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Independent System Operator and Regional Transmission Organization Energy Storage Market Modeling Working Group White Paper

Current State of the Art in Modeling Energy Storage in Electricity Markets and Alternative Designs for Improved Economic Efficiency and Reliability

3002012327

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Technical Update, March 2018

EPRI Project Manager

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ACKNOWLEDGMENTS

The Electric Power Research Institute (EPRI), prepared this report.

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This report describes research sponsored by EPRI.

EPRI acknowledges the support of the following organizations for the Working Group and the development of this report:

California Independent System Operator (CAISO)

Electric Reliability Council of Texas (ERCOT)

Independent Electric System Operator (IESO)

Independent System Operator of New England (ISO-NE)

Midcontinent Independent System Operator (MISO)

New York Independent System Operator (NYISO)

Pennsylvania Jersey Maryland Interconnection (PJM)

Southwest Power Pool (SPP)

This publication is a corporate document that should be cited in the literature in the following manner:

Independent System Operator and Regional Transmission Organization Energy Storage Market Modeling Working Group White Paper: Current State of the Art in Modeling Energy Storage in Electricity Markets and Alternative Designs for Improved Economic Efficiency and Reliability. EPRI, Palo Alto, CA: 2018. 3002012327.

ABSTRACT

The goal of the Independent System Operator/Regional Transmission Organization (ISO/RTO) Energy Storage Market Modeling Working Group is to bring together experts in electricity market design, electricity market clearing software/algorithms, energy storage market modeling, and energy storage technology characteristics to collectively survey the ways in which electric storage resources are currently incorporated in electricity market clearing software and how this may evolve in the future with larger penetrations of electric storage resources. While actual market design evolution is driven through regulatory and stakeholder processes, the discussions of this group should help to prepare ISOs/RTOs and their stakeholders for best practices that can lead to an economically efficient, reliable, and fair electricity market operation. This report describes findings from the ISO/RTO Energy Storage Market Modeling Working Group, discussing the current state of the art, outstanding questions on best practices, and nine topics/objectives to pursue in research. The nine topics requiring further research include

- Efficient methods of bidding and scheduling electric storage resources in day-ahead markets
- Efficient methods of bidding and scheduling electric storage resources in real-time markets
- Management of state-of-charge limits and operational modes that lead to greater reliability, economic efficiency, and incentive compatibility
- Efficient price formation with electric storage resources as marginal injector/withdrawer resources
- Provision of ancillary services and co-optimization of energy with ancillary services considering characteristics of electric storage resources
- Efficient settlement design for electric storage resources including make-whole payment structures
- Automatic generation control methods for electric storage resources that use resources in the most efficient manner possible
- Small-resource impacts and computational impacts of significant levels of electric storage resources
- Efficient allocation of electric storage resources in capacity markets

Keywords

Energy storage
Electricity markets
Independent system operator (ISO)
Regional transmission organization (RTO)

ACRONYMS

A/S	Ancillary Services
ACE	Area Control Error
AGC	Automatic Generation Control
ATR	Alternative Technology for Regulation
ATRR	Alternative Technology Regulation Resource
CAES	Compressed Air Energy Storage
DAM	Day-Ahead Market
DARD	Day-ahead Asset Related Demand
ESR	Electric Storage Resource
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
ITSCED	Intermediate Term Security Constrained Economic Dispatch
LAC	Look Ahead Commitment
LESR	Limited Electric Storage Resource
LMP	Locational Marginal Price
MIP	Mixed Integer Programming
MW	MegaWatt
NERC	North American Electric Reliability Corporation
NGR	Non-Generation Resource
NOPR	Notice of Proposed Rulemaking
O&M	Operations and Maintenance
PFR	Primary Frequency Response
PSH	Pumped Storage Hydro
REM	Regulation Energy Management
RTM	Real-Time Market
RTSCUC	Real-Time Security Constrained Unit Commitment
RUC	Reliability Unit Commitment
SCED	Security Constrained Economic Dispatch
SCUC	Security-Constrained Unit Commitment
SER	Stored Energy Resource
SOC	State-of-Charge
STUC	Short Term Unit Commitment
VER	Variable Energy Resource
WSL	Wholesale Storage Load

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EPRI greatly appreciates the contributions and review of the working group members. However, any opinions, errors, or inadvertent omissions are solely those of the EPRI authors and do not necessarily reflect those of the external working group members nor the ISO/RTO organizations, nor any other EPRI members.

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INTRODUCTION

In 2017, EPRI and the North American Independent System Operators and Regional Transmission Organizations (ISOs/RTOs) (see Figure 1-1) formed a working group under the ISO/RTO Market Design Technical Task Force which is facilitated by EPRI's membership program. Formation of working groups under this collaboration are done to form a more specialized group of experts to discuss a topic that is of great interest to the majority of the ISOs/RTOs. One of the most significant initiatives at all the ISOs/RTOs as of this writing is around the integration of emerging technologies that are entering the electricity markets and significantly changing the resource mix [1]. At the end of 2016, due to recent state regulatory storage mandates, reducing costs and greater adoption of energy storage, and a recent Federal Energy Regulatory Commission (FERC) Notice of Proposed Rulemaking (NOPR) on the topic of how storage can participate in different product areas that are a part of the organized electricity markets, the ISO/RTO energy storage market modeling working group (ESMMWG) was formed.

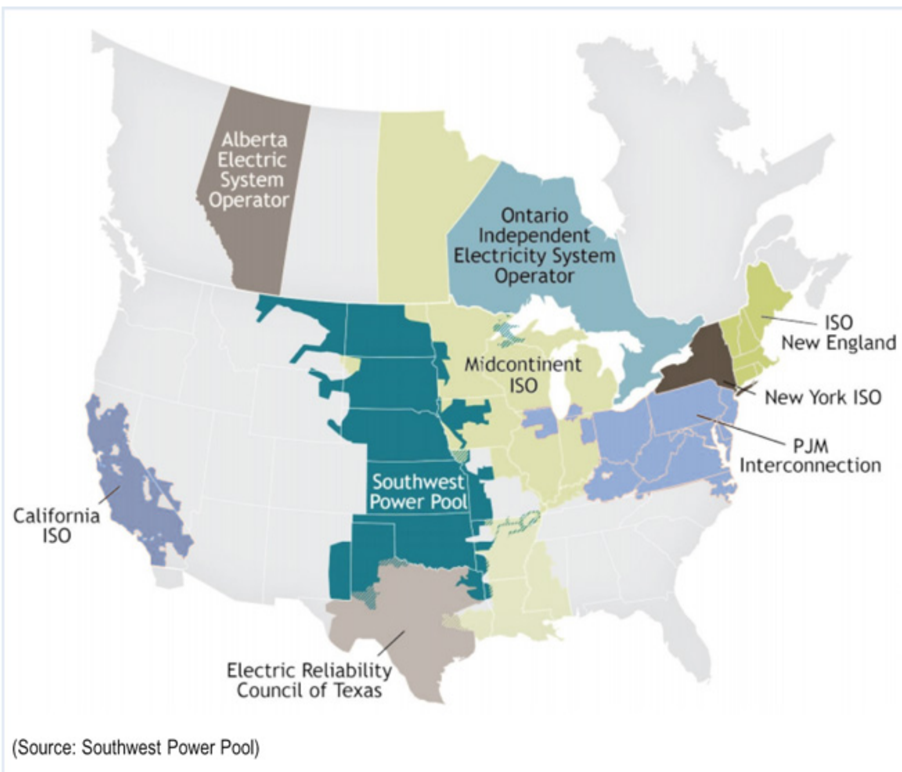


Figure 1-1
ISO and RTO map of North America

The goal of this working group is to gather the experts in electricity market design, electricity market clearing software/algorithms, and energy storage market modeling and technology characteristics to discuss challenges and best practices of electric storage resources within the energy, ancillary services, and capacity markets. While actual market design evolution is driven through the regulatory and stakeholder processes, the discussions of this group should help prepare the ISOs/RTOs and their stakeholders for best practices that can lead to an economically efficient, reliable, and fair electricity market operation. We focus our efforts on electric storage resources that *offer as a single participant into the market for any product, with storage resources on the distribution system or customer-sited that participate through aggregators as out of scope of this working group* (but an electric storage resource on the distribution system that participates in the wholesale market as a single participant is in scope). The ISOs/RTOs are evaluating market design options for DER aggregations separately.

The group met several times throughout the year via teleconference to discuss different topics relating to energy storage participation in organized electricity markets and the software requirements to do so. The group also met in person at the 3rd annual ISO/RTO Market Design Technical Forum to discuss and prioritize the topics that were reviewed throughout the year. In addition to the shared learnings provided throughout these discussions, a primary objective of this white paper is to provide detailed review of the state of the art, current challenges and questions the ISOs/RTOs are facing, and potential market design alternatives that would be worth pursuing through further study. Additional effort in the prioritization of which topics are most pressing will all feed into the scope of research that EPRI is pursuing in the future on the topic of energy storage participation in electricity markets.

The white paper is organized as follows. In Section 2, we give a brief review of the current state of the art for electric storage resource participation in the North American organized electricity markets. In Section 3, we then summarize some of the greatest current challenges facing the ISOs/RTOs and their stakeholders. Then in Section 4, we review nine topics that stem from those challenges and potential future market design alternatives that may address the challenges. Section 4 is a direct feed-in to the research scope that EPRI plans to pursue in 2018. Finally, Section 5 provides a summary and set of next steps to achieve the goals laid out.

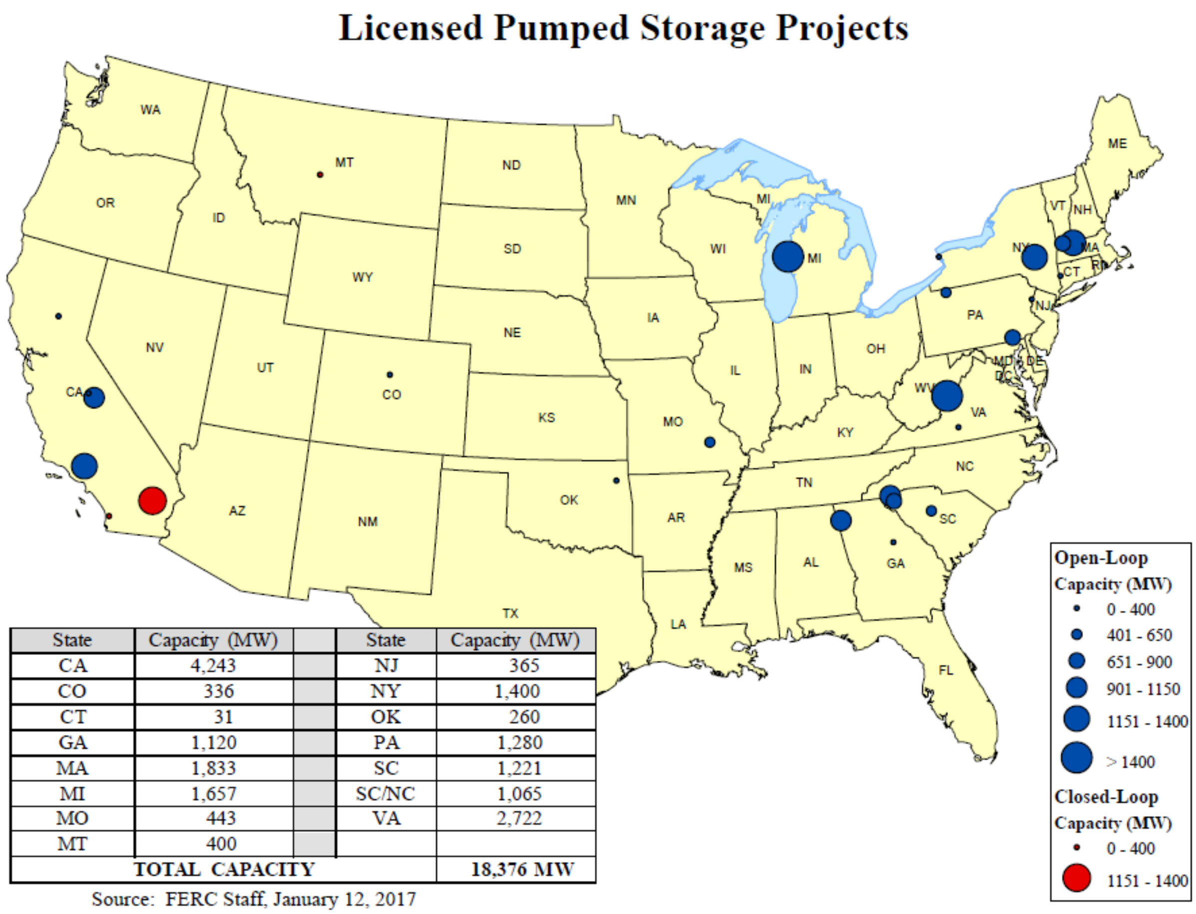
2
ENERGY STORAGE PARTICIPATION AND MODELING IN ELECTRICITY MARKETS – STATE OF THE ART

Electric Storage Resource Market Modeling State of the Art

In this section, we describe the current state-of-the-art in electric storage resource participation in each of the North American ISOs/RTOs within the energy, ancillary services, and capacity markets. This report requires a detailed understanding of the existing electricity market design state of the art and most general terms are not described in detail within this report. For a comprehensive review of the (2016) state of electricity markets and initiatives being pursued in the U.S. electricity markets, see [2]. It is important to note that the details of these designs are continuously evolving, and are a moving target from when the review is being performed in each area. As such, the group did their best to capture the state of the art, but in some cases, recent changes may override those provided in this section.

Participation of Pumped Storage Hydro in Energy and Ancillary Service Markets

The most common electric storage resource technology in North America is pumped storage hydro (PSH). Over 18 GW of PSH capacity exists in the United States (See Figure 2-1) and a 175MW plant also exists in Ontario, Canada. As can be seen, large quantities of PSH exist in CAISO, MISO, PJM, NYISO, and ISO-NE and small quantities also exist in IESO and SPP. Because PSH has been around for decades, the ISOs/RTOs have the most experience with these technologies participating in electricity markets compared to other storage technologies.



State	Capacity (MW)		State	Capacity (MW)
CA	4,243		NJ	365
CO	336		NY	1,400
CT	31		OK	260
GA	1,120		PA	1,280
MA	1,833		SC	1,221
MI	1,657		SC/NC	1,065
MO	443		VA	2,722
MT	400			
TOTAL CAPACITY				18,376 MW

Figure 2-1
Licensed Pumped Storage Hydro Plants in the United States (Source: FERC Staff)

The ISOs/RTOs that have PSH have ways that pumped storage can participate in energy and ancillary service markets that are often unique from other generating units. This can include special "participation models[1]" that may allow unique representation of the resource to reflect its ability to operate as a generator and a load, or simply ways to allow it to operate as a generator participation model or a demand response (or price capped load) participation model. Other methods are moving toward an optimization of the mode (generating, pumping, offline) that the PSH operates in, determined through ISO/RTO software. Some specific examples are provided below.

- Many ISOs including NYISO and MISO, have a participation model where the PSH market participant must choose to offer in as a generator or load separately for the hours in which the market participant determines to operate in the different mode. This is generally constrained to the day-ahead market, but the ISO may allow different offers in the real-time if they are approved by operators.

[1] Participation model is a term used by FERC and others to refer to a "model" specific to a type of resource or technology such that a set of tariff provisions accommodate the resources participation in organized electricity markets with its particular physical and operational characteristics considered.

- Some ISOs have or are developing different levels of storage optimization models for pumped storage such that rather than the PSH market participant pre-selecting the hours to operate in generating mode or pumping mode, the ISO/RTO software will optimize the operational mode of resource as part of the day-ahead security constrained unit commitment (DASCUC) process based on production cost minimization.
  - PJM uses a separate optimization model that allows the ISO to determine the optimal mode of PSH to lead to cost minimization. The model is called the pumped hydro optimizer and is only applied in the day-ahead market. No offer curves are required for PSH plants.
  - In NYISO's energy storage roadmap Phase 2, the ISO plans to allow for ISO optimization of energy storage, including PSH, through its software [3]. The goal is to include this option for the asset owners in both the day-ahead and the real-time market solutions.
- In ISO-NE, the participation model for Dispatchable-asset related demand (DARD) pump storage includes features to more realistically capture the parameters of PSH in pumping modes, including minimum pumping levels, minimum run and down times, maximum starts by the pump, and maximum daily consumption limits [4].
- Other areas have included or proposed maximum daily energy limits, which are not specific to PSH (e.g., they are often used for emissions limits), but can be used to ensure the reservoir levels of the PSH are within limits. However, with the exception of PJM's current model and some being proposed, these maximum daily energy limits only are enforced in one mode (e.g., only when the PSH is in generating mode).
- CAISO has plans for its storage resources to provide cost offers from withdrawal mode (negative energy and negative cost) to injection/generation mode (positive offers and positive costs) [5]. However, the current proposal is for this only to apply for electric storage resources that have a continuous operation between maximum withdrawal to maximum injection (excluding PSH).

These participation models are a product of stakeholder processes, current software functionality, and levels of PSH and other technologies within the footprint. While there is not likely a trend for significant amounts of more PSH plants to interconnect and participate in organized electricity markets, the emergence of other storage technologies may cause new designs that may apply to all forms of storage with these designs above as a starting point.

In terms of ancillary services, PSH are usually allowed to provide most ancillary services no differently than other technologies. The below describes the examples that are generally true in all ISOs/RTOs.

- PSH are eligible to provide regulation and spin/synchronized reserve when in generating mode and head room (and floor room, when applicable) is available
- PSH are usually eligible to provide non-spin or replacement/30-min reserve when offline, as most technologies can start in less than 30 minutes. Some may be able to also provide 10-minute non-spin depending on their start-up capability.

- Most areas allow pumped storage to provide non-spin when in pump mode, assuming they can turn off the pump within 10-30 minutes in a way that reduces demand giving similar effect as turning a unit on.
- PSH are generally not able to provide regulation or spin/synchronized reserve when in pumping mode. This is because all PSH in North America are fixed speed pumps meaning that while in pumping mode they cannot adjust output [6].

Limited Electric Storage Resources Participating in Energy and Ancillary Services

The increase in electric storage resources has come primarily from those that have limited energy reservoirs, compared to PSH. This includes lithium ion batteries, flow batteries, flywheels, and other battery technology. Most areas have participation models for this set of technologies, generally referred to as limited energy storage. The current participation models for these technologies are mostly for allowing the limited electric storage resources to participate in regulation markets only. In FERC-jurisdictional ISOs/RTOs, benefits for providing regulation were observed for these resources once FERC Order 755 was implemented [7], which introduced a "pay-for-performance" mileage payment procedure. This was beneficial to these resources who were able to perform more "mileage" (absolute value of upward and downward movement) than conventional resources.

- ISO-NE, NYISO, PJM, MISO, ERCOT, and CAISO have a 15-30-minute duration requirement for storage participating in regulation market. These resources operate under a "regulation only" participation model:
  - NYISO: Limited Electric Storage Resource (LESR)
  - ISO-NE Alternative Technology Regulation Resource (ATRR)
  - MISO: Stored Energy Resource (SER)
  - PJM: Large growth in electric storage resources providing regulation only (greater than 250 MW)
  - CAISO: Non-generation Resource (NGR) & LESR with regulation energy management (REM)
  - ERCOT: A duration limit of up to 15 minutes is enforced in one direction for resources offering primary frequency response service
- SPP currently has an hour-long duration requirement for regulation service but is moving to a 15-minute duration requirement.
- IESO: Alternative Technologies for Regulation (ATR) procurement offer long-term contracts for energy storage to provide regulation only [8].
  - Phase 1 Energy Storage program consisting of 34 MW of storage capacity across 11 facilities. Two of those facilities are providing regulation service and the remaining 9 are providing reactive support and voltage control service.
  - In September 2017, the IESO concluded a technology-agnostic, competitive procurement for 55 MW of incremental regulation service which was awarded to two energy storage facilities.

The trend is for allowing limited storage resources to provide regulation in a beneficial way while still maintaining energy state-of-chargelimits. For regulation, these markets will either manage the state-of-charge of energy storage through the control signal, or will create a separate AGC signal that by design will statistically lead to efficient management of state-of-charge by filtering for just the high frequency imbalances.

- ISOs/RTOs that differentiate signals to different resources
  - PJM uses the dynamic regulation signal (REGD) for fast resources which controls the faster component of the area control error (ACE), vs. the traditional regulation signal (REGA) which is used for the slow component of area control error (ACE). Changes in early 2017 were made to add a conditional neutrality signal to provide better performance in correcting for ACE [9]. The new control replaces the older one where the RegD signal was energy neutrality even when the control would be counter to correcting ACE. By linking the RegA and RegD signals together better, this possibility was eliminated while still maintaining energy neutrality in the RegD signal as best as possible while still maintaining reliability.
  - ISO-NE allows ATRR to choose signal, either conventional or statistically energy neutral signal. The energy neutral signal contains either an energy neutral trinary (ENT) signal (full power charge, neutral, or full power discharge) which is the sent to all ATRRs together, or an energy neutral continuous (ENC) signal, sent based on participation factors [10].
  - MISO has a proposal to send faster signal for fast response resources and create a separate category for fast ramping group and recently completed a study evaluating the benefits [11]. The algorithm would include a fast resource deploy first and fast resource undeploy first methodology.
- ISOs/RTOs that explicitly manage electric storage resources state-of-charge in the AGC
  - NYISO AGC model will transfer regulation deployment from LESR to other suppliers when metered energy storage is approaching limits [12].
  - CAISO Regulation energy management (REM) for LESR.
  - SPP is planning on managing SOC within AGC
  - In IESO management of state-of-chargein the AGC is left to the energy storage market participants.

These same limited electric storage resources are typically not able (or not willing) to participate in energy markets, spinning/synchronized reserve markets, or non-spinning/replacement reserve markets due to energy limitations or otherwise. The recent FERC Order 841 (discussed later) is put in place to eliminate any potential barriers for these resources to be able to participate in those markets when technically capable of doing so. Most of their entire capacity ranges are providing regulation, and in most market designs any part of a resource's capacity cannot be shared across energy, regulation, or spinning/synchronized reserve. In addition, regulation prices are most commonly higher than spinning/synchronized reserve prices. Energy would have to also be bought in greater or equal amounts to that which is sold such that the revenue of limited electric storage resources is likely maximized by providing regulation only (the amount of energy that must be purchased is netted within the interval). Electric storage resources can provide all services when they qualify as a generator in some ISOs such as PJM and ISO-NE. But their ability to buy power back may be limited. Still, one of the primary objectives of all ISOs/RTOs and of EPRI research is to find ways such that all electric storage resources can participate and provide all energy and ancillary services, when technically capable of doing so and in a way that maintains power system reliability. It can be up to the market participant or the optimization software on which services will best support economic efficiency and reliability.

Bidding options of Electric Storage Resources

Another part of the market design that makes the electric storage resource (and its derivative) participation models unique, is what parameters and costs the resource must offer and provide to the ISO/RTO. The ISOs/RTOs have a number of different parameters either required or that can be optional to provide. Parameters include static values which do not change for every market interval, or dynamic values which do. The list below includes examples of parameters either part of the current implementations or proposed by the RTO/ISO to include in the future.

- PJM: pumped storage bids/offers a final reservoir level – does not offer energy costs
- NYISO: pumped storage bids as a negative generator for interval when it desires to be in pumping mode. This is similar to bidding as a price capped load as the resource pays LMP, but PSH is not allocated certain costs that are only allocated to loads. PSH offers as a generator in intervals when the resource desires to sell and supply energy.
- CAISO: NGR can bid as both load and generator simultaneously with a bid curve that goes from negative to positive on a continuous monotonically increasing pattern. CAISO recently revised the tariff to allow scheduling coordinators representing non-generator resources to include state-of-charge as a bidding parameter.
- Since MISO manages the state-of-chargefor Stored Energy Resources, it requires the following additional bidding parameters for these resources: hourly maximum energy storage level; hourly maximum energy charge rate; hourly maximum energy discharge rate; hourly energy storage loss rate; and hourly full charge energy withdrawal rate.
- ISO-NE: Pumped storage is encouraged to bid economically with maximum daily consumption limits
- IESO: Energy storage facilities that are dispatchable are modeled as both a generator and a load. These facilities must manage their bids and offers in such a manner as to avoid conflicting dispatch instructions and remain within their upper and lower bids and offers. Market participants for these facilities are entirely responsible for these activities.
- Additional Parameters by the ISOs:
  - Maximum daily energy consumption (ISO-NE)
  - Maximum number of daily starts (ISO-NE)
  - Round-trip efficiency (PJM, CAISO)
  - Minimum and maximum state-of-chargelimits (PJM, CAISO)
  - Pump shut-down cost for PSH (CAISO)
  - Minimum charging time (FERC, ISOs)
  - Transition times (CAISO, ISO-NE)

- New tentative proposals for parameters by the ISOs:
  - Maximum running time (NYISO)
  - Cost per cycle (CAISO)
  - Offer cost stack that is dependent on state-of-charge(CAISO)

The above set of parameters cover most but not all of those required to be provided by ESR to the ISO/RTO (or proposed). Some parameters are necessary for enhanced modeling and optimization of these resources within the SCUC or SCED algorithms. Others may be for informational purposes only (i.e., so that an operator has an idea on how the storage plant can or cannot be used). In addition, the ISOs/RTOs differ on which parameters are provided as part of a daily/hourly offer and which parameters are static in nature and only provided as part of interconnection (or otherwise when the parameters have changed).

Energy Price Setting and Settlement

Energy price formation is an important topic being reviewed by all of the ISOs/RTOs and FERC.[2] The general agreement for prices are that they should be set as the cost of the marginal resource for providing energy (or an ancillary service). There may be some question/debate as to what a marginal resource is (see [13]). Since ESR are a different technology that are sometimes used in different ways, determining when they are marginal and what the marginal cost is a unique challenge. When operating as a generator independently, they can typically set the price similar to how a generator would. But more advanced utilization of ESR can be more challenging on how ESR can and should set prices. In addition, settlement rules may require additional thought due to the unique characteristics of ESR.

Some brief examples of price setting with ESR are shown below.

- In PJM, PSH cannot set price as part of the pumped storage optimization since the optimization is separate from the energy price calculation.
- In ISO-NE, PSH have their minimum consumption level (minimum pumping power) relaxed in the pricing pass and can set price. This is part of the ISO's fast-start pricing method and allows the PSH to set price in pumping mode even when blocked at minimum pumping level.
- In CAISO, NGR can set price throughout their negative to positive offer/bid curve.
- In all other ISOs, if ESR are participating in the energy markets as generators or price capped loads, they are able to set the price similarly to generators or price capped loads.
- In ISO-NE, PSH are given net commitment period compensation (NCPC, or make-whole payments) when in pumping mode when the price is above their bid but are scheduled by the ISO.
- In IESO, energy storage facilities that are dispatchable are factored into the unconstrained price calculation.[3] However, facilities that are providing regulation service are not visible to the unconstrained run of the Dispatch Scheduling and Optimization engine. Rectifying this issue is a matter currently under investigation by the IESO.

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[2] https://www.ferc.gov/industries/electric/indus-act/rto/energy-price-formation.asp

[3] The IESO determines prices based on an unconstrained dispatch run, where the network constraints are ignored.

Mitigation Procedures for Electric Storage Resources

Variable costs for electric storage resources can be either directly offered by the ESR market participant, or created implicitly through the optimization software. In times where ESRs may be located in import constrained areas or otherwise involved in uncompetitive conditions, ISO/RTO automatic mitigation and market monitoring procedures may need to know verifiable costs for these resources to prevent market power and to mitigate to those verifiable costs, when applicable. A few of the ISOs/RTOs have particular rules in place for verifiable costs for ESR.

- SPP has pumped storage verifiable fuel cost calculated as Sum RTLMP*Pump Power/(Total Pump Power*PumpEfficiency) plus variable O&M costs (which may include cost of labor, maintenance of fish and wildlife, and recreation facilities) [14].
- ERCOT has verifiable costs for natural gas drive compressed air electric storage resources, non-natural gas driven compressed air electric storage resources, and all other storage resources that are lumped into the same category [15]. For the “other” category, start-up and no-load costs are zero, and incremental energy costs are determined based on a formula that uses the previous month’s DAM average prices at the ESR location for the first fifteen days of that month, a fuel price index, and various static values.

Electric Storage Resource Participation in Capacity Markets

In the markets that have capacity markets or capacity procurement mechanisms, most have rules that dictate a capacity resource must be able to provide sustained power for a minimum amount of time in order to contribute to the capacity procurement. The idea was that in order for the resource to meet peak load conditions that it must be able to sustain as the peak load condition may last for a particular duration of time. This impacts ESR due to the energy limitations.

- In most areas this was traditionally between two and four hours. PSH plants generally are able to participate in capacity markets, while most limited ESR are not.
- In PJM and ISO-NE, capacity performance and pay for performance capacity market rules may have some differences to these rules (PJM now requires 10 hours of duration for stand-alone storage). The penalties for not contributing during emergencies in both designs could be severe as well.
- In CAISO: ESR must provide maximum power for at least four hours for three consecutive days to contribute to resource adequacy requirements [16]
- In CAISO, energy storage can contribute to flexible capacity based on ability to adjust output over 3-hour continuous charge/discharge for those that do not use regulation energy management, and 15-minute capability for those that do [17]
- IESO does not currently have a capacity market, but this is currently under consideration. In November 2015, the IESO offered 10-year contracts nine separate energy storage projects totaling 16.75 MW for providing capacity services. One requirement in the RFP was to have a minimum of four hours’ duration of service.

Small size impact on economic treatment

Another issue being reviewed is not necessarily directly tied to participation of ESR, but may present itself with adoption of significant amounts of ESR and low capacity levels. The first issue is simply related to increased computational challenge. Some of the design principles for

ESR participating in the ISO software (e.g., SCUC and SCED) are difficult to solve from a computational perspective. Computationally, significant increases in resources participating in the problem set (i.e., more variables to the optimization problem) can generally increase the amount of time required to reach a solution. With ESRs the difficulty may increase more due to added complexity of how the resource is modeled. The other challenge is that where during the unit commitment procedure, the solution usually is dependent on the production cost value at which the Mixed Integer Programming solver will cease to search for a lower production cost (referred to as the MIP gap). The MIP gap is very small relative to total production cost, but can be large relative to a very small resource. The MIP gap balances the need to minimize production cost (the objective) with the need to post timely results. Once the MIP gap is reached, the solver will stop and report the best feasible solution as final. When smaller resources have costs associated with their unit commitment that are significantly lower than that MIP gap, they may be chosen at random, and committed or not committed based solely on where the solver stopped searching. If numerous small ESR enter the market this can be a challenge in providing clear market signals and maximizing profitability to these resources.

- The pumped storage model in PJM has been said to increase computation times significantly with just 3-4 offering units [18].
- Some ISOs are making large-scale updates to their solution software to keep up with computational challenges. Other changes including combined cycle configuration modeling, increased virtual offers, and enhanced reserve modeling all have similar computational challenges. In addition, ISOs/RTOs have also had to solve the problem in shorter timeframes, due to example natural gas market timelines [19].
- In PJM, the SCUC solution performs adjustments after commitment decisions are made for small generator commitments needed due to the MIP gap
- NYISO has a similar proposal for two steps in the SCUC process, one with a larger MIP gap, and a second with commitments of the previous units frozen (not decided upon) with a smaller MIP gap so that decisions for the smaller resources can be made. [20]
- Minimum bid requirement for most ISOs are either 500 kW or 1 MW. The FERC Order (discussed below) suggests 100 kW.
- Other ISOs (MISO) have implemented heuristic methods where day-ahead SCUC operators may manually adjust the output of small resources after the SCUC program solves [21].

Federal Energy Regulatory Commission Notice of Proposed Rulemaking on Energy Storage and Distributed Energy Resources

As discussed, most ISOs are currently considering any market design changes that may be necessary for ESR to participate in the electricity markets. In November 2016, FERC released a Notice of Proposed Rulemaking (NOPR) on energy storage and distributed energy resources [22]. The NOPR provided several proposed changes related to the topics discussed in this section. Some of the proposals are currently met by some ISOs, while a majority of the proposed changes are not and may require substantial changes by the ISOs[4]. Several topics were brought up regarding energy storage as well as several questions on best practices. These proposed rulemakings can have significant impacts on the market design of each of the FERC-jurisdictional ISOs/RTOs, which in turn can have impacts on the other ISOs and areas without ISO market operators, and therefore we believe it is important to capture the most important components. Some of the most significant proposed rules and questions are listed below.

- Energy storage to be allowed to participate in energy, ancillary services, and capacity markets when technically able to do so
  - ISO must create a participation model for it to participate in a manner that captures any unique aspects
  - They should also be allowed to provide non-market (i.e. cost-based) services that they are capable of providing
- Some more specific requirements for what the ISOs/RTOs must modify to allow for participation from electric storage resources
  - They must be allowed to provide spinning (or synchronous/synchronized) reserve even though they are not synchronous resources, if they are capable of providing the service when called upon
  - They must be allowed to participate in capacity markets and able to provide capacity up to a prorated amount of how much power they can provide at the minimum capacity market duration requirement
- Several bidding requirements were proposed for energy storage to provide, and for ISOs to use, within the market clearing process
  - State of charge, upper/lower charge limits, charge/discharge rates
  - Other optional parameters were mentioned as well
- FERC specifically stated that there is no requirement for the ISO/RTO to manage the stage of charge of the electric storage resource
  - If the ISO/RTO has the capability to manage SOC in its software, it must be optional such that the ESR participants can choose whether to self-manage SOC or let the ISO manage it.
- Storage must be able to participate as a wholesale buyer and wholesale seller
  - The energy it charges to sell later must be at wholesale
- The ISO must allow ESR that are at least 0.1 MW to participate in the various markets
- Energy storage must be able to set the wholesale (energy) price as both a buyer and seller

[4] For purposes of this report, we focus on the energy storage resource section of the NOPR and not on the DER section of the NOPR.

EPRI, each ISO, and several other organizations submitted comments to FERC in response to the NOPR. Comments were summarized in a recent EPRI presentation (requires log-in to EPRI member center).[5] FERC issued Order 841 in February 2018, which mostly held the proposals above as final rulings [23].

[5] https://membercenter.epri.com/Programs/027560/pages/eventdetails.aspx?eventID=778C6BF0-422E-4393-A1F8-627797D04CDA&eventScope=Cockpit&referer=EVENT_LIST

3
ENERGY STORAGE MARKET MODELING QUESTIONS

Based on the state-of-the-art in current inclusion of energy storage into various products within the organized electricity markets as well as the questions posed by the FERC NOPR that were discussed in Section 2, a number of challenges were identified by the Working Group that may require additional research and development, analysis, and stakeholder discussion. The following are a number of these challenges involving the inclusion of energy storage into energy, ancillary services, and capacity markets in a reliable and efficient manner and how the markets may adapt to the inclusion.

As discussed in the previous section, a number of ISOs have adapted new methods for treating pumped storage hydro as an electric storage resource with decision of operating mode and state-of-charge(SOC) level being made by the ISO (ISO-Management). These have generally been applied to the day-ahead market and not in real-time. For those that have pursued this, they have generally been considered beneficial for economic efficiency and reliability purposes. However, the following related questions arise.

- Do the ISO-optimized PSH models (e.g., PJM's pumped storage hydro optimizer) lead to improved economic efficiency and reliability or are there practical limitations that prevent theoretical benefits?
  - Is the 1-day optimization horizon a limitation?
  - What is the right horizon for day-ahead models that optimize PSH (or other ESR)?
  - Does the uncertainty that occurs between day-ahead and real-time negate the benefits that may be seen from optimizing in the day-ahead?
- Are the ISO-optimized PSH models sufficient and beneficial from the PSH resources perspective? Does the theoretical system-wide economic efficiency benefits also lead to profit maximization for the ESR market participant?
  - Can the model lead to potentially adverse impacts on revenue for the individual pumped storage plant? I.e., while cost minimization can lead to profit maximization in a convex optimization model using dual variables for pricing, this is not generally true for non-convex models (unit commitment problems)
  - Can the decisions of the ESR operator result in greater revenue than the ISO decision of mode and SOC?
- Can the advanced pumped storage models be applied to limited energy storage (e.g., batteries and other technologies with less than one-day storage and more likely a few hours or less of storage)?
  - Are there unique differences that must be considered, or will the method, with adjusted parameters (lower SOC limits), work well without additional challenges or software changes?

- If modifications are required for other ESR technologies (beyond parameter values), what changes are required?
- What parameters/attributes need to be included to be general for both PSH and limited ESR?

- More generally, how does energy storage with less than one hour of storage (at maximum discharge) provide energy in hourly day-ahead energy markets?
  - Is there practical benefit for the ISO or the storage owner to doing so?
- Can limited energy storage participate in the real-time market?
  - How do sub-hourly settlements (FERC Order 825 [24]) change participation benefits/impacts?
  - How can the ISO or ESR owner know when/if to change from its day-ahead schedule?
  - How do intermediate SCUC models (e.g., intra-day SCUC, hour-ahead SCUC) support real-time operation of ESR?
- Can limited energy storage provide multiple ancillary services while also providing energy?
  - How do ancillary services impact state-of-chargeand ability to provide energy?
  - Are the current reserve sustainability rules (e.g., 1-hour of sustainability) justified?
  - Is co-optimization of energy and ancillary services more challenging with both power capacity and energy capacity constraints?
  - Can ESR provide ramping capability services (flexible ramping or ramp capability), and if so, should energy limitations be considered?
- How much load carrying capability (capacity value or unforced capacity) do limited electric storage resources contribute and how should their energy limitations impact their participation in capacity markets?
  - How does the level of energy (SOC limits) impact capacity value?
  - Does the load shape and "peakiness" of the load impact storage capacity value?
  - How does renewable resource levels impact capacity value of ESR?
  - How does the way that ESR are operated impact capacity value (e.g., minimizing cost vs. saving energy for peak hours)?
  - How do new pay-for-performance capacity market rules affect ESR?
- How can (and what are the most efficient ways that) the ISO manage the state-of-charge of energy storage in its electricity market?
  - In Day-Ahead SCUC (DASCUC)?
  - In reliability unit commitment process directly following or integrated with the DASCUC?
  - In Real-time SCUC (RTSCUC)/Intermediate Term SCED (ITSCED)/ short-term unit commitment (STUC)/ look ahead commitment (LAC)?

- In the real-time dispatch and real-time market?
- In AGC?
- How are these all linked in the presence of unanticipated forced generator outages, load forecast uncertainty, and VER forecast uncertainty?

- How can storage set price when it is the marginal resource– what is its marginal cost?
    - What are differences between different scheduling operation (ISO managing SOC, ISO managing operational mode, or self-managing of both)?
    - How can it set price in the real-time market?
    - Does it differ in markets that use single-period compared to those that have multi-period pricing?
    - What can trigger a mitigation conduct threshold for storage (i.e., when the storage is offering uncompetitive (excessive) costs and may have market power)?
    - Are there inter-temporal lost opportunity costs that should be considered in price setting (i.e., by providing energy now, ESR loses the opportunity to sell it later)?
    - How can an ESR set ancillary services prices without an energy offer?
- How do small resources impact the market clearing engines that use a nonzero MIP gap?
    - How do numerous small electric storage resources with or without complex scheduling procedures impact computational time of day-ahead and real-time market clearing software?
- Should energy storage be guaranteed to be held financially whole through out of market (e.g., make-whole) payments and if so, how would that be calculated in settlements?
    - Particularly during periods where the storage is bidding as a load and prices are higher than its bid-in costs?
    - When the ISO/RTO is managing SOC and operational mode (charge or discharge), and overall there is a net loss in revenue, how is the make-whole payment calculated?
    - When the ISO manages SOC and the ESR ends the day at a different SOC than it started, how can make-whole payments be calculated?
    - Are there other settlements procedures that should be evaluated given the uniqueness of energy storage?
- How can fast responsive limited electric storage resources be used most efficiently in automatic generation control?
    - Are current AGC tools and pay-for-performance regulation market rules sufficient for economic efficiency and reliability objectives?
    - Is explicit SOC management in the AGC needed, or are signal modulations that should lead to energy-neutral signals sufficient?
    - How should payment be affected when SOC is being managed for the ESR, rather than it helping with control?

There are many more questions that can come up with the entire gamut of discussion on how ESR participate in electricity markets. We use these questions as a starting point to aim at some new research and development concepts that may be able to help answer them. The next section discussion potential designs that, when analyzed, may help answer some of these questions.

4

ENERGY STORAGE MARKET MODELING POTENTIAL DESIGNS

The objective of this white paper is to capture the state of the art in energy storage market modeling, some of the existing questions and challenges that remain, and potential design alternatives that may further lead to enhanced economic efficiency and/or reliability. By reviewing the questions of Section 3, we developed a potential plan of answering those questions through ideas on alternative market designs. We are evaluating benefits in terms of economic efficiency, reliability, incentive compatibility, revenue sufficiency, (reduced) complexity, and fairness. These designs may or may not lead to the desired benefits, or, likely, will lead to benefits in some categories and not in others. Simulation and analysis of the different alternative designs can provide some insight into the benefits and consequences that are possible.

The following is a list of nine topics/objectives as discussed through the WG that categorize the vast majority of challenges foreseen with incorporating ESR within the ISO electricity markets. The nine topics generally link with the categories in Section 2 and those in the FERC NOPR. In each of these we briefly introduce the challenge and then provide some high level options for alternative market clearing and software designs that can be evaluated to address the challenge. In some cases, we lay out the specific options (of which are not comprehensive) and in other cases we summarize how the challenge can be addressed. It is important to note that there is also significant overlap in each of these categories. A holistic view is important in knowing how benefits in one aspect may lead to shortcomings in others.

Efficient Methods of Bidding and Scheduling of Electric Storage Resources in Day-ahead Markets

The WG discussed the different design options to allow for utility-scale energy storage (both large reservoir and limited energy) to participate in day-ahead energy markets. We list five high-level options. The options are not mutually exclusive but focused on different aspects (i.e., two or more options can be combined).

DAM Option 1: Storage resource bids as two distinct resources, either a responsive withdrawer of energy or a responsive injector of energy. Each bid can have costs and resource parameters associated with it including decremental/incremental cost offer curves, but there is no link between the two other than the owner and location. Logic in SCUC can prevent the solution from choosing both offer/bid of the same resource for the two configurations simultaneously, similar to how two configurations of combined cycles cannot be chosen simultaneously. The storage resource must manage its own state-of-charge to ensure that it has energy to meet its obligations. It will require dynamic hourly offer/bids and dynamic hourly Pmax and Pmin parameters (i.e., a daily fixed offer curve would not be sufficient). In ESDER Phase III, CAISO also discussed a SOC-dependent offer curve which could potentially be added here [25].

Advantage: simple solution, ESR treated similar to other resources, does not require SOC management and generally limited impact to SCUC performance time.

Disadvantage: No guarantee to meeting SOC or optimal scheduling and thus can impact economic efficiency and/or reliability

DAM Option 2: The electric storage resource would provide a single incremental energy offer curve which can range from negative Pmin value to a positive Pmax value with negative to positive incremental energy costs (similar to CAISO NGR model). In this case the ESR would also manage its own state-of-charge. It would also require dynamic hourly offer/bids and dynamic hourly Pmax and Pmin parameters. This could potentially also include SOC-dependent offer curve or similar.

Advantage: simple solution, ESR treated similar to other resources, does not require SOC management and limited impact to SCUC performance time. Also no logic required to prevent resource from moving from withdrawer to injector in a seamless manner.

Disadvantage: No guarantee to meeting SOC and thus can impact economic efficiency and/or reliability. May be challenge for resources with minimum charging power levels or rough zones (e.g., PSH or CAES)

DAM Option 3: The ESR would provide a beginning SOC (or the ISO would use directly from previous day's DAM result) and an offered end-of-day SOC, with max/min SOC limits, and round-trip efficiency ratio. The ISO software would then optimize the schedule of the ESR to minimize costs while making sure that it ends with desired end-of-day SOC while obeying other SOC limits. The ESR can estimate the end-of-day SOC based on how much it would like to save for the next day (e.g., less if next day is a weekend, more if next day is anticipated to be high load). Thus, the ISO would manage SOC limits based on ensuring SOC is between minimum and maximum SOC limits and that the SOC results at the desired level at the end of the day.

Advantage: Can better ensure that the obligation given can be met in real-time due to energy limits, while still allowing the ESR to provide parameters on how it would like to be used.

Disadvantage: Complex and can impact SCUC performance. The ending reservoir value may be constraining and can limit ability to take advantage of different daily results. May result in usage at revenues that cannot cover costs of operating. Unclear how it would work for limited energy storage.

DAM Option 4: The ESR would provide a beginning SOC (or the ISO would use directly from previous day's DAM result) similar to above. However, instead of offering an end-of-day SOC, it would offer a SOC "surplus storage value" which is a $/MWh offer based on the desired amount of energy left at end of day. This would guide the market clearing software on how much of the energy to use rather than a hard constraint on the energy that is left over at end of the horizon. The ESR would base its value on how much its energy may be worth the following day. This would still include SOC min/max limits. Thus, the ISO would manage SOC limits based on ensuring SOC is between minimum and maximum SOC limits and that the SOC results in desired level at end of day depending on how valuable the energy is worth during the day.

Advantage: Can better ensure that the obligation given can be met in real-time due to energy limits, while still allowing the ESR to provide parameters on how it would like to be used. A little more flexibility than Option 3 as it can be used more or less if the daily costs (and therefore prices) are higher than the ESR predicted.

Disadvantage: Complex and can impact SCUC performance. May result in usage at revenues that cannot cover costs of operating. Unclear how it would work for limited energy storage.

DAM Option 5: The ISO would optimize the ESR production based on a horizon that is longer than the one day. Forecasts for additional days ahead would be used to determine how the ESR is used for the current day. This potentially eliminates the need for the end-of-day SOC parameter as well as the surplus storage value offer. The production for the future days is advisory only. Some ISOs (e.g., MISO) are already looking at explicit multi-day SCUC.

Advantage: Potentially (but not necessarily) eliminates needs for parameters that help with end-of-day horizon. Forecasts of future days may allow for more economically efficient operation of current day for ESR, as long as forecasts are generally accurate.

Disadvantage: Additional horizons can impact SCUC performance. This would likely not be beneficial for limited energy ESR.

DAM Option 6: In addition to either Option 3 -5, add an "arbitrage/spread cost" that allows the ESR to offer the cost that it has for operating. For example, this cost may be based on its O&M costs for operating, and thus can allow for the ISO to ensure SOC limits are obeyed, while also considering the costs of operating the ESR when determining the solution.

Advantage: Can better ensure that the obligation given can be met in real-time due to energy limits, while still allowing the ESR to provide parameters on how it would like to be used. Can better capture the costs of operating the ESR.

Disadvantage: Complex and can impact SCUC performance. Since costs and prices are not perfectly aligned, may result in out of market payments rather than corresponding market revenue that makes up for spread costs. Unclear how it would work for limited energy storage.

Summary: Some resources would require commitment constraints and minimum charging levels (PSH and CAES) while others do not (batteries, flywheels). Interim SOC levels may improve the solution as well, particularly for limited energy resources. For example, for option 3, the resource could also suggest SOC levels for Hour Beginning 4, 8, 12, 16, and 20 instead of just the end of the day. Finally, some hybrid approach may be beneficial. For example, using Option 1 or Option 2 in the day-ahead market, and simply evaluating the SOC limits in the RUC process to ensure that sufficient resources are committed when the ESR may not be able to meet its day-ahead market obligation. This would be similar to how VER are treated with unverified offers in the day-ahead and ISO forecasts in the RUC.

Many of these options can be tested via simulations. Very little is known about day-ahead ISO enabling SOC limits for limited energy storage, and thus, experience from pumped storage models can provide learning. Simulations at moderate and high ESR penetrations can show how often self-management of SOC can lead to deteriorated economic efficiency or reliability impacts when ESR are not able to produce as expected due to SOC limits. Price setting should be evaluated as well in each of these designs.

Efficient Methods of Bidding and Scheduling of Electric Storage Resources in Real-time Markets

While the principles are much the same, there are some particular differences between the real-time market (including within-day commitment and within-day look-ahead processes) and the day-ahead market. First, there is less uncertainty in the real-time market. While the real-time market is still making decisions “in advance”, it is typically less than 15 minutes and up to a few hours in advance, with any changes within the 15-minute horizon being adjusted by regulation resources or operator actions. Also, while the day-ahead market is for an entire day, the real-time market horizon is for much shorter horizons. The real-time dispatch, which solves for real-time prices is either a single five-minute interval, or sometimes with up to an hour of look-ahead. Commitment models that precede the real-time dispatch are often for a few hours, but still less than 24 hours. This essentially means that while there is better information to make decisions about the optimal use of ESR, there is less information to do so. In order for ESR to be an enabler for integration of VER, the ESR participant and the ISO together must be able to efficiently use ESR in the real-time market, when VER forecast errors become apparent but other resources are not able to be recommitted, or not able to be adjusted as quickly or efficiently.

Second, the real-time dispatch schedules and prices are being solved at more granular of time intervals than the day-ahead market, at five minutes rather than hourly. The ability to meet five-minute needs and not be required to sustain power output for an entire hour allows for greater ability for ESR with limited energy storage to meet energy needs. It also may provide for better arbitrage of pricing for these resources than they are able to in the day-ahead market. Finally, fewer commitment decisions that are made in the real-time market mean that there are further opportunities for ESR to be the resource to meet needs for changing system conditions in real-time.

We will give an example first of the challenge with real-time markets.

An ESR is given a 24-hour day-ahead schedule such that it optimized to reduce total costs for the day and had ending SOC based on offered amount (end at 400 MWh)

> Hour 10:00-11:00: DAM schedule of 100 MWh, DAM LMP of $30/MWh
>
> Unit Pmax of 200 MW, Pmin of -200 MW, SOCMin 0 MWh, SOCMax 800 MWh
>
> Hour 16:00-17:00 of the DAM is when the ESR runs out of energy with a SOC of 0 MWh

The RTM uses a 1-hour horizon at 5-min intervals

> RTM 10:00-10:05 LMP is $50/MWh, all 5-min intervals in horizon are generally high ($50/MWh)
>
> Should the ESR provide additional energy above its 100 MWh DAM schedule?

If it were to achieve the same SOC of 400 MWh at end of day as desired through the DAM, if it were to increase above 100 MW during 10:00, it would have to reduce output (or increase charging) at some other hour before the end of the day.

Because of its anticipated running out of energy during hour 16:00-17:00, if it were to increase above 100 MW during 10:00, it would have to reduce output (or increase charging) before 16:00.

It is hard to know whether the options would be beneficial as there are no real-time prices yet for the future intervals beyond 10:00 hour. This example shows the challenge of re-optimizing in the real-time market. The simple option of just remaining at its day-ahead schedule for all hours in the real-time, prevents the ESR from providing real-time flexibility, a trait that is becoming more desirable as systems are seeing more variability and uncertainty in system conditions.

Similar to the day-ahead bidding and scheduling, we list a few potential high-level options for the real-time market that could be evaluated further. It is possible that any of the DAM options can be used with any of the RTM options. Given the horizons of DAM, it is most likely that the ISO management options are developed first in the DAM to observe which benefits can be realized before adding these features to the RTM.

RTM Option 1: Even if the ISO optimizes the ESR schedules based on SOC limits and preference in the DAM, the ESR must bid on its own either through explicit self-scheduled quantities, or an economic cost curve. The economic cost curve would be similar to DAM Option 2 where the ISO must allow offers and quantities to be updated by the ESR (or SOC-dependent offer curve).

Advantage: simple solution. In case of poor real-time decisions, they are made by the owner rather than the ISO.

Disadvantage: No guarantee to meeting SOC in real-time and thus can impact economic efficiency and/or reliability. It may not be the most economically efficient solution.

RTM Option 2: The ISO can optimize the ESR production over the given real-time horizon (intra-day SCUC, short-term SCUC, real-time SCED) with an end-of horizon SOC that equals the SOC from that time period within the DAM (somewhat analogous to DAM Option 3).

Advantage: Could improve economic efficiency and reliability, as the DAM schedules, which were already optimal for the given DAM conditions, are somewhat held intact for the time periods that the real-time market is not evaluating.

Disadvantage: There is a limitation on just how much the ESR can do within the short real-time market time horizon. It will need to make up for any changes within the real-time market horizon even if it may be more beneficial to make up for it at a different point of the day. Can be complex.

RTM Option 3: The ISO can optimize the ESR production over the given real-time horizon (intra-day SCUC, short-term SCUC, real-time SCED) with end-of horizon "surplus storage value" that is determined based on revenues that would be received for the rest of the hours not included in the RTM as determined through the DAM (somewhat analogous to DAM Option 4).

Advantage: Could improve economic efficiency and reliability, as the DAM schedules, which were already optimal for the given DAM conditions, are somewhat held intact for the time periods that the real-time market is not evaluating. Allows for more flexibility to fix the SOC limits at a point beyond the real-time market horizon.

Disadvantage: The surplus storage value as decided through the day-ahead market, may constrain the flexibility of the ESR to change its strategy. Could potentially lead to poor decisions later on in the day. Can be complex.

RTM Option 4: The ISO can optimize the ESR production over the given real-time horizon (intra-day SCUC, short-term SCUC, real-time SCED) with an end-of horizon "surplus storage value" that is determined by the ESR (somewhat analogous to DAM Option 4) rather than set by DAM results.

Advantage: Could improve economic efficiency and reliability, as the DAM schedules, which were already optimal for the given DAM conditions, are somewhat held intact for the time periods that the real-time market is not evaluating. Allows for more flexibility to fix the SOC limits at a point beyond the real-time market horizon and lets the ESR owner, rather than the ISO, drive the decision on the value of its surplus storage.

Disadvantage: May lead to reduced economic efficiency from the DAM value or SOC violations if the surplus storage value is chosen incorrectly. Could potentially lead to poor decisions later on in the day. Can be complex.

Many of these options can be tested via simulations and integrated with the day-ahead simulations. As challenging as the options are for the DAM, the real-time market becomes even more challenging, as additional complexities are added, and potential to degrade an already optimal set of decisions from the DAM is possible.

Management of State-of-charge Limits and Operational Modes that lead to Greater Reliability, Economic Efficiency, and Incentive Compatibility

One of the challenges that is most debated by those involved in including energy storage in the market, is whether the ISO should manage the ESR's SOC to be within limits and preferences provided, or whether ESR should ensure it offers in a way such that it can ensure it is within SOC limits while being treated in the market clearing software more similarly to traditional generators and loads. The different options shown under the DAM and RTM each are examples of either self-management or ISO-management of SOC limits. Thus, the options below are contained within those above options. Here we list them with a focus on SOC management with the advantages and disadvantages aimed at this aspect of the options.

SOC management Option 1: ESR would participate similar to a generator or similar to a load resource and bid/offer in a way that should enforce SOC limits.

Advantage: Least effort included in software enhancements and ability to solve SCUC/SCED within timeframes. Allows ESR owner to have most flexibility to "decide own fate" in provision of energy

Disadvantage: Theoretically less economically efficient as state-of-charge not optimized with all system information. Could potentially lead to impact on reliability with large ESR quantities and persistent SOC mismanagement that leads to insufficient committed capacity

SOC Management Option 2: ISO would gather SOC limits and schedule/optimize the operation of the ESR to ensure within SOC limits as well as schedule to SOC preferences (e.g., end of horizon SOC).

Advantage: Theoretically, would be most economically efficient and most reliable as the ISO would have the information to push ESR to its SOC limits to reduce costs and only rely on its energy when it can ensure it is there.

Disadvantage: Complex and may have challenge to solve within market clearing software times. May eliminate flexibility of ESR to operate based on its own parameters (however, providing this as an option would let the ESR owner decide which method to use).

SOC Management Option 3: Self-management from ESR owners in DAM, ISO-management in reliability unit commitment (RUC) process. The RUC process typically follows the DAM and ensures that sufficient physical resources are committed to meet forecasted conditions (the RUC is more about reliability and less about the market, but still attempts to make most economic commitments). The ESR would bid on its own as generator and load resource in the DAM, but then would be checked for its SOC limits in the RUC process. If any SOC limits are violated in the RUC, the ISO could potentially turn on an additional unit if needed. In RTM, operators may want to check to make sure that if SOC was violated in the RUC, it does not follow that schedule, or that at least the ISO is aware that it may be constrained by SOC and that commitment and dispatch changes of other resources may be necessary.

Advantage: Allows additional flexibility such that the ISO management does not have significant impact on market clearing in DAM, while also ensuring reliability by not relying on ESR with limited SOC when making unit commitment decisions. Less complex than Option 2

Disadvantage: Could potentially be less economically efficient than Option 2. Decommitments are typically not present in the RUC.

These options, as is the case with all market design alternatives have many pros and cons. These options can also be tested via simulation with careful attention to inputs including the system and ESR levels, existing market design, and the way that an ESR may offer if it is managing SOC on its own. The objective would be to evaluate whether ISO-management of SOC does lead to improved economic efficiency and reliability in practice, and the probability that self-management of SOC by ESR at various ESR penetration levels may potentially lead to reliability challenges when insufficient capacity is committed and available. Other evaluation metrics should be compared like transparency, incentive compatibility, and software complexity.

Efficient Price Formation with Electric Storage Resources

When an ESR bids separately as a generator or load resource (with the primary difference from traditional generators and price capped load being the ISO cannot schedule it in both modes simultaneously for the same interval), price setting is not much different than it is for a generator or load resource, respectively. When an ESR bids as one resource with a continuous supply curve from negative minimum charging to positive maximum discharging, it should also be able to set price similar to a generator. While charging and a marginal resource, then the next increment of load would be met by reducing the charge by the same increment, causing a positive energy price. It could also set price while at 0 output, since it can be marginal (it is above minimum and below maximum).

Where price setting and settlement becomes more complex is when the ESR is operated in a way where the ISO is determining operational mode and operating point based on reducing costs, subject to SOC limits, charging efficiency losses, and SOC preferences/values (e.g., DAM Solution 3 or DAM Solution 4). In this case there is potentially no input offer incremental cost ($/MWh) that the ESR provides that directly will set the price during every hour the ESR is a marginal resource. It is important to understand the different ways that ESR can set price to ensure prices that reflect marginal value and ensure resources have the incentive to follow schedule.

The way in which the ESR sets the price will depend on the option chosen for SOC management. As an example, for DAM Option 3 (End of Horizon SOC Constraint), the price of any interval within a multiple-interval horizon will be set from the shadow price of the End of Horizon SOC Constraint. If the SOC minimum and maximum constraints are never binding, then any interval during the entire horizon (e.g., entire 24 hours of the DAM) will be equal to the shadow price of the End of Horizon SOC Constraint whenever the ESR is marginal during that interval. If there are SOC limits that bind, then the energy price during the interval in which the ESR is marginal will be adjusted based on the shadow price of the minimum/maximum SOC limit constraint.

Alternatively, for DAM Option 4 (SOC “surplus storage value”), the price will instead be set based on the surplus storage value that is bid by the ESR owner. Without SOC limit constraints, the surplus storage value would set the price of any interval during the horizon when the ESR is marginal. If there are SOC limit constraints that are binding, then the price set when the ESR is binding would be the surplus storage value modified by the shadow price of the SOC limit constraints.

One important feature is that the dual solution, that which is used to calculate energy and ancillary service prices, is the same horizon as the horizon that is used for the primal solution, that which is used to determine schedules. Otherwise, ESR may not actually be able to set the prices correctly. Some ISOs determine prices on an hourly basis, even for the DAM which sets schedules based on 24-hour time-coupled solution. This is important for ensuring that ESR are able to set the price when marginal.

Numerous different calculations can be used to ensure an effective price is set when ESR are marginal resources. The price setting does not have a direct effect on reliability or economic efficiency. Thus, the metric that is being evaluated is incentive compatibility. Are the prices that are set efficient for ensuring every resource has an incentive to follow the schedules that were determined as part of the market clearing. Other issues can be looked at as well, including how the new “fast start pricing” logic may apply for ESR, how mitigation may be applied during times when ESR may have market power, lost opportunity costs across products and time, and, if spread bids or variable O&M or other costs are added to the ISO-management of SOC, how can these also be incorporated into the prices.

Provision of Ancillary Services and Co-optimization of Energy with Ancillary Services Considering Characteristics of Electric Storage Resources

In order for ESR of different technologies to participate in the ancillary services markets, it is important to ensure their energy limitations do not preclude them from doing so in a similar manner to the provision of energy. Because energy and ancillary services are usually co-optimized in day-ahead and/or real-time markets, the provision of both services over time will have an impact on whether ISOs can rely upon them when needed. We will discuss a few different ancillary services and how the impacts may vary depending on their requirements.

Spinning reserve[6] typically has the largest duration requirement of all the active power ancillary services. Spinning reserve must be fully deployed within 15 minutes (though this is typically reduced to 10 minutes) to meet the NERC BAL-002 requirements (also referred to as the Disturbance Control Standard, and specifically, the Disturbance Recovery Period) [26]. However, it must then be maintained until the reserve can be restored for a subsequent event. The timing of the restoration is also part of NERC BAL-002, referred to as the Contingency Reserve Restoration Period, which is currently set at 90 minutes following the Disturbance Recovery Period. Thus, after using 15 minutes' worth of energy to respond to the contingency, the ESR that is providing spinning reserve must sustain its output for another 90 minutes until additional capacity can take its place and the ESR can back down. It is important to note that many areas do restore contingency reserve in shorter timeframes. For example, the Northeast Power Coordinating Council requires 30-minute reserve for second contingencies, but also states that all contingency reserve (spinning, 10-minute reserve, and 30-minute reserve) must be able to be sustained for 30-minutes following deployment [27].

Regulation reserve is not as clear in terms of guidance on sustainability of the deployed energy. In the past, regulation was also considered to be an hourly duration product, primarily because it was sold in hourly intervals in the DAM. Recent changes, many of which aligned the ISOs with direction of FERC Order 755 – Pay for Performance Regulation, adjusted this to shorter duration requirements (e.g., 15 minutes).

Primary frequency response (PFR) is an ancillary service that does not explicitly have a market within the North America. A recent request for supplemental comments by FERC was issued to understand the requirements for ESR to provide PFR capability [28]. Primary frequency response is the immediate response following a frequency deviation to stabilize system frequency. The sustainability requirement is simply enough time for spinning reserve or regulation to bring the frequency above the frequency deviation dead band. This results in a duration requirement of between 5-8 minutes. In addition, the typical response of 5% droop, results in a response of about 3.33% of capacity per 0.1 Hz (or less due to dead band). Thus, ESR SOC limits are likely to have the least impact on the duration requirements from this service.

The following are options for market design alternatives of how to ensure ESR have the energy to provide the various ancillary services.

A/S Provision Option 1: Leave it up to the ESR owners to offer ancillary service capacity to the market only when energy is available. ESR owners would bid 0 capacity from ancillary services when they foresee SOC limits that may prevent them from delivering energy if the ancillary service must be deployed.

Advantage: Simple without need to make significant software changes. Most services may not have significant impacts due to SOC limits so over prescription for services may not be substantial.

Disadvantage: Hard for ESR owner to know limits within a multi-period optimization when offering for both ancillary services and energy. Could lead to inefficiencies (ESR offering less

[6] Also called synchronized reserve or contingency reserve. This reserve refers to online capacity with head room to respond to disturbance (contingency) events, primarily loss of supply.

that actual energy available) or undeliverable services (ESR offering capacity when energy is not available to deliver service).

A/S Provision Option 2: The ISO limits the amount of ancillary service capacity the ESR can provide based on its anticipated SOC for the interval and the duration requirement for the service.

Advantage: Improved economic efficiency and reliability by ensuring the service can be delivered assuming anticipated schedules remain intact.

Disadvantage: Added complexity to the market clearing software.

The extent to the benefits of either method will depend on the reliance the ISO must have on ESR to provide ancillary services, the amount of ESR on the system, and the consequences of being short on a particular ancillary service. Simulations may be able to be conducted to compare reliability and economic efficiency of both options. In addition, these can be combined with the day-ahead and real-time options, as well as price setting options to understand the implications of energy and ancillary services sharing of power capacity and energy capacity.

Efficient Settlement Design for Electric Storage Resources

One of the most significant market design features in North American wholesale electricity markets is the guarantee that if you participate as a flexible resource to be scheduled by the ISO, that you will be made whole to your bid-in operating costs. This currently includes incremental energy costs, no-load or minimum generation costs, and start-up costs. Similar to our discussion in the price setting challenge topic, when an ESR bids separately as a generator or as a load resource, it likely can receive the same guarantee in the same manner that a generator does while in generator mode. Guarantees are not quite the same for load resources that offer in negative prices to consume, but are nonetheless technically straightforward. If offering with a continuous supply function from negative charging to positive discharging, the challenges are unique across the load and generator segments of its offer curve. There are some policy challenges that must first be overcome, as was brought up within the FERC NOPR and several commenters of the FERC NOPR, on whether those guarantees should be upheld while charging. The technical challenge is less significant on determining what those make-whole payments are. One challenge is to determine whether the make-whole payments should be netted to the entire day or period the ESR is online, or to net it for periods while charging or discharging individually.

A greater technical challenge exists for ESR that are under ISO-management of SOC. It is possible that when an ESR is being used to reduce costs by the ISO, that it does not earn a positive profit. In other words, it may pay more for consuming energy while charging than it earns for supplying power while discharging. While this is likely to be an exceptional condition rather than the norm, it is particularly possible in the DAM due to pricing impacts from non-convex optimization and due to the fact that the ESR must charge more energy than it supplies due to efficiency losses. For example, it is possible that the ESR is discharging led to a different unit commitment selection than if it hadn't been discharging, such that the incremental energy costs are lower but no-load and start-up costs are higher (however, overall combination of costs are lower due to cost minimization). This could lead to a depressed LMP. Additionally, it is possible that the ESR modified selection across all intervals within the DAM such that overall the prices lead to a negative profit based on the selected operation of the ESR. During these intervals, the ESR participated in the market based on the ISO discretion, and as a flexible resource should likely be made whole just as thermal generators are when the prices do not cover the sum of their incremental energy, no-load, and start-up costs. However, if the ESR has more SOC stored at the end of the day, then it may be more likely that it has a negative profit, as it charged more than it discharged. In addition, if some sort of spread or variable O&M cost were used (See DAM Option 6) the calculation may need to somehow include these. These variables may all have an impact on the determination of make-whole payment for the ESR. In addition, other settlement rules including day-ahead profit assurances, price volatility make-whole payments, uplift allocation, and penalties for energy limitations that affect schedules will need to be evaluated to ensure that ESR can participate in the energy and ancillary services to their fullest capabilities in a reliable, economically efficient, and fair manner. Studies can evaluate the different calculation options to evaluate whether they provide the corrective incentives for ESR to provide the energy and ancillary services schedules that are desired by the ISO.

Automatic Generation Control Methods for Electric Storage Resources that use Resources in Most Efficient Manner Possible

The primary participation of limited energy ESR to date has been in the regulation ancillary service market. This is a natural role for ESR as regulation requires both an upward and downward movement and a fast response rate. The upward and downward movement requirement allows the ESR to charge while providing downward regulation so that it may have energy once it is required to provide the upward regulation. Typically, the ESR would only pay the efficiency losses and not have to pay for the charged energy. The fast response times are something many small-scale storage (batteries and flywheels) are known for. On top of that, most ISOs include mileage payments and some have benefits "adders" that mean the faster responding resources get paid higher quantities for providing the same regulation capacity. This is why regulation has been such an attractive service for ESRs in most of the ISO/RTO markets.

It is important that the unique attributes of ESRs are used within the AGC and regulation market in an optimal manner. This means ensuring that they are used to provide superior reliability support based on the objectives of AGC, ensuring that they are used in a manner that leads to reduced costs (than if they were not used) and that the prices that they are paid are compatible with the directions provided by the ISO and AGC, and not excessively so. Importantly, each ISO in the United States that has made modifications to FERC Order 755 has implemented design changes to the regulation market and to the AGC process differently from each other. These differences may all have different advantages and disadvantages compared to one another. This analysis can provide great benefits to making enhancements to these designs.

Advanced simulations could be used to better understand the reliability benefits of different AGC algorithms that may use ESR differently from other technologies to see the benefits that they provide to overall frequency control and interchange error. This analysis can be coordinated with other market simulations to understand the different mechanisms for scheduling and pricing regulation from ESR to ensure reliability, efficiency and incentive compatibility.

Small Resource Impact and Computational Impacts of Significant Levels of Electric Storage Resources

One of the proposals of the FERC NOPR was that the ISO should allow all resources that are at least 0.1 MW capacity in size to participate in the ISO markets. It is generally agreed upon that the more resources that can participate into the electricity markets for different products, the better, as it improves competition and thus economic efficiency, and can improve reliability as well with more options to meet the services the ISO needs. It also ensures fairness to include all resources that are technically capable of providing the services. However, it does come with technical challenges.

The first challenge is not necessarily the minimum size requirement, but how it may lead to larger quantities of participants. The small minimum requirement may lead to a substantial amount of new resources who start to participate in the ISO markets. This increases the size of the market clearing problem that the ISOs are trying to solve. If these resources also were treated within unit commitment, with SOC limits and other complex constraints, such that multiple continuous and integer variables and constraints are added for every single new participant, this can increase the problem size further. To allow for the problem to solve within market clearing timelines, additional solutions may be needed including hardware improvements, software and solver enhancements, and added heuristics.

The second challenge is related to how these resources may be treated within the electricity markets. Most ISOs use a MIP gap in their unit commitment solutions, such that the problem may not be solved to global optimal as long as the difference between the integer solution and the relaxed continuous solution is below the MIP gap. The MIP gap is usually below 1%; however, even at 0.2% of total daily costs of several million, this is a substantial number when comparing to the cost of an individual resource. What may happen is that the smaller resources with overall costs well below the MIP gap may get “ignored” in the solution. Once the solution reaches below the MIP gap, the commitment of the small resource won’t make a difference and so it can somewhat randomly be left on or off, regardless of whether it is truly economic or not. This can be a significant challenge for the individual small resources. Some ISOs have already began to develop solutions for this issue. Some of the solutions are somewhat manual and ad hoc, which may be acceptable when only a small number of resources are affected. More streamlined, automatic processes may be necessary with larger amounts of these small resources. Potential designs and solutions can be tested to see which may lead to fairest and most economically efficient way of scheduling these small resources within the energy and ancillary service markets.

Efficient Allocation of Electric Storage Resources in Capacity Markets

The FERC NOPR proposed that all ISOs who use minimum duration requirements within their capacity markets allow ESR to participate in these capacity markets by prorating their capacity to how much can be provided consistently for the length of the minimum duration requirement. So for example, if an ISO requires that a capacity resources that clears in the capacity market must be able to provide capacity consistently for four straight hours, then a 1-hour ESR (ESR has an energy limit such that starting at full SOC, it can provide power at maximum power/discharge capacity for 1 hour before it runs out of SOC) would receive 25% of its nameplate capacity credit in the capacity market. The alternative in some ISOs that may currently exist, is that if the ESR has less energy limit than the minimum duration requirement, it would not be able to participate in the capacity market whatsoever.

Generally, the change proposed by FERC appears to be an improvement over the all or nothing approach. It is clear that resources that cannot provide energy for the entire length of the minimum duration requirement have some capacity value. Thinking otherwise can lead to overbuilt capacity (assuming large penetrations of ESR). However, it is not clear that the simple prorating provides the correct capacity value either. It is possible that it could be over-qualifying the capacity value of certain ESR, especially if the ESR has low SOC at the beginning of a peak period. It may still, however, be undervaluing the capacity value. Some researchers have shown that the capacity value is highly volatile from BA to BA, and for different years (see Figure 4-1) [29].

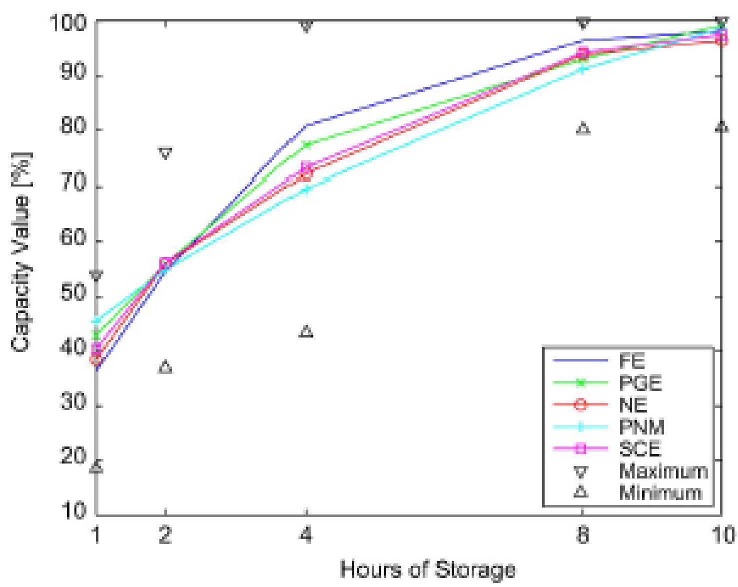

Figure 4-1
Capacity value of storage for different utilities and different hours of storage [29].

Research needs to be conducted to ensure a scientific, proven approach to determining the capacity value of ESR, with a number of different scenarios tested. ESR provide energy based on prices, and if high prices occur prior to the most critical time periods, they may not have energy to provide during the critical time periods, thereby providing less capacity value. Conditions that may impact the capacity value include the amount of storage of the ESR, the “peakiness” of the load or net load, the correlation between energy prices and load, the quantity of ESR that are part of the system, and the uncertainty that is present between when the decisions are made for the ESR and real-time. Once the capacity value is well understood, other challenges are still present in being able to participate in capacity markets. These include mitigation rules, contribution to capacity performance markets, and whether and how ESR contribute to flexible capacity which is in place in CAISO.

5
SUMMARY AND NEXT STEPS

This white paper provides a detailed review of electric storage resources and their participation in North American electricity markets. Each of the ISOs/RTOs have different designs in place for the participation of ESR into energy, ancillary services, and capacity markets. This is due to the stakeholder process, the current levels of ESR in the footprint, software, and other differences. There are no one size fits all to the designs that can lead to the most economically efficient and reliable power systems. However, careful review and eventual simulation and analysis can provide some valuable insights on designs that may be considered as best practices.

The nine topics/objectives discussed in Section 4 of this WG report are the topics that were found as most important to ensuring ESR can be fully integrated into the energy, ancillary service, and capacity markets of the North American ISOs in a reliable, economic, and incentive compatible manner. Each of the topics are interlinked to each other and should be studied in a holistic manner. Alternative market designs can be compared through comprehensive research, analysis, and simulation to evaluate reliability, economic efficiency, and incentive compatibility. It is important that existing market design features of the ISOs are also included to ensure that the evaluations of design changes to incorporate energy storage are realistic.

The team will prioritize the nine topics above as part of the WG and technical Task Force. Research to evaluate the specific design features will be conducted as part of EPRI's 2018 Project Set on Market Operations and Design. In addition, the research related to ESR and capacity markets will also be conducted in EPRI's Flexibility and Resource Adequacy Project Set, specifically testing methods to develop the effective load carrying capability of energy storage technologies. The research will be reported back on an ongoing basis to ensure feedback on the practical issues are being captured well in the analysis. The team will also work with the WG throughout 2018 to make sure any new market designs that impact ESRs being planned or implemented in the North American ISOs are understood well and findings brought into the research.

6
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