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Opportunities and Challenges to Capturing Distributed Battery Value via Retail Utility Rates and Programs

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Prepared for the
Energy Resilience Division and Advanced Grid Research and Development Division
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Executive Summary

Distributed battery storage deployment has increased in recent years and is projected to continue as a result of customer concerns with resilience, falling adoption costs, new value streams, and financial incentives at the local, state, and federal levels. Currently, the majority of these systems provide personal value behind the meter in the form of outage protection and utility bill reduction, which often includes arbitraging net solar exports to load and may or may not align with electricity grid value. As adoption levels increase in tandem with advanced technology that enables a higher level of visibility, communication, and control, retail utilities will have an under-utilized but highly flexible resource in aggregate to support and improve electric grid operation.

This paper seeks to provide a high-level assessment on how utilities can best align their retail rates and incentive-based programs with electricity system needs in order to encourage beneficial adoption and dispatch of distributed batteries. In addition, this paper identifies a number of considerations and different implementation challenges associated with increasing this alignment and more comprehensively utilizing distributed battery resources for grid services. We focus on the retail utility perspective because these organizations have a strong understanding of their respective grid needs, have jurisdiction over systems interconnected at the distribution level, maintain an obligation to provide affordable and reliable electricity service to their customer base, and likely have established points of communication with transmission system operators.

Distributed batteries have the ability to provide a number of different services beyond solely the individual customer domain that could improve grid operation at both the distribution and bulk system levels. The value associated with each of these services can vary considerably across, and even within, utility territories. While services that are competitively procured in organized markets produce a transparent assessment of value, those procured outside of organized markets must rely on avoided costs. The ability for distributed battery owners to capture these values are driven, in part, by policies, regulations, and practices promulgated at the state and federal level, all of which have implications for how utilities design and administer their rate and incentive-based program opportunities.

Retail utility rate designs have a varying ability to provide grid services, either directly or indirectly, by how they encourage customers to alter their behavior, including decisions to adopt or dispatch their batteries. Time-based rates allow the price of electricity to reflect seasonal, diurnal, and even hourly price patterns, while rates that incorporate locational specificity can more granularly reflect geographic differences in utility incurred costs. However, utilities face challenges when trying to balance accurately reflecting dynamic grid conditions with simple and feasible designs that are customer-friendly. On one end, flat and unchanging rates are simple but provide no price signal to manage their load or DER for grid benefit. On the other end, real-time pricing provides hourly prices that more accurately align with system value, but requires a level of complexity and engagement that may lead to customer fatigue and dissatisfaction. Factors like grid constraints, load growth, DER adoption levels, and penetration of

communications and controls could influence how a utility may regard these tradeoffs and, consequently, which rate designs they may promote.

In contrast to retail rates, incentive-based utility programs allow distributed batteries and other DERs to provide direct services to the grid. Typically, these have encompassed demand response (DR) resources focused primarily on load shedding or shifting for bulk system-level services. However, over the past few years, utilities have begun to expand their offerings to include non-wires alternatives (NWAs) that provide location-specific transmission and distribution (T&D) relief and infrastructure deferral. Even more recently, virtual power plants (VPPs) that include automated controls, communication, and aggregation of multiple DERs have emerged to provide a portfolio of bulk system and/or distribution level services consistent with traditional supply-side generators. Each program has its own required level of controls and communication. Simpler programs may only require day ahead notification and manual controls while programs with more dynamic pricing and dispatch require more advanced communication and controls. Utilities may decide what types of programs and level of control and communication are necessary depending on the value of services, communication and controls in place, and DER penetration. Consequently, as with utility rate design, there are various tradeoffs between more complex programs with real time control versus cost and feasibility surrounding challenges with compensation, data management, and more. While most current programs are fairly simple, as penetration of DER and advanced controls increase alongside a better understanding of program implementation, more dynamic, automated programs could become prevalent.

Of the grid services that distributed batteries can provide via utility-administered rates or programs, many may only require a portion of the battery's capacity over an extended period, or may only require participation during a small number of hours per year. Further, provision of one service alone may not provide sufficient compensation to encourage customer participation in any single utility retail rate or incentive-based program designed solely around one service. This leaves opportunity for utilities to offer a portfolio of rates and programs that stack multiple services to optimize distributed batteries' dispatch and increase their value streams.

Recently, the industry has made considerable progress in reducing many market and policy barriers that have historically prevented distributed batteries from providing multiple grid services. Nevertheless, implementation challenges remain, especially when trying to stack services across distribution and bulk system levels. For example, the distribution utility typically has very little visibility of the real-time operation of DERs beyond any details in an interconnection agreement. This has adverse implications for the utility's effort to ensure real-time reliable and safe operation of the distribution system as well as longer-term impacts on resource planning. Further, there is little coordination between the distribution and bulk system operators. IEEE 1547-2018 standards focus on "interoperability" and require inverter-based DERs to have a local interface through which to communicate with an outside entity. For distributed batteries providing grid services dually between distribution and bulk system levels, advanced inverters could improve communication, coordination, and controls when implemented alongside protocols that address prioritization of services, compensation to avoid double counting, and protocols to ensure that provision of a service does not exacerbate grid conditions elsewhere. As more distributed batteries begin to participate in wholesale market services, distribution utilities will need to ensure, at a minimum, that DERs providing bulk system level services do not produce reliability issues at the distribution level. Further, utilities may be able to partner with third parties or aggregate resources themselves to create programs that dispatch these systems dually across both grid levels. Understanding both the time period for which a service is offered as well as the participation requirements for each service is critical to understanding which services can be stacked. Complications arise when a DER commits to providing two or more discrete services concurrently, which necessitates a high level of coordination between operators and a clear hierarchy of DER commitments. One way to address this is to separate commitments either by time, by capacity (via state of charge management), or both.

This temporal or capacity segmentation could be implemented by grouping types of grid services and exploring which utility rates or incentive programs could best address them. The four groups of services include those that are: (1) Cyclic; (2) Peak-driven; (3) Continuous; or (4) Unexpected (see Table ES-1). For services that follow cyclic, predictable patterns (e.g., seasonal or diurnal), or for those that are peak driven and occur only a few times annually with some predictability, a battery operator can plan ahead to ensure sufficient state of charge for participation. This leaves scheduled time in which a distributed battery could otherwise provide different services by segmenting participation *temporally*. On the other hand, to provide continuous (e.g., frequency regulation) or unexpected services (e.g., emergency services), a battery operator may use state of charge management to reserve some percentage of the battery's capacity. For example, the operator might specify a minimum and maximum depth of discharge to reserve appropriate battery capacity to constantly run or be on standby for high-value, unexpected events, allowing for the remainder of the battery to provide any other service- segmenting participation *by capacity*. Segmenting commitments both temporally and by capacity could be done for continuous or unexpected services that may occur more frequently or provide more value during one season over another. Table ES-1 outlines the four service types, examples of each, and which rate or program design may best align with them, considering different levels of control and communication.

Table ES-1. Identifying potential ways to segment battery commitments by type of service provided

Type of Service	Examples	Commitment Segmentation	Utility Rate or Program Offering	Metering, Communication, Controls
Cyclic	• Diurnal morning and evening ramps • Diurnal energy arbitrage	Temporal	• Time-based rates, updated to accurately represent cyclic patterns	• Hourly metering required • No automated controls • No communication beyond billing cycle
Peak-Driven	• Economic arbitrage • Resource adequacy/ capacity • Emergency DR • Location-specific T&D relief	Temporal	• Manual DR program, or dynamic time-based rates (e.g., CPP, V-TOU, or RTP) for economic services • DR or VPP programs with controls for resource adequacy, capacity, emergency DR • NWA program for T&D relief	• Hourly or sub-hourly metering required, depending on program • Communication required (coarsely, with day-ahead notice for economic services; likely more granular for reliability services such as resource adequacy, capacity, emergency DR, T&D services) • Automated controls optional for events called with advance notice, but required for programs that require instantaneous and precise response
Continuous	• Frequency regulation • Volt/VAR services	Capacity	• VPP program with controls for frequency or voltage regulation	• Metering depends on compensation structure. If compensated based on capacity committed [kW] or number of events, granular metering may not be required for compensation. However, if stacked with concurrent, performance-based services, granular tracking may be required to ensure that delivering the continuous service does not count towards, or against, participation in the other • Communications required: bidirectional and instantaneous with system operator(s) for status and availability • Automated controls required
Unexpected	• Reserves, instantaneous responses • Local reliability during short-duration outages	Capacity	• DR or VPP program with controls for reserves or contingency support	• Hourly or sub-hourly metering required for reserves or contingency services (especially if stacking with a concurrent performance-based service as described above) • Communications required: sub-hourly for reserves, instantaneous with distribution operator for local outages • Automated controls required

Minimally, temporal segmentation may not require advanced controls and communication, however, would require more customer touchpoints. On the other hand, capacity segmentation can run fairly autonomously based on operational parameters and set modes with customer interaction only necessary in order to override defaults. However, this would require advanced technology to maintain operation within set parameters, respond automatically to grid conditions, and communicate status to operators for dispatch and planning.

Region-specific macroeconomic trends, climate, load patterns, generation profiles, grid configurations, and more all drive variation in value and the subsequent implications for what a utility may offer and how a customer might choose to participate. There may be additional consequences from participating in one service that may preclude battery operators from participating in another (e.g., opting to be compensated via retail rates may preclude all participation in bulk system services). Regardless, if well-designed and successfully implemented, utility rates and programs could lead to a more efficient use of existing grid resources, lower operating costs, improved grid reliability, increased battery value streams, and alignment with policy goals that promote battery or renewable interconnection. As distributed battery adoption increases, both regulators and utilities will need to understand how these systems operate in order to, at a minimum, ensure no adverse grid impacts, but more proactively encourage provision of societal and grid value beyond the customer domain.

1. Introduction

Battery storage deployment exceeded 1.4 GW in 2020. While most of this was due to utility-scale systems, distributed adoption saw positive growth as well, especially for the residential sector (Wood Mackenzie and ESA, 2021). This growth is anticipated to persist over the next few years as battery costs continue to fall and policies at various levels enable compensation for additional value streams (Wood Mackenzie and ESA, 2021). At the utility level, availability and deployment of hardware and software have increased visibility and enabled control of distributed batteries on a more granular level both spatially and temporally. In addition, some utilities have leveraged these advances to implement rate structures that allow battery owners to reduce their bills via load management. At a state level, an increasing number of renewable portfolio standards, clean peak standards, storage mandates, and directives to include storage in resource planning have led to concentrated adoption (Twitchell, 2019). Furthermore, some states have accompanied targets with direct financial incentives, such as California's Self Generation Incentive Program (SGIP). At a federal level, recent regulations such as the Federal Energy Regulatory Commission's (FERC) Order 841 for batteries and Order 2222 for aggregated DERs have directed wholesale markets to restructure rules in a more technology-agnostic way and allow newer technologies to compete and provide any service that they are capable of providing.

As battery storage and other DER adoption increase, utilities are particularly well-positioned to act as distribution system operators and align price signals with location- and temporally-specific grid needs. Retail utilities have a strong understanding of their grid topology and condition, have a close connection to their customers, an obligation to provide affordable and reliable service, and likely have established points of communication with transmission system operators. Despite currently low visibility into DER operation, advanced control and communication technologies are becoming more prevalent. This could soon provide transparency of grid operation at higher levels of spatial and temporal granularity. In parallel, some states have policies that require or incentivize utilities to increase renewables and/or distributed resource adoption or to find alternative ways to reduce rates via infrastructure investment deferral. Such efforts will necessitate changes to grid modeling and utility business models that could provide information such as hosting capacity levels to guide interconnections, rate structures, and incentive program design.

Moreover, for utilities in organized wholesale market territories, new rules will permit DERs to join aggregations and participate in wholesale markets to provide grid services. Since distribution utilities have jurisdiction over interconnections on their system as well as distribution grid operation, they will likely retain rights to override DER operation that may cause safety or reliability concerns (FERC, 2020). Minimally, this would require distribution utilities to increase visibility of DER operation to understand consequent grid impacts of wholesale market participation. Going further, this could be an opportunity to capture additional distribution-level value via new or expanded programs administered by utilities or third party aggregators. More involved coordination of these DERs between all of these different entities may allow for increased grid efficiency, reduced costs, increased value streams for the customer, and future opportunities for optimization and coordination between all grid levels. With a growing number of states moving away from traditional net metering as well as a growing number of customers adopting batteries for resilience against infrequent outages, there is an opportunity to determine how to secure distributed battery value through more targeted rate structures and incentive-based programs that allow for stacking value across services and grid levels.

Batteries' operational characteristics make them better suited for some services than others.[1] One benefit is a battery's ability to provide instantaneous and accurate "four-quadrant" signal response in order to provide services typically provided by traditional transmission, distribution, generation, or load flexibility resources (Figure 1). Additionally, batteries' modular design allows for locational flexibility and placement at constrained locations on the grid. On the other hand, batteries are limited by the amount of power that they can charge or discharge in any given moment, as well as the duration of energy delivery. This precludes any typical distributed battery from providing long-duration services at their rated capacity. Additionally, battery operators may place limits on the number of cycles or depth of discharge to mitigate degradation and impacts from wear and tear.

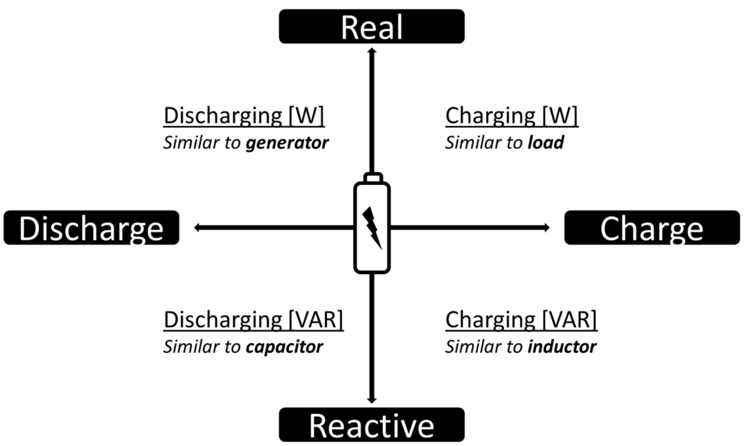

Figure 1. Four-quadrant signal response that batteries are capable of providing

Existing literature acknowledges and explores grid benefits of battery storage services (Aneke and Wang, 2016; Denholm et al., 2013a; Guney and Tepe, 2017; Katsanevakis et al., 2017; Palizban and Kauhaniemi, 2016). However, even with falling costs, some battery storage investments still may not be cost effective if designed to perform only one service (Edmunds et al., 2017; Metz and Saraiva, 2018). Many academics and industry experts subsequently acknowledge the need to increase utilization and cost recovery of battery storage assets, both utility-scale and distributed. This could be done by stacking services, which would improve battery storage economics and lead to more reliable and cheaper retail electricity delivery (Fitzgerald et al., 2015; Hledik et al., 2018; Mégel et al., 2015). Some researchers have confronted technological challenges associated with dynamically stacking services by creating feasible control strategies to optimize prioritization and dispatch of four-quadrant services either day ahead or in real time (Calvillo et al., 2016; Katsanevakis et al., 2017; Lampropoulos et al., 2015; Mégel

[1] It is important to note that, while much of this paper could apply to various battery storage technologies, lithium ion batteries are the main focus as they make up the majority of the distributed battery market at present.

et al., 2015; Namor et al., 2019; Wu et al., 2015; Xi et al., 2014). Meanwhile, other researchers have argued that market and policy barriers may prove to be a harder challenge due to market designs with operational parameters that conflict with battery characteristics (e.g., duration requirements) that rely heavily on strict classification of incumbent technology (Bhatnagar et al., 2013; Forrester et al., 2017; Sioshansi et al., 2012; Winfield et al., 2018). While recent guidance from FERC and grid operators aims to reduce these barriers, implementation challenges remain and questions persist on how the industry may shift away from separate consideration of bulk transmission system and distribution services as well as how to change participation models to be more flexible, competitive, and inclusive.

A recent body of work has focused on aggregating and dispatching distributed batteries and other DERs to maximize grid and societal benefits not fully captured by current utility business models (Burger and Luke, 2017; Castagneto Gissey et al., 2019; Fitzgerald et al., 2015; Römer et al., 2012; Wilson, 2016; Young et al., 2019). Traditionally, distributed batteries and other DERs have provided benefits at the customer level through a combination of bill management, utility or government incentives, and avoided service disruptions or outages. Utility rates and incentive-based programs have significantly affected both the adoption and operation of distributed batteries and other DERs (Darghouth et al., 2019; Hledik et al., 2018; McLaren et al., 2017; Sioshansi, 2016; Young et al., 2019; Zinaman et al., 2020). Even so, various examples show where poorly-designed utility rates have driven increased DER adoption, but have not aligned price signals with optimal dispatch (Itron, 2017; Moshövel et al., 2015; Ranaweera and Midtgård, 2016; Schreiber et al., 2015). This, in turn, has introduced strategies that may maximize value for the customer, but provide minimal or negative value to the grid and other ratepayers. This paper seeks to fill a literature gap and provide a high-level assessment on how utilities can best align their rates and programs with electricity system need, how grid conditions or regional differences may affect the ability to maximize and extract value, implementation challenges, and how multiple services could be feasibly stacked to participate in services at various grid levels.

This paper intends to provide guidance to policymakers and utilities on structuring retail rates and incentive-based programs in the near future to create opportunities that utilize distributed battery storage systems for the provision of grid services. Understanding all possible value streams and how they may vary by region will likely determine which services distributed batteries could best provide. Additional understanding will allow policymakers and utilities to determine which strategies they might want to pursue to increase utilization of existing resources and drive new adoption in locations of high value, improving distributed battery storage economics while reducing the overall cost of electricity system operation. Finally, when considering multiple value streams or dual participation[2], it is important to assess battery storage value in the context of its operational protocols, considering which suite of services may be both economical and feasible as well as the various technological and programmatic tradeoffs.

[2] Dual participation refers to a battery's participation across wholesale and retail markets. In this paper, we generalize this definition to be the participation across bulk-level (for regions without wholesale markets) and distribution-level services.

The remainder of this paper is structured as follows. Section Distributed Battery Storage Services and Enablers outlines the various services that distributed batteries are capable of providing along with a selection of federal, state, and local policies that enable them. Section 3 outlines existing utility rate structures and how they could provide price signals to better align with distributed battery value. Section 4 considers various incentive-based utility programs with and without controls such as DR, non-wires alternatives (NWAs), and virtual power plants (VPPs) that capture system value beyond that which rates can provide. Section 5 discusses considerations and implementation challenges with stacking services, dual participation, and aggregation. Finally, Section 6 introduces methods to segment battery commitments to prevent double counting along with three generic grid prototypes for which distributed batteries may be able to provide value via segmentation temporally, by capacity, or both.

2. Distributed Battery Storage Services and Enablers

2.1 Potential Services

Battery storage systems can offer a range of services due to their dispatchable, instantaneous, and accurate four-quadrant response. This enables them to operate flexibly to provide a number of services comparable to those traditionally provided by incumbent generators, transmission and distribution infrastructure (Fitzgerald et al., 2015; Forrester et al., 2017; Hledik et al., 2017; Palizban and Kauhaniemi, 2016). However, duration, cycle degradation, and other operational parameters may prevent batteries from cost-effectively providing some services. Figure 2 summarizes the response rate and duration required by benefit category (duration of response), the commitment and procurement lead time (commitment lead time), and whether they currently are competitively procured as energy, capacity/resource adequacy, or ancillary service products. Those not competitively procured include ancillary services that are not typically valued as standalone services, transmission and distribution infrastructure services that are typically rate based, and those that directly benefit the customer.

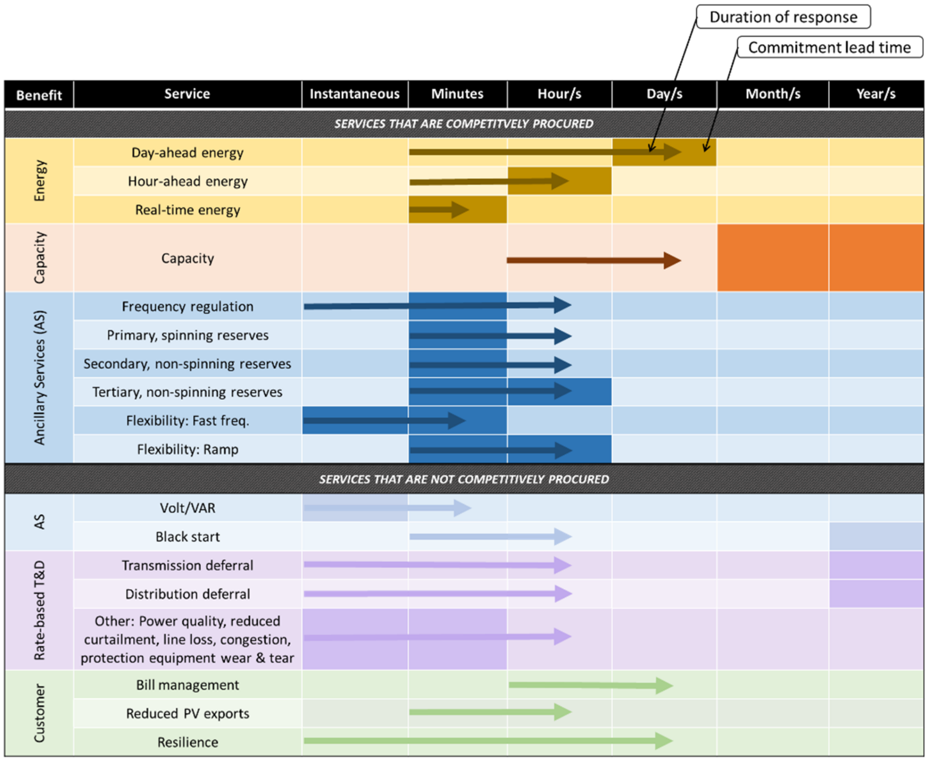

Figure 2. Services that distributed battery storage systems are capable of providing

Note: Services are organized by whether they are competitively procured. Shaded cells correspond to typical commitment schedules, while arrows correspond to common response time to a signal as well as typical duration of service commitment. This table generalizes these services. As such, some products may have different nomenclature, functions, and/or operational requirements in different regions (e.g., some regions have wholesale markets and others do not. Even within wholesale markets, capacity markets and flexibility products do not exist in some regions and specific ancillary service products may differ). For specifics on wholesale markets, Appendices A and B have more information derived from a number of sources (Hummon et al., 2013; IRENA, 2019; Katsanevakis et al., 2017; NERC, 2014; Palizban and Kauhaniemi, 2016).

In existing wholesale markets, distributed batteries have only begun to participate, and in relatively small quantities (Gundlach and Webb, 2018). Organized wholesale market rules vary, but all provide price signals to best align bulk-level supply with demand, matching fast fluctuations with instantaneous response (ancillary services), economically committing and dispatching resources minutes to a day ahead of time (day-ahead or real-time energy services), or ensuring sufficient capacity is available to meet peak demand months or years ahead of time (capacity services). In regions without organized wholesale markets, these services still exist, but their value is represented by an avoided cost as opposed to a market clearing price. In all cases, some form of resource planning, day-ahead commitment and real-time dispatch creates opportunities to procure capacity, energy, and various types of ancillary services.

Each service may have different participation rules, magnitude of value, and frequency of events. Services with shorter required response times and more temporal granularity (e.g., real-time market products as opposed to day-ahead) have greater volatility, which provide batteries with opportunities for economic arbitrage. Additionally, services with high penalties for non-performance (e.g., capacity, emergency services) may offer higher compensation, but are called upon less frequently and sometimes with greater uncertainty. Over time, values for a service may also change as demand, supply, and market rules shift. For example, compensation for frequency regulation was quite lucrative in 2012 for battery operators located in PJM's footprint (PJM, 2013), but the market was shallow and compensation fell quickly as more fast-responding resources entered the market (Sackler, 2019). Alternative value streams or flexibility to commit concurrently or sequentially to multiple services over a battery's lifetime may be necessary to ensure long-term positive net value and counteract market and regulatory risk.

While this paper focuses on the utility perspective, we include customer-side benefits in Figure 2 since they are currently the primary driver of distributed battery adoption. Grid-level value streams are often considered secondarily. As such, program design, value, participation requirements, and performance obligations will influence whether a customer may be willing to participate in a utility rate or program. Well-designed rates and programs aligned with grid need in high-value areas could result in customers providing these services, whereas poor alignment may lead to counterproductive battery dispatch that could exacerbate grid conditions. This is discussed in detail in Section 3.

2.2 Enabling federal policies

As cost reduction, technological advances, and customer preference drive battery adoption from the bottom-up, market and policy changes at the federal level will open additional value streams for DERs and promote adoption from the top-down. FERC has begun to identify and address various discriminatory or preferential organized wholesale market rules that favor incumbent technologies as opposed to focusing on the specific services desired in a technology-agnostic manner. Table 1 briefly summarizes a selection of relevant changes to organized wholesale markets and transmission tariffs. While some orders address specific technologies (e.g., Order 719 for DR, Order 764 for variable renewable energy (VRE) generators, or Order 841 for batteries), most are intended to encourage independent system operators (ISOs) and regional transmission organizations (RTOs) to increase transparency and competition that allow all resources to provide any service that they are capable of providing. Resulting market changes include the compensation of rapid and accurate response, as well as opening organized wholesale markets to newer technologies such as DR, batteries, and other DERs.

Table 1. Summary of Relevant FERC Orders

Order	Affected Markets	Brief Description
FERC 890 16 Feb, 2007	Ancillary Services, Transmission	Amends the open access transmission tariff to be less "unduly discriminatory or preferential." This allows storage technology and other "non-generator resources" to provide reliability, ancillary, and transmission services. (FERC, 2007).
FERC 719 17 Oct, 2008	Wholesale Markets	Increases competition in wholesale markets by opening participation to DR (FERC, 2008).
FERC 1000 17 Jun, 2010	Ancillary Services, Transmission	Requires regional and interregional transmission planning and coordination, promoting cost-effectiveness as well as public policy goals like lower emissions, including distributed resources, etc. Created more uniform market rules. (FERC, 2010).
FERC 745 15 Mar, 2011	Energy	Requires locational marginal price compensation for cost-effective DR resources' response to grid operator dispatch signals as if it were generation (FERC, 2011a).
FERC 755 20 Oct, 2011	Ancillary Services-Frequency Regulation	Pay for performance regulation that specifically compensates the speed and accuracy of ancillary service response. This opened up additional value streams for technologies like batteries, flywheels, and other fast-responding regulation. (FERC, 2011b).
FERC 764 22 Jun, 2012	Wholesale Markets	Requires transmission planners to allow 15-min. interval scheduling (vs. hourly), removing variable energy resource integration barriers. In return, VER generators must provide weather and forced outage data to improve transmission planning (FERC, 2012).
FERC 784 18 Jul, 2013	Ancillary Services-Frequency Regulation	To increase competition and transparency, this revises accounting and reporting requirements and expands the pay for performance regulation in ancillary services to require a two-part compensation method to reward speed and accuracy. (FERC, 2013).
FERC 825 16 Jun, 2016	Wholesale Markets	Requires wholesale markets to trigger shortage pricing as well as align market dispatch and settlement intervals in real-time markets, more accurately compensating services provided and reducing penalties to fast-ramping resources (FERC, 2016).
FERC 841 15 Feb, 2018	Wholesale Markets	Requires wholesale markets to: (1) Allow energy storage eligibility in providing any service that it is capable of; (2) compensation for charge AND discharge (e.g., can both buy and sell in energy as ancillary service markets); (3) consider operational and physical characteristic limitations; and (4) set a minimum size requirement less than or equal to 100 kW (FERC, 2018a). While some took issue over FERC's jurisdiction and ability to issue this Order, 841 was upheld by the D.C. Circuit Court on July 10, 2020.
FERC 2222 17 Sep, 2020	Wholesale Markets	After releasing a Notice of Proposed Rulemaking in Nov. 2016, FERC issued Order 2222 to allow DER aggregations to participate directly in wholesale markets via an aggregator. This Order directs ISO/RTOs to include participation models that can accommodate the physical and operational characteristics of DER aggregations, but leaves many details (e.g., locational requirements, metering, etc.) to regional decision makers (FERC, 2020).

Historically, aggregators and utilities have successfully bid distributed batteries and other DERs into markets, but as DR. With Orders 841 and 2222, FERC requires ISO/RTOs to address respective market barriers to battery and aggregated DER market participation. Doing so separately from DR accounts for their unique characteristics and improves overall market competition and efficiency. Even so, these orders are relatively new and there remain implementation challenges surrounding how markets will alter participation models to address issues of double counting, metering, coordination and control, dual participation, and more (described further in Section 5). With ISO/RTOs in different stages of rule changes and implementation, organized markets vary by the level at which they accommodate distributed battery storage participation (see Appendix A). Generally, markets that promote distributed battery participation are those that allow aggregated batteries or heterogeneous DER aggregations to participate in more services and those that have more flexible participation parameters. While not all utilities fall into wholesale market territories and some fall into markets outside of FERC jurisdiction (i.e., ERCOT), these changes cover a large portion of the country and could demonstrate how distributed batteries could provide value at the bulk level and reduce cost of operation.

2.3 Enabling state policies

Distributed battery adoption remains concentrated in specific regions, often driven by state- and utility-specific policies and practices (SEPA, 2019a; Twitchell, 2019; Wood Mackenzie and ESA, 2021). Some states address storage explicitly via energy storage targets (e.g., California, Massachusetts, New Jersey, New York, Oregon, Nevada, and Virginia) or energy storage studies that may lead to customer financial incentives or storage-specific programs (NCCETC, 2021; SEPA, 2019a). However, a series of indirect, related policies have also encouraged regional adoption. These range from state-level goals or targets, such as high clean and renewable energy standards or clean peak standards; state regulator-driven utility actions, such as grid modernization, DER integration studies, performance-based regulation, distribution system planning, consideration within integrated resource planning, and others;[3] and even utility-specific DR programs, tariffs, or interconnection practices (NCCETC, 2021).

Distributed battery adoption has been driven primarily by regionally specific customer benefits. Additionally, distributed batteries across all sectors are increasingly co-located with solar photovoltaic (PV) systems (Barbose and Darghouth, 2019; U.S. DOE, 2019). Response to utility rates is one motivator. Commercial and industrial adopters subject to high, volumetric energy and demand charges have largely adopted batteries for peak reduction and economic arbitrage (SEPA, 2019a). While batteries can mitigate peaks more generally, high VRE adoption in some regions have moved energy value from midday to evenings and have increased the difference between daily levels of high and low net load. In response, some utilities have implemented more dynamic price signals that incentivize load shifting from peak hours to hours of high VRE generation to mitigate high ramp rates. With more than a dozen states, Washington D.C., and Puerto Rico boasting 100 percent goals or mandates for clean energy resources (UCLA Luskin Center for Innovation, 2019), interconnection of additional distributed and utility scale VRE capacity will likely continue, increasing storage's potential to mitigate steep ramp periods and intermittency. For example, after changes to solar compensation tariffs that offered larger benefits for solar-plus-storage and disincentivized net grid exports, Hawaii saw an increase in battery attachment to solar (SEPA, 2019a). Similarly, California's shift to default time-of-use rates with peak periods centered in evening hours preceded an increase of battery adoption as well.

[3] One notable example is Massachusetts' energy efficiency legislation change to define efficiency as a measure that reduces peak demand as opposed to one that reduces overall electricity consumption (MA DPU, 2019). This allows for cost-effective storage (determined via 10-year levelized cost [$/kWh discharged] (Stanton, 2018)) to receive performance-based participation in 30–60 events per year, across both winter and summer seasons. This also allows for stacking incentives across other customer-side upfront incentives or bill management. The state has calculated a benefit cost ratio of 2.8 for low-income residential and 3.4 for C&I systems, which may lead to $13M of value over three years and an additional 34 MW of new storage adoption behind the meter (Olinsky-Paul, 2019).

Even with rates that provide arbitrage opportunities, current battery prices do not always allow for a purely economic investment, especially for residential customers. While still a relatively new driver, resilience has led to significant spikes in residential adoption (e.g., in Vermont and California). Parts of the Northeast and Midwest have dealt with power outages due to winter storms while other regions have experienced extreme weather events such as hurricanes in Puerto Rico and the U.S. Virgin Islands, wildfires in California, extremely cold temperatures in Texas, and others that have exposed various grid vulnerabilities. For example, Puerto Rico's recent integrated resource plan (IRP) calls for co-location of storage with generating resources that can be disconnected from the broader grid with load centers to reduce reliance on aged wires following Hurricanes Maria and Irma (Siemens, 2019). Additionally, California's residential battery market surge that started in late 2019 has been credited in large part to the public safety power outages (Wood Mackenzie and ESA, 2021). This growth is likely to continue in California as residential customers in disadvantaged and/or fire-prone areas take advantage of the amended SGIP incentive (CPUC, 2019) and as community choice aggregators acquire distributed hybrid PV/battery systems for resilience (EBCE et al., 2019). Since distributed batteries installed for resilience are only required for this primary purpose during a small subset of hours, this presents an opportunity to provide additional grid services for the remainder of the time.

Utilities across the country are well positioned to increase utilization of already-existing battery systems or guide new adoption in high-value areas as regional policies, new value streams, and resilience concerns increase potential battery value to the grid. Distributed adoption is driven by customer-side benefits. As such, without designing rates and programs aligned with grid services that encourage participation, this opportunity will not be captured.

3. Utility Rate Structures and Impacts on Distributed Battery Storage Value

Traditional electricity rates have generally been time-insensitive, especially for residential customers where 94 percent were under flat retail rates in 2019 (U.S. EIA, 2020). With general rate cases taking place relatively infrequently, flat volumetric rates cannot shift with changing value over the course of days, months, or even years and do not guarantee that operating DERs to maximize bill savings will provide commensurate grid benefits.

Time-based rates allow the price to reflect seasonal, diurnal, and even hourly price patterns. Historically, time-based rates have been offered on a very limited basis to residential and small commercial customers in part because they have required customer adoption of (and thus payment for) advanced metering to capture the temporal aspect of electricity usage. However, FERC predicts that time-based rate adoption will grow in part due to advanced meter infrastructure deployment, which reached 60 percent of residential meters and 58 percent of commercial meters in 2019 (FERC, 2019; U.S. EIA, 2020). Advanced meter deployment is far higher than that of time-based offerings, indicating upward potential for utilities to expand beyond flat volumetric rate offerings to better reflect grid value.

Of the 668 utilities that reported time-based rate offerings in 2019 through EIA Form 861, 48 percent offered any form of time-based rates to residential customers, whereas 91 percent offered them to either commercial or industrial (i.e., non-residential) customers. Further breaking this down, for those with residential and/or non-residential time-based rate offerings, the vast majority had time-of-use (TOU) rates, representing 95 percent and 87 percent, respectively (Figure 3) (U.S. EIA, 2020).

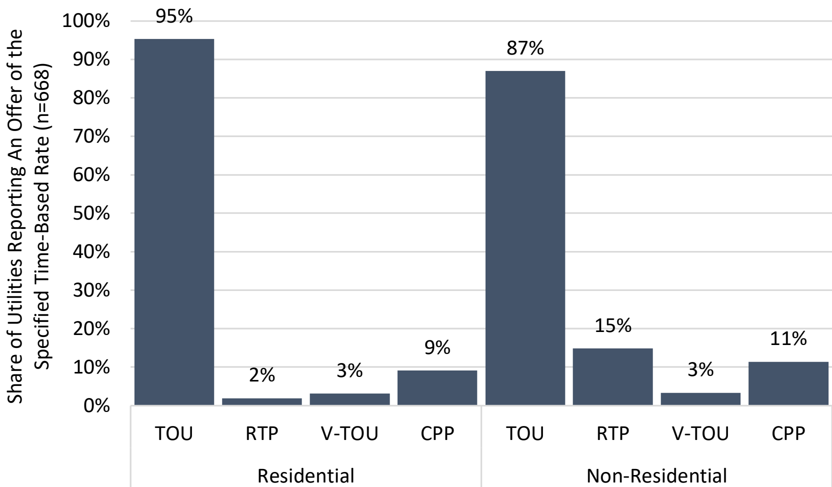

Figure 3. Breakdown of time-based residential and non-residential rate designs offered by U.S. utilities with at least one time-based rate offering (U.S. EIA, 2020)

While most time-based rates are voluntary, some TOU rates are becoming default and others may be required for certain utility programs or end-use technologies such as electric vehicle charging (Satchwell et al., 2019). TOU rates reflect general market conditions across large diurnal and seasonal time blocks, so are fairly simple for customers to understand; however, they do not capture variation beyond these general trends. Further, time-based rates derived from historic price trends do not necessarily reflect current conditions (Verzijlbergh et al., 2014). For example, as VRE adoption increases, temporal and geographic price patterns shift and could misalign new market conditions with old TOU peak periods if these trends change faster than rate case schedules (Seel et al., 2018). On the far end of the spectrum is real-time pricing (RTP), which offers dynamic rates that readily reflect contemporaneous market conditions (Table 2). These are more prevalent among non-residential offerings due to their increased complexity and variability (Figure 3). Variable TOU pricing (V-TOU) is somewhat of a hybrid between TOU and RTP (Table 2) where the periods are established *ex ante*, but the exact price that a customer may pay varies by more current (e.g., day-ahead) market conditions.[4] Though fairly new, residential V-TOU rates are offered by a limited number of utilities including Oklahoma Gas and Electric (OGE, 2018).

[4] This type of rate design is also commonly referred to as Variable Peak Pricing.

Table 2. Various utility rate structures available, both flat and time-based

RATE STRUCTURE	DESCRIPTION
FLAT	Price ($/kWh) is fixed for all electricity consumed over a given period of time (e.g., monthly).
TIERED	Price ($/kWh) varies based on blocks of total electricity consumed over a given time period (e.g., monthly).
TIME-OF-USE (TOU)	A unique but fixed price ($/kWh) is provided for two or three blocks of hours (i.e., periods) each day; these may vary seasonally.
VARIABLE TOU (V-TOU)	Blocks of hours are established similar to those of TOU rates, but the specific prices ($/kWh) within each period may vary to reflect contemporaneous market conditions. The prices for each period are usually made available in advance (e.g., the day before).
REAL TIME PRICING (RTP)	Prices ($/kWh) change on an hourly basis. They are either provided as a 24-hour schedule a day ahead of time (*ex ante*) or provided individually shortly after the operating hour (*ex post*).
CRITICAL PEAK PRICING (CPP)	Overlaid on other rate structures, a single pre-determined price ($/kWh) or sometimes variable price schedule during a narrowly defined period (e.g., summer weekday between 12 noon and 6 PM) is applied only during specific system operating or market conditions (e.g., 30-minute operating reserve shortages, wholesale prices exceed $250/MWh). Utilities may specify conditions on how events can be called such as a cap on the number of events or hours per year, a specified season or time period, and/or how much advanced notice customers must receive.
DEMAND CHARGES	Able to be combined with other rate structures, price ($/kW) is based on usage during the period (e.g., one hour or 15 minutes) of either highest customer usage over the billing period ("non-coincident") or concurrent with the maximum demand on the grid ("coincident").

Additional mechanisms may be layered onto volumetric energy rate structures, such as critical peak pricing (CPP) and/or demand charges (Table 2). These apply to only a few hours of a customer's billing period and can serve as an additional, often significant, price signal to guide net customer consumption. While demand charges often apply to one time period within each billing cycle, critical peak pricing events occur more sporadically, called with a frequency and duration dictated by grid conditions and parameterized by program design. CPP invokes substantially higher prices (e.g., 5 to 10 times the normal rate level) for some period of hours during infrequent events to provide resource adequacy and economic value. Demand charges apply to the maximum demand of electricity during a discrete time period (e.g., 15 minutes or 1 hour) at the moment of the customer's individual peak usage ("non-coincident") or the system's peak load ("coincident"). In areas with high demand charges, median levels hover around $15/kW (McLaren et al., 2017) and can make up 25 percent – 60 percent of a customer bill (Hledik, 2014), depending on the demand charge as well as the duration and magnitude of a customer's peak (Darghouth et al., 2017). Currently, these charges are more common for commercial and industrial customers rather than residential ones (Hledik, 2014). This is partly because, to manage one's bill under demand charges, customers must be aware of peak timing and have load flexible enough to shift.

On top of rate structures for purchasing electricity, various structures govern compensation for DER exports. Net metering has been the primary form of compensation in most states, valuing distributed generation at full retail rate with varying stipulations or caps on the total state net metered capacity. Some states have extended net metering to battery attachment with various restrictions on charging, exports, and/or combined capacity (NCCETC, 2021). As distributed PV penetration has increased, some states are considering alternatives to net metering (NCCETC, 2019). In locations where PV may not provide equivalent value, there may be issues with a cost shift from PV adopters to non-PV customers (Eid et al., 2014; Picciariello et al., 2015) or adverse impacts to the distribution system such as voltage violations, wear and tear of protection equipment, and other concerns associated with reverse power flow and PV's lack of inertia. A variety of successors to net metering have emerged that include disallowing net grid exports, compensating exports via net billing often at a lower rate, or solutions that seek to better align DER compensation with temporal and locational value to reflect the changing marginal cost of electricity with increasing PV. Various studies have found that these tariffs have a significant impact on a customers' decisions to adopt DERs and how to operate them (Cerino Abdin and Noussan, 2018; Comello and Reichelstein, 2017; Darghouth et al., 2016; Higgins et al., 2014; Janko et al., 2016; Satchwell et al., 2019), highlighting the importance of rate design. While this paper focuses on aligning price signals with grid value, often there are additional objectives to consider such as equity, promoting VRE and DER markets, reaching clean or renewable targets, utility cost recovery, and more.

Whether a rate is successful in changing battery adoption or dispatch may depend on its incentive level and how its design aligns with batteries' operational characteristics. For example, a high price differential or short-duration peak period would allow for batteries to offset larger portions of a customer's bill. Additionally, high values that occur outside of typical summertime peaks may also offer an opportunity unique to batteries due to unavailability of other DERs such as PV or demand response (DR) via air conditioning or pool pumps, for example. Customers aim to maximize personal value. Therefore, misaligned price signals with grid value or societal benefit can lead to adverse impacts (Arciniegas and Hittinger, 2018; CPUC, 2019). On the other hand, the combination of well-aligned price signals and rates that are easy to understand and respond to can lead customers to operate their batteries in support of high-value services.

Rates that incorporate locational specificity can further guide beneficial DER adoption and operation. While fairly nascent, one example is New York's Value Stack (NYSERDA, 2019). Under this rate structure, a DER owner can get compensation for their net exports based on the sum of day-ahead energy, capacity, environmental, and distribution system value with a locational adder specific to constrained zones.[5] The rate includes two distribution values that stand apart from DR programs and NWAs (elaborated further in this paper in Section 4) to compensate smaller DERs: (1) the distribution relief value represents the utility-specific system-wide marginal cost of service and alleviates utility-specific peaks; and (2) the locational system relief value, which only applies to specific, constrained areas on the distribution system, and only generates value by responding to utility calls (similar to the CPP response). New York went through iterations, especially for the distribution values, to balance accuracy and "predictable and reliable compensation" that establishes specific windows of compensation ahead of time and locks in values so as not to deter DER investment due to market uncertainty (NY PSC, 2019). Beyond New York, New Hampshire recently completed a locational value study to identify times and locations of high value up to $4,000/kWh (NCCETC, 2021).

[5] The energy value is determined by NYISO's day ahead market, the capacity value on NYISO's monthly installed capacity market, and the environmental value on the higher of NYSERDA's most recent Tier I REC price or NY regulator-calculated social cost of carbon.

Table 3 outlines various generic rate structures that exist today and their alignment with different services.[6] Well-designed, time-based rates often align with the marginal cost of electricity, from general diurnal patterns (TOU) to specific hourly or sub-hourly values (RTP), as well as those in between (V-TOU). Consequently, a distributed battery owner responding to a well-designed and well-aligned price signal may provide value to themselves via bill management while concurrently providing energy services to the grid (Table 3). Additionally, incorporating CPP or coincident demand charges may further push distributed battery owners to provide relief under specific times of limited generation capacity, which may additionally provide indirect transmission and distribution (T&D) relief. Since ancillary services require automated controls and real-time response, rates are not currently able to provide those services, and a utility may require a dedicated program to do so (described in the next section).

Table 3. Retail rate structures and the system values they best address

		Non-Coincident		Temporal Coincidence					Locational Coincidence
Benefit	Service	Flat Rate/Tiered	Demand Charge (DC)	DC	TOU	CPP	V-TOU	RTP	Locational value adder
Energy	Day-ahead energy			○	○	●	●	●	
	Hour-ahead energy			○		●		●	
	Real-time energy							●	
Capacity	Capacity			○	○	○	○	○	
Ancillary Services (AS)	Frequency regulation								
	Primary, spinning reserves								
	Secondary, non-spinning reserves								
	Tertiary, non-spinning reserves								
	Flexibility: Fast freq.								
	Flexibility: Ramp								
SERVICES THAT ARE NOT COMPETITIVELY PROCURED									
AS	Volt/VAR								
	Black start								
Rate-based T&D	Transmission deferral			○		○	○	○	●
	Distribution deferral		○						●
	Other: Power quality, reduced curtailment, line loss, congestion, protection equipment wear & tear		○	○			●	●	●

● Tariff design likely to address this grid service

○ Tariff design may indirectly address this grid service

Note: "Coincidence" indicates temporal agreement between the utility-level service (e.g., capacity during utility peak) and the rate level that induces a change in load (e.g., high CPP event price or coincident demand charge). Retail rates designed specifically to be coincident with a particular service are represented by a solid circle. Alternatively, retail rates that induce a change in electricity consumption that indirectly helps another grid condition are represented by a hollow circle.

Ultimately, adding both time- and location-based components to rates can guide DER adoption and operation towards higher value. Even so, there will remain additional considerations and tradeoffs. For example, rates aligned with value at one grid level may not align with values at another grid level such as the bulk system. Similarly, while coincident demand charges and CPP are designed for peak reduction

[6] This only considers existing rate structures such as real-time pricing that may provide hourly day-ahead prices, but excludes sub-hourly adjustments (e.g., transactional grid), which would assume a higher level of communication and control than is common today for residential rates.

(e.g., wholesale market-level or utility-specific peaks), non-coincident demand charges may reduce a customer's peak, but not align with grid value.[7] One primary tradeoff in designing rates is between complete alignment with real time grid value and simplicity, which impacts if a customer may respond and whether that response would provide grid value (Figure 4). On one end, flat and unchanging rates are simple but provide no price signal to manage usage or the DER for grid benefit. On the other end, RTP may accurately align with value, but requires a level of complexity and engagement that may lead to customer fatigue and dissatisfaction (Barbose et al., 2004). Additionally, rates that solely reflect real time value may not allow customers to predict their savings over the battery lifetime.

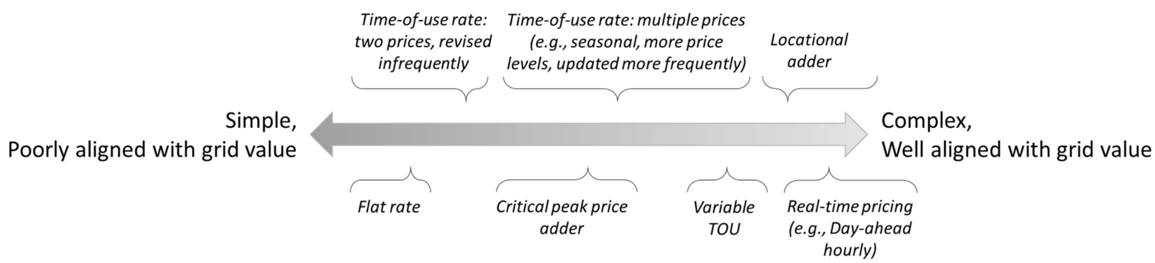

Figure 4. Illustrative tradeoffs for retail rate design between simplicity and alignment with grid value

Factors like grid constraints, load growth, DER adoption levels, and penetration of communications and controls could influence how a utility may regard these tradeoffs presented in Figure 4. Regardless, customers decide whether or not to act upon price signals, which in turn may not necessarily ensure consistent or reliable response (Cappers and Scheer, 2016). For any service such as ancillary services that requires real time response, more firm commitments via incentive-based utility programs may be considered.

4. Utility Incentive-Based Programs and Implications for Distributed Battery Storage Value

Incentive-based utility programs allow distributed batteries and other DERs to provide direct services to the grid. Traditionally this has been accomplished via DR programs that enroll customers for 6–12 month periods to provide emergency, capacity, or energy services, some of which may include up-front payments and performance penalties. However, utilities have begun to expand their offerings to include NWAs that provide localized T&D relief and infrastructure deferral and, even more recently, VPPs that include automated controls, communication, and aggregation of multiple DERs to provide services consistent with traditional supply-side resources.

Although DR, NWAs, and VPPs differ substantially in how they enroll customers and the terms of their commitments, they do share a set of common design characteristics organized into three program

[7] For example, a battery in an area with high distributed PV adoption experiencing net exports midday may be incentivized to charge. However, the bulk system at the same moment may be signaling a high value for capacity or energy services.

design archetypes: Manual, Configurable, and Direct Control (see Table 4). Manual program events often require more advanced notice, but less sophisticated communication technology (e.g., text messages and email) and no automated controls. This may lead to more uncertain participation and performance, both of which can lower the value of the response and subsequent compensation. On the other end of the spectrum, Direct Control programs require automated control by program operators. In between these two extremes lie Configurable programs that incorporate customer preference and override. The two latter program types generally require additional communication equipment for the utility to measure and verify responses, but also often offer higher compensation than manual programs due to increased performance requirements such as financial penalty or disqualification for non-performance. DR and some NWA programs cover the full range of program design archetypes while VPPs and other NWAs in particular usually involve communication and controls to provide a more firm and dependable resource, limiting them to Configurable and Direct Control. This allows for firm commitments and consideration in planning processes to defer infrastructure expenditures or capacity services that may require a specific level of performance for reliability, grid planning, or modeling. In these cases, Direct Control programs would ensure participation, while Configurable programs would likely require some degree of oversubscription to account for customer override. While these programs do exist, and while states are beginning to consider DERs in distribution and integrated system planning (NCCETC, 2021), they are not as common at the residential or commercial level. In fact, of those residential and commercial customers in 2019 who had advanced metering infrastructure, only 55 and 54 percent had daily digital access to their usage and only 6 and 1 percent had direct load control capabilities, respectively (U.S. EIA, 2020).

Table 4. Common characteristics of utility incentive-based programs

Program	Description
MANUAL	Programs that do not require any automated response by participants to utility event signals. Thus, they are technology agnostic and do not require advanced communication capabilities (e.g., telemetry) with system operators. The event signal is usually provided well in advance (2–24 hours) and is often restricted to a certain set of hours and may only be dispatched a certain number of times per year. Such programs usually provide bulk-power system emergency services, much like capacity services but without certainty of performance. These programs have not yet begun to provide any distribution system services.
CONFIGURABLE	Programs that require some form of automated response via a controllable technology to utility event signals but allow customer override. They may or may not require some form of advanced communication capabilities (e.g., telemetry) with system operators. Although the event notification may be provided well in advance (1–24 hours), communication between the program administrator and the device may be as frequent as every hour to every five minutes. The frequency and timing of events may or may not be restricted to a certain number of events per year/season or set of hours, respectively. The event period may be quite long, even if actual events only comprise a small subset of the hours. Such programs usually provide some form of capacity, energy, or non-spinning operating reserve services. These programs may also provide capacity relief of substations at the distribution system level.
DIRECT CONTROL	Programs that require fully automated response via a controllable technology to utility event signals that do not allow customers to override the event signal. These programs likely require some form of advanced communication capabilities (e.g., telemetry) with system operators to signal DER status and availability one way and set desired operation the other way. Apart from customers' inability to override, much of the design elements are similar to Configurable programs.

Adapted from Cappers et al., 2016

4.1 Demand response

Demand response programs originally served as a reliability resource via strategic load shedding (Wedgemere Group, 2016). However, as system planners and operators realized that such resources could be used for other purposes, they began using them for economic reasons to reduce load during sustained high priced periods (Bharvirkar et al., 2009) or to provide ancillary services through fast and precise load shedding (Cappers et al., 2013). More recently, utilities have created programs that also include signals to *increase* a participant's consumption to use excess or low-cost energy from the grid (SEPA, 2019b).

While retail utilities outside of organized markets may use their DR programs to directly reduce their operating costs, those within wholesale market territories have additional options. One option is for retail utilities to aggregate DR resources to deliver grid services under their own unique terms and conditions (Cappers et al., 2010) or compete directly with programs put forth by the ISO/RTO (Cappers and Satchwell, 2015). In these cases, DR participants would not formally be considered wholesale market resources, but would instead affect metrics that the ISO/RTO uses to subsequently allocate costs and/or set requirements that may indirectly impact bulk system operations and planning. For example, DR could reduce coincident peak demand to lower the utility's installed capacity requirement in the following year. Alternatively, retail electric utilities could opt to have resources participate directly in wholesale market opportunities by aggregating DR resources to reach ISO/RTO minimum capacity or duration requirements (Cappers and Satchwell, 2015). In these cases, the utility would act as an intermediate party connecting program participants with opportunities to directly engage in wholesale markets.

Where retail utility DR programs are technology-agnostic, distributed batteries have participated as performance and operational requirements have allowed.[8] Even so, there remain challenges that limit participation. For example, such programs generally do not provide sufficiently long contract terms (i.e, 1-12 months), which can create uncertainty around the payback period for distributed batteries. Due to the legacy nature of most DR programs, customers' net load reductions are credited while distributed battery exports are not. Lastly, very few utility DR programs are designed with a premium payment for more rapid response, which could provide additional value that batteries are particularly capable of providing. A notable exception exists in New York, where recent adjustments to utilities' dynamic load management products and procurement now include three-year terms, credit for exports, and a new product to pay a premium for rapid response (i.e., Auto-DLM 10-minute response) (NY PSC, 2020). It is important to note that other states have implemented rules that address a subset of these

[8] Retail DR program barriers to battery participation could come in a few forms. For example, technology-specific programs could specify subscription only from a programmable thermostat. Another example could be a program with incompatible performance requirements and operational specifications to receive compensation such as long duration requirements. Another main barrier is that traditional retail DR programs primarily measure performance based on historical operational baselines as opposed to actual metered response. Thus, for DERs that change net load such as PV and batteries without separate metering, the resulting baseline will not accurately reflect gross load, resulting in a level of compensation not commensurate with the level of grid services provided.

barriers (e.g., Hawaii's Fast Demand Response) or have created opportunities for batteries outside of DR, such as in the NWAs and VPPs described in the following subsections.

These challenges extend to batteries in wholesale markets as well, where utilities could act as an aggregator, or partner with a third party, to aggregate and dispatch distributed batteries and other DERs. Though ISO/RTOs are in early stages of implementing rules for aggregated DERs, some already have preexisting structures for DR resources (see Appendix B). However, changes in response to Orders 841 and 2222 will better account for batteries' additional limitations (e.g., duration) and opportunities (e.g., fast response and capability to schedule dispatch for any hour or season)[9] (SEPA, 2019b), and these aggregations will be able to set prices and provide market services on both the supply and demand side. Given market-specific parameters and requirements, ease of participation in these new wholesale market opportunities through retail utility DR programs may vary.

4.2 Non-wires alternatives

In contrast to traditional DR programs that have focused on grid services such as energy and capacity, retail utility NWA programs provide T&D system services through DERs (Cappers et al., 2016; Satchwell and Cappers, 2018). These programs manage a portfolio of DERs to defer or avoid capital expenditures on traditional T&D infrastructure. T&D avoided costs are often low for the majority of locations, but specific nodes/zones may have extremely high value due to constraints or imbalances from locational load patterns or grid configuration.

NWA programs differ from traditional retail DR programs in a number of ways. They are location-specific as opposed to territory-wide (Imani et al., 2019). Moreover, the services acquired do not necessarily align with existing markets or other price signals. Instead, value is determined by engineering constraints and local grid configurations, which are typically addressed via capital expenditures recovered through the rate base. Consequently, resources are usually procured via request for proposals, auctions, or are aggregated through utility programs with more strict performance-based compensation (Feldman, 2017).

Presently, NWA programs are not pervasive in the electric utility industry, but rather are just now being pursued for a number of reasons (Satchwell and Cappers, 2018). The biggest hurdle has been that traditional utility rate of return regulation incentivizes increased capital expenditures as opposed to programming for non-utility-owned assets (Kihm et al., 2017). Other notable challenges include the time and uncertainty required to enroll customers, execute contracts, and interconnect all DERs necessary for a NWA when compared to installing a traditional T&D solution. Unlike using an RFP to

[9] For example, emergency DR programs may be based off of a summer system peak, not accounting for the seasonality of resource adequacy. However, some regions like the Midwest are seeing an increased need for demand response during winter hours when large, flexible loads such as air conditioners or pool pumps and other resources such as PV solar are not available. Here, dispatchable DERs such as batteries that are not restricted by seasonality may serve as a valuable resource.

perfectly size the needed resource to address the T&D need, NWA programs run the risk of over- or under-procurement.

Accordingly, NWA programs exist almost exclusively where states have introduced supportive policies such as performance-based incentives and consideration in integrated resource and distribution system planning (E4TheFuture et al., 2018; Leader, 2020; NCCETC, 2021; Schwartz, 2020). Even where these policies exist, remaining challenges have sparked additional innovation. California recently created the Partnership Pilot to address various outstanding issues and better allow DER aggregations to defer utility expenditures (CPUC, 2021).[10] To alleviate risk of under-procurement, the execution of the utility contract triggers only upon reaching 90% procurement, while risk of over-procurement is alleviated by a closure of subscriptions at 120% procurement. Finally, to ensure cost effectiveness, there is a total cost cap at 85% of what the wires upgrade would cost.

Batteries are particularly capable of providing T&D grid services where peaks are short in duration or where continuous services require small, instantaneous injections or withdrawals. In areas of uncertain load growth projections or uncertain avoided costs, Manual or Configurable programs may be sufficient. However, in highly constrained areas with high value and high reliability risk, Direct Control program archetypes may be required for reliable participation, response time, and cost-effectiveness (E4TheFuture et al., 2018). Since NWA resources may only be called upon for a select few number of hours or days in the case of local peak reduction, this provides an opportunity for utility programs that may allow stacking these resources with other services.

4.3 Virtual power plants

Even more nascent than NWAs, some utilities have begun to develop VPPs, which allow aggregated DERs to provide numerous services similar to those of supply-side generation resources. As is the case with NWAs, VPPs use a commitment process to provide a more dependable resource. VPPs also face similar ratemaking policy challenges due to utilities' incentives towards capital expenditures and inability to earn a return on customer assets or benefit from ownership.

VPPs could allow utilities more control and ability to capture a wider array of services from distributed batteries and other controllable DERs. In this paper, VPPs are considered to be DERs with controls and communication, aggregated at a location and grid level for which the services will be provided (e.g., the location and level of aggregation could be as wide as a transmission zone or as granular as a neighborhood or distribution circuit). These aggregated, controllable DERs could together provide flexible grid services at the distribution level or bid into organized wholesale markets similar to supply-side resources. Similar to NWAs, these VPPs would provide the most value via a Direct Control program, but could also be designed as Configurable programs for voluntary services.

[10] Under the Partnership Pilot, the utility would pay the participant via four tiers: (1) payment upfront would compensate DER installation and commitment, (2) payment for participation during test events, (3) payment to reserve capacity during a specified timeframe, and (4) payment for dispatch

While there have been multiple examples of aggregated DER programs in the past (Cook et al., 2018), recent months have seen a surge of various VPPs (see Appendix C for recent examples that include distributed batteries). Within this collection, there are a few firsts-of-their-kind opportunities with a bid of aggregated solar plus storage into a wholesale market. For example, Sunrun's bid of 20 MW into ISO-NE's forward capacity market and Green Mountain Power's battery-specific tariff that expands upon their Bring Your Own Device VPP. Though there only exists a small list of VPP programs, there are some notable commonalities. The aggregations include customer-sited batteries or other controllable flexible load in addition to non-controllable DERs such as solar. In most cases, these DERs are customer-owned, but controlled directly by either an aggregator or the utility itself in exchange for an upfront payment, a discount on the DER investment cost, or monthly payments per kW enrolled. Differences across these recent examples pertain to the types of grid services provided. For example, some programs that more closely resemble DR programs may use these aggregated DERs for distribution-level peak management to provide congestion relief or defer infrastructure expenditures. Other programs are actively exploring how to maximize value over multiple services that include continuous services such as frequency regulation and volt/VAR control in addition to peak services. In these cases, the distribution utility is involved either directly or indirectly through an aggregator. Finally, at the bulk level, there is a subset of programs focused on wholesale market services in addition to, or exclusive of, distribution-level services.

Recent VPPs have largely focused on the residential sector. This may be due to commercial and industrial customers primarily using batteries and other DERs for more frequent and more profitable utility demand charge management, while residential customers are primarily interested in resilience. Some programs account for this and ensure a minimum state of charge around 20% at all times and charge fully ahead of anticipated extreme weather. For the primary function of resilience, the battery is engaged fully only in rare cases, which presents opportunities to use these batteries and other DERs for additional value streams. While in early stages, VPPs have the potential to provide reliability, resilience, and economic grid value, and may additionally support policy goals such as increasing renewable energy supply or supporting targets for battery and DER adoption.

4.4 Grid service alignment with batteries participating in utility programs

Table 5 outlines the different services that batteries enrolled in DR, NWA, and VPP programs could provide under various program design archetypes. Understandably, a higher degree of control allows for more services. The suite of services range from those provided by Manual DR to those provided by a VPP with controls. DR has demonstrated its capabilities in providing all competitively procured energy, capacity, and ancillary services that benefit from load shedding or shifting. NWAs are specific to T&D deferral, but directly provide additional benefits such as reduced line losses and congestion. We only consider VPPs with controls, which can provide all competitively procured services in addition to utilizing reactive power for additional services such as voltage support, reduced wear and tear of protection equipment, power quality issues, and more. While VPPs could conceivably provide black start services in the future, this is still in demonstration phase[11] and thus not marked on Table 5.

Table 5. Utility incentive-based programs and alignment of system benefits

Benefit	Service	Controls (Direct Control, Config.)			Manual	
		DR	NWA	VPP	DR	NWA
Energy	Day-ahead energy	●		●	●	
Energy	Hour-ahead energy	●		●	○	
Energy	Real-time energy	●		●		
Capacity	Capacity	●		●	○	
Ancillary Services (AS)	Frequency regulation	●		●		
Ancillary Services (AS)	Primary, spinning reserves	●		●		
Ancillary Services (AS)	Secondary, non-spinning reserves	●		●	○	
Ancillary Services (AS)	Tertiary, non-spinning reserves	●		●	○	
Ancillary Services (AS)	Flexibility: Fast freq.	●		●		
Ancillary Services (AS)	Flexibility: Ramp	●		●	○	
SERVICES THAT ARE NOT COMPETITIVELY PROCURED						
AS	Volt/VAR			●		
AS	Black start					
Rate-based T&D	Transmission deferral		●			○
Rate-based T&D	Distribution deferral		●			○
Rate-based T&D	Other: Power quality, reduced curtailment, line loss, congestion, protection equipment wear & tear	○	●	●	○	○

● ● ● Utility program design likely to address this grid service (Black for DR, Grey for NWA, Light Grey for VPP)

○ ○ ○ Utility program may indirectly address this grid service (Black for DR, Grey for NWA, Light Grey for VPP)

While batteries are duration limited by capacity and state of charge, their availability is less temporally or seasonally dependent and does not impact customer comfort. This allows them to provide services in hours that other DERs cannot. Furthermore, traditional DR resources have almost exclusively focused on shedding and shifting load from one time period to another. Batteries can additionally respond to events in which they add load to the system via charging (e.g., to reduce VRE curtailment during overproduction) or provide reactive power services that DERs without advanced inverters are incapable of.

When designing utility programs, there exists a similar tradeoff as with rates in the previous section. Whereas with rates the tradeoff between alignment with grid value and simplicity influenced customer participation, here, the tradeoff affects utility cost and resources. Taking full advantage of grid value may necessitate more pricey and advanced controls and communication along with new protocols

[11] See National Grid's Distributed ReStart pilot at https://www.nationalgrideso.com/future-energy/projects/distributed-restart

pertaining to coordination with DERs, customers, and potentially third parties; increased data collection and processing; altered or new compensation mechanisms; and new methods to incorporate DER impacts into forecasting and integrated resource planning (Figure 5).

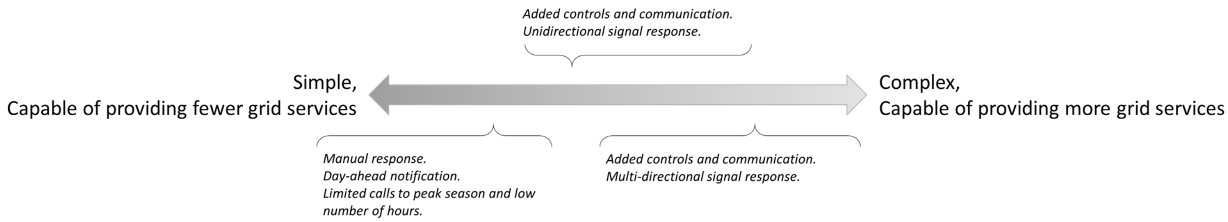

Figure 5. Trade-off for utility incentive-based programs

Note: "unidirectional" here refers to signal response in one of the four-quadrant directions (charge real power, discharge real power, charge reactive power, discharge reactive power) while "multi-directional" indicates signal response in more than one direction.

Complexity comes in the form of technology required, participation rules, compensation structures, data management, modeling, and more. Simple manual programs require no automated controls, very basic communication structures, and data at hourly intervals for performance verification. These may be sufficient for predictable, peak-driven services. However, for more dynamic or unexpected services, additional controls and communication may be necessary. This can be done easily for services that are priced externally and only require signal response in one direction (e.g., emergency resources that signal discharging). In these cases, configurable or direct control utility program can easily determine performance by summing the total response across the time period with advanced metering. This becomes more complex if using the battery for rapid response in more than one direction (e.g., quickly charging and discharging for frequency or voltage regulation as a VPP). In these cases, utilities can still manage the level of data collection by paying to reserve and use the system's capacity (e.g., $/kW-month, $/kW-event) with agreed-upon operational parameters and restrictions that are automatically maintained (e.g., restrictions for levels of dis/charge, mileage,[12] cycling, state-of-charge management, duration of use, or frequency of use within a time period). This requires advanced technology to receive signals from the grid and instantaneously respond via a direct control utility program. Currently, this can be done with technology such as advanced inverters, but DER management software may play a large role in the future as the technology matures and adoption increases.

5. Considerations and Implementation Challenges of Extracting Full Benefits of Distributed Battery Storage

We have shown that customers with distributed batteries have the ability to provide various types of grid services either through utility incentive-based programs or in response to different retail rate

[12] *Mileage* is the summation of the up and down response of a battery. For example, if a battery was used to charge 1 kWh for 30 minutes and discharge 1 kWh for 30 minutes, hourly data collection would average no response. However, if data were collected with sufficient time granularity to mark when the directional response switched, the mileage would be calculated as 2 kWh (this could be generalized to kVA-hr).

designs. Many of these grid services may only require a portion of the battery capacity or only require participation during a small number of hours per year. Further, provision of one service alone may not provide sufficient compensation to encourage customer investment or participation in utility rates and programs. This leaves opportunity to stack multiple services to optimize distributed batteries' dispatch and increase their value.

While there have been recent increases in DER adoption and advanced technology to manage and coordinate those DERs, there remain implementation challenges to successfully aggregating and stacking distributed battery services.

5.1 DER Coordination with the System Operator

Distribution utilities are responsible for delivering electricity reliably, safely, and affordably. They have jurisdiction over batteries and other DERs that interconnect at the distribution level, and are tasked with identifying and mitigating any negative grid impacts. At present, the distribution utility typically has very little visibility of the real-time operation of DERs beyond any details or parameters included in an interconnection agreement. This has adverse implications for the utility's ability to ensure real-time reliable and safe operation of the distribution system as well as longer-term impacts on resource planning. Currently, industry efforts around improving communication, coordination, and controls between DERs and the distribution utility is happening in the context of inverter-based DER interconnection requirements such as IEEE 1547-2018 (IEEE, 2018) and California's Rule 21 (CPUC, 2020).

Among other capabilities, IEEE 1547-2018 includes language on "interoperability" and requires the DER to have a local interface through which to communicate with an outside entity (IEEE, 2018). While the capabilities are required, use of them is not. This leaves utilities and other stakeholders with an opportunity to tap into these capabilities to inform modeling and grid planning, improve safety and reliability, and use distributed batteries and other inverter-based DERs for grid services and additional value streams.

California's Rule 21, which was the basis for certain elements in IEEE 1547-2018 (i.e., Category III) and the process for developing it, provides insight into how a state may use advanced inverters to improve communication, coordination, and controls between utilities and DERs. Various state-level working groups identified, and subsequently addressed, questions concerning which communication and technical functions inverter-based DERs should provide as well as future priorities that would allow such DERs to be more responsive to dynamic grid conditions, provide a wider suite of services, and avoid costly grid upgrades to interconnect while still ensuring grid safety and reliability. Consequently, California recently introduced new rules and definitions for non-export and limited-export DERs. This allows for a higher penetration of batteries and other inverter-based DERs without sacrificing grid reliability that, in turn, opens up the possibility of higher utilization of these DERs. Specifically, the changes allow for speedier and cheaper interconnection of non-export systems via a fast track. Additionally, newly-defined limited-export systems utilize inverter operational modes to allow for submission of a profile to determine a maximum export limit, which would allow the system to be considered for interconnection at that size (whereas previously, these systems were considered as the sum total of their installed capacity) (CPUC, 2020).

Rule 21 begins to demonstrate a scenario in which retail utilities' engagement can lead to increased distributed battery and other DER adoption while maintaining and potentially improving grid efficiency and performance. For example, an advanced inverter could allow for a dynamic generating profile (i.e., varying maximum export limits that correspond to dynamic grid conditions) seasonally, monthly, or even hourly at the utility's discretion in order to maximize DER utilization. Another example could include a DER responding directly to dynamic grid conditions or real-time utility signals. Rule 21 acknowledges that this may only be attractive as DER penetration increases, once IEEE 1547-2018 is fully implemented, and with the introduction of a utility DER management system (DERMS). Nevertheless, state regulators in California want to prioritize this and have provided deadlines (after standards are approved) for utilities convening to refine specifications for non-default inverter settings, allow for varying maximum export values, and for presenting a DERMS roadmap (CPUC, 2020). With additional adoption levels and processes for control, communication, and coordination come additional opportunities and resources for retail utility programs and tariffs.

These control and communication technologies will increase visibility of DERs not only to the retail utility, but potentially to grid operators at the bulk system as well. For DER aggregations participating at the bulk system level, the aggregator has the responsibility of meeting performance and registration requirements, complying with the same rules as other individual wholesale market participants, providing some level of visibility on the individual systems, and settling with individual DERs (FERC 2020, Eisenhardt, 2020; CAISO, 2019d). These technologies would enable aggregators to communicate between DERs and system operators in real time to provide an aggregation's availability and status as well as verify performance when dispatched.

5.2 Coordination between Retail & Wholesale Market Operator

The distribution and bulk system levels have remained separate for the most part in terms of visibility, modeling, and the communication and coordination protocols required. However, recent movement towards a paradigm of stacking services and committing distributed batteries and other DERs across grid levels will require greater coordination between retail and wholesale market operators and program providers.

The concept of stacking services infers that a DER is providing several *different* services. However, there are two key issues when considering the limitations that can and should be imposed on stacking services to avoid conflicts in procurement and excess compensation. First, identifying the time period in which a service is offered is critical when characterizing and defining what constitutes stacked services. For example, a DER participating in a retail export compensation program (e.g., net metering) is providing continuous grid energy services, as it will be compensated for any change to net load. In contrast, a distributed battery that is exclusively enrolled in an organized wholesale market emergency

DR program is only providing a grid service within very discrete time periods. Second, identifying the particular grid service being offered is likewise critical when characterizing and defining what constitutes stacked services. For example, a distributed battery system could remove load from the system to mitigate an overloaded substation or a shortage in operating reserves. Although the use of the battery and its impact on the grid are identical, the particular services being offered are distinctly different. The identification of the specific time period in which grid services could be provided has created some industry-accepted boundary conditions for when it is acceptable to stack services, and when it is not. For example, the very nature of continuously providing a single grid service to the retail utility via net metering precludes any opportunity to provide any service at another grid level (FERC, 2020; CAISO, 2019b). In contrast, a DER providing a specific grid service at one discrete time period separate from a different grid service at another discrete time period is clearly incremental and not in conflict with one another. Complications arise when a DER provides two or more discrete services concurrently, which may or may not be reasonable.

One way to begin to address this complication is to increase the level of coordination between the distribution and bulk-power system operators. A simple but effective approach would be to create a clear hierarchy of DER commitments to allocate the real-time availability and reliability of performance for each planning entity and grid service, similar to what has been proposed or pursued in California and New York (CPUC, 2018a; NY DPS and NYSERDA, 2018). This could give distributed batteries at the customer domain the ability to provide multiple services at every level of the grid, both within and outside of organized markets. California's regulators proposed one way to do so, which would be to define three distinct and independent types of multiple use cases: (1) time differentiated, (2) capacity differentiated, and (3) simultaneous (CPUC, 2018a). In these cases, the battery operator would guarantee performance to a grid operator thereby ensuring full compensation by: (1) committing its full capacity during a predetermined time period, (2) committing a specified level of capacity to a service continuously via state of charge management, or (3) both. Together with granular data collection or controls to verify performance, this could address concerns with double counting and ease coordination across grid levels. Other states, such as New York, have begun to incorporate similar ideas of differentiated use cases such as "time stacking" and explicitly allowing DERs to bid into the wholesale market while not precluding them from providing distribution grid-level services. NYISO rules require participants to specify whether the entire unit is available for wholesale market services ("ISO-Committed" mode) or for retail utility or customer services ("Self" mode) during a scheduled time (Lavillotti and Smith, 2019).

Such hierarchical approaches would still likely need additional information and data sharing between both system operators and the DER or aggregator. For example, NYISO committed to implementing a process that allows for grid operators and market participants to contact NYISO and request scheduling changes to meet respective local reliability needs, requiring retail utility engagement (NYISO, 2020a). As another example, one of the CPUC's proposed rules for multiple use called for specificity and transparency surrounding participation in retail and wholesale programs, while other rules would require retail utility access to a list of a DER's services provided to the wholesale market operator (CPUC, 2018a). Along similar lines, subsequent CAISO rules require entities to compare performance payments to ensure an individual DER or aggregation of resources would not be paid twice for the same load reduction (CAISO, 2019d). However, if different levels of load reduction were committed day-ahead and day-of, the combined performance consistent with both commitments would result in both payments being honored.

6. Examples and Regional Opportunities for Battery Commitment Segmentation

Now with a better understanding of how distributed batteries could provide multiple benefits, we can assess how segmenting battery commitments (by time, by capacity, or both) could create opportunities to achieve those benefits via utility rate and program offerings based on the nature or type of grid service considered most valuable (see Table 6). Factors such as the availability of communications and controls, the relative value of different services and grid needs, and various tradeoffs related to complexity and customer participation will impact rate and program design.

For services that follow cyclic, predictable patterns (e.g., seasonal or diurnal), or for those that are peak driven and occur only a few times annually with some predictability, a battery operator can plan ahead to ensure sufficient state of charge to dedicate fully to these events when they occur. This leaves scheduled time in which a distributed battery could otherwise provide different services by segmenting participation *temporally*. On the other hand, to provide continuous (e.g., frequency or voltage regulation) or unexpected services (e.g., contracted emergency services or VRE balancing under a quick change in output), a battery operator may choose to use state of charge management to reserve some percentage of the capacity. For example, the operator might specify a minimum and maximum depth of discharge to reserve appropriate capacity to constantly run or be on standby for high-value, unexpected events, allowing for the remainder of the battery to provide any other service- segmenting participation *by capacity*. Segmenting commitments both temporally and by capacity could be done for continuous or unexpected services that may occur more frequently or provide more value during one season over another.

Broadly, temporal segmentation could be implemented minimally without advanced controls and communication, however, would require more customer touchpoints. On the other hand, capacity segmentation can run fairly autonomously based on operational parameters and set modes with customer interaction only necessary in order to override defaults, however, would require advanced technology to maintain operation within set parameters, respond automatically to grid conditions, and communicate status to operators for dispatch and planning. In all cases, metering, communication, and automated control requirements will vary based on the service and level of control required. System operators must consider how to compensate, schedule, and verify performance in order to attribute actions to one service or another and ensure that responding to one signal does not count towards, or against, compensation for the other.[13] Some services or segmentation may add further complexity. For example, in a case where a service is compensated per-kVA and may require both charging and discharging, metering must allow for netting intervals granular enough to capture the total mileage up and down that the battery provides. Additionally, dual participation (i.e., stacking services across grid levels) as described in Section 5 requires additional rules for prioritization, coordination, and compensation in the case of concurrent services.

Table 6. Identifying potential ways to segment battery commitments by type of service provided

Type of Service	Examples	Commitment Segmentation	Utility Rate or Program Offering	Metering, Communication, Controls
Cyclic	• Diurnal morning and evening ramps • Diurnal energy arbitrage	Temporal	• Time-based rates, updated to accurately represent cyclic patterns	• Hourly metering required • No automated controls • No communication beyond billing cycle
Peak-Driven	• Economic arbitrage • Resource adequacy/ capacity • Emergency DR • Location-specific T&D relief	Temporal	• Manual DR program, or dynamic time-based rates (e.g., CPP, V-TOU, or RTP) for economic services • DR or VPP programs with controls for resource adequacy, capacity, emergency DR • NWA program for T&D relief	• Hourly or sub-hourly metering required, depending on program • Communication required (coarsely, with day-ahead notice for economic services; likely more granular for reliability services such as resource adequacy, capacity, emergency DR, T&D services) • Automated controls optional for events called with advance notice, but required for programs that require instantaneous and precise response
Continuous	• Frequency regulation • Volt/VAR services	Capacity	• VPP program with controls for frequency or voltage regulation	• Metering depends on compensation structure. If compensated based on capacity committed [kW] or number of events, granular metering may not be required for compensation. However, if stacked with concurrent, performance-based services, granular tracking may be required to ensure that delivering the continuous service does not count towards, or against, participation in the other • Communications required: bidirectional and instantaneous with system operator(s) for status and availability • Automated controls required
Unexpected	• Reserves, instantaneous responses • Local reliability during short-duration outages	Capacity	• DR or VPP program with controls for reserves or contingency support	• Hourly or sub-hourly metering required for reserves or contingency services (especially if stacking with a concurrent performance-based service as described above) • Communications required: sub-hourly for reserves, instantaneous with distribution operator for local outages • Automated controls required

[13] Eliminating unfair double counting or penalization may be especially difficult when stacking a volumetric service with a direct control service under separate programs or across grid levels. Take the example of a battery with 20 percent dedicated to a NWA at the distribution level (direct control by distribution operator) and 80 percent to economic arbitrage (control by customer responding to bulk system operator signals) in the wholesale energy market. If both services signal response in the same direction (i.e., both NWA and energy market signal to charge real power), the battery as a whole may be over-compensated in the wholesale market unless it is compensated for the prescribed portion as opposed to the entire battery's response. On the other hand, if the signals oppose, the customer may be under-compensated or penalized for prioritizing one service over the other. This illustrates the importance of rules that address communication, prioritization, and compensation, and the limitations that may persist in offering multiple services concurrently.

Region-specific macroeconomic trends, climate, load patterns, generation profiles, grid configurations, and more all drive variation in value and the subsequent implications for how a customer might choose to operate their distributed battery. Each customer must weigh the costs and benefits of providing any grid service over their personal use. Additionally, they must weigh the consequences of participating in one service that may preclude them from another (e.g., opting to be compensated via retail rates may preclude all participation in bulk system services). Some locations may be able to capture sufficient value with time-sensitive rates and/or programs that utilize day ahead communication and hour-interval metering. However, other locations with high levels of distributed battery adoption and advanced technology that would enable dynamic control may be able to leverage existing resources for additional grid value (Figure 6).

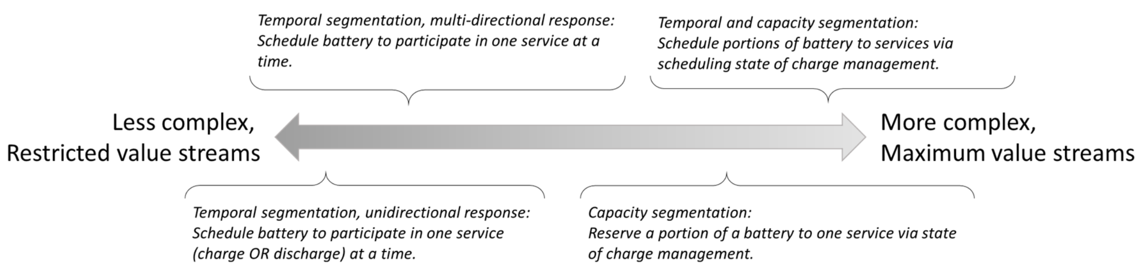

Figure 6. Tradeoff in stacking services

The remainder of this section will go through several use cases to help illustrate how grid conditions will motivate differences in which rates or programs are offered by utilities and how the customer or aggregator might segment battery commitments temporally or by capacity to stack services and thereby maximize value.

6.1 Resource adequacy and generating capacity obligations

Some utilities or regions of the United States may face shortages in generating capacity to meet peak load due, in part, to factors such as retiring or reduced availability of existing generators (Mills et al., 2017) or increasing peak demand (NERC, 2019). Insufficient resource adequacy increases the probability of an outage, resulting in greater value of additional generation capacity. In some cases, resource adequacy is valued in capacity markets such as those in MISO, NYISO, PJM, or ISO-NE. In these cases, specific participation requirements or methods used to assign capacity credit impact whether batteries can provide capacity value economically or at all (see Appendix A). In organized markets without a capacity product (e.g., ERCOT, CAISO, SPP), low reserve margins will affect other grid values: Energy markets may reflect high scarcity pricing, ancillary service markets may reflect high reserve values, and emergency DR programs that pay for performance may be called upon more frequently. For example, in mid-August of 2019 ERCOT's real-time energy market hit its $9,000/MWh cap multiple times over a few days (ERCOT, 2019). Utilities outside of organized markets with generating assets are required to certify that they meet minimum obligations to their regional reliability organization, however, these utilities may still be exposed to operational costs that could increase if circumstances cause capacity shortages, driving up the value of avoided costs.

Batteries are well suited to provide resource adequacy services in cases where system peaks are short in duration. One study estimated the total U.S. practical potential of four-hour duration storage providing peaking capacity to be 28 gigawatts (GW) in the near term before peaks become wider and require longer duration solutions (Denholm et al., 2020). This potential is unevenly spread regionally and will likely change as PV penetration increases, shifting and narrowing net load peaks to increase storage's capacity value during evening hours (Denholm et al., 2020; Stenclik et al., 2018). At high penetration of short-duration capacity, battery value may decrease as residual peaks become wide enough that batteries have to derate their systems and may no longer be cost competitive (e.g., bid in 50 percent of rated capacity in order to provide services for a peak duration twice as long). The consequence of this would be a corresponding reduction in capacity credit, however, utility programs can instead mobilize an aggregated DER portfolio across their territory to address this problem. Utility programs with flexible scheduling would be able to more readily adapt to widening duration requirements by staggering resource dispatch to cover longer peaks without impacting individual systems' response times (Mégel et al., 2015).[14]

Capacity value depends on a resource's availability during a select few number of hours in a year and is largely dependent on seasonal and hourly patterns in generation and load. Since resource adequacy and emergency services are peak-driven, fairly infrequent, and reasonably predictable, battery operators could segment their commitments temporally. Doing so would allow batteries to provide other services off-peak to increase total revenue flow, making them more cost competitive with incumbent generators that traditionally provide resource adequacy.

Well-designed time-based rates could provide indirect capacity value if actual system peak hours are coincident with the rate-defined peak periods and if these rates are updated frequently enough to ensure coincidence. Including a CPP rate or a Manual DR program layered on top of any customer rate would provide extra incentive to alleviate strain. Both of these solutions would treat distributed storage as voluntary flexible load, and would require metering at the hourly level, simple communications for announcing the dispatch of the event (e.g., day ahead automated text, phone call, or email), and no automated controls.

To commit capacity in either system planning processes or markets, more firm performance commitments will be necessary via a DR or VPP program with controls. In these cases, the battery operator might rely on automated controls with advanced notice to ensure a specific state of charge before the start of an event (i.e., temporal segmentation) and availability throughout the duration. Notably, making firm commitments to these services may preclude simultaneous participation in others, as outlined in some organized market products as well as the CPUC Rules 5-7 (CPUC, 2018a). As such, to address resource adequacy by solely temporal segmentation, the battery operator can only stack additional services that are voluntary and can be overridden in the case of competing signals. Else, committing to multiple temporally segmented, potentially concurrent, compulsory services would likely

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[14] NYISO's aggregation tariff explicitly allows for aggregators to operate DERs one after another in order to meet the 8 hour requirement for 100% capacity credit (NYISO, 2020a)

require capacity segmentation as well and a higher degree of data collection and telemetry to ensure no unfair double counting or penalties.

6.2 High variable renewable energy penetration

Renewable energy made up 20 percent of all United States electricity production in 2020, with half coming from variable wind and solar PV generators (U.S. EIA, 2021). Falling costs and maturing technology have expanded these markets from high-resource states to a broader number of locations for both wind, via low specific power machines (Wiser and Bolinger, 2019), and solar PV, with installed costs falling two thirds in just over a decade (Bolinger et al., 2019). Given this, various studies have focused on both opportunities and challenges that may arise with increased penetration of VRE (e.g., Cochran et al., 2014) and how customer response could help (e.g., Cappers et al., 2012).

High VRE penetration impacts multiple aspect of grid operation, including the availability and need for ancillary services, variation of energy prices, and T&D operation. While VRE generators can provide ancillary services (Achilles et al., 2011; Banshwar et al., 2017; IRENA, 2019; Nock et al., 2014), some markets do not allow for it, citing needs for dispatchable and controllable resources. Even in areas where it is permitted, production-based incentives such as the federal production tax credit, renewable portfolio standard compliance and credit value, or power purchase agreement contracts may, in turn, render the decision to reduce VRE production to provide these ancillary services less economical (Jones, 2017). Further, VRE generation itself typically lacks inertia and increases the need for ancillary services (Cochran, 2013; Nock et al., 2014; Seel et al., 2018; Zhou et al., 2016). For example, high VRE penetration has led to both higher and more recurrent frequency violations (Habib et al., 2018). In addition, it may increase regulation and spinning reserve prices as well as lead to a greater number of high-priced outliers compared to low VRE scenarios (Seel et al., 2018). While energy market impacts have been relatively small on average, price variation for specific locations and time periods has increased with VRE penetration, creating higher frequency of negative prices, especially when focused on constrained areas with high VRE resource (Seel et al., 2018; Wiser et al., 2017). Since VRE generation depends on uncontrollable factors such as weather that follow cyclic patterns independent of load, a higher penetration of VRE weakens the correlation between prices and demand and can lead to grid inefficiencies and congestion (Verzijlbergh et al., 2014). This congestion can affect T&D infrastructure, which may also experience increased wear and tear along with line losses when facing larger and more frequent generation fluctuations (Denholm et al., 2013b; Romlie et al., 2014).

With declining VRE costs and recent policies targeting high clean and renewable energy targets, additional flexibility will be needed to maximize environmental benefits and reduce curtailment (Arbabzadeh et al., 2019), as well as mitigate broader impacts from variability and uncertainty introduced by VRE. Batteries can provide this flexibility, as they have very low response times, fast ramp capabilities, and few restrictions regarding minimum operating levels (Lund et al., 2015). Flexibility reduces the rate of coincident marginal VRE value decline, while VRE shortens peak duration and increases the value of flexibility, creating a symbiotic relationship between VRE and storage values (Denholm et al., 2020, 2013a; Seel et al., 2018; Stenclik et al., 2018; Zhou et al., 2019; Zou et al., 2016).

At lower levels, the practical potential for four-hour duration storage at full capacity increases as PV penetration goes up (Denholm et al., 2020), and at levels of VRE penetrations of ~50 percent and greater, storage becomes increasingly competitive and key to ensuring reliability (Conlon et al., 2019; Denholm et al., 2013b; Frew et al., 2016; Go et al., 2016).

Co-locating batteries with generation or load will be valuable as high levels of VRE are interconnected. At the utility scale, there are currently 2.2 GW of hybrid VRE capacity paired with storage with an additional 49.8 GW in development or in interconnection queues (Gorman et al., 2020). Hybrids have arisen as a solution to mitigate issues such as fast fluctuations in generation and power quality (Zhang et al., 2014). On the distributed side, flexibly sited aggregated batteries can provide similar services to balance VRE if in the same region. Moreover, some studies indicate that batteries located at load centers provide more value in reducing congestion (Yacar et al., 2018) and smoothing variability (Denholm et al., 2013b; Waite and Modi, 2019). One study found that 20 percent of VRE penetration in California could lead to curtailment levels above 30 percent, but that integrating distributed resources into planning and operation would reduce curtailment and costs to ultimately achieve higher levels of VRE (Denholm et al., 2015).

VRE generation follows fairly predictable, cyclic trends that account for 80 percent of PV variation and 50 percent of wind variation (Seel et al., 2018) such as the morning and evening ramps associated with residual demand on a system with high PV adoption. As such, splitting a distributed battery's grid service commitments temporally could provide a fair amount of value. For temporal segmentation, less advanced communication and controls could provide cyclic services, however, advanced communication and controls could allow for dynamic response to bulk system imbalances that a high-VRE scenario may introduce. This would allow DER dispatch to counteract uncertainty such as in cases where imperfect forecasts lead to insufficient unit commitment or sudden changes in VRE output impacts grid reliability and/or economics. At a more basic level, well-designed time-based rates could signal distributed batteries to balance high and low net load. In areas with high levels of VRE with zero marginal energy costs, aligning these signals with bulk system energy could reduce curtailment as well as the need for additional generation to meet the higher peak. Indirectly, this may also reduce the ramp rate or alleviate some additional ancillary service needs. Rates could account for both seasonal and diurnal patterns, which could particularly help in spring and fall when residual load is lower, ramp rates are higher, and curtailment becomes more common. Layering on a CPP rate or Manual DR program would further incentivize more targeted shifts for days with exceptional strain or economic opportunity. While such retail utility opportunities may be sufficient to address inter-hour arbitrage, additional value could be extracted via opportunities that reduce intra-hour variability as uncertainty surrounding VRE generation is reflected in real-time prices. Providing energy and ancillary services at this level likely will require additional communications and controls via a VPP or DR program, and may only be comparatively valuable if real-time markets offer significantly higher arbitrage potential than day-ahead markets.

Beyond temporal segmentation of services, capacity segmentation with advanced communication and controls would allow for provision of both continuous services and those that address the increased uncertainty associated with high VRE adoption, such as frequency regulation (Habib et al., 2018). One study demonstrated that a battery providing frequency regulation continuously between the morning and evening ramp periods maintained a steady state of charge within +/- 5 percentage points (Motalleb et al., 2016). As such, reserving some fraction of a battery's capacity to provide energy-neutral ancillary services over the course of the day could be both lucrative and feasible, but would require direct control.

Across this span of services, indirect benefits may include reduced congestion, lower peaks, and reduced VRE curtailment. To maximize value, utilities may be able to aggregate distributed batteries locationally. Since VRE generators are not necessarily co-located with load centers and instead tend to cluster in locations with high resource, grid configuration and transmission line limits unevenly distribute the need for certain services along with the value of storage across a region (Pandžić et al., 2018). A utility program could incentivize adoption in specific zones or incentivize batteries to participate in services that are lucrative within their specific location. These batteries could be dispatched via zonal programs with advance notice to encourage economic arbitrage, reduce congestion, and minimize VRE curtailment. This would reduce the need for overbuilding generation, and/or reduce compliance payments in the case of renewable or clean generation mandates. Increased VRE consumption aligns with various policy goals such as high clean or renewable energy targets or clean peak standards. Finally for the case of NWAs, battery systems on sensitive or imbalanced nodes could reduce congestion and ensure that thermal violations do not occur, avoiding unnecessary T&D expenditures.

6.3 Distribution-level: Infrastructure deferral

Distribution annual capital expenditure almost doubled between 1996 and 2017, driven primarily by the replacement of aging equipment and incorporation of advanced technology to increase resilience and automated control (U.S. DOE, 2018). Operation and maintenance has made up a smaller, though non-negligible, increase in spending due to impacts of extreme weather, increased demand, and increased distributed renewable generation adoption (U.S. DOE, 2018). Due to the high cost of distribution equipment, this creates an opportunity for DERs to capture high avoided cost value through deferring or eliminating these expenditures.

Though distributed battery attachment rates to solar systems still represent a relatively small share of the total market, hybrid systems represented 5 percent of 2018 installations in California and over 60% in Oahu, Hawaii (Barbose and Darghouth, 2019). Moving forward, changes to solar compensation structures, concerns over resilience, and incentives geared towards hybrid systems have led some to project that 33 percent of residential and 25 percent of non-residential solar systems will be paired with storage by 2025 (SEIA and Wood Mackenzie, 2019; Zinaman et al., 2020). As such, distributed battery adoption may cluster around large distributed solar markets. Distributed solar can provide many benefits, but can also create problems at high penetration levels (Eltawil and Zhao, 2010). These may be in the form of voltage violations, congestion, reverse power flow to the grid, overuse of regulating infrastructure, power quality issues, and power factor shifts that necessitate larger equipment (Eid et al., 2016; Haque and Wolfs, 2016; Karimi et al., 2016; Seguin et al., 2016). Additionally, DER activity is often netted with load behind the meter, reducing the operator's visibility of the DERs, increasing load forecasting error, and increasing the need for regulation services (FERC, 2018b).

The amount of DER capacity that can be interconnected on a specific location of the distribution system without upgrades is referred to as *hosting capacity* (McAllister et al., 2019). Hosting capacity varies by grid topology, configuration, distance from substation, size of the DER, the net load profile, and more. Consequently, on a localized level, hosting capacity can differ greatly by circuit or feeder (Ding et al., 2018; Horowitz et al., 2018). Improving hosting capacity would enable increased DER adoption while maintaining grid reliability. Traditionally, this has been done via equipment replacement or upgrades such as adding tap changers, line regulators, and/or capacitor banks that can create more cost than value (Ding et al., 2018; Horowitz et al., 2018; Palmintier et al., 2016). In these cases, customer-side solutions such as advanced inverters or batteries, either co-located with distributed solar or simply on the same circuit/feeder, could be operated in such a way to increase hosting capacity and improve reliability (Adefarati and Bansal, 2017; Mégel et al., 2015; Spiliotis et al., 2016). This could defer or eliminate utility expenditures, improving the benefit-to-cost ratio while allowing for increased DER penetration. In addition, batteries can reduce protection equipment wear and tear, provide volt/VAR services, improve power quality, reduce congestion and line losses, and increase resilience (NREL, 2014) if able to island and provide back-up power (Eid et al., 2016). Doing so optimally will likely require specific locational targeting as well as communication and control between the battery and the distribution operator.

Whether segmenting battery commitments temporally or by capacity, programs and rates will require locational consideration. Where the distribution system is not constrained and hosting capacity is high, locational value will likely be near zero. On the other hand, in areas with reliability issues or low hosting capacity, the avoided cost of infrastructure investment can reach levels valued at annual levels up to hundreds of dollars per kW delivered during particularly strained hours, which may occur only a few times per year (CPUC, 2018b; NYSERDA, 2019).

For local peak-driven events that occur with some advanced notice, temporal segmentation of battery commitments with controls and participation rules to ensure participation could provide services during these more infrequent events. DR for territory-wide peak reduction, or NWAs for location-specific peak reduction, may require additional communication and controls to incorporate participating batteries into planning and better defer or eliminate infrastructure expenditures while maintaining reliability and increasing savings (Spiliotis et al., 2016). Rates or programs without advanced controls could additionally provide voluntary services that occur cyclically, such as arbitraging excess solar generation to serve local peaks. Some utilities have incorporated this locational distribution value through export compensation rates (e.g., New York's Value Stack), providing one additional layer of granularity to predetermined on- and off-peak periods by designing around a zone's typical seasonal and diurnal load pattern.

While segmenting battery participation temporally could provide local peak reduction and arbitrage services, capacity segmentation with dynamic control capabilities would provide more targeted value. Feeders with high levels of solar may have enough generation concentrated in one area such that quick changes in generation output could have a large impact. For example, a passing cloud can reduce PV generation 30 percent (Ebad and Grady, 2016) and, on the other hand, high levels of concurrent generation may lead to issues with voltage, backfeed, or congestion. One study found that optimal, coordinated battery operation on a distribution system with high PV penetration could reduce congestion management costs 33 percent (Kulms et al., 2018), though this value will vary locationally, as demonstrated by a study that found capital cost reductions of 28 percent and 19 percent for two different feeders (Spiliotis et al., 2016). Highlighting the importance of communication and controls for a highly-constrained feeder, improper or coarse price signals could exacerbate circuit loading issues (Reihani et al., 2016). In addition to dynamic real power services, capacity segmentation could also allow for provision of reactive power services not currently incentivized such as volt/VAR services and power factor correction.[15] Since these services may not require the battery's full capacity and utilize both charge and discharge, it could be possible to enroll only a portion of the battery capacity in a program with automated controls to reduce wear and tear on expensive traditional regulating equipment while the other portion of the battery serves other functions. Finally, capacity segmentation would also allow for fast and accurate contingency response. Utilities' reliability indices are primarily hurt by outages on the distribution system (Adefarati and Bansal, 2017). As such, distributed batteries with certain microgrid functionality providing backup for feeders with frequent, short outages can greatly improve a utility's overall reliability (Adefarati and Bansal, 2017). Depending on the duration of typical shorter outages, this also may only require reserving a portion of the battery. For longer outages caused by extreme weather, there may be sufficient advanced notice to fully charge up and the battery will likely only be able to provide resilience services in its islanded state, thus rendering it unable to participate in any other grid service beyond the customer site or microgrid.

When providing distribution level services, an important consideration is that the distribution level needs may not necessarily correspond with bulk system needs. As a result, incentives must be structured in such a way that weighs the benefits at one grid level with the costs at the other while also ensuring fair compensation. Since distribution level values may be near-zero in most places and extremely high in a select few, well-designed locational incentives could drive adoption and operation in specific areas where the value is sufficiently high to motivate participation and where the benefits outweigh the additional cost of controls, communication, running the program, and the opportunity cost of bulk system service provision.

[15] Interconnection agreements could invoke some of these services to avoid violations of a specific end user's DER. However, even in this case, action would only be triggered by conditions at a specific property or DER as opposed to that of the distribution grid (e.g., conditions at the line segment, circuit, or substation).

7. Conclusions and Policy Implications

Falling costs, changing rate structures, new value streams, and resilience concerns have increased distributed battery adoption across the United States. Currently, distributed batteries adopted for the purpose of resilience may lay idle aside from when they are providing emergency services while those adopted for personal bill management to increase solar self-consumption operate in such a way that solely provides value behind the meter, which may or may not coincide with grid value. At worst, existing research shows that these batteries can exacerbate greenhouse gas emissions and peak demand. At best, they may provide some societal value, but still have larger potential for both the grid and owner. Better aligning customer compensation with a larger suite of grid services could increase adopting customers' value streams while concurrently providing societal benefit.

This paper explores ways in which utilities and policy makers can better align utility rates and programs with grid value to leverage existing distributed customer batteries and encourage new adoption where most beneficial. We focus on the retail utility perspective due to their jurisdiction over DER interconnection as well as their existing relationship with customers and existing tools that they could leverage to promote beneficial battery adoption and operation. Through rates and incentive programs of varying complexity, utilities can better align price signals with grid needs. With increasing adoption of advanced metering infrastructure, there is opportunity to offer a more diverse array of time-based rates. With advanced inverter technology, communication, and controls, utilities also have the opportunity to expand beyond manually controlled DR programs to more automated, dynamically-controlled programs that go beyond load flexibility to provide T&D services via NWAs and supply-side services via VPPs.

There remain implementation challenges associated with designing rates and programs that capture multiple grid services related to participation, dispatch, and compensation. These become especially salient when stacking services to participate dually across both the distribution and bulk system, which may become more prevalent as wholesale markets allow distributed resource aggregations to participate under recent FERC orders. As bulk system participation increases, distribution utilities will need to ensure, at a minimum, that systems participating in bulk system services do not produce reliability issues at the distribution level. More proactively, utilities could partner with third party aggregators or aggregate resources themselves to target programs to better capture dual grid value.

Regulators could direct utilities to integrate distributed batteries into grid planning and modeling alongside other DERs. To do this, utilities would need to better understand the operational behavior of these systems and identify their present and potential future grid impact. This could then inform design of rates or incentive-based programs that encourage beneficial dispatch and best provide net value. In some locations, simple time-based rates and manual utility programs could provide sufficient energy arbitrage and peak reduction to meet modest grid needs. However, in other locations DERs could alleviate more substantial grid issues if dispatched more dynamically (e.g., resource adequacy shortages, high penetration of variable renewable generation, local reliability issues, or others). In these cases, it may be worthwhile to design more complex programs with some level of automated controls and communication. Whereas some situations may see value concentrated in one service, batteries are able to provide multiple services and may be able to do so in other cases.

When providing multiple services, it is important to establish the *what* and *when* for battery dispatch in order to prioritize provision of grid services, ensure proper compensation, and provide visibility for grid planning and operation. States such as California and New York have explored the use of more granular telemetry and coordination to ensure performance and fair compensation when dually participating in multiple services. We expand on these ideas to explore how battery commitments could be segmented either temporally or by capacity with state of charge management. Broadly, with any service that is predictable (e.g., follows a cyclic pattern or is driven by peak conditions), battery commitments could be segmented temporally with time-based rates or incentive programs that can range from manual dispatch to automated control. For any service that is continuous or unexpected, battery commitments could be segmented by capacity, reserving a portion of the battery for that service alone and dispatching with automated controls within pre-established operational parameters.

Distributed battery adoption continues to increase concurrently with technology that can improve dynamic communication and control. Nevertheless, current price signals at the customer level do not align with grid value and visibility of these systems' real time operation remains low. In aggregate, these systems offer utilities a relatively under-utilized, flexible resource that can provide value well beyond the individual customer domain. Though there remain various implementation challenges, tradeoffs, and consideration, well-designed utility rates and incentive programs can promote beneficial dispatch of existing systems as well as guide new adoption in locations where most valuable. This could lead to a more efficient use of existing grid resources and lower operating costs, improved grid reliability, increased battery value streams, and alignment with policy goals that promote battery or renewable interconnection.

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Appendix A. ISO/RTO capacity, energy, and ancillary service market information

The tables here reflect the market rules as of August 2020 and may have changed in the months since.

Table A-1. ISO/RTO Capacity Market Participation Rules

ISO/RTO	Capacity Market Product	Commitment Length	Duration Requirement	Specific Considerations
MISO (MISO, n.d.)	Planning Resource Auction	One year	4 hours	• Zonal prices • Voluntary • Procured April of the same year
PJM (PJM, n.d.)	Reliability pricing model	One year	10 hours	• Procured three years in advance
NYISO (NYISO, 2020b, n.d.)	Installed capacity market with three auctions: (1) Spot, (2) Monthly, (3) Capability period	1 month – 6 month, depending	6 hours (see notes column)	• The duration requirement is flexible in that aggregated storage under 1,000 MW can receive 90% credit with 4 hour duration and 45% with 2 hours • Must be available during predefined peak load window, depending on duration of resource and season
ISO-NE (ISO-NE, n.d.a, n.d.b, n.d.c)	Forward capacity market	One year	2 hours	• Procured three years in advance • Auction takes place twice per year
CAISO	N/A			
ERCOT	N/A			
SPP	N/A			

Table A-2. ISO/RTO Energy and Ancillary Services Market Participation Rules

	Energy		Ancillary Services (NERC, 2014; Reishus Consulting LLC, 2017)			
ISO/RTO	Day-Ahead Energy	Real-Time Energy	Spinning Reserves	Non-Spinning Reserves	Regulation	Notes
CAISO (CAISO, 2019c, 2014)	Three parts (7 days to 1 day prior) • Market power mitigation • Integrated forward market • Residual unit commitment	Spot market (1 day to 75 min. before) • 15 min. • 5 min. • 1 min.	• 10-min. response • 30+ min. duration	• 10-min. response • 30+ min. duration	• Reg Up and Reg Down • Mileage included • DA: 60+ min. duration • RT: 30+ min. duration	• Ancillary services bid into day ahead and 15 minute real-time markets • Day Ahead regulation services allow for a 15+ minute duration for non-generating resources that are not providing reserves
ERCOT (ERCOT, 2010)	• DA voluntary, financially-binding	• Security Constrained Economic Dispatch every 5 min	• 30-min. response • 60+ min. duration	• 30-min. response • 60+ min. duration	• Reg Up and Reg Down	• Co-optimized AS and Energy markets • Ancillary services bids into day ahead market • Ancillary services includes other services such as Blackstart (24 month contract), Reliability Must-Run, Voltage Support, Emergency Interruptible Load Service
SPP (IRC, 2017)	• Day Ahead	• 5 min. virtual transactions, cannot set RT price	• Spinning	• Supplemental	• Reg up and Reg Down	• Co-optimized AS and Energy markets • Additionally has intra-day unit commitment (~4 hour) • Ancillary services bid into day ahead and 5 minute real-time market
MISO (Reishus Consulting LLC, 2017)	• Day Ahead	• 5 min.	Spinning • 10-min. response	• Supplemental product • 10-min. response	• Regulation • 5-min. response	• Co-optimizing AS and Energy markets • Ancillary services bid into day ahead and 5 minute real time markets
PJM (PJM, 2017)	• Day Ahead	• 5 min.	Primary • 10-min. response	• Supplemental • 10-30 min. response	• Regulation A • Slow, long response • Regulation D • Fast response	• Ancillary services bid into day-ahead scheduling reserve • Separate ancillary service and energy markets
NYISO (NYISO, n.d.)	• Day Ahead	• 5 min.	Spinning • 10, 30-min. response	• Non-synchronized • 10, 30-min. response	• Regulation	• Co-optimized AS and Energy markets • Ancillary services bid into day ahead, hour ahead, and 5 minute real-time markets • Voltage support product
ISO-NE (ISO-NE, n.d.a, n.d.b, n.d.c)	• Day Ahead	• 5 min.	Synchronized • 10-min. response	• Non-synchronized operating reserve • 10, 30-min. response	• Regulation	• Currently discussing new day-ahead ancillary service products procured as energy call options: Energy Imbalance Reserves, Generation Contingency Reserves, Replacement Energy Reserves, and Seasonal Forward Procurement of reserve products • Voltage support product

Appendix B. Current ISO/RTO demand response and/or DER specifications

The tables here reflect the market rules as of August 2020 and may have changed in the months since.

Table B-1. Rules and participation guidance for DER participation in organized markets

ISO/RTO	Emergency Services	Day Ahead Energy	Real Time Energy (Non-Emergency)	Ancillary Services	Capacity/ Resource Adequacy	Notes
CAISO (CAISO, 2019a, 2019b)	X	X	X	X	X	• Bids into market as supply • Can operate as a Proxy DR, Reliability DR, or Non-generating resource • Flexible resource adequacy three types: Base Ramp, Peak Ramp, Super-Peak Ramp • Has minimum bid of 0.5 MW for AS, which FERC has asked them to lower to 0.1 MW as per Order 841
ERCOT (ERCOT, 2015, 2013, n.d.a, n.d.b)	X	X		X	N/A	• Bids into market as load response • Security Constrained Economic Dispatch is committed in DA but compensated at RT prices
SPP (Walton, 2019)	DR in SPP has come exclusively from retail programs, however, in 2019, Voltus became the first to aggregate customers to participate in SPP markets, which may signal development in this space in upcoming years.					
MISO (Chen, 2019; MISO, 2019a, 2019b)	X	X	X	X	X	• Bids into market as load, but can set prices as emergency DR • MISO will allow 100 kW minimum for storage, but has caps on number of resources that FERC considers counter to Order 841
PJM (McAnany, 2020; PJM, 2019, 2017)	X	X	X	X	X	• Retail DR can bid into market as supply-side for energy services • DER emergency generators make up 45% of DER participants and can only operate during emergency conditions no matter what • Most DR that participate in capacity market do so exclusively
NYISO (Lavillotti and Smith, 2019; NYISO, n.d.)	X	X		X	X	• Bids into market as supply • Aggregates DERs by transmission node (vs. zone) to more correctly align signal with response • Explicitly allows dual participation between wholesale markets and distribution network (can schedule as “self” or “ISO” and will separate telemetry for compensation) • emergency DR resources cannot overlap with capacity resources; day-ahead DR resources cannot overlap with AS resources • Emergency DR is compensated at the higher level of RT LMP or $0.50/kWh • Day ahead demand response compensated at the higher level of DA LMP or monthly net benefit test offer floor (up to $2/kWh)
ISO-NE (ISO-NE, n.d.a, n.d.b, n.d.c)	X	X	X	X	X	• Passive DR can only bid into forward capacity market and its capacity is rated based on average hourly demand reductions during pre-determined times (on-peak or seasonal-peak) • Active DR is dispatchable by ISO and can be bid into all markets as supply

Appendix C. Selection of recent virtual power plants

Table C-3. Recent residential virtual power plants that leverage distributed batteries

	Size	Ownership & control structure	Customer Value	Grid services	Incentive structure	Notes
SCE/Sonnen Demo (CA)		Customer owned, Sunrun-controlled via utility signals (Southern CA Edison)	Compensation for enrollment Resilience (20%+ SoC)	Distribution-level peak reduction, CAISO RA	Upfront rebate at sign up for one-year demo	Limit on number of calls per year at 80, though dispatch amount and duration can vary Includes a low income carve out of 10%
Sonnen/Wasatch Group (CA)	3,000+ homes 24 MW, 60 MWh	Landlord/ Developer owned	Bill reduction Resilience	TBD CAISO market	N/A System comes with home and customers get bill savings and resilience, but don't own/control system	
HECO/Swell (HI)	6,000 homes 80 MW, 100 MWh	Customer owned, Swell-controlled via utility signals (HECO)	Bill credits Resilience	Capacity Fast Frequency	HECO bill credits	
Sunrun in ISO-NE (NE)	5,000 homes 20 MW	Customer owned, Sunrun-controlled	Resilience	Capacity via active and passive DR (ISO-NE) TBD (Note that this contract is only for one year)	Upfront rebate Monthly credits	
O&R/Sonnen (NY)	300 homes	Customer owned, Sunrun-controlled via utility signals (Orange & Rockland)	Compensation for enrollment Resilience (20%+ SoC)	Distribution-level peak reduction	Discounted system	
PGE pilot (OR)	525 homes 4 MW	Customer owned, Utility controlled (Portland General Electric)	Monthly credit, Resilience (20%+ SoC)	TBD The pilot allows full utility direct control to maximize value over multiple services (capacity, frequency response, upgrade deferral, peak reduction, volt/VAR)	Upfront rebate for new/qualified systems, Monthly credits for all	Notes that there may be negative bill impacts in some cases, but these should be negligible compared to monthly credit levels. Includes a low income incentive
Green Mountain Power tariff (VT)	5 MW per year	Utility owned (or customer owned), utility controlled (Green Mountain Power)	Resilience	Distribution-level services (peak reduction, congestion relief)	Customers pay upfront or monthly for resilience benefit in the case of utility ownership Utility credit at enrollment in the case of customer ownership	Tariff approval Battery ownership and control on customer property may not be allowed in other locations
Soleil Lofts (UT)	600 homes 5.2 MW PV, 12.6 MWh BESS	Landlord/Developer owned, Utility controlled (Rocky Mountain Power)	Bill reduction Resilience	DR Distribution-level Peak reduction Reduced congestion	N/A System comes with home and customers get bill savings and resilience, but don't own/control system	