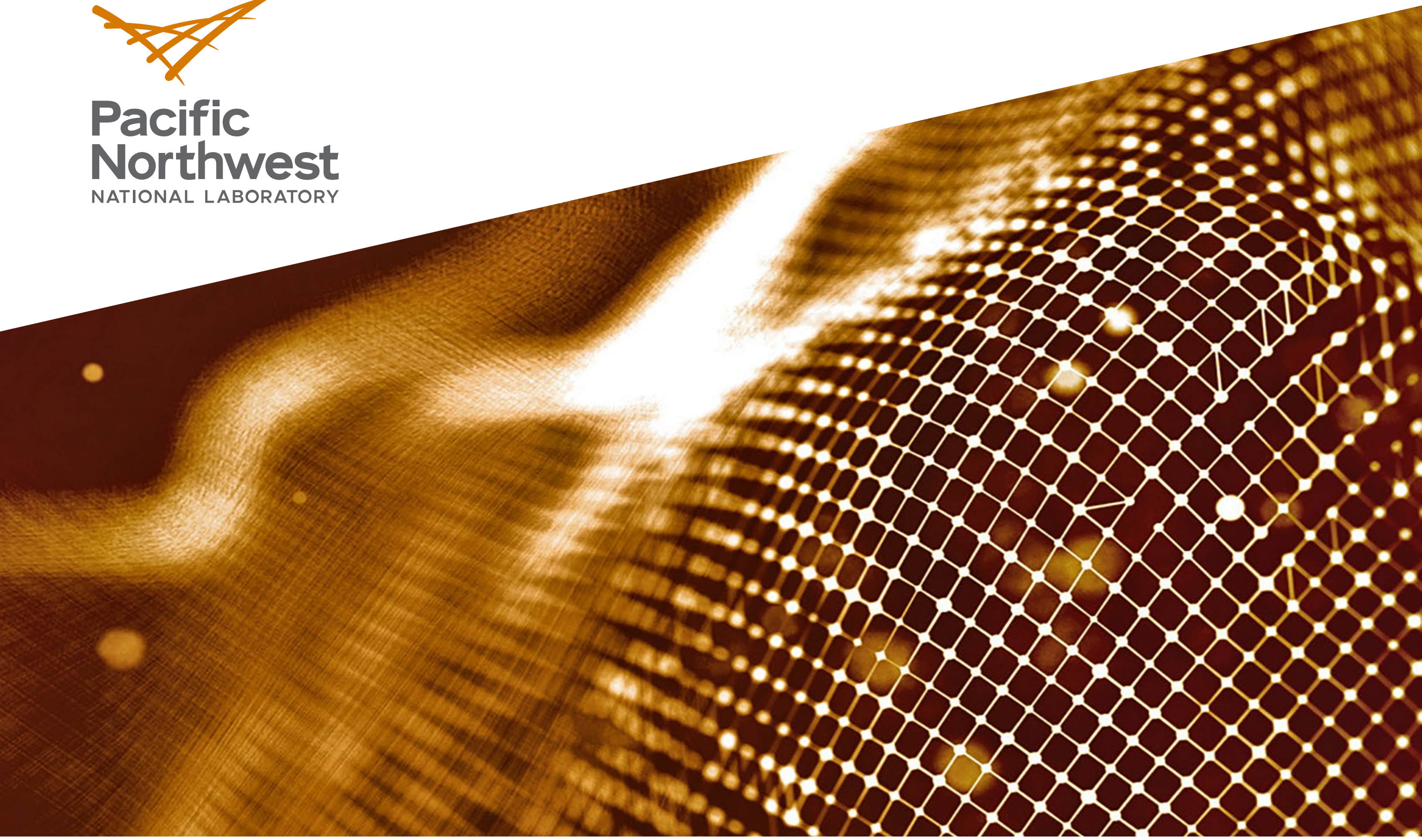

PNNL-33599

Potential for Transactive Energy to Improve the Provisioning of Grid Services from Batteries

Final Report

October 2022

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Prepared for the U.S. Department of Energy
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Abstract

This study assessed the degree to which transactive energy systems could help reduce or remove barriers to the deployment of battery energy storage and realize the full potential of battery resources to supply needed services to the grid and fairly compensate various types of battery owners. To enable this assessment, typical battery deployments were characterized, along with energy markets, Federal Energy Regulatory Commission Orders, wholesale and distribution-level grid services, and current deployment barriers. Finally, this study analyzed the value that accrues to batteries supplying today's grid services as a function of the participation models associated with three primary types of battery ownership: merchant-owned transmission-connected batteries; utility-owned distribution-connected batteries; and customer-owned behind-the-meter batteries. This provided both quantitative and qualitative assessments comparing opportunities for battery storage in business-as-usual and transactive energy scenarios.

Summary

This study assessed the degree to which transactive energy systems could help reduce or remove barriers to the deployment of battery energy storage and realize the full potential to supply needed services to the grid and fairly compensate various types of battery owners. To enable this assessment typical battery deployments were characterized, along with energy markets, grid services, and current deployment barriers.

To aide in cataloging potential barriers and comparing analysis results, this study defined three types of prototypical battery owners: merchant; utility; and behind-the-meter (BTM) batteries located at customer premises. This is important as the rules regulating how various battery owners may conduct the business of providing grid services is dependent on the physical location of the battery's point of interconnection to the power system. Based on the three typical battery ownership types, the study defines three battery participation models that have distinct rules, interconnection locations, and financial perspectives.

To understand currently permissible market access, this study reviewed the implications of Federal Energy Regulatory Commission (FERC) Order 841 for large storage resources and FERC Order 2222 for aggregations of small, distributed resources (including batteries) pertinent to the participation of battery energy storage. It also examined their likely influence on independent system operator (ISO) practices for battery participation over a range of possible interpretations that could conform to or enhance FERC's stated regulatory objectives, depending on how those objectives are implemented in practice. Battery participation is also influenced by how their physical capabilities meet the requirements for performing various individual grid services and combinations thereof.

Finally, this study analyzed the financial value that accrues to battery owners supplying today's grid services as a function of the participation models associated with three primary types of battery ownership: merchant-owned transmission-connected batteries; utility-owned distribution-connected batteries; and customer-owned BTM batteries. This provided both quantitative and qualitative assessments comparing opportunities for battery storage in business-as-usual (BAU) and transactive energy (TE) scenarios. The quantitative assessment was normalized for battery performance and capacity and analyzed across a range of market and grid services using typical wholesale energy and ancillary service market prices from the PJM and ERCOT ISOs. The study found that if batteries participated in energy arbitrage under the BAU scenario they could earn approximately $22/kW-yr if allowed to charge and discharge at wholesale energy prices. However, this is reduced to only ~$4/kW-yr if the FERC Order 2222 is instead interpreted as only requiring aggregated customer-owned BTM batteries to discharge at wholesale prices, leaving charging to occur at retail prices. When participation in the capacity market is included (~$20/kW-yr), the total annual value accrual would be ~$42/kW-yr. To compare, a range of transactive real-time retail tariffs were analyzed. Transactive rates designed to only dynamically recover wholesale energy purchases enabled a value accrual of ~$14/kW-yr, whereas rate designs that also dynamically recover delivery and generation capacity costs accrued annual benefits of $19-31/kW-year. In comparison, ancillary services such as frequency regulation and spinning reserve offer higher values ($48-91/kW-year), as does the opportunity for commercial and industrial customers to address monthly retail demand charges ($101/kW-yr).

This study found that the energy arbitrage performance of customer-owned BTM batteries is significantly affected by any fixed volumetric retail tariff they must incur during charging. Tariff

designs that reduce this flat rate and recover revenue from a dynamic real-time component as well as a fixed monthly charge will result in greater battery participation and compensation for their services. This is important to ensure that BTM batteries are fairly and correctly incentivized to provide storage (peak shifting) in the energy market.

This study also qualitatively assessed the benefits of TE coordination of batteries versus current and emerging implementations in response to FERC orders. First, transactive coordination via a dynamic retail tariff allows batteries to provide local, distribution-level grid services in addition to wholesale market services. The need for local services (such as congestion management, peak load deferral, or voltage and reactive power support) will grow as the distribution system strains to support large amounts of distributed, solar photovoltaic systems and to serve new loads from electric vehicles. Second, TE schemes greatly simplify the participation of a vast number of distributed energy resources (DERs) in support of grid operations. Transactive approaches eliminate the need for submetering of individual DERs behind the customer meter as all DERs and loads are treated equally.[1] Issues of double-counting of benefits are avoided through the use of a consolidated and consistent value signal. TE schemes also simplify the transmission-to-distribution interface, greatly reducing the number of small wholesale market participants that ISOs will need to include in their market-clearing schemes. Third and finally, analysis has shown that TE schemes can ensure the stable and effective coordination of large-scale battery populations. Batteries are classic profit seekers in that they have a natural desire to all make offers to discharge and charge during the highest and lowest price times, respectively. If not effectively managed, this can lead to market instabilities and significant rebound effects.

[1] The need to meter merchant-owned batteries as the same is for wholesale generators. It is implicit for utility batteries in that (as discussed subsequently) the FERC-order requires their bids must be separated from the load serving entities' demand bids so they are not double counted when clearing markets. It is implicit for customer BTM batteries because submetering is necessary to split total customer consumption into that for the battery (at wholesale prices) from that of the customer load (at the retail rate).

Acknowledgments

This project was supported by the Department of Energy, Office of Electricity, Advanced Grid Research and Develop Program. The authors would like to thank Chris Irwin for his support and contributions to shaping the scope and direction of this work.

Acronyms and Abbreviations

AEP	American Electric Power
APS	Allegheny Power System
BAU	business as usual
BTM	behind the meter
CAISO	California Independent System Operator
DER	distributed energy resource
DSO	distribution system operator
DSO+T	Distribution System Operator with Transactive
ERCOT	Electric Reliability Council of Texas (ISO)
ESS	energy storage system
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
ISO	independent system operator
ISO-NE	Independent System Operator New England
ITC	investment tax credit
LMP	locational marginal price
LSE	load serving entity
MISO	Midcontinent Independent System Operator
NYISO	New York Independent System Operator
PJM	Pennsylvania, New Jersey, Maryland (ISO)
PPA	power purchase agreement
PV	photovoltaic
RTO	regional transmission operator
SCED	security-constrained economic dispatch
SCUC	security-constrained unit commitment
SOC	state of charge
SPP	Southwest Power Pool (ISO)
TD	Transmission and Distribution
TDG	Transmission, Distribution, and Generation
TE	Transactive Energy
VAR	Volt-Amps Reactive

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1.0 Introduction

The goal of this study is to assess the degree to which transactive energy (TE) systems could help reduce or remove barriers to the deployment of battery energy storage and realize the full potential of battery resources to supply 1) needed services to the grid and 2) value to various types of battery owners.

The GridWise™ Architecture Council defines TE as a general class of solutions that involve:

> *"… a set of economic and control mechanisms that allows the dynamic balance of supply and demand across the entire electrical infrastructure using value as a key operational parameter."* (GridWise Architectural Council 2015)

Fundamental to TE is the notion that approaches that use prices or incentives are required to engage flexible assets (such as energy storage) <u>at scale</u>.

In service of this goal, the scope and objectives of the study are to:

- ***Classify types of battery owners*** **–** A battery's value to its owner is dependent on the owner's financial perspective, the physical location of the battery's point of interconnection to the power system, and the rules regulating how it may conduct the business of providing grid services. These combine to form the battery's *participation model*. The study's analysis is conducted based on participation models associated with three primary types of battery ownership: merchant-owned transmission-connected batteries; utility-owned distribution-connected batteries; and customer-owned behind-the-meter (BTM) batteries.
- ***Analyze current Federal Energy Regulatory Commission (FERC) regulations applicable to battery participation*** – The study reviews the implications of FERC Order 841 for large storage resources and Order 2222 for aggregations of small, distributed resources (including batteries) pertinent to the participation of battery energy storage. It also examines their likely influence on independent system operator (ISO) practices for battery participation over a range of possible interpretations that could conform to or enhance FERC's stated regulatory objectives, depending on how those objectives are implemented in practice.
- ***Identify and classify grid services that batteries could provide*** – Based on how their physical capabilities meet the requirements for performing various individual grid services and combinations thereof, as a function of battery ownership.
- Provide quantitative and qualitative assessments comparing opportunities for battery storage in business-as-usual (BAU) and TE scenarios:
  - Conduct a quantitative assessment of the value that accrues to batteries supplying today's grid services as a function of ownership type.
  - Discuss how additional grid services can be supported in the future, particularly at the distribution level, that could provide significant additional value from batteries, particularly under TE scenarios.
  - Provide a qualitative assessment of how TE can simplify, rationalize, and improve the participation models for battery storage while enhancing equity across ownership types, consistent with the intentions of FERC Orders 841 and 2222.

While the focus of this study is on battery systems specifically, many of the observations and conclusions apply to energy storage systems (ESSs) in general. Many of the findings will also have relevance to the barriers and value potential associated with other distributed energy resources (DERs) that have many properties analogous to batteries, such as electric vehicle (EV) charging systems, thermal energy storage, and flexible end-use loads.

1.1 Background

To provide context to the analyses and examinations contained in this study, it is important to understand the current state of battery deployments and barriers to such deployments that exist or are emerging, and to more formally define the types of battery ownership analyzed by the study. These are discussed in the three sections that follow.

1.1.1 Current Issues for Battery Deployments

The electric grid is experiencing increased levels of energy storage being deployed on the bulk system, within the distribution system, and behind customer meters. In the United States there are 200 GW (Rand, et al. 2021) of storage in the interconnection queue, equivalent to 18% of the nation's installed generation capacity. A record 1.2 GW of utility-scale storage was installed in 2020. Wood Mackenzie forecasts that utility-scale energy storage will grow by a factor of 7.5 in the next 5 years, equating to over 100 GW of new storage capacity in the United States alone (Convergent 2021). The vast majority of this capacity is in the form of batteries.

BTM deployments are also increasing globally. In Hawaii, 80% of rooftop solar photovoltaic (PV) installations are paired with battery storage (Barbose, Elmaliah and Gorman 2021). In Vermont, Green Mountain Power has deployed 2,567 utility-controlled batteries in customer homes with a combined capacity of 13 MW, equivalent to 2.6% of Green Mountain Power's 2013 average load (Spector-5 2020).

This rapid deployment of storage could enable the grid to integrate more intermittent renewable energy generation, improve resiliency during grid disturbances and peak loads (e.g., from extreme weather events), and lower overall operating costs by displacing traditional infrastructure investments and efficiently providing grid services. For example, the flexibility of batteries and other nonutility-owned DERs helped avoid blackouts in California in August 2020 and again in June 2021.

However, the overall potential of these DERs was limited due to a number of barriers that affect economic compensation and system coordination. For example, some BTM batteries that had received installation incentives were not allowed to participate in demand flexibility to avoid perceived 'double-counting' of incentives (St. John-2 2020). Furthermore, aggregators such as OhmConnect had to pay for the demand flexibility they provided during the August events due to inadequate measurement and verification approaches that did not correctly quantify the support they provided to the grid (St. John-2 2020).

The performance of the system response can also be hampered by existing demand response programs that require commitments to respond for certain blocks of time and can prevent net export of power to the grid (St. John-2 2020). Finally, current rate designs and conflicting battery owner priorities and incentives can result in batteries discharging at times that are less than optimal in supporting overall grid needs. For example, in the August 2020 and June 2021 events, batteries in California exhibited maximum discharge during the mid-afternoon (when solar output was still high) rather than when they were needed most during the evening peak when solar output was declining (Roselund and Cleantechnica 2021). It is expected that the impacts of these barriers and suboptimal coordination will only grow as more energy storage is deployed onto the grid, increasing the magnitude of unrealized economic and operational potential in general and batteries in particular.

This study aims to categorize the barriers that stand in the way of realizing the full potential of battery storage deployed on the grid and the resulting economic and operational impacts should these barriers be addressed. It also seeks to estimate the financial and operational impacts that equitable financial incentives and compensation would have on various types of battery owners.

1.1.2 Energy Storage Ownership Types

This study has defined three types of prototypical battery ownership to aide in cataloging potential barriers and in comparing analysis results: merchant owners, utility owners, and owners of BTM batteries at customer premises. While other ownership types exist and overlap or hybrids of these prototypes already exist in some regions, these protypes have been selected to represent the preponderance of current ownership and the range of ownership effects on the performance of battery resources, as discussed below.

A ***merchant owner*** is considered to be an independent third party who owns battery storage connected to the bulk transmission system, much like a merchant generator. Their battery may or may not be co-located and co-operated with generation resources (e.g., nondispatchable wind and solar resources, intermediate combined-cycle gas, and base-load nuclear or coal plants) owned by the merchant. Merchant owners of resources typically participate directly into a competitive wholesale market, or alternatively participate via a power purchase agreement (PPA) or tolling agreement. In regulated markets, the merchant-owned resource may be part of a vertically integrated utility. For the purposes of this study, it is assumed that the merchant battery is to provide economic returns to the owner by enabling firmer commitments, shifting generation for arbitrage opportunities, and enabling greater participation in the ancillary services market.

A ***utility owner*** (or distribution system operator [DSO]) is assumed to have energy storage located on its distribution system to serve nonmarket-related functions associated with distribution system control and operation. These nonmarket functions may include services such as providing Volt-VAR)[2] control, improving system resiliency, increasing hosting capacity for distributed solar PV systems, and providing congestion management associated with deferring infrastructure upgrades due to load growth, increased EV charging, and electrification of other end uses. Whether the utility can use its storage to participate in competitive wholesale markets and provide grid services (like a merchant-owned battery in wholesale energy and ancillary service markets) is dependent on regional market regulations. This study quantifies the value of such participation.

Finally, a ***customer owner*** who owns, leases, or (for a fee or share of the proceeds) hosts a third-party owned BTM battery. These batteries offer nonmarket value propositions (such as resiliency during gird outages, or self-consumption of on-site solar generation when net metering is not supported or backfeed of excess generation into the distribution system is disallowed), as well as the option to provide some grid services. For the sake of simplicity this study assumes this ownership class includes aggregators who provide market access and participation on the customer’s behalf for a fee or a share of the proceeds. In some cases this

[2] Volt-Amps Reactive (VAR)

extends to situations where the aggregator owns the customer-sited battery and operates under a lease or PPA with the customer, and shares compensation for grid services with the customer.

1.1.3 Transactive Energy Systems

The primary hypothesis examined by this study is that TE approaches can substantially reduce barriers to battery storage deployments by improving the fairness of compensation for grid services, thereby improving their coordination and increasing the value of battery resources. This study leverages prior research on the effectiveness of TE coordination schemes and evaluations of their economic impact on key stakeholders (Reeve et al. 2022). TE approaches coordinate flexible assets through transparent, competitive means using real-time transactions involving prices or incentives, and quantities to provide the feedback necessary to “close the loop”—to provide performance equivalent to closed-loop direct control of traditional generation assets. The basis for this is the transactions themselves, which are used to determine the level of value that must be exchanged with a population of flexible assets to accomplish a grid objective at any given time.

Ultimately, this study intends to examine the extent to which adopting a TE approach can improve the participation of batteries at scale from the perspective of various types of battery owners. In doing this it seeks to answer key questions such as:

- How and to what degree can improved coordination mechanisms help remove and reduce the market barriers that energy storage is currently facing (for example, market participation, coordination)?
- Can TE and other mechanisms expand the ability for utility- and customer-owned battery storage to supply grid services beyond participation in wholesale markets?
- What are the value propositions TE and other coordination schemes can bring to customers, merchants, utilities, and system operators?

1.2 Study Approach

This section describes the overall study process and structure as well as the breadth of its investigation of ESS deployments and regulatory conditions across the United States. As shown in Figure 1.1, the study is performed in two phases: landscaping and analysis.

The first phase of the study is focused on mapping the current landscape of ESS deployment by cataloging projects as to their scale and ownership type. It also covers the various grid services energy storage is capable of providing under BAU and TE scenarios and by ownership type, including barriers to deployment. Finally, it summarizes the legacy barriers associated with ESS, how recent regulatory reforms are addressing those legacy barriers, and stating the remaining barriers that are the subject of this study.

As a part of this landscaping phase, the study:

- Reviewed examples of existing and planned storage projects with different ownership structures that ranged from 5 kW to 460 MW. This included ten merchant generation projects, nine utility-owned projects, and example projects from three prominent BTM storage providers.
- Reviewed 20+ prior technical reports, publications, and news articles related to energy storage.

- Met with subject matter experts from energy storage, grid architecture, policy and regulation, and economics backgrounds.

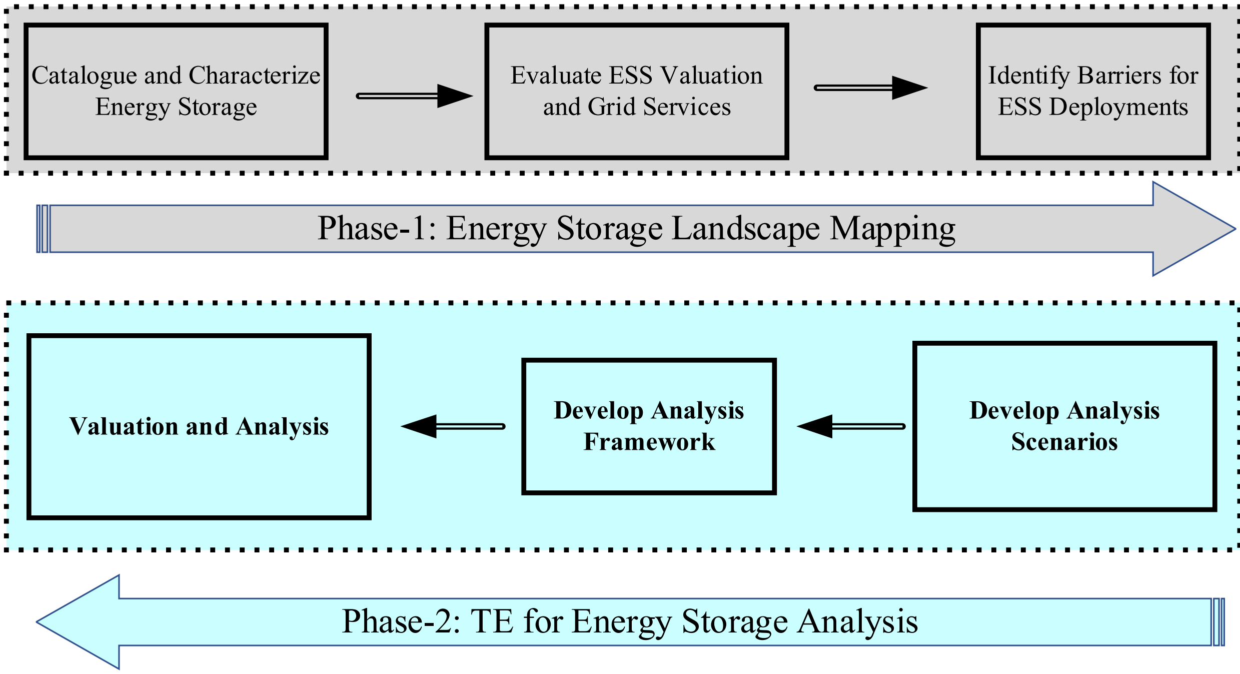


Figure 1.1. Overview of the study approach.

The second phase of the study is focused on how improved market coordination via deployment of TE systems compares to BAU approaches in terms of supporting battery deployment, ensuring equity of compensation across ownership types, providing economic value to various types of battery owners, and offering stable, economically efficient control of battery resources to the grid.

The BAU scenario is assumed to be representative of current regulatory, financing, and market constructs, after adoption by the ISOs of FERC Orders 841 and 2222 as they pertain to batteries. Since FERC leaves many of the specifics of how these orders are interpreted and implemented to the ISOs, these already appear to vary significantly from region to region in the United States. This requires the study to develop participation models that are intended to be generically representative of how ISOs will implement these new regulatory requirements. Key alternatives that arise from different interpretations as they affect the prototypical battery owner are quantified in annual economic terms on a per-battery-kW basis. These results are then compared to those that might be achieved by deploying a TE scenario in which the customer- and utility-owned battery resources are coordinated primarily at the retail level by the distribution utility/load-serving entity (or DSO), which in turn represents their response into the ISO wholesale markets as appropriate.

Finally, three key issues that a TE scenario helps address are discussed qualitatively. First is a discussion of how TE can facilitate batteries in providing additional distribution-level services without conflicting with their contributions to wholesale level services and without double-counting or doubly rewarding them. The second is an examination of how TE can result in a simpler participation model for batteries that is more equitable across ownership types and more uniform across types of DERs. The third describes how TE can address issues in achieving stable control and efficient use of storage resources. These price and response stability issues and utilization issues can occur when batteries are deployed at scale and bid into power markets, as observed during simulation analysis conducted during the course of the previous Distribution System Operator with Transactive (DSO+T) study of TE.

1.3 Report Structure

The remainder of this report is structured as follows. Section 2.0 presents various types of ESSs and lays the foundation of the current state in terms of emerging deployments of energy storage. Section 3.0 presents the various marketplaces for energy storage participation. Section 4.0 summaries relevant FERC orders and Section 5.0 covers the barriers that different types of storage owners and scales of energy storage are facing. It also captures the similarities and disparities of barriers based on ownership, scale, and location of the storage.

Section 6.0 summarizes grid services that energy storage is capable of providing. Section 7.0 presents an overall analysis approach, including the study's assumptions about feasible participation models for customer types under different scenarios. Section 8.0 discusses quantification of the economic performance of batteries under these participation scenarios for various grid services. Section 9.0 provides a summary of key conclusions.

2.0 Catalog and Characterization of Energy Storage

Due to varied services and value streams, ESSs find somewhat different applications in multiple market segments and at different deployment scales. This section attempts to catalog existing ESS projects and classify them based on certain prominent categories. It is important to note that while this classification is viable, it is not an exhaustive list of possible categories due to the wide ranges in deployment scenarios and applications of energy storage projects. For the purposes of this document, ESS is cataloged based on ownership structure, technology, and grid services provided. Each of these categories creates important distinctions in the applicability and value of ESS due to their inherent characteristics as well as associated regulatory and market frameworks.

2.1 Energy Storage Technologies

ESS can be classified based on the fundamental technical principles used to absorb, store, and release energy. Over the years, numerous technologies leveraging electrochemical, mechanical, thermal, and chemical energy principles have been proposed to accomplish this set of capabilities that define an ESS. Figure 2.1 (Hossain, et al. 2020) shows how various ESS technologies map to the fundamental principles upon which they are based.

The type of technology used has large implications for charge and discharge rates, energy storage capacity, and power densities by volume and weight. Figure 2.2 provides a snapshot of typical storage technologies used for some major grid applications. While all these technologies have found deployment ranging from pilot stages to full-scale installations, electrochemical (battery) storage, and in particular Li-ion batteries, is one of the widely used storage technologies for power grid applications (EveryCRSReport.com 2019). The increasing share of Li-ion batteries in storage capacity additions has been largely driven by declining costs in Li-ion technology, which has in turn been driven by the ramp up in production to meet the growing demand for EVs.

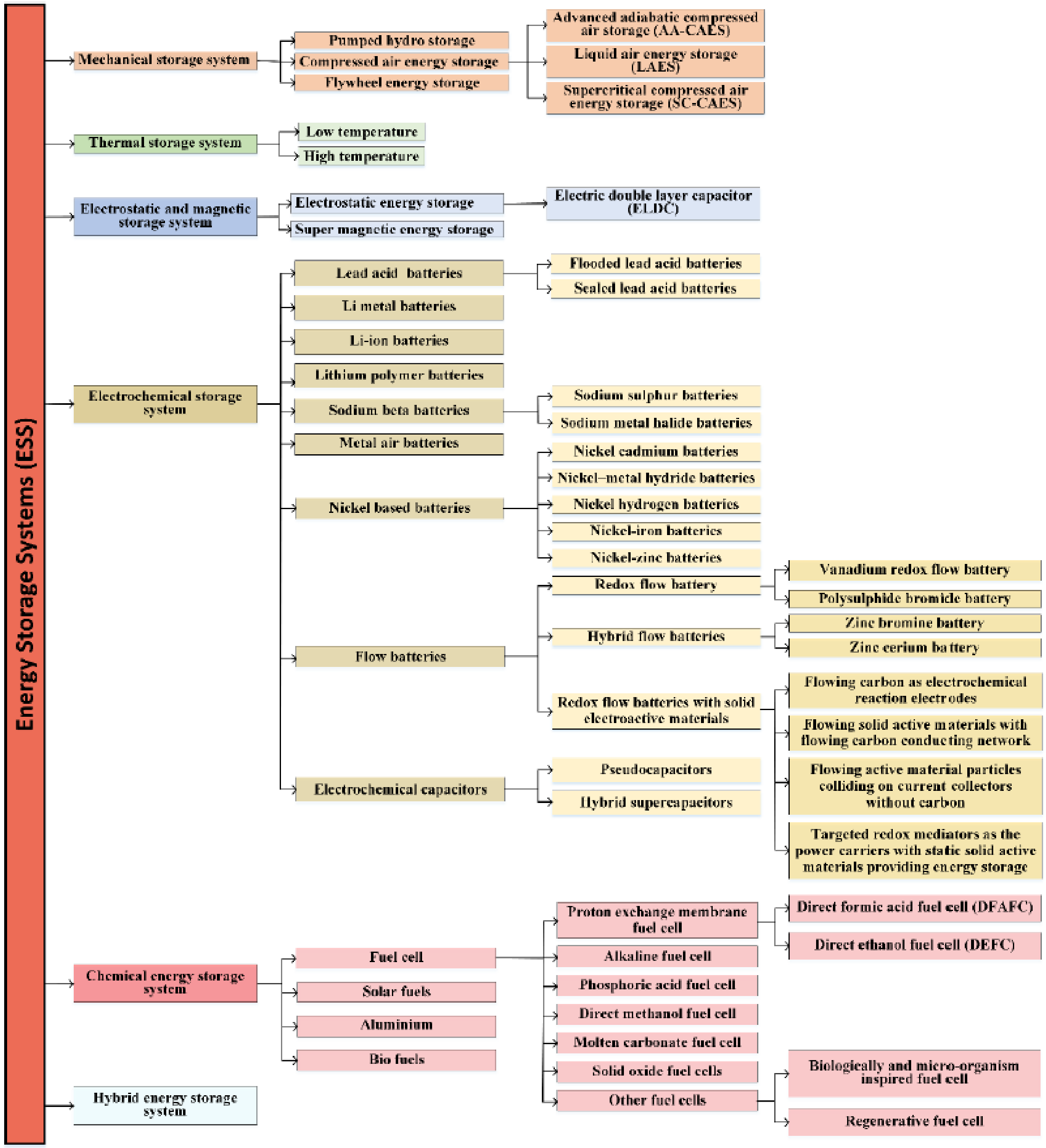
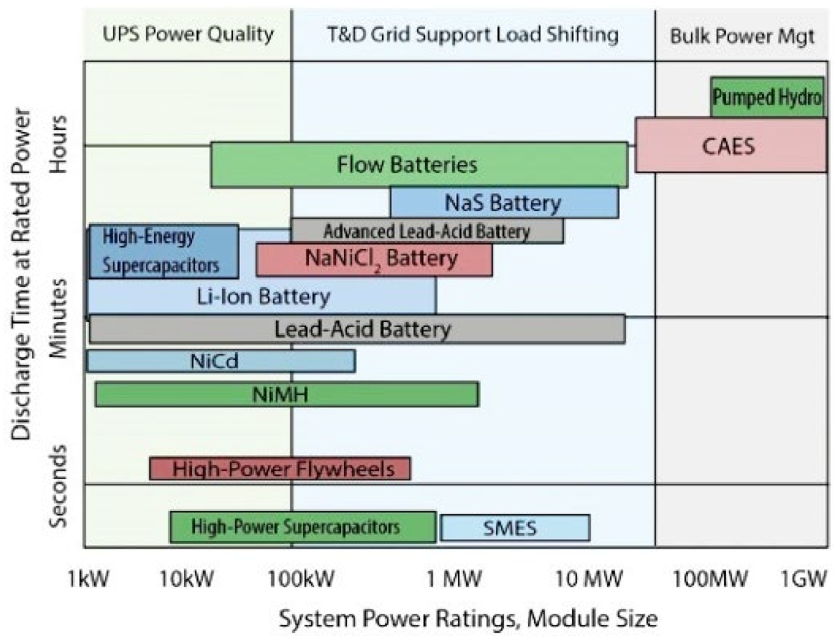


Figure 2.1. Energy storage technology classification (Hossain, et al. 2020).



CAES = compressed air energy storage; SMES = superconducting magnetic energy storage

Figure 2.2. Energy storage technology roadmap for grid applications (EveryCRSReport.com 2019).

2.2 Catalog of Existing Energy Storage Projects

To understand the applicability of different ownership models, a survey of existing grid battery storage projects was conducted. Key attributes such as battery technology, energy storage and power output capacity, and targeted services were captured from this survey. Several existing or planned energy storage projects ranging from 5 kW to 460 MW scale were examined including, projects, and deployments. Table 2.1 shows an overview of nine utility-owned battery storage projects, sorted by capacity. Table 2.2 and Table 2.3 show key attributes of six merchant-owned battery storage projects and four large customer-owned BTM storage projects. The “hour rating” (maximum duration of discharge at full power) for each project is inferred as the ratio of its energy and power ratings.

The surveyed projects show that there are some key services being used from battery storage projects at different scales and under different ownerships. The utility-scale projects surveyed in our study (Table 2.1) seem to be typically geared toward operational improvements and reaching aggressive renewable mandates. Energy shifting, upgrade deferrals, improved resilience, and coupling applications with large PV projects were the primary values derived from energy storage under this ownership structure.

Table 2.1. Surveyed Utility-Owned Battery Storage Projects

Project	Technology & Capacity	Targeted Services
Northampton Planning Board (National Grid) Northampton, MA	Subject to bid 441 kW / 441 kWh 1 hr	Microgrid application includes 386 kW PV system: demand charge reduction, outage mitigation, energy purchase reduction by maximizing utilization of PV output, PV renewable energy credits
Avista Pullman, WA	Flow battery 1 MW / 3.2 MWh 3.2 hr	Energy shifting (peak/off-peak), frequency regulation, volt-VAR control, distribution upgrade deferment, blackstart operation, microgrid (both islanded/grid connected)

Project	Technology & Capacity	Targeted Services
Puget Sound Energy Glacier, WA	LiFePO4 2 MW / 4.4 MWh 2.2 hr	Energy shifting, regulation, upgrade deferment, outage management
SnoPUD-MESA1, Everett, WA	Li-ion 2 MW / 1.2 MWh 0.6 hr	Energy shifting, load shaping, volt-VAR control
SnoPUD-MESA2, Everett, WA	Flow battery 2.2 MW / 8 MWh 3.6 hr	Energy shifting, load shaping, volt-VAR control, frequency regulation
Nantucket, NE	Li-ion (Tesla) 6 MW / 48 MWh 8 hr	Transmission deferral, distribution system reliability improvement, outage mitigation, volt-VAR control, conservation voltage reduction Can also participate into ISO-NE market either as dispatchable generator asset, a dispatchable asset-related demand asset, and alternative technology regulation resource Storage can participate in energy, reserve, regulation, and capacity markets
PG&E Moss Landing, CA (completion early 2021)	Li-ion (Tesla) 82.5 MW / 730 MWh 8.8 hr	Infrastructure deferral, reliability enhancement
Hawaiian Electric Hawaii Island, HI (ongoing)	Li-ion 72 MW / 492 MWh (total) 6.8 hr	Two PV systems co-located with batteries plus one standalone battery: services TBD; in planning stage
Hawaiian Electric Maui, HI (ongoing)	Li-ion 100 MW / 560 MWh (total) 5.6 hr	Three PV systems combined with storage: services TBD; in planning stage
Average Project	30 MW / 205 MWh 4.4 hr	

The merchant-owned battery storage projects that were surveyed (Table 2.2) also point to a market-based revenue model where the entities exchange key grid services with ISOs or utilities. A large number of such projects are being seen in Texas owing to the unique set of participation rules in this deregulated market that inhibit utility ownership of batteries (Spector-4 2020). These merchant entities make revenue by providing services in the ancillary market or via energy-only PPAs. The Hawaiian Electric and Permian Energy Center projects indicate the growing importance of firming generation capacity in regions with high renewables penetrations like Hawaii and Texas.

Table 2.2. Surveyed Merchant-Owned Battery Storage Projects

Project	Technology & Capacity	Targeted Services
Prospect Storage Houston, TX	Lithium iron phosphate 10 MW / 10 MWh 1 hr	Ancillary services and arbitrage in Electric Reliability Council of Texas (ERCOT)
Rabbit Hill Georgetown, TX	Li-ion 10 MW / 12.5 MWh 1.3 hr	Ancillary services
Hawaiian Electric	Li-ion 30 MW / 120 MWh 4 hr	Co-operated with 30 MW solar PV: utility has PPA with developer AES who builds and owns battery storage system; utility pays a monthly lump-sum payment and controls assets
Broad Reach Power Mason, TX, and Williamson, TX	Li-ion 100 MW / 100 MWh + 150 MW / 150 MWh 1 hr	Participation in ERCOT market(s)

Project	Technology & Capacity	Targeted Services
Plus-Power (ISO-NE) Canberry, MA	Not-stated 150 MW / 300 MWh 2 hr	Seven-year capacity contract starting from June 2024
Permian Energy Center Andrews County, TX	Not-stated 40 MW / 40 MWh 1 hr	Co-operated with 460 MW of PV solar: 12-year PPA with ExxonMobil
Average Project	82 MW / 122 MWH 1.7 hr	

The average power capacity (MW) of the merchant-owned battery storage projects in Table 2.2 was 82 MW, nearly three times that of the average utility-owned project in Table 2.1 of about 30 MW. Conversely, the average energy storage capacity of the utility-owned batteries (205 MWh) was nearly double that of the merchant-owned batteries (122 MWh). Given that the cost of batteries involves both their energy storage and power capacities, this suggests that utilities may prefer to invest in batteries with relatively more energy capacity compared to merchant owners, who apparently prefer to invest in batteries with relatively more power capacity. This is also indicated by the ratio of energy to power capacity, i.e., the maximum duration of discharge at full power capacity,[3] which for utility-owned batteries is 4.4 hours whereas for merchant-owned batteries it is 1.7 hours.

The customer BTM storage projects surveyed are typically used to ensure local objectives like backup power, bill reductions, and load shaping by customers (Table 2.3). As would be expected, customer BTM batteries at an average of 6 kW and 23 kWh are much smaller than utility- and merchant-owned batteries. With an average maximum discharge duration of 2.4 hours, customer-owned BTM batteries have a little more energy capacity relative to their power output than merchant-owned batteries, but still considerable less than that of utility-owned batteries. It is possible this shift is associated with the desire to provide backup power to customers.

Table 2.3. Surveyed Customer-Owned BTM Batteries and Storage Projects

Project	Technology & Capacity[a]	Targeted Services
Sunrun Brightbox	Li-ion 5 kW / 9.8 kWh 2.0 hr	Demand charge reduction, energy cost saving
Tesla Powerwall	Li-ion 5 kW / 13.5 kWh 2.7 hr	Energy security and cost-shaving by combining with solar PV system
Soliel Community (Rocky Mountain Power) Herriman, UT	Lithium iron phosphate (sonnen EcoLinx) 8 kW / 20 kWh 2.5 hr	600 batteries in multifamily housing: emergency backup power, daily management of peak energy use, and demand response
Orison (BTM storage company)	Li-ion 13.2 kWh	Load leveling and load shifting (13-40% daily cost shaving)
Sonnen Community (Pearl Homes) Cortez, FL	Lithium iron phosphate (sonnen EcoLinx) 60 kWh (each)	9 MWh of storage in 148 homes, combined with 7.2 MW of solar: PV backup power, demand response, frequency regulation, load management
Average Project	6 kW / 23 kWh 2.4 hr	

[a] For Customer BTM battery projects, the capacities listed are per home or site, unless noted otherwise.

[3] Duration of full output power when the battery is discharged from a 100% state of charge to 0% (at standard temperature and other conditions).

An overview of the services typically being offered by merchant entities, utility-owned storage, and customer-owned projects is provided in Table 2.4. Merchant owners typically leverage market-based incentives and seldom provide any local grid services. The tendency for them to be connected to the bulk transmission system rather than local distribution networks prevents their participation in providing local services. However, this may also indicate there is no perceived current or future near-term market for providing distribution-level services, like congestion relief or Volt-VAR support, from merchant-owned batteries to distribution utilities.

Table 2.4. Catalog of Grid Services Based on Ownership Type

Services / Applications	Merchant	Utility	Customer/BTM
Energy market/arbitrage	●	●	
Capacity market	●	●	
Ancillary services market	●	●	
Infrastructure upgrade deferral		●	
CVR/Volt-VAR support		●	
Reliability improvement/outage management		●	
Blackstart	●		
Microgrid applications	●		
Frequency regulation	●	●	
Demand response		●	●
Peak demand charge reduction			●
Energy security/backup power			●
Store PV output in excess of load			●

Conversely, utility-owned storage appears to be underutilized for wholesale operations compared to merchant-owned batteries. While utility-owned storage adds significant value in terms of local operational resilience, it is often not factored into long-term planning processes to utilize it more as a dispatchable source. This may be partly due to varying regulations associated with different market structures (Twitchell, et al. 2021).

It is clear, based on the types of grid services targeted, that the primary purpose of customer BTM battery storage deployments seems to be providing emergency backup power and a reduction in utility bills, rather than providing wholesale grid services in the current framework. They also enable demand response applications in utility environments that promote these mechanisms. Customer BTM batteries can inherently provide a number of local grid services in addition to wholesale services, but aside from participation as demand response resources they are rarely being engaged for those purposes. For instance, while customer BTM storage can provide distribution-level benefits, such as voltage support and distribution system loss reduction and capacity deferrals, retail distribution utilities have not setup mechanisms for purchasing such services from customer BTM batteries. Similarly, customer BTM batteries can only engage in providing energy and ancillary services to the wholesale markets by signing up with aggregators, which inherently involves sharing the proceeds in exchange.

A deeper discussion of barriers to battery deployment and how batteries can supply grid services appears in Sections 5.0 and 6.0, respectively.

2.3 Battery Storage Systems Analyzed by the Study

From the survey of battery storage projects in the previous section it is clear that typical battery characteristics vary considerably across ownership types. Although Li-ion batteries clearly predominate at present, battery technologies may vary by ownership type in the future as they evolve. Further, simple economies of scale suggest that battery and inverter costs may be lower for larger projects with single points of interconnection to the power system than smaller projects and distributed, multisite installations. With lower inverter costs, higher roundtrip efficiencies may prove cost effective in larger projects. These and other differences associated with ownership types may persist or appear in the future.

However, this study is not focused on comparison of relative merits of various types of storage project design characteristics or specific battery technologies. So, across all ownership types, the study is based on a single type of battery with common characteristics such as roundtrip efficiency, cost, lifetime, and ratio of energy and power capacities as summarized in Table 2.5 and in more detail in Section 8.0.

Recognizing that merchant, utility, and customer owners may purchase somewhat different technologies, battery sizes, efficiencies, etc. and pay different first costs due to the economies of scale, nonetheless studying the effect of such variations is not the focus of this study. To facilitate examination of the equity of opportunity and return on investment across ownership types in BAU and transactive scenarios, a uniform set of battery characteristics (technology, first cost, roundtrip efficiencies, energy/power ratios, etc.) are held constant across ownership types and the analysis is conducted on a per kW basis. This prevents confounding the effects of ownership in terms of BAU versus TE scenarios and associated regulatory policies, with the effects of ownership on technology selection and project design, that would otherwise occur if battery types or characteristics were varied across ownership types.

Since Li-ion batteries are currently the most prevalent and penetrating rapidly, they are selected as the common basis for the analysis. Although the analysis is based on Li-ion batteries, the report's conclusions are generally applicable to a wide variety of energy storage resources. The primary battery storage characteristics that are held constant in the quantitative analysis in Section 8.0 are summarized in Table 2.5.

Table 2.5. Characteristics Common Across Ownership Types

Battery type	Li-ion
Discharge duration	4 hr
Inverter efficiency	94%
Roundtrip efficiency	88%

The quantitative analysis conducted by the study focuses on a single, marginal battery. It does not attempt to address the complexities of large fleets of batteries deployed at scale, where the capacity of the fleet is large enough to affect both market-clearing prices and control stability. Rather, these issues are addressed in a qualitative fashion in Section 8.2 based on the literature and previously conducted analyses.

2.4 Characteristics Associated with Battery Ownership

While battery storage offers a large number of value streams, the revenue and business models are strongly correlated to the ownership types and associated market participation models and battery points of interconnection. The following sections present how key characteristics vary across different ownership models.

2.4.1 Utility-Owned Batteries

Battery storage provides grid operators an efficient way to add tremendous amounts of flexibility to their system operations. For operators, energy storage can add key grid services such as frequency response and regulation reserves, and allow for load shifting. Furthermore, when paired with utility-owned renewable generation, ESSs can help the grid operator address temporal mismatches between available capacity and demand during intervals with high generation and/or load volatility.

Battery storage is also valuable to utilities in terms of addressing long-term infrastructure upgrade concerns. By deploying new battery storage capacity at strategic locations, utilities may be able to defer system upgrades. Battery storage also helps address peak demand requirements without adding significant conventional generation capacity. For example, National Grid has recently undertaken a project to install 48 MWh of energy storage on Nantucket Island to manage peak demand requirements to avoid adding transmission infrastructure (Gheorghiu-2 2019).

In addition to improving energy adequacy (the ability of the electric system to supply aggregate demand and energy requirements), battery storage may also be used to provide grid services such as congestion relief or to defer incremental capacity investments. Most of these applications add operational value without generating much (or any) revenue from the electricity market. Based on local and state regulations, certain utilities may use battery storage to participate in electricity markets. Figure 2.3 provides an overview of various grid services and their value streams for utility-owned battery storage (IRENA 2019).

Utility ownership rules, regulations, and opportunities will all be somewhat different depending on whether the utility is investor owned, a municipal or public utility, or a rural cooperative. However, the utility in this study is assumed to be investor-owned.

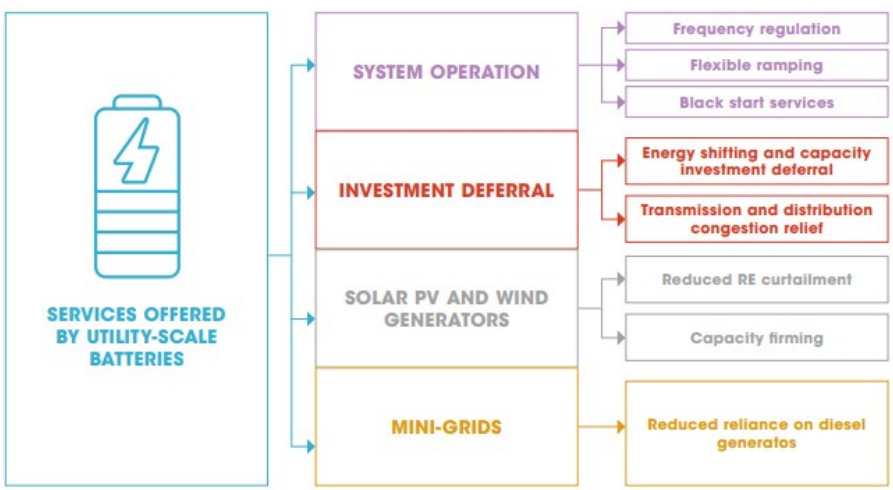


Figure 2.3. Value streams from utility-scale batteries (IRENA 2019).

2.4.2 Merchant-Owned Batteries

Merchant-owned battery storage provides value to power system operators in exchange for revenue. Operators can utilize services they are able to provide while not taking on the investment risks associated with their deployment. Wholesale electricity markets and associated deregulation has provided a marketplace for private merchant entities to procure and operate battery storage while creating business models based on market participation to achieve profits and returns on their investment. Merchant-owned battery storage can also potentially participate in providing services at the retail/distribution level when the battery is connected to the distribution system at a substation or on downstream circuits.[4]

Merchant-owned storage is one of the common business models in jurisdiction areas where local regulations restrict utility-owned battery storage. In some certain jurisdictions (such as ERCOT), a utility is explicitly prohibited from owning battery storage, enhancing opportunities for merchants (Spector-2 2018). Merchant batteries may be deployed as a standalone resource, but are commonly operated in conjunction with generation resources. For instance, in Australia there is one project integrating a 100 MW/129 MWh Tesla ESS and 315 MW of wind generation, and another combining a 900 MW battery with 1200 MW of wind, and 600 MW of solar generation (Maisch 2020).

Under current U.S. law, standalone ESSs are not eligible for the investment tax credits (ITC). But, when integrated into an otherwise ITC-eligible renewable generation facility, an ESS may also be eligible so long as it satisfies certain requirements. This generally pertains only to merchant-owned storage, although investor-owned utilities that own generation in regions allowing vertically integrated utilities may also be eligible. Even though ITCs act as effective additional incentive for the ESS deployment, it might place some limitations on the ESS. For instance, the specific need to use renewable energy to charge the ESS may limit its potential to provide certain grid services and place constraints against otherwise siting it where it can provide the most value to the grid. Also, the amount of the ITC is a function of when the project begins construction (Lewis 2021). For eligible ESS, the current ITC for projects beginning construction in 2021 or 2022 is 26%, while the percentage for projects beginning construction in 2023 drops to 22%. Any project that begins construction after 2023 or is not placed in service for tax purposes prior to 2026 is eligible for a 10% ITC.

From the merchant battery owner's perspective, there are two variations on the battery value proposition. First, the merchant owner may participate in the energy, capacity, or ancillary services markets of an ISO and accrue revenue from them. Alternately, the merchant owner may establish a contract with the grid operator or a utility to provide specific services at specific times through a PPA or tolling. In some cases, merchant storage owners do some combination of both (market participation and PPAs).

The participation of merchant batteries in wholesale and retail markets creates an ecosystem where systemwide benefits can be derived by the grid operator and its customers while generating profit for the merchant entity. From the grid operator's perspective, numerous services can be derived to aid in transmission upgrade deferrals, avoiding outage costs and generation investments, and reducing generation production costs and wholesale market-clearing prices. Other potential benefits involve transmission support and congestion relief. In the process, retail customers see reduced rates from lower revenue requirements due to lower power purchase costs and capital investments in transmission and distribution infrastructure.

[4] ESS owners cannot offer their capacity simultaneously in both wholesale and retail markets. Issues surrounding double-counting and double-rewarding are discussed in detail in Section 4.0.

2.4.3 Customer/Behind-the-Meter Owner Batteries

Customer-owned BTM battery storage is usually owned and operated by the utility customer, but there are some recent instances of BTM storage that is collectively operated by a third-party entity. For instance, providers like Sunrun allow customers to leverage backup power from their batteries while leveraging the fleet to provide grid services as a virtual power plant (St. John-1 2020). The size of individual customer BTM battery installations may be small, but certain regions in the United States already allow for small customer BTM batteries to be aggregated and participate in wholesale markets, even prior to full implementation of FERC 2222, which mandates such participation be allowed.

The falling battery prices and growth of rooftop PV systems and EVs have accelerated the adoption of battery storage at the customer level. In Australia, as of 2020 there are more than 70,000 BTM battery systems, and 28,000 more were projected to be installed that year, with battery prices falling 10% to 15% driving customer interest, according to consulting firm SunWiz (New York Times 2020). In fact, the level of customer-owned storage systems is expected to rise dramatically over the next decade as shown in Figure 2.4.

Figure 2.4. Projection of customer BTM storage projections (IRENA-1 2019).

Figure 2.5 provides an overview of value streams for customer-owned BTM energy storage. While fleets of BTM batteries may also be leveraged by grid operators to manage peak loads and provide frequency regulation or voltage support, most customers use their systems for nonmarket value propositions like backup power and net bill reductions (Eller and Gauntlett 2017). In jurisdictions where time-of-use prices exist, they can optimize their load profiles to reduce utility bills. When subject to peak demand charges (principally commercial and industrial customers), they can use their batteries to reduce this component of their bills. Customer-owned

Where net metering has not been put in place, BTM batteries can also maximize bill savings from self-consumption of on-site solar PV production by storing output that exceeds their current usage.

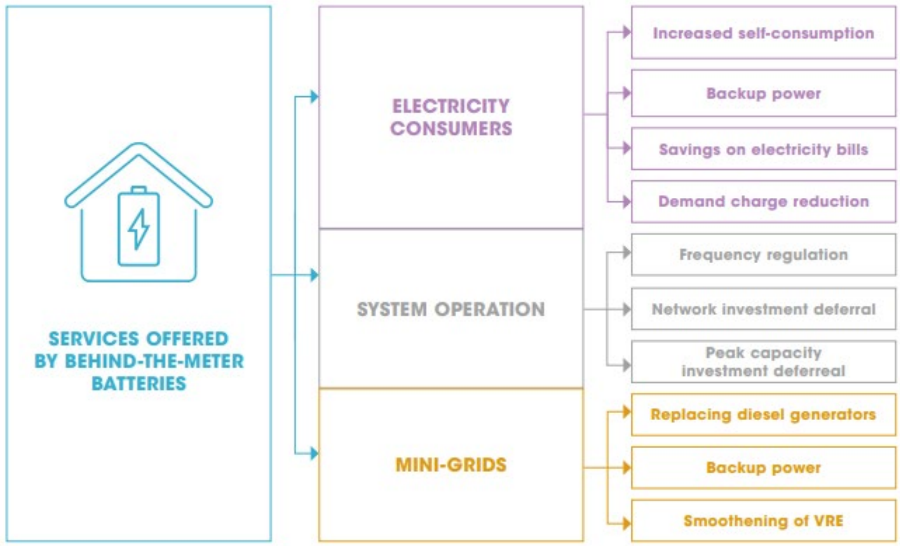


Figure 2.5. Grid services from BTM storage (IRENA-1 2019).

In some regions of the U.S., customer BTM storage may be allowed to participate in a PPA with the utility to receive compensation in exchange for the utility's use of the battery. Several hybrid business models involving combinations of merchant and customer entities are also being piloted in the form of community storage programs (ILSR 2013). In such scenarios, a merchant provider may install and operate a fleet of customer BTM storage systems while maximizing value for each individual owner. For instance, a PV with storage project in Utah aims to install a fleet of batteries in individual residential units where the tenant leases the unit (Spector-3 2019). The operator then uses the fleet to monetize services exchanged with Rocky Mountain Power to gain ITCs and revenue while providing tenants with lower utility bills.

2.4.4 Hybrid Ownership Models

There are a variety of alternative ownership models to the study's three prototypical types, discussed above. These are not specifically analyzed by the study, but the results may help the value propositions involved be better understood. Two examples of alternatives are:

- Merchants who own BTM batteries sited at large retail or wholesale customers (commercial and industrial), whose capacities are large enough (>100 kW) to participate in wholesale markets and with utilities as individual (not aggregated) resources. Merchants may lease the batteries to such customers or pay rent for the use of the site.
- Merchants, utilities, or battery vendors that own distributed BTM batteries and lease them to, or contract for them with, customers. They also may act as aggregators.

3.0 Overview of Wholesale and Retail Markets

This section presents a brief overview of electricity markets in the United States. The electricity market comprises retail and wholesale markets that are either vertically integrated or competitive.

Wholesale Markets. The wholesale markets involve generation and sale of electricity among electric utilities, merchant generators, and load-serving entities (LSEs) such as distribution utilities, whereas the retail markets involve delivery and sale of electricity to the end-consumers. Figure 3.1 illustrates the mapping of vertically integrated (gray) and competitive wholesale markets (nongray) in different parts of the United States.

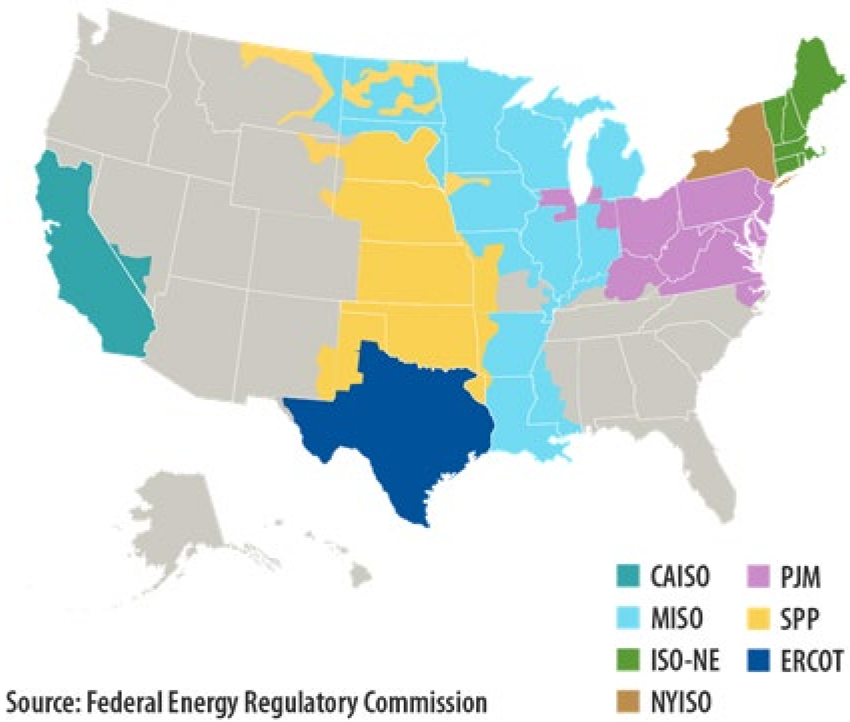


Figure 3.1. Status of regulated and competitive wholesale markets (Environmental Protection Agency 2022).

In a vertically integrated wholesale electricity market, utilities own generation, transmission, and distribution systems, and are responsible for the entire flow of electricity and retail services for electricity customers. In contrast, the competitive wholesale markets in the Northeast, Midwest, Texas, and California use competitive market mechanisms operated by ISOs or regional transmission operators (RTOs[5]) that allow power producers and LSEs to buy and sell energy in an open market. In these competitive wholesale markets, utilities are responsible for retail electricity service to customers, may not own or may be prohibited from owning any generation, and submit the portion of the regional transmission network they own to the ISO for operations.

[5] This study's use of the term ISO should be understood as genericaly including reference to RTOs.

Competitive markets serve about 67% of the U.S. demand for electricity (FERC-1 2020). **The analysis in this study is based on the presumption that battery storage systems exist in the presence of a competitive wholesale market operated by an ISO**, rather than in a fully integrated utility system based on an investor-owned utility, a public power marketing authority and constituent utilities, or a rural cooperative served by a generation and transmission cooperative.

Large merchant- and (where regulators allow) utility-owned ESSs can generally participate in competitive wholesale energy markets, subject to rules and restrictions. However, customer-owned BTM batteries are usually too small and dispersed to participate in such markets as individual resources. They are allowed to do so only as part of an aggregation, in which a third-party aggregator contracts with them to recruit, operate, and reward them to reduce customer load from a defined baseline level. These and other key regulations pertinent to ESS participation are discussed in Section 4.0 of this report.

At the wholesale level, there are a number of competitive markets that are run by ISOs. These consist of three markets (energy, capacity, and ancillary services) to meet energy demand, ensure sufficient resource adequacy to meet peak loads, and maintain system balancing. These markets determine wholesale prices for various grid services such as frequency regulation and reserves. Key features are described in the sections that follow.

Retail Markets. At the retail level, participation by customers is much more limited. Some states have retail markets (shown in blue in Figure 3.2) that allow electricity consumers to choose between competitive retail suppliers. However, these retail marketplaces do not support customers trading their flexibility in dynamic fashion (e.g., real-time, day-ahead). This means the end-consumers make a supply contract with the retail suppliers, but do not have a direct trading option for any flexibility they have in their load shape.

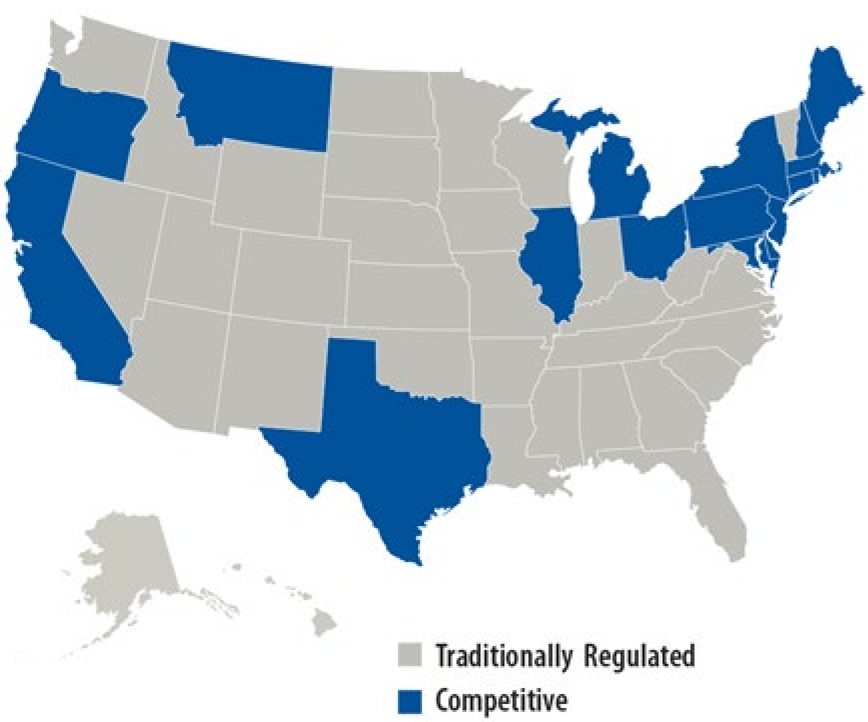


Figure 3.2. Status of regulated and competitive retail markets (Environmental Protection Agency 2022).

Many distribution utilities offer to purchase reductions in customer peak loads in the form of demand response programs. Most such programs require a customer to submit an end-use load, such as an air conditioner or a water heater, to curtailment by the utility on command, limited to a certain number of days per year (e.g., ten days, usually in the summer) and hours on any of those days (typically 2 to 4 hours). The curtailment is enforced by a communicating thermostat or remotely controlled switch activated by the utility.

Some utilities are also experimenting with pilot projects involving dynamic retail rates such as time-of-use, crucial peak pricing, and variable peak pricing that are designed to induce customers to voluntarily shift loads from peak demand periods to shoulder or off-peak periods. Since a BTM battery reduces a customer's load when it discharges, a battery inherently can participate in either a utility's demand response or a dynamic retail rate program.

Currently, there is no established retail marketplace in the United States that allows customers to offer their dynamic flexibility in a continuous fashion to their distribution utility. This limits the ability to provide distribution-level services or participate in wholesale markets as part of the LSE's demand bid into the wholesale markets. It is exactly this limitation that TE mechanisms are designed to remedy and the TE scenario in this study is designed to examine.

3.1 Energy Markets

The energy market provides a marketplace for participants to dynamically trade the system's energy supply and demand. Bilateral contracts between suppliers and LSEs involve a substantial fraction of the energy supply in many regions with competitive wholesale markets, but on a longer-term basis.[6]

While there are some variations in the energy market implementations among ISOs, the majority of short-term energy market trading occurs though either the day-ahead and real-time energy markets. The market participants can participate in one or both of these markets. The day-ahead market, which represents about 95% of energy transactions when all bilateral transactions are incorporated, is intended to trade energy for the next day. The day-ahead market is primarily based on the forecasted demand and available generation, and typically occurs the prior day to allow generators time to prepare for operation. The remining 5% of energy transactions occur in the real-time market, that typically runs every five minutes to account for the difference between forecasted and actual loads that must always be balanced with supply. The primary operational goal of the energy markets is to decide which generation units to schedule and dispatch, and in what order, to minimize the overall cost of energy. The day-ahead market provides an operational plan, including the unit commitment, whereas the real-time market provides economic dispatch points, both taking into account reliability security constraints (PJM 2022).

In the day-ahead market, ISOs compiles quantity and price offers from suppliers offering next-day dispatch, including startup and shutdown costs and constraints. The energy market coordinates the production of electricity on a day-to-day basis by clearing the market at the price where the suppliers (e.g., generators) offer to sell the quantity of electricity that exactly matches

[6] In regions without organized ISO markets, this is accomplished through short-term bilateral spot-market trades.

the LSEs' bids to buy energy, at the lowest feasible cost including security constraints. The real-time market operates in a similar fashion, but only involves plants that are already running or can start within 5 minutes. Purchases in the day-ahead market are generally preferred by LSEs to avoid price volatility exhibited in real-time markets. In the study's quantitative analysis, batteries are assumed to participate in the day-ahead market similarly.

3.2 Capacity Market

The capacity market is a long-term (e.g., multiyear) market that ensures grid reliability by procuring the appropriate amount of power supply resources needed to meet predicted energy demand in the future. In practice, the capacity market does that by creating long-term price signals to attract required investments and ensure adequate power supplies (IRENA-2 2019). LSEs can meet that requirement via their own generation capacity, with capacity they purchase from others under contract, and capacity obtained through market auctions, or through demand response or price response programs. LSEs must prove that their combined capacity from these sources meets or exceeds their annual peak demand. This is enforced by measuring their actual peak demand and comparing it to their reserved capacity (less demand response). For the majority of U.S. ISOs, the market participants that are cleared in capacity markets are obligated to offer into the day-ahead market. It is worth noting that some markets (such as ERCOT) do not have a separate capacity market and rely on prices in the energy market reaching high enough levels to ensure resource adequacy. (Note that while California Independent System Operator [CAISO] does not operate a formal capacity market, it does have a mandatory resource adequacy requirement.)

The capacity market auction works such that suppliers set their bid price at an amount equal to the cost of keeping their plant available to operate if needed (Jenkin, Beiter and Margolis 2016). Suppliers are generally generators, but also include discharge from energy storage, and load reductions from demand response and price-responsive flexible loads. These supply bids are arranged from lowest to highest. Once the bid quantities reach the total forecasted coincident peak demand from all the LSEs plus a reserve margin, the market clears at the price of the marginal bid. At this point, all suppliers that cleared the market receive the clearing price (Jenkin, Beiter and Margolis 2016). Payments to all suppliers in the capacity market are essentially a reward for that generator being available to operate if needed.

3.3 Ancillary Services Markets

While the capacity market ensures enough resources exist to meet predicted energy demand in the future, and the energy market ensures an economically efficient operating plan (e.g., unit commitment, economic dispatch), the ancillary services market helps balance the transmission system as it moves electricity from generating sources to retail consumers. Ancillary services typically include functions that help maintain grid frequency and provide adequate replacement capacity in case scheduled resources suffer an outage (PJM-1 2021).

ISOs operate ancillary markets to procure regulation and reserve services to maintain this balance (PJM-1 2021). Regulation is used to control small mismatches between demand (the electricity being consumed) and supply (the electricity being produced), adjusting output or demand for small deviations in either direction occurring within the real-time 5-minute dispatch interval. Reserves help recover system balance by making up for generation deficiencies if there is a loss of a generator, resulting in a large imbalance. In addition to reserve and regulation services, some ISOs (e.g., PJM) provide a marketplace for blackstart service, which is intended to supply electricity for system restoration in the event that the entire grid loses power (PJM-1 2021).

4.0 FERC Regulations Addressing Participation of Storage in Wholesale Energy Markets

Electricity regulation in the United States is functionally divided between federal and state agencies, who set rules and other regulations to ensure market efficiency and fairness. FERC is responsible for regulating interstate energy commerce and transmission (often referred to as the bulk power system). FERC's jurisdiction is primarily economic, providing review and approval of transmission system investments and setting the rates that transmission owners can charge other parties for use of those facilities. Where competitive interstate energy markets have been established, FERC also has jurisdiction over market designs and rules. Through a series of orders, FERC provides competitive access to the wholesale markets for all participants in them.

Wholesale market rules were conventionally organized around legacy assets, almost exclusively bulk generation and transmission. Over time, it became understood that these rules were restricting access by energy storage to these markets from selling all potential services, and in turn significantly limiting storage's wholesale revenue potential (Twitchell, et al. 2021).

Prior to FERC Orders 841 and 2222, ISOs were not required to incorporate tariffs for participation models that recognize the physical and operational characteristics of energy storage and would permit storage participation in wholesale markets. Participation was largely limited to larger sources, whose definition varied by ISO but were typically 500 kW or more.[7] This was one of the biggest barriers for smaller resources such as batteries or demand response.

In addition, while certain progressive ISOs like NYISO and CAISO did enable aggregations of smaller resources to participate in their markets, there was no clear mandate from FERC requiring ISOs to do so. Generally, this presented barriers to participation by storage resources that were deemed too small by ISOs to participate in their markets. The practical implication of this was that smaller ESSs were limited to providing value allowed by state regulators, creating an uneven playing field.

Over time, FERC has issued a number of orders addressing this and other barriers to the participation of DERs in general and energy storage in particular. This section presents an overview of the two recent orders (FERC 2222 and FERC 841) that were designed to support participation by energy storage and DERs into the wholesale electricity markets. The following sections present key aspects of the FERC orders and how addressing legacy barriers facilitates the participation of energy storage in competitive wholesale markets.

4.1 FERC Order 841 – Participation of Individual Storage Resources

In 2018, FERC issued Order 841, *Electric Storage Participation in Markets Operated by RTOs and ISOs*. It requires regional market operators to provide fair and competitive access for energy storage to the wholesale marketplace, by designing market products that recognize and compensate the unique capabilities of storage technologies (FERC-2 2020).

[7] CAISO had the smallest minimum size, 500 kW (Power Settlements 2019).

4.1.1 Summary of FERC Order 841

FERC Order 841 was intended to direct regional grid operators to remove barriers to the participation of electric storage and open wholesale energy, capacity, and ancillary services markets to energy storage. The order intended to ease participation barriers for energy storage in wholesale markets through revised qualification criteria for resources that are large enough to support direct participation and explicit accounting of the associated power flows. The key qualification criteria directed by Order 841 are as follows:

- Minimum size requirement for participation in the ISO markets that does not exceed 100 kW
- Allows aggregation of multiple storage units to meet the minimum size requirement for the market participation, as long as they are co-located and operated as an integrated unit.

Order 841 also affirms that energy storage resources must be compensated for all of the services provided and moves toward leveling the playing field for storage with other conventional generating resources to participate in wholesale markets. Order 841 creates a clear legal framework for storage resources to operate in all wholesale electric markets to meet electric system needs through the following specific mandates to ISOs, requiring them to:

- Revise their tariff to establish a participation model for electric storage resources
- Properly recognize the physical and operational characteristics of electric storage
- Ensure storage is eligible to provide all capacity, energy, and ancillary services that it is technically capable of providing
- Can participate as a seller (generator) and buyer (load) consistent with existing market rules.

While FERC Order 841 mandated the aforementioned changes, those changes are being implemented at different paces and with variations in specific implementation details by ISOs. Table 4.1 illustrates its implementation status across various U.S. ISOs.

Table 4.1. Implementation Status of FERC Order 841 Across U.S. ISOs (ESA-1 2018)

Topic*	CAISO	ISO-NE	MISO	NYISO	PJM	SPP
B.1 Participation Model 2. Qualification Criteria 3. Existing Market Rules	Green	Yellow	Yellow	Yellow	Yellow	Yellow
C.1 Eligibility to Provide all Services	Green	Red	Green	Yellow	Yellow	Yellow
2. Ability to Derate Capacity	Green	Green	Green	Green	Green	Green
D.1 Participate as a Seller and Buyer 2. Prevent Conflicting Dispatch 3. Make-Whole Payments	Green	Green	Green	Yellow	Green	Green
E. Bidding Parameters	Green	Red	Green	Red	Red	Green
F. State of Charge (SOC) Management	Green	Yellow	Green	Yellow	Yellow	Green
G. Minimum Size	Green	Green	Red / Yellow	Green	Green	Green
H.1 Price for Charging Energy 2. Metering and Accounting	Green	Green	Green	Green	Yellow	Green

Green = likely compliant; Yellow = potentially noncompliant; Red = noncompliant
ISO-NE = Independent System Operator New England; MISO = Midcontinent Independent System Operator; NYISO = New York Independent System Operator; and SPP = Southwest Power Pool
*Topic letters and numbers correspond to layout of Order 841.
Source: Estimation by Customized Energy Solutions, Ltd.

The analysis in this study is not focused on this variation, but rather the potential advantages for batteries of a TE approach in terms of an improved participation model, increased utilization of batteries, and obtaining commensurate revenues from them, compared to BAU. This requires the analysis to forecast a BAU scenario that represents the median or most common implementation details adopted by ISOs as their rules mature, driven by Order 841. This is described in the next section.

4.1.2 Key Assumptions for Analysis of Individual Storage Resources from FERC Order 841

This section summarizes all the clauses in FERC Order 841 pertinent to this study, based on a line-by-line review of its provisions, and documents assumptions made by the study about how they will generally be interpreted and implemented. It is based on direct extraction of text from the order, condensing it to the actionable directives it contains. The condensed extraction is provided in Appendix A for reference. Some additional details on FERCs goals, objectives, motivations, and reasoning were retained in the appendix when they were deemed relevant to this study.

1. FERC Order 841 applies to <u>individual</u> storage resources >100 kW (or less as proposed by a ISO). So, the study assumes that:
    a. ***Utility (substation) and merchant storage resources are assumed to have capacities equal to or greater than 100kW, qualifying them to participate as individual resources***, even if comprised of modular batteries, as long as they are co-located and discharged as a unit. This presumes the intention is that multiple batteries that are co-located, co-owned, and are co-operated as a unified storage resource will be considered to comprise an individual storage resource.
    b. ***However, utility storage comprised of individual resources <u>connected at different locations</u> in a distribution system does <u>not</u> qualify***, despite being connected to the bulk system at a single point of interconnection, because if they are not co-located, they could end up being served by multiple substations in the event of a feeder reconfiguration event.
2. **Order 841 allows storage resource to participate in <u>all</u> wholesale markets** if it meets the required qualifications thereof.
3. **Order 841 requires discharging <u>and charging</u> energy for wholesale market participation** to be priced at wholesale market prices. So, the study assumes that:
    a. ***The ability to recharge at wholesale prices is so attractive that utility and merchant storage will participate as individual storage resources under FERC 841 (rather than under the auspices of an aggregator)***, even if located on a distribution system or behind a customer meter. Note this requires that any storage located behind a customer meter has its own meter (separate from customer total or customer load meter), so that customer bills can be adjusted accordingly. (Storage interconnected to the bulk power system will always have its own meter, as do generators or LSEs.)
4. **Order 841 allows ISOs to prohibit "double-counting"** the response of individual storage resources, in which the resources is rewarding twice for the same response on top of that received from their wholesale market participation. However, Order 841 specifically allows DERs to participate in one or more retail programs and provide more than one wholesale service as long as they are "distinctly different"). So, the study assumes that:

a. ***The distribution utility or LSE must adjust its wholesale demand bids & forecasts to exclude the effects of storage participating in wholesale markets*** to avoid double-counting them in market clearing and the power flow calculations upon which they are based. That is, it must forecast and bid the demand of its customers' end-uses less any self-generation, exclusive of any batteries participating in the wholesale market, so that its bids and forecasts do not include any expectation on whether battery offers to discharge or bids to charge will be cleared by the market or not. Hence, utility-owned storage connected to a distribution system must be metered so it can be distinguished from the LSE's load.

b. ***Storage resources that are not participating in wholesale energy markets and instead are being dispatched for local objectives must be included in the LSE's demand bid and forecast.***

c. ***Storage resources that clear the annual wholesale capacity market*** and receive and annual payment from it ***are prohibited from also being dispatched to reduce the LSE's annual peak demand***, and hence its capacity purchase requirement.

d. ***Stacking retail peak demand reduction (to manage LSE and/or substation peak demand) will be prohibited for storage resources participating in wholesale energy markets*** because of the likelihood of coincidence with peak regional wholesale peak prices.

e. ***FERC's prohibition on double-counting or stacking does not affect any annual wholesale capacity market payment to storage participating in wholesale energy markets***, because wholesale energy market prices do not (directly) reflect capacity value. This is consistent with how generators are treated.

The key assumptions of the study regarding participation of utility (substation) and merchant storage participating as individual storage resources under FERC 841 are summarized in Table 4.2 for convenience. The numbers in the first column of the table correspond to the numbered list above.

Table 4.2. Assumptions for Utility- and Merchant-Owned Batteries from FERC Order 841 (Individual Storage Resources)

No.	Assumption for Study	Rationale and Implications
1a & 3c	Eligible to participate as FERC 841 storage resources	• Because they are assumed to have >100 kW capacity (above FERC limit) • Even if comprised of modular batteries, if co-located[a] & operated as a unit
3a	Participate in all wholesale markets Charge and discharge at wholesale prices	• Because ability to charge at wholesale prices is so attractive • LSE must subtract wholesale charging and discharging from retail customer bill • Requires separate meter for batteries, even if located behind a customer meter
4a & 4c	Prohibits as double-counting a storage resource when: • LSE bids it as price-responsive demand and it bids separately in energy market	• Because it invalidates ISO power flow calculations • Because it double counts resource in market clearing • LSE must adjust its demand bids and forecasts to exclude effect of storage resources participating in wholesale markets • Requires battery have its own meter when connected to a distribution system

No.	Assumption for Study	Rationale and Implications
	• It bids into capacity market and LSE uses it to reduces its peak demand	
4d	Prohibited from participation in both wholesale energy markets and retail peak demand programs[b,c]	• Storage doubly rewarded for same response at times • Because local peak demand often coincident with regional peak demand and prices
4b	Storage resources dispatched for local objectives must not participate in the wholesale energy market and instead must be included in the LSE demand bid and forecast to the ISO	• Must inform ISO about effect on LSE demand • Otherwise invalidates ISO power flow calculations • Utilizing storage capacity for local service invalidates energy bid • Cannot "recycle" unaccepted wholesale bids into "other" services with same effect on bulk system
4e	Can participate in both wholesale energy and capacity markets	• Because energy market-clearing prices do not (directly) reflect capacity value • Consistent with treatment of bulk generators

[a] Multiple batteries are not co-located with respect to FERC 841 if they distributed along a feeder or at multiple substations, because could be served by multiple locational marginal price (LMP) nodes during distribution system reconfiguration events, invalidating ISO power flow calculations. Hence, they must participate as FERC 2222 resources (like customer-owned/BTM batteries; see Table 4.4).
[b] In the special case of a customer BTM storage resource >100 kW participating as a storage resource under FERC 841. Customer BTM storage in the study is assumed to generally be <100 kW.
[c] Merchant storage cannot, in general, physically provide these "retail" benefits unless located on the distribution system, or co-located at one of the LSE's point of connection to the bulk system.

4.2 FERC Order 2222 – Participation by Distributed Energy Resources

In 2020, FERC issued Order 2222 Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators. It was issued to enable DERs (including storage resources) to participate alongside traditional resources in regional organized wholesale markets through aggregations (FERC-3 2020).

4.2.1 Summary of FERC Order 2222

The primary intent of FERC Order 2222 was "…to open organized wholesale markets and create a level playing field that fosters fair competition of DERs with other conventional market participants" (FERC-3 2020). The order seeks to help provide lower costs for consumers through enhanced competition, more grid flexibility, and greater resilience (FERC-3 2020).

FERC Order 2222 eases the market participation of DERs by lowering the minimum size of resources that can participate in the wholesale markets by allowing DER aggregations of all types to satisfy minimum size and performance requirements that each may not be able to meet individually. Unlike FERC Order 841, which lowered minimum size requirements but only for individual resources storage, FERC Order 2222 took an aggressive step to further reduce the minimum size of participating resources across all DER types. It provides an improved and easier qualification criterion by allowing the combined capacity of DERs in an aggregation to meet the minimum size requirement of 100 kW, which otherwise retail customers generally could not meet with their resources. Table 4.3 contains a summary of the key features of the requirements set forth in Order 2222.

Table 4.3. FERC 2222 Features for DER Participation in Wholesale Markets

Parameters	Key Requirements
Eligibility of DER aggregators/DER types	DER aggregators must be an eligible market participant licensed to practice by the ISO according to its published rules. ISOs must allow all technology types and multitechnology combinations. ISO rules must prevent double-counting in retail and wholesale markets. Other than for small utilities, no broad opt-out provisions by states are allowed.
Geographical scope of aggregation	Encourages broad geographic scope of aggregation, but allows ISOs to propose to limit aggregations to a single pricing node.
Distribution factors and bidding parameters	Must account for physical and operational characteristics of DER aggregations and ensure they can fully offer their aggregations into ISO markets.
Information and data requirements	ISOs are required to transparently state the information and data that DER aggregators must provide them about the performance, physical parameters, and components of their aggregations.
Metering and telemetry requirements	ISOs have the flexibility to set these requirements, including whether to require metering and telemetry of individual DERs. ISOs must justify why they are necessary and explain why they do not result in undue barriers to participation.
Coordination	Requires ISOs to establish procedures for coordination between ISOs, DER aggregators, distribution utilities, and state and local regulators.

Again, the analysis in this study is based on a forecasted BAU scenario that represents the median or most common implementation details adopted by ISOs as their rules mature, driven by Order 2222. This is described in the next section.

4.2.2 Key Assumptions for DER Aggregations from FERC Order 2222

This section summarizes all the clauses in FERC Order 2222 pertinent to this study, based on a line-by-line review of its provisions, and documents assumptions made by the study about how they will be generally interpreted and implemented. Like the summary developed for Order 841, this is based on direct extraction of the text of Order 2222's actionable directives which appears in Appendix B.

1. FERC Order 2222 defines DERs and aggregations of DERs, as follows:

   a. ***Defines a DER*** as any resource located on the distribution system, any subsystem thereof or behind a customer meter, including but not limited to electric storage resources, intermittent generation, distributed generation, demand response, energy efficiency, thermal storage, EVs, and their supply equipment.

   b. ***Allows distributed storage/DERs to be aggregated to meet minimum size (not less than 100 kW) and other requirements for wholesale market participation to provide services for which they qualify technically*** as long as they are located on the distribution system, any subsystem thereof or behind a customer meter. This presumes that ISOs do not set lower maximum in their rulemakings proposed in response to the FERC order.

   c. ***Allows a single DER to participate as an aggregation***, i.e., as an "aggregation of one," even if it is otherwise eligible to participate as an individual resource, as long as it meets minimum size requirements (FERC guidance is 100 kW). This presumes that

ISOs prefer to account for large resources individually (under Order 841) because of reliability concerns.

2. Order 2222 further requires that:

a. ***Aggregations of DERs must be able to meet the qualification and performance requirements to provide the service that they are offering into ISO markets.*** For example, because energy efficiency cannot be dispatched, metered, or telemetered, it would likely be impossible for DER aggregations comprised exclusively of energy efficiency resources to be able to provide energy or ancillary services to the RTOs/ISOs because the aggregation would not be technically capable of providing those services.

b. ***ISOs must allow heterogeneous DER aggregations.*** This ensures that complementary resources, including those with different physical and operational characteristics, can meet the qualification and performance requirements such as minimum run times.

c. As a result of the definitions in item 1a and 1b (above) and the requirements in items 2a and 2b (here), ***the study presumes that both FERC and ISO policies will attempt to reconcile participation rules to achieve consistency in the treatment of DER aggregations that include distributed generation, storage, and demand response resources. To be consistent with the treatment of individual storage resources, this policy extends to bulk generators and LSE loads***, as well. This is policy assumed to be a general goal of the developing ISO participation rules, while recognizing that it may not be totally achievable in practice. Implications of this goal for participation of various storage ownership and regulatory scenarios will be discussed as they arise, in subsequent sections.

3. Order 2222 allows ISOs to propose to limit the maximum size of individual DERs in an aggregation (for reliability purposes), so:

a. ***The study assumes the maximum size of any DER in an aggregation will be 100 kW, consistent with 1b and 1c, above.***

4. Order 2222 ***directs ISOs to include any appropriate restrictions on the DERs' participation in ISO markets through DER aggregations, if narrowly designed to avoid counting more than once the services provided by DERs in the markets***. FERC offers examples of such inappropriate participation are:

- Bids that are offered into an ISO market and are not added back to a LSE's load profile, would result in that resource will be double-counted as both a load reduction and a supply resource
- DERs that are included in a retail program to reduce a LSE's obligation to purchase services from the ISO market
- Resources that are registered to provide the same service twice in one or more ISO markets (e.g., in multiple aggregations, or in an aggregation and as an individual resource).

The study assumes these narrowly defined examples clarify FERC's definition of inappropriate stacking of services and double-counting rewards for response

(introduced but not detailed in Order 841) ***for both DER aggregations and individual storage resources***, as articulated on 5c through 5f, below.

5. Order 2222 is much less proscriptive than Order 841, directing ISOs to propose rules on many issues relevant to the study's analysis (see also the discussion of Order 841 in Section 4.1.2 for other relevant issues). ***So, the study must assume how these will be implemented, in a "typical" ISO, as follows:***

   a. ***The study assumes that any utility owned but distributed (not co-located) storage that is less than 100 kW in size will be operated by the utility as an aggregation*** *for purposes of its participation in the wholesale market.*

   b. ***The study assumes that (like Order 841 individual storage resources), wholesale energy sold by DER aggregations occurs at wholesale prices, but that energy purchased by storage for charging might occur a) at retail prices or b) at wholesale prices***, depending on how FERC' intentions are interpreted and how ISOs and LSEs agree to implement Order 2222 in the ISO's participation rules.

   - Charging DER batteries at retail prices is consistent with how demand response "recovery" from a deferred end-use load is treated currently. That is, the energy associated with subsequent recovery[8] is purchased at retail rates, rather than at wholesale rates.
   - Alternatively, consistent treatment of demand response with batteries in aggregations could be achieved by allowing both battery charging and demand response recovery to take place at wholesale prices. However, the latter is not how demand response is treated by ISO's today, and is complicated by the fact that recovery loads cannot be metered other than as part of total customer demand, which would need to be estimated using a baselining method and the retail bill adjusted accordingly.
   - A second alternative is simply allowing batteries to charge at wholesale while continuing the current practice for demand response. This is feasible for aggregations that are homogenously one or the other, or if it is only applied to the storage part of a mixed aggregation. However, compensating resources in aggregations differently based on type violates the presumed intent by FERC of uniform treatment of resources in regardless of type.

   c. Further, consistent with item 4, above, and the study **adopts assumptions made for individual storage resources in Section 4.1.2, items 4a through 4e, based on FERC Order 841:**

   - The distribution utility or LSE must adjust its wholesale demand bids & forecasts to <u>exclude</u> the effects of DER aggregations participating in wholesale markets.
   - DER aggregations that are not participating in wholesale energy markets and instead are being dispatched for local objectives must be <u>included</u> in the LSE's demand bid and forecast.

[8] Recovery is the energy required restore normal thermal mass temperatures associated with space conditioning and water heating curtailments, or to catch up on deferred process loads (manufacturing, laundry, etc.). See also the deeper discussion of this issue in the sidebar in Section 7.1.3.

- DER aggregations that receive capacity payments from the annual wholesale capacity market are prohibited from also being dispatched to reduce the LSE's annual peak demand.
- Stacking retail peak demand reduction (to manage LSE and/or substation peak demand) will be prohibited for DER aggregations participating in wholesale energy markets.
- FERC's prohibition on double-counting or stacking does not affect any annual wholesale capacity market payment to storage participating in wholesale energy markets.

d. In addition, the study assumes that ***using customer-owned BTM storage to reduce a customer's retail demand charge, or to respond to dynamic retail rates, cannot be "stacked" with wholesale participation***, even though they are considered retail transactions rather than providing the LSE with a "service" or participation in a "utility program," because battery output is separately metered, and the customer retail bill adjusted to exclude it. Thus, when participating in the wholesale energy markets, the battery does not affect the customers retail peak demand.

The key assumptions made by the study regarding participation of customer BTM storage as a *DER aggregation* under FERC Order 2222 are summarized in Table 4.4 for convenience. The numbers in the first column of the table correspond to the numbered list, above.

Table 4.4. Assumptions for Customer-Owned/BTM Batteries from FERC Order 2222 (DER Aggregations)

No.	Assumption for Study	Rationale & Implications
3a	Maximum size of any DER in an aggregation will be 100 kW (Larger resources can participate as individual resources)	• Presumes ISOs do not set lower maximum in rulemaking proposed in response to FERC … • … prefer to account for large resources individually (under FERC 841) because of reliability concerns
3a	Eligible to participate only as part of FERC 2222 DER aggregations	• Study does not analyze hybrid ownership case of customer BTM batteries > 100 kW participating directly in wholesale markets as FERC 841 resources
2.c & 2c	Aggregations can include storage, DG, demand response … … so FERC & ISOs will strive for consistency among: • Bulk (e.g., merchant) generation • LSE demand • All types of DERs in aggregations • Individual resources (storage, demand response>100 kW)	• Storage + generation + LSE demand is simple: – Battery discharging = supply – Battery charging = demand • Storage + demand response is complicated: – Demand reduction from load shifting = supply – Extra demand occurring later due to shift is not bid by aggregation into wholesale market – So "recharging" shifted load occurs at retail price
5b	Wholesale energy sold by DER aggregations occurs at wholesale prices (e.g., battery discharge)	Study will analyze two cases: • BAU Retail to be consistent with demand response, aggregated storage charges at retail prices

No.	Assumption for Study	Rationale & Implications
	Unclear if also applies to battery "charging" energy purchases	• BAU Wholesale to be consistent with generation and LSE demand, aggregated storage charges at wholesale prices
5c	• LSEs must adjust wholesale demand bids and forecasts to exclude the effects of DER aggregations participating in wholesale markets • DER aggregations being dispatched for local objectives instead of participating in wholesale energy markets must be included in the LSE's demand bids and forecasts • DER aggregations receiving capacity payments from the wholesale capacity market are prohibited from also being dispatched to reduce the LSE annual peak demand • Stacking retail peak demand reduction (to manage LSE and/or substation peak demand) will be prohibited for DER aggregations participating in wholesale energy markets • FERC's prohibition on double-counting or stacking does not affect any annual wholesale capacity market payment to storage participating in wholesale energy markets	• Consistent with how individual storage resources are treated in terms of prohibitions on stacking and double-counting … • … items 4a through 4f in Table 4.2 for individual storage resources are assumed to also apply to DER aggregations
5d	Responding to customer demand charge or dynamic retail rates and participating in wholesale markets does not reduce the retail customer peak demand charge bill, i.e., cannot be stacked	• Even though these are retail transactions outside FERC jurisdiction • Because the battery's wholesale transactions are at wholesale prices, they are subtracted from the customer's retail bill

5.0 Barriers for Energy Storage Deployments

This section presents an overview of barriers to energy storage deployments other than those addressed by FERC's regulatory reforms and discussed in Section 4.0. While energy storage participation has certainly been eased by the new FERC orders, several barriers remain that limit the potential grid services and value exchange mechanisms energy storage can bring. The barriers also hamper business models that incentivize value exchange. These barriers may include regulatory, market, technology, value offerings, or cross-cutting barriers that cross these different categories. Each of these have a profound impact on either restricting the level of deployment or making the deployment extremely lengthy.

The discussion above presents a range of different barriers that are subjective to each ownership structure. The ownership structure and associated regulations and market rules create different barriers associated with procuring financing and investment, interconnection requirements, and market risks. These risks also create different kinds of uncertainties and hamper value exchanges in different ways for these different owner types. Table 5.1 presents a summary of some of the most important of these barriers. A brief introduction to them follows.

Table 5.1. Summary of Barriers for Multi-Owner Energy Storage Deployment

Owner	Financing Mechanism	Deployment Speed	Market/ Regulatory	Service Offerings	Uncertainty	Value Proposition
Merchant storage	Investment tax credit	Complex and Lengthy interconnection process	Cannot stack service but submit as qualified bids	Some services (e.g., VARs) and intrinsic grid benefits (e.g., congestion relief) not offered	Risk of change in regulation	Smeller market size and shrinking arbitrage opportunity
Utility owned	Regulated rate of return	Utilities may not be allowed to own and trade storage	No retail market	Can theoretically stack services (wholesale and local) but it is harder to meet qualification while value stacking	Risks of return on investment due to fast-changing regulations	Inadequate tools to quantify tradeoffs between market/ nonmarket-based value proposition
Customer BTM	Retail pricing or leasing	Utility restrictions may occur in the approval	Infrastructure and jurisdiction issues limit wholesale participation	Require proper aggregator-customer model for <100 kW to provide services	Uncertainty on long-term incentives and market prices	Inadequate policies/ regulations to ensure revenue

In general, value stacking remains a barrier and is compounded by the lack of a mature retail marketplace. A number of forms of value stacking with capacity are not currently supported in marketplaces, hampering the full use of the resource as well as the associated revenue. Moreover, some of the services that can add operational functionality for utilities are currently not monetized. All storage owners are subject to risks associated with changing and evolving technology, regulations, and market conditions.

For merchant owners, the key barrier to energy storage financing remains the difficulty in accessing ITCs. Interconnection barriers continue to be a challenge for new projects. While merchant entities currently participate heavily in the ancillary market space, trends point to shrinking revenues in a potentially crowded marketplace.

Utility-owned storage is met with financing barriers in the form of rate-basing issues. In many marketplaces, utility-owned storage may not be eligible for market participation. Moreover, traditional planning processes do not include adequate tools to assess the value of added long-term storage on their systems.

For customer BTM storage, interconnection times and standards create significant delays and complexities. While FERC orders have eased some barriers to participation, detailed mechanisms and aggregator models have not been developed to facilitate participation.

Overcoming these barriers is key to unlocking the potential of energy storage across these ownership structures. The discussion that follows attempts to capture a broad set of barriers that energy storage is currently facing from the standpoint of markets, regulatory issues, service models, and value propositions.

The sections that following describe 1) a set of barriers that affect all types of battery owners, highlighting differences and similarities in how the different owners are affected and 2) three sets of additional barriers that exclusively effect only one type of battery owner. (In some cases, some types of owners are advantaged at the expense of other types of owners.) For each barrier, a general indication is shown of its relative importance provided to each type of owner, at one of three levels of importance indicated by the number of down arrows (or advantage, upward arrows), based on subjective evaluation. A zero is used to indicate there is little or no impact on an owner type.

5.1 Wholesale Market Barriers

1. Lack of uniformity in markets. While FERC Orders 841 and 2222 require ISOs to develop participation mechanisms for individual storage and DER aggregations including storage, the specific regulations that embody their provisions will vary by ISO. Each market structure has its own set of rules and regulations about compensation mechanisms, capacity requirements, participation restrictions, and measurement and verification requirements, making it challenging for developers to generate viable business models to operate across multiple markets (Bhatnagar, et al. 2013). Where there are vertically integrated wholesale markets, such regulations exhibit even more variation, including outright prohibition in some jurisdictions.

Merchant Owner	Utility Owner	Customer/ BTM Owner
↓↓↓	↓↓	↓↓

This is a significant barrier to all types of owners, but especially for merchant owners because their batteries are presumed to be connected to the bulk transmission system. Their entire revenue stream comes from the wholesale markets, so they are physically unable to offer distribution- or customer-level services.

2. Thin markets for ancillary services. Battery owners can generate significant revenues by providing ancillary services. However, while storage and DERs offering such services are expected to rapidly proliferate, the demand for ancillary services is relatively finite. PJM, one of the largest wholesale markets in the world (~170 GW of peak load), requires roughly 800 MW of frequency regulation (0.5%). Comparing that to 3,900 MW of energy storage in service or in PJM's queue, these resources will likely saturate the market for ancillary services relatively quickly, with prices for regulation dropping accordingly. The same is true for spinning reserve, although it requires a larger set of resources (~5% of the load).

Even with increasing levels of renewables integrated into the system, the demand for ancillary services is not expected to increase proportionately. While the need for new services such as ramping may arise, the result is that these shrinking "thin" markets are unlikely to form an attractive long-term revenue stream that will attract investment in storage (Sackler 2019).

Merchant Owner	Utility Owner	Customer/ BTM Owner
↓↓↓	↓↓	↓↓

This is an especially significant barrier to transmission-level merchant owners because of their exclusive reliance on revenues from wholesale markets.

3. Merchant Risk. Utilities can minimize or eliminate their risks in relying on energy storage by signing PPAs with merchant owners or aggregators of customer BTM storage and shifting such risks on to them (Lesser 2021). Such 'merchant risks' include evolving technology, policy, and wholesale market conditions. These pose significant risks to business models for energy storage, and hence investments in them (Forrester 2017).

Merchant Owner	Utility Owner	Customer/ BTM Owner
↓↓	0	↓↓

5.2 Retail Barriers

4. Lack of local, distribution-level grid services. The lack of formally defined local grid services has created a scenario in which the bulk of the value of distributed battery deployments remains with the end-user while limiting the services and value that can be offered to the electricity network. For instance, distribution utilities could make much better use of integrated customer PV and battery systems to meet peak electricity demand. In addition to managing peak loads, distribution-level storage can provide grid services such as volt-VAR regulation, manage congestion on feeders and circuits, and enhance utilities' abilities to host solar PV capacity and EVs, thereby deferring costly investment in distribution network infrastructure.

Merchant Owner*	Utility Owner	Customer/ BTM Owner
↓↓	↓	↓↓↓

* affects distribution-connected only

This is a very significant barrier to customer-owned BTM batteries, but also has the effect of discouraging merchant-owned storage projects connected at the distribution-system level. The lack of formally defined grid services also indirectly hurt utility-owned storage, which may face increased scrutiny from their regulators due to a perceived lack of transparency and fairness of opportunity.

5. Lack of retail marketplaces and dynamic retail tariffs. The adoption of dynamic retail rates that seek to maximize benefits for consumers while incentivizing demand-side flexibility could have important benefits encouraging the penetration of distribution-level batteries. Time-of-use tariffs, for example, incentivize consumers to adjust their electricity consumption (including the use of their BTM storage) to reduce their electricity bills (IRENA-1 2019). Time-of-use tariffs allow battery systems to observe the periods of low and high electricity prices and decide when to charge and discharge batteries. Other dynamic tariffs such as critical-peak pricing, variable peak pricing, and real-time rates can express such value streams with even more fidelity, and hence offer even greater opportunities to battery owners.

However, such dynamic tariffs serve to incentivize better net consumption patterns while not creating mechanisms to enable procurement of local, distribution-level grid services. These could be expressed in retail marketplaces once such services are formally defined. The effects on battery owners are similar, but such marketplaces are entirely lacking in today's U.S. distribution utilities. Adopting a TE approach can address this challenge.

Merchant Owner*	Utility Owner	Customer/ BTM Owner
↓↓	↓	↓↓↓

* affects distribution-connected only

5.3 Seams Issues

6. Prohibitions on Value Stacking and Double-Rewarding. Using a unit of capacity to provide more than one service is referred to as 'value stacking' (Hill-Cristol and Fields 2017). In general**,** market rules do not permit value stacking, inhibiting the value proposition behind storage (Maloney-1 2017). Similarly, 'double-counting' (rewarding a resource in two separate venues for the same response) is prohibited.

What exactly constitutes prohibited value stacking bears discussion. For example, a merchant generator that commits to participating in one market structure (for example, the energy market) may use a portion of its capacity for that purpose. The same entity can strengthen its value proposition by using the rest of its capacity in PPAs, in bilateral wholesale contracts with LSEs, or directly bidding into ancillary services markets. The study presumes that FERCs intentions with Orders 841 and 2222 are that batteries be treated similarly.

ISOs generally require that resources bidding into their capacity market must bid that capacity into the energy markets. Part or all of any unsuccessful energy market bids generally can be automatically submitted to the ancillary services markets. Although the same capacity is involved in such automatic rebidding, it not considered prohibited stacking since the firm capacity in the energy bid is formally released by the energy market.

However, the ISOs market rules suggest that any battery capacity that is used to offer other grid services such as local, distribution-level services must be reserved for that purpose and must not to be submitted to the wholesale energy or capacity markets. As discussed in Section 4.0, battery capacity cleared in the wholesale capacity market (and that must bid into the wholesale energy markets) cannot 1) participate in retail demand response or other programs, or provide local, distribution-level grid services such as congestion management, peak load deferral, or volt-VAR support; or 2) participate as part of a LSE's price-responsive demand bid for peak reduction. Therefore, these are examples of stacking likely prohibited by FERC. If this proves to be the case, battery capacity dedicated to such services would have to be set aside as such.

Unfortunately, no mechanism exists to formally release the capacity in unsuccessful bids into the wholesale energy market and allow them to rebid into local markets, assuming they come into existence.[9] Even if such mechanisms were to be established in the form of a local spot market for distribution-level services, it would be very difficult for the utility to count on their availability for local operations with enough assurance to defer infrastructure investments. As a result, significant amounts of battery capacity may go underutilized in BAU futures.

Further, overly strict prohibitions on the closely related issue of "double-reward for the 'same' response" as described by FERC is problematic. For example, the LSE offers an additional incentive for a battery to respond to local congestion events, some of which will often coincide with the LSE's peak demand or high energy market prices. As long as the battery is only rewarded in proportion to the avoided distribution system infrastructure costs (but not the LSE's wholesale costs), this is legitimately added value that the battery has in fact provided. It might be just enough additional revenue to elicit a battery to respond when otherwise it would not be cost effective to do so. One can imagine such a compromise policy could be developed, but enforcing it fairly could be daunting.

It is notable that the energy markets add marginal costs due to congestion constraints when computing LMPs. This adds to the reward a resource otherwise would receive for responding to a pure, uncongested energy market price.

Customers with BTM batteries participating in the wholesale energy and capacity markets will likely simultaneously receive some benefit from reducing their peak demand charge when their load shape is coincident with the bulk power system's peak. FERC is unlikely to have the authority to force utilities to change such long-standing rate designs or force participating customers to sign up for a flat rate (one might not even be available for their customer class). Following this precedent, it seems unlikely that FERC or the ISO rules would try to prohibit such customers from signing up for dynamic retail rates, either.

Similarly, customers should be able to use their battery for backup power during an outage, even having successfully bid into the wholesale markets, as it is unavailable to the power system during such events anyway. However, doing so does drain the battery, which may not allow it to follow through with other, previous market commitments. Does this therefore constitute prohibited stacking? This would clearly prohibit its use as a blackstart resource, for example.

The lack of clarity around what constitutes prohibited stacking is, in itself, a significant barrier to obtaining financing for battery projects for all types of battery owners, given the uncertainty in the business model and expected revenues This is one barrier that adoption of a TE strategy could offer substantial relief. This will be addressed in Section 7.2 of this report.

Merchant Owner*	Utility Owner	Customer/ BTM Owner
↓↓↓	↓↓↓	↓↓↓

* affects distribution-connected only

7. Grid services cut across multiple markets and compensation sources. The variety of different grid and customer services that batteries can provide often cuts across multiple

[9] It would be very difficult contractually to resell in a PPA, given the uncertainty in its availability.

markets and other means of compensation. For instance, frequency regulation may be compensated in a wholesale market, infrastructure investment deferrals and peak load reductions may be compensated as a cost of service by the utility or transmission system owner, while services like volt-VAR regulation may not be valued monetarily at all, today. In some jurisdictions, stacking different services is restricted by local, state, or FERC regulation. Limiting the services batteries can provide, based on where the service is provided or how it is compensated, can influence how often batteries are used and whether they remain an economically attractive investment.

Merchant Owner	Utility Owner	Customer/ BTM Owner
↓	↓	↓↓

This barrier is more significant to customer owners than utility and merchant owners (but affects the latter to some degree as well). Merchant-owned batteries are particularly affected when they are connected at the distribution level.

8. Lack of formalizing any local jurisdiction's requirements. There are no uniform requirements to develop and capture local jurisdictional requirements for DER aggregations, distribution factors, bidding parameters, or coordination mechanisms between aggregators, the utility, and the relevant regulatory authority. This makes it more difficult for battery owners, primarily customer owners and to a lesser extent utility owners, to understand the combined effect of all the local and bulk system technical requirements and business environment, which will likely vary widely across jurisdictions.

Merchant Owner*	Utility Owner	Customer/ BTM Owner
↓	↓	↓↓

* small because it affects only distribution-connected batteries

5.4 Interconnection Barriers

9. Lengthy, complex, and costly transmission interconnection permitting. Other key challenges to battery owners are the complexity and slow pace of interconnection studies leading to permitting for resources connected to the bulk transmission system. Such resources are subject to regional regulations that define the interconnection standards they must meet. These standards are well defined for solar generation but lack specificity for ESSs (Burdick 2020) (Colthorpe 2020). Lengthy and complex interconnection processes often serve to disincentivize the widespread adoption of storage (St. John-5 2021). This is in part due to the often-outdated legacy interconnection standards. Interconnection standards have been designed around generating facilities, largely ignoring the role that storage can play as a source and a load. Legacy standards designed around generators further assume that generators can recover costs through rates, while taking up their own interconnection costs.

Merchant Owner	Utility Owner	Customer/ BTM Owner
↓↓↓	↓	0

This primarily affects merchant owners. Utilities inherently have an interconnection that serves their load, and the fact that the output from their batteries may never exceed their load suggests they may be able to avoid all or at least part of the interconnection process.

10. Owner pays for transmission upgrades, and costs are rising rapidly. Average network upgrade costs have grown significantly. In the MISO's western subregion, the assigned network costs have increased over 300% from 2015 to 2017, while in the SPP region they have increased nearly 700% from 2013 to 2017 (St. John-5 2021). This particularly has consequences for projects lined up in an interconnection queue. The upgrade costs are typically forced on the first project in the queue that triggers the upgrade requirement. In case these costs are not viable for that particular project, it drops out of the queue, leaving the next project to pick up the upgrades. This severely impacts the economic viability of projects in a given queue. For example, in MISO territory, the operator has seen a loss of 5 GWs of renewable projects from its queue due to this issue (St. John-3 2020). A few states, including Massachusetts and Maryland, are exploring new approaches to allocate a share of upgrade costs across multiple projects and with ratepayers to enable proactive grid investments.

Merchant Owner	Utility Owner	Customer/ BTM Owner
↓↓↓	↓	0

Similarly, this primarily affects merchant owners, while utility-owned batteries will likely avoid the need for most if not all transmission upgrades.

11. Interconnection studies may not account for likely operation of batteries. Another challenge in the interconnection procedure is the nature of such studies. They involve assessing the impact of the added storage on the grid. Most rely on the assumption that (analogous to a bulk generator) the maximum capacity or nameplate rating may be imported or exported at any point in time, rather than accounting for the associated controllability of storage (Brown-2 2021). This approach is not appropriate in the case of storage projects because most would never provide maximum capacity to the grid, but rather be dispatched on an as-needed basis (ESA-2 2018). Similarly, unlike LSE demand, it has complete flexibility to charge at a feasible and low-cost (presumably low-demand) time. This primarily affects merchant owners.

Merchant Owner	Utility Owner	Customer/ BTM Owner
↓↓	0	0

12. Owner pays for distribution upgrades. Most interconnection policies currently require individual project owners to pay the full cost of any distribution grid upgrades that are needed to accommodate their projects (Passell 2019). While this is true for solar PV systems and conventional distributed generators that use the system to export the power they generate, it may be inappropriate for storage projects that are usually intended to benefit the grid, not burden it. Because upgrade costs are high, this may prevent new projects in general, and areas of the distribution system with high penetrations of local generation have already stretched the limit of available capacity, just where they are most needed. As for transmission-connected batteries, the upgrade costs may reflect worst-case conditions and not appropriately reflect distributed batteries' flexibility to help rather than burden system operations.

Interconnection customers can avoid hefty grid upgrade fees by designing their projects to operate as non- or limited-export systems, which can reduce grid impacts (Brown-1 2021), but also reduce benefits. These costs, often hundreds of thousands of dollars for larger batteries, can stifle the economics of a project. This limits project development, delays needed investments that avoid new traditional infrastructure capacity, and leaves whole sections of the distribution grid closed to battery deployment.

Merchant Owner*	Utility Owner	Customer/ BTM Owner
↓↓↓	0	↓↓

* affects distribution-connected only

This barrier mostly impacts merchant owners who otherwise want to locate large batteries on the distribution grid to provide local services in addition to participating in wholesale markets. Customer-owned BTM batteries are generally small enough that, like PV systems, upgrades are rarely needed (at least until penetrations become very high). Utility owners are unaffected because any upgrade costs are ultimately borne by their customers in the form of rate recovery. This can be viewed as an unfair advantage compared to other types of owners.

13. Distribution interconnection approval process can be lengthy and costly. Soft costs associated with interconnection, permitting, and development costs can account for a significant share of the installed cost of customer-owned BTM batteries, in particular. It is also stifled by the lengthy utility approval process for interconnection (Gheorghiu-1 2018). As they have done for distributed solar PV systems, regulators may require the processing time for interconnection and permitting of distributed batteries to be reduced, which results in notably lower all-in costs for storage project developers and customers. Utility owners have the (unfair) advantage of having all such costs borne by their ratepayers.

Merchant Owner*	Utility Owner	Customer/ BTM Owner
↓	0	↓↓

* small because it affects only distribution-connected batteries

5.5 Barriers Specific to Merchant Storage

The following regulatory and market barriers are factors that discourage merchant investments in battery storage. They have little or no relevance to utility or customer owners, which are discussed in the subsequent sections.

14. Difficult to finance projects with significant risks. Merchant battery projects face uncertain revenue streams and an unstable regulatory environment. Financing is difficult to acquire for resources participating in the ISO marketplace to the extent that revenue is not predictable. Financing is also difficult to acquire in the non-ISO marketplace as rate base approval from regulators for utilities signing PPAs with merchant batteries is uncertain. This may be due to the uncertainty regulators see with a relatively new technology unnecessarily increasing ratepayer price risk (Bhatnagar, et al. 2013).

Merchant Owner	Utility Owner	Customer/ BTM Owner

↓↓	0	0

15. Difficult for battery projects to qualify for ITCs. Tax credits are a key incentive to the development of solar projects with added storage. There are two primary eligibility requirements that must be met to reap these benefits. The first is that the connected storage must be qualified as a generating asset as opposed to a transmission asset. The second is that at least 75% of the energy stored should come from the renewable energy project to which it is coupled (Barrow 2020). ITCs are instrumental in reducing merchant risk in terms of project financing. However, standalone storage systems are unable to reap the same benefits (Tang 2021). By and large, ITCs have been instrumental to the growth of the U.S. solar energy market and would likely do the same for standalone storage.

Merchant Owner	Utility Owner[10]	Customer/ BTM Owner
↓↓↓	0	0

16. Coupling batteries with renewable generation may delay the project. Merchant owners seeking to site batteries and integrate them with renewable generation for the batteries to qualify for ITCs face two basic challenges. First, there is the burden of proving that the storage component is in fact truly physically and operationally integrated with the renewable component. Second, often ISOs require renewable generation projects that have already begun or gone through the interconnection process to resubmit a new interconnection request for the added storage component (St. John-4 2021). This effectively pushes these projects back to the end of what is an already long interconnection request queue.

Merchant Owner	Utility Owner	Customer/ BTM Owner
↓↓↓	0	0

Several ISOs are attempting to change this interconnection procedure for such cases. CAISO is projected to bring into practice a ‘material modification’ request rather than an interconnection request to speed up the process (Millar and Bradley 2019). MISO is developing a similar ‘Surplus Interconnection Service’ to make the interconnection of storage with renewables easier (Kristian and Prorok 2020).

5.6 Barriers Specific to Utility-Owned Storage

Utility-owned storage can deliver tremendous flexibility to the distribution utility and the ISO, and enable a number of additional value propositions, such as distribution infrastructure cost deferral or increasing PV and EV hosting capacity. However, utilities seeking to own batteries face a number of barriers.

17. Regulatory prohibition of utility battery ownership. Utilities that may choose to avoid infrastructure upgrades through storage procurement may find it difficult to rate base the projects. For instance, American Electric Power (AEP) sought to use storage instead of building transmission corridors to support their system at lower infrastructure costs in a proposal

[10] Since they pay taxes, investor-owned utilities face this barrier as well in rare cases when seeking to integrate a battery with renewable generation they own and operate to seek an ITC.

submitted to the Public Utility Commission of Texas (Cohn 2018). AEP's request to rate base the storage project was denied in Texas's deregulated market structure, by regulators citing issues with the utility's ownership of storage as being akin to prohibited ownership of generation). Rate-basing utility-owned storage can be challenging due to such regulations. This creates lost opportunities in terms of the operational improvements and cost savings that could be achieved.

A key concern that is commonly cited with utility-owned storage is the amount of market power a utility may accrue as a result. The concern is whether a utility should be permitted to own a dispatchable asset to compete with independent power producers and merchant- and customer-owned BTM batteries (Mullendore 2015). Three potential negative outcomes include:

- Concentration of market power. In acting as LSEs on behalf of their customers, utilities have significant power in wholesale markets. For this reason, utilities were forced to divest their generation assets in many states as deregulated, competitive wholesale markets were adopted. Owning their own storage resources puts them in a position of altering both supply <u>and</u> demand, exacerbating fears on the part of regulators about the potential for market manipulation.
- Recovery of capital investments with a regulated rate of return from ratepayers is an unfair advantage. Investor-owned utilities have a significant advantage over other types of battery owners because they earn a regulated rate of return on their capital investment, presuming they can show net benefits to ratepayers and prudency for investments storage. This nearly guaranteed profit greatly reduces the risks they face from investing in storage.
- Using ratepayer funds for utility-owned battery projects may preempt private investments in battery projects from other types of owners. The utility may use ratepayer funds to install storage and recover the capital costs at low risk through their customer rates. As first movers in the marketplace, utility-owned batteries may dilute the value of and opportunities for subsequent nonrate-based investments in battery storage from merchants and customers (O'Boyle and Aggarwal 2015).
- Utilities have a unique and unfair advantage owing to their intimate knowledge of their networks and needs. If a utility were less than transparent about these needs, other types of battery owners may be unable to propose projects to meet them. Likewise, the utility's planning processes give it ready access to knowledge about potential battery sizing, placement, and operation. This extends to their knowledge of communication protocols and control systems, ensuring interoperability and integration is often an easier task.
- Distribution utilities have direct access to customers and branding advantages over third-party installers, presenting barriers to entry and innovation for private companies to finance and/or install batteries at customer sites, while raising the possibility of market manipulation to prevent competition (O'Boyle and Aggarwal 2015).

Regulations preventing utilities from owning storage vary on at the local and state levels. Some states like Texas qualify storage as a generating source. Texas regulations also explicitly forbid utilities from owning any generating facility. While this has served to stimulate merchant storage proliferation, it has inhibited realization of many of the operational values that utility-owned storage can provide.

Other states, realizing the operational value that utility-owned storage can provide, try to restrict utilities' market power and advantages by constraining how much battery capacity they can own, or what services they supply with them. For instance, California restricts utilities from owning more than 50% of installed battery storage located in each sector (transmission, distribution, and customer sited) in their service territories. In New York, the NYREV initiative attempts to achieve a balanced approach between utility involvement and limitations on utility ownership, allowing utility-owned storage only under one of three conditions (NYREV 2016):

1. Sited on utility property and integrated into the distribution systems
2. Designed to improve service in low-income communities that are inadequately served
3. Specifically for a pilot project designed to create and disseminate knowledge about ESSs and their deployment.

While, concentration of market power is a valid concern, the negative outcomes highlighted above presume that storage will become an important option for utilities. This is not the case today, owing to relatively high battery costs compared to bulk generation and the value of avoidable infrastructure investments. In theory, utilities can use storage as a distribution system optimization tool. However, under most regulatory models, utilities have financial incentives for larger, traditional investments as long as they meet the “used and useful” prudency tests. In other words, higher capital expenditures drive higher profits under the traditional regulatory model (O’Boyle and Aggarwal 2015). Since examination of storage-based alternatives are not yet a standard part of most prudency reviews, system optimization of this kind is not necessarily rewarded under traditional cost-of-service regulation.

Merchant Owner	Utility Owner	Customer/ BTM Owner
0	↓↓↓	0

18. Utilities’ requirement to prove the prudency for storage investments is burdensome. Investment decisions associated with utility-owned storage are often determined by traditional long-term planning processes that require significant technical resources and time to conduct. integrated resource plans typically focus on resource adequacy rather than quantifying temporal benefits, making the value of operational improvements at the distribution level from services such as reactive power support and load shaping challenging to define (Climate Impact Capital 2021) (Cooke, Twitchell and O'Neill 2019). While some utilities may specifically deploy storage and use a part of its capacity for operational improvements, FERC Orders 841 and 2222 prohibit selling it in the annual capacity market auction. So, while utilities can sell unused energy from their batteries into the wholesale energy markets on an as-available basis, they must forgo annual capacity payments for any capacity they intend to use for local operation needs at any time. This prohibition significantly reduces the revenue the battery may receive and makes proving prudency that much more difficult.

Merchant Owner	Utility Owner	Customer/ BTM Owner
0	↓↓	0

19. Tools and packages to quantify operational and monetary benefits are also not mature enough to support widespread investment. Typical modeling capabilities do not adequately capture the capabilities of energy storage and undervalue its use, especially when considering opportunities to provide multiple services under various pairings, regulatory constraints, and business strategies. This makes quantifying the tradeoff between market-based and nonmarket-based operations challenging.

A good example of this is production cost modeling. Most production cost models operate at the hourly resolution, looking over a 1-year horizon, and thus do not account for supply and demand variability at shorter timeframes, which can present a significant limitation in evaluating the full range of storage capabilities (Barrows, et al. 2019). Energy storage is well-suited to provide services at fine timescales due to their quick response capabilities. Although newer production cost models do go to finer time resolutions, they are still limited to a 5-minute optimization horizon, which undervalues the use of energy storage to address second-to-second and minute-to-minute variability.

At longer timeframes, capacity expansion models have difficulty in optimally locating energy storage resources and properly accounting for their value compared with conventional resources (Bhatnagar, et al. 2013).

Merchant Owner	Utility Owner	Customer/ BTM Owner
0	↓↓	0

These technical shortcomings lead to difficulty in the consideration of utility-owned storage resources as alternatives to new generation and transmission investment.

5.7 Barriers Specific to Customer-Owned BTM Storage

The rapid adoption of rooftop solar PV systems has spurred the adoption of customer-sited BTM storage as well. BTM storage can provide backup power capabilities and energy market arbitrage opportunities, as well as some other market propositions. In addition to the benefits from direct marketplace participations, BTM storage can also provide resiliency benefits to customers and the power grid. In California, customer-centric programs such as a self-generation incentive program are supporting the rapid adoption of BTM storage by offering a $1,000/kW resilience benefit, which is one of the biggest reasons for BTM storage deployment in California (California Public Utilities Commission 2021).

However, some key barriers exist to realizing the full potential of this ownership model. Some of these are as discussed, below.

20. Requirement for an aggregator. Despite FERC Orders 2222 and 841 providing access by storage resources to the wholesale marketplace, access to it by customer BTM storage with capacity under 100 kW has to be via an aggregator (Condon, Revesz and Unel 2018) (Maloney-2 2018) (Rand 2018). The general business model for aggregators is that they contract with a set of resource owners to represent them in the wholesale markets. They generally install the necessary communications and controls to operate the resources. Typically the aggregator collects the revenues from selling energy and capacity of the resources in the wholesale markets. Of course, they are in business to make a profit.

But how these revenues are shared with customers, and under what circumstances the aggregator can access their resources to participate in the energy markets and/or provide ancillary services varies widely and is the subject of private contracts between aggregators and customers with resources. There are few if any regulations governing aggregators beyond standards for general business conduct, and certainly no standards, regulations, or transparent common practices defining how the resulting revenues are divided and shared with their customers. Nor are there standards or common practices for how, how much, how often, and under what circumstances an aggregator can access a resource for participation.

All this exacerbates a lack of awareness on the part of customers about aggregators that in itself is a barrier to BTM storage. Regardless, splitting the proceeds between the aggregator and customers reduce the customers' share substantially, and is an even bigger barrier.

Because of this lack of uniformity, the study does not try to assess what fraction of the potential revenues from batteries would accrue to each party in the transaction. Instead, the study treats them as a unified business and assesses their combined revenue potential.

Historically, the focus of aggregator business models was to aggregate demand response and dispatchable generation from customers. So, whether they are also responsible for purchasing the energy to recharge batteries is not established by precedent and likely varies widely, as FERC's intent in this regard is not entirely clear as discussed in Section 4.2.2.[11] The lack of clarity regarding who supplies the charging energy for their batteries may prove to add to confusion on the part of customer owners about the role of aggregators.

Merchant Owner	Utility Owner	Customer/ BTM Owner
0	0	↓↓↓

These issues surrounding aggregators form a barrier that the adoption of a TE strategy tries to address. TE designs analyzed and demonstrated previously show how customer resources could participate directly in retail markets, operated by distribution utilities or LSEs. In such designs, they have full access to wholesale markets for energy and capacity via the transactive retail rate structure. Access to ancillary services markets would require the utility or LSE to act as an aggregator, pending reforms as to how they pay for their share of an ISO's costs for purchasing the required ancillary services.

21. Net (retail) metering is not universal, and where in place it is primarily focused on buying generation from solar PV that is in excess of customer loads. Whether net metering is allowed for customers is subject to local regulatory policy. Generally, it is understood to involve two elements: 1) the right of the customer to export more power to the grid when their output is greater than their native end-use demand consumes; and 2) the right to receive payment for that export at their prevailing retail rate.[12] Without net metering, a BTM battery cannot discharge more power than their end-use demand is consuming at the time, or at a minimum it will not displace any of the customer's bill. That would place a limit on their ability to make maximum contributions to power grid operations.

So, when prices are high, it incentivizes prosumers to provide stored energy to the grid beyond supplying their consumption instead of storing it, maximizing their profit potential during high price events. This is especially valuable when coupled with distributed generation technologies, such as rooftop PV, that also inject power, because otherwise their output would further limit the

[11] This is closely related to the issue of whether aggregated batteries are allowed to charge at wholesale rates (in which case the aggregator would have to purchase it from the ISO and charge their customers for it), or whether they must charge at retail rates (in which case the customer likely pays for it unless other arrangements with the aggregator are included in their contract).
[12] A variation on net metering, when the retail rate for exporting and importing power differs it is net billing.

amount of power discharged from storage to at most “zero-out” the customer’s power consumption.

The BAU scenario in this study assumes a separate submeter is required for customer BTM batteries, so their contributions to the wholesale energy can be properly metered and their retail bills adjusted as necessary. However, this is only a viable alternative to net metering if distribution utilities and LSEs are willing (or required) to make the associated adjustments to reflect net consumption in the customer retail bills. Whether this is subject to FERC and hence ISO requirements is not clear.

Merchant Owner	Utility Owner	Customer/ BTM Owner
0	0	↓↓

Presumably these issues are so limiting to customer-owned BTM batteries that state and local regulators will make the necessary adjustments in timely fashion. In the meantime, this is a very significant barrier.

6.0 Grid Services Potentially Provided by Batteries

This section describes grid services and how value is created by batteries (or other resources in general) that supply them. One of the biggest challenges for utilities and investors is to determine how energy storage can provide various grid services in a cost-effective manner. So, understanding what grid services require from energy storage and what they might be worth in terms of revenue to batteries is very important.

First, this section provides a general introduction to the spectrum of services at three levels of the grid: the bulk system, distribution system, and customer levels. It does this in the context of current ISO market structures, distribution utility practices, and customer needs of various kinds. It also includes an overview of ISO market-clearing prices for some of those services broadly targeted by battery storage projects today.

Although this section does not explicitly map grid services to battery ownership, it is important to recognize that batteries can only provide grid services. Obviously, batteries can only <u>physically</u> supply services at the level of the grid to which they are interconnected and above. Utility-owned batteries, as the study has defined the prototype, are not located behind the customer meter and so cannot provide customer-level services. Similarly, the study's prototypical merchant-owned batteries are connected at the bulk system level and cannot supply distribution- or customer-level services.

In addition, the location of energy storage can have varying impacts on the value of services it provides. For instance, the energy storage sited at the customer level (i.e., BTM) may provide some services at the customer level that the storage sited at the distribution or transmission levels cannot. While energy storage deployed at all levels can add value to the grid, the type of services storage provides and their impact might vary greatly.

Second, the section reviews a wide variety of grid services and maps them to the value streams created by supplying them, from the perspectives of the retail distribution utility and battery owner. One of the critical issues for battery deployments is to what extent, if any, can they legitimately:

- bid to supply and deliver more than one service with a unit of their capacity ("stacking")
- supply an alternative service with a unit of capacity whose bid is not cleared in a market and hence released for other uses
- receive payments for supplying two services without double-counting.

FERC regulations and the ISO wholesale market rules in this regard have been described in Sections 4.0 and 5.3, and these are continuing to evolve as ISOs implement FERC Orders 841 and 2222. The deeper question is how batteries could <u>technically</u> provide multiple services to the extent that they overlap in time (are coincident) and require the same type of response. This is particularly important when considering how regulatory policies might change to improve batteries' prospects in the future, and especially when considering how TE approaches might be designed to facilitate this.

As a basis for the above, the study leverages the following prior work on grid services and valuation:

- GMLC 2.5.2: Grid services, energy services interfaces, and grid-connected devices. The grid service definitions and their priority order defined in this project are leveraged in this study.
- Transactive system program valuation. Cash flow and value models developed in the valuation work of the DSO+T project as well as under the valuation task of the transactive system program are leveraged in this study (Pratt, et al. 2022).

6.1 Introduction to Grid Services and Valuation

Figure 6.1 illustrates various grid services energy storage can provide to three different stakeholders (consumers, utilities, and ISOs). It shows that energy storage located at the customer level can, in principle, offer the largest number of services to customers, utilities, and system operators. For instance, any utility storage cannot provide demand charge reductions to customers, whereas customer BTM storage can potentially provide all utility or ISO services.

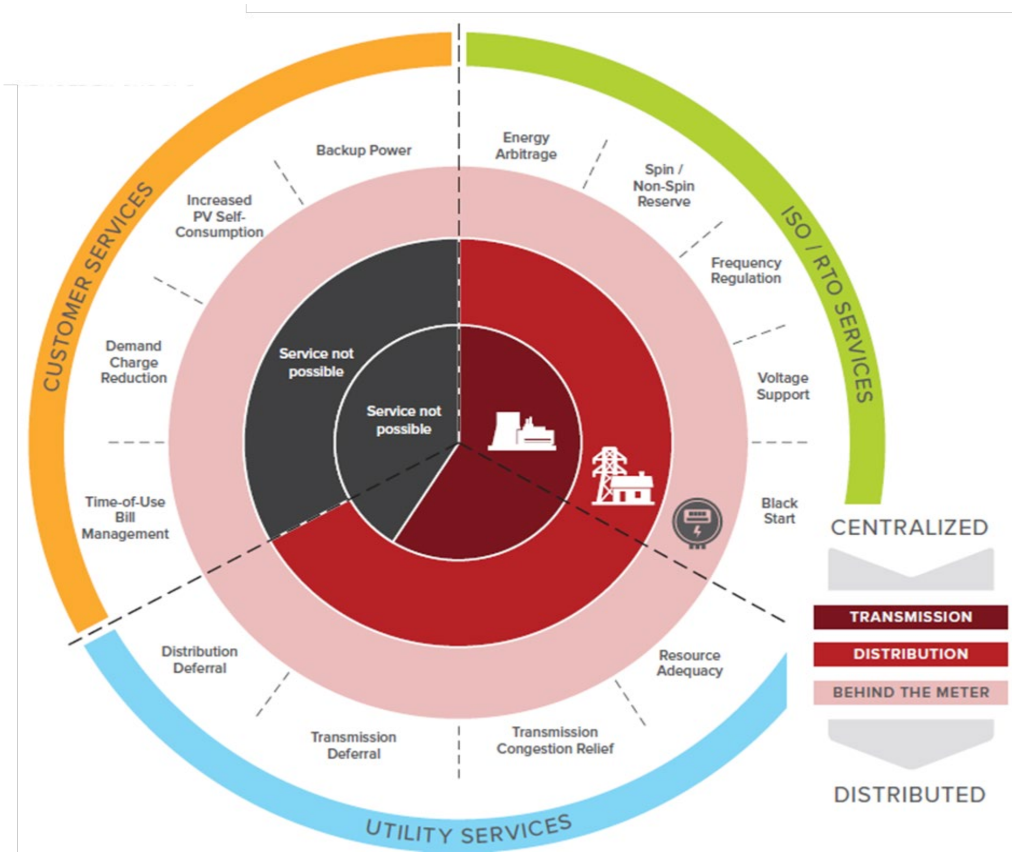


Figure 6.1. Spectrum of various grid services at different levels of the grid (Fitzgerald, et al. 2015).

While Figure 6.1 illustrates the wide spectrum of various grid services, the GMLC 2.5.2 project took a concise approach in reviewing the various services different electricity marketplaces offer and identified a few key services with higher value. Table 6.1 shows grid services DERs can provide. It is important to note that this list is not uniformly applicable to all market and DER types. It is rather meant to provide the most important grid services energy storage can participate in across different marketplaces and system operators.

Table 6.1. Key Grid Services and Their Performance Characteristics from GMLC 2.5.2

Grid Services	Performance Characteristics
Energy arbitrage	Participate in wholesale energy markets by offering supply and bidding demand
Frequency regulation	Detect frequency deviation and inject/absorb real power (or increase/decrease load) near real time
Reserve	Inject real power (or decrease load) upon receiving grid operator's signal (scheduled availability)
Ramping	Inject real power (or decrease load) following a committed schedule
Blackstart support	Supplement real and reactive power (or reduce load) rapidly and then resume normal operation following a schedule
Distribution voltage management	Detect voltage deviation and inject/absorb real or reactive power instantly

Even though the services listed in Table 6.1 represent key grid services applicable among many system operators, their valuations can vary significantly among the system operator. The variation in major value streams among different ISOs is illustrated in Figure 6.2. Clearly some grid services more valuable in one ISO than another. For instance, frequency regulation is by far the highest value stream in PJM and is significantly lower in ISO-NE. Therefore, the study does not advocate for a general ordering of grid services by their values. Instead, it focuses on extent to which adoption of a TE approach mitigates barriers faced by energy storage in benefiting from major value streams.

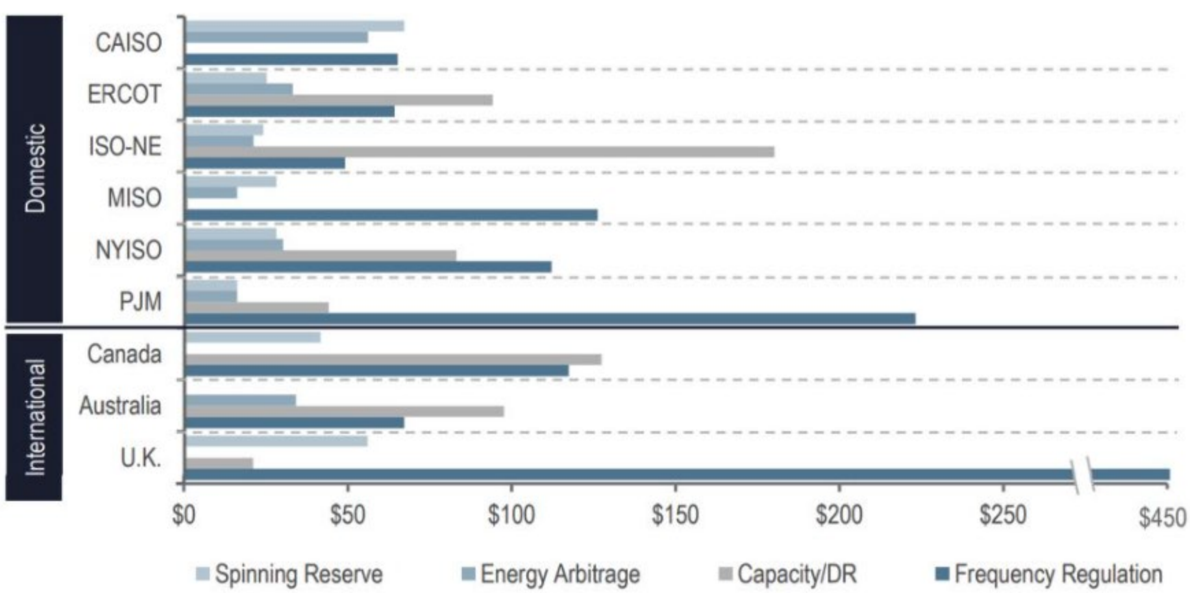


Figure 6.2. Representative value streams across various ISOs in $/MW-yr (Gimon 2019).

6.2 Grid Services from Batteries

Table 6.2 lists a wide variety of wholesale services batteries could provide at the bulk system level. It describes how value to the distribution utility and battery asset owner is derived from the provision of each of the grid services. The list includes wholesale grid services that are common at present, and most are analyzed quantitatively by this study, as indicated by the presence of asterisks trailing their descriptions.

Table 6.2. Potential Wholesale Grid Services from Batteries

Venue	Service	Analysis	Value in BAU Scenario to Distribution Utility	Value in BAU Scenario to Asset Owner[6]
ISO Wholesale Energy Market	Day-ahead scheduled price response*	Optimized daily response to forecasted time-series prices	Lower wholesale energy purchase costs due to lower clearing prices (reflecting lower production and transmission congestion costs) Reduce wholesale energy market price volatility Reduced transmission costs for adding capacity	(Share[a] of) net arbitrage proceeds
	Real-time price response*			
ISO Capacity Market	Capacity*	Battery capacity bid at annual clearing price	Reduce annual capacity market-clearing price	Annual capacity payment
ISO Ancillary Services Markets	Frequency regulation*	Battery capacity bid at average annual price	Reduce LSE's market prices and costs for ancillary services	(Share[a] of) payments for ancillary services
	Spinning reserve*			
	Nonspinning reserve	N/A		
	Black start		?	?

[a] When an aggregator is involved, may be a fractional share of proceeds or a fixed fee (annually, or per instance, like a PPA).

Two notable exceptions to this are the ancillary services blackstart and nonspinning reserve. Blackstart is not analyzed (indicated by N/A) in the study because the financial value streams for participating in blackstart planning and operations are unclear. Nonspinning reserve is excluded from the study because individual batteries do not generally have the duration needed to qualify for providing this service, other than discharging at very low power levels to extend their duration, which dilutes their bid quantity and hence the potential value obtainable. Batteries are much better suited to providing spinning reserve, which also has a higher price, and so they are presumed to not participate in providing nonspinning reserve services.

Table 6.3 lists a wide variety of services batteries could provide to the distribution system, depending on their location, ownership, and applicable regulatory policy. These have not yet been widely put into practice, nor are they formally defined technically or economically. For purposes of this study, the latter are collectively termed as *future distribution services*. Because they do not generally exist in today's operations, many details of the control strategies and incentive mechanisms of the future distribution services are fuzzy, including the distinctions between one another in some regards. This lack of definition, the dependence of their value on location, and the status of grid infrastructure makes them difficult to analyze, and they are not addressed quantitatively in this study. They are, however, a key part of the study's <u>qualitative</u> assessment of how BAU and TE scenarios will likely affect them in the future.

Table 6.3. Potential distribution- and customer-level services from batteries

Venue	Service	Analysis	Value in BAU Scenario to Distribution Utility	Value in BAU Scenario to Asset Owner[6]
Distribution Utility	Reduce wholesale capacity purchase requirement*	Battery capacity bid	Reduce utility's required annual	Share of reduced

Venue	Service	Analysis	Value in BAU Scenario to Distribution Utility	Value in BAU Scenario to Asset Owner[6]
		at annual clearing price	capacity market purchase quantity	distribution utility capital and operational expenses[c] after roundtrip losses
	Manage substation capacity constraint	N/A	Reduce capital costs Increase reliability Satisfy regulators Increase franchise value	
	Local reliability (reduce scope of outages)	N/A		
	Backup retail power (to select customers or critical loads)			
	Feeder voltage regulation (reduced switching)			
	Circuit voltage regulation[a]			
	Manage export constraints to bulk system (from PV)			
	Manage circuit constraints (e.g., from PV, EV, electrification)[a]			
Customer	Reduce retail monthly (noncoincident) peak demand charges[b]	Battery capacity at demand charge price	N/A	Reduced retail energy bill after roundtrip losses
	Avoid backfeed from PV (when retail net metering not available)	N/A		
	Backup power (for critical loads)			Self-supplied reliability
	Store PV output for later use during outage			
	Allow rapid EV charging			Convenience

[a] Battery must be located along circuit to affect this service.
[b] Generally only large commercial and industrial customers have retail demand charges.
[c] May be a demand-side management program participation payment or a retail PPA.

Table 6.3 also lists a number services valuable to customers that can be supplied by batteries when they are located BTM. Principal among these value streams today is providing backup power in event of an outage of limited duration. Where net metering is not available for customers with solar PV systems, either backfeed is entirely prohibited or any energy delivered by reverse flow to the distribution system is simply unmeasured and/or unrewarded by the distribution utility, so the value of any energy generated beyond that needed to serve the instantaneous load is lost to the customer. Storage can mitigate or eliminate this loss of value. Aside from reducing monthly peak demand charges for large commercial and industrial customers, the value of these services to customers is highly subjective, not subject to exchange or transaction with other parties, and so they are also not analyzed quantitively in this study.

In the future, BTM batteries may be employed to support rapid EV charging that would otherwise overwhelm distribution system's delivery capacity at small/medium businesses and homes (this is already occurring at fast charging stations). The principal value to customers of using BTM batteries in this way is convenience of fast charging. Since convenience is difficult to quantify in financial terms, this service is also treated qualitatively.

6.3 Stacking Grid Services

The term ‘stacking’ is widely used by FERC and grid operators in the context of defining market regulations that prohibit inappropriate stacking in the form of infeasible or unfair modes of battery participation. In one such form, doing so invalidates the ISO’s power flow calculations when their contributions are included twice (or more) in multiple markets or venues for grid services. This is clearly unacceptable for safe and secure grid operations. A second form of inappropriate stacking is described by FERC when a resource receives a value stream for providing one grid service while also receiving additional streams from other venues for the same response. Note that FERC Orders 841 and 2222 discuss inappropriate stacking by example but do not formally define it, leaving the development and implementation of specific market rules to the ISOs.

Conversely, storage owners and advocates use the term ‘stacking’ to refer to batteries’ ability to provide multiple grid services, often in context with protesting regulations that unfairly limit the potential value derived from batteries.

Depending on the context, both these positions have validity, and so it is critical to be more explicit about what is meant by stacking when examining these issues. For example, stacking could refer to any or all of the following:

- Allocating a share of a battery’s or a battery aggregation’s capacity to different services. Note that this is entirely consistent with how bulk system generators are treated and is not explicitly prohibited by FERC. Aside from any issues surrounding the minimum size of bids (not resources) in wholesale markets, such *capacity allocation* is a legitimate form of stacking.
- *Time-series switching* of battery capacity offers from one grid service to another from one market interval to the next is a standard practice in wholesale markets today to optimize a battery’s (or other resource’s) income and should be considered a legitimate form of stacking, except where contractually prohibited (e.g., by having accepted an annual capacity payment that requires participation in the energy market).
- For markets to function appropriately, offers by any resource (including batteries) must be firm and, if cleared, binding according to the market rules. Simultaneously offering the same capacity in to two or more markets, *redundantly bidding capacity*, clearly violates this principle and is inappropriate, prohibited stacking.
- However, subsequently *reoffering uncleared (released) capacity* in a second venue is a standard practice in wholesale markets today, where uncleared energy may be offered into the ancillary service markets. Forwarding such offers is accomplished automatically, with the advance permission of the resource owner. This is critical to maximize resource utilization. While today there is no such mechanism for forwarding uncleared battery capacity offers from wholesale markets to distribution-level venues for grid services, such mechanisms could be developed in the future, and should be considered a legitimate form of stacking. Executing such maneuvers manually, where feasible and market timing allows it to be accomplished, is equally legitimate.
- *Double-dipping with a battery’s offers is inappropriate, prohibited stacking.* This occurs when a battery offers the same capacity simultaneously into two or more services, each of which is directed toward purchasing the same capacity to supply the same grid benefit. One clear example of such inappropriate stacking occurs if a battery accepts a capacity market payment (requiring it to offer into the energy market) and is included in a price-responsive

bid from and LSE to the energy market (offering to discharge, displacing the LSE's need to purchase capacity). Thus, if both offers clear, the battery is being paid twice for responding to high energy prices. Worse, the ISOs will count the battery's discharge twice, invalidating its power flow calculations and the market-clearing price.

- *Superposition of incentives* to induce a response that is supported by two separate value streams for two separate grid benefits is a legitimate form of stacking, with some caveats. FERC makes a statement to that effect in Order 2222. One clear example of such stacking is when a distribution utility offers an incentive for reducing net load when a substation is congested, to avoid having to upgrade the substation capacity. In many cases, the substation peak demand will be coincident with the ISO's peak demand (and typically high energy prices). As long as the distribution utility only uses the value of the displaced distribution capacity upgrade as the basis for its incentive, the additional value offered may be just what is required to get the level of response needed to manage the localized peak demand. A second caveat is that the distribution must include the expected level of additional response from the batteries, as a function of the wholesale clearing price, in its load forecast and demand bids into the wholesale energy market. Otherwise it would be providing a misleading and inaccurate forecast of its demand to the ISO.

Clearly, the superposition of incentives is tricky to implement fairly in some circumstances. How can the ISO ensure that the additional incentive offered by the distribution utility does not, in part or in whole, reflect its desire to reduce its annual coincident wholesale peak demand, and therefore its capacity purchase requirement? On the other hand, providing distribution circuit congestion relief or voltage regulation would only rarely coincide with wholesale peak demand, so this problem is greatly diminished but not eliminated entirely. Hopefully, over time, application of well-intentioned and well-reasoned policy alongside deployment of advanced technology can help resolve these concerns and subtleties.

From the discussion above, there are two forms of stacking by batteries that are clearly appropriate: allocating shares of capacity to different services and time-series switching from one service to another. The other forms of (appropriate and inappropriate) stacking—redundantly bidding capacity, reoffering uncleared capacity, double-dipping, and superposition of incentives—all have inherent, practical limitations on whether stacking is even physically feasible for a battery. To be deemed physically feasible, two conditions must be met: 1) the response required from the battery must be identical or nearly identical for each service proposed to be stacked; and 2) demand for the services must generally occur at the same time, if not be fully coincident.

For example, to best provide some gird services, batteries need to be fully charged in advance so they can be discharged on command. For this group of grid services a battery could claim to supply any or all of them if demand was to arise coincidently, even if some stacks are deemed inappropriate. For other types of grid services, it is desirable for batteries to be fully discharged so they can absorb power when called upon, while in other cases it is best if they are at 50% SOC so they are ready to charge or discharge on command.[13]

[13] Note that such considerations also facilitate time-series stacking of services by batteries. Because the roundtrip efficiency of batteries is less than 100%, their SOC is gradually depleted when supplying a grid service, even when it is otherwise energy neutral. Thus there is merit in (for example) first supplying a service that is best supported by a fully charged battery, then switching to supplying a service that requires a partially discharged battery, followed by switching to a service best supported by a fully discharged battery, and so on in a circular fashion.

Thus, when examining the issue of whether stacking a set of grid services is appropriate or inappropriate, it is helpful to cluster the set of services presented in Table 6.3 according to the type of response required and the typical timing of demand for them.[14] Such a clustering appears in Table 6.4. Each service is "tagged" with a general description of the required response from the battery and the grid condition that triggers the need for the service, which in turn implies the general timing of the service. The responses are classified into eight generic types (arbitrarily labeled Types A through H for convenience).

Table 6.4. Battery Responses Required to Provide Various Grid and Customer Services

Type	Description	Timing	Venue	Service
A	Charge and discharging for arbitrage in response to varying prices	Hourly prices, ~diurnal time scale	ISO Wholesale Energy Market	Day-ahead scheduled price response*
		5-min prices, ~diurnal time scale		Real-time price response*
B	Maintain 100% SOC to offer into energy market and discharge when cleared	Typically on or near regional peak demand	ISO Wholesale Energy & Capacity Markets	Resources receiving capacity payments are required to make offers in energy markets[a]
C	Maintain 100% SOC on to discharge on command	LSE's potential peak days/times	Distribution Utility	Reduce wholesale capacity purchase requirement
		Substation's potential peak days/times		Manage substation capacity constraint
		Customer's potential peak days/times	Customer	Reduce retail (noncoincident) peak demand charges*
D	Maintain 100% SOC to discharge on command	Random contingency	ISO Ancillary Services Markets	Spinning reserve*
		Random local outage	Distribution Utility	Local reliability (reduce scope of outages)
				Backup retail power (to select customers or critical loads)
			Customer	Backup power (for critical loads)
E	Maintain ~50% SOC to charge/discharge	Continuous	ISO Ancillary Services Markets	Frequency regulation*; follow ~1-min ISO regulation signal
			Distribution Utility	Feeder voltage regulation (reduced switching)
				Circuit voltage regulation
F	Maintain 0% SOC to charge to charge on demand	Maximum of solar output net of distribution utility demand	Distribution Utility	Manage export to bulk system (from PV)
		Maximum of solar output net of customer demand	Customer	Avoid backfeed (from PV when retail net metering not available)
		Random local outage when PV		Store PV output for later use during outage

[14] Consideration of the desired initial and final condition of the battery's also plays an important role in the feasibility of time-series switching.

Type	Description	Timing	Venue	Service
		output is above consumption		
G	Maintain location-specific optimal SOC to charge or discharge on command		Distribution Utility	Manage circuit constraints (e.g., from PV, EV, electrification)
H	Charge to 100% prior to EV charging time		Customer	Allow rapid EV charging

[a] Some ISOs "test" aggregations for their ability to deliver, who may offer at high prices unlikely to clear the market in most circumstances, by occasionally accepting such an offer outside normal price-merit order (e.g., once a year). Failure to deliver on such offers can subject aggregators to financial liabilities or other sanctions.

Table 6.3 includes the future distribution services and the customer services that are treated qualitatively (and are not marked with asterisks), as noted in the discussion of Table 6.2, above. This classification of the battery responses and timing thereof facilitates examination of whether any of the services can legitimately be provided simultaneously, in the current regulatory environment or a future regulatory environment that may be liberalized in this regard.

The first four classifications (A through D) are facilitated by having a battery fully charged so it can sustain discharge to the maximum extent. Associated with managing peak loads and periods of high prices (often coincident), these classifications differ primarily in subtleties associated with the timing of demand for the services. Type A is energy arbitrage that can generally be expected to follow a diurnal pattern involving low prices in the late evening and early morning hours and high prices in the afternoon and midevening.

Type B is similar to Type A, involving participation in the energy market, unless an out-of-merit order offer is accepted by the ISO to test the readiness of the resource (generally an aggregation). In that circumstance it more closely resembles Types C and D, which can be summarized as involving peak load management. Types B, C, and D primarily differ in the type and economic value of the physical constraint that is being managed. They are often, but not always coincident or nearly coincident, as peak demands associated with local constraints (LSE- and substation-level) can sometimes vary greatly in their timing relative to a regional, ISO-level peak demand.[15] Note also that Types C and D vary in terms of the venue or recipient of the services, ranging from a customer to the distribution utility and the ISO's market for spinning reserve.

The similarity and number of grid service Types A through D make them primary targets for the development of policies and regulations regarding stacking. Type E is facilitated by having a battery at an intermediate SOC so that it can alternately charge and discharge to provide a form of frequency or voltage regulation. Type F is facilitated by having a battery that is fully discharged so that it is ready to absorb energy upon command. This is generally associated with managing or preventing backfeed of power from distributed generation (primarily from solar PV systems). Types G and H are idiosyncratic services whose forms and timing will vary widely based on local conditions and any control algorithms involved.

[15] A given LSE or substation may exhibit a winter peak, even in a summer peaking region, for example. Similarly, a residential substation may peak later in the evening than a substation serving an area dominated by commercial customers.

7.0 Participation Models for Battery Owners

The term *participation model* used by FERC in its Orders 841 and 2222 is adopted here to include the rules, regulations, processes, and business practices involved in two basic scenarios for grid operations using batteries:

1. A BAU scenario based on today's ISO market rules and practices, including projections on how the FERC orders will be implemented (as described in previous sections of this report).
2. A TE scenario based on the design simulated in the DSO+T study, extended to include a presumed mechanism in which a distribution utility aggregates its own and customer batteries to provide ancillary services to the ISO.

Each of these are discussed in the sections that follow.

7.1 Business-as-Usual Scenarios

This section describes participation models for the BAU scenario. They are rooted in the participation model for merchant-owned batteries, which in turn is a direct extension of the merchant-owned resources in general as articulated by FERC Order 841. It is then adapted as the basis for the participation of batteries owned by distribution utilities. The participation of customer BTM batteries is assumed to be based on aggregation of resources by for-profit entities acting as aggregators who represent them to ISO markets, consistent with the presumed implementation of FERC Order 2222.

7.1.1 Merchant-Owned Battery BAU Participation Model

Merchant-owned batteries are presumed to participate in wholesale markets as individual *storage resources* as defined by FERC Order 841 because:

- They are assumed to generally have capacities over the 100 kW minimum size limit. Even though they may be composed of modular batteries, they are assumed to be co-located and discharged as an integrated unit.
- The resulting ability to charge at wholesale prices is very attractive.

Merchant-owned batteries are assumed to be equipped with a wholesale revenue-grade meter. All telemetries associated with generators that participate in energy and ancillary service markets, and are capable of distinguishing positive (supply) and negative (load) power flows at short time intervals.

Merchant batteries participate in the ISOs wholesale markets as a functional combination of a generator and a LSE, with regulations intended to be consistent with how both participate, respectively. The details of this for participation in the various markets or venues for grid services are assumed as outlined below.

Energy markets

1. Merchant-owned batteries participate by making supply offers for discharging and load bids for charging.
2. The merchant owner is solely responsible for ensuring their supply offers and demand bids for each market interval are physically feasible and logically self-consistent (demand bid prices are lower than supply offer prices).

3. The merchant owner is fully subject to any penalties to which generators are subject associated with failure to deliver cleared offers in the day-ahead (hourly) and real-time (5-minute) markets.
4. The merchant owner is fully subject to any penalties to which LSEs are subject associated with failure to provide accurate demand forecasts and bids. For example, any differences between day-ahead demand bid quantity and actual real-time demand quantity are billed at the real-time price. Further, any penalties to which LSEs are subject for failure to provide accurate forecasts of actual real-time demand apply equally to storage resources.

Capacity market

1. Merchant-owned batteries receive an annual capacity payment equal to the product of their nameplate discharge capacity and the market-clearing price. Their participation is not assumed to lower the clearing prices of today's capacity markets.
2. Merchant-owned batteries are not required to purchase capacity to cover their maximum charging power consumption. Since charging energy is the equivalent of demand, if treated in fully consistent fashion with LSEs, they would be required to purchase capacity to cover their coincident annual peak demand. Due to the inherent price responsiveness of batteries, their coincident peak demand is presumed to be universally zero, and so any such ISO requirement is moot and therefore likely waived for batteries a priori.

Ancillary service markets

1. Merchant-owned batteries participate in ancillary service markets as do generators.
2. These markets are assumed to be cleared day-ahead (hourly intervals) and dispatched in real-time.
3. Available battery charging and discharging capacity (i.e., that is not cleared in the day-ahead energy markets) may be used to form bids into the frequency regulation or spinning reserve markets, but the sum of the capacities bid onto those markets must be less than or equal to that of the storage resource after the energy market clears.
4. The frequency regulation market is assumed to clear after the energy market, so any uncleared capacity can be bid into the regulation market. Then the spinning reserve market is assumed to clear, so any remaining uncleared capacity can be bid into it.
5. For spinning reserve:
    a. The available capacity of batteries is defined as the power output capacity that, given its current SOC, it can sustain over a time period equal to the ISO's duration requirement for spinning reserve resources (e.g., often in the range of 10–30 minutes) at which point nonspinning resources take over and the spinning reserve resources are returned to their original on-call status.[16]
    b. For the standby reservation for spinning reserve, the battery receives the integral of its bid quantity and the market-clearing price for spinning reserve.

[16] Note that, unlike a generator, a storage resource may need to restore its SOC to its original level (by charging, bidding into the real-time energy market), and so may not be immediately re-available as a qualified spinning reserve resource at its normal capacity (although it can cease charging and discharge any remaining energy if called upon during this time). The quantitative analysis in this study does not account for this effect.

c. Like a generator, when a battery is called upon to discharge in response to a spinning reserve event, it receives payment for the energy supplied during the event at the real-time energy market price.[17]

d. The merchant owner is solely responsible for ensuring their spinning reserve offers are physically feasible.

e. The merchant owner is fully subject to any penalties to which generators are subject associated with failure to deliver spinning reserve when called upon.

6. For frequency regulation: As for generators, the capacity for storage resources supplying frequency regulation is defined as the range of power modulation (MW) that is available for dispatch above and below the current energy supply operating point (zero in the case of idle batteries). The study does not presume there are separate markets and hence prices for up and down regulation, as in CAISO.

   a. Batteries whose offers clear the frequency regulation market receive a payment equal to the integral of the product of the offer quantity and the frequency market-clearing price (like generators).

   b. Batteries receive a “mileage payment,” recovering their costs for following the frequency regulation dispatch signal. This represents fuel plus wear and tear for generators; the equivalent for storage resources is their roundtrip energy losses, so they are presumed to be reimbursed for this based on their nameplate charging and discharging efficiencies.

   c. The study assumes batteries qualify for participation as fast-response resources, and are paid as such for supplying regulation.

   d. The frequency regulation market in the study, as in PJM, is assumed to be comprised of a fast-regulation market and a slow-regulation market (whereas in some ISOs they are combined as a single market), rather than receiving a bonus payment for the quality of their response.

Distribution-level services. Merchant-owned batteries are assumed to be physically unable to provide distribution-level services because their point of connection is at a location on the transmission system. The sole possible exception is the ability to reduce a distribution utility’s peak demand charge for capacity. Since this is the functional equivalent of bidding directly into the wholesale market, and because doing both is clearly an example of FERC-prohibited double-counting, it is assumed to be unallowable in the current regulatory environment.

Customer services. Due its interconnection at the bulk system level, BTM services cannot be provided by merchant batteries to customers.

7.1.2 Utility-Owned Battery BAU Participation Model

Wholesale energy, capacity, and ancillary service markets. Utility-owned batteries are assumed to participate in all wholesale markets as *individual storage resources*, in exactly the same way that merchant storage does. Because the capacity of the batteries involved are assumed to be greater than 100 kW, it is presumed that the ISO tariffs as revised to comply with FERC Order 841. Unlike merchant-owned batteries, their point of connection is assumed to be on the distribution system (presumably at the substation bus or head of a feeder), and therefore

[17] Since such events occur only a few times a year, the value of such discharge is not included in the study’s quantitative analysis.

power that flows to and from utility-owned batteries are included in the distribution utility's wholesale metered load.

FERC's rules against double-counting and stacking of storage resources require that the distribution utility acting as a LSE submit demand bids and load forecasts, and is billed for its net demand, rather than its total demand that would include any positive (charging) or negative (discharging) contribution from its batteries. Because these are bid separately into the wholesale markets, the utility must forecast and bid for its *native load* in the absence of any contribution from its batteries. Another way of saying this is that any energy expected to be consumed (for charging) by a utility's batteries must be added, and any energy expected to be supplied by discharging must be subtracted from its total load forecasts and bids.

The utility owner is eligible to receive annual capacity payments if the resource they represent is cleared in the wholesale capacity market. Since the LSE's annual coincident peak demand sets its capacity purchase requirement, and any coincident discharge from its storage resources offsets this, the resources would be double-counted if the utility-owned battery bids into the capacity market and the LSE's metered demand reflects battery usage. So, just as for the energy market, the LSE's metered demand must be adjusted to represent the peak demand of its customer loads exclusive of their batteries' contribution for purposes of defining the LSE's capacity purchase requirement.

This set of adjustments will be termed *wholesale net billing* and is analogous to, but the exact opposite of, *retail net metering* (subtracting energy from solar PV systems from customer's gross load and billing them for the remainder, or paying them for any negative balance).[18] These adjustments add complexity to a LSE's market operations, but are not overly burdensome when dealing with batteries it owns. The additional complexity increases substantially and extends to the retail level when customer BTM batteries are involved, however. (One benefit of a TE approach is avoiding this complexity, for both types of batteries.)

Distribution-level services. The regulatory framework envisioned by FERC Orders 841 and 2222 appear to imply that the distribution utility is free to use batteries it owns to provide any of the distribution-level services for itself that it wishes, with the stipulation that the prohibition on double-counting and double-incentivizing (i.e., inappropriate stacking) of responses that are offered to the wholesale markets is honored. Implementing *wholesale net billing* in which the distribution utility's LSE and owned storage are bid and accounted separately in the wholesale energy market prevents them from becoming an issue.

Note that, because the utility's batteries are presumed eligible to receive an annual capacity payment, and their energy usage patterns are not included in its forecasts, bids, or metered net demand, the distribution-level service *reduces the wholesale capacity purchase requirement* that appears in Table 6.2 and Table 6.3 becomes moot.

As described in the discussion on barriers in Section 5.3, in a BAU scenario, market rules regarding stacking and double-counting make it very difficult to effectively use utility batteries to provide local, distribution-level grid services unless they forgo participation in wholesale

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[18] An alternative approach is to simply allow the LSE to make demand bids that include the sum of their load and the charging or discharging energy to their utility-owned storage. While a great deal simpler, this violates FERC's intent that storage resources above a given size (e.g., 100 kW) participate in wholesale markets individually for the purpose of reliability. Once aggregated BTM batteries are involved, this is no longer sufficient and the *wholesale net billing* approach becomes necessary.

markets. At present, the typical value of such services is not yet known, so it is assumed that active participation in the wholesale capacity and energy markets is an essential component of the value proposition for batteries across all ownership types, and these services take priority over local services for battery dispatch as a result.

While this may change for utility-owned (and customer-owned) batteries in the future, wholesale market rules suggest that one set of services must take priority at the expense of the other, in any event. This is because current market rules require wholesale offers be binding. Combined with the lack of any means of releasing uncleared offers to participate in local services and maintaining the integrity of the LSE demand bids that accurately reflect the battery participation, optimizing the use of distribution-connected batteries to provide local services in addition to wholesale services appears quite difficult, and is therefore assumed to be severely limited in the study's BAU scenario.

Customer services. Like merchant-owned storage, utility-owned storage cannot provide BTM services to customers because it is located on the utility side of the customer meter and service drop.

7.1.3 Customer-Owned/BTM Battery BAU Participation Model

Batteries located behind the customer meter are assumed to have capacity much less than the 100 kW limit, so in general they are ineligible to participate in wholesale markets as individual *storage resources* under the auspices of FERC Order 841. Instead, they must participate under FERC Order 2222 as member of a *DER aggregation* whose capacity is greater than 100 kW.

Such batteries can be customer owned or third-party owned and possibly leased to the customer. In any case, they may be operated by the customer, aggregator, or third-party owner. The aggregator combines the output of multiple batteries to form a "single" resource with a total capacity greater than the minimum required by the ISO, allowing them to participate in wholesale markets (assumed to be 100 kW). The aggregator may provide the network, communications, and on-site controls necessary to operate the batteries as a single resource. The aggregator represents them to the ISO as a single resource by making bids on their behalf for supplying energy, capacity, and ancillary services in the wholesale markets, just as demand response resources do. In exchange, the aggregator charges the battery owners a share of the proceeds to cover its costs and profit.

These financial arrangements between the aggregator and battery owner can take a number of forms ranging from a percentage of the proceeds to a PPA (functions almost like a rental agreement). The agreements may allow the customer to control a share of the battery for their own purposes—for example, reducing their monthly peak demand charge, maintaining a guaranteed SOC so as to provide a specified amount of backup energy—or to use its energy under specific conditions described contractually (such as an outage). Such agreements can also cover who pays for the energy used to charge the battery, for roundtrip energy losses, and for the wear and tear of battery operations. Needless to say, how the costs and benefits of storage ownership and operations are allocated is subject to negotiation and likely to change over time as the technologies involved mature and penetrate and business models evolve.

It is not the intent of the study to examine the various forms or effects of such agreements. Instead, the study treats these arrangements generically by combing the financial perspectives of the customer where the battery is located, the battery owner, and the aggregator into a single virtual entity referred to here as a *customer*.

Energy markets. The discussion of FERC Order 2222 in Section 4.2.2 raises the issue of whether a battery that is part of a DER aggregation purchases the energy it consumes for charging at retail or wholesale prices. To be consistent with how individual storage resources are treated under FERC Order 841, charging energy is part of market participation and would be purchased at wholesale. Since the batteries are assumed to be individually metered, proper adjustments could be made to pay wholesale rates for charging energy consumed by batteries in such aggregations. However, this would violate FERC's presumed desire that all types of DERs in all aggregations (heterogeneous or not) be treated uniformly, and for the aggregator to present the aggregations as a single, combined resource to the ISO market.

On the other hand, to be consistent with how demand response is treated as part of an aggregation, and how batteries are treated when used to reduce customer demand instead of participating in markets directly. Except for large, wholesale customers customers, the energy consumed by batteries for charging would be purchased at the normal retail rate. The basis for this argument appears in the sidebar.

Since which of these policies prevail in ISO implementations of the FERC orders is not yet clear, and since the economic implications of the policy choice is so profound, the study analyses both cases.

Aside from this issue, the aggregated customer-owned BTM batteries participate in the wholesale energy markets as do utility-owned batteries, including the requirement for wholesale net billing adjustments to demand bids, forecasts, and metered demand.

Why Charging Customer BTM Batteries at Retail Rates is Consistent with the Treatment of Demand Response in Aggregations

Note that aggregators do not purchase energy on behalf of utility customers whose resources they aggregate. In the case of distributed generation or storage, they may sell the energy supplied as measured by a separate meter. For demand response they sell displacement of the customer's normal energy consumption as "supply" in the wholesale energy market and share the proceeds with the customer.[a] In the case of demand response, the energy supplied is in the form of a reduction in the consumption of one or more customer end uses.

For most end uses this results in shifting load to a later time rather than forgoing the consumption altogether, resulting in higher than normal energy consumption later. This is required to restore the temperature of thermal mass in the building or water heater, or to catch up on deferred process loads like manufacturing, for example. The result is a corresponding increase in the customer's retail bill. This is precisely analogous to recharging a battery after it has discharged. Hence, maintaining consistency suggests that the battery should recharge at the retail rate.

This argument is also supported by the fact that a customer BTM battery can instead be used to provide demand response by discharging it to displace the customer's load. This is indistinguishable from demand response based on end use load shifting as long as its output does not exceed the customer's demand. If the battery is operated in this fashion. The energy it consumes while recharging is then inherently priced at the retail rate.

[a] They also typically sell the capacity of the displacement in the annual wholesale capacity market.

[b] The primary exception to this consequence of demand response is for lighting loads, which are avoided not deferred.

Capacity markets. The aggregator of DERs expects and deserves to be eligible to receive annual capacity payments if the resource they represent is cleared in the wholesale capacity market. Since the LSEs annual coincident peak demand sets its capacity purchase requirement, and the aggregated response from customer BTM storage contributes to this, the resource would be double-counted and both the aggregator and the LSE would be rewarded for the aggregation's response. Hence, as for the case of utility-owned batteries, the LSE must bid for the energy consumed by its customer loads exclusive of the DER aggregation's contribution to reducing it.

This implies that the DER aggregator and/or the ISO must inform the LSE of any capacity from the DER aggregations in its service territory that are cleared in the market.

Ancillary services markets. Aggregators of DERs are assumed to participate in ancillary service markets just as merchant- and utility-owned individual storage resources do, as described in the previous sections. When such aggregations are solely composed of batteries, the presumed metering of individual batteries serves as the basis for measurement and verification that may be required for participation in some jurisdictions. In jurisdictions that do not allow participation by other resources such as demand response, the aggregator is nonetheless expected to be allowed to bid capacity from (metered) batteries in its aggregation into ancillary services markets.

Distribution utility services. Currently, aggregators do not generally engage distribution utilities by offering their aggregated resources to participate in retail programs. Since most programs are generally directed at reducing peak loads, and FERC's intention is that load reduction from a DER aggregation cannot be double-counted by both a distribution utility's LSE and an aggregator bidding into the wholesale market, LSEs are prohibited from offering to pay aggregators for peak load reductions from resources that cleared and are receiving an annual capacity payment the wholesale capacity markets.

Alternatively, an aggregator could participate in retail peak demand reduction programs or provide other local distribution-level grid services if it were to forgo participation in wholesale energy markets. As discussed for utility-owned batteries, trying to do both appears quite problematic with respect to rules requiring the integrity of offers in wholesale markets and accurately reflecting such battery operations in LSE demand bids and forecasts.

Customer services. Some retail customers (primarily larger commercial and industrial) have a monthly demand charge based on the customer's noncoincident peak load. Even though the design and structure of retail customer rates likely lies well outside FERC's jurisdictional authority, FERC's assertion under Orders 841 and 2222 that output from batteries (if not also input for charging) participating in wholesale energy markets be priced at wholesale rates implies the battery must be separately metered and the customer retail bill adjusted accordingly. Thus, although batteries owned by customers can be used to reduce the customer peak demand charge, this customer service cannot be functionally stacked with participating in the wholesale energy market. Note that, if dynamic retail rates are widely adopted in the future,[19] the same logic suggests that customers cannot benefit by using their batteries to respond to these rates while simultaneously participating in the wholesale markets.

An equally important issue is whether battery capacity from customer BTM batteries needs to be withheld from wholesale market participation in order to supply the other customer-level services described in Table 6.3. During an outage, the battery is unavailable to the bulk system and so is effectively released from any commitments it has made in wholesale markets. Therefore, during an outage any energy stored is presumably available to the consumer to use as backup power for critical loads, and its capacity can be used to store excess solar PV output for later use in an extended outage.

[19] Short of a TE rate, these include time-of-use rates, with or without critical-peak or variable-peak pricing.

However, the two other customer-level services not associated with outages are problematic. Avoiding backfeed from solar PV output when retail net metering is not available essentially requires maintaining a low SOC and reserving battery capacity to absorb energy for this purpose. Similarly, the capacity of a fully charged battery must be reserved if it is to be used to support fast charging of EVs. Hence, these two services cannot be stacked with other services that could be supplied from the battery.

7.2 Transactive Energy Scenario Participation Models

The GridWise™ Architecture Council (GridWise Architectural Council 2015) defines TE as a class of solutions that employ a set of economic and control mechanisms that use value as a key operational parameter to dynamically maintain the balance of supply and demand across the electric power delivery infrastructure. This broad definition encompasses a wide range of possible TE designs with diverse goals, features, and processes.

A core TE principle is the notion that such approaches are required to engage and coordinate flexible assets (such as energy storage) deployed <u>at scale</u> (not just on the margin). Equally fundamental is the principle that all types of distributed resources, including batteries, should be rewarded for the services they provide in an equitable, transparent fashion alongside traditional bulk generation resources and transmission and distribution system assets.

The purpose of this study—examining whether adoption of a TE approach can substantially improve the enhance the coordination and fairness of compensation for grid services provided by battery resources, increasing the value obtained from them and reducing barriers to their deployment—is best accomplished by examining the properties of a specific TE design. The results represent the <u>potential</u> benefits of the broader class of TE solutions, which are necessarily dependent on the properties and details of any specific design.

For this purpose the study uses a TE design that has been the subject of substantial simulation analysis (Reeve et al., 2022) and real-world demonstration (Hammerstrom et al., 2007) (Widergren, et al. 2014). This TE design coordinates flexible assets through transparent, competitive means using real-time transactions involving prices or incentives and quantities to provide the feedback necessary to “close the loop” (i.e., provide performance equivalent to closed-loop direct control of traditional generation assets). The basis for this is the transactions themselves, which use dynamic, real-time prices or incentives and market-clearing processes to determine the level of value that must be exchanged with a population of resources to accomplish a grid objective at any given time.

A key feature of the TE design is that the distribution utility functioning as the LSE is charged with acting as a public-goods aggregator of distributed flexible assets. It does this by assembling their expressed real-time willingness to adjust their consumption or output in response to energy prices in the form of bid curves, aggregating the price-quantity curves from individual customers and resources (including any from its own batteries). It then incorporates them into the price-responsive component of the LSE’s demand bid into wholesale energy markets, a standard feature in supported by most ISOs.

In a TE scenario, the primary changes are in how customer BTM storage participates, so that will be discussed first, followed by utility- and merchant-owned storage in subsequent sections.

7.2.1 Customer-Owned BTM Battery TE Participation Model

Features of the TE design. The key features of the TE scenario participation model for customer BTM batteries are summarized as follows:

- All customer BTM battery resources participate at the retail level for their energy and capacity responses rather than at the wholesale market level.
- The LSE combines wholesale energy costs with their needs to 1) manage substation congestion to avoid capacity upgrades in existing substations, and reduce the initial capacity of new substations; and 2) manage the need to purchase capacity from the wholesale market.
- Because the rate design structure has a component equal to the wholesale energy price, the benefits of energy arbitrage in the wholesale market of batteries charging and discharging are nearly the same as if all charging and discharging occurred at wholesale prices (just like merchant- and utility-owned batteries acting as individual storage resources). The difference is that the roundtrip losses of battery charging and discharging accrue cost in proportion to the retail price instead of the wholesale price.
- In effect, the LSE aggregates all responses from customer BTM storage, including any dispatch to supply local distribution services, stacking the result into battery dispatch offer curves as a function of retail day-ahead and real-time prices, which reflect the corresponding wholesale energy prices and local congestion management services, and avoids double-counting responses from any customer-owned BTM batteries in their representation to the wholesale markets.
- The LSE represents their total demand, including that from charging and discharging of responsive DERs, in their demand bids to the wholesale energy markets. To the extent that their wholesale energy costs, peak demand, and corresponding need to purchase wholesale capacity are reduced, they receive the benefits in terms of reduced wholesale purchase costs.
- The LSE, in turn, passes these savings along to their customers in proportion to their responses to the stacked value streams reflected in the real-time retail prices.
- After passing savings along to responsive participants, the LSE uses a small portion of the savings from their reduced annual wholesale operations and capital expenses to cover their added costs for market and retail operations, acting as the aggregator.
- The LSE does not need to adjust its 1) demand bids, 2) capacity requirement, or 3) metered consumption to reflect the contributions of customer BTM storage (i.e., the communications and complexities of adjustments involved in *net wholesale metering* are not required).
- Customers are billed for their gross demand net of the contribution of their batteries at the retail rate, without need for the LSE to adjust their bills to reflect any portion of their energy consumption associated with charging and discharging batteries they own at wholesale prices.

Energy Market TE Participation Model. The process by which the customer-owned BTM batteries participate in the day-ahead and real-time energy markets is summarized as follows:

- Retail rates are structured as real-time prices designed to recover a distribution utility's regulated revenue requirement, comprised of
    1. the wholesale energy price

2. a local congestion marginal price that is allowed to float above wholesale to sufficiently obtain response from batteries (and other DERs) to limit the local substation peak demand and/or the LSE's overall peak demand to a prespecified level reflective of the available capacity
3. a congestion rebate designed to equalize customer bills for identical, nonresponsive TE customers on congested and uncongested substations while maintaining an opportunity for savings by responsive TE customers
4. a flat rate distribution charge for costs of infrastructure, operations and maintenance, and retail operations labor that are unrelated to peak demand
5. a small fixed monthly meter charge.

- The distribution utility's LSE serves as a public-goods aggregator, operating local day-ahead and real-time energy markets at substations for customers submitting price-responsive total demand bid curves (including the operations of their batteries).
- The LSE clears those markets to serve (net) customer loads while allowing real-time prices to float when required to manage local congestion by acquiring demand reduction sufficient to reduce loads to conform to an imposed substation constraint reflecting its capacity or the substation's share of the LSE's capacity limit.
- The LSE operates the retail markets at two timescales: real-time 5-minutes and hourly 48-hour ahead (spanning the timeframe of the wholesale day-ahead market).
- The LSE forecasts customer demand and retail clearing prices for the 48-hour future intervals for each of its substations. This is based on its forecast of wholesale demand and prices, combined with its forecast of unconstrained retail demand at each substation. It then communicates those forecast prices to customers (who may use their own price forecast, at their discretion).
- Customer BTM batteries use the forecasted 48-hour future retail prices to automatically optimize their battery's dispatch schedule, based on criteria they set, and communicate them as price-responsive offer curves to the LSE.
- Each hour, the LSE clears the day-ahead retail market at each substation market.
- Aside from 10 a.m. each day when wholesale market bids are due for the following day (midnight to midnight) from the LSE to the ISO, all day-ahead retail offers from customer BTM batteries are informative (not binding) to allow the population of batteries to reach consensus on their collective dispatch schedules and resulting retail prices.
- At 10 a.m. each day when wholesale market bids <u>are</u> binding, the retail day-ahead offers from the batteries are also binding. The LSE combines its forecast of customer demand with the offers from the batteries and submits the combination as a price-responsive demand bid to the ISO's wholesale day-ahead energy market.
- At 10 a.m. each day, the ISO clears the wholesale day-ahead market and communicates the resulting hourly clearing prices at each wholesale pricing node to the LSEs, who in turn convert them to binding retail day-ahead prices based on their substation load forecasts and battery offer curves. The LSEs then communicate the cleared day-ahead hourly retail prices to the batteries.
- At 5-minute intervals, the LSE collects real-time dispatch offers from the customer BTM batteries at each substation, and combines them with its forecast of wholesale prices and the demand at each substation to develop a forecast of the real-time retail price.

- The LSE communicates the real-time price to the batteries, who adjust their dispatch accordingly based on their real-time offers.
- Any imbalance between the battery's day-head offer quantity and their actual dispatched quantity is corrected for the difference between the real-time and day-ahead prices.

Capacity market. The LSE/aggregator does not seek an annual capacity payment for the aggregated resources in the annual wholesale capacity market auction, which, if cleared, results in a binding obligation to offer their capacity into the wholesale energy markets. Instead, it simply recovers the same value stream by using it to reduce its requirement to purchase capacity to cover its annual coincident peak demand. This, too, is a standard feature of ISO markets. In the process, however, because the resources are not bound to offer into the energy markets, the distribution utility is then free to schedule the capacity of the resources to supply other, local distribution-level services when they are of higher value, or when superimposing the combined values is require to trigger the resource's response. The LSE passes along its savings to the batteries based on their contribution to displacing the LSE's coincident annual peak demand.

Ancillary services markets. In parallel, the LSE aggregates offers from the distributed flexible assets to provide fast frequency regulation and spinning reserve services and submits them to the respective wholesale ancillary services markets. In the process, the LSE checks the combined offers from each resource to the energy and ancillary services markets to ensure that they do not exceed the rated capacity of the resource involved.

Distribution-level services. In principle, adoption of a TE approach can greatly facilitate the utilization of customer-owned (and utility-owned) batteries to provide distribution-level grid services. There are two basic reasons for this. First, using batteries to manage local constraints such as substation capacities is inherently reflected in the LSE's demand bid curve to the ISO, and is rewarded distinctly in the form of opportunity to respond to higher-than-normal retail prices resulting from such congestion. This makes such services clearly distinct from responding to wholesale prices and appropriately and transparently superimposes the associated value stream on top of the wholesale market opportunity.

Second, because the batteries' capacities are not offered into the annual wholesale capacity market auction, they are not bound by market rules requiring them to offer into the wholesale energy markets. This allows the distribution utility to transact with them to supply other, local services instead, when they are more valuable. In the future, particularly in light of increased penetration of solar PV systems and EVs, the value of managing circuit-level congestion and providing voltage regulation services may become higher than wholesale market opportunities for batteries, at certain times and on certain portions of the distribution system. A TE approach in which the distribution utility allows batteries to provide the most valuable services needed at any given time lets batteries optimize revenues and thereby the benefits they bring to the grid.

Customer services. Since customer-level services are self-supplied by customer-owned BTM batteries, no transactions are involved and they are presumed to be provided as described for the BAU scenario in Section 7.1.3.

7.2.2 Utility-Owned Battery TE Participation Model

In a transactive case, utility-owned batteries will be presumed to be required by distribution utility regulators to compete with customer-owned BTM batteries on a level playing field. One way to ensure this would be to require utility batteries to participate just as the customer BTM batteries do, in local retail markets established for all grid services and open to all qualified participants.

Due to the form of the TE design's dynamic retail rate structure, if batteries had perfect roundtrip efficiency, the arbitrage opportunity seen by utility-owned batteries charging and discharging at wholesale would be identical for the customer-owned and utility-owned batteries doing so at retail rates. However, the roundtrip energy losses for utility-owned batteries would be covered at wholesale rates, whereas for customer BTM battery owners it would be covered at retail rates. Simply requiring that utility-owned batteries buy and sell energy at the prevailing local retail TE price resolves this, and allows them to be seamlessly incorporated into the utility's energy bidding and substation peak demand management practices.

While the utility had to show regulators that their proposed battery investments were prudent, it is equally important that the <u>operation</u> of their batteries be equally prudent and non-discriminatory toward customer-owned BTM batteries. In a TE scenario, this boils down to ensuring their offers to the local grid service markets fairly reflect their actual costs. If their offers are priced lower than their costs, including capital recovery, roundtrip losses, and battery wear and tear, then they could, for example, prematurely wear out their battery by underbidding for services while at the same time foreclosing opportunities for lower cost services from customer BTM batteries. Since they presumably earn a rate of return on such capital investments, they might welcome the opportunity to buy another battery sooner rather than later. Some simple rules and oversight of their operational bidding practices are likely to be required.

7.2.3 Merchant-Owned BTM Battery TE Participation Model

The participation model for merchant storage in the TE scenario is unchanged from that in the BAU scenario.

8.0 Study Results

This section provides quantitative and qualitative assessments comparing opportunities for batteries in BAU and TE scenarios. The quantitative analysis in Section 8.1 compares annual value streams per unit capacity for a benchmark 4-hour battery for various types of battery owners and corresponding points of interconnection as discussed in Section 2.4. The value streams analyzed are primarily derived from participation in wholesale markets.

Notably, potential value streams from providing distribution-level services are not included, because the control technology and incentive mechanisms for batteries (and other DERs) to provide them at scale are immature. They are, however, an important focus in the qualitative assessments in Section 8.2, which discusses how adoption of a TE approach can simplify, rationalize, and enhance the participation model for battery storage while enhancing equity across ownership types, consistent with the intentions of FERC Orders 841 and 2222.

8.1 Quantitative Analysis

The quantitative analysis focuses on well-established value streams derived from wholesale market participation—proceeds from energy arbitrage in day-ahead and real-time markets, sale of battery capacity in the annual wholesale capacity market auction, and sales for providing capacity to the fast regulation and spinning reserve ancillary services markets—and from displacement of retail peak demand charges for large commercial and industrial customers. The value of other services that batteries self-provide to customers, such as backup power during outages, are implicit and idiosyncratic, so the study acknowledges their importance but does not attempt to quantify them.

The quantitative analysis compares the annual value that is obtained to the battery owner in the BAU scenario (with two variations, or *cases*) to the TE scenario (with three such variations), as follows:

BAU Scenario Cases

1. BAU-Wholesale: In this case, FERC Order 2222 is interpreted to treat customer BTM batteries in aggregations just as batteries operating as individual storage resources under Order 841 are treated, in allowing them to buy and sell energy at wholesale energy market prices. In this case, the value stream resulting from energy arbitrage in all BAU cases is the same for merchant, utility, and customer BTM-owned batteries.
2. BAU-Retail: In this case, FERC Order 2222 is interpreted so as to treat customer BTM batteries in aggregations as it does demand response and distributed generation in aggregations, in allowing them to sell the energy they provide (supply) at wholesale energy market prices. By implication, customer BTM batteries then charge at retail energy prices, which are normally substantially higher. Note that **results labeled ‘BAU-Retail’ only apply to customer BTM batteries in this case**; the merchant- and utility-owned batteries continue to earn the BAU-Wholesale value stream.

TE Scenario Cases

1. TE-Base: This case is based on the TE design used in the DSO+T study (Reeve, et al., 2022a) and summarized in Section 7.2 of this report.

2. TE-Transmission and Distribution (TE-TD): In this case, the annualized capital costs for existing distribution substation and transmission infrastructure are recovered using a *dynamic rate allocation method* as described in Appendix C. This increases the dynamic range of the retail transactive prices and hence increases the potential revenue for batteries from energy arbitrage.
3. TE-Transmission, Distribution, and Generation (TE-TDG): This case is like the TE-TD case, except that in addition to allocating the transmission and distribution costs, it also allocates the annual market cost of generation capacity, further enhancing the potential battery revenue from energy arbitrage.

The analysis is based on a standard battery. Despite the wide variation in typical battery power and energy ratings across ownership types, exhibited in the catalog of battery projects in Section 2.2, a standard battery was chosen for analysis of all ownership types, so as not to confound the effects of ownership with the effects of battery capacity, energy, and efficiency. So, the analysis assumes a 4-hour battery with a roundtrip efficiency of 88%, and normalizes all results on the basis of annual revenue per unit of rated capacity ($/yr-kW).

Market prices and rules from PJM were selected arbitrarily as the basis for analysis because it is the largest ISO in the United States, and its market rules are generally prototypical of those found in other U.S. ISOs (although there is considerable variation among them).

8.1.1 Value of Arbitrage from Energy Markets

This section compares the value of a battery conducting energy arbitrage, i.e., the annual battery revenue from participating in the energy markets, for each case in the study's BAU and TE as it varies by ownership type. It defines the energy prices seen by the batteries, the agent-based optimization used to control battery charging and discharging, and how the annual value of arbitrage is estimated for each case. It then compares the resulting value of energy arbitrage value streams for each case and ownership type.

8.1.1.1 Wholesale and Retail Energy Prices

Table 8.1 summarizes the wholesale and retail energy price assumptions that are foundations of the analysis. All batteries in the BAU-Wholesale case buy and sell energy at the day-ahead and real-time wholesale energy market prices. In the BAU-Retail case, only customer-owned BTM batteries are assumed to be required by market rules to buy their charging energy at their normal, fixed retail rate (assumed to be at the U.S. average of $0.11/kWh).

The LMPs used in the analysis of energy arbitrage have a significant impact on the resulting value stream obtained by a battery, so selecting a node with LMPs that are reasonably representative of those in the United States is important. As PJM market prices vary significantly from one pricing node to another, selecting one that is relatively typical is important so that the value streams from arbitrage can be properly placed in context with other value streams analyzed.

A key metric for the effect of time-series variation of LMPs on the energy arbitrage opportunity is the daily difference from peak to valley. PJM's Allegany Power System (APS) transmission zone represents the median average daily price difference among the available PJM transmission zone pricing data. Prices from 2019 were used because they were recent and prior to any effect of the economic downturn during the COVID-19 pandemic.

Table 8.1. Wholesale Energy and Capacity Price Assumptions

Data Description	Unit	Variable	Value	Source
Wholesale day-ahead energy price	\$/MWh	$W_{da}(t)$	PJM 2019 day-ahead LMPs for APS node	PJM (2109a)
Wholesale real-time energy price	\$/MWh	$W_{rt}(t)$	PJM 2019 real-time LMPs for APS node	PJM (2019b)
Wholesale day-ahead energy delivered	MWh	$Q_{da}(t)$	PJM 2019 day-ahead hourly energy for APS node	PJM (2109a)
Wholesale real-time energy delivered	MWh	$Q_{rt}(t)$	PJM 2019 real-time hourly energy for APS node	PJM (2019b)
BAU retail energy fixed rate	\$/kWh	R_{bau}	\$0.11/kWh	Average U.S. retail volumetric price
BAU monthly retail peak demand charge (large commercial and industrial customers only)	\$/kW	R_{bau}^{peak}	\$15/kW-month	DSO+T study (Pratt, et. al, 2022; Sec. 4.3.1)

The various components of the TE retail rate design are described in Section 7.2.1. For the TE-Base case, the retail transactive rate structure is based on that used in the DSO+T study (Pratt, et al., 2022). When a substation is not congested, and at times when the distribution utility is not trying to manage its overall annual peak demand, the local congestion marginal price is zero, and the form of the base case TE rate reduces to

$$R_{TE-Base}(t) = A\,W(t) + D \tag{1}$$

where: *W(t)* ≡ wholesale price at any time, *t* (real-time or day-ahead)

A ≡ retail multiplier (1.05), accounting for assumed distribution losses (5%)

$D_{TE\text{-}Base}$ ≡ constant volumetric price of distribution energy, TE Base case

$R_{TE\text{-}Base}(t)$ ≡ retail TE Base case price at any time, *t* (real-time or day-ahead) corresponding to wholesale price *W(t)*

The study assumes that the distribution utility remains a regulated entity and must recover its costs in the form of revenues from customer bills. In the simplest case of a marginal deployment of batteries, the revenue required and the wholesale market prices *W(t)* and quantities *Q(t)* are unchanged. Since the retail multiplier (*A*) is known, the constant volumetric price of distribution energy ($D_{TE\text{-}Base}$) can be determined so as to recover the same amount of revenue as in the BAU case for customers without a demand charge:

$$Revenue = \sum_{t=1}^{8760} R_{bau}\,Q(t) = \sum_{t=1}^{8760} R_{TE-Base}(t)\,Q(t) = \sum_{t=1}^{8760} (A\,W(t) + D_{TE-Base})\,Q(t)$$

which can be rearranged to solve for the constant volumetric price of distribution energy ($D_{TE\text{-}Base}$) required to recover the needed revenues:

$$D_{TE-Base} = R_{bau} - A\left(\sum_{t=1}^{8760} W(t)\,Q(t) \Big/ \sum_{t=1}^{8760} Q(t)\right) \tag{2}$$

In addition to the TE-Base case rate, a modified transactive rate design is also analyzed, in which some infrastructure capacity costs are moved from the fixed component of the rate to the dynamic, time-dependent component of the rate:

$$R_{TE-Mod}(t) = A\,(W(t) + C_{TE-mod}(t)) + D_{TE-mod} \qquad (3)$$

where: $C_{TE\text{-}mod}(t)$ ≡ the annualized capacity cost of infrastructure allocated based on analysis of its load duration curve to any time, t (see Appendix C for details)

and where the subscript 'TE-mod' refers to either the TE-TD or the TE-TDG case.

Again, recovering the same revenue requires that the fixed component of the rate ($D_{TE\text{-}mod}$) be:

$$D_{TE-Mod} = R_{bau} - A\left(\sum_{t=1}^{8760}\left(W(t) + C_{TE-mod}(t)\right)Q(t) \Big/ \sum_{t=1}^{8760} Q(t)\right) \qquad (4)$$

While there are slight differences in the resulting value of the constant volumetric prices $D_{TE\text{-}Base}$ and $D_{TE\text{-}mod}$ depending on whether they are based on real-time or wholesale prices, for the PJM's APS price node in 2019 the resulting differences are less than one-quarter of a precent, so the study ignores these differences.

The constant volumetric component of the TE retail rates resulting from the ratemaking for all the TE cases are as shown in Table 8.2. It is seen to decline from $0.082/kWh in the TE-Base case, to $0.061/kWh when distribution substations, transmission, and generation infrastructure are included. The proportion of the fixed BAU price that is remains constant in the TE cases declines from 75% in the TE-Base case, declining substantially to 68% in the TE-TD case and 55% in the TE-TDG case.

Table 8.2. Constant Volumetric Distribution Energy Price for TE Cases

TE Case	Capacity Cost Allocated					$D_{TE\text{-}mod}$	Ratio, R_{bau} / $D_{TE\text{-}mod}$
	Distribution		Transmission		Generation		
	($/kW)	($/kW-yr)	($/kW)	($/kW-yr)	($/kW-yr)	($/kWh)	
TE-Base	-	-	-	-	-	$0.082	75%
TE-TD	$223	$21.6	$169	$13.9	-	$0.075	68%
TE-TDG	$223	$21.6	$169	$13.9	$75	$0.061	55%

Table 8.2 also shows the assumed distribution, transmission, and generation infrastructure capacity costs allocated to the dynamic component of the rates in each case. They are based on those assumed in the DSO+T study (Pratt, et al., 2022). For distribution substations and transmission, first costs of $223/kW and $169/kW are assumed as shown. The levelized annual costs ($/kW-yr) are based on an assumed annual capital cost factor of 9.72% of the first cost, representative of investor-owned utility financing, taxes, depreciation, etc. over a 20-year investment lifetime. For generation, the levelized annual capacity cost is based on a typical U.S. ISO's capacity market-clearing price of $75/kW.

Figure 8.1 shows the annual time series of wholesale and retail TE-Base prices for day-ahead and real-time for PJM's APS pricing node, along with a fixed retail price for customers. There are several pertinent observations that can be drawn from the price data. First, is the obvious correlation of the wholesale and TE-Base retail prices. This simply reflects the fact that the TE rate design has a significant component that is directly proportion to the wholesale prices markets. Second, close inspection reveals that real-time prices on average are slightly lower than their day-ahead counterparts, but that there is considerably more volatility in the real-time prices than the day-ahead prices, and this volatility seems to be mostly biased toward the side of higher prices. All these are characteristic of energy prices in most ISOs. Further, no very low or negative wholesale prices are observed for this pricing node, presumably because significant renewable generation resources are not located in its vicinity.

The offset between the TE-Base prices and wholesale prices simply reflects the difference between retail and wholesale rates necessary for the distribution utility to recover sufficient revenues to cover its costs. In the case of the BAU fixed price (R_{bau}), this is a constant \$0.11/kWh as noted in Table 8.1, indicated by the purple horizontal line in Figure 8.1. The fact that this lies in the middle of the dynamic TE-Base real-time and day-ahead rates is a direct, intentional result of the TE ratemaking process, which is intended to provide revenue-neutral TE rates. The offset is equal to the constant volumetric distribution energy cost in the TE-Base rate ($D_{TE\text{-}Base}$, equal to \$0.082/kWh, as shown in Table 8.2).

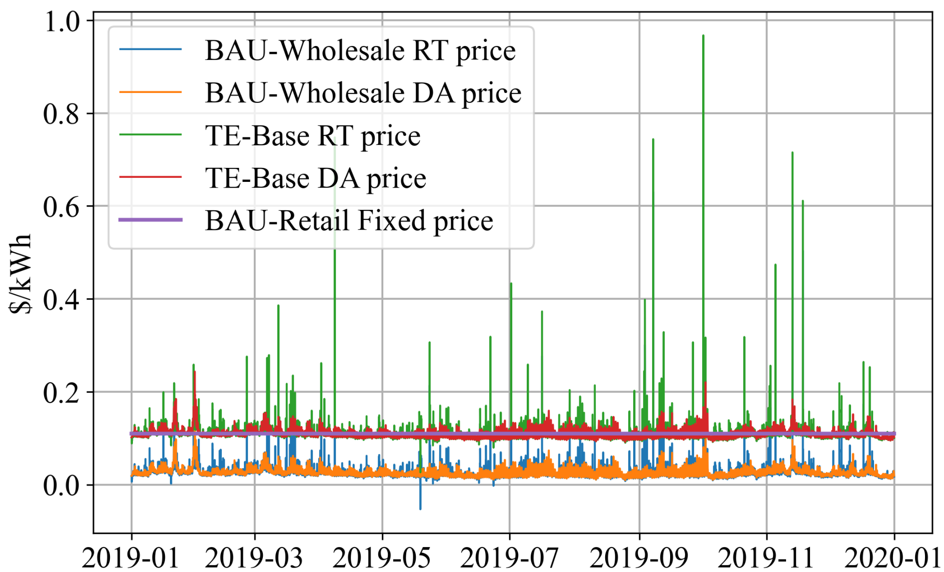

Figure 8.1. Annual time series wholesale and retail prices.

The results of the modified TE rate design allocating various infrastructure capacity costs to the dynamic portion of the rate are shown in Figure 8.2, which depicts the base case and modified retail day-ahead and real-time TE prices for a week in July 2019. The increased arbitrage opportunity that results from adoption of the modified TE rates is evident in the much higher prices during high price periods. This is because the shrinking, constant volumetric distribution prices become a diminishing portion of the total retail price during daily high price excursions.

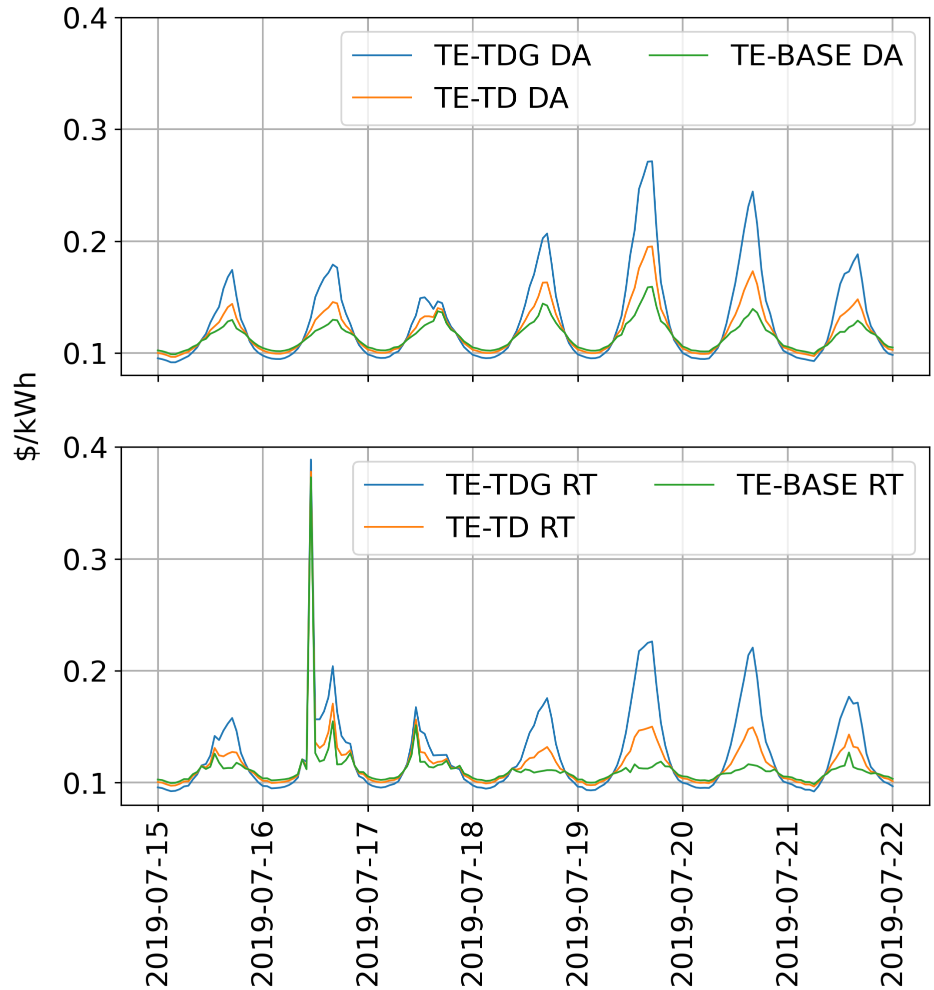

Figure 8.2. A week of TE energy prices under base case and modified transactive rate design cases.

8.1.1.2 Battery Control Agent Optimization Methodology

The batteries in all BAU or TE scenarios are assumed to be controlled by an agent that optimizes the daily arbitrage value of the battery's response to the forecasted prices it receives for discharging and pays for charging. That is, the optimal battery response for each hour in a 24-hour look-ahead period from midnight to midnight is determined for every day. To simplify this optimization, the prices are assumed to be forecasted without error. The details of the optimization details are as follows.

Define the following variables:[20]

C^{dis} ≡ battery's rated discharging power capacity to the chemical store (assumed to be 1 kW)

[20] Parameter value assumptions for the variables defined below use a nameplate rating convention based on the total chemical energy that can be stored in a battery, and the maximum rates of addition and withdrawal of that energy. This is not fully consistent with nameplate ratings based on electrical output capabilities; however, any errors introduced are very small and do not affect the analysis appreciably.

C^{ch} ≡ battery's rated charging power capacity to the chemical store (assumed to be 1 kW)

η ≡ battery's energy conversion efficiency to and from the chemical store, including the inverter efficiency (assumed to be 94%)

Δt ≡ time-series interval (1 hr)

$P^{dis}(t)$ ≡ price for electrical energy supplied by the battery to the grid when discharging in any time interval, t ($/kWh)

$P^{ch}(t)$ ≡ price for electrical energy consumed by the battery from the grid when charging in any time interval, t ($/kWh)

$Q^{dis}(t)$ ≡ electrical energy supplied to the grid by discharging the battery in any time interval, t (kWh)

$Q^{ch}(t)$ ≡ electrical energy consumed from the grid by charging the battery in any time interval, t (kWh)

$E^{dis}(t)$ ≡ chemical energy withdrawn from the battery by discharging in any time interval, t (kWh)

$E^{ch}(t)$ ≡ chemical energy added to the battery by charging in any time interval, t (kWh)

$E(t)$ ≡ chemical energy stored in the battery at the end of any time interval, t (kWh)

E_{max} ≡ maximum chemical energy stored in the battery; for a battery with a 1 kW discharging power capacity and a 4-hour battery rating: E_{max} = (1 kw) (4 hr) = 4 kWh

E_{min} ≡ minimum chemical energy stored in the battery (kWh), based on an assumed 20% minimum SOC in order to extend the battery's lifetime: E_{min} = (20%) (4 kWh) = 0.8 kWh

E_{init} ≡ chemical energy stored in the battery at the start of the optimization (kWh), assumed to correspond to a SOC of 50%: E_{init} = (50%) (4 kWh) = 2 kWh

Then, the optimization:

$$\underset{Q^{dis},\,Q^{ch}}{maximize} \sum_{t \, \epsilon \, T} P^{dis}(t)\, Q^{dis}(t) - P^{ch}(t)\, Q^{ch}(t)$$

is conducted subject to the following constraints:

$$Q^{dis}(t) \geq 0$$

$$Q^{ch}(t) \geq 0$$

$$0 \leq E^{dis}(t) \leq C^{dis}$$

$$0 \leq E^{ch}(t) \leq C^{ch}$$

$$E_{min} \leq E(t) \leq E_{max}$$

$$Q^{dis}(t) = \eta\, E^{dis}(t)$$

$$Q^{ch}(t) = E^{ch}(t)/\eta$$

$$E(1) = E_{init} - E^{dis}(1) + E^{ch}(1)$$

$$E(t) = E(t-1) - E^{dis}(t) + E^{ch}(t)$$

Note that the prices for charging and discharging energy vary by scenario and ownership type, as discussed in the previous section. The optimal charging and discharging schedule $Q^{ch}(t)$ and $Q^{dis}(t)$ obtained from the daily optimizations are then used to estimate the annual revenue from energy arbitrage as described in the following section.

8.1.1.3 Arbitrage Value in BAU Scenarios

The study's BAU scenario has two cases: BAU-Wholesale in which all batteries charge and discharge at wholesale market price; and BAU-Retail in which only the customer BTM batteries are required to purchase the energy they consume for charging at the retail BAU rate. How the value of energy arbitrage from batteries in each case of these are described here.

Arbitrage calculation for merchant and utility batteries (in all cases of the BAU scenario) and customer BTM batteries (only in the BAU-Wholesale case). Both FERC Orders 841 and 2222 require that batteries participating in wholesale markets, whether as individual storage resources or as part of DER aggregations, respectively, be paid for the energy they supply (discharge) at wholesale market-clearing prices.

If FERC Order 2222 is interpreted to require that the participation of batteries in DER aggregations be consistent with that of individual storage resources, then all types of battery owners also purchase the energy they consume for charging at wholesale market prices. As noted previously, for customer-owned BTM batteries, this implies a submeter must be installed to measure energy flows to and from the battery so they can be separated from the customer's measured consumption and excluded from 1) the customer's retail bill, 2) the LSE's demand bid, 3) the LSE's demand forecast, and 4) the LSE's measured wholesale energy consumption that defines its market purchases and annual coincident peak demand.

So, in the study's BAU-Wholesale case, regardless of the type of battery owner, the value earned by a battery from arbitrage in the day-ahead market ($V^{arb}_{da,bau-w}$) over a series of time intervals (t) is:

$$V^{arb}_{da,bau-w} = \sum_t W_{da}(t) \left(Q^{dis}_{da,bau-w}(t) - Q^{ch}_{da,bau-w}(t)\right) \qquad (5)$$

where:

$W_{da}(t)$ ≡ wholesale day-ahead market-clearing price at any time, t

$Q^{dis}_{da,bau-w}(t)$ ≡ quantity of energy the battery offers to supply (by discharging) that is cleared by the day-ahead wholesale market at any time, t

$Q^{ch}_{da,bau-w}(t)$ ≡ quantity of energy the battery bids to consume (for charging) that is cleared by the day-ahead wholesale market at any time, t

Similarly, the value earned by a battery from arbitrage in the real-time market ($V^{arb}_{rt,bau-W}$) is the difference between the value of net energy actually consumed in real-time and the value of net energy it purchased in the day-ahead market. That is, the battery purchases or sells the difference between its day-ahead purchase and its actual consumption at the real-time clearing price:

$$V_{rt,bau-w}^{arb} = \sum_t W_{rt}(t)\left(\left(Q_{rt,bau-w}^{dis}(t) - Q_{rt,bau-w}^{ch}(t)\right) - \left(Q_{da,bau-w}^{dis}(t) - Q_{da,bau-w}^{ch}(t)\right)\right) \quad (6)$$

where: *$W_{rt}(t)$* ≡ wholesale real-time market-clearing price at any time, *t*

$Q_{rt,bau-w}^{dis}(t)$ ≡ quantity of energy the battery supplies (by discharging), as measured in real-time, at any time, t

$Q_{rt,bau-w}^{ch}(t)$ ≡ quantity of energy the battery consumes (for charging), as measured in real-time, at any time, t

So, the total value earned by any battery in the BAU-Wholesale case (V_{bau-w}^{arb}) is simply the sum of that earned in the day-ahead and real-time markets:

$$V_{bau-w}^{arb} = V_{da,bau-w}^{arb} + V_{rt,bau-w}^{arb} \quad (7)$$

Arbitrage calculation for customer BTM batteries (the BAU-Retail case). If FERC Order 2222 is interpreted to require participation of batteries in DER aggregations be consistent with that of demand response resources in such aggregations, then all customers who own BTM batteries must purchase the energy they consume for charging at retail prices. In this case, the submeter is only used to remove battery discharging energy from 1) the customer's retail bill, 2) the LSE's demand bid, 3) the LSE's demand forecast, and 4) the LSE's measured wholesale energy consumption.

So in the study's BAU-Retail case, the value earned by a customer BTM battery from arbitrage in the day-ahead market ($V_{da,bau-r}^{arb}$) over a series of time intervals (t) is:

$$V_{da,bau-r}^{arb} = \sum_t W_{da}(t)\, Q_{da,bau-r}^{dis}(t) \quad (8)$$

where: *r_{bau}* ≡ fixed BAU retail price

$Q_{da,bau-r}^{dis}(t)$ ≡ quantity of energy the battery offers to supply (by discharging) that is cleared by the day-ahead wholesale market at any time, t

Similarly, the value earned by a battery from arbitrage in the real-time market ($V_{rt,bau-W}^{arb}$) is the difference between value of the net energy actually consumed in real-time and the value of net energy it purchased in the day-ahead market. That is, the battery purchases or sells the difference between its day-ahead purchase and its actual consumption at the real-time clearing price:

$$V_{rt,bau-r}^{arb} = \sum_t W_{rt}(t)\left(Q_{rt,bau-r}^{dis}(t) - Q_{da,bau-r}^{dis}(t)\right) \quad (9)$$

where: *$W_{rt}(t)$* ≡ wholesale real-time market-clearing price at any time, *t*

$Q^{dis}_{rt,bau-r}(t)$ ≡ quantity of energy the battery supplies (by discharging), as measured in real-time, at any time, t

The total value earned by a customer BTM battery in the BAU Retail case (V^{arb}_{bau-r}) is simply the sum of that earned in the day-ahead and the real-time markets:

$$V^{arb}_{bau-r} = V^{arb}_{da,bau-r} + V^{arb}_{rt,bau-r} - R_{bau}\, Q^{ch}_{bau-r}(t) \quad (10)$$

where: r_{bau} ≡ fixed BAU retail price

$Q^{ch}_{bau-r}(t)$ ≡ quantity of energy the battery consumes (for charging), as measured in real-time, at any time, t

Energy arbitrage value for the BAU scenario's BAU-Retail vs. BAU-Wholesale cases. The annual value earned by a battery operated to provide energy arbitrage is shown in Figure 8.3 for the BAU-Wholesale and BAU-Retail cases. In the BAU-Wholesale case all batteries are allowed to charge and discharge at wholesale rates when participating in the wholesale energy market, and the annual value stream for the standard battery is nearly $22/kW-yr. If, on the other hand, FERC Order 2222 is interpreted to require customer BTM batteries in DER aggregations to buy energy for charging at their normal, fixed retail rate ($0.11/kWh in the BAU-Retail case), the ability of the batteries to earn revenues from energy arbitrage is drastically reduced to just a little over $4/kW-yr. When the battery is selling (discharging) at the time of daily wholesale peak prices that hover around $0.04/kWh, as shown in Figure 8.1, it clearly cannot make money when it has to recharge at the much higher retail rate of $0.11/kWh, except on rare days with exceptionally high wholesale prices.

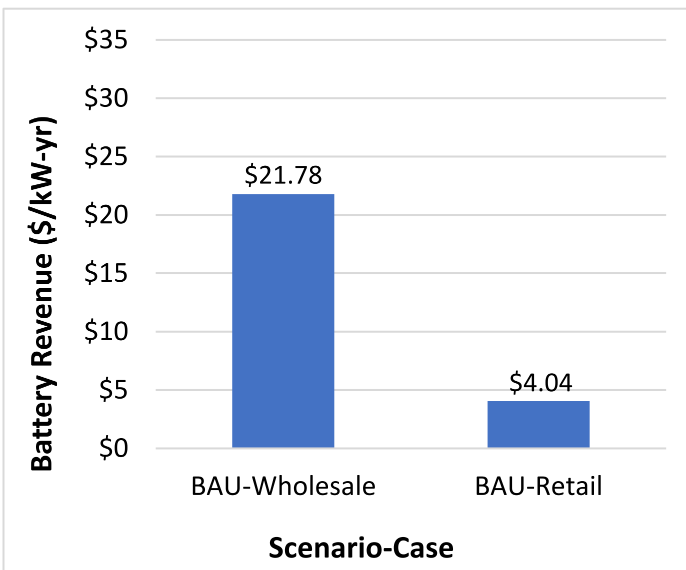

Figure 8.3. Annual value of energy arbitrage in BAU cases.

While FERC made clear its intentions to support participation of storage resources in wholesale markets by issuing Orders 841 and 2222, it is not yet clear how their specific rulings in regard to charging of batteries in DER aggregations at wholesale or retail prices will be interpreted and implemented in practice by the ISOs. FERC may also choose to clarify their position on this issue. Given the devastating result for battery revenues from energy arbitrage in the BAU-Retail case, it seems unlikely that recharging batteries when participating in wholesale markets will be allowed at wholesale prices, at least eventually.

8.1.1.4 Arbitrage Value in TE Scenarios

Arbitrage calculation for the TE scenario. In the TE scenario, merchant-owned batteries connected to the bulk system are assumed to participate as individual storage resources under FERC Order 841 in all cases, and hence charge and discharge at wholesale rates just as they do in the BAU scenarios. So, the value of arbitrage over a period of time can be estimated from Equations (5), (6), and (7).

However, customer- and utility-owned batteries in all cases of the TE scenario participate in the transactive, retail markets, buying and selling energy at the prevailing dynamic transactive retail price as defined in Section 8.1.1.1. The structure of the equations describing the arbitrage value of these batteries in all cases of the TE scenario is the same as for the BAU-Wholesale case except the batteries charge and discharge at local, retail day-ahead and real-time TE market-clearing prices instead of the corresponding wholesale rates.

So, the value of arbitrage for a customer- or utility-owned battery connected at the distribution system ($V_{da,TE}^{arb}$) in all cases of the TE scenario can be estimated from the retail analog of Equations (5), (6), and (7) as:

$$V_{da,TE}^{arb} = \sum_t R_{da,TE}(t)\left(Q_{da,TE}^{dis}(t) - Q_{da,TE}^{ch}(t)\right) \tag{11}$$

where: $R_{da,TE}(t)$ ≡ local, retail day-ahead TE market-clearing price at any time, *t*

$Q_{da,TE}^{dis}(t)$ ≡ quantity of energy the distributed battery offers to supply (by discharging) that is sold at the local, retail day-ahead TE market-clearing price at any time, t

$Q_{da,TE}^{ch}(t)$ ≡ quantity of energy the distributed battery bids to consume (for charging) that is purchased at the local, retail transactive day-ahead price at any time, t

and the value earned in the real-time market ($V_{rt,TE}^{arb}$) is:

$$V_{rt,TE}^{arb} = \sum_t R_{rt,TE}(t)\left(\left(Q_{rt,TE}^{dis}(t) - Q_{rt,TE}^{ch}(t)\right) - \left(Q_{da,TE}^{dis}(t) - Q_{da,TE}^{ch}(t)\right)\right) \tag{12}$$

where: $R_{rt,TE}(t)$ ≡ local, retail day-ahead TE market-clearing price at any time, *t*

$Q_{rt,TE}^{dis}(t)$ ≡ quantity of energy the distributed battery supplies (by discharging), as measured in real-time, at any time, t

$Q_{rt,TE}^{ch}(t)$ ≡ quantity of energy the distributed battery consumes (for charging), as measured in real-time, at any time, t

So, the total value earned by any battery in the BAU-Wholesale case (V_{TE}^{arb}) is simply the sum of that earned in the day-ahead and real-time markets:

$$V_{TE}^{arb} = V_{da,TE}^{arb} + V_{rt,TE}^{arb} \tag{13}$$

Energy arbitrage value in the TE and BAU scenarios. Based on the methodology and assumptions described above, the annual value of arbitrage for batteries participating in the wholesale energy markets is compared with that for batteries participating in transactive retail markets in this section.

Figure 8.4 compares battery revenues from energy arbitrage in the BAU-Wholesale and TE-Base cases. Note that the participation model for merchant-owned batteries in any TE scenario is unchanged from the BAU-Wholesale case, with revenues of nearly $22/kW-yr. The TE results only apply to utility- and customer-owned batteries; merchant batteries in a TE scenario participate just as they would in the BAU-Wholesale case.

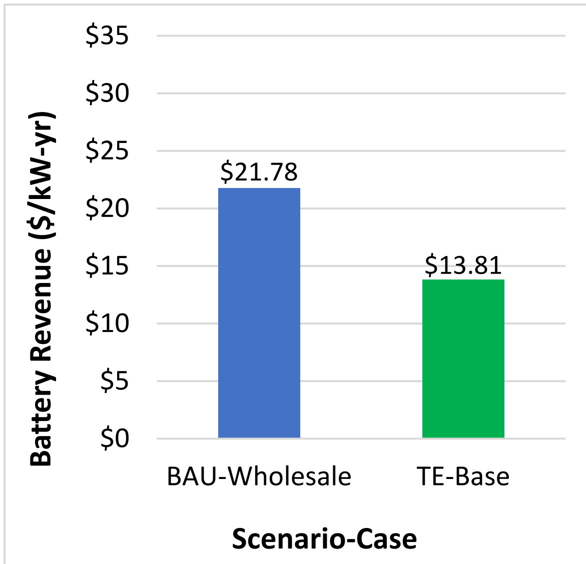

Figure 8.4. Revenue from energy arbitrage in the BAU-Wholesale and TE-Base cases.

At about $14/kW-yr, the TE-Base case has significantly lower revenues than the BAU-Wholesale case at about $22/kW-yr. This is entirely associated with the roundtrip losses involved in discharging and then recharging the battery. Figure 8.1 shows that the daily range of the TE market prices is almost identical to that of the wholesale market prices, as expected based on design of the TE rate structure. So, the potential for energy arbitrage might be expected to be similar as well.

However, in the BAU-Wholesale case, the roundtrip energy lost when a battery discharges and then recharges is purchased at wholesale prices, whereas in the TE-Base rate it is purchased at the TE retail market prices. The retail TE prices are higher than the wholesale prices due to the fixed component in the rate structure that collects additional revenues to recover distribution system costs.

To prove that this is, in fact, the direct cause of the difference in battery revenues from arbitrage, a simple test was conducted in which the battery charging and discharging efficiency (η) was set to 100%. The results are shown in Figure 8.5. Now the revenues from energy arbitrage are nearly identical, with the TE-Base case revenues higher by a factor of 1.05 corresponding to the retail markup of 1.05 on the wholesale rates to account for the 5% energy losses in the distribution system.

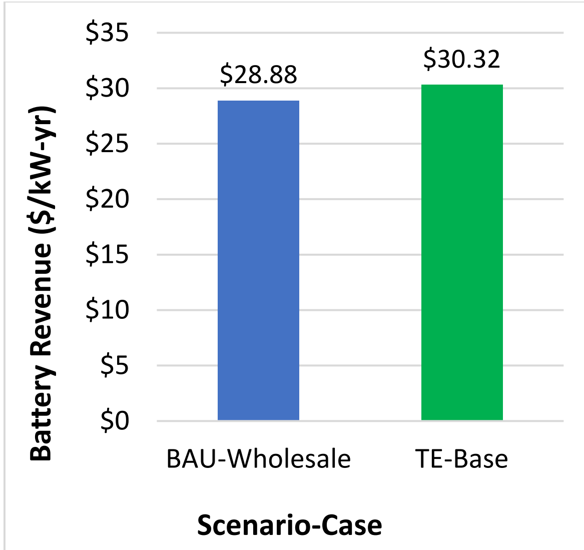

Figure 8.5. Revenue from energy arbitrage in the BAU-Wholesale and TE-Base cases without roundtrip losses.

Figure 8.6 shows the effect of modifying the TE rate design to allocate the capacity cost for transmission and distribution infrastructure to the dynamic retail TE rate in the TE-TD case, and further including the cost of generation capacity (as defined by the wholesale capacity market-clearing price of $75/kW-yr) in the TE-TDG case. By increasing the dynamic range of the TE retail prices, allocating these capacity costs based on the relevant load duration curve is seen to improve energy arbitrage potential in the TE-TD case to almost $19/kW-yr, nearly approaching the BAU-Wholesale case at $22/kW-yr. When the generation capacity cost is also allocated to the dynamic portion of the TE rate, the arbitrage opportunity rises further to over $31/kW-yr.

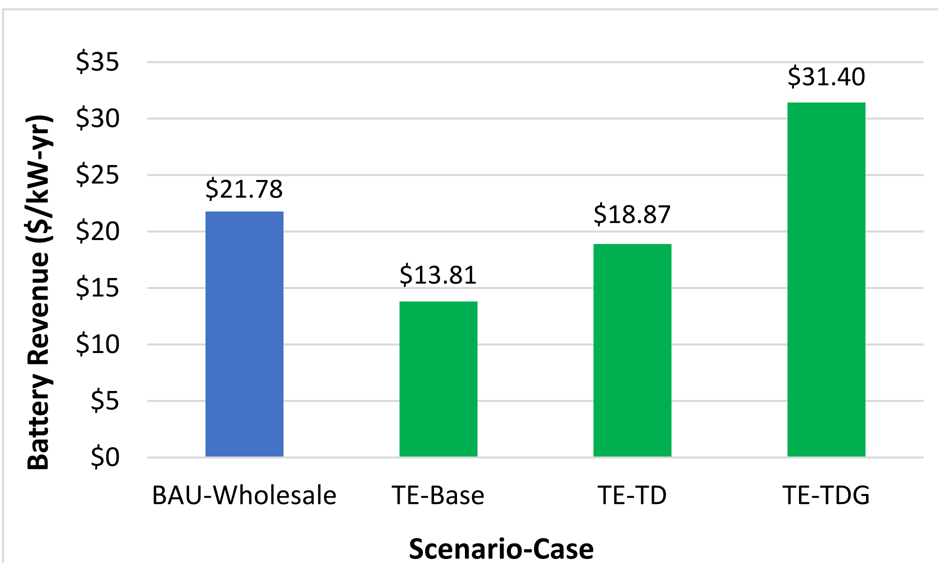

Figure 8.6. Energy arbitrage revenues for BAU-Wholesale and all TE cases.

Note that the revenues in Figure 8.6 do <u>not</u> include the stacked benefit of being cleared in the wholesale capacity market. This is discussed in the next section.

Note that the TE cases do not include additional arbitrage revenues that would occur when the local, retail TE markets stack congestion costs from distribution substation capacity limits or LSE peak demand limits. In the BAU cases, any additional revenues corresponding to these conditions are not included because the mechanism for this is their participation in retail peak demand programs. FERC defines these as inappropriate stacking in the current versions of its Orders 841 and 2222.

A closer look at how the daily revenues from arbitrage vary over the course of a year is provided by Figure 8.7. It shows considerable variation from day to day, with very high revenues occurring on roughly a dozen days per year, and moderately high revenues on fewer than one hundred days per year. The sole exception to this is the BAU-Retail case, where significant revenues occur on just a few days when wholesale prices are substantially above the retail BAU price of $0.11/kWh.

The prices seen by the batteries in the BAU-Wholesale and all the TE cases enable the batteries to perform arbitrage on most days of the year. The TE-Base case revenues are notably lower than the BAU-Wholesale revenues, and there are more days when the TE-Base prices are too low for arbitrage to occur at all.

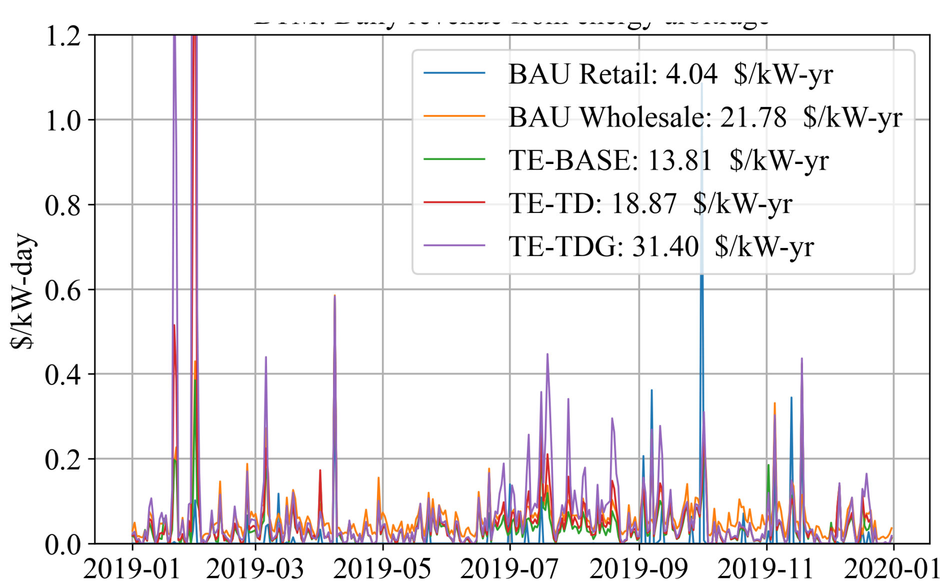

Figure 8.7. Daily arbitrage revenues for all cases in BAU and TE scenarios.

8.1.2 Capacity Market Sales

A generator's or battery's full nameplate capacity rating does not define the capacity it may sell in the wholesale capacity market. Levitt and Bell (2020) describe PJM's market rules defining capacity ratings used in the wholesale capacity market auction (unforced capacity), and include a specific example for a 4-hour 100 MW (output) battery. All resources are subject to the "10-hour minimum duration rule," that is their maximum full output must be sustained for 10 hours. So for a four-hour battery, its nameplate capacity is reduced by 4/10, or 40%. All resources lose an additional 12.5% because of the likelihood of forced outages. So the 100 MW battery is rated for sale at 35 MW, i.e., 35% of its nameplate output capacity.

For the standard battery used in this study, its 1 kW rating is defined in terms of the output from its chemical store, so the unforced capacity is further reduce by the assumed one-way conversion efficiency of 94%, to 33%. If it is unwilling to commit to discharging beyond a 20% SOC, an additional capacity derating factor of 80% applies.[21] So if it clears the wholesale capacity market auction at $75/kW, the value of its sale of capacity in the market is $25/kW-yr:

$$\begin{aligned} V_{bau}^{cap} &= (1\text{-kW})\ (4\text{-hr}/10\text{-hr})\ (1 - 0.125)\ (94\%)\ (80\%)\ (\$75/\text{kW-yr}) \\ &= \$19.74/\text{kW-yr} \end{aligned} \quad (14)$$

Now the stacked values for energy and capacity market participation can be compared for the BAU-Wholesale and TE cases, as shown in Figure 8.8. As noted earlier, stacking the proceeds from energy market arbitrage with sale of wholesale capacity is standard practice in ISOs today. But it also appears that stacking distribution-level services will be significantly inhibited, and so none are indicated in the BAU-Wholesale case.

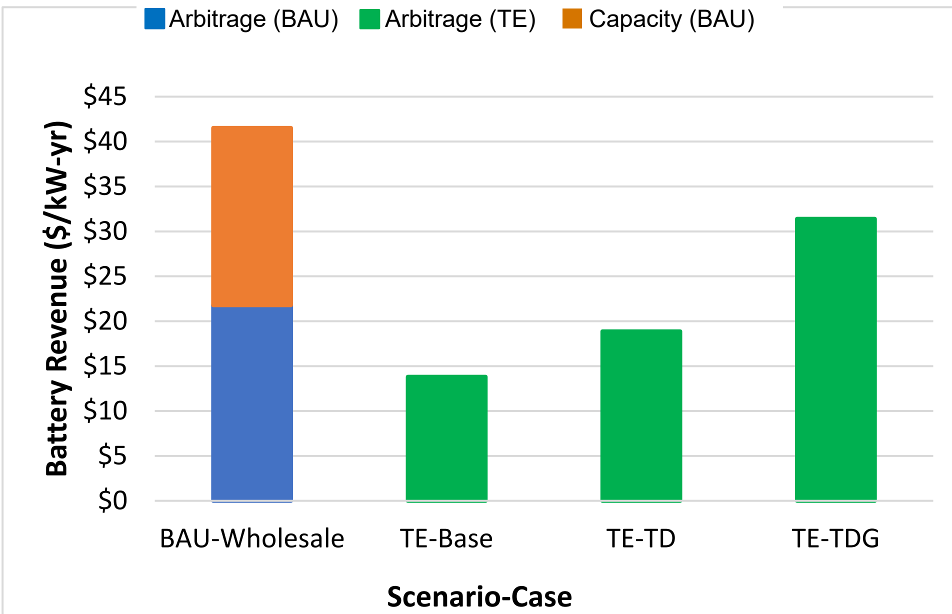

Figure 8.8. Stacked arbitrage, capacity, and distribution services revenues.

In the TE cases, the batteries do not sell capacity in the wholesale market. Instead, to the degree to which the value of capacity is increasingly allocated to the TE rate in TE-TD and TE-TDG cases, the value of energy arbitrage increases correspondingly, and is seen to approach that of the BAU-Wholesale case. What is unique to all the TE cases is that, instead of selling capacity in the wholesale market, the batteries are rewarded for their participation in the TE retail markets for limiting LSE costs for substation capacity, other future distribution services, and managing the LSE peak demand (for which it is required to purchase capacity in the wholesale market). Estimating what these will be worth in the future as the grid evolves is speculative and outside the scope of this study.

[21] This 20% minimum SOC is consistent in terms of the value derived from allocating the value of $75/kW-yr capacity market price to the dynamic component of the TE rate in TE-TDG case. This is because the battery dispatch is limited to a 20% minimum SOC by the battery agent control algorithm that is then managing both energy arbitrage and responding to the allocated market value of capacity.

8.1.3 Ancillary Services

The value of providing two forms of ancillary services is estimated in the study: spinning reserve and frequency regulation. Each of these services consist of two revenue parts: sale of capacity reserve and compensation for mileage to supply the ancillary service.

The annual value stream from each is estimated as the product of the average price and the output capacity offered by the battery to provide the service (at 94% conversion efficiency). The capacity offered for frequency regulation is based on a minimum SOC of 20%, to conserve battery lifetime. The full battery nameplate capacity was offered for spinning reserve, since such events being called are rare and consequent wear and tear on the battery from full discharge is therefore minimal.

Based on the DSO+T study (Pratt, et al., 2022), the average prices for the ancillary services are assumed as shown in Table 8.3.

Table 8.3. Average Prices Assumed for Ancillary Services

Data Description	Value
Spinning reserve	\$11.10/MWh
Fast frequency regulation	\$7.34/MWh

The mileage costs for spinning reserve events are designed to pay for the cost of fuel for generation. When applied to batteries, it presumably pays for the cost of energy plus roundtrip losses.

Since spinning reserve events are very few (~8–10 per year), the mileage compensation is very low and insignificant compared to the revenue for providing the service. It is neglected here.

For frequency regulation the compensation for mileage is designed to reimburse a generator for the extra fuel consumed due to the loss of efficiency from modulating its output. The counterpart for a battery is again the roundtrip losses for the energy output while providing regulation. Thus, the net effect of compensating the battery owner for mileage when providing regulation is assumed to be zero beyond the payment for services received, and so is ignored in this study.

The annual value streams from providing ancillary services are shown in comparison with other options batteries have to sell presented in Figure 8.9. They are significantly higher than any other stack of services batteries might offer. Note that market rules that providers of ancillary services offer firm capacity are strictly enforced because they are so critical for reliable grid operations. So stacking them, including with each other, while simultaneously offering to supply other services is not allowed.[22] Providing spinning reserve is particularly attractive, since under normal circumstances offering to reserve capacity for spinning reserve does not result in any discharge by a battery, and hence does not result in any wear and tear.

Note, however, the total quantities of capacity involved in the ancillary services markets are very small relative to the energy markets, with spinning reserve capacity at around 5% of demand and frequency regulation at less than 1% of demand.

[22] Wholesale market clearing processes do allow uncleared offers to the energy markets to be 'recycled' into the ancillary services markets, as discussed in Section 6.3.

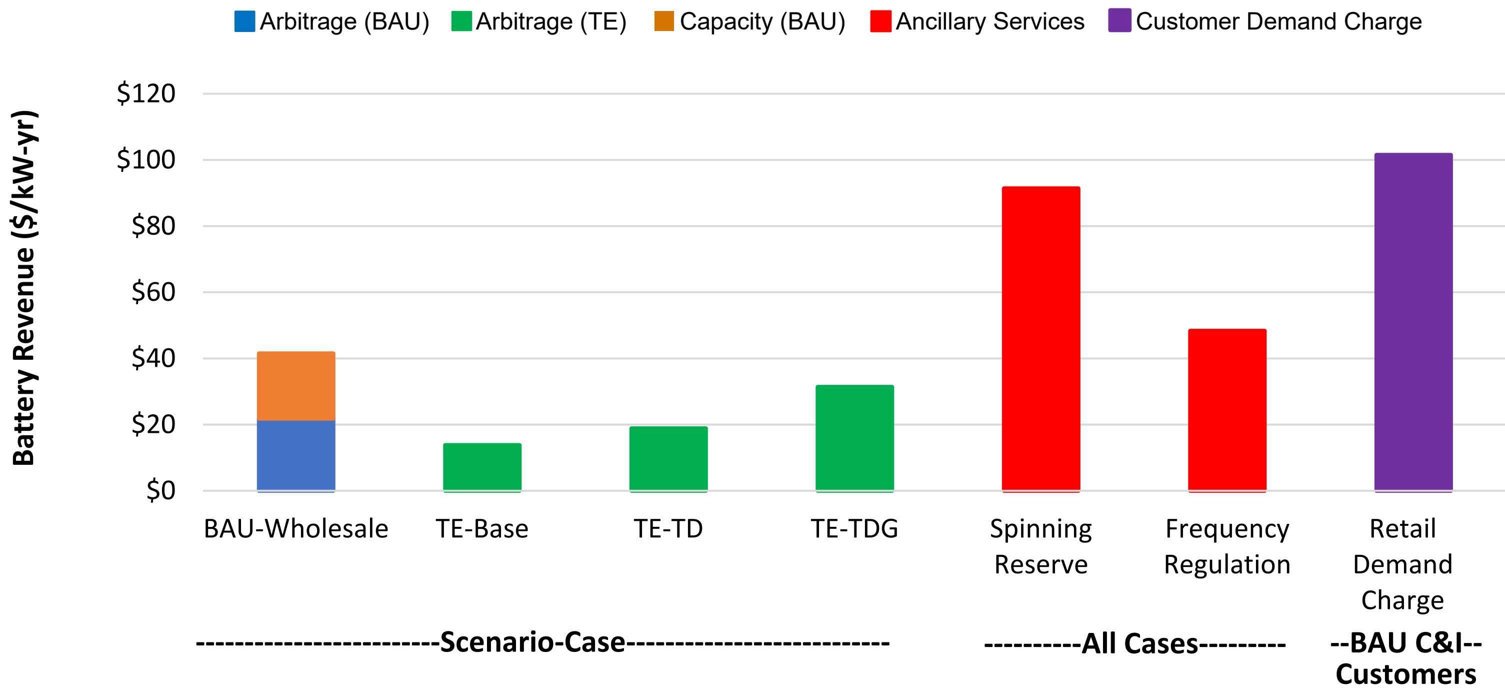

Figure 8.9. Value of stacked service options for batteries.

8.1.4 Customer Peak Load Reduction Value

In most utilities some customer classes are subject to a monthly peak demand charge, typically in exchange for a reduction in the fixed price of energy they consume. Generally, this only applies to large commercial and industrial customers, and for simplicity and transparency it is usually based on their noncoincident peak demand, i.e., the customer's demand rather than the utility's or the region's. It is also typically based on the highest level of the customer's consumption in any 15-minute interval during the month. The study adopts the assumption from the DSO+T study (Reeve, et al., 2022) that the monthly peak demand charge is \$15/kW-month, the equivalent of \$180/kW-yr.

As discussed in Section 6.3, the study assumes that, in the BAU scenario only, large commercial and industrial customers that own BTM batteries cannot stack the benefit of reductions in their monthly peak demand charges with energy arbitrage because the customer's retail bill will be adjusted to exclude the effect of battery discharge (and charging, in the BAU Wholesale case). Such customers are free to use their batteries to reduce retail peak demand charges in lieu of participating in the wholesale energy markets. Note there are no such benefits for utility- or merchant-owned batteries since they are assumed to not be installed BTM, nor are there any for such customers in the TE scenario because there are no peak demand charges in the rate design.

Customer load shapes tend to be much "peakier" than aggregated peak demand at other levels in the power grid. The more customers are aggregated, the more diversified their combined load becomes. So a key assumption for estimating the value to a commercial/industrial customer involves the number of consecutive hours the battery must discharge to displace the customer's peak demand. During months of high (near-peak) demand, this is likely to be on the order 4 hours or so (compared to PJM's 10-hour requirement for displacing regional generation capacity). Thus, a 4-hour battery will displace peak demand in those months equal to its output capacity. Months of near-peak demand would typically correspond to the three or four summer months for most consumers in most utilities.

In the other, off-peak months of the year, most customer load shapes are significantly flatter, and so energy must be supplied for many consecutive hours on many days of the month to displace the customer peak. A 4-hour battery clearly cannot do this with its entire output capacity. So, assuming a 10-hour peak demand duration for the other eight months of the year, and derating the battery capacity during those months, is perhaps a reasonable approximation of this effect.

The study assumes the annual benefit of reducing peak demand charges for large commercial and industrial customers with BTM batteries with 94% charging efficiency per unit of battery capacity is:

$$V_{C\&I}^{pdc} = \text{(1-kW) (94\%) (\$15/kW-mo) [(4-mo/yr) + (8 mo/yr) (4-hr/10-hr)]} \tag{15}$$
$$= \text{\$101.52/kW-yr}$$

This is also shown in Figure 8.9. It is notable that, although only pertinent to some customers, this is the single largest value stream estimated by the study.

8.2 Qualitative Analysis

The sections that follow describe qualitative assessments of how adoption of a TE-based strategy helps address three basic challenges facing BAU approaches for coordinating large fleets of batteries:

- Allowing batteries to provide distribution-level grid services
- Simplifying, rationalizing, and enhancing the participation model for batteries while improving equity across ownership types, consistent with the intentions of FERC Orders 841 and 2222
- Achieving stable, effective control and utilization of batteries when deployed at scale.

8.2.1 Supporting Distribution-Level Grid Services

This section describes how adoption of a TE-based approach could allow batteries to effectively and appropriately stack distribution-level grid services with wholesale services.

There is much discussion in the power industry that providing local, distribution-level grid services will become an increasingly significant value that batteries can provide to the grid, and in turn, their owners, in the future. This is expected to occur as the distribution system strains to support large amounts of distributed, solar PV systems, and to serve new loads from EVs and the electrification of previously nonelectric customer end-uses like space and water heating and transportation. The need to manage voltage and power flow constraints, not only at substations but also along neighborhood distribution circuits, will become increasingly difficult and is complicated by the prospect that they involve power flows both upstream toward substations, not just downstream from them. Maintaining (and improving) the reliability of electric service in the face of these challenges will increasingly require substantial infrastructure investments.

ISOs generally require all resources (including batteries) that are cleared in their capacity market must routinely offer to produce energy in the energy markets. Since doing so requires them to make firm offers of their capacity, they cannot simultaneously offer their capacity for other services, such as:

- provide local, distribution-level grid services such as congestion management, peak load deferral, or volt-VAR support
- participate as part of a LSE's price-responsive demand bid to the wholesale market.

Instead, any battery capacity that offers to commit to providing other grid services (i.e., at the local, distribution level) must be reserved for that purpose and not offered to the wholesale energy or capacity markets.

Because there is no mechanism for uncleared wholesale offers to be released to provide local, distribution services, they can only provide such services on a spot market basis. Even if such mechanisms were eventually established, the distribution utility cannot count on their availability with enough assurance to defer infrastructure investments. Further, since the LSE has not included the operation of such batteries in its forecasts and demand bids to the ISO, the LSE cannot use them for local purposes to the extent that their charging or discharging disrupts the integrity of those bids or ISO operations.

Also a LSE might offer an additional incentive for a battery to respond to a local congestion event, which will often coincide with the LSE's peak demand or high energy market prices. While this might be just enough additional revenue to elicit a battery to respond when otherwise it would not do so, the FERC orders may be interpreted as defining this as "double-rewarding a resource for the 'same' response," and therefore as inappropriate and not allowed. As a result of these effects, significant amounts of battery capacity may go underutilized in BAU futures.

In the study's TE scenario with the battery participation model described in Section 7.2, the distribution utility stacks wholesale energy market values alongside its own operational needs for local grid services, using its own utility batteries and customer BTM batteries for an optimal mix of wholesale and local services. It does this by reflecting both wholesale and local values superimposed as a supply curve in its dynamic retail TE markets at each substation. This presents local batteries with the combined set of opportunities to which batteries can respond. It also forms the basis for the distribution utility, acting as the LSE, to assemble them into the price-responsive portion of its demand bid and submit it to the ISO.

So, for example, using batteries to manage local constraints such as substation capacity limits is inherently reflected in the LSE's demand bid curve to the ISO, and the batteries that respond are rewarded with the opportunity to respond to higher-than-normal retail prices resulting from such congestion. This makes providing such services clearly distinct from responding to wholesale prices and appropriately and transparently superimposes the associated value stream on top of the wholesale market prices.

In lieu of batteries receiving wholesale payments when cleared in the annual capacity market auction, instead the distribution utility receives the capacity market-clearing price indirectly to the extent that it uses the batteries to reduce its peak demand, and hence its LSE requirement to purchase capacity to cover it. Therefore, the batteries are not bound by market rules <u>requiring</u> them to offer their capacity into the ISO's wholesale energy markets. The benefit created by reducing the LSE costs is passed down to the batteries performing that service indirectly with the opportunity to respond to the higher retail TE prices that result during such periods.

The key benefit of this arrangement is that it allows the distribution utility to transact with the batteries to supply other, local services instead, when and where they are more valuable. This involves services that may not be readily expressed in the form of an energy supply curve or in the LSE's price-responsive demand bid. Managing circuit-level congestion and providing voltage regulation may become higher in value than wholesale market opportunities for batteries. In that case, the LSE simply includes battery capacity reserved for these services in the portion of its demand bid to the ISO that is not price responsive, providing a clear and consistent signal to the ISO of its intentions to use the batteries for other services and preventing their participation from being double-counted or doubly rewarded.

Adopting a TE approach allows batteries to provide the most valuable services needed at any given time, and lets batteries optimize their revenues and thereby the benefits they bring to the grid.

8.2.2 Qualitative Benefits of a Transactive Energy Participation Model

This section provides a qualitative assessment of how adoption of a TE approach can simplify and rationalize the participation model for battery storage while enhancing equity across ownership types, and doing so in a way that is consistent with the apparent intentions of FERC Orders 841 and 2222.

Under these orders, FERC requires ISOs to establish rules governing battery participation in wholesale markets at wholesale prices. FERC acknowledges that this may require even customer-owned batteries located BTM to be submetered, so that a battery's usage can be distinguished from the consumer's consumption for their end-uses, which remains billed at the utility's retail rates. Use of a submeter is assumed rather than using an empirical baselining approach as the basis for the adjustment. Regardless of method is used, this adds complexity for the retail utility in the form of needing to make adjustments to its retail customers' bills.

Further, to avoid violating FERC's prohibitions on double-counting and double-rewarding resources for same response, the utility's LSE must subtract the batteries' wholesale offers and bids from its demand bids and forecasts. Otherwise the response of storage resources would be double-counted in the ISO's power flow and market-clearing processes as both supply and demand, invalidating both and endangering system operations.

FERC's intent that ISO rules should treat storage resources consistently with how other resources are treated is explicitly stated as an overriding principle, and is also implicit in a number of the clauses in Orders 841 and 2222. Also, it seems more than clear that FERC's intent with Order 2222 is that, beyond just batteries, resources in DER aggregations should be treated consistently with how batteries acting as individual resources (under Order 841) are treated.

In light of this stated and implicit desire for consistent treatment of various resources, FERC's intent in stating "allow battery participation in wholesale markets at wholesale prices" is not entirely clear. As introduced in Section 4.2.2, Order 841 clearly implies that batteries participating as individual storage resources means the energy they produce by discharging and consumed when charging is to be billed at wholesale rates rather than retail rates. This is entirely consistent with how offers from bulk generation and demand bids from LSEs (including any price-responsive component) are incorporated. Storage simply fits into this framework by offering to discharge as a form of supply and to charge in the form of a demand bid.

Participation of storage alongside distributed generation resources in DER aggregations under Order 2222 is equally clear and consistent. However, maintaining consistency between storage and demand response in such aggregations is problematic. Reductions in demand from responsive loads in aggregations are treated as a form of supply in wholesale markets, which is also consistent.

But, when such demand reductions are created by deferring or shifting load to another time period, such as from air conditioners or water heaters, then "extra" load will occur later as full-service conditions (temperatures in these examples) are restored. This is the exact analog to recharging a battery, but such aggregated loads are not permitted to "recharge" at wholesale rates. Nor do the aggregators typically involved purchasing energy for the entire customer load at wholesale rates. Instead the customers involved pay for this energy at their normal retail rate.

So, to be consistent with the treatment of aggregated demand response resources, customer batteries would also need to charge at retail rates. But this would be inconsistent with how individual storage resources owned by merchants and utilities are treated under Order 841. Even if there was a desire to allow such "recharging" of responsive loads at wholesale rates, accurately distinguishing it from the portion of the customer's demand that is 'normal' is extremely difficult if not impossible in practice.

Storage resources in DER aggregations could receive special dispensation to charge at wholesale rates, at the expense of achieving consistency with demand response. But it appears to be impossible if not impractical in the BAU scenario to achieve consistent treatment among aggregated storage and aggregated demand response.

Adoption of a TE approach largely resolves these conflicts. This is because net metering customer batteries at dynamic retail TE rates exposes them to wholesale energy prices as a specific component of the rate simply and transparently. The added complexity of changing retail billing processes to adjust customer bills for their battery's participation at wholesale prices is eliminated. By incorporating battery response to prices or commitments to other local services in the LSE's demand, the need to adjust the LSE forecasts and demand bids to exclude batteries from them is eliminated. If the retail customer's loads are also on the TE rate, the need for submetering customer batteries also is removed, and participation with price-responsive loads encouraged.

The only unresolved issue is that roundtrip losses for consumer batteries are, in effect, billed at retail rates; whereas for merchant- and utility-owned batteries they are billed at wholesale prices. However, the quantitative analysis described in Section 8.1 shows that even this discrepancy can be largely, if not entirely, eliminated by increasing the dynamic range of the TE rate, by allocating more of the capacity cost of infrastructure to the rate's dynamic component.

Adopting a TE approach adds complexity of its own, certainly, but the benefits of doing so, combined with its ability to support increased distribution-level services, and to help support stable coordination and control, make it worth considering.

8.2.3 Issues with Control and Stability Addressed by a TE Approach

There are significant challenges in achieving stable, effective coordination of batteries deployed at scale. This was highlighted by the effort to construct transactive agents for batteries in the DSO+T study (Widergren et al., 2020a; Bhattarai 2020). This section discusses the basic nature of these difficulties, how challenges are likely to affect the BAU scenarios in the present study, and how adoption of a TE approach can mitigate them.

Batteries are classic price-takers for both charging and discharging, as they are indifferent as to the times they are scheduled. As such, they have a natural desire to make offers to discharge and charge during the highest and lowest price time periods, respectively.

In the transactive battery cases of the DSO+T study, this initially resulted in the individual batteries in the fleet all bidding on the same hours. This mitigated the price excursions of those hours to the point they were no longer the highest and lowest price hours. In the next iteration of the 48-hour look-ahead window, they would all offer and bid for the hours that became the highest and lowest price hours.

Thus the value of the transactive look-ahead window in achieving consensus among the individual batteries was initially defeated. As a result, the battery agent algorithms underwent considerable experimental modification to dampen the degree to which they shifted their bids from one iteration to the next to prevent this unstable price-quantity oscillation. Thus, that study showed that TE systems can be made to work for batteries deployed at scale, with existing wholesale market functionality.

BAU scenarios of battery operation will have the same issues. However, by making offers to discharge as supply resources and making bids to charge as demand resources, a price equilibrium can be achieved by the security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) algorithms in the day-ahead and real-time markets, respectively. However, the batteries cannot hedge the risk of their offers and bids by making offers and bids for more hours a day than their energy storage capacity can support. So, when deployed at scale, considerable battery capacity is likely to be unused—left uncommitted and unscheduled—because of the tendency to cluster individual bids on relatively few hours of the day.

Existing wholesale market structures do not support “flexibility bids” for a given diurnal quantity of energy when prices are above or below a threshold included in the bid. Future BAU market designs could implement such bids, assuming the SCUC and SCED optimizations can be modified to accommodate them. If so, this could, in principle, allow BAU Wholesale markets to provide for effective, stable utilization of batteries at scale that is equivalent to that achieved by the transactive batteries in the DSO+T study. However, this may require new technical advances in optimal power flow algorithms, in which they are revised and/or restructured to account all the operational permutations inherent in each of a large number of flexibility bids. There is also the attendant risk that the computational power required or such a revised optimization structure may be intractable (especially with the very large number of DER market participants).

By contrast, the DSO+T study showed a TE-based coordination scheme can work for batteries deployed at scale, with existing wholesale market functionality and optimization tools.

9.0 Conclusions and Future Work

This study analyzed the value that accrues to batteries supplying today's grid services as a function of the participation models associated with three primary types of battery ownership: merchant-owned transmission-connected batteries, utility-owned distribution-connected batteries, and customer-owned BTM batteries. The study provided both quantitative and qualitative assessments comparing opportunities for battery storage in BAU and TE scenarios. The quantitative assessment was normalized for battery performance and capacity, and analyzed across a range of market and grid services using typical wholesale energy and ancillary service market prices from PJM and ERCOT. Results found that if batteries participated in energy arbitrage under the BAU scenario, they could earn approximately \$22/kW-yr if allowed to charge and discharge at wholesale energy prices, but only ~\$4/kW-yr if forced to charge at retail prices and discharge at wholesale energy prices. When participation in the capacity market is included (~\$20/kW-yr), the total annual value accrual would be ~\$42/kW-yr. In comparison, a range of transactive real-time retail tariffs were analyzed. Transactive rates designed to only dynamically recover wholesale energy purchases enabled a value accrual of ~\$14/kW-yr, whereas rate designs that also dynamically recover delivery and generation capacity costs accrued annual benefits of \$19-31/kW-year. In another comparison, ancillary services such as frequency regulation and spinning reserve offer higher values (\$48-91/kW-year), as does the opportunity for commercial and industrial customers to address monthly retail demand charges (\$101/kW-yr).

This study also qualitatively assessed the benefits of TE coordination of batteries versus current and emerging implementations in response to FERC orders. First, transactive coordination via a dynamic retail tariff allows batteries to provide local, distribution-level grid services in addition to wholesale market services. The need for local services (such as congestion management, peak load deferral or volt-VAR support) will grow as the distribution system strains to support large amounts of distributed, solar PV systems and to serve new loads from EVs. Second, TE schemes greatly simplify the participation of a vast number of DERs in support of grid operations. Transactive approaches eliminate the need for submetering of individual DERs behind the customer meter, as all DERs and loads are treated equally. Issues of double-counting for benefits are avoided through the use of a consolidated and consistent value signal. Transactive schemes also simplify the transmission-to-distribution interface, greatly reducing the number of small wholesale market participants that ISOs will need to include in their market-clearing schemes. Finally, analysis has shown that transactive schemes can ensure the stable and effective coordination of large-scale battery populations. Batteries are classic price-takers and, as such, they have a natural desire to all make offers to discharge and charge during the highest and lowest price time periods, respectively. If not effectively managed, this can lead to market instabilities and significant rebound effects.

Based on this work there are several areas warranting further investigation. For example, this study found that the energy arbitrage performance of batteries is significantly affected by any fixed volumetric retail tariff they must incur during charging. Tariff designs that reduce this flat rate and recover revenue from a cost-causation-based dynamic real-time component, as well as a fixed monthly charge, will result in greater battery participation and compensation for their services. As such, further investigation is needed into advanced incentive designs that reduce any penalty batteries incur for charging inefficiencies beyond the actual system costs they cause. This is important to ensure that BTM batteries are fairly and correctly incentivized to provide storage (peak shifting) in the energy market. In addition, further investigation is needed into understanding dynamic approaches to capacity cost allocation and recovery versus traditional capacity payment methods. This is important for battery systems that do not have indefinite discharge durations and are subject to capacity factor derating. Resulting candidate dynamic tariffs will also impact the economic attractiveness of other DERs such as rooftop solar, EVs, and electrification of space heating.

Further research is needed into how the provisioning of local grid services should best be incentivized and harmonized with existing wholesale market services. This includes determining which local services (such as congestion management, peak load deferral, or volt-VAR support) should be coordinated through market-based means versus mandated through DER standards and, in both cases, how providers of these services should be fairly compensated. Finally, there is a need to understand how the best emerging solutions should be adopted and deployed. This may involve integrating key findings with other FERC order implementation and market analysis to jointly develop a regulatory roadmap for grid service coordination and compensation.

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Appendix A – Summary of FERC Order No. 841

Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators

In the following summary of FERC Order 841, section numbers from the FERC order precede underlined section titles. FERC's paragraph numbers from which these notes are abstracted appear in parentheses preceding the notes. Notes in gray font are judged to not affect the current analysis of transactive energy and storage, but are included for completeness. Comments and/or discussion added by the authors of this report (not by FERC) are included as footnotes.

I. Introduction

(1) Remove barriers to the participation of electric storage resources in the capacity, energy, and ancillary service markets operated by ISO markets. Each RTO and ISO establish market rules that, recognizing the physical and operational characteristics of electric storage resources, facilitates their participation in the ISO markets:

1. ensure that a resource using the participation model is eligible to provide all capacity, energy, and ancillary services that the resource is technically capable of providing in the ISO markets
2. ensure that a resource using the participation model can be dispatched and can set the wholesale market-clearing price as both a wholesale seller and wholesale buyer consistent with existing market rules that govern when a resource can set the wholesale price
3. account for the physical and operational characteristics of electric storage resources through bidding parameters or other means
4. establish a minimum size requirement for participation in the ISO markets that does not exceed 100 kW.

Additionally, the sale of electric energy from the ISO markets to an electric storage resource that the resource then resells back to those markets must be at the wholesale locational marginal price.[23]

[23] This clause seems to imply that a BTM storage resource must have a separate meter (that can be subtracted from the retail meter, and thus billed at wholesale prices). How does this work when an aggregator intermediates between a retail customer and the wholesale market? Does it mean the aggregator is buying and selling at wholesale? Isn't the retail customer, buying and selling the same energy at retail, if their retail bill is based on the customer meter that includes the battery and their native load?

III. Discussion

A. Definition of Electric Storage Resource

(29) ***Definition of Electric Storage Resource*** – *electric storage resource* is defined as "a resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid."

- capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid, regardless of their storage medium (e.g., batteries, flywheels, compressed air, and pumped-hydro).
- located on the interstate transmission system, on a distribution system, or behind the meter fall under this definition, subject to the additional clarifications provided below.

(32) The definition of *an electric storage resource does apply to behind-the-meter resources that do not inject electricity onto the grid*. These are considered demand response. This rule is not intended to disrupt or otherwise conflict with well-established rules for demand response that are in some cases unique to its characteristics.

(33) The definition of an electric storage resource excludes a resource that is either (1) physically incapable of injecting electric energy back onto the grid due to its design or configuration or (2) contractually barred from injecting electric energy back onto the grid.[24]

B. Creation of a Participation Model for Electric Storage Resources

(51) ***Participation Model for Electric Storage Resources*** – Each ISO is required to revise its tariff to include a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, facilitates their participation in the ISO markets.

This will help eliminate barriers to their participation in the ISO markets, which will enhance competition and, in turn, help to ensure that these markets produce just and reasonable rates.

(53) The final rule does not adopt prescriptive, uniform market rules to which each ISO must adhere. Instead, the regulations establish minimum requirements (for, among other things, bidding parameters and resource size) that each ISO must meet when proposing market rules to comply, permitting each ISO to propose market rules that comply with these minimum requirements in the way that best suits its individual market design.

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[24] The intent seems clear that a BTM battery at a customer without permission from the retail utility to export net power is not included in the definition. Its operation is then as a means of providing demand response, presumably.

(56) All electric storage resources are not required to use the participation model (e.g., this Final Rule does not preclude electric storage resources from continuing to participate in demand response or other participation models). Other FERC rules still apply, so electric storage resources that elect not to use the participation model would still be able to pay the wholesale LMP for the electric energy they purchase from the ISO markets and then resell back to those markets.[25]

(61) ***Qualification Criteria for the Participation Model for Electric Storage Resource –*** Each ISO is required to define in its tariff the criteria that a resource must meet to use the participation model for electric storage resources (i.e., *qualification criteria*). These criteria must be based on the physical and operational characteristics of electric storage resources, such as their ability to both receive and inject electric energy, must not limit participation under the electric storage resource participation model to any particular type of electric storage resource or other technology and must ensure that the ISO is able to dispatch a resource in a way that recognizes its physical and operational characteristics and optimizes its benefits to the ISO.

(68) ***Relationship between Electric Storage Resource Participation Model and Existing Market Rules –*** Each ISO is required to propose any necessary additions or modifications to its existing tariff provisions to specify: (1) whether resources that qualify to use the participation model for electric storage resources will participate in the ISO markets through existing or new market participation agreements and (2) whether particular existing market rules apply to resources participating under the electric storage resource participation model.

C. Eligibility of Electric Storage Resources to Participate in the ISO Markets

(76) ***Eligibility to Provide all Capacity, Energy, and Ancillary Services*** – Each ISO is required to establish market rules so that an electric storage resource is eligible to provide all capacity, energy, and ancillary services that it is technically capable of providing, including services that the RTOs/ISOs do not procure through an organized market.

(77) "Technically capable" means that a resource can meet all of the technical, operational, and/or performance requirements that are necessary to reliably provide that service. For example, these requirements may include a minimum run-time to provide energy or the ability to respond to automatic generation control to provide frequency regulation.

(79) Electric storage resources are eligible to provide services that the RTOs/ISOs do not procure through an organized market mechanism (such as blackstart service, primary frequency response service, and reactive power service) if they are technically capable of providing those services. Each ISO is not required to revise or revisit the technical requirements or compensation provisions of those markets.

[25] This seems to mean they can, but are not required, to use the participation model in order to participate in wholesale markets at wholesale prices.

(93) ***Ability to De-Rate Capacity to Meet Minimum Run-Time Requirements* –** Each ISO is required to revise its tariff to allow electric storage resources to de-rate their capacity to meet minimum run-time requirements. For example, this requirement would allow a 10MW/20MWh electric storage resource to offer 5MW of capacity into a capacity market with a 4-hour minimum runtime because that is the maximum output that the resource can sustain for the duration of the minimum run-time.

(94) The Final Rule does not exempt an electric storage resource that is participating in ISO capacity markets from any applicable penalties for nonperformance.

(95) Each ISO may request that its market monitor verify whether an electric storage resource de-rated its capacity to meet a minimum run-time requirement to ensure that these resources are not engaging in physical withholding

(97) Each ISO is provided flexibility either to use its existing rules for must-offer quantities or to modify its existing rules as necessary to reflect the physical and operational characteristics of electric storage resources. If an electric storage resource elects to derate its capacity, it must not de-rate its capacity below any capacity obligations it has assumed, such as any applicable must-offer requirement. The de-rated quantity should be based on the quantity of energy that an electric storage resource can discharge continuously over the minimum run-time set by the ISO.

(98) RTOs/ISOs are not required to make specific changes to minimum run-time or must-offer requirements associated with **providing capacity** in order to accommodate electric storage resources.

Each ISO is required to demonstrate on compliance with this final rule that its existing market rules provide a means for electric storage resources to provide capacity. If an ISO does not have existing tariff provisions that enable electric storage resources to provide capacity, such as the ISO tariff provisions described below (99), we require the ISO to propose such rules on compliance with this final rule.

(99) For example, NYISO has an Energy Limited Resource model that facilitates the participation of electric storage resources in the capacity market by limiting their commitments to one four-hour interval per day, while CAISO requires that flexible resource adequacy resources be available only during peak hours. Other RTOs/ISOs rely on opportunity costs in incremental energy offer reference levels, allowing for a resource to reflect its energy-limited nature through high offers in the energy market that make it unlikely to be dispatched. For example, ISO-NE's tariff allows opportunity costs included in an incremental energy reference level based on costs associated with complying with emissions limits, water storage limits, and other operating permits that limit production of energy. While some of these market rules may apply to electric storage resources, we require each ISO to demonstrate how such rules are applicable on compliance with this final rule.

(117) ***Energy Schedule Requirement for Provision of Ancillary Services*** – Some electric storage resources may be technically capable of providing ancillary services without an energy schedule and could represent those capabilities in their bidding parameters and performance tests. However, requiring the RTOs/ISOs to change the requirement to have an energy schedule to provide ancillary services could result in less efficient dispatch, potentially increasing costs. Moreover, we recognize the importance of co-optimization in clearing and dispatch software and appreciate that the RTOs/ISOs have developed different, individual approaches to co-optimizing their energy and ancillary service markets. So, a requirement to have an energy schedule to participate in the ancillary service markets is not necessarily unreasonable for the participation of electric storage resources in those markets because it may be necessary to support economically efficient dispatch within a particular ISO market.

(118) Some fast-responding electric storage resources are technically capable of providing ancillary services without an energy schedule. We also acknowledge that some ISO market rules already allow resources to provide some ancillary services, namely regulation, without the requirement to participate in the energy market. Such opportunities for participation in certain ancillary service markets without an energy schedule suggest that there may be instances (i.e., for certain ancillary services in certain ISO markets) in which allowing a resource to provide an ancillary service without an energy schedule may enhance market efficiency. Therefore, we encourage each ISO to consider whether fast-responding electric storage resources may be able to provide certain ancillary services in its markets without an energy schedule.

(124) ***NERC Definitions –*** The NERC reliability standards, the associated Glossary of Terms, and regional reliability standards do not create barriers to the participation of electric storage resources or other non-synchronous technologies in the ISO markets. NERC's reliability standards are technology neutral and provide electric storage resources with flexibility to meet their performance-based requirements.

D. Participation in the ISO Markets as Supply and Demand

(140) ***Eligibility to Participate as a Wholesale Seller and Wholesale Buyer –*** Each ISO is required to revise its tariff to ensure that a resource using the participation model for electric storage resources can be dispatched as supply and demand and can set the wholesale market-clearing price as both a wholesale seller and wholesale buyer, consistent with rules that govern the conditions under which a resource can set the wholesale price.

Electric storage resources can set prices in the ISO markets, as either a wholesale seller or a wholesale buyer, must be available to the ISO as a dispatchable resource. Also:

1. Electric storage resources can set the price in the capacity markets, where applicable;
2. RTOs/ISOs must accept wholesale bids from electric storage resources to buy energy;

3. electric storage resources must be allowed to participate in the ISO markets as price takers, consistent with the existing rules for self-scheduled resources.

(146) The option to self-schedule applies to electric storage resources both as buyers and as sellers. That is, their ability to participate as price takers will not be limited to their participation as load. Electric storage resources should also be able to self-schedule when they participate in the ISO markets as a supply resource consistent with rules governing how other resources self-schedule.

(148) Electric storage resources in charging mode are not deemed to be negative demand response.

(160) ***Mechanisms to Prevent Conflicting Dispatch Instructions –*** Each ISO is required to either (1) demonstrate that its market design will not allow for conflicting supply offers and demand bids from the same resource for the same market interval or (2) modify its market rules to prevent conflicting supply offers and demand bids from the same resource for the same market interval.

(163) Each ISO should allow electric storage resources to participate as supply and demand <u>simultaneously</u> (i.e., submit bids to buy and offers to sell during the same market interval), the RTOs/ISOs should not <u>require</u> them to participate as supply and demand simultaneously.

(172) ***Make-Whole Payments –*** Each ISO is required to revise its tariff to ensure that resources available for manual dispatch as a wholesale buyer and wholesale seller under the participation model for electric storage resources are held harmless for manual dispatch by being eligible for make-whole payments.

> Such make-whole payments must be allowed when (1) a resource is [manually] dispatched as load and the wholesale price is higher than the resource's bid price and (2) when it is [manually] dispatched as supply and the wholesale price is lower than the resource's offer price.

Any such make-whole payments must be consistent with the rules for make-whole payments for other dispatchable resources.

(174) Uplift, or make-whole, payments may be needed to ensure that resources committed and dispatched out-of-market are able to recover their operating costs. Electric storage resources participating in the ISO markets are subject to the same system conditions as other resources that may cause them to be dispatched out-of-market and unable to recover their operating costs.

E. Physical and Operational Characteristics of Electric Storage Resources

(187) ***Requirement to Incorporate Bidding Parameters as Part of the Electric Storage Resource Participation Model –*** Each ISO is required to have tariff provisions providing a participation model for electric storage resources that accounts for the physical and operational characteristics of electric storage resources through bidding parameters or other means.[26]

(189) To the extent that an ISO adopts bidding parameters to account for the physical and operational characteristics set forth in this final rule, it must permit a resource using the participation model for electric storage resources to submit those bidding parameters in both the day-ahead and the real-time markets.

> *Allowing a resource using the participation model for electric storage resources to provide updated information through any applicable bidding parameters, consistent with the opportunities that other market participants have to do so, will help to ensure that each ISO has the information necessary to efficiently dispatch its system, fully accounting for the physical and operational capabilities of the electric storage resources participating in its markets.*

(206) ***State of Charge, Upper and Lower Charge Limits, and Maximum Charge and Discharge Rates –*** Each ISO is required to revise its tariff to include a participation model for electric storage resources that accounts for the following physical and operational characteristics of such resources: State of Charge, Minimum State of Charge, Maximum State of Charge, Minimum Charge Limit and Maximum Charge Limit, whether through bidding parameters or other means.

To the extent that an ISO proposes to comply with this requirement through its existing bidding parameters or other existing market mechanisms, it must demonstrate in its compliance filing how its existing market rules already account for these characteristics of electric storage resources.

(207) An ISO should have flexibility in how electric storage resources will be allowed to represent their physical, operational, and commercial circumstances. This will allow an ISO to determine, consistent with how it treats other resources, whether it is mandatory for resources using the participation model for electric storage resources to submit information regarding these physical and operational characteristics, or whether resources using the participation model for electric storage resources should be allowed to submit this information at their discretion.

> *FERC notes that not all these physical and operational characteristics are applicable to all electric storage resources, particularly when a resource is managing its own state of*

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[26] Originally, FERC proposed the following physical parameters: state of charge, upper charge limit, lower charge limit, maximum energy charge rate, and maximum energy discharge rate. It also proposed the following parameters representing physical constraints or desired operation minimum charge time, maximum charge time, minimum run time, and maximum run time. The final rule (above) recognizes some physical characteristics are constant and can, for example, be part of characteristics registered with the ISO rather than included in bids, and that the set of parameters that must be included in bids and their definitions can vary from the original proposal.

charge and when the resource is providing multiple services. The physical and operational characteristics adopted in this final rule may need to acknowledge commercial obligations in addition to physical and operational limitations.

(208) *State of Charge* represents the amount of energy stored in proportion to the limit on the amount of energy that can be stored, typically expressed as a percentage. State of Charge as a bidding parameter is the level of energy that an electric storage resource is anticipated to have available at the start of the market interval rather than the end.

> **(209)** Each ISO has the flexibility to propose telemetry requirements for State of Charge in their compliance filings. This will allow the RTOs/ISOs to set the telemetry requirements for different services and other market participants.
>
> *For example, telemetry may be necessary if an electric storage resource is participating exclusively in the frequency regulation market but less important if that resource is providing capacity or energy.*

(210) *Maximum and Minimum State of Charge* represent the states of charge that should not be exceeded: gone above when receiving electric energy from the grid, and gone below when injecting electric energy onto the grid, respectively.

(211) *Maximum Charge Limit* [rate] for an electric storage resource is the maximum MW quantity of electric [power ~~energy~~] that it can receive from the grid, and the *Maximum Discharge Limit* [rate] is the maximum MW [power ~~quantity~~] that the resource can inject onto the grid.

(215) ***Minimum Charge Time, Maximum Charge Time, Minimum Run Time, and Maximum Run Time –*** Each ISO is required to revise its tariff to account for the following physical and operational characteristics of electric storage resources: Minimum Charge Time, Maximum Charge Time, Minimum Run Time, and Maximum Run Time, whether through bidding parameters or other means.

Each ISO can determine, consistent with how it treats other resources, whether it is mandatory for electric storage resources to submit information regarding these physical and operational characteristics, or whether resources using the participation model for electric storage resources should be allowed to submit this information at their discretion.

(217) *Minimum Charge Time* represents the shortest duration that an electric storage resource is able to receive electric energy from the grid.

> *Minimum Charge Time is similar to the Minimum Run Time for traditional generation resources but represents the minimum time the resource can receive electric energy from the grid, rather than provide electric energy to the grid.*

(218) *Maximum Charge Time* represents the maximum duration that an electric storage resource is able to receive electric energy from the grid.

If the ISO is not managing the state of charge of the electric storage resource in real time, then this parameter will prevent it from dispatching the resource to charge for a duration that would exceed the resource's Maximum State of Charge. It also provides useful information about how long the electric storage resource can be relied upon to receive energy from the grid if the system operator needs to dispatch it to do so.

(219) *Minimum Run Time* and *Maximum Run Time* are the minimum and maximum amounts of time that an electric storage resource is able to discharge electric energy.

Maximum Run Time reflects physical or operational constraints, such as its state of charge or potential obligations to provide other services.

Minimum Run Time already exists in the RTOs/ISOs to prevent excessive wear and tear on traditional generation resources due to starting and stopping a resource too frequently and to ensure they are able to recover the costs of starting.

(224) ***Additional Physical and Operational Characteristics –*** Each ISO is required to revise its tariff for electric storage resources to account for the following physical and operational characteristics: Minimum Discharge Limit, Minimum Charge Limit, Discharge Ramp Rate, and Charge Ramp Rate, whether through bidding parameters or other means.

(226) *Minimum Discharge Limit* represents the minimum MW output level that a resource can inject onto the grid, and *Minimum Charge Limit* represents the minimum MW level that the resource can receive from the grid.

(229) *Discharge Ramp Rate* is the speed at which a resource can move from zero output to full output, or its Maximum Discharge Limit.

This is the same as the current ramp rates provided by traditional generation resources.

Charge Ramp Rate represents the speed at which an electric storage resource can move from zero output to fully charging, or the resource's Maximum Charge Limit.

(231) Summary of Physical and Operational Characteristics of Electric Storage Resources[27]

Physical or Operational Characteristic	**Definition**
State of Charge	The amount of energy stored in proportion to the limit on the amount of energy that can be stored, typically expressed as a percentage. It represents

[27] Many of these parameters don't work for aggregations of heterogenous storage resources, because they don't add linearly or orthogonally. However, as noted later, Order 841 applies only to individual DERs, not aggregations.

	the forecasted starting State of Charge for the market interval being offered into.
Maximum State of Charge	A State of Charge value that should not be exceeded (i.e., gone above) when a resource using the participation model for electric storage resources is receiving electric energy from the grid (e.g., 95% State of Charge).
Minimum State of Charge	A State of Charge value that should not be exceeded (i.e., gone below) when a resource is injecting electric energy to the grid (e.g., 5% State of Charge).
Maximum Charge Limit	The maximum MW quantity of electric [power ~~energy~~] that a resource can receive from the grid.
Maximum Discharge Limit	The maximum MW quantity [of electric power] that a resource can inject to the grid.
Minimum Charge Time	The shortest duration that a resource is able to be dispatched by the ISO to receive electric energy from the grid (e.g., one hour).
Maximum Charge Time	The maximum duration that a resource is able to be dispatched by the ISO to receive electric energy from the grid (e.g., four hours).
Minimum Run Time	The minimum amount of time that a resource is able to inject electric energy to the grid (e.g., one hour).
Maximum Run Time	The maximum amount of time that a resource is able to inject electric energy to the grid (e.g., four hours).
Minimum Discharge Limit	The minimum MW output level that a resource using the participation model for electric storage resources can inject onto the grid.
Minimum Charge Limit	The minimum MW level that a resource using the participation model for electric storage resources can receive from the grid.
Discharge Ramp Rate	The speed at which a resource using the participation model for electric storage resources can move from zero output to its Maximum Discharge Limit.
Charge Ramp Rate	The speed at which a resource using the participation model for electric storage resources can move from zero output to its Maximum Charge Limit.

F. State of Charge Management

(246) Each ISO must permit electric storage resources to manage their state of charge because it allows these resources to optimize their operations to provide all of the wholesale services that they are technically capable of providing, similar to the operational flexibility that traditional generation resources have to manage the wholesale services that they offer.

> *While the RTOs/ISOs may be in a better position to effectively manage the state of charge for a resource using the participation model for electric storage resources that, for example, exclusively provides frequency regulation service, some electric storage resources may be able to provide multiple services or services to another entity outside of the ISO markets.*
>
> *Ensuring that a resource owner/operator is able to manage its own state of charge may also limit the need for the ISO to telemeter the resource in real time to ensure that the Minimum and Maximum States of Charge are not violated.*

(248) Resources that self-manage their state of charge will be subject to any applicable penalties for deviating from a dispatch schedule to the extent that the resource deviates from the dispatch schedule in managing its state of charge.

> *To the extent that the provision of a particular wholesale service, such as frequency regulation, requires a resource providing that service to follow a dispatch signal that has the effect of maintaining the resource's ability to provide the service, a resource that is managing its own state of charge would still be required to follow such a dispatch signal, just as all other resources providing that same service.*

(249) If an ISO already has a mechanism to manage a resource's state of charge (such as regulation energy management in CAISO or pumped-hydro resource operation in PJM), then they are required to make the use of such mechanism optional to the resource owner.

(250) Nothing in this final rule precludes an ISO from establishing telemetry or other communication requirements necessary to determine the capabilities of the electric storage resource in real time.

G. Minimum Size Requirement

(265) Each ISO is required to revise its tariff to include a participation model for electric storage resources that establishes a minimum size requirement for participation in the ISO markets that does not exceed 100 kW.

This minimum size requirement includes all minimum capacity requirements, minimum offer to sell requirements, and minimum bid to buy requirements for resources participating in these markets under the participation model for electric storage resources.[28]

(268) Minimum size requirements do not need to be resource-specific or location-specific.[29]

> **(271)** An ISO <u>could</u> allow offer and/or bid quantities smaller than 100 kW, as CAISO indicates it does. An ISO <u>could</u> also allow minimum offer and/or bid quantities equal to 100 kW, as PJM indicates it does. However, this requirement <u>does not permit</u> an ISO to require a resource using the electric storage resource participation model to submit offer and/or bid quantities larger than 100 kW.

H. Energy Used to Charge Electric Storage Resources

(289) ***Price for Charging Energy –*** The final rule requires that the sale of electric energy from the ISO markets to an electric storage resource that the resource then resells back to those markets be at the nodal wholesale LMP, regardless of whether the electric storage resource is

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[28] The second clause seems to imply that offers and bids can be limited to >100kW???

[29] This seems to pertain to aggregations. Note sure how an aggregation that spans LMP nodes can be properly taken into account … if that's what this means. If an aggregator has 50 kW at one node and 50 kW at another, it can submit a combined bid, but how SCED or OPF processes can clear such a bid is not obvious.

using the participation model for electric storage resources or another participation model, as long as the resource meets the definition of an electric storage resource.[30]

> *The Commission has found that the sale of energy from the grid that is used to charge electric storage resources for later resale into the energy or ancillary service markets constitutes a sale for resale in interstate commerce.*

(293) Electric storage resources should not be charged transmission charges when they are dispatched by an ISO to provide a service because (1) their physical impacts on the bulk power system are comparable to traditional generators providing the same service and (2) assessing transmission charges when they are dispatched to provide a service would create a disincentive for them to provide the service.

> *FERC found that electric storage resources that are dispatched to consume electricity to provide a service in the ISO markets (such as frequency regulation or a downward ramping service) should not pay the same transmission charges as load during the provision of that service.*

(294) This final rule does not compel an electric storage resource to purchase all of its energy for future use from the ISO markets.

While this rule requires each ISO to allow electric storage resources to be able to pay the wholesale LMP for their charging energy, it does not restrict them from paying for it at some other rate or source, such as a retail rate or charging from co-located generation.

Like other market participants that purchase energy from the ISO markets, an electric storage resource that pays the wholesale LMP for charging energy may enter into bilateral financial transactions to hedge the purchase of that energy.

(296) It may be appropriate, on a case-by-case basis, for distribution utilities to assess a wholesale distribution charge to an electric storage resource participating in wholesale markets.

(297) Efficiency losses are charging energy and therefore not a component of station power load. Accordingly, the charging energy lost to conversion inefficiencies should also be settled at the wholesale LMP as long as those efficiency losses are an unavoidable component of the conversion, storage, and discharge process that is used to resell energy back to the ISO markets and are not a component of what an ISO considers onsite load.

With respect to directly integrated and other ancillary loads, FERC provides the RTOs/ISOs flexibility to determine whether they are a component of charging energy or a component of station power.

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30 The phrase “from the ISO markets” is critical here; you can generate it yourself, buy it retail, or buy it in a bilateral arrangement. See section (294), below.

(317) ***Metering and Accounting Practices for Charging Energy –*** Each ISO is required to implement metering and accounting practices as needed to address the complexities of implementing the requirement that the sale of electric energy from the ISO markets to an electric storage resource that the resource then resells back to those markets be at the wholesale LMP.

To help accomplish this, we require each ISO to directly meter electric storage resources, so all the energy entering and exiting the resources is measured by that meter.

However, we recognize some electric storage resources (such as those located on a distribution system or behind a customer meter) may be subject to other metering requirements that could be used in lieu of a direct metering requirement by an ISO.

Therefore, the Commission will consider, in the individual ISO compliance filings, alternative proposals that may not entail direct metering but nonetheless address the complexities of implementing the requirement that the sale of electric energy from the ISO markets to an electric storage resource that the resource then resells back to those markets be at the wholesale LMP.[31]

I. Issues Outside the Scope of this Final Rule

(No relevant notes)

V. Compliance Requirements

(343) FERC finds that it is reasonable to provide the RTOs/ISOs additional time to submit their proposed tariff revisions in response to the final rule, given that the changes could require significant work on the part of the RTOs/ISOs. FERC requires each ISO to file the tariff changes needed to implement the requirements of this final rule within 270 days of its publication date.

(344) FERC is not establishing any requirements for distributed energy resource aggregations as part of this final rule.[32]

[31] This data must also be used to adjust the quantity purchased by the LSE from wholesale markets for the customer/BTM battery energy purchases and sales, for the same reasons. Otherwise, both the customer/BTM resource AND the customer are purchasing and selling the same energy for charging and discharging the battery from the wholesale market. One possible solution is one in which the customer/BTM is simply billed full retail, and reimbursed by the LSE for the difference between retail and wholesale. (However, this does not account for the complicating factor of properly accounting for the losses.)

[32] This is critical regarding some of comments presumed to be about aggregations, above.

Appendix B – Summary of FERC Order No. 2222

Summary of

FERC Order No. 2222 – Final Rule

Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators

In the following summary of FERC Order 2222, section numbers from the FERC order precede underlined section titles. FERC's paragraph numbers from which these notes are abstracted appear in parentheses preceding the notes. Notes in gray font are judged to not affect the current analysis of transactive energy and storage, but are included for completeness. Comments and/or discussion added by the authors of this report (not by FERC) are included as footnotes.

I. Introduction

(1) In this final rule, the Federal Energy Regulatory Commission (Commission) is adopting reforms to remove barriers to the participation of DER aggregations in the Regional Transmission Organization (RTO) and Independent System Operator (ISO) markets (ISO markets).

1. A *distributed energy resource* (DER) is defined as any resource located on the distribution system, any subsystem thereof or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment
2. For purposes of this final rule, *ISO markets* are defined as the capacity, energy, and ancillary services markets operated by the RTOs and ISOs.

For the reasons discussed below, existing ISO market rules are unjust and unreasonable in light of barriers that they present to the participation of DER aggregations in the ISO markets, which reduce competition and fail to ensure just and reasonable rates

(2) Barriers to the participation of new technologies, such as many types of DERs, in the ISO markets can emerge when the rules governing participation in those markets are designed for traditional resources and in effect limit the services that emerging technologies can provide. For example:

- DERs tend to be too small to meet the minimum size requirements to participate in the ISO markets on a stand-alone basis, and may be unable to meet certain qualification and performance requirements because of the operational constraints they may have as small resources.

- Existing participation models for aggregated resources, including DERs, often require those resources to participate in the ISO markets as demand response, which limits their operations and the services that they are eligible to provide.

(3) Where such barriers exist, resources that are technically capable of providing some services on their own or through aggregation are precluded from competing with resources that are already participating in the ISO markets. These restrictions on competition can reduce the efficiency of the ISO markets, potentially leading an ISO to dispatch more expensive resources to meet its system needs. By removing barriers to the participation of DER aggregations in the ISO markets, this final rule will enhance competition and, in turn, help to ensure that the ISO markets produce just and reasonable rates.

(4) Facilitating DER participation in ISO markets will provide a variety of benefits to those markets because:

a) Integrating their capabilities into ISO planning and operations will help the RTOs/ISOs account for the impacts of these resources on installed capacity requirements and day-ahead energy demand, thereby reducing uncertainty in load forecasts and reducing the risk of over procurement of resources and the associated costs.

b) They are able to locate where price signals indicate that new capacity is most needed, potentially helping to alleviate congestion and congestion costs during peak load conditions and to reduce costs related to transmitting energy into persistently high-priced load pockets.

c) They can be co-located with load and provide associated benefits.

d) Their relatively short development lead time allows DERs to respond rapidly to near-term generation or transmission reliability-related requirements, further improving their ability to enhance reliability and reduce system costs.

(5) This final rule will help enable the participation of DERs in the ISO markets by providing a means for these resources to, in the aggregate, satisfy minimum size and performance requirements that they may not meet on a stand-alone basis. Aggregations of DERs can help to address the commercial and transactional barriers to their participation in the ISO markets, such as sharing the significant costs of participating in those markets, including the costs of the necessary metering, telemetry, and communication equipment.

(6) To address barriers to the participation of DER aggregations in the ISO markets, we require each ISO to revise its tariff to establish DER aggregators as a type of market participant that can register DER aggregations under one or more participation models in the ISO tariff that accommodate the physical and operational characteristics of each DER aggregation.

(8) Each ISO's tariffs must:

1. allow DER aggregations to participate directly in ISO markets and establish DER aggregators as a type of market participant;
2. allow DER aggregators to register DER aggregations under one or more participation models that accommodate the physical and operational characteristics of the DER aggregations;
3. establish a minimum size requirement for DER aggregations that does not exceed 100 kW;
4. address locational requirements for DER aggregations;
5. address distribution factors and bidding parameters for DER aggregations;
6. address information and data requirements for DER aggregations;
7. address metering and telemetry requirements for DER aggregations;
8. address coordination between the ISO, the DER aggregator, the distribution utility, and the relevant electric retail regulatory authorities;
9. address modifications to the list of resources in a DER aggregation; and
10. address market participation agreements for DER aggregators.

Additionally:

- Each ISO must accept bids from a DER aggregator if its aggregation includes ***[only]***[33] DERs that are customers of utilities that distributed more than 4 million megawatt-hours in the previous fiscal year.
- An ISO must not accept bids from a DER aggregator if its aggregation includes ***[any]***[34] DERs that are customers of utilities that distributed 4 million megawatt-hours or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers to be bid into ISO markets by a DER aggregator.

II. Procedural History – Relationship to FERC 841

(10) This final rule arises out of the same FERC inquiry that led to Order 841, in which FERC amended its regulations to remove barriers to the participation of electric storage resources in

[33] Without the added word "only", this implies that a single DER from a >4MMWh/yr utility qualifies an aggregation for participation, even if the remainder of the DERs are in utilities with less sales. Based on subsequent expression of FERC's intent, this modification seems implicit.

[34] The intent expressed by FERC subsequently is to exclude required participation when DERs from smaller utilities (< 4MMWh/yr) are being aggregated. A strict reading suggests when they are aggregated with DERs from larger utilities, this seems to be in direct conflict with the previous clause. I.e., an ISO could be both required to allow participation of such an aggregation and prohibited from doing so. However, the inclusion of the added word "any" seems to correctly interpret FERC's intent, as expressed later.

ISO markets. Many of the responses and comments to the proposed Order 841 discussed types of DERs and general market participation issues beyond concerns specific to electric storage resources.

(11) When FERC issued its NOPR in the Order 841 proceeding, in addition to its proposed reforms to facilitate the participation of electric storage resources in ISO markets, the Commission proposed to amend its regulations to remove barriers in current ISO market rules that may prevent new, smaller DERs that are technically capable of participating in the ISO markets from doing so.

(12) When FERC issued its final rule for Order 841. it noted that more information was necessary to inform it regarding facilitating the participation of DER aggregations in ISO markets and stated that it would continue to explore DER aggregation reforms.

III. <u>Need for Reform</u>

(26) FERC affirms that existing ISO market rules are unjust and unreasonable because they present barriers to the participation of DER aggregations in the ISO markets, and such barriers reduce competition and fail to ensure just and reasonable rates.

- Specifically, current ISO market rules present barriers that prevent certain DERs that are technically capable of participating in the ISO markets on their own or through aggregation from doing so.
- Permitting DER aggregations to participate in the ISO markets may allow these resources, in the aggregate, to meet certain qualification and performance requirements, particularly if the operational characteristics of different DERs in a DER aggregation complement each other.
- The reforms adopted in this final rule will remove the barriers that qualification and performance requirements currently pose to the participation of DERs in the ISO markets.

(27) Wider scale use of DERs is enabled by increased deployment of, and improvements in, metering, telemetry, and communication technologies.

Aggregations of new and existing DERs can provide new cost-effective sources of energy and grid services and enhance competition in wholesale markets as new market participants.

(28) Individual DERs often do not meet the minimum size requirements to participate in the ISO markets under existing participation models and often cannot satisfy all the performance requirements of the various participation models due to their small size.

- In order to participate in ISO markets, DERs tend to participate in ISO demand response programs. While these demand response programs have helped reduce barriers to load curtailment resources, they often limit the operations of some types of DERs, such as electric storage or distributed generation, as well as the services that they are eligible to provide.

(29) The reforms required by this final rule will help the RTOs/ISOs account for the impacts of DERs on installed capacity requirements and day-ahead energy demand, thereby reducing uncertainty in load forecasts and the risk of over procurement of resources and the associated costs, and provide numerous other benefits.

(30) To the extent that an ISO proposes to comply with any or all of the requirements in this final rule using its currently effective requirements for DERs, it must demonstrate on compliance that its existing approach meets the requirements in this final rule.

IV. Discussion

A. Commission Jurisdiction

(39) ***Authority to Issue Regulations Pertaining to DER Aggregations*** – FERC's Authority stems from both its jurisdiction over the wholesale sales by DER aggregators into ISO markets and from its jurisdiction over practices affecting wholesale rates.

(40) Sales of electric energy by DER aggregators for purposes of participating in an ISO market are wholesale sales subject to FERC's jurisdiction, to the extent that such a transaction entails the injection of electric energy onto the grid and a sale of that energy for resale in wholesale electric markets.

(41) Market rules governing sales in ISO markets by DER aggregators from demand resources (e.g., demand response and energy efficiency) are practices affecting wholesale rates.

- This finding aligns with the decision of the U.S. Supreme Court in EPSA, which found FERC has jurisdiction over the participation in ISO markets of demand response resources: a type of non-traditional resource that, by definition, is located behind a customer meter and generally is located on the distribution system.
- The Court also found that FERC's regulation of demand response resources did not regulate retail sales.

(42) ***DER Aggregators will be Considered a Public Utility*** – subject to FERC's jurisdiction if it sells electric energy into ISO markets

- If a DER aggregator (1) aggregates only demand resources; or (2) aggregates only customers in a net metering program that are not net sellers, that DER aggregator would not become a public utility.[35]

[35] This may be very significant for demand response aggregations. Not sure FERC wanted this, but their jurisdiction over transactions involving "sales" may have prevented them from enlarging their authority here.

(43) ***Participation by DERs does not Subject a Public Utility to FERC Regulation*** – an individual DER's participation in a DER aggregation would not cause that individual resource to become subject to FERC's jurisdiction of public utilities since FERC is only exercising jurisdiction over the sales by DER aggregators into the ISO markets.

(44) ***States and Local Authorities Regulate the Safety and Reliability of the Distribution System, Including DERs*** – nothing in this final rule preempts the right of states and local authorities to regulate the safety and reliability of the distribution system, and all DERs must comply with any applicable interconnection and operating requirements.

- FERC recognizes a vital role for state and local regulators with respect to retail services and matters related to the distribution system, including design, operations, power quality, reliability, and system costs.[36]

(65) ***Opt-out Provision for Small Utilities*** – recognizing the potentially greater burden on small utility systems, FERC includes in this final rule an opt-in mechanism for small utilities similar to that provided in Order No. 719-A.

- Customers of utilities that distributed 4 million MWh or less in the previous fiscal year may not participate in DER aggregations unless the relevant electric retail regulatory authority affirmatively allows such customers to participate in DER aggregations.[37]

Each ISO is directed to amend its market rules as necessary to:

1) accept bids from a DER aggregator if its aggregation includes [only] DERs that are customers of utilities that distributed more than 4 million MWh in the previous fiscal year, and
2) not accept bids from DER aggregators if its aggregation includes [any] DERs that are customers of utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers to be bid into ISO markets by a DER aggregator.

(90) ***Interconnection Agreements*** – FERC is not exercising its jurisdiction over the interconnections of DERs to distribution facilities for the purpose of participating in ISO markets exclusively as part of a DER aggregation.

FERC does not require standard interconnection procedures and agreements or wholesale distribution tariffs for such interconnections.

[36] This is a critical statement for transactive systems, since, at least in the DSO+T formulation, they entirely involve retail market transactions (although those, in turn, affect the wholesale market prices).
[37] This clearly expresses FERC's intent. The words added in bold italics in section (8) reflect this.

(92) FERC Orders 2003 and 2006 established what some RTOs/ISOs have labeled the "first use" test, under which the first interconnection to a distribution facility for the purpose of making wholesale sales is not subject to FERC jurisdiction.

- This is because, at the time of the request, the distribution facility is not used to transmit electric energy in interstate commerce or subject to wholesale open access under an OATT.
- Therefore, the first interconnecting resource "that plans to engage in a sale for resale in interstate commerce or to transmit electric energy in interstate commerce" on a distribution facility is not required to use the transmission provider's Commission-jurisdictional Generator Interconnection Procedures or obtain a Commission-jurisdictional Generator Interconnection Agreement.[38]
- As a result, such interconnections are governed by the applicable state or local law.
- **(93)** Subsequent interconnections to the same distribution system for the purpose of engaging in wholesale sales or interstate commerce are subject to FERC jurisdiction because the distribution system is already being used to facilitate wholesale transactions and therefore are subject to an OATT.

FERC adopted this approach to avoid "allow[ing] a potential wholesale seller to cause the involuntary conversion of a facility previously used exclusively for state jurisdictional interconnections and delivery, and subject to the exclusive jurisdiction of the state, into a facility also subject to the Commission's interconnection jurisdiction."

(95) However, a large influx of distribution-level interconnections could create uncertainty as to whether they are subject to FERC jurisdiction or state/local jurisdiction, and whether they would require the use of the FERC's standard interconnection procedures and agreement.

- Increased participation of DERs in ISO markets via distributed energy will substantially increase the number of DER interconnections to distribution facilities for the purpose of engaging in wholesale transactions and/or transmission in interstate commerce.
- Such growth could increase the number of distribution-level interconnections subject to FERC's jurisdiction.
- It could additionally burden RTOs/ISOs with an overwhelming volume of interconnection requests.[39]

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[38] The meaning of "first use" here seems to be that the first use of the distribution system is to serve load, not wholesale sales from DERs]

[39] This doesn't seem to minimize the burden of obtaining a distribution interconnection agreement for DERs, only the additional burden of gaining another one at the wholesale level for DERs that will be aggregated.

(97) Since FERC is not exercising its jurisdiction over the interconnection of a DER to a distribution system for the purpose of participating in ISO markets exclusively through a DER aggregation does not constitute a first interconnection for the purpose of making wholesale sales under the "first use" test.

Interconnection of a DER resource for the purpose of directly engaging in wholesale transactions (other than as part of a DER aggregation) does constitute a "first use" and any subsequent DERs interconnecting for that purpose would be under FERC's jurisdiction for [wholesale-level] interconnection.

- The intent is to minimize any increase in the number of distribution-level interconnections subject to FERC's jurisdiction that this final rule may cause.

(98) This final rule does not require any changes to the pro forma Generator Interconnection Procedures or Generator Interconnection Agreements.

Standard interconnection procedures and agreement terms originally established in Order Nos. 2003 and 2006 and later amended by Order No. 845 will continue to apply to the interconnections of DERs that participate in ISO markets individually, independent of a DER aggregation.

This final rule also does not revise FERC's jurisdictional approach to the interconnections of qualifying facilities (QFs) that participate in DER aggregations.

(99) FERC is declining to create new universal requirements or initiate a process to standardize tariffs with respect to these matters at this time.

- Some state or local authorities may choose to voluntarily update their distribution interconnection processes to assess the impacts of DER aggregations on the distribution system at the initial interconnection stage, while other state and local authorities may not.
- In the latter scenario, it may be both necessary and appropriate for the ISO, in coordination with affected distribution utilities, to conduct separate studies of the impact on the distribution system after a DER joins a DER aggregation.
- Moreover, the electrical characteristics of the aggregation may change significantly enough over time to require restudy; therefore, RTOs/ISOs and distribution utilities may perform such aggregation restudies if necessary.
- FERC believes that coordination between RTOs/ISOs and distribution utilities, as discussed below, should ensure that RTOs/ISOs have the information that they need to study the impact of the aggregations on the transmission system.
- In general, where needed, such studies of the impact of an aggregation as a whole on the transmission system should be the only aggregation-related studies that the ISO needs to undertake.

B. Definitions of DER and DER Aggregator

(114) ***Definition a DER*** – FERC defines a *DER* as any resource located on the distribution system, any subsystem thereof or behind a customer meter.[40]

These resources may include, but are not limited to:

- resources that are in front of and behind the customer meter
- electric storage resources
- intermittent generation
- distributed generation
- demand response
- energy efficiency
- thermal storage
- electric vehicles and their supply equipment.

(115) FERC notes that energy efficiency and demand response resources are capable of providing demand reductions at customer sites, and therefore customer sites capable of demand reduction may meet the definition of a DER.

(117) DER aggregations must be able to meet the qualification and performance requirements to provide the service that they are offering into ISO markets.

- For example, because a type of resource like energy efficiency cannot be dispatched, metered, or telemetered, it would likely be impossible for DER aggregations comprised exclusively of energy efficiency resources to be able to provide energy or ancillary services to the RTOs/ISOs because the aggregation would not be technically capable of providing those services.

(118) ***Definition of a DER Aggregator*** – FERC defines a *DER aggregator* as an entity that aggregates one or more DERs for purposes of participation in the capacity, energy and/or ancillary service markets of the RTOS and/or ISOs.

- Because demand response falls under the definition of DER, an aggregator of demand response could participate as a DER aggregator. However, this final rule does not affect existing demand response rules.

C. Eligibility to Participate in ISO Markets through a DER Aggregator

(129) ***Participation Model*** – each ISO is required to have tariff provisions that allow DER aggregations to participate directly in ISO markets.

(130) Each ISO is required to establish DER aggregators as a type of market participant and to allow DER aggregators to register DER aggregations under one or more participation models in

[40] This clause excludes utility or merchant storage that are connected to the bulk system at transmission or sub-transmission voltages from being a DER and participating under FERC 2222.

the RTO's/ISO's tariff that accommodate the physical and operational characteristics of the DER aggregation.

Each ISO can comply with the requirement to allow DER aggregators to participate in its markets by modifying its existing participation models to facilitate the participation of DER aggregations, by establishing one or more new participation models for DER aggregations, or by adopting a combination of those two approaches.

(141) ***Types of Technologies*** – FERC requires that each RTO's/ISO's rules do not prohibit any particular type of DER technology from participating in DER aggregations.

(142) Each ISO is required to revise its tariff to allow different types of DER technologies to participate in a single DER aggregation (i.e., allow heterogeneous DER aggregations). This will ensure that complementary resources, including those with different physical and operational characteristics, can meet qualification and performance requirements such as minimum run times.

- FERC finds that the benefits of allowing heterogeneous aggregations outweigh the concerns regarding complexity of implementation.

(143) Concerns about RTOs'/ISOs' ability to manage a diverse set of DERs are misplaced because the DER aggregator, not an individual DER in the aggregation, is the market participant with whom the ISO would be interacting.

Moreover, the aggregator, not the ISO, would be responsible for ensuring that the DER aggregation meets applicable ISO performance and registration requirements.

(145) FERC clarifies that the participation of demand response in DER aggregations is subject to the opt-out and opt-in requirements of FERC Orders 719 and 719-A.

Therefore, if the relevant electric retail regulatory authority where a demand response resource is located has either chosen to opt out or has not opted in, then the demand response resource may not participate in a DER aggregation.

(159) ***Double-Counting of Services*** – each ISO is required to revise its tariff to:

1) allow DERs that participate in one or more retail programs to participate in its wholesale markets;
2) allow DERs to provide multiple wholesale services; and
3) include any appropriate restrictions on the DERs' participation in ISO markets through DER aggregations, <u>if narrowly designed to avoid counting more than once the services provided</u> by DERs in ISO markets.

Each ISO to describe how it will comply with this final rile by properly accounting for the different services that DERs provide in the ISO markets.

(161) For instance, if a DER is offered into an ISO market and is not added back to a utility's or other load serving entity's load profile, then that resource will be double-counted as both load reduction and a supply resource.

Also, if a DER is registered to provide the same service twice in an ISO market (e.g., as part of multiple DER aggregations, as part of a DER aggregation and a standalone demand response resource, and/or a standalone DER), then that resource would also be double-counted and double compensated if it clears the market as part of both market participants.

It is appropriate for RTOs/ISOs to place restrictions on the ISO market participation of DERs through aggregations after determining whether a DER that is proposing to participate in a DER aggregation is:

1) registered to provide the same services either individually or as part of another ISO market participant; or
2) included in a retail program to reduce a utility's or other load serving entity's obligations to purchase services from the ISO market.[41]

(162) This restriction is similar to that adopted by FERC Order 719 in the context of aggregations of demand response, which states that "[a]n RTO or ISO may place appropriate restrictions on any customer's participation in an [aggregation of retail customers]-aggregated demand response bid to avoid counting the same demand response resource more than once."

(163) There may be instances in which an individual DER could technically, reliably, and economically provide multiple, distinct services at wholesale and retail levels.

<u>The final rule requires RTOs/ISOs to address double-counting concerns</u> (see 159, clause 3).

(164) The final rule is consistent with the determination that a single DER can participate in both retail and wholesale programs and be compensated <u>in each</u> for providing "<u>distinctly different services</u>."[42]

Commenters suggested several tests to identify duplicate services, but FERC does not agree they offer a consistent or practical method to universally define "same services" across wholesale and retail markets, and therefore does not prescribe a uniform approach across all RTOs/ISOs.

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[41] Item 2) is a clear and critical statement defining double counting that is associated with reducing a retail utility/LSE's bid into the RSO/ISO market. Care must be taken in interpreting this in practice, however. If the utility is using the DER aggregation to manage peak capacity on a distribution resource, that is distinct as long as it does not also reduce the utility's coincident or non-coincident wholesale peak demand (charge). However, when it does, then it seems there is room for the ISO to disallow it (or part of it).

[42] This is also a critically important clause, with the burden of proof being that the services are distinctively different. The comment offered on section (161), above, is a good test case with uncertain outcome. It can be interpreted that the utility/LSE would have to argue that 1) distribution and utility peak loads are not always coincident and 2) it is only offering incentives tied to the distribution capacity benefit. It may be instructive to read key portions of the comments FERC received, so as to better interpret the final rule. Sections (147), (149), and (151) are included here to provide such context.

(147) FERC's original NOPR proposed that, to ensure that there is no duplication of compensation, DERs that are participating in one or more retail compensation programs such as net metering or another wholesale market participation program will not be eligible to participate in ISO markets as part of a DER aggregation. *After considering comments received, FERC rejected their original proposal as overly broad*.

(149) CAISO believes FERC's approach in the NOPR is consistent with FERC orders determining that exports to the transmission grid under a net energy metering program do not constitute a sale for resale of electricity under the FPA because these customers are, on a net basis, consumers.

(151) Some commenters argued that:

a) DERs should not receive duplicate compensation for the same service but should receive compensation for each distinct or incremental value they provide at the retail or wholesale level, and that being allowed to do so will improve efficiency and lower overall costs.

b) There is precedent for dual participation; for example, capacity markets have long avoided duplicate compensation for demand response and for generators providing multiple services at once (e.g., energy and reserves).

c) There are a number of scenarios in which providing distinct wholesale and retail services is feasible and explain that dispatch triggers for these programs usually do not overlap, which further indicates that they are not the same services.

d) Certain criteria could be used to determine when a service provides incremental value to the retail or wholesale system and/or metrics could be used to enable segmentation of time or service provided.

e) Clarification is needed so that RTOs/ISOs are not precluded from allowing DERs to provide multiple nonoverlapping wholesale services.

(172) ***Minimum and Maximum Size of Aggregation*** – FERC requires each ISO to implement on compliance a minimum size requirement not to exceed 100 kW for all DER aggregations.

FERC will consider any future post-implementation requests to increase the minimum size requirement above 100 kW if the ISO demonstrates that it is experiencing difficulty calculating efficient market results and there is not a viable software solution for improving such calculations.

(173) FERC agrees that a minimum size requirement that is lower than some existing ISO minimum size requirements will help alleviate concerns about the ability of single node aggregations to achieve the necessary minimum size, particularly given our findings on locational requirements for DER aggregations (see subsequent discussion).

(174) FERC is not adopting a maximum size requirement for DER aggregations that span multiple pricing nodes.

Also, FERC is not requiring RTOs/ISOs to establish multi-node DER aggregations (see Section D).

(179) ***Minimum and Maximum Capacity Requirements for Participating DERs*** – FERC directs each ISO to propose a maximum capacity requirement for individual DERs participating in its markets through a DER aggregation or, alternatively, to explain why such a requirement is not necessary.

Capping the maximum capacity size of an individual DER participating in a DER aggregation would ensure that larger resources are required to participate individually, thereby allowing RTOs/ISOs to independently model and verify the metering of these larger resources.

(180) FERC declines to require RTOs/ISOs to adopt minimum capacity requirements for individual DERs to participate in their markets through a DER aggregation.

(185) ***Single resource aggregation.*** Each ISO is required to revise its tariff to allow a single qualifying DER to avail itself of the proposed DER aggregation rules by serving as its own DER aggregator.

D. Locational Requirements

(204) Each ISO is required to revise its tariff to establish locational requirements for DERs to participate in a DER aggregation that are as geographically broad as technically feasible.

- Each ISO must provide a detailed, technical explanation for the geographical scope of its proposed locational requirements.
- This explanation could include, for example, a discussion of the ISO's system topology and regional congestion patterns, or any other factors that necessitate its proposed locational requirements.

Multi-node aggregations allow for greater market participation by reducing transaction costs and assembling appropriately sized resources optimized for the wholesale electricity markets.

The challenges of managing a multi-node aggregation—especially around a transmission constraint—can be overcome through coordination between RTOs/ISOs, aggregators, and distribution system operators.[43]

E. Distribution Factors and Bidding Parameters

(225) Each ISO that allows multi-node aggregations is required to revise its tariff to

[43] This rule does not prohibit multi-node aggregations, either for purposes of simplifying market clearing and dispatch or meeting minimum size requirements, it does not require the RTOs/ISOs to allow them. Rather, it leaves this up to the ISO to explain/justify in its compliance proposal to FERC.

1) require that DER aggregators give to the ISO the total DER aggregation response that would be provided from each pricing node, where applicable, when they initially register their aggregation and to update these distribution factors if they change; and
2) incorporate appropriate bidding parameters into its participation models as necessary to account for the physical and operational characteristics of DER aggregations.

Distribution factors indicate how much of the total response from a DER aggregation would be coming from each node at which one or more resources participating in the aggregation are located.

(226) This information is particularly important if the resources in a DER aggregation are located across multiple points of interconnection, multiple transmission or distribution lines, or multiple nodes on the grid.

(229) RTOs/ISOs that allow multi-node aggregations must, at a minimum, propose clear protocols explaining how a DER aggregation can provide the required information and update that information when needed.

F. Information and Data Requirements

(236) Each ISO is required to revise its tariff to:

1) include any requirements for DER aggregators that establish the information and data that a DER aggregator must provide about the physical and operational characteristics of its aggregation;
2) require DER aggregators to provide a list of the individual resources in its aggregation; and
3) establish any necessary information that must be submitted for the individual DERs.

Each ISO is also required to revise its tariff to require DER aggregators to provide aggregate settlement data for the DER aggregation and to retain performance data for individual DERs in a DER aggregation for auditing purposes.

(237) The RTOs/ISOs are required to revise their tariffs to establish any necessary physical parameters that DER aggregators must submit as part of their registration process only to the extent these parameters are not already represented in general registration requirements or bidding parameters applicable to DER aggregations.

(238) Each ISO is required to revise its tariff to require DER aggregators to provide a list of the individual DERs participating in their aggregations to the ISO.

If an ISO needs additional information beyond this list, the ISO should identify and explain in its compliance filing what additional specific information about the individual DERs within an aggregation that the ISO needs.

The ISO should also propose how the information requested must be shared with the ISO and affected distribution utilities.

As part of these tariff revisions, and as further discussed in Section I below, each ISO must also require that the DER aggregator update that list of individual resources and associated information as it changes.[44]

(239) The DER aggregator, not an individual DER in the aggregation, is the single point of contact with the ISO, and the aggregator would be responsible for managing, dispatching, metering, and settling the individual DERs in its aggregation.

(240) Each ISO is required to revise its tariff to require each DER aggregator to maintain and submit aggregate settlement data for the DER aggregation, so that the ISO can regularly settle with the DER aggregator for its market participation, and to provide, upon request from the ISO, performance data for individual resources in a DER aggregation for auditing purposes.

The requirements for settlement and performance data should be consistent with the settlement and auditing data requirements for other market participants.

DER aggregators should only be required to retain performance data for individual DERs in an aggregation that the ISO deems necessary for auditing purposes (to reduce the burden on DER aggregators and the RTOs/ISOs).

G. Metering and Telemetry System Requirements

(262) Each ISO is required to revise its tariff to establish market rules that address metering and telemetry hardware and software requirements necessary for DER aggregations to participate in ISO markets.

(263/264) The RTOs/ISOs are provided with flexibility to

a) establish the necessary metering and telemetry requirements for DER aggregation in its compliance filing; and

b) explain why such requirements are just and reasonable and do not pose an unnecessary and undue barrier to individual DERs joining a DER aggregation, e.g., why its proposed metering requirements are necessary to:

   i. provide the settlement and performance data to the ISO; and/or

   ii. prevent double-counting of services (as discussed in Section C) and/or

   iii. for the ISO to have sufficient situational awareness.

This explanation should also include

[44] This is important to transactive systems in the sense that all registration information on individual DERs must be shared with the ISO and kept up to date.

iv. whether the proposed requirements are similar to requirements already in existence for other resources; and

v. steps contemplated to avoid imposing unnecessarily burdensome costs on the DER aggregators and individual resources in DER aggregations.

(265) Given the variety of potential aggregation business models, as well as the variety of existing distribution utility requirements to which the DERs participating in aggregations will be subject, imposing standard requirements is unwarranted and could run the risk of imposing unnecessary costs on RTOs/ISOs, DER aggregators, and the individual DERs.

(268) RTOs/ISOs are <u>not</u> required to establish metering and telemetry hardware and software requirements for DER aggregations <u>that are identical</u> to those placed on existing resources, <u>or</u> to establish <u>different or additional</u> metering and telemetry requirements for DER aggregations.

Metering and telemetry requirements may vary depending on:

a) the types of DERs participating in an aggregation,

b) the size of the individual DERs or aggregated resource,

c) or the particular service provided.

For example, more granular or precise telemetry may be necessary for a DER aggregation that is participating in the frequency regulation market than one that is exclusively providing energy or capacity.

(269) Each RTO's/ISO's proposed metering requirements for settlement and auditing purposes should rely on existing telemetry infrastructure and meter data obtained through compliance with distribution utility or local regulatory authority metering system requirements whenever possible.

(270) To the extent that the ISO proposes that such information come from or flow through distribution utilities, we require that RTOs/ISOs coordinate with distribution utilities and relevant electric retail regulatory authorities to establish protocols for sharing metering and telemetry data, and that such protocols minimize costs and other burdens and address concerns raised with respect to privacy and cybersecurity.

H. Coordination between the ISO, Aggregator, and Distribution Utility

(278) ***Market Rules on Coordination*** – each ISO is required to revise its tariff to establish market rules that address coordination between the ISO, the DER aggregator, the distribution utility, and the relevant electric retail regulatory authorities.

(292) ***Role of Distribution Utilities*** – each ISO is required to modify its tariff to incorporate a comprehensive and non-discriminatory process for timely review by a distribution utility of the individual DERs that comprise a DER aggregation, which is triggered by initial registration of the DER aggregation or incremental changes to a DER aggregation already participating in the markets.

Each ISO must coordinate with distribution utilities to develop a distribution utility review process that includes criteria by which the distribution utilities would determine whether:

1) each proposed DER is capable of participation in a DER aggregation; and
2) the participation of each proposed DER in a DER aggregation will not pose significant risks to the reliable and safe operation of the distribution system.

To support this review process, RTOs/ISOs must share with distribution utilities any necessary information and data collected under Section F of this final rule about the individual DERs participating in a DER aggregation. In addition, the results of a distribution utility's review must be incorporated into the DER aggregation registration process.

(293) To balance the need for distribution utility review with the need to avoid creating potential barriers to DER aggregation, each ISO is required to demonstrate on compliance with this final rule, that its proposed distribution utility review process is transparent, provides specific review criteria that the distribution utilities should use, and provides adequate and reasonable time for distribution utility review.

(295) A reasonable amount of time may vary among RTOs/ISOs but should not exceed 60 days.

Each ISO is required to specify the time that a distribution utility has to identify any concerns regarding a DER seeking to participate in the ISO markets through an aggregation.

(296) Each ISO is required to include the distribution utility review criteria by which distribution utilities can determine that a DER

1) is capable of participating in an aggregation, e.g., the DER is not already participating in a retail DER program in which the relevant electric retail regulatory authority conditioned the resource's participation on not participating in ISO markets; and
2) does not pose significant risks to the reliable and safe operation of the distribution system.

(297) The RTOs/ISOs must include potential impacts on distribution system reliability as a criterion in the distribution utility review process.

For example, if a distribution utility determines during the distribution utility review process that a DER operated as part of an aggregation may increase voltage above acceptable limits or create potential equipment overloads, the distribution utility should have the opportunity to alert the ISO and recommend removal of that DER from the DER aggregation.

In addition, the distribution utility should have the opportunity to request that the ISO place operational limitations on an aggregation or removal of a DER from an aggregation based on specific significant reliability or safety concerns that it clearly demonstrates to the ISO and DER aggregator on a case-by-case basis.

For example, the RTOs/ISOs may consider requiring a signed affidavit or other evidence from the distribution utility that a DER's participation in ISO markets would pose a significant risk to the safe and reliable operation of the distribution system, and processes to contest the distribution utility's recommendation for removal or for operational limitations to be placed on the aggregation.

(299) Each ISO is required to incorporate dispute resolution provisions as part of its proposed distribution utility review process.

(310) ***Ongoing Operational Coordination*** – each ISO is required to revise its tariff to

1) establish a process for ongoing coordination, including operational coordination, that addresses data flows and communication among itself, the DER aggregator, and the distribution utility; and
2) require the DER aggregator to report to the ISO any changes to its offered quantity and related distribution factors that result from distribution line faults or outages.

Further, each ISO is required to include coordination protocols and processes for the operating day that allow distribution utilities to override ISO dispatch of a DER aggregation in circumstances where such override is needed to maintain the reliable and safe operation of the distribution system.

(312) Each ISO is required to revise its tariff to apply any existing resource non-performance penalties to a DER aggregation when the aggregation does not perform because a distribution utility overrides the RTO's/ISO's dispatch. This requirement will

a) ensure that DER aggregations are subject to non-performance penalties similarly to other resources participating in ISO markets.
b) incent DER aggregators to register individual DERs on less constrained portions of distribution networks in order to minimize the likelihood of incurring non-performance penalties from the ISO.

(322) ***Role of Relevant Electric Retail Regulatory Authorities*** – each ISO is required to specify in its tariff how each ISO will accommodate and incorporate voluntary relevant electric retail regulatory authority involvement in coordinating the participation of aggregated DERs in ISO markets.

(324) Possible roles and responsibilities of relevant electric retail regulatory authorities may include, but are not limited to:

a) developing interconnection agreements and rules;
b) developing local rules to ensure distribution system safety and reliability, data sharing, and/or metering and telemetry requirements;
c) overseeing distribution utility review of DER participation in aggregations; establishing rules for multi-use applications; and

d) resolving disputes between DER aggregators and distribution utilities over issues such as access to individual DER data.

Any such role for relevant electric retail regulatory authorities must be included in the ISO tariffs and developed in consultation with the relevant electric retail regulatory authorities.

Further, as noted in Section G, to the extent that metering and telemetry data comes from or flows through distribution utilities, RTOs/ISOs are required to coordinate with distribution utilities and the relevant electric retail regulatory authorities to establish protocols for sharing metering and telemetry data that minimize costs and other burdens and address concerns raised with respect to customer privacy and cybersecurity.

(330) ***Coordination Frameworks*** – because the topic of coordination frameworks is still developing and was not fully considered in this record, we encourage, but do not require, each ISO to develop a coordination framework that addresses the needs of its region.

A broader, holistic approach to coordination—referred to herein as a coordination framework—could help ensure that different elements of DER aggregations do not work at cross-purposes.

It may be beneficial for the RTOs/ISOs and their stakeholders to take into consideration in developing coordination frameworks the interoperability of new information technology and communications systems. Such systems will likely need to exchange mutually recognizable data, and will become more important as DER penetration reaches higher levels. Early consideration of these issues could help prevent redundancy and unnecessary costs later.

I. Modifications to List of Resources in Aggregation

(335) Each ISO is required to establish market rules that address modification to the list of resources in a DER aggregation.

(336) DERs in each aggregation (i.e., reflect additions and subtractions from the list) and any associated information and data, but that, when doing so, DER aggregators will not be required to re-register or re-qualify the entire DER aggregation.

(337) While any modification of a DER aggregation will trigger distribution utility review, FERC clarifies that it may be appropriate for each ISO to abbreviate the distribution utility's review of modifications to the distributed energy

Incremental impacts on ISO markets and operations that would result from the addition or removal of individual DERs from a DER aggregation, after the initial registration, are likely to be minimal and thus individual DERs should generally be able to enter and exit DER aggregations participating in ISO markets without impairing safety and reliability.

Utility review could occasionally indicate changes to the electrical characteristics of the DER aggregation that are significant enough to potentially adversely impact the reliability of the distribution or transmission systems and justify restudy of the full DER aggregation.

However, even in such circumstances, FERC does not believe that participation of the DER aggregation will need to be paused during the review of modifications or restudy, and aggregators should be able to continue to bid the unmodified portion of their aggregation into ISO markets.

(338) To the extent that an ISO requires DER aggregators to provide information on the physical or operational characteristics of its DER aggregation (pursuant to Section IV.F), each ISO is required to revise its tariff to ensure that DER aggregators must update such information if any modification to the list of resources participating in the aggregation results in a change to the aggregation's performance.

J. Market Participation Agreements

(352) Each ISO is required to establish market rules that address market participation agreements for DER aggregators. Specifically:

a) each ISO is required to revise its tariff to include a standard market participation agreement that defines the DER aggregator's role and responsibilities and its relationship with the ISO

b) an aggregator is required to execute the agreement before it can participate in the ISO markets

c) the agreement must include an attestation that the DER aggregator's aggregation is compliant with the tariffs and operating procedures of the distribution utilities and the rules and regulations of any relevant electric retail regulatory authority.

(353) FERC requires that the market participation agreements not limit the business models under which DER aggregators can operate.

Allowing DER aggregators with varying business models to be included in such agreements should increase the ability of the DER aggregators, and resources within such aggregations, to participate in the ISO markets.

(354) RTOs/ISOs and stakeholders are given the flexibility to develop appropriate agreements, and increase the ability of the distributed energy resource aggregators, and resources within such aggregations, to participate in ISO markets by better tailoring agreements to the operating conditions and needs of those markets.

The reasonableness of such proposals will be evaluated in each ISO-specific compliance proceeding.

K. Compliance

(360) Each ISO is required to file the tariff changes needed to implement the requirements of this final rule within 270 days of the publication date of this final rule in the Federal Register.

To the extent that an ISO proposes to comply with any or all of the requirements in this final rule using its currently effective requirements for DERs, it must demonstrate on compliance that its existing approach meets the requirements in this final rule.

L. Issues Beyond the Scope of this Rulemaking

(362) Some commenters raise issues that were not addressed in the NOPR; these are outside the scope of this proceeding and will not be addressed here:

a) how the deduction of behind-the-meter resources from reserve margin requirements affects price formation;

b) impacts of subsidizing resources on functioning of ISO markets;

c) capacity market mitigation policies for DERs;

d) impacts on system variability and unpredictable operation due to ISO market participation of DERs;

e) impacts of DER aggregations on distribution system operations and reliability, and necessary distribution system adjustments;

f) reflecting distribution system benefits associated with DER aggregations into ISO market operation;

g) distribution system configuration issues;

h) need for modernizing distribution system equipment, such as the deployment of DER management systems (DERMS);

i) privacy and cybersecurity concerns;

j) data collection practices during DER registration focused on attributes available for essential grid services, but not necessarily in support of a market product;

k) differing compensation for short-duration resources to account for reduced run times in the capacity market; and

l) clarification that the term electric storage resource as defined in Order 841 may include an aggregation of distributed electric storage resources.

Appendix C – Dynamic Rate Allocation Method to Recover Infrastructure Capital Costs

This section summarizes the method used to create a continuous dynamic price to recover the infrastructure capacity cost. This method was developed by Don Hammerstrom and the description below is adapted from (Hammerstrom-1, et al. 2022).

A large fraction of electricity revenues pay for infrastructure capacity. The *marginal* cost of distribution, transmission, and generation capacity is technically applicable only during the planning time domain, when the cost of additional capacity is assessed and committed. A capacity market could be conducted during planning to invite infrastructure suppliers to offer capacity to a utility's aggregate demand. Such a capacity market is not easily extensible to hourly rates. However, (Hammerstrom-2 2022) offers a novel, defensible method for allocating the annualized marginal cost of capacity among a year's hours and to consumers as they use the distribution capacity.

As illustrated in Figure C.1, the method determines the incremental power demand associated with each time period (i.e., hour) of the year, then determines the associated incremental capacity costs, and finally allocates this cost across all time periods in the year that require this incremental capacity. This results in the peak load hour having to recover the entire cost of the required incremental capacity for this hour, plus its contribution to the remaining capacity. In contrast, the cost of meeting the lowest annual load (i.e., base load) is spread across all 8,760 hours of the year. As will be shown below, this results in very low prices in most hours, and high prices in the peak hours of the year. This novel cost allocation is a smooth function of system demand, so it may be used both as a metric and as a dynamic price component.

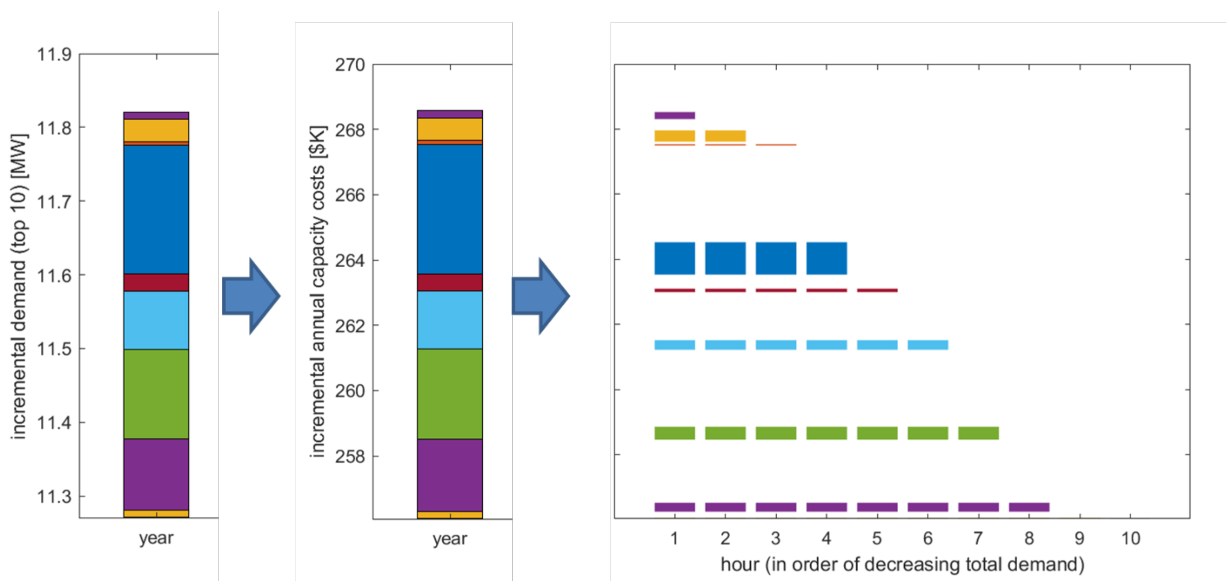

Figure C.1. Method for allocating incremental capacity cost to annual operating hours.

For this study, the novel algorithm was applied to sums of hourly PJM electricity demand in 2019 for APS transmission zone. The dynamic capacity cost price allocation was calculated as follows:

1. Estimate the amortized marginal cost of capacity for a customer class. The study assumed this method would recover distribution system ($21.6/kW-yr), transmission system ($13.9/kW-yr), and generation system ($75/kW-yr) annual capacity costs.
2. Sort the system demand by magnitude for the period of interest (2019).
3. Determine incremental demand at each hour for the sorted demand periods (ΔkW).
4. Monetize each incremental demand using the amortized marginal cost of capacity (ΔkW * ~$/kW-y = Δ$/y, an incremental yearly cost for the demand increment).
5. Divide each incremental cost by the number of periods (hours) that use its total demand or more. For example, the least hourly demand in a year is divided by 8,760 hours; the peak demand hour is divided by 1 hour.
6. Cumulatively sum the divided cost increments from lowest to highest total demand period. The result is an allocation of grid capacity cost among the time periods.
7. Divide each period's sum cost by its total demand. This is a price that allocates the marginal cost of system capacity among the time periods [$/avg. kW]. This can be used to determine a dynamic volumetric charge ($/kw-hr) that can be incorporated into a real-time price to recover capacity costs.

The results are summarized in Figures C.2 through C.4. Some important qualities of this metric should be emphasized. First, it is directly correlated to the magnitude of demand needed to supply a region. Second, like conventional demand charges, this price is allocated primarily among only the very highest demand periods, as demonstrated by Figure C.3. Finally, unlike demand charges, the impacts of this metric are large in months having high demand and become insignificant in months that do not challenge supply capacity.

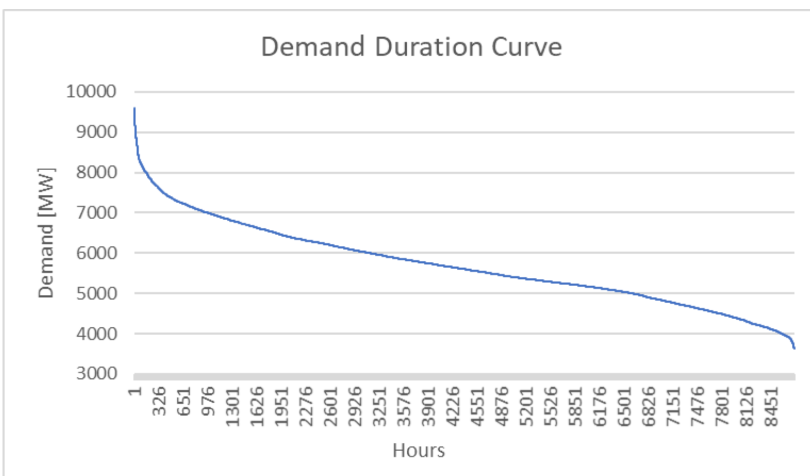

Figure C.2. Load duration curve for PJM APS transmission zone.

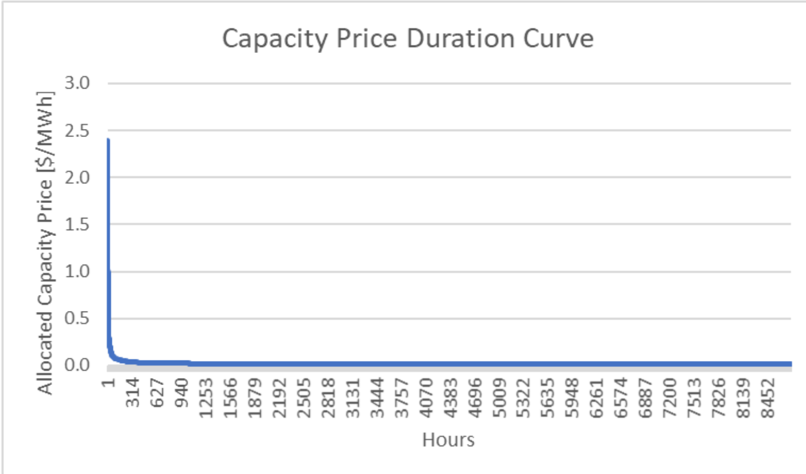

Figure C.3. Resulting capacity cost allocation duration curve.

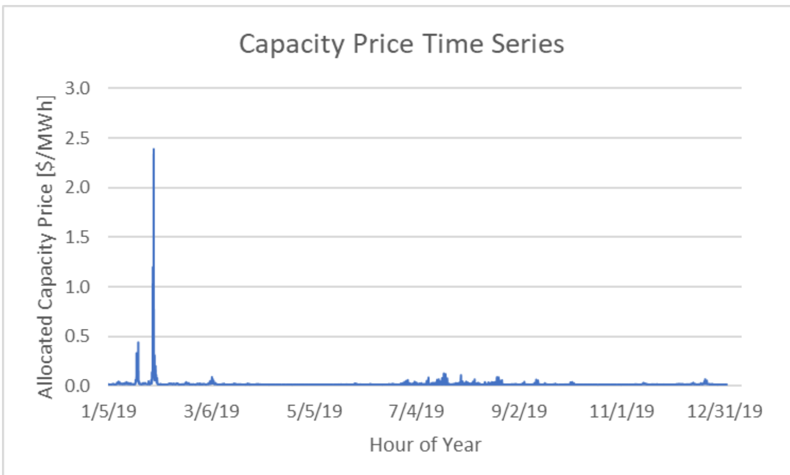

Figure C.4. Resulting dynamic capacity cost recovery price throughout the year.

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