectively, see **Figure 1**). CAISO and ERCOT have deployed storage broadly in line with rapid renewable growth, whereas lower renewable penetration and slower storage buildout in the Eastern Interconnection have constrained comparable storage value.

However, there are signs of momentum. Over 2 GW are under construction and 3.8 GW are awaiting regulatory or interconnection approval, though development attrition and long queue timelines mean expected online dates are uncertain. The difference between leading and lagging regions reflects not only economics but market design, capacity accreditation rules, interconnection/permitting friction, and the prevalence of different resource mixes. Federal incentives and state storage targets could accelerate Eastern growth, but whether reform and financing convert the pipeline into reliable deployments remains an open question.

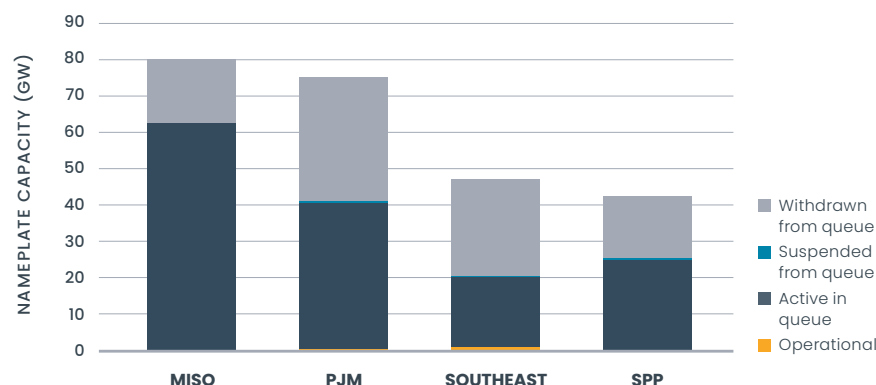
Interconnection Queues

Interconnection queue data underscores the uneven geography of BESS deployment across the United States. In MISO, PJM, SPP and the Southeast, there are 147.5 GW of battery or hybrid storage projects in their respective queues.⁵ While **Figure 2** below suggests latent interest it also highlights the gap between proposed and realized projects, particularly in these four Eastern regions where regulatory uncertainty or transmission constraints may impede development.

⁴ U.S. EIA, Monthly Electric Generator Inventory (August 2025)

⁵ Lawrence Berkeley Lab, U.S. Interconnection Queue Data Through 2024 (August 2025)

FIGURE 2. Nameplate Capacity of Storage Projects in the Queue by Region and Status⁶



Standalone versus Alternative Configurations

A notable trend in recent years is the rise of “co-located” and hybrid configurations⁷, wherein battery systems are co-located with generating resources, most commonly solar or wind. Nationally, developers submitting interconnection requests for hybrid configurations has increased substantially.⁸

Lawrence Berkeley National Laboratory’s tracking shows sharp growth in hybrid interconnection activity and operating plants, with clear benefits for single point of interconnection projects that coordinate inverters and balance-of-system (BOS) equipment to reduce costs and improve dispatch flexibility. However, these benefits vary by whether a project is a co-located or a fully coordinated hybrid and by regional market and interconnection rules that affect how hybrid services are valued and settled. Interconnection speed and efficiency are a primary reason developers choose a hybrid configuration because these configurations can facilitate efficient single interconnection and lower BOS costs.

Developers also hybridize in order to reduce curtailment, share equipment, improve dispatch and revenue stacking, access tax or procurement incentives, and deliver additional grid services, with the net value from these decisions depending heavily on project design and regional market/interconnection rules.

While this paper does not explore issues specifically impacting hybrid configurations, the emergence of hybrid configurations will be a key piece of storage deployment going forward.

⁶ *Id.*

⁷ From a control and market perspective, hybrid facility refers to a single controlled, monitored, facility at the point of interconnection, whereas co-located resource refers to separately controlled and monitored. For the purposes of this discussion, we refer to either one when using either term.

⁸ (LBNL)

Looking Ahead

Looking ahead, industry forecasts project continued growth in BESS deployment. Under current policy trajectories, Wood Mackenzie projects that total installed capacity could exceed 87 GW by 2029.⁹ This estimate reflects both utility-scale and distributed deployments and assumes continued cost declines, supportive regulatory environments, and increased integration of renewable energy. BloombergNEF expects that the U.S. will continue to see strong annual installations, reaching 25 GW of annual additions by 2035.¹⁰

In 2025, the emergence of data centers as a new force pushing load forecasts up dramatically across regions has reinvigorated discussions about large-scale generation build-out, and storage certainly has a role to play in that expansion. Simultaneously, the changes made in the One Big Beautiful Bill Act (OBBBA), including major changes to federal energy tax credit policy, will doubtless affect the pace and nature of resource build-out in the years to come. In particular, the dynamic between OBBBA's tax credit adjustments is already driving decision-making related to generation build-out across all resource classes, and storage may benefit from those changes. In the other direction, the Foreign Entities of Concern (FEOC) provisions included in the bill may stymie market growth given the number of battery storage components sourced internationally.

Deployment Drivers in California & Texas

California ► Procurement-Driven

California has long been a pioneer in BESS deployment, driven by a robust policy and market framework that facilitates long-term contracts with bulk energy storage. Installed battery storage capacity expanded from 0.5 GW in 2018 to over 15.7 GW by Q1 2025. An additional 8.6 GW is projected by 2027, with a statewide target of 52 GW by 2045.¹¹ Several key efforts in the state contributed to this build-out:

In 2010, California Assembly Bill (AB) 2514 established the first state-level mandate for energy storage procurement in the U.S.¹² It directed the California Public Utilities Commission (CPUC) to require the state's investor-owned utilities (IOUs) to procure 1.325 GW of storage capacity by 2020.¹³ The top-down mandate provided a clear, long-term market signal that spurred initial development. The CPUC issued decisions to implement the AB 2514 target, split among transmission, distribution, and customer-sited domains. Concurrently, the state leveraged

9 <https://www.woodmac.com/press-releases/us-energy-storage-installations-reach-new-quarterly-record-in-q2-with-5.6-gw/>

10 <https://about.bnef.com/insights/clean-energy/global-energy-storage-boom-three-things-to-know/>

11 [California Energy Storage Alliance](#)

12 <https://www.energy.ca.gov/data-reports/reports/energy-storage-targets-publicly-owned-utilities>

13 <https://docs.cpuc.ca.gov/publisheddocs/published/g000/m079/k533/79533378.pdf>

the Self-Generation Incentive Program (SGIP)¹⁴ and set aside funding for behind-the-meter storage.

Following periods of grid stress and near-miss power shortages, particularly during the 2020 and 2022 heatwaves, the CPUC began ordering substantial new volumes of battery storage through its Resource Adequacy (RA) mechanism.¹⁵ This approach aimed at California’s net peak (or “duck curve”) challenge, where solar-driven daytime surpluses give way to evening reliability risks intensified by heat-driven demand. Policy intervention directly translated the resource adequacy (RA) challenge into procurement requirements. The CPUC issued mandates requiring load serving entities (LSEs) to procure substantial new capacity as part of the Mid-Term Reliability (MTR) Procurement.¹⁶

Furthermore, the state’s RA program has been reformed to value storage: The CPUC and CAISO adopted the “Slice-of-Day” RA requirement, which obligates LSEs to demonstrate capacity for every hour of the day for each month.¹⁷ This structure specifically compensates batteries for their time-shifting capability, making them essential for compliance. Stable, market-based revenue from RA capacity contracts provides the primary financial engine for BESS deployment.

Texas ► Market-Driven

Texas took a different approach, relying on its merchant market model under the Electric Reliability Council of Texas (ERCOT). Without mandates or centralized procurement, TX became the fastest-growing battery market, adding over 10 GW of storage since 2020.¹⁸

Texas’ deployment is accelerated by:

1. High price volatility creating arbitrage opportunities paired with ancillary service markets;
2. The relative speed of ERCOT’s “first-ready, first-served” interconnection process; and
3. ERCOT’s approach to interconnection, which tolerates congestion rather than triggering network upgrades to ensure deliverability of resources, thereby enabling storage to provide congestion management.

Unlike the cluster study models used in some other markets (like CAISO), ERCOT uses a “first-ready, first-served” approach for interconnection. This model, combined with a “connect and manage” approach (where generators connect quickly and manage congestion in real-time), allows developers to bring projects online quickly without waiting for lengthy and costly system-wide network upgrade studies. This model also enables targeted battery storage

¹⁴ <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/self-generation-incentive-program>

¹⁵ <https://www.caiso.com/documents/2024-special-report-on-battery-storage-may-29-2025.pdf>

¹⁶ [Expectation of 28 GW of batteries and 2 GW of long-duration storage, by 2035](#)

¹⁷ <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/guides-and-resources/2025-ra-slice-of-day-filing-guide.pdf>

¹⁸ <https://www.latitudemedia.com/news/how-solar-and-storage-are-changing-ercot/>

deployment to address congestion. Fewer network upgrades are triggered through ERCOT's interconnection approach, as ERCOT's interconnection studies do not require resources to be deliverable to loads. This allows storage to serve a function like transmission, while stacking revenues with other value streams.

Texas's battery deployment is driven by high wind and solar penetration, price volatility enabling arbitrage, and ancillary service opportunities. Operating under an energy-only market without a centralized capacity mechanism or mandates, Texas has still demonstrated the economic value of BESS. Policy signals from the Inflation Reduction Act and pending state legislation may yet shape investment and siting, while the state's decentralized model enables IPPs to respond quickly to market signals. However, challenges including grid congestion and declining ancillary revenues are emerging.

Lessons Learned

The success of ERCOT and CAISO is strongly rooted in transparent price signals and certainty in policy structures that reward the flexibility inherent in storage assets. Conversely, the slow deployment trajectory in PJM, MISO, and SPP despite the massive national interconnection pipeline indicates that the underlying issue may be as much a regulatory and market design bottleneck as it is a lack of technology viability or developer interest.

IN FOCUS

SPP VS PJM — DRIVERS OF BESS GROWTH

As Audrey Lee and Daniel McCormack of Macquarie Asset Management explain, “[a]ttractive BESS markets have common features: These markets tend to have high renewables penetration, growing electricity demand, grid constraints, and retiring thermal generation.”¹⁹ Both SPP and PJM are experiencing some growth drivers, including rising electricity demand and, until very recently, large amounts of retiring thermal generation. Both regions are experiencing tightening supply margins, with PJM’s board chair recently stating that “the PJM system could see a capacity shortage as soon as the 2026/2027 Delivery Year.”²⁰ Similarly, SPP sought to justify an expedited interconnection process for certain resources based on its projected resource adequacy shortfall.²¹

However, SPP, as compared to PJM, has greater variable energy participation and is increasingly experiencing more congestion. With wind already accounting for nearly 40% of generation and renewables expected to exceed 50% of installed capacity by 2035, SPP’s system increasingly requires short-duration flexibility to manage variability and net-load ramping. Further SPP experiences significant congestion, with congestion payments exceeding \$1.8 billion in 2024.²² PJM’s congestion payments rose significantly, up from just over \$1 billion to nearly \$1.8 billion in 2024,²³ but those were spread across an RTO with a peak load nearly 3 times larger than SPP’s.

Despite these underlying fundamentals, SPP lags in BESS deployment, with just 13 MW installed in 2024, as compared to 40 MW in PJM, 14.4 GW in CAISO, and 9 GW in ERCOT. This raises the question whether market structure, procurement practices, or other barriers explain the gap between expectation based on these drivers and real-world deployment.

19 Audrey Lee and Daniel McCormack, Battery storage: Strategies for revenue stacking and investment success (2025).

20 PJM, 2024 in Review: Maintaining an Adequate Generation Supply.

21 See 2025 SPP Summer Season Resource Adequacy Report.

22 SPP, State of the Market 2024, at 7.

23 2024 Annual State of the Market Report for PJM, Press Briefing, at 9.

Value Proposition

The economic viability of utility-scale BESS hinges on its ability to generate multiple revenue streams simultaneously or sequentially, a strategy known as “revenue stacking”. Because BESS assets involve substantial capital costs and have limited energy storage capacity, relying solely on a single revenue source, such as simple price arbitrage, is often insufficient to justify the investment. Revenue stacking involves combining distinct opportunities across three main categories: energy arbitrage, capacity value and resource adequacy, and ancillary services.

Storage operates as a flexible, enabling technology, capable of functioning as a generator, demand resource, or even a substitute for transmission and distribution infrastructure. The primary focus for merchant development, however, lies in monetizing participation across the centralized markets for energy, capacity, and ancillary services, consistent with the requirements set forth by FERC Order No. 841. More recently, the focus has shifted toward navigating marginal capacity accreditation rules, where a large portion of the value of a battery is increasingly tied to its forecasted ability to provide reliable energy during the grid’s most stressed “net peak” hours (capacity) rather than simply responding to short-term price signals.

The BESS Value Stack

Ancillary Services: BESS is exceptionally well suited for providing ancillary services, particularly frequency regulation, due to its ability to respond rapidly often within sub-seconds to grid frequency fluctuations. This swift response contrasts sharply with the slower ramping capabilities of traditional thermal power plants. The ancillary services stack includes frequency regulation, spinning reserves, and ramp products, all of which are essential for managing grid stability and the volatility introduced by variable generation.

Energy Arbitrage: Energy arbitrage is the core market function of battery storage. Storage systems charge when wholesale prices are low, often during periods of high renewable output and discharge when prices rise during peak demand or scarcity. The profitability of this strategy depends on the size of intraday price swings, which are increasingly shaped by growing renewable generation. As solar deployment expands, it reshapes the net load curve and, in turn, the timing and value of storage arbitrage opportunities.

Capacity Value and Resource Adequacy: Capacity revenue compensates resources for supporting system reliability and meeting resource adequacy needs during peak or stressed conditions. For storage, this value depends on its accreditation, which converts installed capacity into an effective capacity credit based on the resource’s ability to perform during

highest risk periods. Most markets provide higher accreditation values to storage with longer durations, incentivizing developers to design batteries with relatively longer durations to secure this stable, long-term revenue stream.

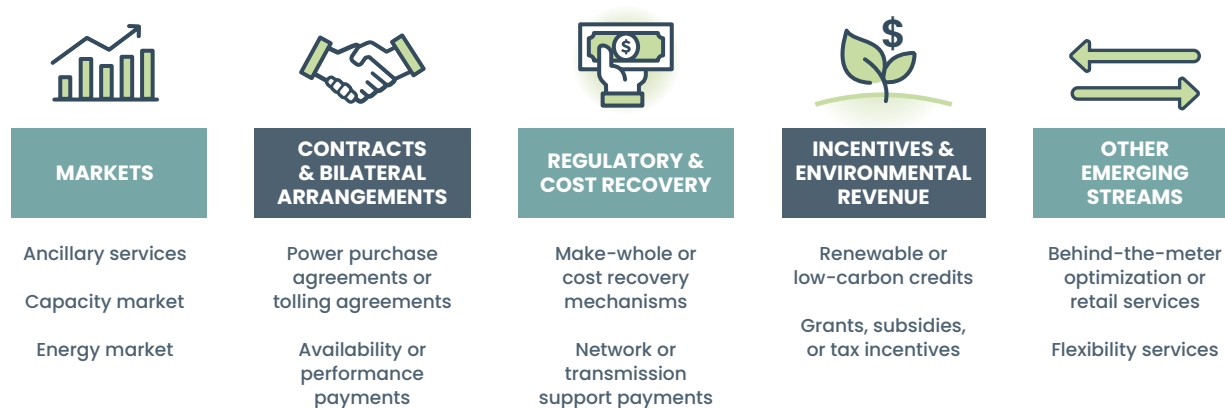
Non-Market Benefits (Reliability and Resilience): In addition to wholesale market revenues, energy storage delivers essential benefits that are challenging to monetize directly through market mechanisms but offer great value. These benefits include enhanced grid stability, voltage control, and overall system security, which are increasingly necessary given the growing reliance on inverter-based resources.

Today's wholesale markets were originally designed to accommodate a thermal generation fleet. As load grows and legacy fossil units retire, resource adequacy and system flexibility needs are increasing, driven by higher shares of variable renewables. While BESS can help meet these challenges, its value remains limited by markets that were not designed to fully recognize or reward its unique capabilities and constraints.

Market Revenue Trends

Large utility-scale battery resources monetize value both inside wholesale markets and outside them via bilateral tolling or offtake contracts. To satisfy the rigorous bankability requirements of project finance, many developers rely on tolling agreements, capacity contracts with load-serving entities, and government or environmental payments. Projects typically stack multiple revenue streams rather than relying on a single long-term agreement, and many use tolling or fixed-payment arrangements. The makeup of these revenue sources varies substantially from region to region and from year to year, driven by market design, duration and dispatch strategy, available tax and incentive mechanisms, and local procurement practices. Below, we identify trends in the key market streams.

FIGURE 3. BESS Value Stack



Trends in Ancillary Services

In nearly all markets with early BESS deployment, ancillary service revenues dominated the value stream. Ancillary service prices, especially for services like regulation that require fast response and accurate control, have historically started high and don't require storage operators to purchase energy in advance. Ancillary service value is largely independent of other factors, including portfolio-wide dynamics, providing a stable, high-margin entry point for early movers.

However, ancillary service revenues decline as more storage participates and markets become saturated. Demand for many ancillary services is unlikely to increase substantially above current levels. System conditions influence prices and ancillary prices correlate with energy prices. So, while extreme weather events that cause scarcity conditions and high fuel costs raise both energy and ancillary service prices, the level of ancillary services needed has already been met and is unlikely to rise substantially. Between market saturation and recent mild weather, CAISO and ERCOT saw revenues decline from 2023 to 2024, with ERCOT prices reduced by as much as 80%. Given that storage provides most of these services (84% of CAISO regulation reserve and 84% of ERCOT regulation up), such a major price drop functionally degrades the storage value proposition for these services.

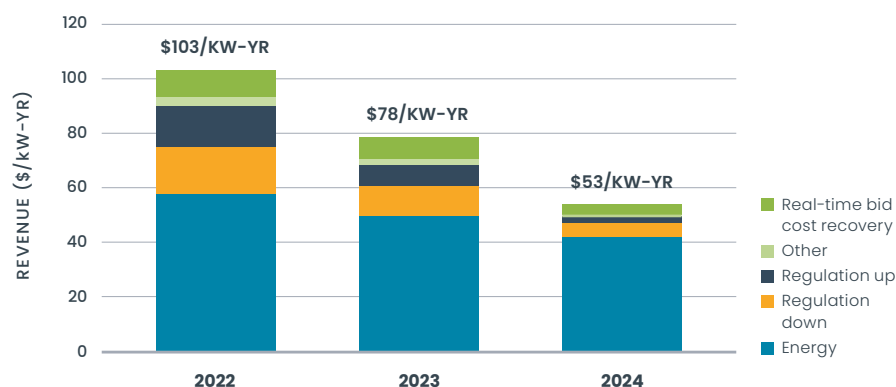
As ancillary revenues decline, battery owners commonly re-optimize toward other value streams; energy arbitrage, capacity markets, bilateral tolling or offtake contracts, and non-market payments (resilience or transmission/distribution deferral). This shift requires more sophisticated strategy and longer duration assets (2+ hours), marking the end of the "ancillary-only" era for grid-scale storage.

Trends in Energy Markets

As ancillary service revenues reach saturation, the BESS value proposition is pivoting toward energy arbitrage and, increasingly, capacity markets. Both CAISO and ERCOT saw higher participation and overall revenue from storage providing energy arbitrage in the energy markets in 2024 compared to previous years due to the reduction in ancillary service revenues. In ERCOT, battery storage technologies continue to generate revenue, driven primarily by participation in ancillary services when not actively charging or discharging. However, approximately 33% of projected revenues were attributed to ancillary services, while 60–65% were derived from energy arbitrage. In CAISO, the energy markets are a substantial part of the strategy, with batteries increasingly charging during midday solar peaks and discharging during the evening ramp. Energy market value depends on the price spread between charge and discharge, and how well state-of-charge is maintained. Large price spreads within a short period can provide value even for very short-duration batteries. Large spreads across a day (common where afternoon prices are low and evening prices are high) are valuable for most batteries but especially for longer-duration systems.

Energy market volatility depends on system conditions, transmission constraints, renewable curtailment, and allowance of things like reserve shortage conditions. The level of variable energy resources can play a substantial role — the more volatile output is across the day, the greater the volatility in energy prices as different types of resources set the price. Volatility may also increase in locations where transmission congestion can bind and unbind multiple times throughout the day. However, in regions with few variable energy resources and low congestion where the marginal resource is generally a gas fuel resource, for nearly all hours of the day price spreads remain small and thus arbitrage value for electric storage is limited.

FIGURE 4. California ISO, Average revenue for batteries with a full year of operation, 2024²⁴



Trends in Capacity Markets

Capacity revenues for BESS can provide substantial revenues in regions with either organized capacity markets and/or long-term procurement mechanisms. The 2025–2026 delivery year marked a historic inflection point for the Eastern Interconnection, where stagnant markets were replaced by record-setting capacity prices driven by rapid data center expansion and accelerating thermal retirements. These auctions, clearing at an unprecedented \$666/MW-day in MISO and \$333/MW-day in PJM have established a new “reliability-driven” revenue pillar that offers a theoretically more stable return than volatile energy arbitrage. However, a critical financing gap remains: while these price signals are strong, they are merchant streams secured for only one to three years, lacking the 10- to 20-year contractual certainty seen in markets like CAISO. Without long-term procurement mechanisms to provide terminal value and unlock low-cost debt, developers in the East remain exposed to significant year-over-year price volatility, keeping the cost of capital high despite the record-breaking clearing prices.

This rise in capacity market value will likely remain high in the coming years due to tighter reserve margins and continued growth (especially from data centers). Capacity markets are designed to capture the missing money in energy markets required to incentivize an adequate supply fleet, and given their linkage, can impact revenues earned in the energy and ancillary

24 <https://www.caiso.com/documents/2024-special-report-on-battery-storage-may-29-2025.pdf>

service markets. Where resources earn significant capacity/resource adequacy revenue, that will tend to reduce earnings opportunities in the energy and ancillary services markets.

Capacity Accreditation: Capacity accreditation methodologies dictate that a resource's capacity value changes as the resource mix evolves. As such, as the accreditation of BESS resources changes, battery capacity eligible for market participation may decline. As market penetration of a specific battery class increases, the value of that class of resources is expected to decline.²⁵ As of this paper's publication, the most recent PJM capacity contribution of a four-hour battery is about the same as a combustion turbine (CT) in today's resource mix (58% versus 61%), PJM projects the value of that battery to be as low as 23% of the nameplate discharge capacity in the year 2035 while CT remains at 70–80%.²⁶ For a developer, this means that even if capacity prices remain high, the UCAP (Unforced Capacity) revenue for a battery asset could be cut by nearly half over its operational life.

Importantly, it may be difficult for BESS developers to predict how capacity accreditation of stand-alone and hybrid storage resources may evolve over time. Recent years have seen significant revisions to capacity accreditation across PJM, MISO, and SPP.²⁷ These methods may be subject to further changes over time, creating risk for BESS investors and lenders relying on capacity market revenue streams.



25 Gupta et al., *Capacity Accreditation Reforms in US Wholesale Electricity Markets and Implications for Battery Storage Assets*, at 48 (2025)

26 <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/preliminary-elcc-class-ratings.pdf>

27 See Gupta et al., *Capacity Accreditation Reforms in US Wholesale Electricity Markets and Implications for Battery Storage Assets* (2025); see also FERC approves PJM capacity accreditation, modeling reforms aimed at boosting reliability (Feb. 1, 2024); 189 FERC ¶ 61,065 (2024) (Order accepting MISO capacity market accreditation reforms); 192 FERC ¶ 61,058 (2025) (Order addressing proposed SPP capacity accreditation revisions).

BREAKOUT

STORAGE AS A TRANSMISSION ONLY ASSET

In addition to the many market-based value streams that they provide, BESS resources can also function as transmission assets. For example, energy storage can serve as an alternative to address transmission line constraints, by reducing the amount of energy that needs to be delivered over the transmission system during peak periods.²⁸ Energy storage may also be used to maintain voltage and manage power flows, and to address certain reliability contingency scenarios.²⁹ Finally, energy storage can be configured to “inject or absorb reactive power into the grid to maintain the voltage within limits.”³⁰

Despite this value, however, battery storage deployed to provide transmission services has proven complicated in practice. Under FERC’s current framework, use of energy storage transmission must be approved for specific circumstances. This need for specific approval, along with FERC’s evaluation process, means that storage’s transmission value usually cannot be neatly stacked on top of its other values to form an integrated revenue stream. As highlighted in a 2017 FERC policy statement, the use of energy storage as a transmission asset raises potential concerns in three areas: (1) double recovery of costs, (2) adverse market impacts, and (3) RTO/ISO independence.³¹

FERC does not provide blanket authorization for transmission providers to use energy storage as transmission where these circumstances are addressed. Rather, the Commission has evaluated particularized requests to use storage as transmission on a “case-by-case basis.”³²

FERC has approved participation frameworks for storage to provide transmission services in both MISO and SPP, but the participation frameworks for each RTO are narrow.³³ Both the MISO and SPP tariffs provide for Storage as a Transmission-only Asset (SATO).³⁴ MISO’s proposal provides only for participation “to the extent necessary to allow the SATOA to [receive and inject energy] to provide the services for which it was included in the [MISO Transmission Expansion Plan (MTEP)] or selected for cost allocation.”³⁵ Similarly, in SPP’s tariff, “a SATOA must be connected to the transmission system as a transmission facility solely to support SPP’s transmission system.”³⁶ PJM does not have a general storage-as-transmission framework, although the issue is currently being discussed in the stakeholder process.³⁷

28 See Jeremy Twitchell, PNNL, Energy Storage as a Transmission Asset, at 10 (Dec. 2023), available at <https://pubs.naruc.org/pub/87107D6D-C75A-2471-5F9D-68885685F3C2>.

29 *Id.* at 10–11. See also William Brown et al., Quanta Technology, *Storage as a Transmission Asset Market Study*, at 11–13 (2023).

30 *Id.* at 14.

31 Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-based Rate Recovery, 158 FERC 61,051, at P 10 (2017).

32 *AEP*, 173 FERC 61,264, at P 35 (2020), *order on reh’g*, 175 FERC 61,094 (2021); see also *id.* at P 37; *Nevada HydroCo.*, 122 FERC 61,272 (2008); *Western Grid Dev.*, 130 FERC 61,056 (2010); *MISO*, 172 FERC ¶ 61,132 (2020); *SPP* 183 FERC ¶ 61,153 (2023).

33 See *MISO*, 172 FERC ¶ 61,132; *SPP*, 183 FERC ¶ 61,153 (2023).

34 *MISO*, 172 FERC ¶ 61,132, at P 1 (emphasis added); *SPP*, 183 FERC ¶ 61,153, at P 7.

35 *MISO*, 172 FERC ¶ 61,132, at P 67.

36 *SPP*, 183 FERC ¶ 61,163, at P 18.

37 See, e.g., Exelon/PPL Modifications to Constellation Storage as a Transmission Asset Issue Charge Proposal (July 23, 2025). See also *AEP*, 173 FERC 61,264, at P 37, *order on reh’g*, 175 FERC 61,094.

A key issue being debated by stakeholders is the extent to which PJM may adopt similar limits to MISO and SPP, or whether it could allow for dual-use assets (i.e. Storage as a Transmission Asset (SATA) rather than Storage as a Transmission-Only Asset (SATO)).³⁸ Notably, FERC is clear that the three potential concerns listed above could theoretically be addressed without limiting the facility at issue to provide only a transmission function. For example, it explains that the potential for double recovery can be addressed by “crediting any market revenues back to the cost-based ratepayers,” or by using the “market-revenue offset . . . to reduce the amount of the revenue requirement to be used in the development of the cost-based rate.”³⁹

Unless and until an effective dual-use framework is established, BESS developers will be forced to choose between using storage as a transmission asset, and operating it to provide other values to the market. As such, the transmission portion of the value stack is not easily added to the other values that energy storage brings to these markets. Accordingly, to date BESS has been used as transmission in relatively specialized circumstances, where the transmission value alone justifies the investment in energy storage. This greatly limits its potential use and accordingly limits the ability of storage-as-transmission to enhance system reliability and affordability for customers.

38 See *id.* at 5.

39 Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-based Rate Recovery, 158 FERC 61,051, at PP 16, 18.

Challenge 1

Market Design

While Eastern RTOs have made significant progress in developing market designs to integrate energy storage resources, further reforms remain necessary to fully realize the value of and appropriately compensate BESS. ERCOT, where energy price volatility and robust ancillary services markets have driven deployment, demonstrates the importance of market design.⁴⁰ At the same time, targeted policies and procurement practices overlaid on market design also drive (or inhibit) BESS deployment in many regions.

Historically, electricity markets were driven by thermal generation, but as the supply fleet evolved, RTOs made incremental design enhancements to accommodate the change. Each RTO differs from the other, based on unique⁴¹ stakeholder prioritization. FERC Order No. 841 required each jurisdictional RTO to develop participation models for storage resources enabling participation in energy, ancillary services, and capacity markets. Each operator responded to FERC Order No. 841 and made further enhancements based on their own market or stakeholder committee processes. While this process expanded participation options for BESS, substantial opportunities remain in each of the Eastern RTOs.

In this section, we highlight market elements that inhibit the full realization of BESS value and identify reforms that may help to address these barriers. The need to address these barriers does not necessarily explain the differences in deployment between CAISO, ERCOT, and the Eastern RTOs — in many cases the CAISO and ERCOT markets are equally in need of reform. Nevertheless, addressing these challenges would substantially improve the ability of energy storage resources to capture potential value.

Energy Markets

Energy market design is essential for realizing the full, unique value of BESS resources. As discussed in the previous section, the most highly valued service storage provides is energy arbitrage. The challenge lies in how most RTOs require resources to participate. Market rules impose limitations that prevent storage from accurately reflecting costs and maximizing efficiency:

⁴⁰ See Context: Value Proposition.

⁴¹ Participation models have been defined by some ISOs and by FERC as the Tariff revisions that consist of market rules and market software provisions that, recognizing the physical and operational characteristics of the resource, facilitates a technologies participation in RTO/ISO markets

- Most RTOs demand that resources submit a fixed offer (their price to buy or sell power) 30 to 75 minutes before the hour, and that offer must remain locked in for the entire hour, even though the actual market settles in five-minute intervals.
- This fixed offer severely handicaps storage because its true costs are highly dynamic, changing every five minutes based on:
 - The variable cost of the power it has charged recently.
 - A dynamic calculation of its lost opportunity cost (the potential profit it gives up by operating now versus waiting for a future, higher-value market interval).

This mismatch between fixed offers and dynamic costs results in a higher risk of inefficient dispatch, which can raise overall system costs and degrade the profitability of BESS. The critical solution is to allow resources with dynamic costs, like storage, to update their offers as close to real-time as possible to align operations with true market conditions. For instance, ERCOT has successfully implemented a system that allows storage to adjust offers every five minutes for each market interval through its telemetry. Market regions looking to increase BESS efficiency should investigate ways to adopt similar mechanisms to enable dynamic bidding, overcoming the limitations that required long-lead-time offers (like market mitigation processes).

The marginal cost of operating electric storage is fundamentally driven by its opportunity cost across time. Unlike thermal generators that incur variable fuel costs, a battery's primary expense is the potential profit sacrificed by discharging now rather than during a more stressed grid interval later. In simple terms, opportunity cost is the cost of using stored energy now versus potential profit from using it later. While energy markets generally do a good job of setting prices that reflect opportunity costs between different services (like energy vs. ancillary services), they largely fail to incorporate the cost of using energy now versus later.

This inefficiency stems from a key limitation in how many RTOs run their market optimization. In major regions, including PJM, SPP, and MISO, the day-ahead market determines prices and schedules on an hour-by-hour basis, not through a single, continuous 24-hour optimization. This fragmented approach means the calculated opportunity costs do not fully reflect optimal storage schedules and, crucially, do not have a direct, accurate impact on the resulting energy prices.

A similar issue exists in the Real-Time (RT) markets; even those that attempt a more forward-looking approach. Only two RTOs, NYISO and CAISO, currently use a "multi-period economic dispatch" (a look-ahead function) in their real-time markets. This is a positive step intended to help optimize charging and discharging over multiple intervals. Unfortunately, even in these two markets, the design prevents the energy price from fully reflecting opportunity cost, because only the very first real-time interval is financially binding (sets the price). All subsequent look-ahead intervals are merely advisory. This creates a scenario where the look-ahead intervals may influence the dispatch of the first interval (e.g., instructing the storage to hold its state-

of-charge for a better price later). However, the resource receives no explicit payment for the energy it holds back — it is holding reserve without a reserve price to cover its opportunity cost.

Ultimately, market price signals do not accurately reflect the true, forward-looking cost of dispatching energy storage, leading to suboptimal or inefficient operation.

Ancillary Services Markets

As discussed previously, ancillary services (AS) markets drove early energy storage adoption. One remaining barrier is ancillary service market design that prevents storage from accurately reflecting its dynamic costs when providing ancillary services. Several RTOs, including PJM, do not allow non-zero offers for certain reserve products (e.g., all ramp products, real-time operating reserve). This feature was designed for thermal resources which have near-zero marginal costs to provide reserve. Unlike thermal plants, providing an ancillary service drastically impacts a storage resource's ability to provide energy or other ancillary services in future intervals. Unless the market can intrinsically price these opportunity costs across time, battery storage resources have no mechanism to correctly communicate its true cost to the market.

A more specific issue lies within short-term ramp reserve products (5-15 minute ahead) — despite storage being eligible and participating in these ramp markets, the price is \$0/MWh for over 90% of all market intervals in regions where the product exists. The ramp products inherently hold value by reducing the need for costly unit commitments, avoiding price spikes, and improving reliability. The frequent \$0 price does not mean the service is valueless, but rather that the pricing mechanism often ignores non-convex (lumpy, one-time) costs, such as unit start-up costs. While the energy market has largely solved this issue with the introduction of “fast-start pricing” and similar approaches, the impact on AS markets is still evolving.

Price formation for ramp products and other AS needs further study to ensure that value and price are properly aligned, creating correct incentives.

Additionally, several new design features are being considered or implemented across different RTOs to improve ancillary services valuation and BESS integration:

- Ancillary services markets have begun to include a minimum duration requirement (e.g., sustain reserve for a set time). While this may limit some participation, it appropriately incentivizes longer-duration assets and must be applied logically to match reliability needs.
- RTOs are adding a component that reflects the impact of an AS schedule on a storage resource's state-of-charge. If applied accurately (and perhaps dynamically, not as fixed values), these factors could be a crucial mechanism for better price formation by intrinsically incorporating opportunity costs across time and different products.

- RTOs are also moving toward the introduction of nodal constraints and/or nodal pricing for reserve products. This is advantageous because BESS assets have fewer locational constraints than other generators, and precise price signals point new storage projects to parts of the system where they provide the most locational value and reliability benefit.

Capacity Markets

In capacity and resource adequacy market regions (all areas except for ERCOT), capacity value is a significant and growing portion of anticipated BESS revenue streams.⁴² However, the bankability of these assets is threatened by the volatility of Capacity Accreditation. It depends both on:

1. Factors that influence BESS's intrinsic value to the system, such as future grid mix, which may be difficult to predict; as well as
2. market design choices by the grid operator about how to accredit resource capacity.

BESS resources seeking financing based on offtake agreements with customers must contract around the risk of accreditation changing over time.⁴³

Accreditation uncertainty is a major concern for the industry given the short duration of the revenue signal. In the Eastern Interconnection, capacity markets typically clear only a single year or season at a time, creating a structural mismatch: BESS is a capital-intensive asset with a 15–20 year operating life, yet its core revenues are reset every year. This results in a highly uncertain revenue profile that directly raises financing costs. Unlike CAISO, which offers long-term (10–20 year) contract structures, lenders view PJM and MISO capacity revenues as largely speculative, forcing developers to rely more heavily on high cost of equity versus lower cost debt. Because BESS costs are overwhelmingly upfront CapEx, this elevated cost of capital can determine whether a project is financeable or ultimately withdrawn from the interconnection queue.

Mechanisms that allow for correction of any resource's capacity accreditation value through actual performance are critical to ensure appropriate investment. This is admittedly difficult given that resource adequacy utilizes many scenarios and quantifies contribution over many years, but self-correcting feedback from any miscalculation, poor data, or poor assumptions must be built into any rigorous ex ante accreditation process. PJM and ISO-NE have included capacity performance processes for the last decade now, but such intervals are rarely enacted (PJM performance assessment intervals have only been activated once during Winter Storm Elliott). Improved performance assessments can better reflect storage's true capacity value,

⁴² See *supra* section 3.

⁴³ See *Comments of Eolian, L.P. on PJM's Critical Issue Fast Path proposal concerning large load additions*, at 2–3 (Aug. 29, 2025), available at <https://www.pjm.com/committees-and-groups/cifp-lla>.

ensure underestimated accreditation values are less impactful through additional bonuses, and provide greater certainty of capacity revenue streams over time.

Capacity markets focus squarely on capacity and delivering energy during critical time periods. However, simulation tools that assess system resource adequacy metrics and resource accreditation metrics include less consideration of flexibility attributes across all resource classes. While energy state-of-charge limits are a parameter used in electric storage resource accreditation, attributes such as ramp rates and commitment constraints (or lack thereof) are typically not. Given fast ramp rates and zero start-up times, storage may provide greater resource adequacy contribution than these models suggest. When a reliability event occurs without advance notice, a storage resource can ramp from standstill to maximum discharge in seconds, while other resources may have minimum down times and long start-up times that can take up to an hour or more before they can contribute. This vulnerability was evident in the 2025 Iberian Peninsula blackout, where several thermal resources were not being used at the start of the event and were unable to be brought online quickly enough to arrest the frequency drop.⁴⁴

The use of flexibility attributes in capacity accreditation can be very valuable in determining accurate accreditation. In some cases, separate forward markets for attributes, such as the CAISO and CPUC Flexible Capacity Procurement process, may ensure incentivization and investment in flexibility, to support reliability when these attributes are otherwise scarce.

Interaction with State Procurement

While wholesale markets determine the underlying revenue streams that BESS may earn, states have an important role in regulating how these revenue streams may support financing of, investment in, and ultimately deployment of BESS. As discussed under Challenge 3, in many vertically integrated states and some restructured states, public service commissions oversee procurement of resources by utilities. They may also set rules for standard offer service auctions, which procure default service for retail customers who do not choose a provider.⁴⁵ The rules for these auctions influence the overall financing environment for BESS. For example, where auctions procure service on a short-term basis (1–3 years), this may create risks for providers who enter into long-term contracts (10–15 years), which in turn may make such contracts more difficult to secure for BESS developers.

Under current standard offer service structures across PJM, very little long-term price hedging occurs in the provision of this service, even though long-term contracts hold the potential to

44 https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/Publications/2025/entso-e_incident_report_ES-PT_April_2025_06.pdf

45 See Rob Gramlich and Frank Lacey, *Who's the Buyer?: Retail Electric Market Structure Reforms in Support of Resource Adequacy and Clean Energy Deployment*, at 9 (March 2020).

offer symmetrical benefits to buyers and sellers by protecting them from market volatility.⁴⁶ In these cases, states could explore policies to encourage more long-term contracting from load serving entities to hedge their customers from price extremes and volatility. Following the 2025/2026 PJM capacity auction where prices surged by over 800% to record highs, states like Maryland and New Jersey have accelerated their own independent procurement targets. For BESS to scale in the East, states should explore policies that bridge this gap. By encouraging LSEs to enter into long-term contracts, states can protect retail customers from wholesale volatility while providing the revenue certainty that lenders require to finance.

The imposition of tariffs on foreign manufactured batteries has introduced a new challenge. In the Eastern Interconnection, where arbitrage spreads are thinner and capacity payments are the primary revenue mechanism, a 10–20% increase in Capital Expenditure (CapEx) can render a project unfinanceable. In PJM and MISO, the lack of a track record for battery arbitrage makes debt financing significantly more expensive. Lenders view the revenue stack in PJM, which is heavily dependent on capacity payments that are difficult to secure due to accreditation rules, as speculative. Consequently, developers in the East often face equity requirements of 40–50% (compared to 20–30% in mature markets), drastically reducing the Internal Rate of Return (IRR).

This financing pressure is not a standalone barrier; it is the direct result of the structural challenges in market design, interconnection, procurement, and planning.

Paths Forward

This section covers an array of opportunities for market reform, though of course the ability of any adjustment to create change will depend on the specific region and form, timeline, and nature of implementation.

Dynamic Pricing and Forward Looking Markets: A foundational step is the transition to dynamic price offers and look-ahead market functions that compensate resources for providing flexibility across future intervals. By allowing non-zero offers for certain reserve products (such as ramp products and real-time operating reserves) and studying the resulting price formation, RTOs can ensure that the “fast-response” value of storage is not suppressed during periods of high grid stress. Continued refinement of price formation for ramping and ancillary services will be increasingly important as system flexibility needs evolve, alongside progress toward nodal pricing for reserve products where feasible.

Operational Reforms and Reliability-Based Mandates: Additional operational reforms include applying state of charge impact factors dynamically in ancillary service scheduling and evaluating minimum duration requirements where they improve reliability. Any duration requirements, including those that may provide premiums for longer-duration storage, should

⁴⁶ *Id.* at 10.

be chosen strictly based on their reliability need when necessary.

Performance Based Accreditation and Flexibility Valuation: Improving capacity market outcomes will require mechanisms to correct accreditation based on observed performance, as well as accurately representing flexibility attributes through accreditation or through a separate mechanism, such as flexible capacity. Improving accreditation methodologies and providing certainty for that value stream may prove the most important driver of future investment in MISO, PJM, and SPP.

Closing the Revenue Certainty Gap through Long Term Contracting: Finally, these technical reforms must be paired with state-level policies that encourage long-term contracting, providing the revenue certainty that the current three-year merchant cycle lacks.

IN FOCUS

ANCHOR TENANT MODELS

Beyond RTO-led reforms, independent customers, specifically tech hyperscalers are increasingly becoming the primary catalysts for BESS deployment. There is a distinct strategic pivot occurring from large-scale buyers moving away from traditional utility service agreements supplemented with renewable credits toward direct, infrastructure-backed power supply agreements.

CASE STUDY

In a 2025–26 deal, a major Midwestern investor-owned utility finalized a deal with a 1.5 GW hyperscale data center. This single project represents a massive increase in the utility's total existing electric load, necessitating a rapid scaling of infrastructure.

- To meet state mandated reliability targets and manage the new load, the utility's five-year plan now includes nearly \$2 billion in new energy storage investments, aiming for over 2 GW of battery capacity by 2032.
- The data center will pay for the storage through a 15-year energy storage contract, providing the long-term revenue certainty that merchant markets lack.
- The deal, where the data center funds storage as an "anchor tenant", features a multi-year power supply agreement.

Challenge 2

Interconnection

Backlogs and the slow processing of the federally regulated interconnection queues impede rapid entry of all generation, and storage is no exception. Since 2003, FERC has required public utilities to adopt standard procedures for generators larger than 20 MWs to interconnect to the transmission system.⁴⁷ In jurisdictions where an independent entity (such as an RTO), oversees the interconnection process, FERC provides greater flexibility to deviate from these standards.⁴⁸

While standardized interconnection procedures sufficed during periods of low load growth and limited generation turnover, there is mounting evidence that the standard approach is failing to accommodate simultaneous rapid load growth, generator retirements, new generation development, and constrained transmission capacity. FERC issued a major reform in 2023 to address a substantial backlog in interconnection requests and required studies,⁴⁹ but Order No. 2023 focused primarily on best practices and did not institute more fundamental changes to interconnection processes.⁵⁰ As such, while Order No. 2023 implementation is ongoing,⁵¹ there is widespread agreement that FERC's initial set of reforms is not sufficient to solve the backlogs, slow processing times, cost and timing uncertainties, or high interconnection costs due to inadequate transmission capacity.⁵²

Interconnection Processes

The average time spent in an interconnection queue is now nearly five years, up from three years in 2015 and two in 2008.⁵³ The backlogs and delays are worse in RTOs compared to non-RTOs, although recent evidence indicates that non-RTO queues are also experiencing increasing

47 *Standardization of Generator Interconnection Agreements and Procedures*, FERC Order No. 2003, 104 FERC ¶ 61,103 (July 24, 2004) (“Order No. 2003”).

48 Order No. 2003 at P 26 (describing the “independent entity variation”).

49 *Improvements to Generator Interconnection Procedures and Agreements*, FERC Order No. 2023, 184 FERC ¶ 61,054 (July 28, 2023) (“Order No. 2023”).

50 For example, the requirement to shift from serial to cluster interconnection studies, which were already widely adopted at issuance.

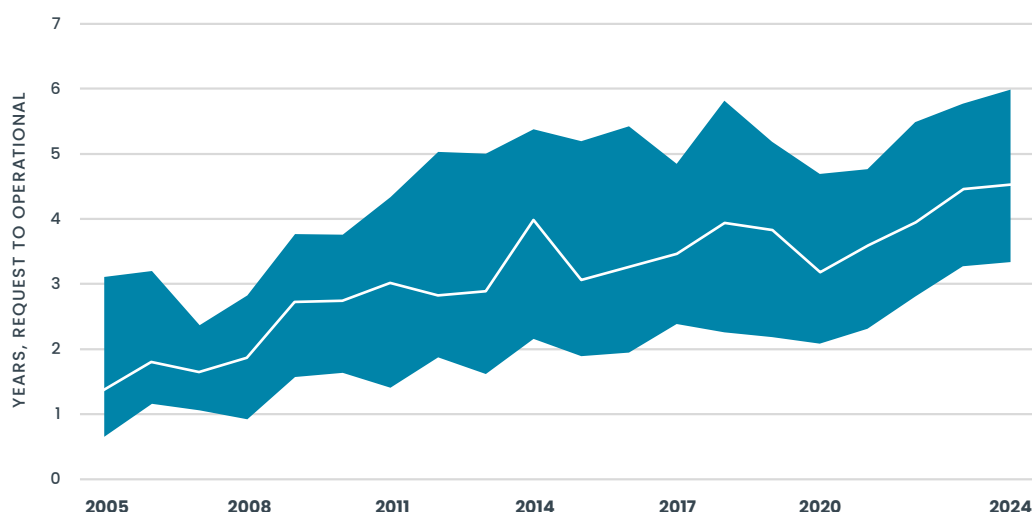
51 At the time of drafting, FERC had initially approved in whole or in part all transmission providers Order No. 2023 compliance filings, but implementation will take years, and change longer.

52 *FERC Commissioner David Rosner Lays Out Ambitious Agenda*, Energy Bar Association (July 18, 2025 available at: [Link](#). FERC Commissioner Judy Chang, June 2025 technical conference on *Meeting the Challenge of Resource Adequacy in RTO/ISO Regions*. Transcript, AD25-7 (June 4, 2025).

53 Lawrence Berkeley National Laboratory, *Queued Up 2024 Edition* at slide 3 (April 2024) available at https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_R2.pdf

delays.⁵⁴ Interconnection customers must participate in the interconnection study process, sometimes for years, and provide financial security and additional investments before learning whether the expected network upgrade costs are too costly and render a proposed project non-viable. These long delays are problematic for all generation technologies and impose additional costs for relatively new and still-evolving technologies like BESS. For example, battery technology and supportive software may improve drastically over a five-year waiting period, but in order to implement such improvements, a storage developer would need to request a “material modification” and would lose their interconnection queue position, pushing them to the back of the line. While, in theory, FERC required that each transmission provider define a set of “technological advancements” that an interconnection customer may modify without losing its queue position in Order No. 845,⁵⁵ in practice this requirement has been poorly and unevenly implemented.⁵⁶ Interconnection customers therefore continue to lack clarity as to which types of changes to the interconnection request are acceptable and which are not.

FIGURE 5. Years from Interconnection Request to Operation, LBNL Queued Up



Despite severely congested interconnection queues, few RTOs have implemented comprehensive reforms, allowing persistent inefficiencies in the interconnection process to remain largely unaddressed. Instead, RTOs have applied band-aid solutions that move a select small group of generators to the head of the queue with expedited study processes, and which FERC approves case-by-case to address acute resource adequacy concerns.⁵⁷ Absent systematic reform, interconnection queues are unlikely to keep pace with load growth and retirements.

54 Lawrence Berkeley National Laboratory, Queued Up 2025 Data File, available at: https://emp.lbl.gov/sites/default/files/2025-08/LBNL_ix_Queue_Data_File_thru2024_v2.xlsx

55 See Reform of Generator Interconnection Procedures and Agreements, Order No. 845-A, 166 FERC ¶ 61,137 at P 152 (Feb 21, 2019)

56 *Interconnection Queue Rationing Reforms*, ACORE (2025)

57 PJM proposed the Reliability Resource Initiative, which FERC approved in Feb 2025. *PJM Interconnection*, 190 FERC ¶ 61,084 (Feb 11, 2025). MISO proposed the Expedited Resource Addition Study (ERAS), which was approved after revisions in July 2025. *MISO*, 192 FERC ¶ 61,064 (July 21, 2025). And SPP proposed the Expedited Resource Adequacy Study (ERAS), which FERC also approved in July 2025. *SPP*, 192 FERC ¶ 61,062 (July 21, 2025).

IN FOCUS

PJM'S RELIABILITY RESOURCE INITIATIVE (RRI)

Administratively determined “expedited interconnection” programs may favor gas over energy storage, as seen with PJM’s Reliability Resource Initiative (RRI):

As it projected reliability challenges in the 2026–30 timeframe, PJM designed its RRI initiative to expedite the interconnection of certain resources, allowing them to skip the standard interconnection queue process. Given its promise to lift projects out of the morass of its standard interconnection queue (which generally takes more than 5 years to complete), the RRI initiative garnered significant interest, including from BESS developers. Yet out of more than 11,000 MW of resources selected for expedited interconnection, only about 1 in 5 (2,275 MW) were BESS projects.⁵⁸

These results reflect PJM’s scoring methodology rather than the true ability of resources to address PJM’s projected shortfall. As summarized in Commissioner Judy Chang’s dissent to FERC’s order approving the RRI process, the PJM scoring criteria “primarily prioritize[d] the size of new connecting resources over speed, and thus [were] poorly designed to address” PJM’s reliability challenges.⁵⁹ RRI allocated points to resources according to certain scoring criteria, with the single biggest category measuring a project’s Unforced Capacity.⁶⁰ But Unforced Capacity measures a project’s size, not its commercial viability or technical ability to provide service to the system.

In summary, the RRI outcome reflects regulatory choices that prioritize other generation technology types rather than any true assessment of battery storage value versus its competitors. It shows that, in an environment where the development of viable resources is stymied by interconnection queue delays, favoritism by the grid operator towards other resource types in establishing eligibility criteria for “fast track” interconnection erects yet another barrier to BESS.

SPP is one notable exception among the FERC-regulated grid operators — it has developed a new approach to managing interconnection called the Consolidated Planning Process, which seeks to proactively plan the grid for upcoming generator interconnection.⁶¹ Under this approach, the cost of grid access is less dependent on individualized study of the generator’s interconnection request, calculating a fixed “entry fee” that covers the cost of upgrades needed for a larger group of resources. This mitigates the cost and timing uncertainty associated with

58 PJM Chooses 51 Generation Resource Projects to Address Near-Term Electricity Demand Growth (May 2025).

59 *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 (2025) (Chang, dissenting at P 6) (setting forth the RRI scoring factors).

60 See *id.* at P 7 (setting forth the RRI scoring factors).

61 See SPP Transmittal Letter, FERC Docket No. ER26–414 (Nov. 3, 2025).

the reactive interconnection study process. If the proposal is approved by FERC and successful, it would represent the first groundbreaking new approach to interconnection processes.

Interconnection Studies

While clogged interconnection queues will likely persist, the interconnection study process enabling actual deployment poses unique challenges to BESS. Notably, battery storage technologies have distinctive technical capabilities and economic incentives that are, in general, poorly reflected in the assumptions in the models used to study the impacts of interconnecting generation. Many existing study processes were designed to model resources which simply withdraw energy from the system at peak load and discharge during light load. These study assumptions do not match how battery storage actually operates, and may result in unnecessary network upgrades and increased customer costs.⁶²

While FERC acknowledged this problem, its reforms were insufficient to solve it. Order No. 2023 required grid operators to incorporate more realistic assumptions into their interconnection studies, but only (a) for charging the storage resource, not its discharge; (b) only at the request of the interconnection customer; and (c) only to the extent that the operator does not determine that the proposed charging assumptions are in conflict with good utility practice.⁶³ And as explained below, FERC has approved deviations these requirements in some regions over objections.

Further, assumptions regarding BESS charging may be studied under an entirely separate process: the transmission service request study process.⁶⁴ FERC requirements apply to the interconnection study process, as described above, but do not necessarily apply to the transmission service request study process. As a result, where a transmission provider has elected to study a storage resource's charging behavior as part of the separate transmission service study process, a storage resource may face wholly distinct study assumptions, and therefore additional network upgrade cost obligations above and beyond those imposed by the interconnection study process.

Existing Study Differences within Eastern Markets

MISO, SPP, and PJM differ in how they study energy storage resources through the transmission service request process versus the interconnection process. PJM allows participating BESS resources to rely on the RTO for transmission service if they take dispatch instructions from PJM.⁶⁵ However, to the extent they self-schedule dispatch, energy storage resources must procure transmission service on their own and will therefore be subject to additional study of

⁶² See Order No. 2023 at P 52.

⁶³ Order No. 2023 at PP 1509 – 1511.

⁶⁴ Order No. 2023 at P 1499

⁶⁵ See PJM Manual 27, § 8.2.

charging impacts to the transmission system and potential network upgrade costs.⁶⁶ MISO studies energy storage withdrawals as part of its interconnection process, yet also requires energy storage resources to separately procure transmission service.⁶⁷ Until recently, SPP studied charging behavior through its transmission planning process alone, not as part of its interconnection process.⁶⁸ However, FERC recently accepted revisions to SPP’s study process that integrate storage charging assumptions into the interconnection process.⁶⁹ As a result, storage resources will generally be studied for their charging impacts to the transmission system twice, once in the generator interconnection process and again in the study to obtain firm transmission service. A storage developer in SPP may only avoid additional network upgrade costs due to the second study process if it elects non-firm transmission service, which would leave the resource subject to curtailment without limit.⁷⁰ Longer run, if FERC approves its Consolidated Planning Process (CPP) proposal, SPP will assess energy storage impacts on generator interconnections and transmission system upgrades simultaneously.

		
PJM “CONDITIONAL” APPROACH	MISO “SEQUENTIAL” APPROACH	SPP (FUTURE) “CONSOLIDATED” APPROACH
PJM may waive the second transmission study if the developer agrees to follow RTO dispatch instructions. If a developer wants to “self-schedule” (decide for themselves when to charge), they must undergo a separate, additional transmission study that can trigger new costs.	Even though MISO looks at withdrawal during the initial interconnection phase, it still mandates a completely separate Transmission Service study. This creates a “dual-track” regulatory burden where developers must navigate two distinct processes to get a single asset online.	Through the Consolidated Planning Process (CPP), SPP aims to study Injection, Withdrawal, and all necessary grid upgrades simultaneously. This eliminates redundancy, provides “Firm” certainty from the start, and aligns the study timeline with the actual speed of BESS construction.

Moreover, FERC has accepted major compromises to the requirement to use more realistic study assumptions for BESS charging behavior, which further waters down the effectiveness of Order No. 2023 reforms. CAISO and SPP adopted FERC’s proposed requirements without material deviation, demonstrating their feasibility.⁷¹ Yet for other RTOs, FERC approved less accurate input assumption requirements over the objection of developers, who argued that

66 *Id.* (“[H]owever Non-Dispatched Charging Energy does pay transmission charges, and must arrange for Network Transmission Service”).

67 See MISO, Electric Storage Resources FAQ <https://help.misoenergy.org/knowledgebase/article/KA-01334/en-us>

68 See SPP, 191 FERC ¶ 61230, at P 217 (June 26, 2025)

69 See *Southwest Power Pool*, 193 FERC ¶ 61,172 (2025).

70 SPP Aggregate Transmission Service Study FAQs, available at: <https://opsportal.spp.org/documents/studies/Aggregate%20Transmission%20Service%20Study%20FAQs.docx>

71 CAISO, 191 FERC ¶ 61119 at P 191 (May 15, 2025); *Southwest Power Pool*, 193 FERC ¶ 61,172, at PP 11, 26, 30 (2025).



they undercut the goal to reduce unnecessary network upgrade costs for BESS.⁷² PJM's approach to this issue remains pending after an initial rejection.⁷³ MISO and PJM now stand out in their use of charging assumptions that stymie the workable interconnection of energy storage resources.

- **MISO's** interconnection study process uses the "fuel dispatch methodology," which treats BESS as firm fixed load capable of using 100 percent maximum charging capacity during shoulder peak load and 0 percent maximum charging capacity during summer peak. Developers argued that this assumption overestimates the impact of BESS on the transmission network, but FERC rejected those arguments.⁷⁴
- **PJM** declined entirely to implement Order No. 2023's requirement to use more realistic study assumptions for BESS charging, contending they would slow down processing of its backlogged queue.⁷⁵ FERC rejected PJM's proposed non-compliance and required further compliance filing,⁷⁶ and PJM has now responded with a fuel dispatch methodology similar to that proposed by MISO.⁷⁷ While a resolution is still pending, PJM's dilatory tactics have impeded BESS queue entrants from reaping proposed reform benefits.

72 As discussed above, SPP does not assess withdrawals from energy storage resources through its interconnection process. See *supra* n. 17.

73 See FERC Docket No. ER24-2045.

74 *MISO*, 191 FERC ¶ 61229 at PP 282 – 291 (2025).

75 *PJM*, at 192 FERC ¶ 61077, at PP 295 – 308 (July 25, 2025); see also Letter from OEMR Director of Division of Electric Power Regulation — East, Kurt Longo to PJM, ER24-2045 (July 31, 2024)

76 *Id.*

77 See PJM Tariff filing, Docket No. ER24-2045 (Oct. 23, 2025).

IN FOCUS

LARGE LOAD INTERCONNECTION

Large load interconnection is the next frontier for regulatory innovation, as state and federal regulators seek to accommodate rapid load growth generation and transmission infrastructure development remains constrained. Battery storage resources may better enable operators to integrate large loads by allowing these loads to be flexible and shift their reliance on the transmission system.⁷⁸ Yet, this use case is not yet reflected in current interconnection study processes.

For example, there are no standardized study requirements for co-located generation with large loads. If an energy storage facility is studied separately from the co-located load, a grid operator may assume that the co-located load and energy storage would simultaneously withdraw electricity, and trigger grid reliability issues. In reality, co-located storage and load may deploy equipment and control measures explicitly to avoid such issues and, instead, operate to the grid's benefit.

Likewise, co-located storage operation may be confined only to load reduction because interconnection studies are so timely and cost prohibitive. The overall system may then lose the substantial additional value storage could otherwise provide. Such barriers, both in study requirements and process hurdles, pose a major barrier to storage deployed to support new large loads.

The Department of Energy (DOE) recently directed FERC to consider an Advanced Notice of Proposal (ANOPR) calling for FERC to take jurisdiction over load interconnection for facilities above 20 MW in size, and “to the extent practicable,” to study interconnection requests of generating facilities (including BESS) “together with” interconnection requests from load and hybrid facilities.⁷⁹ RTOs have only begun to navigate this new frontier of large load interconnection procedures.⁸⁰ DOE's directive puts forward high-level principles for large load interconnection and joint study of load, hybrid, and generation resources, but whether and how these principles will be developed and implemented remains uncertain.

78 See also Comments of Members of the Dispatchable Battery coalition, Docket No. AD25-7 at 13 (July 7, 2025)

79 Secretary of Energy, Letter Re: the Interconnection of Large Loads Pursuant to the Secretary's Authority under Section 403 of the Department of Energy Organization Act, FERC Docket No. RM26-4-000 (Oct. 23, 2025) (DOE ANOPR).

80 SPP existing tariff provisions for large load interconnection: See Transmittal Letter, FERC Docket No. ER26-247 (Oct. 24, 2025). See PJM, “PJM Board Fast-Tracks Effort To Reliably Serve Large Loads” at <https://insidelines.pjm.com/pjm-board-fast-tracks-effort-to-reliably-serve-large-loads/>

Paths Forward

Addressing the queue crisis requires fundamental process change. Experts recommend moving beyond the existing model by implementing more stringent commercial readiness requirements, financial commitments, withdrawal penalties, and time limits to deter speculative requests.

Shifting from Reactive Studies to Proactive Transmission Planning: The biggest opportunities, not only to eliminate barriers to BESS implementation but to support rapid development of new supply in general, are initiatives like SPP's Consolidated Planning Process that shift away from a paradigm of exhaustive study and ensure full deliverability of interconnecting resources before interconnection and operation. This traditional approach is both too slow and fails to capture the potential value of new technologies like BESS. Ultimately, impending load growth validates the need to shift from reactive, project-by-project interconnection studies to proactive, centralized regional transmission planning that identifies optimal placement for all resources to meet system needs.

Utilizing Fast-Track and Surplus Interconnection Options: Even absent deeper reforms to the generator interconnection process, more modest reforms could ease barriers to interconnecting BESS. One approach that RTOs can use to help address this challenge is to better utilize and create new fast-track options. For example, Surplus Interconnection Study processes, enabling new and existing resources to share interconnection rights, are a promising and growing approach in Eastern RTOs.⁸¹ BESS is uniquely positioned to maximize these Surplus programs due to its minimal physical footprint and highly flexible generation profile.

Targeted Large-Load Interconnection: Proposals to more narrowly study generator interconnection, which aim to match intended operation to a specific large load rather than the whole market, are under discussion in PJM's Large Load Addition stakeholder process.⁸² These new approaches could provide grid operators with more experience and comfort dealing with tailored interconnection studies. Ultimately, such approaches could quickly integrate resources (BESS and other) to serve large load customers and allow those resources to simultaneously provide non-firm energy to the system.

⁸¹ See Miles Farmer and Abe Silverman, *Unlocking the Power of Surplus Interconnection* (Feb. 21, 2025).

⁸² See e.g., Eolian Proposed Options for Bilateral Integration of Generation Portfolios and Load at slides 5–6 (Oct. 14, 2025) available at: <https://www.pjm.com/-/media/DotCom/committees-groups/cifp-lla/2025/20251014/20251014-item-03b---eolian-brattle-proposed-options.pdf>.

Challenge 3

Procurement Design

Battery storage is no longer an experimental technology — it is a proven, flexible grid asset capable of delivering a unique array of services. Yet, in many procurement settings, storage is treated as a niche or supplemental option rather than a core component of system reliability and resilience. Originally, this undervaluation may have stemmed from an experience gap: utilities were and are still learning how to optimally dispatch batteries and developers are still building the institutional knowledge that is typically gained from years of large-scale deployment. Skepticism may still linger from past experience with duration-limited resources, leading some planners to be hesitant about overestimating storage's reliability contribution, and utility-scale storage has seen renewed local opposition driven by a perception that the projects are associated with high fire risk.

Compounding the challenge, accreditation rules and reliability metrics set at the regional or market level and outside the control of individual load-serving entities risk misalignment with actual battery capabilities. Storage accreditation is highly dependent on system-wide modeling assumptions (e.g., clean energy penetration, load additions, temporal granularity) and without careful attention may not provide an accurate long-term investment signal. While storage is not a cure-all for every loss-of-load scenario, its ability to provide fast, precise, and location-specific support is unique. The problem is that in traditional procurement frameworks, batteries are too often seen as higher-cost resources that deliver “less” simply because their value is not captured in conventional capacity-only procurements.

If storage is to fulfill its potential, procurement processes must evolve to recognize and reward its full suite of services. That means moving beyond lowest-cost, firm-capacity-based approaches toward structures that explicitly value flexibility, speed, and the ability to integrate and optimize other resources. The following section examines how procurement design, legislative mandates, and integrated resource planning can either unlock or constrain storage deployment. We conducted limited interviews with storage developers to inform the array of topics covered.

Procurement Structures

The structure of any procurement sends a clear signal about what the utility or customer values, and for battery storage, those signals often determine whether the technology competes on a level playing field. As discussed in the markets section of this paper, battery

storage can provide a wide array of services which are treated differently in size and definition across each individual market. Similarly, the scope of the procurement indicates the value that a utility assigns to each of these services. Typical procurements from vertically integrated utilities focus on procuring capacity on a dollar per megawatt basis. These simple volume procurements advantage resources that can provide firm, continuous output, typically thermal generation, and disadvantage resources with variable availability (e.g., renewables) and non-generating assets (e.g., battery storage). When the procurement scope does not explicitly value the flexibility, speed, and multi-service potential of storage, those capabilities become inconsequential to the evaluation.



The breadth of a procurement also makes a tremendous difference to outcomes. Some solicitations are tightly defined and focus on a specific site, battery technology, size, and operating profile while others are broad all-source requests for any form of generating capacity. In either case, the lowest-cost bid most often wins, which can put storage at a disadvantage when competing against cheaper, energy producing resources. Technology-neutral solicitations can unintentionally sideline new or marginally more expensive technologies, limiting the delivery of potential long-term benefits from resource diversity.⁸³

Geographic requirements further influence outcomes. Procurements without locational specificity may favor resources less flexible in terms of siting, while those that require geographic adaptability can create opportunities for storage to shine. This is particularly critical for service areas that are constrained or have high reliability concerns where the rapid deployment and modularity of battery storage are valuable and necessary attributes.

Finally, utilities may effectively bar storage developers from participation simply by the structure of their contract. RFPs that mandate a single delivery model, such as a Build-Transfer Agreement (BTA), can inadvertently exclude newer market entrants or developers whose business models are structured around other delivery models. Because battery storage development is still relatively nascent as compared to legacy thermal asset development, developers may be less equipped to offer multiple contract options. Allowing flexibility in contract structures, or enabling hybrid approaches, can broaden participation and allow developers to deliver more services at a lower cost.

83 [RFF 2021](#)

IN FOCUS

STRUCTURAL BARRIERS IN THE SOUTHEAST (NON-RTO REGION)

In regions served by regulated utilities, resource expansion and deployment are dictated by the Integrated Resource Plan (IRP) process. The IRP guides the utility's allocation of resources and amounts included in subsequent procurements. This centralized planning process, while providing long-term visibility, is inherently slower and less dynamic than a competitive merchant market where developers respond instantaneously to price signals and volatility.

The structure of the utility business model itself presents a significant barrier. Vertically integrated utilities typically favor capital recovery through rate base mechanisms, which can suppress innovative, merchant-led BESS deployment that thrives on optimizing market efficiency.

A significant limiting factor in the Southeast is the general absence of aggressive, binding state-level energy storage mandates or defined targets. Deployment, therefore, remains subject to regulatory approval of the utility's proposed capital expenditure and is not enforced by specific legislative targets. Moreover, without an RTO structure that has transparent price signals, competitive merchant developers cannot independently provide energy and ancillary services based on wholesale market signals. This structure removes the primary incentive mechanism that drives rapid deployment in ERCOT and CAISO.

Deployment in the Southeast is achieved primarily through utility-led RFPs that track and implement the resource plans laid out in the IRP. While utilities increasingly incorporate BESS into their plans, the pace is constrained by regulatory cycles. For example, Duke Energy's 2025 RFP included substantial volumes: 900 MW of solar-only resources and up to 800 MW of solar paired with approximately 300 MW of battery storage. Florida Power and Light (FPL) also projected substantial solar and storage in its Ten Year Site Plan (~7,603 MW of battery storage by 2034.)

Despite these large blocks of procurement, the process can slow timelines rather than expedite deployment. Utility RFP cycles and the subsequent commercial operation dates (COD) often span five to seven years. Georgia Power's 2025 RFP outlined a 5–6 year process with CODs in 2029 and beyond, and the Tennessee Valley Authority (TVA) announced a 7-year process with CODs in 2031. This built-in procedural delay means that growth in the Southeast, while predictable, cannot match the rapid, market-driven pace seen in deregulated markets. The future of regional storage deployment rests heavily on state regulatory commissioners, to ensure that IRPs inform rigorous competitive procurement processes that reflect the full value of available resources.

Procurement Evaluation Criteria

Experience Level: As previewed above, the experience level of storage developers remains central to procurement outcomes, both in terms of technical expertise and financial capability. Many storage developers are building their capabilities and credibility in real time. Utilities and evaluators often require indicators of financial strength and prior project delivery as proxies for execution risk. While this is a standard criterion for any procurement, some developers express concerns that these requirements exceed reasonable levels, making them difficult to achieve given the relative nascence of the storage market. Only few developers have a years-long portfolio of completed projects — after all, storage deployment is new. Striking the right balance between rewarding proven capability and enabling market entry for qualified but less established developers is essential to ensuring the procurement process fosters competition and innovation while also protecting customers from project risk.

Cost versus Other Value: A central question raised by developers is: Is cost truly king? If so, then why don't evaluation criteria reflect that? Many procurement frameworks purport to be holistic, with weight given to services provided, domestic manufacturing content, and labor standards, among other criteria. In practice, however, cost often remains the deciding factor. Developers interviewed for this paper expressed concern that when evaluation criteria are not transparently weighted, or when there is an impression that those weights are not actually applied, bidders may feel pressure to undercut prices unrealistically to win, even if it means over-promising on other requirements. This dynamic can lead to projects that fail to deliver on all stated commitments, creating uncertainty in utility costs and eroding trust in the procurement process. Further at issue, this may lead to winning bidders passing projects onto other companies who cannot themselves deliver the project at the bid cost, resulting in no project at all. If cost is truly the primary determinant, evaluation criteria should clearly reflect that, and utilities should ensure enough process transparency to create developer trust. If utilities truly are not putting out RFPs seeking the lowest-cost project, and rather the project that wins across many criteria, they should structure procurements so that non-price attributes meaningfully (and transparently) influence outcomes.

Labor Requirements: Labor provisions are increasingly common in energy procurements, reflecting broader emerging policy goals around workforce development and job quality. While many developers support these objectives, meeting such requirements can be challenging in regions with limited availability of qualified labor or tight timelines. Nearly always, securing the necessary workforce adds complexity and cost to these projects. Procurement designs that incorporate labor standards should consider regional labor market realities and provide flexibility to ensure compliance is feasible without deterring participation.

Domestic Content: Similarly, domestic content requirements are intended to strengthen local supply chains and capture more economic value from clean energy investments. However, developers note that these requirements can be difficult to meet given the current globalized

nature of battery manufacturing and component sourcing. In most cases, the domestic supply of key components is insufficient to meet demand, raising questions about the attainability of such standards in the near term. Clear guidance on compliance, realistic timelines for ramping up domestic production, and defined consequences for non-compliance are critical to ensuring these provisions drive the intended outcomes without stalling project deployment.

Services: Procurement outcomes are also shaped by how performance, availability, and duration are defined. Requirements that implicitly assume thermal-style availability or prescribe fixed duration thresholds can misrepresent the reliability contribution of storage resources designed for fast response, ramping support, or multi-cycle operation. When procurements rely on static capacity constructs, these attributes go unrecognized, reinforcing the perception that storage delivers less value.

Resource Planning & Procurement

Competitive procurement processes have long been a part of utility resource planning in some form. Increasingly, utilities incorporate procurements into their integrated resource planning (IRP) frameworks. Rather than relying wholly on modeling outcomes, with assumptions informed by public sources or previous capital projects, many utilities now issue RFPs either ahead of the IRP to inform planning inputs or after selecting a preferred IRP scenario to guide resource acquisition. This shift reflects a growing recognition that real-world market signals and up-to-date developer data can enhance the credibility and effectiveness of long-term planning.

Some states have more explicitly codified the relationship between IRPs and procurement. Michigan, for example, requires utilities to competitively procure all long-term resources through technology-neutral RFPs tailored to the “energy or capacity needs” identified in the relevant IRP. This requirement applies for all proposed resources greater than 225 MW.⁸⁴ The Michigan Public Service Commission’s (MPSC) guidelines require open and non-discriminatory processes that consider both utility-owned and third-party resources. Further, the MPSC’s guidelines require procurements be open to hybrid projects, a range of sizes, ancillary service providers, and considers specific resource benefits capable of reducing costs. Finally, the MPSC requires transparency across evaluation criteria.⁸⁵

Georgia also mandates RFPs for all blocks of supply-side resources identified in the IRP, though it places fewer restrictions on the scope and criteria bounding the RFPs themselves.⁸⁶ Instead, the modeling assumptions within the utility-developed IRP drive the success of proposed resources (e.g., a resource shown to be least-cost in the IRP will be sought in a subsequent procurement), underscoring the importance of a robust planning process with a high level of regulatory scrutiny.

84 [2022 IRP Filing Guidelines](#)

85 [Competitive Procurement Guidelines](#)

86 [GA IRP rules](#)

Real-world market signals and up-to-date developer data can enhance the credibility and effectiveness of long-term planning.

Utilities are moving away from all-source procurements as a primary method for informing their IRPs, despite lingering perceptions that they remain dominant (and preferred). As utilities step back from these broader procurements, they more commonly use targeted RFPs that focus on specific technologies or services, such as low-carbon generation or dispatchable resources. Examples include TVA’s highly specific procurement for the Kingston Energy Complex, including 100 MW of battery storage to supplement new thermal capacity⁸⁷, Entergy’s 2025 combined renewable and storage solicitation⁸⁸, and DTE’s RFP targeting 1,500 to 3,000 MW of firm capacity to support the retirement of the Monroe Power Plant.⁸⁹

From a storage perspective, targeted procurements, especially those focused on specific sites for BESS deployment and services rather than resource types, offer significant advantages. Service-based RFPs tend to value the unique capabilities of storage more highly than cost-drive all-source procurements, which may favor lowest-cost generation regardless of flexibility or grid support. As utilities refine their planning and procurement strategies, the interplay between IRP modeling and competitive acquisition will continue to evolve, with huge implications for how battery storage is valued and deployed.

Legislative Mandates

State-level legislative mandates for storage procurement are among the most direct and effective mechanisms for accelerating battery deployment. By setting clear targets, these laws compel utilities to incorporate storage into their long-term planning and procurement strategies, often with specific deadlines and capacity goals. For example, Michigan established a 2.5 GW storage target by 2029⁹⁰, while Virginia has set a more ambitious utility-specific 3.1 GW mandate by 2035.⁹¹ These laws create certainty for developers and signal a strong policy commitment to grid modernization utilizing storage technologies. Unlike voluntary or market-driven approaches, legislative approaches leave little room for delay or ambiguity, making them a powerful lever for advancing battery adoption.

However, comparing these legislative mandates as tools across regions is not straightforward. New England utilities, for example, operate within a deregulated market with a substantially different structure and planning process from vertically integrated utilities in the Midwest and Southeast. While storage legislation has proliferated in the Northeast, state governments arguably have a higher incentive there to institute storage procurement mandates to ensure

⁸⁷ [TVA BESS](#)

⁸⁸ [Entergy Solar+Storage](#)

⁸⁹ [DTE](#)

⁹⁰ [MI](#)

⁹¹ [VA](#)

the deployment of such technologies. Virginia and Michigan are pioneering storage policy in regions where legislative action can directly drive deployment, but where that action is less necessary as a prerequisite to generation planning.

Paths Forward

As discussed in this section, addressing procurement barriers to energy storage deployment will require a substantive shift from treating storage as a nascent, untested technology toward recognizing its use as a core grid asset. Procurement processes must evolve, both incrementally and structurally, to better align with the full range of services storage can provide.

Modernize Procurement to Reflect Multi-Service Value or Specific Needs: Procurements that rely on outdated firm capacity metrics or evaluation structures designed for thermal resources systematically undervalue battery storage. Utilities should consider adoption of procurement structures that explicitly value multiple benefits or targeted system needs and where they use all-source procurements, utilities should carefully design evaluation frameworks to ensure that non-price attributes meaningfully affect outcomes.

Increase Transparency and Credibility in Evaluation Criteria: Procurement outcomes hinge not only on stated criteria but appropriate application. Clear weighting of all factors, consistent application of scoring methodologies, and greater disclosure of results would improve developer confidence and reduce incentives for unrealistic bidding.

Enable Contractual Flexibility: Rigid contract requirements may unintentionally narrow the pool of viable bidders. Wherever possible, utilities should allow multiple contract structures, which both lowers barriers to participation and allows flexibility in planned and future operations.

Leverage Legislative Mandates in Regions with Weak Market Signals: State-level legislative mandates are direct and effective methods to spur increased deployment and should be considered in states which see impending grid reliability issues and have political appetite.

Challenge 4

Planning and Modeling Limitations

Integrated Resource Planning sits at the heart of planning for many utilities, shaping not only long-term investment strategies but also procurement opportunities, as outlined in the previous section. As discussed previously, the services a resource can provide are only as important as the extent to which they are valued in a market or by the utility — and in many jurisdictions, the IRP modeling process is the primary venue where that recognition occurs. Stated simply, if a utility does not ‘select’ storage in its IRP, it is unlikely to build storage.

IRPs rely heavily on capacity expansion and production cost modeling to simulate generation resource portfolios that meet future demand in a reliable and affordable manner while also satisfying policy goals and operational constraints. Because these modeling exercises directly inform utility investment decisions and carry substantial weight in related proceedings before public utility commissions (such as rate cases or Certificate of Need proceedings), their design and assumptions warrant close scrutiny. Projects absent from the IRP framework may face stricter scrutiny in subsequent regulatory reviews, if they reach that point at all, underscoring the critical role of modeling in determining which technologies ultimately make it from concept to construction.

Modeling Assumptions

Several foundational considerations shape how utilities model storage in their IRP. These issues are not unique to storage — they apply equally to all resources — but their treatment can influence whether storage emerges as a competitive option. The table below outlines key modeling assumptions, and the questions planners may ask to ensure fair and accurate representation. From inclusion of multiple storage technologies and durations, to cost accuracy, accreditation values, build limits, and operational flexibility, each assumption can materially affect modeled outcomes. Equally important is ensuring that assumptions for other resources are held to the same standard. Of course, these are only the highest-level assumptions that deserve attention, and a good IRP process will incorporate far closer examination of all elements by utility analysts, regulatory staff, and external stakeholders.

TABLE 1. Modeling Assumptions & Questions to Ensure Appropriate Resource Representation

MODELING ASSUMPTION	KEY CONSIDERATIONS
Inclusion	Which storage technologies are included? Are there multiple duration options? Are these technologies included as selectable resources or are they fixed into the model?
Cost	Are costs represented accurate, appropriate, and up-to-date? Does the range of resource types reflect the full cost range available?
Accreditation	Does the accreditation value reflect the full value that energy storage can provide to the grid? Are benefits from coordination with other resources reflected?
Build Limits & Online Dates	Are the build limits modeled binding? If so, do they represent a true ceiling on construction? Is storage made available across the entire modeling period?
Project Structure	Are hybrid resources available to the model? Are PPA projects available given they have different cost or operational parameters?
Operation	Are batteries modeled as dispatchable and flexible as they operate in reality?
Relative Assumptions for Other Resources	Are other modeled resources also modeled appropriately on a cost, inclusion, and operational basis?

Let's take one element of the above table as a demonstration of the influence of each of these rows. First and foremost, storage must be included in the IRP with a diversity of durations, chemistries, and cost points, comparable to the variety of thermal resources typically modeled. A common shortcoming in recent IRPs is the limited range of storage options considered, which can skew results. For example, TVA's 2024 Draft IRP includes only one 50 MW 4-hour lithium-ion battery option and one 10-hour "advanced chemistry" battery option.⁹² Similarly, Santee Cooper's 2023 IRP included only 4-hour lithium-ion and an 8-hour lithium-ion options. Following their IRP, Santee Cooper released an RFP focused solely on procurement of a 4-hour lithium-ion resource.⁹³ When a limited array of battery technologies are modeled, it can directly influence the procurement that follows.

Dynamic Dispatch Capabilities & Sub-Hourly Modeling

Dynamic dispatch capabilities and sub-hourly modeling are increasingly recognized as critical for capturing the full range of services energy storage can provide, from energy shifting to ancillary services. While much has been written about the strengths and limitations of current modeling tools in representing these capabilities and associated value streams⁹⁴, their application in IRP processes remains uneven. Sub-hourly modeling techniques, which

⁹² TVA 2025 IRP Draft

⁹³ 2023 Santee Cooper IRP, 2025 Battery RFP

⁹⁴ Twitchell 2021, Hutchinson 2025

can better reflect storage’s operational flexibility, are becoming more accessible but often come with significant trade-offs in model run time. These approaches can limit the breadth of scenarios and sensitivities that can be explored across the full IRP.

Some utilities are experimenting with hybrid approaches to bridge this gap: for example, DTE modeled specific tranches of battery resources with an added credit to represent ancillary service value⁹⁵, while NIPSCO applied a post-processing credit across multiple resource types, including standalone storage, hybrid storage, and combustion turbines, to adjust portfolio present value of revenue requirements (PVRs).⁹⁶ These emerging practices illustrate ways to incorporate storage’s dynamic capabilities without fully shifting to computationally intensive sub-hourly modeling for every IRP case.

Modeling Non-Traditional Applications

Some utilities have begun exploring battery storage development with a more expansive lens, considering not only traditional applications but also opportunities to add capacity using the surplus interconnection service process, through which new capacity shares interconnection rights with existing resources. Operationally, surplus storage can be sited alongside existing generation to capture excess production that would otherwise be curtailed, store it, and discharge it later to meet demand or provide grid services. Accreditation for such surplus resources typically reflects their contribution to capacity needs and, in some cases, their ability to deliver ancillary services.⁹⁷

Otter Tail Power’s 2024 IRP modeled a level of surplus battery capacity co-located with an existing solar facility,⁹⁸ while Georgia Power’s 2025 planning process evaluated adding battery resources to several of its solar sites.⁹⁹ These approaches illustrate how surplus storage can enhance asset utilization, improve grid flexibility, and unlock additional value streams beyond those captured in conventional IRP modeling.

Paths Forward

In regions where resource planning drives the majority of infrastructure deployment, planning and modeling practices must evolve to reflect actual storage operation and value. Without reform, IRPs risk systematically understating storage’s contribution, constraining downstream procurement.

⁹⁵ [DTE 2022](#)

⁹⁶ [NIPSCO 2024](#)

⁹⁷ [GridLab Surplus Ix](#)

⁹⁸ [OtterTail 2024](#)

⁹⁹ [Georgia Power 2025](#)

Model All Resources Equal: Utilities should ensure that storage is modeled with a realistic range of technologies (including hybrid resources), durations, cost points, and operating profiles comparable to conventional resources. Assumptions for both storage and other resource types should be held to the same standard to avoid distorted portfolio outcomes.

Incorporate Dynamic Capabilities & Non-Traditional Use Cases: When possible, utilities should incorporate modeling approaches which represent sub-hourly operational dynamics of battery storage resources as core scenarios or tested sensitivities.

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