Grid Integration Group
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Navigating modeling frontiers for electric storage resources in wholesale electricity markets

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Executive Summary

Electric storage resources (ESRs) are vital for decarbonizing power systems, but this necessitates their effective integration into electricity markets. While system operators have adapted scheduling frameworks to better integrate ESRs, significant research gaps persist for representing and valuing ESRs in market clearing optimization models. Addressing these gaps is essential for ensuring economic efficiency, system reliability, and incentive compatibility.

This report presents key insights gathered from representatives across the seven U.S. ISOs/RTOs through surveys and interviews. These industry experts identified the most critical ESR-related modeling research gaps and prioritized the order in which they should be addressed. Additionally, we reviewed the state-of-the-art to further define these gaps and explore potential advanced modeling solutions. Based on expert feedback and a review of existing literature, this report's key findings are as follows:

- **Real-time Market**: Respondents said the top priority for ESR research and development should be real-time markets, and specifically to improve incentive compatibility in multi-interval real-time security-constrained economic dispatch (RTSCED) problems.

- **Ancillary Services Market**: Respondents generally agreed on the necessity of developing enhanced approaches for adhering to ESR SoC technical constraints in the provision of ancillary services.

- **Day-ahead Market**: ISO/RTO market representatives highlighted a need for improved computational efficiency and/or enhanced modeling approaches to facilitate ISO state of charge (SoC) management. More precise ESR modeling in reliability unit commitment (RUC) and enhanced energy representation may be essential for ensuring feasible and accurate computation of SoC levels.

- **Priorities for future research**: Based on industry needs and the state of current literature, the following five topics rose to the top in terms of where modeling and analysis research could have a significant near-term impact:
    1. Approaches to augmenting incentive compatibility of multi-interval real-time security-constrained economic dispatch problems for ESRs through enhanced price formation and other market enhancements
    2. Impact and feasibility of ancillary services on SoC management
    3. Computational and/or modeling improvements to simplify SoC management of ESRs by the ISO/RTO in day-ahead markets
    4. Adequate representation of ESR degradation within market-clearing software
    5. The impact of different SoC management options for ESRs in real-time markets

1. Introduction

The deployment of energy storage resources (ESRs) plays a pivotal role in the transition to a clean energy future. In the U.S., various state policies and federal regulations have emerged to facilitate the integration of ESRs onto the power grid. This integration is essential for balancing the intermittency of renewable energy sources, which are increasingly prevalent across various regions. However, electricity markets were not initially designed to incorporate ESRs in their clearing processes. Although system operators have adapted their frameworks to include ESRs, it remains unclear how best to model their participation to maximize their benefits. This white paper identifies and discusses the primary ESR-related modeling and computational challenges and priorities from an industry perspective.

Among the array of policies fostering energy storage adoption, several key initiatives and regulatory mandates stand out.

- **Clean Energy Goals:** States have set ambitious targets, such as achieving 100% carbon-free and/or renewable energy as well as net-zero emissions goals, which incentivize the integration of energy storage technologies.
- **Procurement Targets:** Regulators and/or legislators have imposed procurement goals and mandates in some jurisdictions, compelling utilities to procure or contract storage solutions.
- **Resource Plans:** State agencies or regulators often fund studies or direct utilities to formulate resource plans with storage considerations. In some cases, utilities voluntarily include storage in their resource plans.
- **Incentives:** Economic incentives such as rebates and subsidies have been established by state legislators to encourage storage deployment.
- **FERC Order No. 755:** Compensation models like “pay-for-performance” in regulation markets have led to the rapid growth of storage capacity. Between 2013 and 2015, for example, about 300 MW of lithium-ion batteries were deployed to provide frequency regulation in PJM.
- **FERC Order No. 841:** A pivotal step for integrating ESRs into U.S. wholesale electricity markets, this order mandated that RTOs and ISOs develop market rules and regulations facilitating ESR participation in energy, ancillary services, and capacity markets.
- **FERC Order No. 845-A:** A revision of large generator interconnection requirements, this order facilitated the integration of hybrid solar-plus-storage systems, a substantial number of which have requested interconnection.
- **FERC Order No. 2222:** This order facilitates the participation of aggregated distributed energy resources (DERs), including distribution-connected storage, in ISO/RTO markets.
- **FERC Order No. 2023:** To streamline the interconnection process, this order offered further guidance on operational assumptions for interconnection studies related to ESRs and increased opportunities for co-located storage resources.

Table 1 provides insight into various ESR-related metrics including average duration, average capacity, project count, total installed capacity, and capacity in interconnection queues across U.S. RTO/ISOs by the end of 2023 [1]. CAISO and ERCOT have by far the largest installed capacity of ESRs, reflecting the accelerated deployment in these regions. In contrast, other regions show lower installed capacities, indicating less widespread storage adoption. For example, ISO-NE has a similar project count to CAISO but a lower installed capacity, suggesting smaller project sizes.

Average duration of energy storage is key to understanding technology applications and characteristics of different markets. CAISO and NYISO exhibit longer average durations, which align with the sustained duration requirements of their respective resource adequacy program or capacity market. Conversely, PJM and ERCOT demonstrate the shortest average durations at 1.2 hours; this is associated with the provision of regulation and responsive reserve services, the primary roles of energy storage in these regions, which require sustained durations of one hour or less. Notably, CAISO leads with the highest average nameplate capacity at 50.4 MW, followed by ERCOT and then PJM.

Table 1. 2023 Review of Energy Storage Participation in U.S. Electricity Market Regions

	Operational energy storage resources				Interconnection queue ESR capacity (GW)	Peak load in 2023 (MW)[1]
	Average duration (hours)	Average capacity (MW)	Project count (#)	Total capacity (MW)		
CAISO	3.2	50.4	156	7,858	149.20	44,534
ERCOT	1.2	40.7	84	3,416	75.74	85,508
ISO-NE	2.3	3.0	110	332	19.30	24,043
MISO	1.9	3.9	21	82	37.32	124,229
NYISO	3.2	4.9	40	198	36.01	30,206
PJM	1.2	10.7	32	343	54.88	146,843
SPP	2.4	3.3	8	27	24.73	56,184

Over the next five years, the U.S. is expected to add roughly 59 GW of energy storage capacity, mostly in grid-scale projects.[2] As shown in Table 1, there are currently around 400 GW of standalone storage projects in ISO/RTO interconnection queues, in addition to about 13 GW and

[1] Sources: CAISO - https://www.caiso.com/Documents/2023Statistics.pdf, ERCOT - https://www.ercot.com/static-assets/data/news/Content/a-peak-demand/2023/all-time-records.htm, ISO-NE - https://www.iso-ne.com/about/key-stats/electricity-use, MISO - https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3ASummary%2FMarketReportName%3AHistorical%20Daily%20Forecast%20and%20Actual%20Load%20by%20Local%20Resource%20Zone%20(xls)&t=10&p=0&s=MarketReportPublished&sd=desc, NYISO - https://www.nyiso.com/documents/20142/40206684/Updated Summer 2023 Peak Load & Weather Experience.pdf/384a7ded-afc0-71b3-cf5e-14280370f3b3, PJM - https://www.pjm.com/-/media/planning/res-adeq/load-forecast/summer-2023-peaks-and-5cps.ashx, SPP - https://kslegislature.org/li/b2023_24/committees/ctte_spc_2023_special_committee_on_energy_and_ut_1/documents/testimony/20231017_08.pdf

[2] Wood Mackenzie Power & Renewables / American Clean Power Association, *U.S. Energy Storage Monitor, Q1 2024 and 2023 Year in Review Executive Summary*, March 2024.

92 GW in the Southeast and West non-ISO regions, respectively.[3] While all projects will not come to fruition, the sheer quantity of interconnection requests highlights the industry's keen interest in near-term energy storage deployment. At the same time, the size of these interconnection queues represents a key challenge, as backlogs can significantly delay project development. In response, ISOs are revising their interconnection processes, and some have ceased accepting new applications altogether.

Notably, storage deployment also faces numerous modeling challenges, especially with regard to its representation in market clearing software and participation in wholesale electricity markets. Accordingly, electricity market operators may need to adjust their market clearing software and market design to fully harness the benefits of energy storage and the wholesale market products and services it can provide.

This white paper identifies and analyzes the industry's perspective on complex ESR modeling challenges and explores advanced solutions to enhance the representation and implementation of ESRs in market clearing software. The objective is to foster an environment that is conducive to efficient ESR deployment by effectively addressing these modeling challenges.

2. Methodology

The methodology for presenting the primary ESR-related modeling and computational challenges from an industry perspective involved two main activities. First, we conducted a series of surveys and interviews with representatives from major U.S. ISOs/RTOs to gather their opinions on the critical modeling research gaps regarding ESR integration into their markets, the implications of these gaps, and their recommended priorities for addressing them. The findings from these interactions are summarized in Section 3.

Second, we performed a literature review to further explore research gaps identified by the ISOs/RTOs. This review, detailed in Section 4, provides an in-depth analysis of these gaps, their context, and potential alternative solutions.

3. Research Gaps and Potential Designs for Enhancing ESR Integration in Electricity Markets

3.1 ISO/RTO Engagement

We engaged 17 representatives from the seven U.S. ISOs/RTOs, including at least one from each, to understand research and development (R&D) needs related to ESRs from a wholesale electricity market perspective. This engagement occurred through a combination of paper surveys, online surveys, and in-depth interviews.

[3] J. Rand, N. Manderlink, W. Gorman, J. Seel, J. M. Kemp, S. Jeong, D. Robson, and R. H. Wiser, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection*, Lawrence Berkeley National Laboratory, April 2024. [Online]. Available at https://emp.lbl.gov/queues.

3.1.1 Industry Survey Results

All 17 representatives completed an identical survey in which they ranked markets according to how extensive their R&D needs are, as it relates to ESRs. The results indicate that the most extensive ESR R&D is needed in the real-time market, followed closely by ancillary services markets, while the day-ahead market is generally perceived to require less R&D. Survey participants also prioritized research topics within each market, including the day-ahead market (DAM) and real-time market (RTM) for energy, and the day-ahead (DA) and real-time (RT) ancillary services (A/S) markets. Every research topic was considered high priority by at least one survey participant, highlighting the breadth of storage modeling challenges. Some topics were prioritized by nearly all ISOs/RTOs, whereas others are critical to only a subset of them. Figure 1, below, summarizes the survey results.

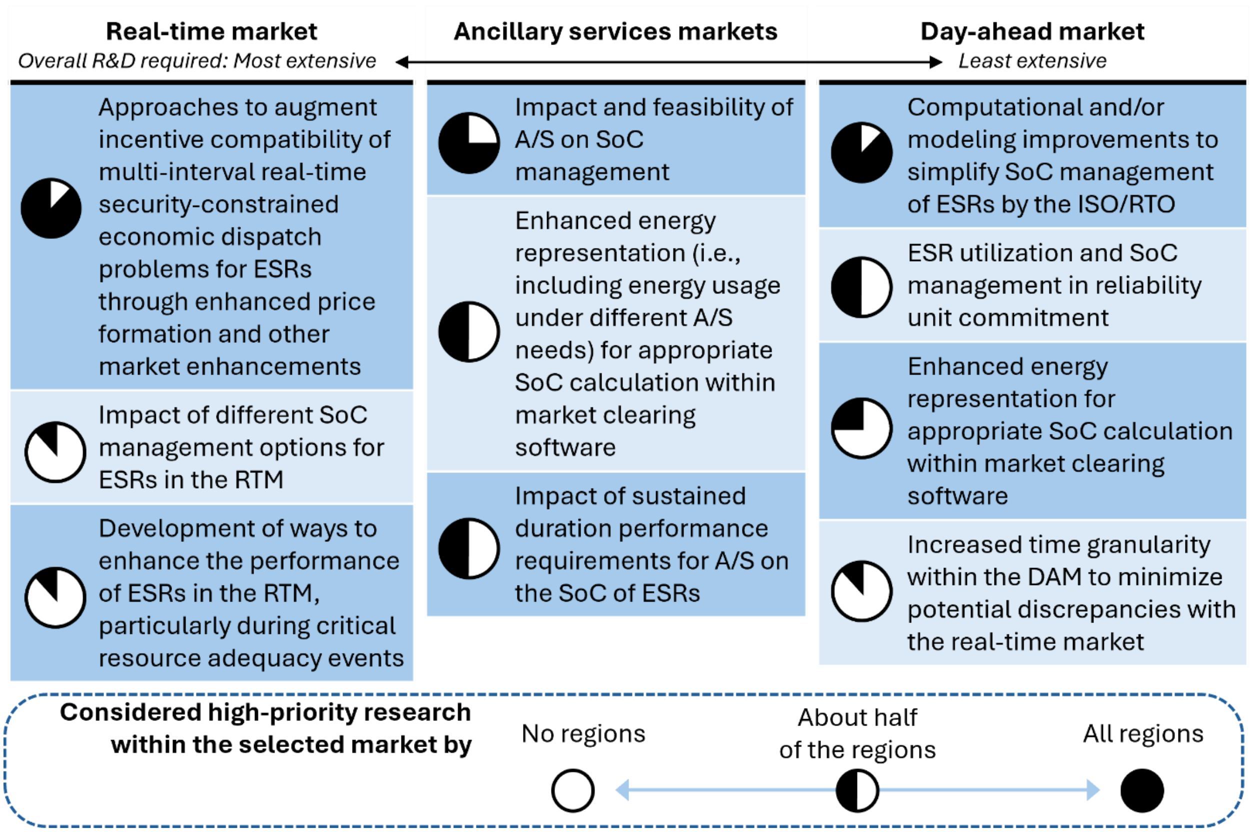

Figure 1. Results of industry survey prioritizing ESR research topics within specific market types

Finally, we asked survey participants to prioritize ESR research topics that are not confined to these specific market products. Prioritization of the miscellaneous topics varied considerably, even within respondents from the same organization. However, two topics did stand out as the highest priority: 1) price formation in electricity markets dominated by renewables and storage; and 2) representing ESR degradation in market clearing software. Table 2 summarizes the survey results on these miscellaneous topics, and Table 3 highlights some of the key priorities raise by each organization we surveyed.

Table 2. Results of industry survey prioritizing ESR research topics that are not confined to specific market products

Miscellaneous challenges (not market-specific)	
Price formation in renewables-dominated power systems with energy storage participation	Highest priority
Adequate representation of ESR degradation within market clearing software	↕
Market participation models for long-duration energy storage	
Market power mitigation approaches for storage-based resources	
Modeling storage as transmission assets (SATA) and transmission-only assets (SATOAs)	Lowest priority

Table 3. Results of industry survey prioritizing ESR research topics by ISO/RTO

	Key challenges identified with a need for R&D (not exhaustive)
CAISO	• A/S impact on SoC management, particularly in day-ahead co-optimization • Incentive compatibility of multi-interval real-time security-constrained economic dispatch (RTSCED) • Market power mitigation
ERCOT	• A/S impact on SoC management, particularly reserve deployment factors • Incentive compatibility of multi-interval real-time security-constrained economic dispatch (RTSCED) • Enhanced energy representation for appropriate SoC calculation within market clearing software
ISO-NE	• Price formation in renewables-dominated power systems with energy storage • Incentive compatibility of multi-interval real-time security-constrained economic dispatch (RTSCED) • ESR utilization and SoC management in reliability unit commitment
MISO	• Impacts of sustained duration performance requirements for A/S • Performance of ESRs in the RTM, particularly during critical resource adequacy events
NYISO	• Enhanced energy representation of A/S needs for appropriate SoC calculation • Adequate representation of ESR degradation within market clearing software
PJM	• Incentive compatibility of multi-interval real-time security-constrained economic dispatch (RTSCED) • Price formation in renewables-dominated power systems with energy storage • Computational or modeling improvements to simplify SoC management by the RTO
SPP	• Performance of ESRs in the RTM, particularly during critical resource adequacy events • Price formation in renewables-dominated power systems with energy storage

3.1.2 Summary of Industry Interviews

We conducted numerous in-depth interviews across the industry, engaging market design experts including engineers, managers, and directors. Specifically, we interviewed individuals overseeing storage modeling decisions and implementation for the two key electricity market regions in the U.S. with the highest observed storage penetrations: ERCOT and CAISO.

CAISO highlighted a number of pressing challenges associated with DA energy, RT energy, and A/S markets, as well as the links between them, plus two medium-term challenges that could benefit from early research.

The first challenge relates to the link between A/S (primarily regulation) and energy in the day-ahead timeframe, where they are jointly procured in a co-optimized manner. CAISO is unique in that most A/S are procured in the DAM, whereas only incremental A/S are procured in the RTM. CAISO needs an enhanced model to better capture the state-of-charge (SoC) impacts of deploying A/S products from storage in order to inform feasible day-ahead energy schedules. Modifying SoC constraints can create unexpected incentives in CAISO's experience – for example, arbitrage opportunities between regulation down and afternoon energy prices.

A second SoC management challenge comes from the non-linear relationship between power and energy near batteries' SoC limits (i.e., when SoC is less than 20% or greater than 85%). As a result, batteries near their SoC limits may not be able to perform as accurately due to dispatch or ramp-rate infeasibilities. More precise SoC management (e.g., improved formulations that consider the non-linearities) would be valuable, but there are computational and practical challenges. An improved understanding of their simplified models' accuracy would be beneficial as well.

In the RTM, CAISO currently optimizes dispatch for the upcoming *binding* interval while considering an advisory look-ahead period with *non-binding* schedules and prices. This setup can create incentives to deviate from dispatch instructions given the nature of how these various prices are used in settlements, though little of this behavior is observed today. They have identified that continuous rolling multi-interval settlements would be the gold standard, but also ruled it out due to practicalities of settlement implementation, including the data handling difficulties for CAISO in tracking correct outcomes given the interaction between their 200+ charge codes (e.g., for instructed/uninstructed deviations going from day-ahead to real-time); revenue neutrality codes that are already complicated for the binding interval; and challenges for large market participants in maintaining their current shadow settlement systems. Research on practical alternatives – such as using DA schedules to guide RT dispatch, exploration of an energy capability product (including compatibility with existing reserve products) for incentive alignment, and the ideal look-ahead horizon for an advisory period – are needed, in addition to determining the granularity of settlements.

CAISO also identified that research on temporal system market power (i.e., the ability of large portfolios including storage to drive scarcity over time) and participation models for long-duration energy storage would be useful today to prepare for issues that may emerge in the coming years.

ERCOT emphasized that storage modeling problems cut across markets and that the challenge is how to make better-informed decisions at each step. SoC management and modeling is central to each of the challenges ERCOT raised. First, they have already been tasked with improving SoC calculations in the real-time market by enhancing energy representation. Second, they are seeking methods to eliminate the need for exceptional dispatch of storage to maintain battery

SoC to better manage evening net load ramps. In this context, exploring an energy capability reserve product could be beneficial but defining the quantity and duration of available reserves is a challenge for storage (and all limited-availability resources). Researching ways to better determine reserve deployment factors for adequate SoC accounting could also be beneficial. Finally, considering non-linearities in battery behavior, particularly at low SoC levels, would be difficult. Instead, their preferred solution is to require storage resources to define their SoC bounds such that zones with non-linearities are avoided.

For markets where storage is less prevalent, we conducted two in-depth interviews (with MISO and ISO-NE) and several shorter semi-structured conversations (with NYISO, PJM, and SPP). These discussions focused on stakeholder concerns and storage design enhancement options currently under consideration for implementation. Topics included daily cycle limitations and lifecycle degradation, improvements to market participation models, observed performance differences vs. expectations, implementation of desired SoC levels in the real-time market, price formation with significant storage-based resources, and the impacts of varying storage durations, along with the aforementioned challenges.

4. Ongoing Modeling Challenges and Potential Solutions

Energy transactions in U.S. electricity markets occur through a sequence of time-differentiated auctions. All ISOs may conduct pre-day-ahead scheduling for long-start resources without financial settlement. Then, the day-ahead market clears supply and demand for each hour of the next day (i.e., the operating day) based on offers or self-schedules from suppliers and bids or load forecasts from buyers. Deviations from day-ahead schedules are settled in the real-time market at real-time prices, thereby forming a two-settlement system. In the real-time stage, market clearing is generally optimized for the next five minutes; sometimes a non-binding advisory look-ahead, consisting of a few five-minute intervals, is also involved. In CAISO, an additional real-time, fifteen-minute market creates a three-settlement system.

While this market structure has generally worked well for systems of firm generation (i.e., power sources intended to be available at all times), several challenges are emerging as power systems increasingly rely on variable renewable energy (VRE) resources and ESRs. The following subsections detail the challenges of integrating ESRs in the day-ahead and real-time energy and ancillary services markets. These subsections also propose solutions drawn from both academic and industry literature.

4.1 Day-ahead Market

4.1.1 Computational and Modeling Improvements to Simplify SoC Management of ESRs by the ISO/RTO

Effective state-of-charge management (SoCM) for ESRs is crucial for improving economic and reliability outcomes as their market participation grows. SoCM options can benefit both ESR owners and system operators by facilitating efficient dispatch schedules, avoiding penalties, and satisfying operational constraints. For system operators, adequate SoCM enhances scheduling certainty, optimizes resource utilization while respecting physical and operating constraints, reduces operating costs, and improves system reliability.

SoCM options can be classified on a spectrum from self-managed to ISO-managed. Figure 2 illustrates the four SoCM options and how responsibility shifts from the ESR owner (on the left) to the ISO (on the right).

- The Self-Schedule option is the simplest form of market participation. Like other generators, the ESR can submit energy schedules for each market interval, and the ISO will schedule the ESR at the specified output regardless of conditions or prices, except during emergencies.
- In Self-SoCM, ESR owners assume responsibility for incorporating SoC constraints implicitly into their market bids/offers, making them accountable for ensuring SoC feasibility and optimality.
- In SoCM-Lite, system operators do not schedule ESRs if it would lead to infeasible SOC but do not optimize ESR schedules across time.
- In ISO-SoCM, system operators explicitly integrate SoC constraints into the market clearing software engine to ensure SoC feasibility and optimality.

In short, the SoCM-Lite and ISO-SoCM options differ in how the ISO's market clearing software handles economic dispatch and pricing.

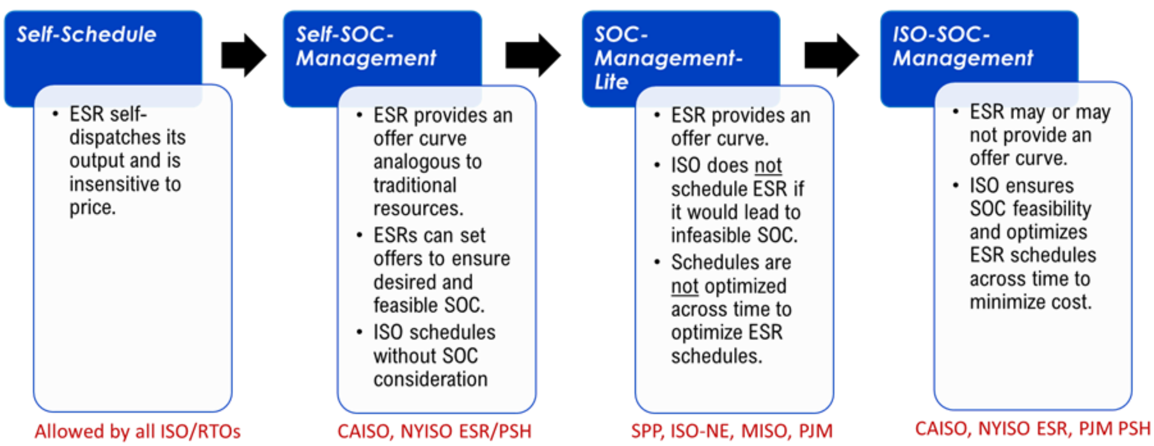

Figure 2. SoC management options. Responsibility shifts from the ESR owner (left) to the ISO (right)

Figure 3 illustrates differences in ISO day-ahead market clearing software. ISO-SoCM is common among ISOs using a 24-hour optimization horizon (similar to day-ahead security-constrained unit commitment) for economic dispatch and pricing. In contrast, SoCM-Lite is prevalent among ISOs that determine economic dispatch and pricing independently and sequentially for each hour.

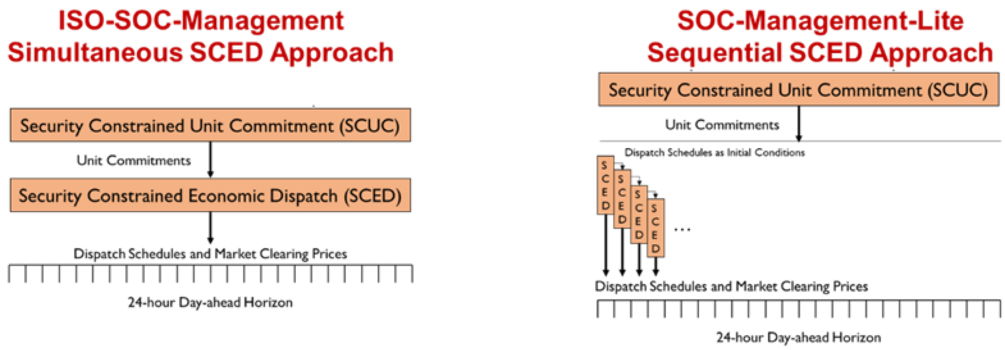

Figure 3. Differences in ISO day-ahead market clearing software

Research has shown the advantages of ISO-SoCM due to its economic efficiency, reliability, SoC feasibility guarantees, and reduced market power concerns [2]. It was also shown to have greater profits for storage participants. However, computational challenges may arise with increased ESR market penetration due to the complexity of SoC constraints, necessitating computational and modeling improvements by the ISO/RTO [3].

Recent research has investigated a straightforward, adaptable approach to modeling ISO-SoCM in the day-ahead market [4]. It involves simplified “wrapper energy constraints,” which both account for the energy exchanged by an ESR within a given time window and implicitly monitor SoC similar to energy constraints used in modeling fuel limitations. Its aim is to tackle computational hurdles while maintaining SoC feasibility, economic efficiency, reliability, and incentive compatibility.

However, further research is needed to extend wrapper energy constraints to include the provision of ancillary services and analyze differences compared to the energy-only case. Additionally, it would be beneficial to assess performance issues arising from other factors such as model degeneracy. Continued investigation should also explore alternative modeling solutions for ISO-SoCM that avoid adverse impacts on economic efficiency, reliability, and computational performance.

4.1.2 ESR Utilization and SoC Management in Reliability Unit Commitment

ISOs/RTOs use various versions of a reliability unit commitment (RUC) process, which complements the DAM by ensuring physical commitments are sufficient to meet projected system conditions. Because RUC aims for accurate real-time (RT) operation predictions, it relies more on ISO/RTO forecasts for load and variable energy resources than on market participants’ bids and offers. It also treats different resource technologies differently. Committed thermal and hydro generators and offline quick-start resources are prioritized by discounting their commitment costs. For offline long-start resources, commitment costs are included in the RUC objective function and these resources are committed only when required so the ISO avoids making nonreversible, out-of-market decisions.

This raises the question of how storage is best treated in the RUC process. Standalone storage resources such as batteries may not require an explicit decision in RUC, since they can be adjusted in RT without additional out-of-market costs requiring make-whole payments. However, it is crucial to recognize when committing an offline long-start resource at the RUC stage becomes necessary to make up for the energy deficit that would occur if storage were slated to supply more energy in the DAM than it could feasibly provide in RT due to SoC limitations. Recognizing such situations requires adequate predictions of ESR RT operation, but this is challenging because ESR operation is dependent on RT price forecasts.

DA prices may be the most accurate predictors of RT prices. In this case, one option for the RUC is to optimize storage schedules without considering its DAM offers but instead by imposing its SoC constraints [5]. However, this option may be complicated by the incorporation of discounted offers from other resources, given the impact of such offers on market clearing prices and storage operation.

An interim decision-support tool that does not discount offers or costs for online resources or offline quick-start resources could be explored to better anticipate RT storage operations. However, provision of ancillary services by storage may further complicate predicting RT operations. In this case, analyzing historical deviations between DA and RT operations could offer insights into predicting RT storage operations, aiding decision making in RUC.

Figure 4 summarizes the previously mentioned options for better incorporating storage into the RUC process. Note that some emerging storage technologies might operate like traditional thermal resources and therefore need explicit decisions in RUC.

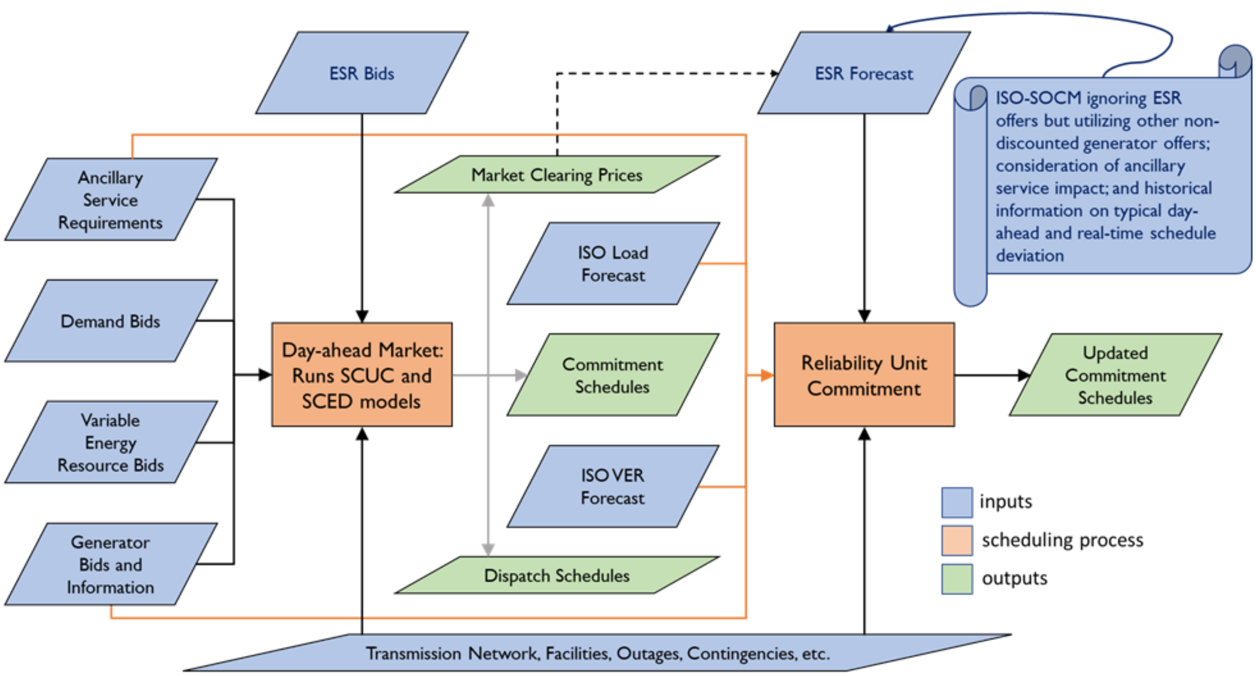

Figure 4. Integrating storage into the RUC process

4.1.3 Enhanced Energy Representation for Appropriate SoC Calculation Within Market Clearing Software

The state-of-the-art approach for SoC calculation within optimization models involves a simplified method based on traditional market clearing software practices, assuming no differentiation between the use power and energy as decision variables. However, with increasing ESR market penetration, accurate energy calculation becomes crucial to ensuring SoC feasibility, particularly for ESRs with rapid output fluctuations. In this context, research has discussed the distinction between power and energy in market clearing software [6].

Figure 5 explains this, where transitioning from the previous ESR discharge schedule ($P^d_{ESR,t-1}$) to the new ESR discharge schedule ($P^d_{ESR,t}$) depletes energy stored, represented by the area under the curve [2].

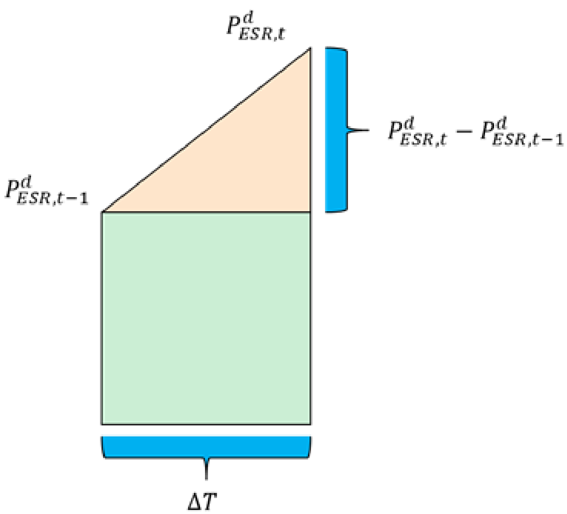

Figure 5. Improved accuracy of energy calculation for SoC constraints

Correspondingly, the equation below presents an enhanced SoC calculation for market clearing software, assuming a linear ramp-up between dispatch schedules as a close approximation of ESR behavior

$$SOC_{ESR,t} = SOC_{ESR,t-1} - \frac{1}{\eta^d_{ESR}}\left(\left(P^d_{ESR,t-1}\right)\Delta T + \frac{1}{2}\left(P^d_{ESR,t} - P^d_{ESR,t-1}\right)\Delta T\right)$$
$$+ \eta^c_{ESR}\left(\left(P^c_{ESR,t-1}\right)\Delta T + \frac{1}{2}\left(P^c_{ESR,t} - P^c_{ESR,t-1}\right)\Delta T\right)$$

Note that although battery storage can transition instantaneously from a previous discharge schedule to a new one, ISOs/RTOs will likely require this transition to be smooth and follow a linear ramp profile based on the market interval to prevent area control error excursions, especially if multiple battery storage resources act similarly. This equation may be applicable to both multi-period and single-period market clearing, where previous schedules are known parameters with single-period clearing.

Future research should expand on the described enhanced energy representation for appropriate SoC calculation and improved accuracy. This should include transitions that involve ramping up and down when discharging, ramping up and down when charging, and shifts from discharge to charge mode (and vice-versa) to ensure comprehensive configurations. Additionally, there is a need to assess the impact on price formation from dual variables through simulation and analysis, should an ISO adopt this approach.

4.1.4 Increased Time Granularity Within the DAM to Minimize Potential Discrepancies with the Real-time Market

There is a growing perception that increased time granularity in day-ahead electricity markets could facilitate the increasing integration of VRE resources [7], and that current market designs, particularly day-ahead market designs, are unable to take full advantage of the potential benefits offered by flexible resources, including storage [8]. One challenging aspect of today's market design is the substantial difference in time granularity between DAM and RTM processes. Day-ahead markets typically schedule resources on an hourly basis, whereas real-time markets typically dispatch resources in 5- to 15-minute periods.

As VRE resource participation increases, this discrepancy introduces greater uncertainty in terms of available generation output intra-hour in the RTM, which then necessitates greater reserves and potential out-of-market actions [9]. With respect to storage, the discrepancy can lead to a lack of reference (or desired SoC target) in the intra-hour real-time scheduling timeframe, potentially impacting SOCM. It could also result in considerable divergence between DAM and real-time schedules, potentially depleting SoC during critical peak net-load instances.

Various solutions have been proposed. For instance, CAISO has considered increasing the granularity of its DAM from hourly to 15-minute increments through its Day-ahead Market Enhancements (DAME) initiative [9]. CAISO expects greater resolution in the DAM to better position system to manage intra-hour net load changes in real-time, thereby reducing the need for RTM adjustments due to granularity differences and uncertainty.

This approach entails a trade-off, however, as it increases the computational time required to solve the DAM and requires more granular forecast data. Consequently, it has not yet been put into practice. Instead, CAISO is shifting towards implementing a new product known as "imbalance reserves," which are 15-minute dispatchable reserve products intended to address net load imbalances resulting from uncertainties in day-ahead net load forecasts and differences in granularity between the day-ahead and real-time markets [10].

In technical literature, intraday settlements have been proposed to overcome granularity discrepancies and enhance current market designs to better integrate ESRs [8]. The lack of consensus on this topic highlights the need for future research to validate proposed solutions and/or explore alternatives.

4.2 Real-time Market

4.2.1 Approaches to Augmenting Incentive Compatibility of Multi-Interval Real-Time Security-Constrained Economic Dispatch Problems for ESRs Through Enhanced Price Formation and Other Market Enhancements

U.S. real-time electricity markets rely on single- or multi-interval optimization procedures to dispatch the power system in the very near term (e.g., the next five minutes to one hour), as summarized in
Table 4.

Table 4. U.S. ISO/RTO Real-time Market Characteristics

Real-time Scheduling Process	NYISO	CAISO	PJM	SPP	ISO-NE	MISO	ERCOT
RTSCED software option	Multi-interval	Multi-interval	Single interval	Single interval	Single interval	Single interval	Single interval
RTSCED optimization horizon	55-65 minutes	35-50 minutes	10 minutes	5 minutes	15 minutes	10 minutes	Immed-iate
RTSCED solve frequency and time step	5 minutes						

Comparing single-interval real-time security-constrained economic dispatch (RTSCED) models with time-coupled, multi-interval RTSCED models reveals several advantages of the latter. In theory, multi-interval RTSCED models generally enhance reliability by reducing infeasibilities and lead to decreased production costs and fewer price spikes. However, they often encounter challenges related to computational complexity and incentive compatibility.

Incentive compatibility challenges arise because, in existing multi-interval RTSCED designs, dispatch decisions and prices are binding for settlements only for the first interval and are merely advisory for the look-ahead intervals (Figure 6). Hence, an ESR may be instructed to take an uneconomic action in the current (financially binding) interval due to an expected opportunity in a future interval as indicated by advisory prices. But if expected circumstances do not materialize, the ESR may be uncompensated for its earlier foregone opportunity. Therefore, the existing settlement structure of the multi-interval RTSCED design can make it uneconomic for storage resources to follow central dispatch decisions or make truthful offers, thereby jeopardizing market equilibrium.

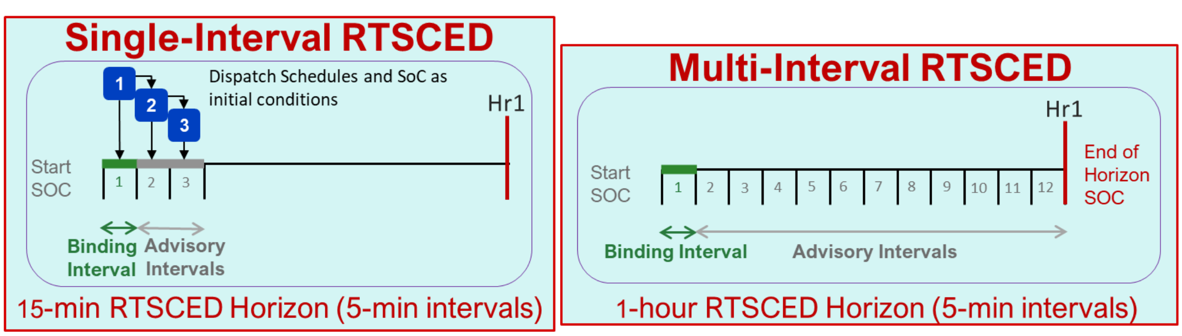

Figure 6. Differences in ISO real-time market clearing software

To mitigate price spikes resulting from ramp-induced infeasibilities, some contemporary single-period RTSCED market models have introduced *ramp capability products*. These products hold back capacity and ramp capability in the current interval to manage variability and sometimes uncertainty in future intervals. While the introduction of ramp capability products in single-period RTSCED models has improved reliability concerns and lowered price spikes, these models may still not be as effective as multi-period RTSCED models in reducing system operating costs. Furthermore, the inclusion of VRE resources and ESRs, which necessitates the incorporation of intertemporal constraints, could exacerbate the aforementioned issues in both single-period and multi-period RTSCED market constructs.

Several alternatives could improve incentive compatibility. One approach complements the real-time dispatch model with a pricing model that considers the same look-ahead as the RTSCED along with prior intervals' dispatch decisions and optimal dual variables in RTSCED runs to determine the upcoming interval's market price [11]. In this approach, all resources are paid the same market price and those with past financial losses are appropriately compensated in future intervals to eliminate the incentive to deviate from centralized dispatch instructions.
Alternate pricing approaches would entail extracting prices from the dual solution to reflect the opportunity cost incurred across the multi-period horizon and then compensating those resources accordingly using temporal locational marginal pricing (TLMP) [12] or cross interval marginal price (CIMP) [13]. Addressing incentive compatibility may ultimately involve implementing a multi-settlement system where binding prices would essentially also be assigned for look-ahead periods, with each subsequent market run settling deviations from previous runs [14].

Finally, another approach to addressing RTSCED problems involves introducing a new market product similar to a ramp capability product. The purpose of this proposed *energy capability product* (or *energy adequacy product*) is to hold back energy in the current interval (or optimization horizon) to manage net load variability (and potentially uncertainty) in future intervals.

The time horizon for this product can vary depending on system characteristics. For example, the product may be implemented in single-interval RTSCED to hold back energy for future intervals in the upcoming hour (or beyond, depending on the chosen time horizon); or similarly, in multi-interval RTSCED; or in intra-day markets, to hold back energy for critical net load periods. Storage participants could offer their opportunity costs to hold SoC until the end of the current optimization window.

This product may help address incentive compatibility by creating an additional revenue stream for all resources that are eligible to provide energy, while providing system operators with some control over the level of energy available during high net ramp events. This approach may be similar to CIMP but with the incorporation of SoCM.

The overarching goal of resultant pricing mechanisms should be to prevent resources from having uncompensated lost opportunity costs (LOCs) when they follow ISO dispatch instructions. Additional research is warranted to study the implications of these alternative proposals.

4.2.2 The Impact of Different SoC Management Options for ESRs in the RTM

In navigating differences between the DAM and RTM, managing the SoC of ESRs presents unique challenges. While the DAM allows for longer optimization horizons, the RTM considers shorter horizons (
Table 4), complicating optimal decision making. The difficulty is primarily due to limited forecasting abilities beyond the immediate future (Figure 7). Shortsightedness can lead to premature ESR activity earlier in the day, impacting their effectiveness later in the day, especially under demanding system conditions. Additionally, disconnects between DAM and RTM can further exacerbate this issue, yielding sub-optimal decisions and infeasible outcomes beyond the RTM software's window.

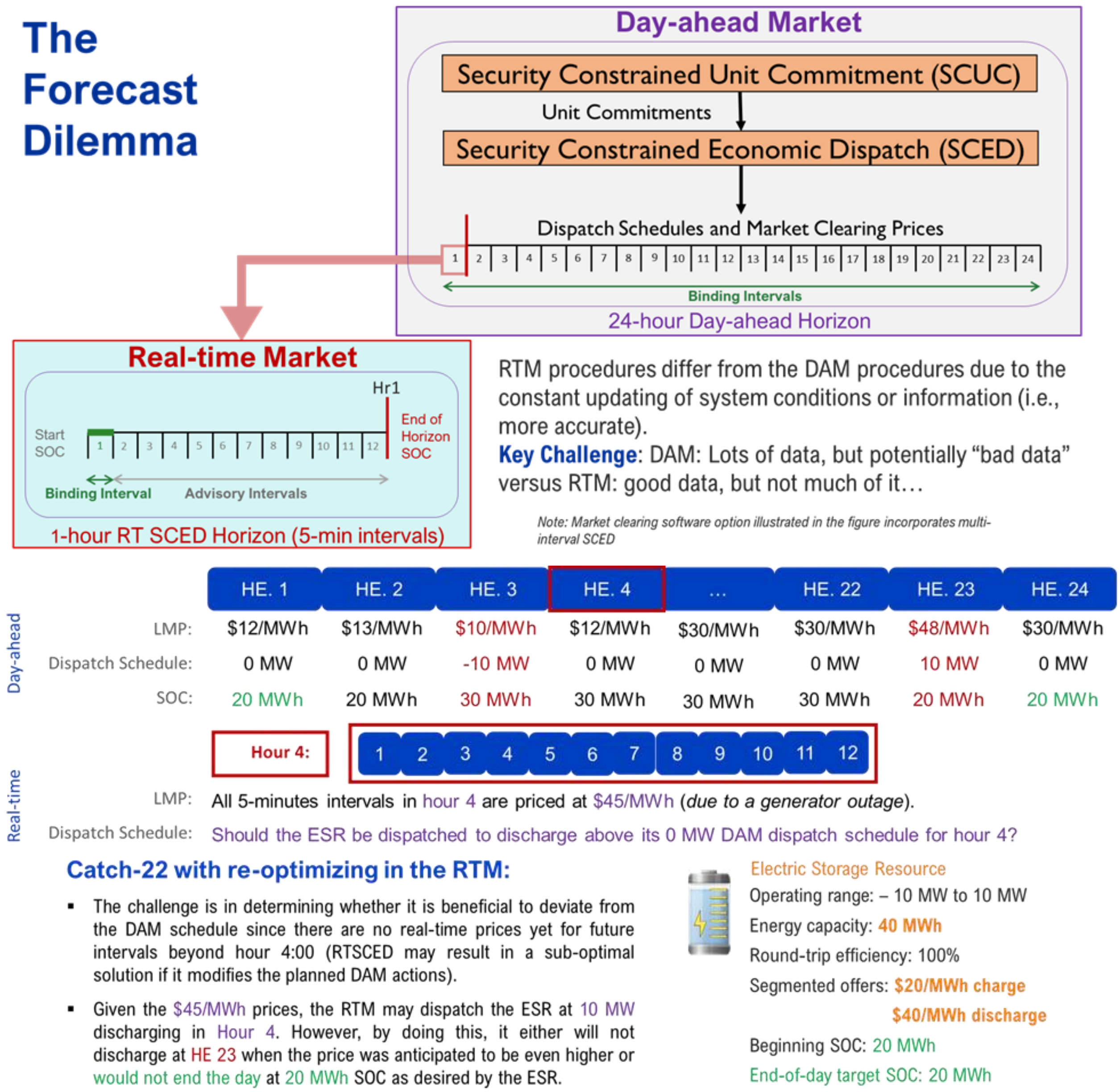

Figure 7. The "forecast dilemma" and challenges with re-optimizing ESRs in the real-time market

Prior research suggests several strategies whereby ISO-SoCM can address these challenges within the RTM. These include aligning end-of-horizon SoC in the RTM with corresponding DAM periods, either as a hard or soft constraint, with penalty value derived from the dual of the SoC constraint from DAM. Additional strategies involve incorporating surplus storage value into the RTM objective function, established either by the ESR owner or the ISO/RTO based on DAM revenues for hours beyond the RTM horizon. Another approach includes extending the RTM horizon with lower-resolution look-ahead periods and incorporating multiple desired SOC levels throughout the extended horizon [5], [15]-[16]. Alternative RT SoCM strategies include Self-SoCM, resembling the DAM, where market participants manage ESR SoC and the RTM relies on submitted short-term bids with limited foresight.

Each option comes with complexities and trade-offs, necessitating careful consideration in implementation to ensure economic efficiency, reliability, and flexibility for ESR owners while avoiding potential drawbacks like computational complexity and suboptimal decisions. Further research, including extensive simulations and analyses, is warranted to better understand the market implications of proposed RT SoCM options.

4.3 Ancillary Services Market

4.3.1 Impact and Feasibility of Ancillary Services on SoC Management.

ESRs have become increasingly important to U.S. electricity markets, offering various products like ancillary services (A/S), with potential for further expansion due to significant pending storage capacity, though challenges arise from their operational differences compared to conventional resources [17]. Although conventional resources are typically not impacted by fuel availability and can sustain their power output over a given time period, an ESR awarded an A/S supply responsibility may not be capable of sustaining that award (i.e., if it needs to be deployed) for the required duration mandated by regulatory standards (e.g., NERC criteria) due to energy capacity constraints. In other words, limitations in available energy to discharge and available storage to charge can correspondingly impede upward and downward ancillary service provision and deployment from storage, particularly if the market clearing optimization problem does not adequately consider the impact of ancillary service provision on the SoC.

Within this context, different ISOs have adopted various measures to address this SoCM issue and ensure the reliable provision of A/S. For example, ERCOT has reportedly observed an increasing risk of SoC insufficiency for the provision of A/S. Hence, to mitigate this problem, as per the Nodal Protocol Revision Request (NPRR) 1186, ERCOT currently requires ESRs to be able to provide the agreed power output for the full remainder of a given hour to be eligible for an ancillary service award [18]. CAISO also requires a minimum SoC depending on the awarded ancillary service. Further, CAISO has identified the possibility that storage may be inadequately compensated to respect the A/S SoC constraint (which requires the ESR to maintain sufficient headroom to provide the awarded A/S should it be deployed). For example, if an ESR is awarded reg down responsibility and lacks sufficient headroom to provide it, CAISO instructs the ESR to discharge and compensates the owner with the difference between the LMP and their energy bid. But because energy bids could be unjustifiably high, CAISO has proposed to cancel this cost recovery compensation mechanism [19].

These solutions still need to be assessed under more varied market conditions, which could impact ESR owners' appetite to contribute to A/S, so impacts on owner revenues and economic viability should also be studied. Research on improved methods for determining dynamic reserve deployment factors (e.g., "attenuation factors" in CAISO, "reliability factors" in MISO, etc.) for accurate SoC accounting could also be beneficial. Progress here is crucial for regulation reserve, where multiple intervals of unexpected SoC impacts can pose significant issues, especially during extreme events; and for products like spinning and non-spinning reserves, where the probability of being deployed in successive intervals is low but still possible.

4.3.2 Enhanced Energy Representation, Including Energy Usage Under Different A/S Needs for Appropriate SoC Calculation Within Market Clearing Software

Ancillary service participation is the prevailing option for ESRs due to their limited duration. Given the crucial role A/S plays in ensuring system reliability, it is logical that ISOs/RTOs would use SoC to ensure feasibility, particularly in the real-time market. SoC may be telemetered for real-time A/S market provision or calculated as a variable through optimization in the day-ahead A/S market.

To supplement the enhanced energy representation for appropriate SoC calculation discussed in Section 4.1.3, Figure 8 (not drawn to scale) illustrates the movement and energy usage under spinning reserve needs as an example [2].

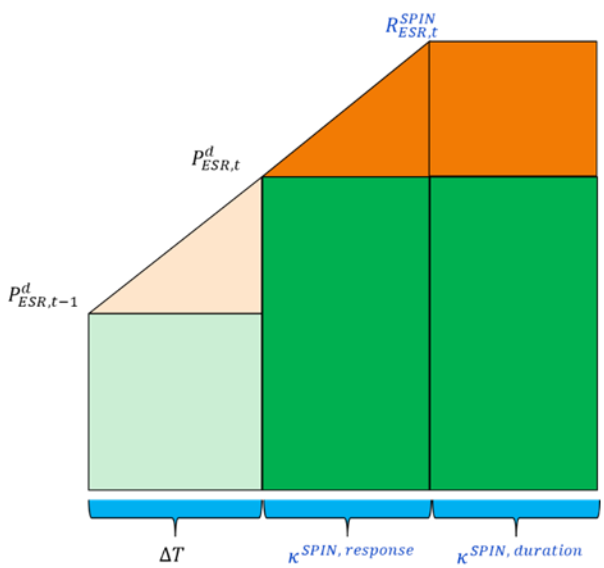

Figure 8. Example of movement and energy usage under spinning reserve needs

Correspondingly, the equation below presents an enhanced energy calculation under spinning reserve needs within market clearing software, assuming a linear ramp-up between discharge energy schedules (i.e., $P^{d}_{ESR,t-1}$ and $P^{d}_{ESR,t}$) as well as the spinning reserve schedule ($R^{SPIN}_{ESR,t}$) as a close approximation of ESR behavior.

$$\underline{SOC}_{ESR} \leq \ SOC_{ESR,t-1} - \frac{1}{\eta^{d}_{ESR}}\left(\left(P^{d}_{ESR,t-1}\right)\Delta T + \frac{1}{2}\left(P^{d}_{ESR,t} - P^{d}_{ESR,t-1}\right)\Delta T\right) - \frac{1}{\eta^{d}_{ESR}}\left(\kappa^{SPIN,response} P^{d}_{ESR,t} + \frac{1}{2}\kappa^{SPIN,response} R^{SPIN}_{ESR,t} + \kappa^{SPIN,duration}\left(P^{d}_{ESR,t} + R^{SPIN}_{ESR,t}\right)\right) \leq \overline{SOC}_{ESR}$$

Charge parameters are not considered here. Further, the equation assumes a constant discharge energy schedule ($P^{d}_{ESR,t}$) throughout the sustained duration time requirement for spinning reserve ($\kappa^{SPIN,duration}$); given that ISOs typically require all energy during contingencies for the entire duration, this assumption is of practical importance. The impact on SoC from spinning reserve provision, specifically calculated for the entire reserve need, differs from the one used for energy dispatch and must also undergo SoC feasibility checks.

Prior research does not delve into the formulation or management of SoC concerning A/S provision from ESRs while respecting A/S eligibility criteria such as response time requirement (i.e., deployment time for reserve providers to ramp up to scheduled reserve amounts) and sustained duration requirement (i.e., how long reserve providers must sustain output after ramping). In this context, A/S eligibility criteria refer to a predetermined set of performance metrics, encompassing both technical and regulatory requirements, utilized by U.S. ISOs/RTOs. These criteria serve as benchmarks for assessing performance and qualifying diverse resources for participating in A/S markets.

For example, the response time requirement for spinning reserve ($\kappa^{SPIN,response}$) is 10 minutes in all ISOs/RTOs, whereas the sustainability requirement is 60 minutes in most ISOs/RTOs (except CAISO and PJM, where it is 30 minutes). While the actual formulation for A/S provision may vary based on ISO/RTO rules and operating procedures, employing illustrations to depict how an ESR would need to provide energy over the entire A/S duration can aid in developing constraints to ensure feasibility.

Understanding these concepts through illustrations can provide additional insights into potential constraints on A/S schedules imposed by ESR's current SoC. Accordingly, future research should analyze implications of adequate SoC calculation on SoC feasibility.

4.3.3 Impact of Sustained Duration Performance Requirements for Ancillary Services on the SoC of ESRs and A/S Marginal Prices Under Different Reserve Models

Historically, A/S have been defined based on deployment triggers such as response speed and MW capacity, with an infinite supply of energy assumed to sustain the required MWs. However, with the increasing penetration of storage resources, industry surveys indicate a shift towards prioritizing the sustainability of A/S deployment from ESRs given their limited duration rather than response speed.

Several ISOs/RTOs have implemented minimum duration requirements for various A/S products. However, some requirements are based on traditional reliability standards or tariff language that may require a comprehensive re-examination given the changes in resource characteristics and other aspects. Looking ahead, markets may shift toward valuing reserve products designed for longer durations over those with faster responses but shorter durations.

Accordingly, future research must explore alternative scheduling and pricing options for A/S with ESRs to assess A/S provision and SoC management. In addition, there is a need to examine the implications of SoC depletion when relying on ESRs to provide these services with the aim of ensuring that ESRs can reliably deliver them when called upon.

Future research should also reevaluate the traditional pricing hierarchy for reserves, considering the duration requirements for these products. The debate revolves around whether the conventional order (i.e., five-minute regulation, 10-minute spinning, 10-minute non-spinning, and 30-minute replacement reserves) remains valid when considering the inverse relationship between duration and speed requirements, with longer duration requirements implying greater importance in future resource portfolios.

ERCOT is considering setting duration requirements for A/S, particularly non-spinning reserves, whose requirement was initially set at four hours by NPRR1096 [20] but is now set at one hour per NPRR1186[4]. Meanwhile, various ISOs/RTOs are contemplating adjustments to A/S definitions and performance requirements, as well as gaining insight into the factors influencing these requirements. For example, NYISO's "Balancing Intermittency" project is exploring updates to sustainability requirements for reserve products [21].

There is a pressing need for a paradigm shift in how reserve products are priced, particularly given the industry discussion around the impact of fuel- and duration-limited resources on energy adequacy. This pricing complexity increases when considering the multiple dimensions of interaction, such as varying sustainability requirements for different products or the introduction of new products with longer sustainability requirements. For instance, if a 60-minute reserve product has a sustainability requirement of four hours, should the resources designated for a 30-minute reserve also be eligible to fulfill the 60-minute requirement? Questions also arise regarding pricing. Should the 60-minute price establish a floor for the 30-minute price, and should prices be cascaded or remain independent in this new framework?

Understanding the impact on incentive compatibility for ESRs under this new framework is also crucial. These considerations are critical for future research and policy decisions in the energy sector, necessitating a comprehensive evaluation through detailed simulations and analysis of scenarios with non-intuitive results.

4.4 Miscellaneous Challenges

4.4.1 Price Formation in Renewables-Dominated Power Systems with ESR Participation

In contrast to conventional energy resources, for which current electricity markets were mostly designed, VRE resources have zero marginal cost of operation. Consequently, as renewables gain dominance in power systems, market clearing prices are expected to significantly change their trend compared to current patterns.

While market participants' initial concerns center on the potential collapse of wholesale electricity

[4] ERCOT, NPRR1186, *Improvements Prior to the RTC+B Project for Better ESR State of Charge Awareness, Accounting, and Monitoring*. [Online]. Available: https://www.ercot.com/mktrules/issues/NPRR1186#keydocs

prices, the increased integration of renewables may in fact lead to an increase in average prices due to a higher incidence of scarcity prices [22]. However, a rise in average prices may also be accompanied by much higher price volatility due to the occurrence of various periods with zero prices and sudden periods of price spikes, potentially impacting revenue sufficiency and therefore discouraging long-term investments in generation capacity [23]. Moreover, storage and renewable assets may have the opportunity to exert market power and substantially impact price formation in renewables-dominated power systems [24].

These issues are further complicated when zero-fuel-cost resources dominate the system and unique features of emerging technologies (e.g., SoC for storage) are integrated into market clearing. Scarcity prices, battery degradation costs, and opportunity costs are all expected to play a more significant role in price-setting. Additionally, specific price formation challenges related to ESRs need exploration, including better estimation of reference bids for market power mitigation and better accounting of battery degradation costs in market software and/or in offers. It might also be crucial to assess the continued use of day-ahead markets and other potential adjustments needed with fewer thermal resources on the system.

For long-duration ESRs, consideration should be given to whether providing price guarantees to ensure availability during peak conditions is necessary. In renewables-dominated power systems, a potential measure for reducing the risk of long-term investments in generation capacity is the inclusion of a long-term component in the remuneration of the assets. For instance, a long-term energy market could be combined with a real-time market as described in [25]. In this case, the long-term market would determine an amount of forward energy for a predefined time horizon ranging from months to years ahead, and the short-term market would determine final delivery location and timing.

In the long-term market, prices would form according to the long-term levelized costs of generation of their technologies and, in the short-term market, prices would relate to short-term locational costs, which can also include scarcity signals during shortage periods. Moreover, market power mitigation will require constant monitoring from regulators using metrics such as the Herfindahl-Hirschman-Index [26] to observe if mergers and acquisitions among storage developers and owners of renewable units could create market inefficiencies due to intentional behaviors.

4.4.2 Adequate Representation of Storage Degradation Within Market Clearing Software

Effectively integrating battery storage into electricity markets presents a challenge in accurately determining its marginal operation costs, which are predominantly driven by variable, nonlinear, temporally coupled, and usage-dependent battery degradation costs. Within existing market frameworks that allow battery storage participation, storage bids and offers do not explicitly represent different physical and operational characteristics such as the SoC, discharge rate, and degradation.

Existing market auction models typically overlook the lifetime capacity loss of ESRs due to deep cycling, which significantly impacts operational costs and may require a fundamental reevaluation of contemporary market auction models, especially in future portfolios with increased penetration of storage-based resources. Deep cycling can also lead to high replacement costs, necessitating appropriate consideration within market clearing software. However, such an implementation poses computational challenges, potentially requiring contemporary market auction models to be overhauled. Alternatively, the cycle aging cost may be factored in the economic bidding process with the aim of avoiding deep cycling occurrences, i.e., by integrating the cycling lifetime costs into the bid/offer curves developed by participants.

Recent studies have proposed two primary approaches to representing battery degradation in market clearing models. One involves creating charging/discharging bids, leveraging existing market and reserve interfaces to enhance revenue for storage operators [27]-[29]. The Rainflow algorithm, along with its various adaptations, has been extensively applied in numerous studies for estimating battery wear during energy arbitrage and frequency regulation activities. This algorithm uses the cycle depth stress function to quantify the degradation for each cycle based on the depth of discharge (DoD). The degradation cost for each cycle is derived from the cost to replace the battery. This cost is then factored into the objective function by employing a piecewise-linear function to simulate the battery's aging process accurately.

However, this approach faces challenges, especially for frequency regulation. Rainflow degradation models are typically trained on cell-level data that do not account for increased temperatures when providing regulation and often assume consistent cycling depth, thereby underestimating degradation. Future research should prioritize developing bid/offer strategies that more accurately incorporate lifetime loss due to deep cycling.

The second approach incorporates storage operation costs by explicitly introducing a usage cost based on battery physical and operational characteristics such as DoD and discharge rate [30]-[31]. In [30], a degradation cost function based on DoD and discharge rate was developed. Additionally, a detailed bid/offer structure based on the proposed battery storage operational cost functions is integrated into a mixed-integer linear program to obtain a bidding strategy in the energy and reserve markets. In [31], an empirical degradation model that uses charging/discharging current and state of energy dependencies is proposed to quantify and account for the non-linear degradation behavior of lithium-ion batteries in storage scheduling models.

Several research avenues warrant deeper investigation to address challenges associated with storage bids and offers by representing diverse physical and operational battery characteristics such as SoC, discharge rate, and degradation. These avenues include exploration of two-stage settlement bids/offers for strategic energy storage participation in electricity markets; addressing price forecast uncertainty in storage bid/offer design; and analyzing the impact of storage participants' price prediction strategies on market efficiency and market power.

Future research should evaluate the market implications of using similar approaches, with a particular emphasis on computational tractability, as well as the economic efficiency, reliability, and incentive compatibility of the resultant market auction models.

4.4.3 Market Participation Models for Long-Duration Energy Storage

Various entities including companies, cities, states/provinces, and the U.S. administration have established goals or policies to decarbonize the electric sector or achieve net-zero emissions. Researchers and industry professionals exploring net-zero pathways have recognized a need for firm, dispatchable, zero- or low-carbon technologies to supply energy over extended periods when VRE output is low. Studies indicate production gaps may occur between intermittent renewables, short-duration batteries, and existing hydropower and nuclear resources.

Emerging solutions to address these gaps include long-duration energy storage (LDES), hydrogen, renewable natural gas and other low-carbon fuels, seasonal storage technologies, new nuclear, and carbon capture and storage. LDES could store energy across days, weeks, or even seasons from times of wind and solar abundance to times of critical need. Additionally, LDES can provide a range of valuable services to decarbonized power systems including clean dispatchable energy capacity, reliability, resilience, congestion relief, and transmission and distribution investment deferrals [32].

However, critical challenges remain for the substantial adoption and participation of LDES technologies. For instance, it is unclear whether these technologies can integrate seamlessly into existing market participation models within electricity markets or if their unique characteristics will pose new challenges and require the introduction of new participation models and market features to ensure efficiency and reliability. In most ISOs, hydropower resources often employ thermal participation models, wherein owners typically embed their long-term opportunity costs into bids. Devising offer strategies is therefore important to hydropower owners, who rely on their own tools to do so. For LDES, key questions relate to quantifying opportunity costs over extended periods (e.g., multiple days or weeks), as the SoC cycle in LDES systems can extend well beyond a single day, posing challenges for current market clearing processes which typically operate on a 24-hour horizon.

Different options exist for integrating LDES into electricity markets. One potential solution to enhance the market clearing process is to assign a value (in $/MWh) to the SoC of LDES systems at the end of a 24-hour horizon [33]. In this case, an LDES system would charge or discharge depending on the difference between the current energy price and the end-of-horizon SoC value. The key concern with this approach, however, would be appropriately determining this end-of-horizon SoC value, as it significantly impacts the solution. This approach essentially requires optimizing LDES operation over a longer timeframe in advance of the day-ahead timeframe – possibly weeks or even months ahead – and prompts consideration of the need for an extra decision-making stage that is run multiple days, weeks, or months ahead and seeks to accommodate and optimize such technologies.

Another approach to including LDES in the market clearing process would be to arbitrarily impose an end-of-horizon SoC target for each day [34]. Targets could be based on optimization procedures that consider longer horizons with potentially less detailed operational representations.

A third approach would be to extend the horizon of market clearing processes beyond 24 hours, which would entail a significant increase in computational burden to obtain a solution, as well as a greater reliance on ISO data and prices. Other concerns stem from the possibility that additional settlement procedures would need to be developed. Necessary modifications for planners, system operators, and market operators will need to be explored to enable the integration of LDES technologies.

There are several tradeoffs with using existing market features vs. introducing new features that require conducting detailed market simulation studies to better assess how to address integration challenges, evaluate potential market implications, and determine practical paths forward. Additional research is warranted to explore these topics and prompt discussion of how ISOs and the industry can proactively prepare to integrate these “gap resources” without jeopardizing reliability.

4.4.4 Market Power Mitigation Approaches for Storage-Based Resources

Designing market power mitigation approaches for storage-based resources involves identifying and addressing the potential misuse of market power. This includes comparing a resource’s offer to an estimate of its short-run marginal cost, called the “reference level,” and mitigating offers exceeding this level. The reference level serves as a competitive offer set by the ISO to better reflect a resource’s short-run marginal costs.

Determining short-run marginal costs for traditional resources with minimal fuel supply constraints (e.g., thermal resources) is straightforward, relying on factors such as fuel costs and variable O&M expenses. However, determining these costs for energy-limited resources – which are constrained by factors like regulatory requirements (e.g., air permits), physical restrictions (e.g., duration and reservoir capacity), or fuel limitations – is challenging.
In energy markets, the short-run marginal costs for energy-limited resources mainly comprise opportunity costs, necessitating an adequate capture in their reference levels. Generally, opportunity costs may consider different horizons varying from several days to a year, or other factors such as expenses related to meeting emissions regulations, water storage restrictions, seasonal river flows, storage capacity, and other operational permits restricting energy production.

In CAISO, for instance, the reference level for storage resources includes expected energy costs, variable operation costs, and opportunity costs, with a 10% increase [35]. In contrast, ERCOT lacks a method for quantifying opportunity costs, instead using mitigated offer caps based on adjusted previous prices observed at the storage resource’s location [36]. This temporary approach aims to roughly address the complexities until a more precise method is developed. NYISO estimates dynamic opportunity costs for a storage resource on a daily basis to establish its reference level. This dynamic opportunity cost is based on the previous 30-day history of available locational-based marginal prices (LBMPs) for the day-ahead market, adjusted for fuel price changes; and the day-ahead LBMPs from the current market day for the real-time market [37].

Future research should devise better approaches to estimating reference levels for storage-based resources, ensuring transparency and standardization in calculations. Such approaches will enable RTO/ISOs to optimize the utilization of these resources efficiently, while fostering competitive outcomes. Doing so necessitates detailed comprehension of the associated costs and operational constraints, including consideration of the impact of excessive cycling on battery storage warranties, through the incorporation of opportunity cost adders.

Further, it is important to note that not all storage-based resources are utilized solely for energy price arbitrage. It is therefore crucial to avoid misjudging the actual opportunity costs for these resources by assuming a single use case application. Allowing market participants the flexibility to estimate their own opportunity costs, subject to verification by market monitors, could prove beneficial since they possess the most pertinent information for such assessments, such as forecasts of future energy prices and relative compensation including non-ISO revenues [38].

Further investigation is also needed in another realm, which concerns accurately estimating reference bids for mitigation during extreme events characterized by tight supply conditions. This is important because ESR opportunity costs during such occurrences exceed normal conditions due to exceptionally high market clearing prices [5].

4.4.5 Modeling Storage as a Transmission Asset

MISO, SPP, and ISO-NE allow the participation of Storage as a Transmission-Only Asset (SATOA), in which storage is dedicated to performing a specific transmission function or resolving the transmission system issue for which it was built (i.e., as the identified preferred solution in a transmission study) [39]-[41]. SATOAs are controlled by the system operator and can recover costs through transmission rates akin to traditional transmission assets [42].

However, strict operational guidelines govern SATOAs, which are considered price takers and largely disallowed from participating in ISO/RTO markets. This restriction from providing market services or participating in resource adequacy or capacity markets aims to prevent dual recovery of costs via both cost-of-service rates and market-based rates, thereby minimizing market impacts. Moreover, in MISO, for instance, SATOAs planned for reliability purposes are not deployed to alleviate congestion unless all other market mechanisms have been exhausted [39]. Nonetheless, such storage projects may be utilized to prevent load shedding during declared emergency conditions [39].

Future research should assess the implications of allowing storage to participate both as a transmission and a market asset, which some ISOs/RTOs plan to explore. Such assets are more commonly referred to as Storage as a Transmission Asset (SATA). Evaluation should account for system, ratepayer, and asset owner perspectives, ensuring adequate safeguards to prevent double cost recovery and mitigate adverse market impacts while developing better ways to predict the size and time of transmission need.

Enabling SATA dual participation requires investigating several important factors: addressing generator interconnection issues (to operate as a market resource); refining operating practices to allow further market participation by better predicting the transmission need the SATOA is currently addressing; enhancing emergency procedures to specify which obligation is dominant and when; developing ways to prevent double compensation; and upholding ISO/RTO independence. Moreover, attributing costs of asset degradation due to market activities and cost allocation for resource use also needs attention. Future research should also examine the implications of increased SATOA penetration, compensated through cost-of-service rates, on locational marginal prices for energy and ancillary services marginal prices, potentially leading to price suppression.

4.4.6 Accrediting the Capacity Contribution of ESRs to Resource Adequacy

Nearly every market region is exploring new ways to determine the capacity contribution of different technologies toward resource adequacy needs. This accreditation value usually represents a capacity that is derated from the maximum capacity a resource can inject onto the grid (or, in some cases, withdraw from the grid). This value is determined based on the available energy a resource can provide during the highest-risk time periods. Determining this value for ESRs involves significant complexity.

Historically, calculating the accreditation of thermal generators has been straightforward and was determined by the thermal resource's historical forced outage rate. For variable renewable resources like wind and solar, accreditation values have typically been calculated using past production during the highest load, or net load, periods. These methods did not require making assumptions about how resources might be operated or how they might participate in markets.

With storage resources, however, it is difficult to quantify their contribution without making operational assumptions and simulating the operational time frame of those critical periods (or more likely, all hours of multiple years). This is because storage operations determine likely charge and discharge periods as well as ability (based on state-of-charge) to provide maximum energy during critical periods. Probabilistic metrics based on multi-year, hourly chronologic simulation tools are starting to become more widely used for calculating these values, not just for ESRs but also for other technologies.

FERC Order 841 requires that accreditation methods allow a derate for ESRs to be counted for capacity. For example, if a requirement specified four hours of energy state-of-charge to provide and sell capacity, a two-hour battery would be eligible to provide half its discharge capacity to meet the four-hour requirement (as opposed to being ineligible altogether). Duration requirements in capacity markets and resource adequacy calculations were determined via historical knowledge of peak conditions or via studies. In regions such as PJM and SPP, probabilistic metrics such as marginal effective load carrying capability (ELCC) are increasingly being used for energy storage. These metrics can better capture ESRs' contribution during high-risk periods and allow more equitable treatment across resource types.

Additional ESR characteristics may need to be considered, particularly at higher penetrations. For example, the ESR's efficiency loss, or round-trip efficiency value, may impact its contribution. Minimum state-of-charge may also need accounting for, as it can limit how much energy a resource could supply before it stopped discharging (even if energy were still available). Degradation costs may also impact ESR operation. For hybrid and co-located ESRs, several other factors (e.g., coupling arrangement, over-paneling practice for solar, ability to charge from the grid, and capacity ratio) all may impact the combined facility's overall contribution.

Detailed market operations and specific market designs are typically ignored when processing resource adequacy studies or accreditation studies that compute metrics such as ELCC. In particular, the impact of short-term, net load forecast uncertainty is rarely considered. For example, if a day-ahead forecast error led storage operators and/or system operators to misjudge an upcoming critical time period, this could significantly impact the ability of ESRs to contribute to the actual critical period. However, these studies are performed for a future point in time when such granular data may be inaccurate.

Many other discussion areas in this paper can also impact the capacity accreditation of ESRs, depending on how they are considered. For example, the limited time window of CAISO's real-time market led to confusion during a September 2022 heat wave, during which ESRs may not have had the incentives or knowledge to keep stored energy beyond the real-time market horizon [5] [43]. Price caps and shortage pricing can also be a factor with ESR capacity accreditation.

Knowledge of these factors and determination of relevant characteristics and system features will be important for planners seeking to improve the overall accuracy of ESR accreditation values. At the same time, planners must acknowledge the computational limits of simulation studies and accuracy of the input data.

Table 5. Duration Values and Accreditation Methods for ESRs in U.S. Electricity Market Regions [44]

Region	Resource Adequacy Contribution
NYISO	Low penetration (< 1000 MW): ≥ 6hr, 100%; 4hr, 90%; 2hr, 45% High penetration (≥ 1000 MW): ≥ 8hr, 100%; 6hr, 90%; 4hr, 75%; 2hr, 37.5%
PJM	2023/24 Base Residual Auctions (BRA): FERC approved an ELCC construct for capacity accreditation of ESRs in various duration classes (10hr, 100%; ≥ 8hr, 100%; 6hr, 98%; 4hr, 83%)
SPP	ELCC for determining capacity credit for summer 2023: > 4hr prioritized first; 4hr, 100% accreditation based on 4-hr curve for ESR penetration level; 2hr, 50% accreditation based on 4-hr curve for ESR penetration level. 4 sustained hours needed to meet RA requirements
ISO-NE	2 sustained hours
MISO	4 sustained hours
CAISO	4 sustained hours for RA participation For 2024–2027 compliance: 2024: 89% for 4 hr, 89% for 8 hr 2027: 85% for 4 hr, 90% for 8 hr

5. Key Takeaways and Forward Path

Integrating greater amounts of ESRs necessitates significant enhancements in modeling capabilities and various aspects of wholesale electricity markets to maintain economic efficiency, system reliability, and incentive compatibility. In this context, market operators were surveyed to identify and prioritize key areas that demand further research. This report detailed the challenges of integrating ESRs in the day-ahead and real-time energy and ancillary services markets, and it proposed solutions drawn from both academic and industry literature.

Real-time Market Challenges: The consensus among survey respondents is that most ESR research and development should focus on real-time markets, particularly on multi-interval real-time security economic dispatch (RTSCED) problems. In theory, multi-interval RTSCED models generally enhance reliability and lead to decreased production costs, but they often encounter challenges related to computational complexity and incentive compatibility. Even multi-interval models currently consider much shorter horizons in real-time, and this shortsightedness can lead to suboptimal decisions and reliability risks. While options for addressing these challenges have been proposed, each comes with complexities and trade-offs that warrant further study.

Ancillary Services Concerns: Effective SoC management is crucial for ESRs to reliably provide A/S when called upon. Market representatives agree on the necessity of developing robust approaches to ensure feasible A/S provision while adhering to SoC technical constraints. About half of surveyed representatives believe that enhanced energy representation could be beneficial. Meanwhile, CAISO and ERCOT are addressing this issue by imposing SoC requirements on ESRs offering A/S, as detailed in Subsection 4.3.

Day-ahead Market Challenges: Several challenges in the day-ahead market relate to SoC management and time granularity. To accommodate the growing number of ESR market participants, improvements in computational efficiency and/or improved modeling approaches are needed enable ISO SoC management modeling. Additionally, more precise ESR modeling in reliability unit commitment and enhanced energy representation may be required to ensure feasible and more accurate computation of SoC levels. Although the hourly granularity in day-ahead markets may not be sufficient to adequately inform storage dispatch, this issue is currently of lower priority for most surveyed participants.

5.1 Priorities for impactful near-term research

Based on input from U.S. ISO/RTOs and the state of existing research, we identify the following five topics as the highest priority gaps for immediate modeling and analysis research:

1. Approaches to augmenting incentive compatibility of multi-interval real-time security-constrained economic dispatch problems for ESRs through enhanced price formation and other market enhancements.
2. Impact and feasibility of ancillary services on SoC management.
3. Computational and/or modeling improvements to simplify SoC management of ESRs by the ISO/RTO in day-ahead markets.
4. Adequate representation of ESR degradation within market-clearing software.
5. The impact of different SoC management options for ESRs in real-time markets.

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