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# Incorporating Electric Storage Resources into Wholesale Electricity Markets While Considering State of Charge Management Options

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## SUMMARY

The Federal Energy Regulatory Commission (FERC) issued Order 841 in 2018. FERC Order 841 directs the U.S. independent system operators (ISOs) and regional transmission organizations (RTOs) to incorporate appropriate modifications to their market design rules and market clearing software to enable an enhanced participation of electric storage resources (ESRs) in energy, ancillary services (A/S), and capacity markets. One specific requirement within the FERC Order 841 necessitates that each ISO provide ESRs with the option to self-manage their state of charge (SOC) and not impose ISO management of SOC as a requirement. Self-management of SOC implies that it would be the ESR asset owner's responsibility to ensure that its SOC levels are feasible based on how it offers into the electricity markets. An ISO can potentially provide the option to manage the SOC of an ESR, but it must be up to the ESR asset owners to choose that option. This specific requirement is in alignment with the allowance of self-scheduling for conventional resources; however, at certain penetration levels of ESRs, it will become important for an ISO to evaluate the feasibility of an ESR's SOC from a reliability perspective. This warrants innovation and research to ensure ESRs can be modeled and captured appropriately in ISO market clearing software in a reliable and economically efficient manner. There are numerous ways in which the characteristics of ESRs can be incorporated into electricity market design and market clearing software; therefore, it is crucial to evaluate the different design options that are currently being proposed and those that are close to implementation. This study provides specific examples of those implementations including, but not restricted to, contemporary designs prior to the recently proposed changes, a review of Order 841, an overview of market design proposals filed by U.S. ISOs and RTOs to address the rulings from Order 841, and a comprehensive evaluation of the different SOC management options. Although there are many common proposals in place, certain unique aspects proposed by some ISOs provide useful insights.

This study focuses on incorporating ESRs into wholesale electricity markets and evaluating the potential implications of greater levels of ESRs on the operation of wholesale electricity markets. To this end, the study conducted detailed simulations and analyses to understand the implications of higher levels of ESRs participating in wholesale electricity markets with different options to manage and optimize ESR schedules given their unique SOC constraints. Furthermore, the study provides both formulaic and quantitative insights into the ways in which the different SOC management options can be implemented. Results provide key insights on the potential outcomes, e.g., economic efficiency and reliability outcomes, and SOC feasibility outcomes, for different levels of ESRs, different levels of variable energy resources or renewable energy resources, different SOC management options, and different SOC duration capacities. All numerical results are based on a modified IEEE 73-bus test system (reliability test system 1996, RTS 96). The modifications to the test system were made by the Grid Modernization Laboratory Consortium (GMLC).

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The results show that the ISO SOC management option has greater economic advantages from both the ISO’s perspective and the ESR’s perspective; however, this option is found to be computationally more expensive by most ISOs. In addition, self-management of SOC without SOC feasibility constraints from the ISO is also found to be an acceptable option at lower but not higher ESR penetration levels because SOC infeasibility can lead to economic and potential reliability consequences unless offer strategies or other implementations are improved. The potential implications and promising features of a third hybrid SOC management option – SOC management lite option – between the ISO SOC management option and the self SOC management option are also discussed. The SOC management lite option allows more of the offering strategy to be in the hands of the ESR asset owners while still ensuring SOC feasibility. Future phases of this research will continue to evaluate emerging technology, such as hybrid resource technology (e.g., ESR plus wind/solar), participation in wholesale electricity markets, real-time (RT) re-optimization and SOC management, A/S provision and SOC management, and other possible new designs that will have to be validated as the ISOs accommodate more ESRs on their systems.

## KEYWORDS

Ancillary services, electricity market design and operations, energy storage, price arbitrage, state of charge, state of charge management, wholesale electricity markets.

## 1. DESIGNS TO INTEGRATE ENERGY STORAGE IN MARKET OPERATIONS

There are a variety of ways in which the characteristics of ESRs can be included into electricity market design and clearing software. This section provides a detailed review of the state-of-the-art in ESR participation in electricity markets including the existing designs prior to recent changes related to Order 841, directions of Order 841, and a summary of the proposals filed by each of the ISOs to meet Order 841.

### *1.1. ISO Existing State-of-the-Art in Energy Storage Market Modelling (prior to FERC Order 841)*

Many of the ISOs had some of the unique characteristics of ESRs already incorporated within its market design prior to the changes proposed to meet Order 841. Specifically, ISOs had designs for pumped storage hydro (PSH) participation in their energy, A/S, and capacity markets. PSH could offer in as a generator for hours in which it wanted to generate (discharge) and bid in as a load resource in hours in which it wanted to pump (charge). The PSH plant would provide an offer (price/quantity) curve that was used by the ISO to determine the plant's commitment and dispatch. The ISO would then commit the resource to the mode that was offered for the corresponding hour or keep it online or turn it offline. This design was specific to the day-ahead market (DAM) and there was typically not an option (other than self-commitments) to change the commitment after day-ahead (DA). In PJM, a separate optimization model (i.e., pumped hydro optimizer) is utilized as part of their DA unit commitment process. Here, PSH would not provide an offer curve, but would provide its roundtrip efficiency and its desired SOC (e.g., reservoir level) at the end of the 24-hour DA horizon. PJM software would then determine its operating mode (generating, pumping, or offline) and dispatch level based on reducing costs and meeting the ending SOC level. Here, the ESR does not need to select the hours to operate in each mode nor does it need to determine an offer curve for its energy. In real-time (RT), the schedules of these units are supposed to follow the DA solution; the decisions that were made in the DAM are not to be changed in RT except for unique situations. Other ISOs have begun to include maximum daily energy limits that can be used for other technologies and not just ESRs (e.g., for emissions limits). These can be used similar to PJM's pumped hydro optimizer, but the other ISOs had only used them for a single mode (e.g., only generating). In CAISO's existing non-generator resource (NGR) model, an ESR with a continuous dispatch range could provide an offer curve from maximum charging limit to maximum discharging limit; the market clearing engine treats ESRs similar to traditional generators, but the offer curve also considers the cost willingness of the ESR to consume on the same offer curve as its offered cost to supply energy.

Outside of the above options, ESRs have had limited ways to participate in the ISO markets for energy provision primarily through existing generator and demand response participation models. However, significant market design and software changes were made to incorporate ESRs in certain A/S markets, primarily the regulating reserve market. Regulation reserve is used to balance variations within the 5-minute time frame and utilizes automatic generation control (AGC) as the software that determines the control signals. Recently, AGC algorithms have been modified to either send a high-frequency signal to ESRs and other fast responding resources, or strictly provide SOC management (SOCM) through the AGC so that the AGC would explicitly maintain the SOC of ESRs to certain levels and not deplete available energy stored. For instance, PJM uses the dynamic regulation signal (RegD) for fast resources. This signal controls the faster component of the area control error (ACE), versus the traditional regulation signal (RegA) that is used for the slow component of ACE. NYISO explicitly manages an ESR's SOC in AGC, where the AGC model will transfer regulation deployment from limited-energy storage resources to other suppliers when metered energy storage is approaching limits [1]. These existing participation models have been a product of stakeholder processes, current software functionality, and levels of ESRs and other technologies within each of the footprints. It can be seen through the future subsections that such designs will see significant changes based on the ISO proposals made in 2018, which will be implemented in late 2019 and beyond.

### *1.2. FERC Order 841 on Energy Storage Participation in ISO/RTO Markets*

FERC initiated a proceeding on ESR participation in ISO markets in 2016 with a notice of proposed rulemaking [2]. After receiving substantial comments from the industry, FERC issued its final ruling in 2018 [3]. This subsection describes the ruling's main requirements and how they may impact the ISO market designs:

1) ISOs must include a participation model for ESRs that allows them to participate in energy, A/S, and capacity markets when technically capable of doing so. ESRs should also be eligible to provide those services that the ISO currently does not procure through organized markets.
2) ESRs must be able to set wholesale price as both a buyer and seller when it is a marginal resource. Thus, ESRs may set the price when charging when they are the marginal buyer (the next increment of fixed load increases will result in a reduction in the ESRs charging load) and the price would be set to the bid the ESR provided as its willingness to buy energy or equivalent. Other price setting criteria for existing resources still apply: when ESRs self-schedule their output or are scheduled at their minimum output they cannot set price. ESRs must also be able to set the price for A/S markets and capacity markets when marginal.
3) ISOs must account for physical parameters of ESRs through bidding or otherwise (including telemetry). This includes a list of 13 parameters that must be provided to the ISO, i.e., state of charge (SOC), minimum and maximum SOC limits, minimum and maximum charge and discharge limits, minimum and maximum charge and discharge/run times, and charge and discharge ramp rates.
4) ISOs must establish a minimum size requirement of 100 kW for ESRs (for all services).
5) ISOs must specify that the sale of energy from ESRs that was previously purchased and stored for later use by the ISO must be at wholesale prices. Nodal price must be used for both selling and buying power to prevent gaming between nodal and zonal pricing differences.
6) Make-whole payments must be provided for ESRs when dispatched as a generator and price is lower than offered cost, and when dispatched as a load and price is higher than bid.
7) ISOs must allow self-management of SOC. ISO-management of SOC is not required. This is an important component of the Order, and one that is of high relevance to the studies conducted in this paper. As part of the self-management requirement, ESRs would be subject to financial penalties for uninstructed deviation when managing their SOC and not providing energy schedules due to running out of SOC.

FERC defined ESRs as “a resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid”. Hybrid resources (e.g., solar plus storage) are not given any special treatment but may participate through the ESR participation model. ESRs do not necessarily have to use the new “storage participation model” that the ISO would establish and may continue to use existing participation models (e.g., PSH, demand response models). ISOs must have market rules in place to prevent its software (unit commitment and economic dispatch) from selecting ESRs to simultaneously charge and discharge in the same interval. For capacity markets, ESRs should be allowed to de-rate to meet the minimum continuous supply requirements instead of not being eligible. For A/S markets, FERC was not requiring any modification to rules to allow ESRs to provide A/S without an energy offer but encouraged ISOs to allow this for some A/S. Transmission charges that are typically applied to load can also apply to ESRs while charging, but not if the ESR was charging as a “service” to the ISO. ISOs must implement new metering and accounting practices that allow for wholesale buying and selling from ESRs.

### *1.3. ISO/RTO ESR Market Design Proposals and Implementations in Response to FERC Order 841*

This subsection provides a comparison across the ISOs with a concise review of all the common market design proposals and those which are unique to one or few of them to comply with Order 841. More detailed accounts of the proposed market designs can be obtained from [4].

***Participation Model.*** Most of the ISOs have proposed two separate participation models for continuous (e.g., batteries) and discontinuous (e.g., PSH) ESRs. ESRs can participate in energy, A/S, and capacity markets in all ISOs. PJM has a unique modeling option for PSH; PSH can participate in PJM’s energy markets either by self-scheduling or by using its pumped hydro optimizer (DA only) but are required to submit zero-cost offer curves, are disallowed from setting wholesale prices and offering negative dispatchable range. NYISO and SPP have restricted PSH from submitting a charge and discharge offer in the same hour, but CAISO is allowing the submission of both charge and discharge offers in the same hour.

***Offer Parameters.*** Almost all ISOs have proposed a continuous model for ESRs with the eligibility to submit a continuous offer curve that excludes commitment related parameters, e.g., no-load and start-up costs, minimum and maximum charge and run times (to be managed by ESR owners). PJM requires ESRs to submit RT SOC telemetry only for situational awareness, whereas a few of the other ISOs require the submission of SOC parameters, e.g., start SOC in DAM, RT SOC telemetry, roundtrip efficiency, SOC limits. ISO-NE requires ESRs to provide two new telemetry points in RT, i.e., available energy and available storage, that will account for an ESR's maximum charge and run times; minimum charge and run times are required parameters in ISO-NE's DAM and real-time market (RTM).

***Ancillary Services.*** All ISOs are allowing ESRs to provide A/S (without requiring energy schedules; SPP requires energy offers but not energy schedules) provided ESRs meet the corresponding duration requirements while allowing for capacity de-rates to meet the duration. NYISO will restrict ESRs from providing non-spinning reserve (ESRs can instead opt to provide a higher quality reserve that has higher marginal prices) given their proposed dispatch only participation model that fixes the commitment status to available. Also, A/S schedules will respect RT telemetered SOC regardless of SOCM mode. ISO-NE has restricted binary storage facilities (BSFs) from providing regulation as dispatchable asset related demand until January 2024. ISO-NE is unique in that it has proposed to automatically de-rate the maximum charge/discharge limits for continuous ESRs to meet the duration requirements but not for BSFs (who have the option to instead phone the ISO to de-rate; note the provision of reserve downflag for limited duration ESRs). Finally, MISO has stated that regulation deployment by ESRs should respect SOC limits.

***Capacity Market.*** All ISOs will allow ESRs to de-rate their capacity to meet the minimum continuous supply requirements; however, note that NYISO requires ESRs to choose ISO-Managed Energy Level mode in its DAM offer if participating in its installed capacity (ICAP) market. Although SPP and CAISO do not have a centralized capacity market, they have proposed to allow ESRs to de-rate their capacity to meet their corresponding resource adequacy duration requirements.

***State of Charge Management.*** CAISO will allow for both ISO-SOCM and Self-SOCM. ISOs that are offering only Self-SOCM are ensuring SOC feasibility excepting PJM. PJM has proposed Self-SOCM only for continuous ESRs (PJM excludes an explicit consideration of SOC limitations; ESR owner is responsible to ensure the feasibility and optimality of SOC) while it essentially has already had an ISO-SOCM option for PSH. NYISO has restricted PSH from electing ISO-SOCM. SPP has proposed Self-SOCM but will incorporate some SOC constraints in its scheduling and dispatch models to ensure feasible levels (start SOC, calculate SOC using ESR loss factor and SOC limits), which is analogous to the SOCM-Lite option detailed in the next section. However, note that parameters such as maximum daily energy limits will continue to exist for ESRs in SPP to reflect its energy limitations in the DAM and reliability unit commitment. ISO-NE has proposed Self-SOCM but will consider two newly proposed telemetered points in RT that will account for SOC and SOC limits. ESRs will be allowed to submit its maximum daily energy limit in ISO-NE's DAM. MISO has proposed Self-SOCM but will incorporate SOC, ESR efficiency factor and respect SOC limits. MISO will include the maximum daily energy limit only for PSH. NYISO has proposed SOCM-Lite and Self-SOCM for ESRs.

## 2. STATE OF CHARGE MANAGEMENT

This section provides a brief review of SOCM, the market clearing simulation tool used in this study, the modifications made to enable the tool to perform the different SOCM simulations, the simulation setup and the description of the case studies, and the results of those case studies that focused on the DAM. A more detailed account of the SOCM study can be obtained from [5]. This section also provides the mathematical formulations used in this study. The goal is to incorporate ESRs into wholesale electricity markets in an efficient and reliable manner and to provide both formulaic and quantitative insights into the ways in which this can be done. The main characteristic of ESRs explored in this research is its SOC limitation since it has a significant impact on the quantity of energy, capacity, and A/S that the ESR is able to sell.

### *2.1. State of Charge Management Introduction*

Before describing the various modeling efforts, it is first worthwhile to review what is meant by SOCM, the different SOCM options, and the potential impacts on different aspects of market design and market clearing software. SOCM can mean different things to different organizations. In the power system sector, the term was historically used as part of the AGC function. A few ISOs would manage the SOC of ESRs providing regulation by explicitly monitoring the telemetered SOC and providing regulation control signals (based on system ACE) that would maintain a desired SOC. SOCM in AGC ensured that, given the random movements, ESR would still maintain a SOC as desired and that was feasible. However, the provision of energy in DAM and RTM is not quite the same as the deployment of regulation through AGC. There is not a definitive statement within Order 841 on what SOCM means resulting in different interpretations. At least two of the ISOs issued requests for clarification based on confusion that FERC both directed that SOCM by the ISO not be needed while at the same time requiring certain bid parameters such as SOC, maximum and minimum SOC to be provided by ESRs. Based on observations including filings by the ISOs and the research presented in this section, EPRI provides a slightly modified definition of the terms to provide a broader interpretation. *ISO-SOCM* – The ISO monitors current SOC, anticipated SOC, and other related ESR parameters (e.g., round-trip efficiency) and makes scheduling decisions that explicitly lead to a desired and feasible SOC at all times. *Self-SOCM* – ESR owners provide cost/quantity offer curves that, to the best ability of the owner, lead to desired and feasible SOC at all times without the need for explicit ISO intervention. *Figure 1* shows the different SOCM options with more responsibility lying with the ESR owner as one moves left, and more scheduling responsibility with the ISO as one moves right.

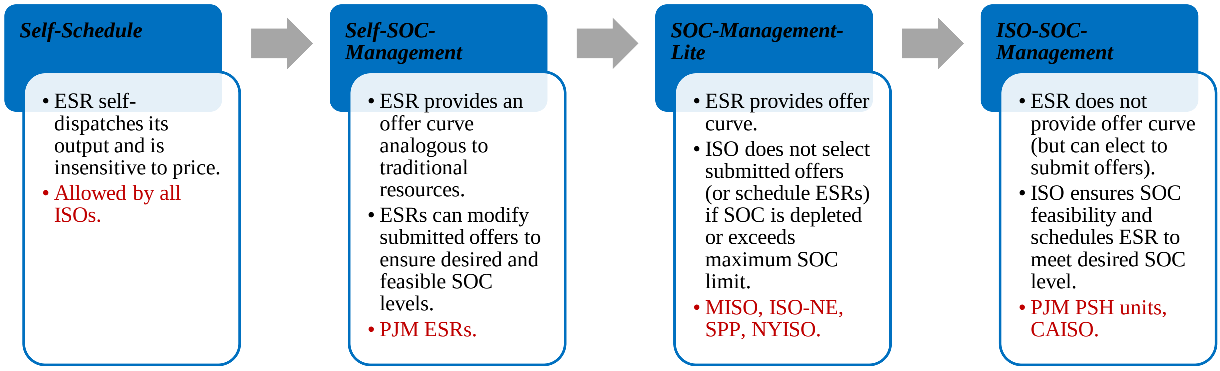


**Figure 1.** ESR SOCM options, with more management responsibilities from the ESR (ISO) toward the left (right)

The *Self-Schedule* option is the most basic form of market participation. Just like other generators, the ESR can explicitly put in energy schedules for each market interval and the ISO will schedule the ESR at that desired output regardless of conditions or prices (except during emergencies). This actually has an advantage in that it is fairly straightforward for the ESR to ensure SOC is feasible given the schedules are known before the market solution is complete. However, this means the ESR owner may be scheduled in a way that is inconsistent with prevailing prices and conditions and can lead to inefficient solution for the ESR and for the system. The *Self-SOCM* option is when the ESR now provides an offer curve (price in $/MWh and quantity in MWh) from maximum charging (furthest negative it can go when withdrawing) to maximum discharging (highest power injection it can provide). The offer curve can be piecewise linear monotonically increasing with the values reflecting the price at which the ESR is willing to pay when in the negative part of its curve, and the price at which it is willing to sell when in the positive part of its curve. SOC and related parameters are not needed by the ISO but may still be monitored for situational awareness or emergency reasons. The ESR owner may use a bidding strategy with its offer curve to ensure it reaches desired SOC levels throughout the scheduling horizon and a feasible SOC within minimum and maximum SOC limits. It is possible that the ESR owner offers a power output range within its offer curve that is less than its full range to ensure it does not get scheduled at power outputs that may result in infeasible SOC levels, e.g., if the ESR is at 10% SOC, is a 50 MW resource, but operating in the next interval at anything above 35 MW will result in an undesirably low SOC, it may only provide an offer curve up to 35 MW. It may also do this by including offer prices in that part of its offer curve that would make it unlikely to be scheduled. It may put a $1,000/MWh price paired with the energy output between 35 and 50 MW discharging. The option of how this is done may be up to ISO market design rules and physical withholding interpretations. *SOCM-Lite* is an option that is being proposed by some ISOs and may be a response to the two statements in Order 841 mentioning that *ISO-SOCM* is not required but that the ISO must consider an ESR's SOC and SOC limits as parameters that account for the ESR's operational characteristics. Here, the ESR uses a similar offer curve as in the *Self-SOCM* option, but the ISO monitors the SOC and ensures that the SOC levels are feasible. The ISO does not ensure that the SOC is optimal or set to desired levels. Lastly, *ISO-SOCM* is where the ISO uses SOC parameters to calculate SOC and bring it to both a desired and a feasible level. Here, no offer curve is necessarily needed (can potentially be combined), and the ISO schedules the ESR to ensure its SOC is within limits while also bringing the SOC to desired levels, as requested by the ESR through bidding parameters or otherwise, at the end of the market horizon, and potentially other times throughout the horizon.

The different SOCM options can have different implications for reliability, economic efficiency, SOC feasibility, optimization in RT, price setting, market settlements, make-whole payments, market mitigation and withholding, and computational efficiency. The impacts are not clear cut and may be dependent on the detailed design of each option as well as the offering strategies being made by the ESRs. A few basic case studies are provided in the subsequent subsections to present the potential outcomes for reliability and economic efficiency metrics; however, a more comprehensive description of the SOCM options, offer strategy development (including mathematical formulation) by ESRs when self-managing its SOC, and the aforesaid far reaching implications of the different SOCM options are provided in [5].

### *2.2. ISO/RTO Market Design Modifications to Model ESRs in its DAM Clearing Software*

A minimalistic representation of an ISO's day-ahead security-constrained economic dispatch (DASCED) problem, wherein the ISO manages the SOC (ISO-SOCM) of the system's ESRs, is detailed below. The detailed formulation only includes equations that are related to the subset of ESRs (indexed by $k$) for the sake of simplicity, discussion, and ease of understanding; however, in actual practice, an ISO's DASCED formulation will include additional equations that correspond to other resource types and other system constraints.

$$\underset{G_{k,t,i},L_{k,t,i},R^R_{k,t},R^S_{k,t}}{\text{Minimize:}} \sum_{k,t,i}\left(c^G_{k,t,i}G_{k,t,i} - c^L_{k,t,i}L_{k,t,i}\right) + \sum_{k,t}\left(c^{Reg}_{k,t}R^R_{k,t} + c^{Spin}_{k,t}R^S_{k,t}\right) \quad (1)$$

Subject to:

$$-G_{k,t,i} \geq -\overline{GM_{k,t}}G^{max}_{k,i} \quad \forall k,t,i \quad (2)$$
$$-L_{k,t,i} \geq -\overline{LM_{k,t}}L^{max}_{k,i} \quad \forall k,t,i \quad (3)$$
$$-R^R_{k,t} \geq -R^{R,max}_{k,t} \quad \forall k,t \quad (4)$$
$$-R^S_{k,t} \geq -R^{S,max}_{k,t} \quad \forall k,t \quad (5)$$
$$-\sum_i\left(G_{k,t,i} - L_{k,t,i}\right) - R^R_{k,t} - R^S_{k,t} \geq -\overline{GM_{k,t}}MaxD_k \quad \forall k,t \quad (6)$$
$$\sum_i\left(G_{k,t,i} - L_{k,t,i}\right) - R^R_{k,t} \geq -\overline{LM_{k,t}}MaxC_k \quad \forall k,t \quad (7)$$
$$\sum_{k,i} G_{k,t,i} - \sum_{k,i} L_{k,t,i} = \overline{D}_t \quad \forall t \quad (8)$$
$$\sum_k R^R_{k,t} \geq \overline{Reg_t} \quad \forall t \quad (9)$$
$$\sum_k R^S_{k,t} \geq \overline{Spin_t} \quad \forall t \quad (10)$$
$$SOC_{k,0} = SSOC_k \quad \forall k \quad (11)$$
$$-SOC_{k,t} \geq SOC^{max}_k \quad \forall k,t \quad (12)$$
$$SOC_{k,t} \geq SOC^{min}_k \quad \forall k,t \quad (13)$$
$$SOC_{k,t} = SOC_{k,t-1} + \sum_i\left(-\frac{1}{\eta^G_k}G_{k,t,i} + \eta^L_k L_{k,t,i}\right) \quad \forall k,t \quad (14)$$
$$SOC_{k,end} \geq TSOC \quad \forall k \quad (15)$$
$$G_{k,t,i} \geq 0, L_{k,t,i} \geq 0, R^R_{k,t} \geq 0, R^S_{k,t} \geq 0, SOC_{k,t} \geq 0.$$

The objective of the ISO, (1), is to maximize the social welfare given the offers from the generators ($c^G_{k,t,i}$, $G^{max}_{k,i}$) and the bids from the load ($c^L_{k,t,i}$, $L^{max}_{k,i}$). The size of the individual piecewise discharging ($G_{k,t,i}$) and charging ($L_{k,t,i}$) segments/blocks ($i$) of an ESR is bounded by (2) and (3), respectively. The generating mode ($\overline{GM_{k,t}}$) and the load mode ($\overline{LM_{k,t}}$) are inputted as parameters based on the ESR owner's opted mode election (enhances computational tractability of unit commitment, i.e., DASCUC, problems). Most of the ISOs have proposed to provide ESRs with the option to select a specific mode (equivalent to the UC status variable for traditional resources in DASCUC) in their submitted offers. Consecutively, the ISOs have proposed a continuous model for ESRs that excludes commitment-related variables and parameters from the UC problems to enhance solvability. The scheduled regulation ($R^R_{k,t}$) and spinning ($R^S_{k,t}$) reserve from a specific ESR is bounded by the corresponding reserve's maximum capacity (or upper bound) in (4) and

(5), respectively. Constraint (6) and (7) impose maximum discharge ($MaxD_k$) and charge ($MaxC_k$) limitations on the real power scheduled from ESRs, respectively. Constraint (8) ensures system-wide power balance between generation and demand ($\overline{D}_t$), and (9) and (10) require that the system-wide scheduled regulation and spinning reserve be no less than a pre-defined reserve amount (or reserve margin, $\overline{Reg_t}$, $\overline{Spin_t}$). Although (8)-(10) include only the ESRs' contribution for illustration purposes, the reader is encouraged to assume that (8)-(10) also include additional contributions from other generating and demand resources. Equations (11)-(15) model the SOCM constraints for ESRs. Here, (11) and (15) model the required SOC level at the start ($SSOC_k$) and the end ($TSOC$) of the operating horizon, respectively; (15) allows the ESR to get to a desired SOC level at the end of the optimization horizon and to avoid myopic decisions that may empty out the ESR without leaving any stored energy for the subsequent day. Another option is to include multiple desired SOC levels throughout the horizon. The ESR's SOC is restricted by the maximum ($SOC_k^{max}$) and minimum ($SOC_k^{min}$) allowable SOC limits in (12) and (13), respectively. An ESR's energy throughput constraint, which models the relationship between the SOC in two different time periods (time-coupled) and the effect that scheduled generation and load have on SOC is modeled in (14). Note that (14) accounts for the effect of roundtrip efficiency ($\eta_k^G$, $\eta_k^L$) on the SOC of ESRs. *The main focus of this phase of the study is on SOCM in the DAM.* This helps separate out the impacts from RT re-optimization and the challenges that are associated with A/S impacts on SOC, which will be evaluated in future phases of this study.

In the *Self-SOCM* option, the ISO can potentially exclude (11)-(15) from its DASCED problem. The key assumption for *Self-SOCM* is that the ISO will not explicitly incorporate constraints that are usually related to SOC in its market clearing software. Instead, the ESR owner will ensure SOC feasibility via its submitted offer curves for instance. An optimization-based algorithmic approach was adopted to obtain hourly offer curves for ESR participation in the DAM [5]. The *SOCM-Lite* option potentially only excludes (15) from the DASCED problem. The economic selection of an ESR is determined primarily based on its bidding strategy to maximize profit; however, the bidding strategy itself no longer needs to attempt to also ensure feasibility with regard to SOC limits because the ISO does not allow infeasible solutions, which was otherwise necessary when developing an ESR's offer strategy in the *Self-SOCM* option.

### *2.3. State of Charge Management Case Studies*

***Market Clearing Software Simulation Tool and RT Modifications.*** The **F**lexible **E**nergy **S**cheduling **T**ool for **I**ntegrating **V**ariable generation software tool (**FESTIV**) was used for the case studies [6]. It is a multi-cycle, multi-timescale, steady-state power system operations simulation tool that aims at replicating the full-time spectrum of scheduling resources to meet energy and reliability needs of the bulk power system. It currently uses a suite of five scheduling sub-models: DASCUC, RTSCUC, RTSCED, AGC, and reserve pick up (RPU). Each of these sub-models is integrated within FESTIV at various timescales that are configurable by the users. In this study, RTSCUC is run every 15-minutes throughout the day and DASCUC is repeated every 24-hours, with interval decision points of 15-minutes and 1-hour and look-ahead horizons of 3 and 24 hours, respectively. All parameters are configurable by the user. For initial evaluation of energy only impacts, ACE control by the AGC is not allowed in these studies, AGC simply interpolates energy schedules from one five-minute dispatch to the next. FESTIV allows for add-on functionality that can be placed throughout the software to account for unique functionality of the study. It is what makes it so valuable as a research tool, as different types of studies can be undertaken without having to make substantial software changes, but by just adding in the additional features. These are called "mods" for short and include either functional mods or formulation mods. Functional mods are used to provide for new inputs or modify inputs that are used in one of the scheduling processes, or to adjust outputs from the scheduling process after it has solved such that a different value can be passed through time within the simulation. Formulation mods include modifying or adding new parameters, variables, or constraints to the various optimization models that are used by FESTIV. Several functional and formulation mods are used in this study to account for the different SOCM processes. A new mod was included so that ESRs could have piecewise linear offers that included negative production when charging and that could differ by hour for the DASCUC process. In this study, all of the SOCM options are applied to the DAM and DASCUC only. In the subsequent RT scheduling processes, the schedules are interpolated from the DASCUC schedules as long as SOC is at a level that it can do so. Note that there is load and variable energy resource

(VER) forecast error occurring between the DAM and RT; however, in these simulations the ESR will not be used to try to better accommodate those impacts and simply follows the DA schedule until SOC limits require otherwise. Thus, as long as the RTSCUC notices the SOC violation as it is about to occur, and has other solutions to correct it (e.g., committing a quick-start resource to replace the energy it cannot provide), then reliability issues should be resolved. Only when there are no other decisions to correct the schedule deviation will there be potential for reliability issues. However, note that the decisions to accommodate the schedule deviations from ESR may be costlier. If the DA solution is ensuring feasible schedules that are within SOC limits, then theoretically the RT should always be able to meet the interpolated DA schedule. However, due to the calculation of energy in the DA model and the interpolation that is done, this is not entirely true in practice. This may show how a better accounting of energy in the market clearing models may be important for ESR SOC calculations.

***System Information and Test Case Scenarios.*** A modified IEEE 73-bus system (RTS 96) was used for the weekly simulation runs conducted in this study (includes time-series data for a week from the year 2020). The modifications, including several changes to enable multi-timescale, multi-cycle operational simulations, were made by the GMLC [7]. The total installed generation capacity is 23,876 MW. This includes 8,026 MW of dispatchable generation (e.g., CTs, CCGTs and nuclear), 1000 MW of hydro and 14,850 MW of VERs (11,850 MW of solar, 3000 MW of wind). Given the high VER penetration scenario (100% instantaneous penetration in several periods) in the test data, VERs were scaled down (considered to be under an outage) to reflect near-term anticipated system conditions. Two VER penetration levels were considered: a) low VER level (installed capacity of 2,250 MW; average penetration of about 9% of energy demand), and b) high VER level (installed capacity of 11,000 MW; average penetration of about 32% of the energy demand). Two ESR penetration levels were considered: a) low ESR level of 300 MW (six 50 MW ESRs; 4% of peak demand), and b) high ESR level of 800 MW (sixteen 50 MW ESRs; 10% of peak demand). Each ESR was rated at 50 MW (maximum charge/discharge limit, with ability to operate continuously across that range) with an 85% roundtrip efficiency and 200 MWh (50 MWh) maximum SOC limit for 4-hour (1-hour) duration ESRs. The *ISO-SOCM* and the *SOCM-Lite* sub-cases maintained a 50% SOC in the DAM at the end of every day. It is important to test the SOCM options under a large set of scenarios to understand the implications on different systems with different resource mixes. Higher VER penetrations may show higher price volatility and more reliance on ESRs to provide economic energy arbitrage, while the lower VER penetrations may be closer to current conditions. ESR penetration level is also adjusted. Higher ESR levels has the potential for greater imbalance when more ESR's SOC are not managed simultaneously. The low ESR penetration levels, while still high compared to existing systems, may show closer conditions to what may be expected on the existing system or in the near-future. Finally, a few sensitivities are included with limited duration ESRs, with the amount of storage that can be kept reduced from 4-hours to 1-hour. With less ability to store energy for later use, the ESRs can run into SOC limitations more commonly and may be used in a different manner with more continuous cycling to ensure sufficient energy is charged to supply back to the grid.

### *2.4. Numerical Results and Analysis*

Each of the aforementioned cases were simulated for a one-week time period. The production cost and reliability impacts of each of the cases are evaluated.

***Economic Efficiency Results.*** *Figure 2* shows the operating cost differences across the different cases. There are a few observations that can be gained from the production cost results. **First**, the Self-SOCM option seems to have a negative impact by actually increasing operating costs compared to the system without any ESR, when the ESR level is high. The algorithm for determining the offer curves in the Self-SOCM case is likely more sophisticated compared to what may be done by ESR owners in practice today, but it cannot capture a human element that would adjust and tune the algorithm before bidding and over time. Note that ESR owners are likely to use historical prices when determining offers in the Self-SOCM option, but the forecast accuracy of such prices is dicey. Out-of-sample prices, that result from a different energy schedule than anticipated, in the Self-SOCM case may not appropriately capture an ESR's physical and operating characteristics. The primary reason for higher costs in these cases is that the ESRs are selling more generation than they have available in the DAM, which must be replaced with more expensive quick-start generation in the RTM. **Second**, the SOCM-Lite option has a consistent cost reduction regardless of the VER or ESR levels. This offers promising news such that the use of offer curves provided solely by the ESRs are not the primary cause of the cost increases in the Self-SOCM case, and rather, it is the fact that SOC is not ensured to be feasible. **Third**, the ISO-SOCM has an even greater cost reduction compared to the SOCM-Lite (with the exception of low VER, low ESR), and perhaps more importantly, costs are further reduced as more ESRs are added. This provides support that ISO-SOCM can ensure the best utilization of all ESRs. In addition, the greater the quantity of VER, the greater the savings when going to ISO-SOCM. This is due to greater arbitrage benefits with the higher VER levels. **Finally**, limited duration storage has some noticeable effects. It can increase costs even greater when in Self-SOCM mode but did not do so in both cases. Since the offer curve was adjusted for the ESR to account for the lower energy stored capacity, it does not necessarily lead to higher costs than a similar case with higher duration storage. With the case of ISO-SOCM, the cost savings are not as high as with the higher duration ESR, which is intuitive as the ESRs would have less ability to operate as effectively with lower stored energy. ISO-SOCM still provides some substantial economic efficiency benefits over SOCM-Lite even though both are ensuring that SOC levels are feasible during the DASCUC process. When ignoring the offer curve and using the ESRs to reduce costs, it can be imagined as an offer curve being automatically set such that the discharging costs are equivalent to the prices paid to charge multiplied by the round-trip efficiency. This takes the guessing out and uses the ESRs in a way that should reduce total costs as much as possible.

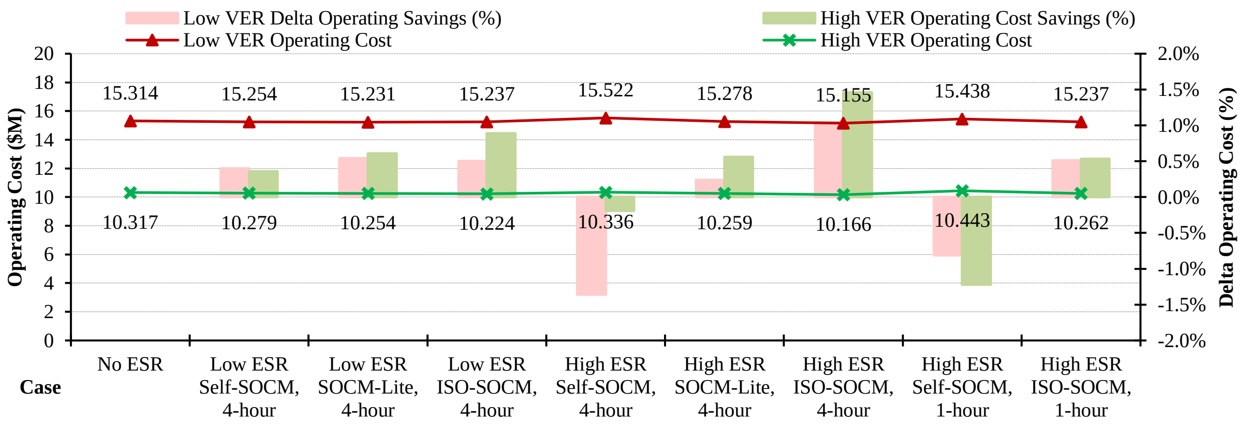


**Figure 2.** Operating cost differences across the different SOCM cases

***Reliability Results.*** The reliability results do not give a full picture of the reliability analysis of having ESRs on the system. Since the ESRs are fixed to the interpolation of their DA schedule, their fixed non-dispatchable energy displaces other dispatchable energy in RT. Thus, the results are really providing an indication of the reliability impacts of determining ESR schedules in the DAM and fixing those schedules in RT regardless of RT conditions (even during shortage conditions). It will be important to evaluate the re-optimization of ESRs in RT and analyze the corresponding reliability metrics to get a more realistic understanding of implications. *Table 1* shows the amount of load shortage in RT for each case. Since the simulations did not include any A/S, forecast errors and variability that occurs in RT can lead to load shortages, which may result in ACE, frequency error, or if large enough, actual load shedding. In reality, ISOs carry operating reserve that would be used to correct the errors and variability to some degree before not meeting energy. However, the metric is still useful as a proxy for how well each system was balanced. The number of 5-minute intervals with imbalance (out of 2016 intervals) and the largest MW imbalance within any of the 5-minute intervals is also shown.

**Table 1.** Reliability of different ESR SOCM cases

| Case | RT imbalance (MWh) | # 5-minute intervals with imbalance | Largest imbalance within a 5-minute interval (MW) |
|---|---|---|---|
| Low VER, No ESR | 49.9 | 28 | 96 |
| Low VER, Low ESR, Self-SOCM | 41.4 | 17 | 90 |
| Low VER, Low ESR, SOCM-Lite | 49.1 | 27 | 83 |
| Low VER, Low ESR, ISO-SOCM | 34.5 | 15 | 78 |

| | | | |
|---|---|---|---|
| Low VER, High ESR, Self-SOCM | 97.1 | 50 | 96 |
| Low VER, High ESR, SOCM-Lite | 94.5 | 41 | 101 |
| Low VER, High ESR, ISO-SOCM | 26.8 | 9 | 95 |
| High VER, No ESR | 1152.6 | 34 | 102 |
| High VER, Low ESR, Self-SOCM | 1520.1 | 56 | 93 |
| High VER, Low ESR, SOCM-Lite | 1129.5 | 36 | 95 |
| High VER, Low ESR, ISO-SOCM | 935.9 | 37 | 85 |
| High VER, High ESR, Self-SOCM | 2565.7 | 69 | 113 |
| High VER, High ESR, SOCM-Lite | 2297.2 | 64 | 133 |
| High VER, High ESR, ISO-SOCM | 2284.1 | 63 | 153 |

The more RT fixed schedule ESRs being added to the system, the more imbalance is observed. This is somewhat obvious again based on the nature of how the simulations are using the ESRs and is not entirely reflective of what happens in practice. When more ESR energy is scheduled, other generation is not committed, and less flexible capacity is available to correct for the forecast errors that occur in RT. This can be corrected by allowing ESRs to respond to RT needs, or even by having flexibility reserve constraint across scenarios such that more flexibility is committed DA to accommodate the RT impacts in each scenario. The imbalances in these examples were all due to there being no reserve and the RT dispatch not being able to commit additional resources. In all cases, there were sufficient resources to meet the RT conditions, and operators could have turned on resources manually to avoid imbalances in the larger cases. In some cases, it is possible that with higher ESR levels, and modes where SOC is not ensured as feasible, there could be potential reliability issues when there are no sufficient resources to meet the shortfalls. In the RTS-96 system, especially with renewables added in and no retirements made, there is an ample supply of quick-start generation. So even with Self-SOCM, the issues with having SOC infeasibilities in RT did not necessarily lead to reliability issues, as there were sufficient quick-start resources in all cases to use to correct the energy deficiency. On systems with less quick-start generation, this could be a potential challenge.

***Future Research.*** All of the cases had forecasts of VER and load in the DA time frame that were imperfect and result in different outcomes during RT. In the results in this study, the ESR schedules are not re-dispatched in RT (and instead fixed to the interpolation of their DA schedule) to better accommodate the realization of load and VER production. This is a challenge because any change in RT ESR schedules when the forecasts errors are realized may impact the optimal ESR schedules later on in the day, that do not have updated accurate forecasts yet. For this reason, we plan to evaluate RT "re-optimization" of ESR schedules, A/S provision and SOCM, and analyze the corresponding reliability metrics to get a more realistic understanding of implications in the next phase of this research.

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