CLF Exhibit 1

THE ECONOMICS OF BATTERY ENERGY STORAGE

HOW MULTI-USE, CUSTOMER-SITED BATTERIES DELIVER THE MOST SERVICES AND VALUE TO CUSTOMERS AND THE GRID

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ROCKY MOUNTAIN INSTITUTE

Rocky Mountain Institute (RMI)—an independent nonprofit founded in 1982—transforms global energy use to create a clean, prosperous, and secure low-carbon future. It engages businesses, communities, institutions, and entrepreneurs to accelerate the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables. In 2014, RMI merged with Carbon War Room (CWR), whose business-led market interventions advance a low-carbon economy. The combined organization has offices in Snowmass and Boulder, Colorado; New York City; Washington, D.C.; and Beijing.

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IMAGE: PAVEL IGNATOV-SHUTTERSTOCK

EXECUTIVE SUMMARY

UTILITIES, REGULATORS, and private industry have begun exploring how battery-based energy storage can provide value to the U.S. electricity grid at scale. However, exactly where energy storage is deployed on the electricity system can have an immense impact on the value created by the technology. With this report, we explore four key questions:

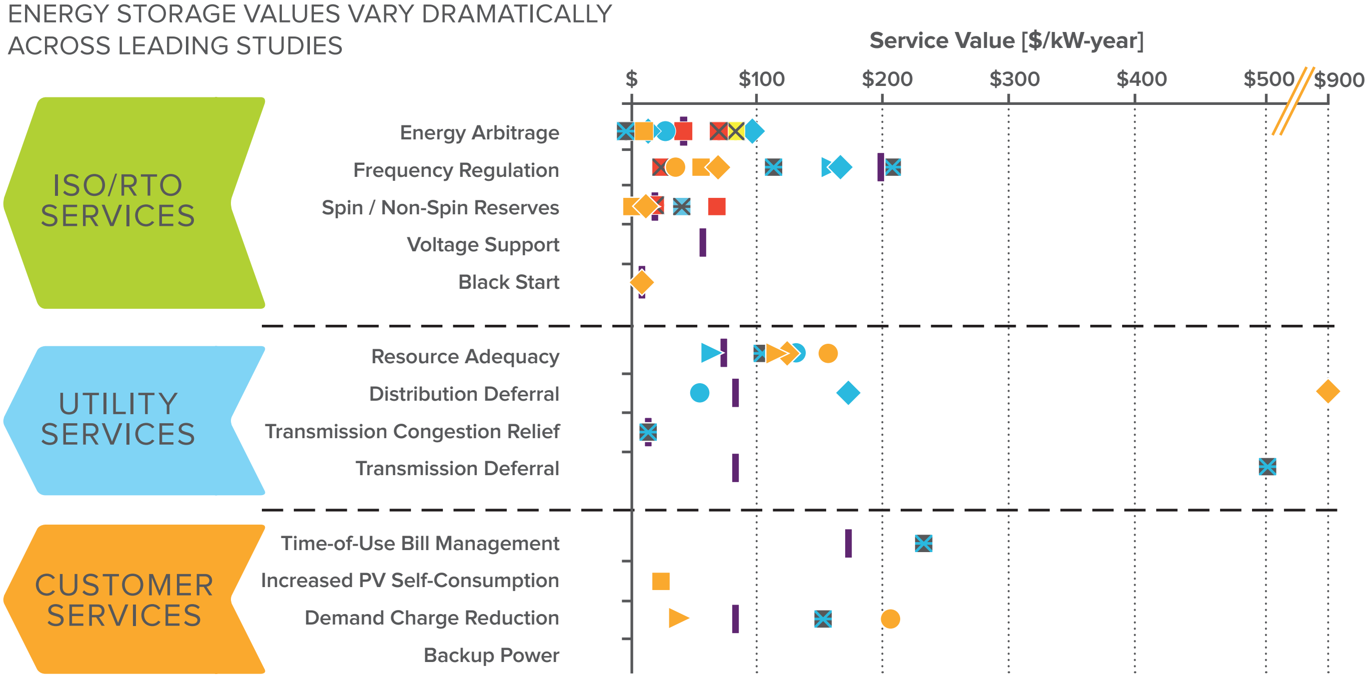
1. What services can batteries provide to the electricity grid?
2. Where on the grid can batteries deliver each service?
3. How much value can batteries generate when they are highly utilized and multiple services are stacked?
4. What barriers—especially regulatory—currently prevent single energy-storage systems or aggregated fleets of systems from providing multiple, stacked services to the electricity grid, and what are the implications for major stakeholder groups?

1. What services can batteries provide to the electricity grid?

Energy storage can provide thirteen fundamental electricity services for three major stakeholder groups when deployed at a customer's premises (behind the meter).

To understand the services batteries can provide to the grid, we performed a meta-study of existing estimates of grid and customer values by reviewing six sources from across academia and industry. Our results illustrate that energy storage is capable of providing a suite of thirteen general services to the electricity system (see Figure ES1). These services and the value they create generally flow to one of three stakeholder groups: customers, utilities, or independent system operators/regional transmission organizations (ISO/RTOs).

FIGURE ES1
ENERGY STORAGE VALUES VARY DRAMATICALLY ACROSS LEADING STUDIES



Results for both energy arbitrage and load following are shown as energy arbitrage. In the one study that considered both, from Sandia National Laboratory, both results are shown and labeled separately. Backup power was not valued in any of the reports.

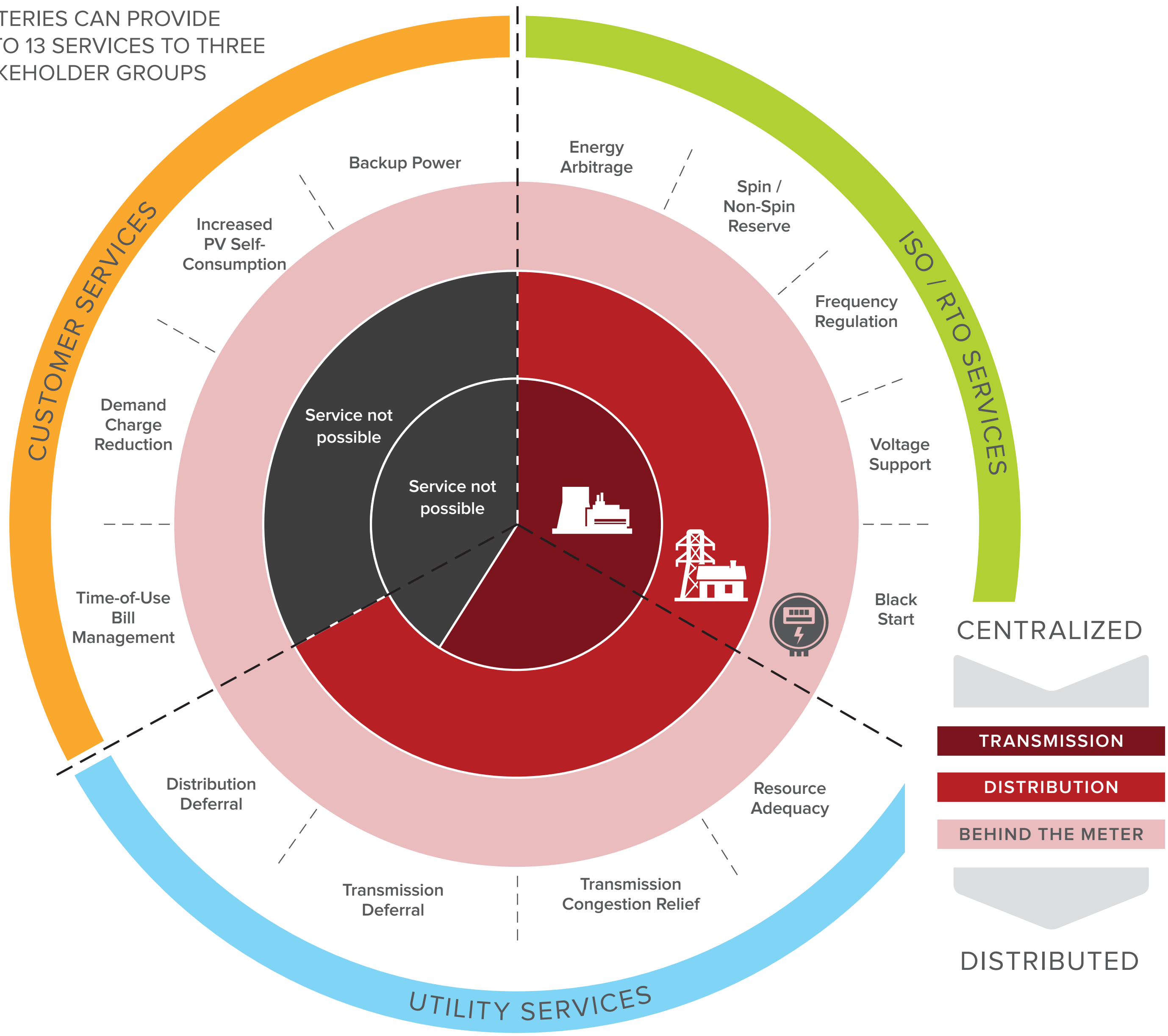
RMI UC I · RMI UC II · RMI UC III · RMI UC IV · NYSERDA · NREL · Oncore-Brattle · Kirby
EPRI Bulk · EPRI Short Duration · EPRI Substation · Sandia · Sandia: LF

2. Where on the grid can batteries deliver each service?

The further downstream battery-based energy storage systems are located on the electricity system, the more services they can offer to the system at large.

Energy storage can be sited at three different levels: behind the meter, at the distribution level, or at the transmission level. Energy storage deployed at all levels on the electricity system can add value to the grid. However, customer-sited, behind-the-meter energy storage can technically provide the largest number of services to the electricity grid at large (see Figure ES2)—even if storage deployed behind the meter is not always the least-cost option. Furthermore, customer-sited storage is optimally located to provide perhaps the most important energy storage service of all: backup power. Accordingly, regulators, utilities, and developers should look as far downstream in the electricity system as possible when examining the economics of energy storage and analyze how those economics change depending on where energy storage is deployed on the grid.

FIGURE ES2
BATTERIES CAN PROVIDE UP TO 13 SERVICES TO THREE STAKEHOLDER GROUPS



3. How much value can batteries generate when they are highly utilized and multiple services are stacked?

Energy storage can generate much more value when multiple, stacked services are provided by the same device or fleet of devices...

The prevailing behind-the-meter energy-storage business model creates value for customers and the grid, but leaves significant value on the table. Currently, most systems are deployed for one of three single applications: demand charge reduction, backup power, or increasing solar self-consumption. This results in batteries sitting unused or underutilized for well over half of the system's lifetime. For example, an energy storage system dispatched solely for demand charge reduction is utilized for only 5–50% of its useful life. Dispatching batteries for a primary application and then re-dispatching them to provide multiple, stacked services creates additional value for all electricity system stakeholders.

... but the net value of behind-the-meter energy storage to the electricity system is difficult to generalize.

A summary of grid values and services is not enough to answer a fundamental question: How does the value of energy storage shift when deployed at different levels on the electricity grid? Answering this question proves greatly complicated. The net value of providing each of thirteen services at different levels on the grid (transmission level, distribution level, or behind the meter) varies dramatically both across and within all electric power markets due to hundreds of variables and associated feedback loops. Hence, the values energy storage can provide vary dramatically from study to study, driven by grid-specific factors (see Figure ES1).

Under prevailing cost structures, batteries deployed for only a single primary service generally do not provide a net economic benefit (i.e., the present value of lifetime revenue does not exceed the present value of lifetime costs), except in certain markets under certain use cases. However, given that the delivery of primary services only takes 1–50% of a battery's lifetime capacity, using the remainder of the capacity to deliver a stack of services to customers and the grid shifts the economics in favor of storage.

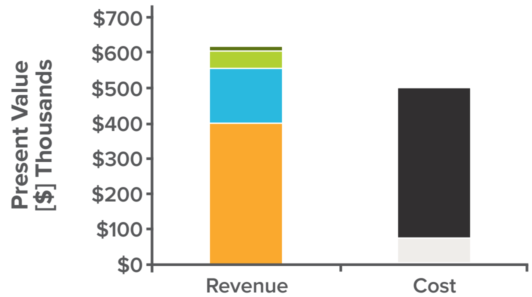
Using a simplified dispatch model, we illustrate the value of four behind-the-meter energy storage business cases and associated capital costs in the U.S. (conservatively, \$500/kWh and \$1,100–\$1,200/kW). Each case centers on delivery of a primary service to the grid or end user: storage is dispatched primarily to deliver this service and then secondarily provides several other stacked services based on the relative value of the service, battery availability, and other user-defined inputs to the model (see Figure ES3).

Our results come with one major caveat: for any of the scenarios illustrated herein to manifest in the real world, several regulatory barriers to behind-the-meter energy storage market participation must be overcome.

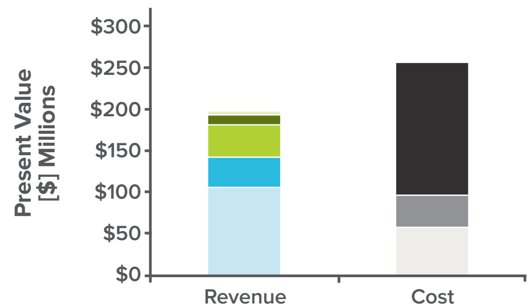
FIGURE ES3

BATTERY ECONOMICS GREATLY IMPROVE WHEN SERVICES CAN BE STACKED: FOUR EXAMPLES

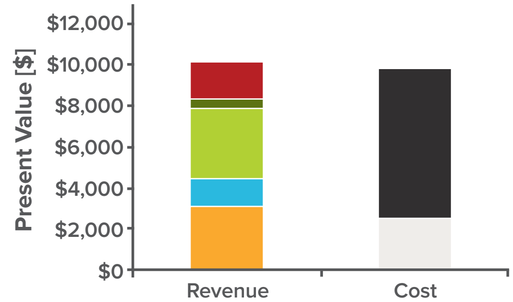
USE CASE I. Commercial demand-charge management in San Francisco. Primary service: commercial demand-charge management. **Secondary services:** frequency regulation, resource adequacy, and energy arbitrage.



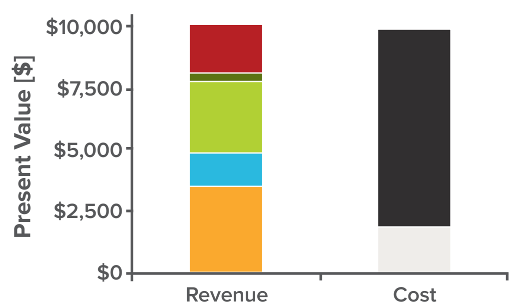
USE CASE II. Distribution upgrade deferral in New York. Primary service: distribution upgrade deferral. **Secondary services:** a suite of ISO / RTO services and resource adequacy.



USE CASE III. Residential bill management in Phoenix. Primary service: time-of-use optimization / demand-charge reduction. **Secondary services:** a suite of ISO / RTO services and resource adequacy.



USE CASE IV. Solar self-consumption in San Francisco. Primary service: solar self-consumption*. **Secondary services:** time-of-use optimization, a suite of ISO/RTO services, and resource adequacy.



ISO/RTO SERVICES: Load Following, Frequency Regulation, Spin Reserve, Non-Spin Reserve, Black Start

UTILITY SERVICES: Resource Adequacy, Dist Deferral CUSTOMER SERVICES: TOU, Self-Consumption, Demand Charge Reduction

COSTS/TAX: Capital Cost, O&M & Charging, Tax Cost, Tax Benefits

** This analysis is based on a hypothetical scenario in which net energy metering is replaced with a value-of-solar tariff at 3.5 cents per kWh. While RMI does not think this scenario is likely (nor would we advocate for it) we did want to understand the economics of solar and storage under an avoided-fuel-cost compensation model.*

Energy storage business models that deliver multiple, stacked services can provide system-wide benefits. With appropriate valuation of those services, such battery business models can also provide net economic benefit to the battery owner/operator. As illustrated by the three cases analyzed in this report that modify customer load profiles in response to rate structures, energy storage systems deployed for a single customer-facing benefit do not always produce a net economic benefit. However, by combining a primary service with a bundle of other services, batteries become a viable investment.[i] Importantly, the positive economics for bill management scenarios (e.g., demand-charge reduction, time-of-use optimization) even without applying a value to backup power suggests that customers are likely to seek out behind-the-meter energy storage. In light of the fact that these assets can be used to provide grid services on top of this primary use, creating business models that take advantage of this capability—rather than procuring ultimately redundant centralized solutions—should be a high priority for grid operators, regulators, and utilities.

The New York distribution upgrade deferral case was the only one without positive economics examined in this report. However, after delivering the primary service of distribution deferral, if the batteries were secondarily dispatched to deliver customer-facing services, like demand charge reduction or backup power (instead of wholesale market services), the economics would likely flip in favor of storage. Accordingly, this case demonstrates the importance of considering all services, including customer services, when building an economic case for battery storage.

Batteries are often deployed for primary reasons that use the battery only a small fraction of the time, leaving an opportunity for other, stacked services. For example, distribution deferral typically demands only 1% of the battery's useful life; demand charge reduction represents a 5–50% utilization rate. Building business models that, at the outset, only plan to utilize batteries for a minority of the time represents a lost opportunity. While the stacked-use business models we analyzed are not necessarily the right ones for all real-world situations, the development of robust stacked-use business models should be a priority for industry.

4. What barriers—especially regulatory—currently prevent single energy storage systems or aggregated fleets of systems from providing multiple, stacked services to the electricity grid, and what are the implications for major stakeholder groups?

Distributed energy resources such as behind-the-meter battery energy storage have matured faster than the rates, regulations, and utility business models needed to support them as core components of the future grid. Even though behind-the-meter energy storage systems have the potential to economically provide multiple, stacked benefits to all stakeholder groups in the electricity system, many barriers largely prevent them from doing so. In order to address these issues, we recommend the following next steps to enable behind-the-meter energy storage to provide maximum benefits to the grid:

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[i] This report considers where batteries should be deployed to enable the broadest suite of multiple, stacked services. The issue of who would make the investment in those batteries—such as customers, utilities, or third parties—remains an open question.

For Regulators

- Remove barriers that prevent behind-the-meter resources such as battery energy storage from providing multiple, stacked services to the electricity grid that benefit all stakeholder groups, including customers, ISOs/RTOs, and utilities.[ii]

- Require that distributed energy resources (including storage) be considered as alternative, potentially lower-cost solutions to problems typically addressed by traditional "wires" investments and/or centralized peaking generation investments.

- Across all markets, require utilities to use a standardized, best-fit, least-cost benefit methodology that compares energy storage providing a full suite of stacked services with incumbent technologies.

For Utilities

- Restructure utility business models and rates to reflect the value that storage can provide to the grid via temporal, locational, and attribute-based functionality, making utilities indifferent to the distinction between distributed and centralized resources.

- Prior to considering new centralized assets, look first for opportunities to leverage existing assets, such as storage, via stacking of uses; provide education so that distribution planners, grid operators, and rate designers can work together to leverage storage's full suite of capabilities.

For the Research Community

- Develop a widely recognized modeling tool or a consistent methodology and approach capable of comparing, on an equal basis, the net cost of stacked services provided by energy storage and other distributed energy resources as compared to incumbent technologies such as combustion turbines and traditional infrastructure upgrades.

- Develop a detailed state-by-state roadmap that specifically identifies policy and regulatory changes that must be adapted or revised to enable widespread integration of energy storage and other distributed energy resources.

For Battery and Distributed-Energy-Resource Developers

- Pursue business models that fully utilize the battery.

- Pursue cost reduction efforts for all power-focused elements of energy storage systems (all $/kW components) in order to unlock more energy storage markets.

- Collaborate with utilities and regulators to help them understand what values distributed energy storage can provide and what new utility business models will be needed to scale them.

[ii] *Ongoing efforts that tend towards this outcome include New York's Reforming the Energy Vision proceeding, California's order for development of distributed resource plans, Massachusetts' Grid Modernization Plan, ERCOT's proposed rules and regulations on distributed energy resource integration, Minnesota's e21 initiative, ongoing regulatory proceedings in Hawaii, and others.*

INTRODUCTION

01

IMAGE: PAVEL IGNATOV-SHUTTERSTOCK

01 INTRODUCTION

BATTERY-BASED ENERGY storage is an important component of an increasingly secure, reliable, low carbon, and cost-effective electricity future. Energy storage has the potential to help integrate deeper penetrations of renewable energy onto electricity grids large and small, accelerate the adoption of other distributed energy resources by enabling customer independence, and, perhaps most importantly, deliver efficient, low-cost, fundamental electricity-grid services to society at large.

Utilities, regulators, and private industry have begun exploring how battery-based energy storage can provide value to the U.S. electricity grid at scale. However, exactly where energy storage is deployed on the electricity system can have an immense impact on the value created by the technology. With this report, we explore four key questions:

1. **What services can batteries provide to the electricity grid?**
2. **Where on the grid can batteries deliver each service?**
3. **How much value can batteries generate when they are highly utilized and multiple services are stacked?**
4. **What barriers—especially regulatory—currently prevent single energy-storage systems or aggregated fleets of systems from providing multiple, stacked services to the electricity grid, and what are the implications for major stakeholder groups?**

This report includes a meta-study of several energy storage studies and tools developed over the past decade and a summary of their findings[iii]. The meta-study is used to develop a high-level framework to help guide decision-making on energy storage deployment. Finally, the report details results from an energy-storage dispatch model in order to shed additional light on the services energy storage can deliver. Our modeling results, although contingent upon a suite of regulatory changes, illustrate how **energy-storage business models that deliver a stack of services to both customers and other electricity system stakeholders can provide positive net value to the electricity system under prevailing energy-storage cost structures.**

Using the literature review, an energy-storage valuation framework, and the results of our modeling exercise, this report is intended to help overcome the many cost, regulatory, business-model, and procedural barriers to making energy storage a meaningful component of the U.S. electricity future.

[iii] *See Technical Appendix A.*

WHAT SERVICES CAN BATTERIES SUPPLY TO THE ELECTRICITY GRID

02

IMAGE: PAVEL IGNATOV-SHUTTERSTOCK

02 WHAT SERVICES CAN BATTERIES PROVIDE TO THE ELECTRICITY GRID?

MANY STUDIES have been conducted on the different values and services that energy storage can provide to the electricity grid over the past decade. The number of services storage can provide and the definitions of those services vary across reports. We synthesize the several services defined across six reports, in expert interviews, and in internal analysis, and offer a set of thirteen fundamental services that energy storage can provide to the grid.

We have divided the thirteen services that energy storage can provide according to the stakeholder group that receives the lion's share of the benefit from delivery of each service. The stakeholder groups are: independent system operators (ISOs) and regional transmission organizations (RTOs), utilities, and customers. Although some services benefit more than one group, segmenting services by which group receives or monetizes the majority of value helps to better define the services themselves.

Considering these stakeholder groups and the services that energy storage can provide to each of them in isolation raises an interesting challenge that is at the heart of regulatory proceedings[iv] across the U.S. right now: batteries installed behind the meter create value for customers and the grid—as do business models focused on distributed energy resources like demand response and distributed solar. However, these services are not utilized to their full potential and are not valued to an extent commensurate with the benefit they provide to each stakeholder group. Furthermore, the range in value that energy storage and other distributed energy resources can deliver to all stakeholders varies dramatically depending on hundreds of variables. These variables are specific to the location where resources are deployed, making generic approximations of value difficult.

As outlined in the following section, we briefly define the thirteen services and how they create value for each stakeholder group.[v]

ISO/RTO SERVICES

Energy storage devices are capable of providing a suite of ancillary services that largely benefit ISOs/RTOs and, in states where the electricity markets have not been restructured, vertically integrated utilities. These services, outlined in Table 1 (on page 15) are largely differentiated from each other by the time horizon for which they are needed.

In restructured areas of the U.S., generation, capacity, and ancillary services are traded on wholesale electricity markets. In regulated areas where organizations operate as vertically integrated utilities, a system operator / scheduling coordinator conducts a merit order dispatch of generation assets to provide both energy and a suite of ancillary services to minimize total production costs.

[iv] For example, in California, dual-participation issues are of major concern to commercial customers who have installed energy storage behind the meter for a primary purpose (demand charge reduction) but are looking to deliver resource adequacy services to the wholesale market, while also providing other utility services. Current regulations on dual-participation use-cases are unclear and largely prevent behind-the-meter systems from delivering services to both utilities and the ISO or delivering multiple services to either the ISO or the utility.

[v] For an in-depth overview of all thirteen services, see Technical Appendix A.

TABLE 1: ISO / RTO SERVICES

	SERVICE NAME	DEFINITION
ISO / RTO SERVICES	Energy Arbitrage	The purchase of wholesale electricity while the locational marginal price (LMP) of energy is low (typically during nighttime hours) and sale of electricity back to the wholesale market when LMPs are highest. Load following, which manages the difference between day-ahead scheduled generator output, actual generator output, and actual demand, is treated as a subset of energy arbitrage in this report.
	Frequency Regulation	Frequency regulation is the immediate and automatic response of power to a change in locally sensed system frequency, either from a system or from elements of the system.[1] Regulation is required to ensure that system-wide generation is perfectly matched with system-level load on a moment-by-moment basis to avoid system-level frequency spikes or dips, which create grid instability.
	Spin/Non-Spin Reserves	Spinning reserve is the generation capacity that is online and able to serve load immediately in response to an unexpected contingency event, such as an unplanned generation outage. Non-spinning reserve is generation capacity that can respond to contingency events within a short period, typically less than ten minutes, but is not instantaneously available.
	Voltage Support	Voltage regulation ensures reliable and continuous electricity flow across the power grid. Voltage on the transmission and distribution system must be maintained within an acceptable range to ensure that both real and reactive power production are matched with demand.
	Black Start	In the event of a grid outage, black start generation assets are needed to restore operation to larger power stations in order to bring the regional grid back online. In some cases, large power stations are themselves black start capable.

UTILITY SERVICES

Utility services generally fall into two categories. One set of services—**transmission- and distribution-system upgrade deferral**, focus on using investments in energy efficiency and distributed energy resources to defer large investments in transmission and distribution infrastructure. Typically, distribution infrastructure upgrades are driven by peak demand events that occur on only a few, fairly predictable occasions each year. Transmission upgrades, on the other hand, are driven by large new interconnection requests or transmission congestion. On the distribution side, using incremental amounts of energy storage to deal with limited time-duration events can defer large investments and free up capital to be deployed elsewhere. This can also avoid "over-sizing" the distribution system in the face of uncertain demand growth. This dynamic is illustrated in Figure 1, where a distribution system's load is projected to exceed its rated capacity during a specific time of the day. Energy storage can be used to reallocate this demand to a period when the system is not capacity constrained, thus shaving off the peak of the projected system load and not exceeding the capacity of the system.

The other set of utility services is comprised of **resource adequacy and transmission congestion relief.** These services are needed to meet system peaking requirements on a day-to-day basis. Table 2 (on page 16), outlines the full set of utility services.

FIGURE 1
GENERIC SYSTEM LOAD PROFILE BEFORE AND AFTER ENERGY STORAGE IS USED TO DEFER A TRADITIONAL DISTRIBUTION SYSTEM UPGRADE.

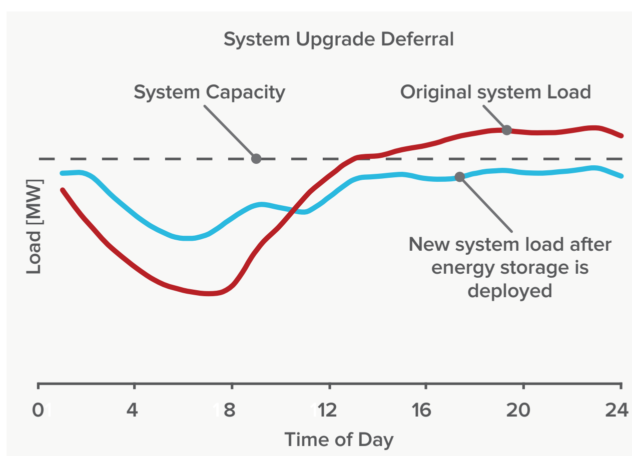


TABLE 2: UTILITY SERVICES

	SERVICE NAME	DEFINITION
UTILITY SERVICES	Resource Adequacy	Instead of investing in new natural gas combustion turbines to meet generation requirements during peak electricity-consumption hours, grid operators and utilities can pay for other assets, including energy storage, to incrementally defer or reduce the need for new generation capacity and minimize the risk of overinvestment in that area.
	Distribution Deferral	Delaying, reducing the size of, or entirely avoiding utility investments in distribution system upgrades necessary to meet projected load growth on specific regions of the grid.
	Transmission Congestion Relief	ISOs charge utilities to use congested transmission corridors during certain times of the day. Assets including energy storage can be deployed downstream of congested transmission corridors to discharge during congested periods and minimize congestion in the transmission system.
	Transmission Deferral	Delaying, reducing the size of, or entirely avoiding utility investments in transmission system upgrades necessary to meet projected load growth on specific regions of the grid.

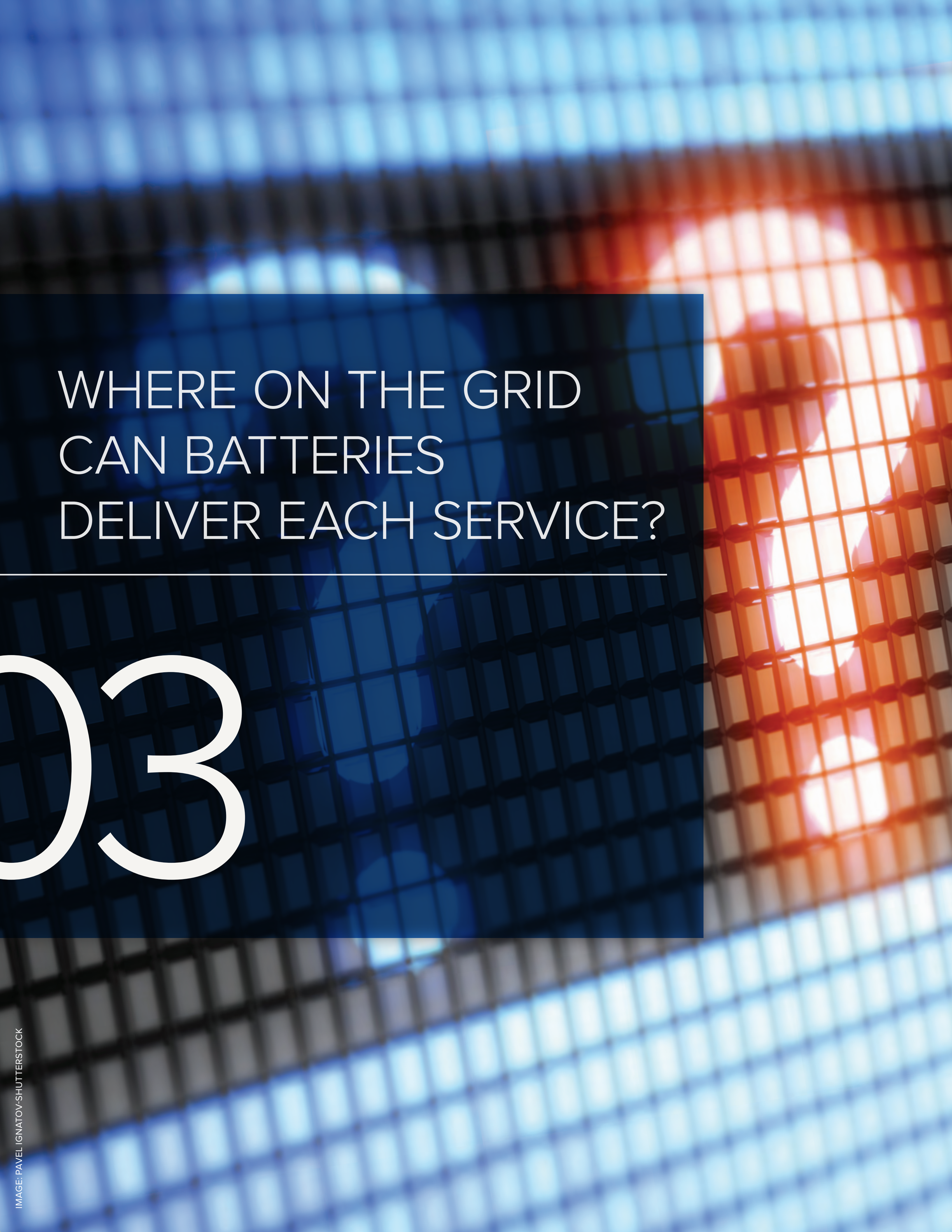
CUSTOMER SERVICES

Customer services like bill management provide direct benefits to end users. Accordingly, the value created by these services can only be captured when storage is deployed behind the meter. Table 3 defines these customer-facing services.

The monetary value of these services flows directly to behind-the-meter customers. However, the provision of these services creates benefits for ISOs/RTOs and utilities, as well. When energy storage either maximizes on-site consumption of distributed solar photovoltaics (PV), generates savings by optimizing load against a time-of-use rate, or reduces a building's peak demand charge, it is effectively smoothing the load profile of the building where it is deployed. A smoother, less peaky load profile is much easier and less costly to match up with the output of centralized generating assets. This is why price signals such as peak demand charges and time-of-use pricing exist: to incent end users to alter their metered load profile in a way that lowers overall system production costs.

TABLE 3: CUSTOMER SERVICES

	SERVICE NAME	DEFINITION
CUSTOMER SERVICES	Time-of-Use Bill Management	By minimizing electricity purchases during peak electricity-consumption hours when time-of-use (TOU) rates are highest and shifting these purchase to periods of lower rates, behind-the-meter customers can use energy storage systems to reduce their bill.
	Increased PV Self-Consumption	Minimizing export of electricity generated by behind-the-meter photovoltaic (PV) systems to maximize the financial benefit of solar PV in areas with utility rate structures that are unfavorable to distributed PV (e.g., non-export tariffs).
	Demand Charge Reduction	In the event of grid failure, energy storage paired with a local generator can provide backup power at multiple scales, ranging from second-to-second power quality maintenance for industrial operations to daily backup for residential customers.
	Backup Power	In the event of grid failure, energy storage paired with a local generator can provide backup power at multiple scales, ranging from second-to-second power quality maintenance for industrial operations to daily backup for residential customers.



WHERE ON THE GRID CAN BATTERIES DELIVER EACH SERVICE?

03

IMAGE: PAVEL IGNATOV-SHUTTERSTOCK

03 WHERE ON THE GRID CAN BATTERIES DELIVER EACH SERVICE?

THE VALUE proposition of energy storage changes significantly depending on where it is deployed on the electricity grid. In order to understand where energy storage can provide the most value to stakeholders and the grid, and to understand where storage delivers the greatest number of services, we divide the U.S. electricity system into three general levels:

Transmission Level:

The farthest **upstream** location that energy storage can be deployed on the grid, generally characterized by higher voltages (in the 115–765 kV range). This includes large central generation stations, transmission lines, transmissions substations, or transmission-connected customers.

Distribution Level:

A **midstream** deployment location for energy storage, the distribution level of the grid includes medium voltage distribution lines, distribution substations, and commercial / industrial customers tied directly to the distribution system, through customer substations, at voltages ranging from 4 to 69 kV.

Behind the Meter:

The furthest **downstream** location where energy storage can be deployed, behind-the-meter storage includes any storage on the customer side of the meter in or near residential, commercial, or industrial buildings (this level includes electric vehicles as well).

Energy storage can be deployed at all three of these levels in different ways to provide value to the electricity system. Examples of business models currently being offered at various levels include:

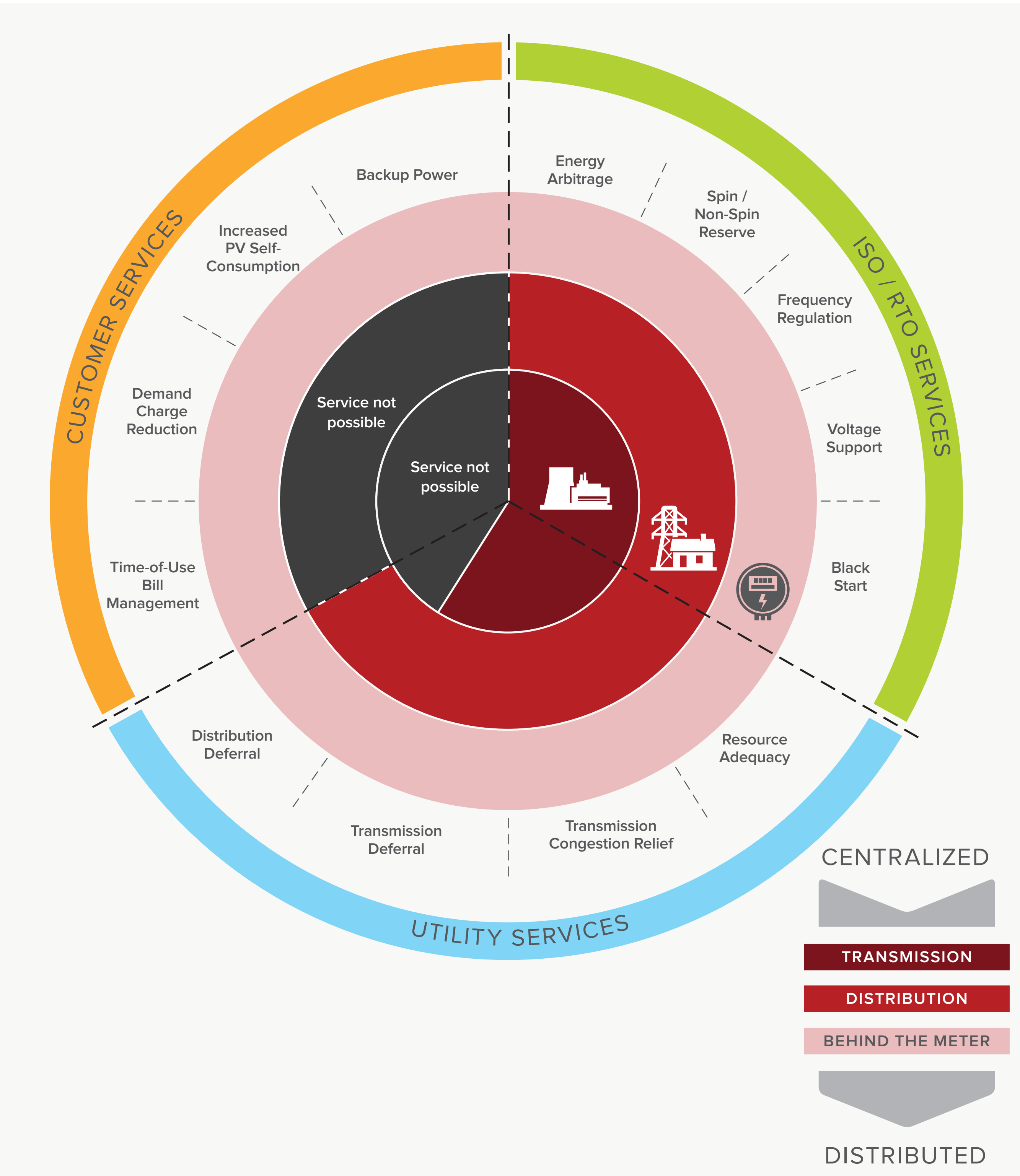
- Grid-scale, transmission-connected batteries deployed by companies like AES and Eos Energy Storage that are reportedly directly competing with natural gas plants to set the market clearing price for flexible-ramping wholesale electricity market products[2]
- Modular, transportable energy storage deployed at distribution substations to defer upgrades; a concept that's been researched for some time and with which some utilities are currently experimenting[3]
- Customer-sited, demand charge reduction-focused energy storage in select U.S. markets by companies like Tesla, Stem, Sunverge, and Coda[4]

These value propositions and the business models behind them vary dramatically due to local electricity-system characteristics, including transmission- and distribution-system age and configuration, the cost of the storage technology itself, regulatory constraints, rate structures, and customer load profiles. Accordingly, it is next to impossible to generalize about where on the electricity system energy storage can provide the most value.

However, after reviewing myriad energy storage studies and tools and conducting our own modeling exercise on the topic, we posit that **the further downstream energy storage is located on the electricity system, the more services it can offer to the system at large.**

Figure 2 on page 19 gives an overview of this concept.

FIGURE 2
BATTERIES CAN PROVIDE UP TO 13 SERVICES TO THREE STAKEHOLDER GROUPS



When energy storage is deployed **behind-the-meter**, it can technically[vi] provide all thirteen services benchmarked in this report, even though many regulatory barriers currently prevent behind-the-meter systems from providing and monetizing these services in the U.S.[vii] When storage is deployed at the **distribution level**, it loses the ability to provide any customer bill management services to end users or to provide any backup power, except in certain specific applications.[viii] When storage is deployed at the **transmission level**, it faces the same limitations as distribution-connected storage and also loses the opportunity to defer distribution system upgrades—generally a very high-value service for the electricity grid.

Furthermore, most systems deployed to date are comprised of single-use, underutilized batteries. These batteries may sit unused for anywhere between 50 and 95% of their useful life[ix] when dispatched to provide only one primary service. This is a waste of a useful asset, and increasing the utilization factor of batteries by re-dispatching them for an additional stack of services once they have performed their primary intended use (e.g., demand charge reduction) can create additional value for all electricity system stakeholders.

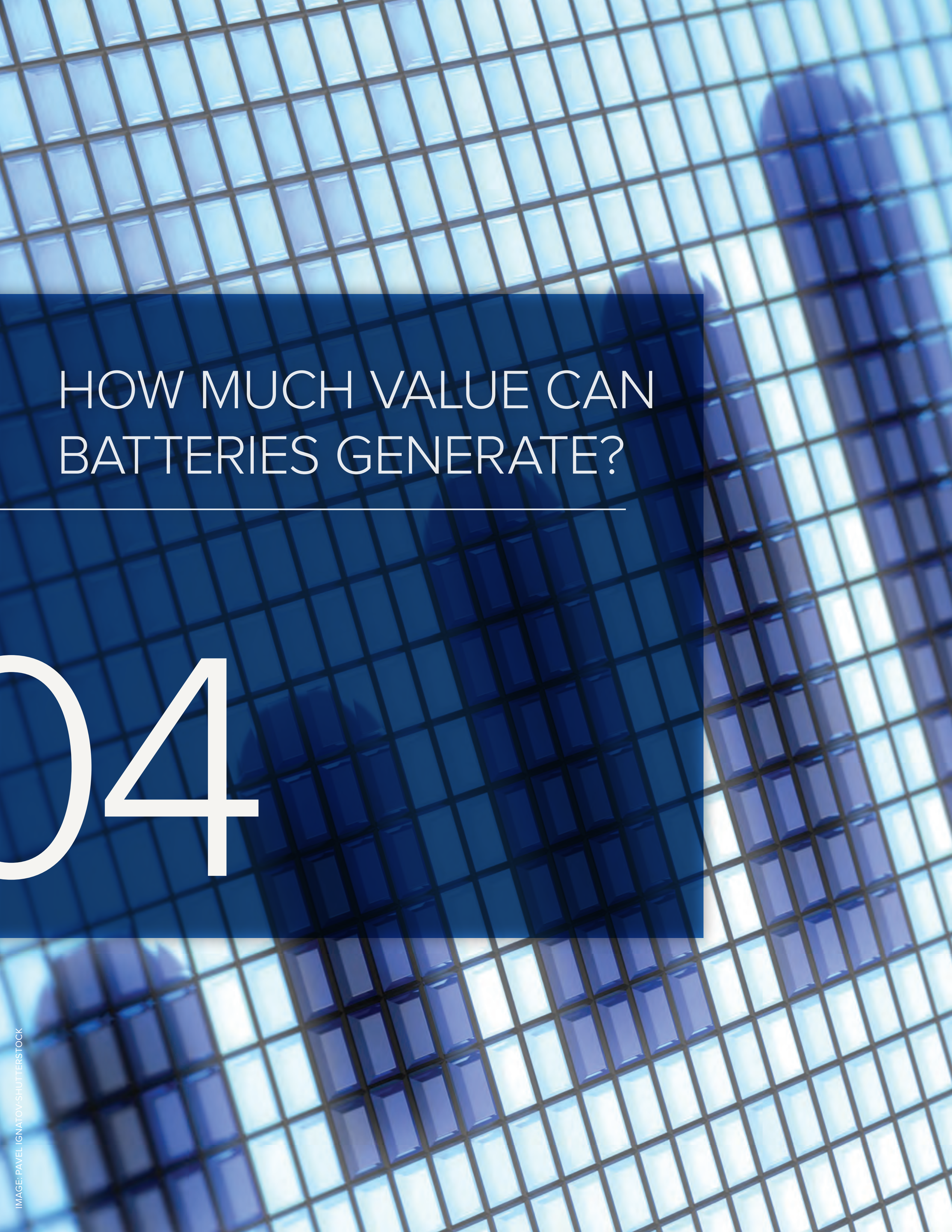
Even though behind-the-meter energy storage systems have the potential to provide multiple, stacked benefits to all stakeholder groups in the electricity system, many rate-related, regulatory, and utility barriers currently prevent them from doing so. These are discussed in more detail in the final section, "What Barriers Exist—And What Are The Implications?"

[vi] Assuming the appropriate communication infrastructure is in place to allow real-time signals from the system operator to the third-party aggregator and, subsequently, to the battery fleet.

[vii] A detailed review of the thirteen services and how they are valued in our dispatch model can be found in Technical Appendix A.

[viii] Although customer-sited energy storage is the most direct way to provide backup power to most customers, energy storage can provide backup power when deployed at the distribution and transmission levels. For example, the University of San Diego's microgrid uses a distribution-connected battery to provide grid services to the microgrid when operating in island mode and can provide backup power for the entire microgrid. For more information, see http://sustain.ucsd.edu/highlights/microgrids.html

[ix] See the dispatch results in Technical Appendix B.



HOW MUCH VALUE CAN BATTERIES GENERATE?

04

IMAGE: PAVEL IGNATOV SHUTTERSTOCK

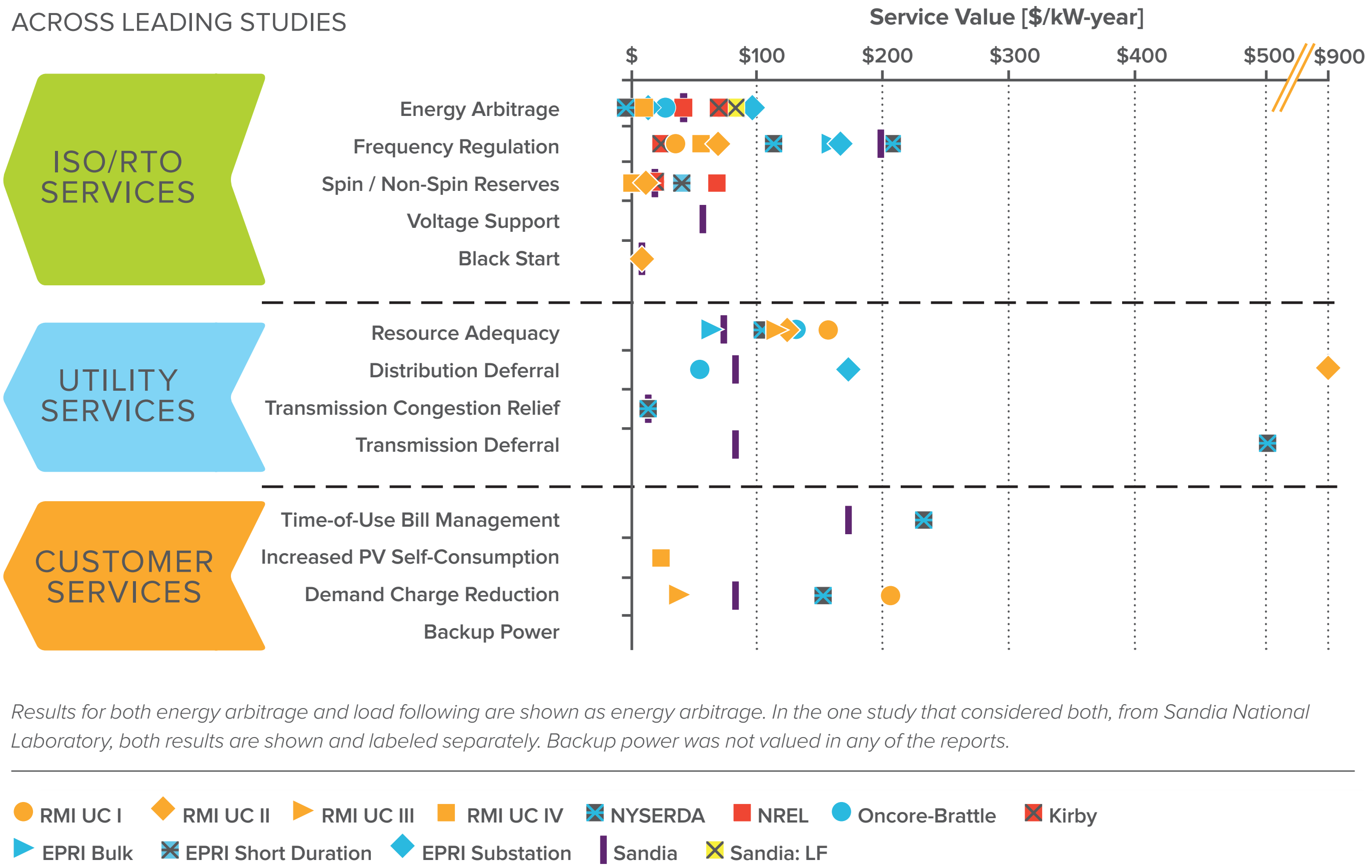
04 HOW MUCH VALUE CAN BATTERIES GENERATE?

ENERGY STORAGE is capable of delivering a suite of thirteen general services to the electricity grid and **the further downstream energy storage is located on the electricity system, the more services it can offer to the system at large.**

However, this characterization does not answer the third question we set out to explore in this report: **how much value can batteries generate when they are highly utilized and multiple services are stacked?** Unfortunately, this question is greatly complicated by the fact that the net value of providing all thirteen services at different levels on the grid (transmission level, distribution level, or behind the meter) varies dramatically. In this report, we offer the results of a meta-study performed by normalizing the key outcomes from six studies, supplemented by expert interviews and internal analysis, in order to compare their different estimates of value. Figure 3 summarizes the estimates of value from these studies using a $/kW-year metric.

The wide variation in each service's value makes generalizations about value difficult. For example, depending on the report cited, the value of transmission and distribution upgrade deferral ranges from $50 to $350/kW-year—a 600% difference.[5] Spreads like this exist for nearly all the services discussed in this report. This value spread is not simply a result of inconsistent modeling methodologies or differing assumptions among the studies. Instead, it is a direct result of the sheer number of variables involved in determining the value of energy storage to the electricity grid. These variables fall into three general categories: electricity-market and regulatory variables, technical variables, and primary dispatch constraints.

FIGURE 3
ENERGY STORAGE VALUES VARY DRAMATICALLY ACROSS LEADING STUDIES



Results for both energy arbitrage and load following are shown as energy arbitrage. In the one study that considered both, from Sandia National Laboratory, both results are shown and labeled separately. Backup power was not valued in any of the reports.

VARIABLES AND CONSTRAINTS

Electricity-Market and Regulatory Variables

Each study analyzed in the meta-study detailed in this report is specific to one of the Federal Energy Regulatory Commission-defined U.S. electric power markets. These markets each have their own distinct characteristics that influence the overall value of energy storage, making value generalization next to impossible.

Perhaps the most significant variable in this area arises from the difference between restructured and non-restructured markets in the United States. In restructured areas like California and New York, where ISOs manage electricity markets for wholesale energy and a number of ancillary services, clearing prices for specific services that could be delivered by energy storage systems are known and can be applied to any modeling effort. In non-restructured states such as Colorado, however, no such wholesale-market coordinator exists. Instead, ancillary services are delivered using an economic dispatch that either uses assets owned and controlled by the utility or assets under contract for the delivery of specific services. Utilities in non-restructured areas are not required to unbundle and publicly disclose the value of ancillary services, like spin and non-spin reserves, from published contract prices. As an example, there is no way for a third party to disaggregate a ten-year, $150/MWh contract between a vertically integrated utility and a company operating a combustion turbine in order to understand how much of that $150/MWh is attributable to wholesale energy sales, frequency regulation, black start, or spin / non-spin reserves. This makes energy storage valuation in non-restructured states challenging and oftentimes forces third parties to overlay wholesale-market data from restructured states onto non-restructured ones when estimating value.

Other electricity-market and regulatory variables include:

- Regulatory policies
- System generation-fleet characteristics
- Transmission- and distribution-infrastructure age
- Customer- and distribution-level load profiles

Technical Variables

In addition to these variables, the value of a storage device is highly sensitive to technical system specifications, such as energy capacity (measured in kWh) and power capacity (measured in kW). These specifications determine which services an energy storage device can provide and for how long it can provide it. Valuation becomes even more complicated when regulatory and market variables are combined with system-specification variables (e.g., minimum system-size requirements that vary across electricity markets). In the meta-study detailed above, we normalized service value on a $/kW-year basis in an attempt to compare apples to apples. However, our generalization of value is of little practical use because each of the studies that went into the meta-study investigated deployments of different power-to-energy ratios—a critically important technical variable for determining the value of specific services provided by energy storage.

Primary Dispatch Constraints

Each energy storage device is typically assigned a primary dispatch, such as backup power, transmission and distribution upgrade deferral, or demand charge reduction. The value batteries can generate is very sensitive to the primary application of any energy storage device or fleet of devices. The battery must be available to dispatch and provide this primary service whenever it is needed. For example, if a system's primary service is backup power and it must be available 100% of the time at a full state of charge, it is unlikely that this system could provide other services. However, if the system's primary use is to deliver demand charge reduction, the system will be available to provide other services—and generate additional revenue—for a large portion of its operational life.

Energy Storage in Action: Four Case Studies

In light of these hundreds of variables and the feedback loops created by them, we have developed four case studies based on specific scenarios to illustrate the range in value that energy storage can create with behind-the-meter. To date, a number of organizations—including the Electric Power Research Institute (EPRI), Pacific Northwest National Laboratory (PNNL), the National Renewable Energy Laboratory (NREL), and many commercial firms—have developed modeling tools and software packages capable of estimating the net value of energy storage. However, these tools and the results generated by them almost exclusively focus on net-benefit analyses of distribution- or transmission-level energy storage systems, in contrast to the case studies in this report.

Drawing upon the methodologies of existing modeling tools and software, we developed a simplified dispatch model to illustrate the net value of behind-the-meter energy storage under four generalized use cases in the U.S. Each case centers on the delivery of a primary service to the grid or to the end user. Storage is dispatched primarily to deliver this service and secondarily provides other services based on the relative value of the service, battery availability and state-of-charge, and other user-defined inputs to the model. Use cases that involve customer bill management are modeled using region-specific, building-level load (appliance-level load when available) and PV performance data to determine a baseline energy bill. The baseline bill is compared to an energy bill that has been optimized by energy storage.

The four cases outlined in this report were developed with the following high-level assumptions in mind:[x]

- **Because all cases evaluate behind-the-meter energy storage, we assumed no regulatory barriers to aggregated, behind-the-meter market participation or revenue generation.** Many regulations do not currently allow behind-the-meter assets to receive payment for deferral services, to provide grid services through bilateral contracts in non-restructured states, or to bid into wholesale markets in restructured states. However, to illustrate the potential net value of systems deployed behind the meter, we artificially remove all regulatory barriers. For example, in many markets, storage is classified as a "load modifying resource" or, in some cases (e.g., in ERCOT), it is classified both as a generation asset and as a load. These misclassifications prevent behind-the-meter energy storage from offering the full suite of services it is technically able to provide.
- **We assign zero value to backup power as an extreme conservatism.** While recognizing that backup power will be a large driver for the early adoption of energy storage, we choose to be conservative here. Zero value is assigned to the backup power energy storage could provide in the event of a larger grid failure.
- **Predetermined dispatch strategy.** For each case, we do not always dispatch the battery to the highest-value service over the lifetime of the system. Instead, we manually dispatch energy storage across different combinations of services to illustrate the broad range of value that storage can create in different electricity markets. This dispatch method necessarily undercuts the true maximum value of storage.
- **Batteries are dispatched for a minimum of one hour.** Some services can be provided and monetized at time scales well below one hour. However, in our model, for every hour the battery is dispatched, it cannot provide any other service during that time, therefore undercutting its maximum value.
- **The cost of all power electronics falls on the battery systems.** For two of the cases, solar PV is paired with energy storage. In reality, the cost of power electronics would most likely be shared between the PV system and the energy storage system. However, as another conservatism, each case assumes the energy storage system will bear the full cost of all power electronics (i.e., all $/kW costs).
- **Each case modeled assumes a third-party developer or the utility is operating either a single battery or an aggregated behind-the-meter fleet of energy storage devices.**

[x]*Detailed assumptions can be found in Technical Appendix C.*

CASE 1: COMMERCIAL DEMAND-CHARGE MANAGEMENT IN SAN FRANCISCO

Description

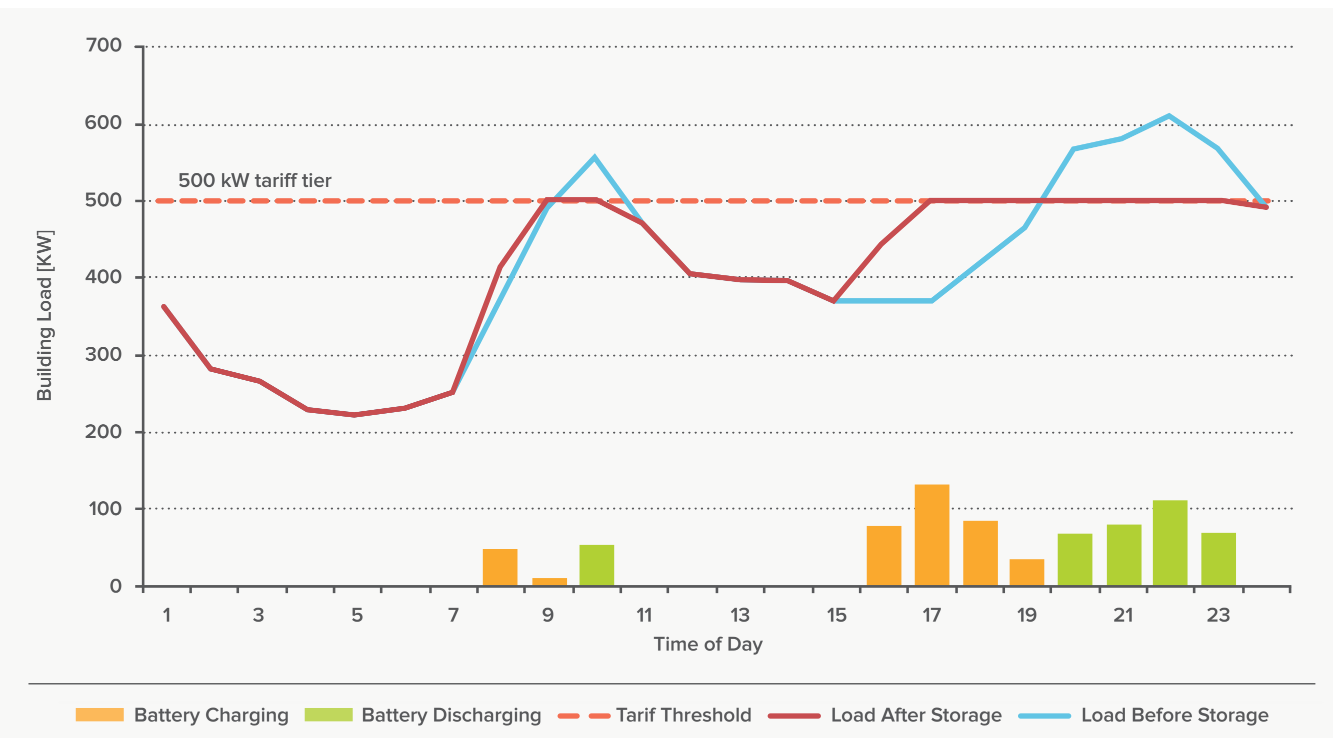
Largely through the Distributed Energy Resource Provider (DERP) proceedings, California is one of a select few states actively working to enable widespread participation of aggregated behind-the-meter energy storage systems in wholesale electricity markets. Furthermore, many commercial rate structures in California make demand charge reduction an attractive option for customers. This is due, in part, to the state's Self Generation Incentive Program (SGIP), which provides a large subsidy to energy storage developers. In accord with these market realities and ongoing industry development in the state, we model a single, commercial, behind-the-meter energy storage system as part of a large fleet that is deployed primarily to reduce demand charges and secondarily to provide ISO/RTO services and resource adequacy to the California grid.

This use case simulates a large hotel in San Francisco that uses energy storage for demand charge management. Figure 4 shows a representative large-hotel load with and without energy storage for a sample day.

On this particular day, the building's original load (blue line) would have exceeded a 500 kW threshold, automatically subjecting commercial customers to a utility tariff with very high demand charges and slightly lower energy charges. The commercial-scale energy storage device is charged during off-peak periods and discharged at key times throughout the day to prevent the building's new load profile (red line) from exceeding the 500 kW threshold. The power and energy rating of the system is sized to keep monthly peak demand below 500 kW. Based on the simulated hourly load of a large hotel in San Francisco with perfect load-forecast knowledge, the required system size is 140 kW and 560 kWh.[6]

FIGURE 4

BUILDING-LEVEL LOAD BEFORE AND AFTER ENERGY STORAGE DEPLOYMENT



Primary Service: Commercial Demand Charge Reduction

This scenario uses a demand charge reduction model to understand exactly when and how much energy storage is needed to shift building-level loads to reduce demand charges. While the battery is shifting building-level loads, it is unable to provide other services.

Secondary Services: ISO/RTO Services and Resource Adequacy

When not shifting building loads, energy storage is dispatched to provide a suite of other services to the grid: regulation, spinning/non-spinning reserves, resource adequacy, and load following (energy arbitrage). The fractional breakdown of hours dispatched to each service is based on average hourly market-clearing prices for ancillary services, the capacity required for each service, and the availability and state-of-charge of the battery.

Figure 5 summarizes the revenues and costs of this fleet over a 20-year project lifetime, including battery replacement in years seven and fourteen.

Results

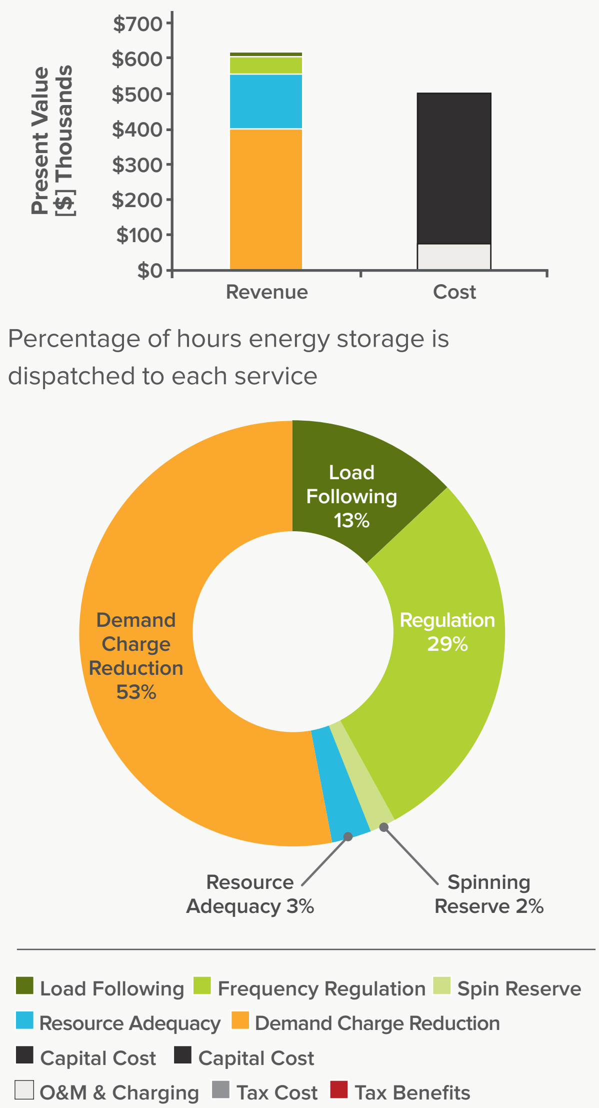
Demand charge reduction presents a compelling business case for commercial customers facing high demand charges today. Using the same battery to provide a stack of secondary services to the grid makes the system a cash-positive investment without the help of SGIP, but such a stacked business case is not being deployed today except in a handful of special projects. Although each service provided by this system is being provided by different behind-the-meter energy storage systems in California today, very few projects are simultaneously providing all services with a single device or fleet of devices.[7]

Our results are suggestive of what many buildings will see, but cannot be generalized across all commercial buildings. The load profile of the building modeled in this use case happens to align closely with the tariff's 500 kW threshold and the storage system allows the customer to transition to a more favorable tariff structure. Where such alignment does not exist, significant savings in demand charges can still be realized (even when the customer remains in the same tariff structure) simply by lowering peak demand charges, as demonstrated in the residential bill management case in Phoenix.

FIGURE 5

USE CASE I MODELING RESULTS

Commercial demand-charge management in San Francisco.



CASE 2: DISTRIBUTION UPGRADE DEFERRAL IN NEW YORK

Description

In 2014, the utility Consolidated Edison (ConEd) filed a proposal with the New York State Public Service Commission for the Brooklyn-Queens Demand Management (BQDM) program. The aim of the BQDM program is to defer two substation upgrades in Brooklyn and Queens that would cost the utility and ratepayers an estimated $1 billion. To avoid this $1 billion investment, ConEd proposed spending $200 million on behind-the-meter load management and an additional $300 million on traditional substation upgrades. At projected rates of load growth, ConEd needs to reduce or realign the timing of 52 MW of load by 2018 to avoid overloading the substations. For this case, we assume that demand response and energy efficiency programs will help reduce projected load growth on the substations by 50%, or 26 MW. We then assume that a fleet of residential and commercial energy storage systems installed behind the meter will avoid the remaining 26 MW of substation peak overload and help completely defer the original $1 billion planned investment by ConEd.[8]

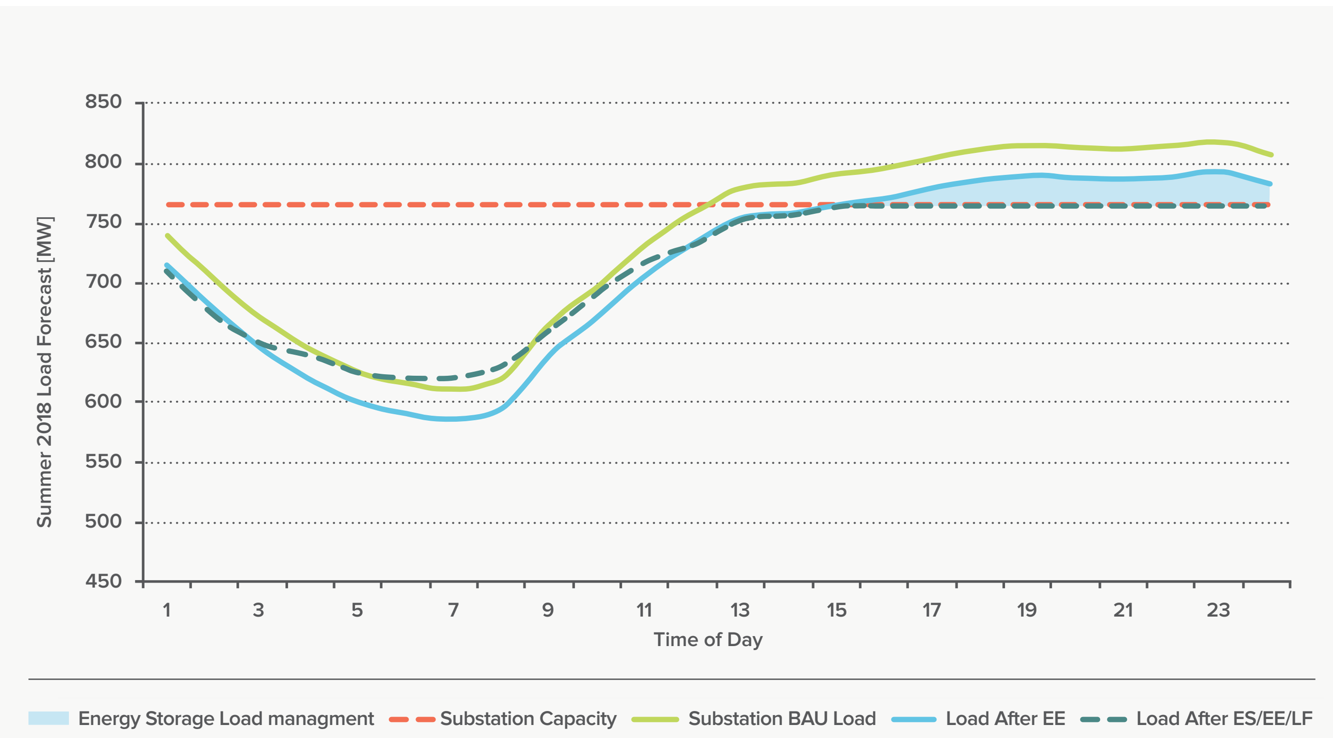
Figure 6 illustrates this scenario. The green line shows the expected load shape with no energy efficiency, demand response, or energy storage installed. The blue line is the new load profile after energy efficiency and demand response measures have been installed throughout the area. Finally, the light blue area illustrates the contribution of energy storage to ensure that the system's load never exceeds the rated substation capacity. Effectively, energy storage will shift load from the late afternoon peak to early morning hours when load is at a minimum.

Primary Service: Distribution Upgrade Deferral

This combination of energy efficiency, demand response, and energy storage devices installed behind the meter could defer ConEd's planned distribution

FIGURE 6

BQDM SYSTEM-LEVEL LOAD BEFORE AND AFTER DISTRIBUTED ENERGY STORAGE DEPLOYMENT



system upgrade. The batteries are committed to be available specifically for upgrade deferral for 120 hours each year during summer substation peak events. This leaves the batteries available to provide other services for the remainder of the year.

The BQDM program expects that solutions like these will defer the substation upgrade from 2017 to 2019, at the earliest. The installation of a fourth and fifth transformer and supporting infrastructure will allow the deferral to be extended to 2024. The value assigned to storage for providing this service is calculated using an assumed installed cost of $1 billion and an equipment carrying charge of 12%, resulting in an annual deferral value of $120 million. We assume this value is distributed equally between the energy storage fleet (paid out over two years) and the energy efficiency/demand response programs.

Secondary Services: ISO/RTO Services and Resource Adequacy

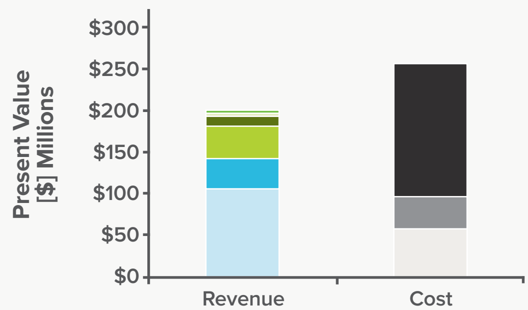
When the fleet is not committed to providing distribution system deferral, it is deployed as an aggregated resource to participate in the New York Independent System Operator's (NYISO) ancillary service market, where it provides a mix of frequency regulation, spinning and non-spinning reserves, and black start services. In addition to participating in the ancillary market, the fleet is dispatched as a load-following generator (providing energy arbitrage services) and in the NYISO installed-capacity market where it provides resource adequacy. The fractional breakdown of hours dispatched to each service is based on average hourly market-clearing prices for ancillary services, the capacity required for each service, and the state-of-charge and availability of the aggregated fleet to provide those grid services[xi]. In this case, the fleet is not dispatched to deliver any direct customer-facing services,[xi] such as demand charge reduction or TOU bill management. Furthermore, this model assumes zero value for backup power, although in reality many customers would assign some value to this service. Including these customer-sited services could substantially improve the economics of this case, and represents a strong argument for locating batteries where they are able to provide customer services.

[xi] *See Technical Appendix B for a comprehensive list of market-clearing price assumptions.*

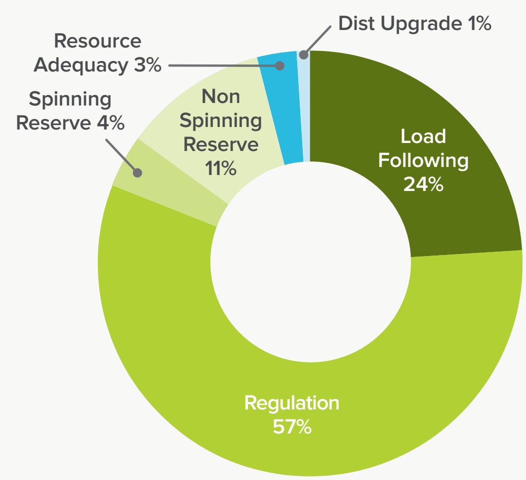
FIGURE 7

USE CASE II MODELING RESULTS

Distribution upgrade deferral in New York



Percentage of hours energy storage is dispatched to each service



Load Following · Frequency Regulation · Spin Reserve · Non-Spin Reserve · Black Start · Resource Adequacy · Dist Deferral · Capital Cost · O&M & Charging · Tax Cost · Tax Benefits

The aggregated fleet is comprised of 4,000 residential systems [5 kW/10 kWh] and 1,500 commercial systems [30 kW/90 kWh] providing an aggregated capacity of 65 MW/175 MWh.[xii]

Figure 7, previous page, summarizes the revenues and costs of this fleet over a 20-year project lifetime, including battery replacement in years seven and fourteen.

Results

Distribution deferral is an immensely valuable service—especially when one considers that the batteries in this use case are only dispatched for 1% of their useful life to provide it. However, even after downsizing the energy storage requirement with energy efficiency and demand response, this storage fleet does not produce a net economic benefit—largely because the batteries deliver no services to end users. This case demonstrates the challenges associated with batteries focused only on utility and ISO/RTO services, and the importance of considering customer benefits.

Several approaches could be pursued to make this scenario cash positive, however, including:

- Secondarily dispatching the fleet to deliver customer-facing services, like demand charge reduction or backup power, instead of wholesale market services. This single change would likely flip the economics in favor of storage.
- Using a hybrid battery design that combines lithium-ion systems with lower cost, long-discharge batteries (such as flow batteries) capable of providing the long, eight-hour discharge required to provide the distribution upgrade deferral service
- Reduced energy-storage system costs (this scenario would break even with lithium-ion costs of $223/kWh and $849/kW)
- Since these batteries are not generating any revenue from customer services, this specific set of services may be better provided by a combination of energy efficiency, demand response, and larger distribution-connected batteries that can be installed next to the distribution substation to provide a similar combination of services at a lower cost
- This scenario requires eight hours of sustained energy capacity to shift the system peak, requiring a dramatically oversized energy storage fleet. Pursuing deeper and broader energy efficiency and demand response measures could downsize the storage requirement and dramatically improve project economics

Even if this particular scenario were cash positive, the ability of behind-the-meter resources to deliver critical, time-sensitive services (such as distribution system upgrade deferral, where failure to deliver could result in localized grid failure) would remain to be proven to grid operators. Historically, grid operators and/or scheduling coordinators had the ability to 'flip the switch' on a conventional centralized generator or other asset when a system was nearing capacity. Conceptually, flipping a switch that engages an aggregated, behind-the-meter energy storage fleet is no different than activating a centralized asset, provided the appropriate level of communication infrastructure is in place. However, empirical evidence to demonstrate a fleet's ability to provide such a critical, time-sensitive service is currently minimal. The guaranteed availability of an aggregated, behind-the-meter resource during system overload events is of paramount concern to utilities and will need to be validated via pilots or demonstration projects in order for use cases like this one to be deployed at scale.[9]

[xii] *Additional assumptions can be found in Technical Appendix B.*

CASE 3: RESIDENTIAL BILL MANAGEMENT IN PHOENIX

Description

Recently, the utility Salt River Project in Arizona enacted a new tariff for residential customers who choose to install rooftop PV systems. This tariff increases a customer's fixed charge and incorporates a residential demand charge. Under this new tariff, behind-the-meter energy storage systems can be used to reduce demand charges, navigate time-of-use rates, and offset the increased fixed charge by providing ancillary services to the utility. Figure 8 presents a sample profile of a single customer's metered load before (dotted green line) and after (solid blue line) energy storage is used to lower the customer's metered peak demand. The demand charge is incremental and increases when demand exceeds the 3 kW mark and increases again at the 10 kW mark, shown as a dotted red line in the figure.

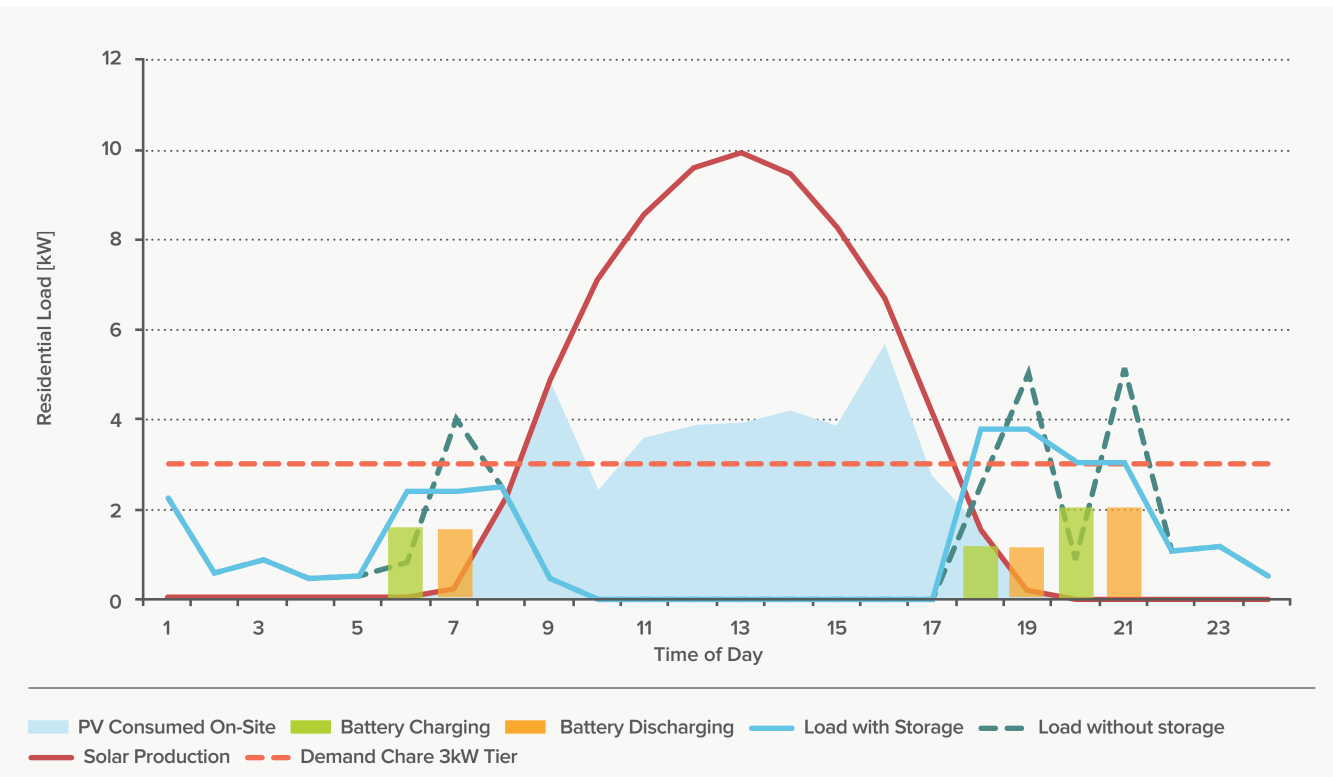
Primary Services: Residential Demand Charge Management, Time of Use Management

Under this scenario, the energy storage system's primary objective is to reduce demand charges and minimize grid purchases during time-of-use peak periods. The system is first dispatched to shift residential demand from the peak-load hours of each day to periods of lower demand (assuming perfect load-forecast knowledge). The value to the customer is calculated as the difference between the customer's bill with and without energy storage under the new Salt River Project tariff.[10]

This case assumes that all storage systems are paired with a rooftop PV system sized for annual-net-zero power purchases from the grid. The hourly charging and discharging requirements of the system to provide these primary services are calculated using hourly load data coupled with hourly PV-performance data.

FIGURE 8

RESIDENTIAL LOAD IN PHOENIX, BEFORE AND AFTER ENERGY STORAGE IS DISPATCHED



Load data is taken from RMI's *Economics of Demand Flexibility* report[11] and PV performance is modeled in the NREL System Advisor Model.[12] When the battery is not being dispatched for bill management as shown above, the system is available for roughly 6,000 hours each year to provide other services.

Secondary Services: ISO/RTO Services and Resource Adequacy

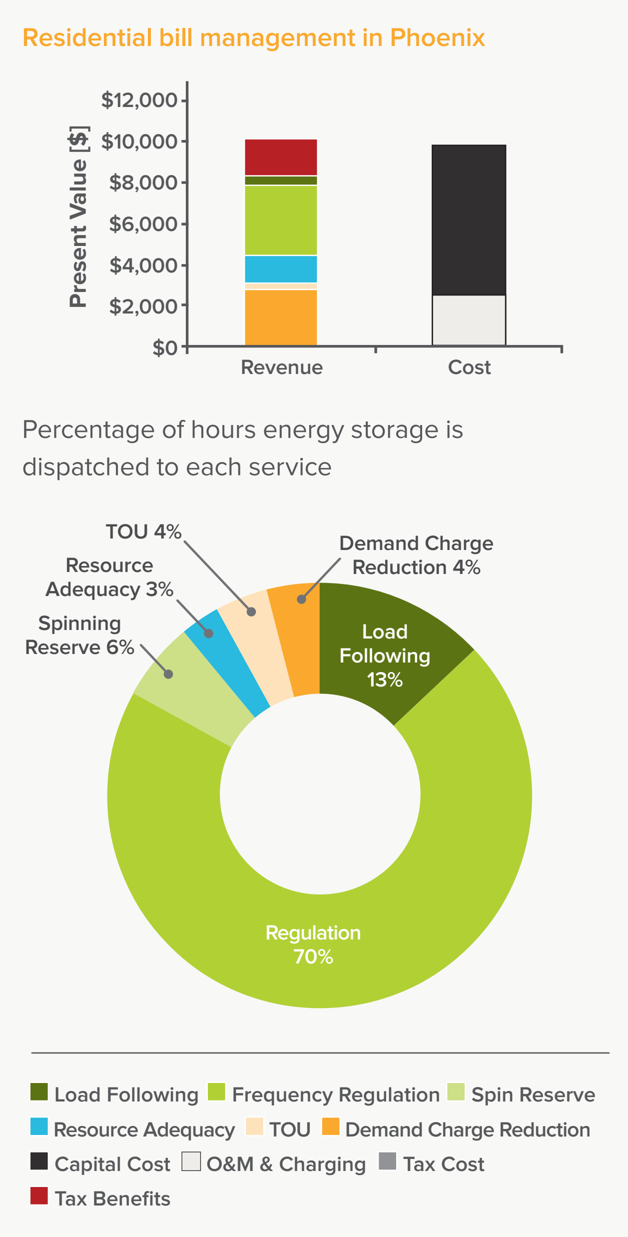
When the system is not dispatched for its primary use, the energy storage device is aggregated with other, similar systems and dispatched to provide a suite of other services to the grid, including regulation, spinning /non-spinning reserves, resource adequacy, and load following. The fractional breakdown of hours dispatched to each service is based on average hourly market-clearing prices for ancillary services, the capacity required for each service, and the availability and state-of-charge of the aggregated storage fleet.

Because Arizona is a non-restructured state, the true revenue opportunity presented by these services in Salt River Project's territory is unknown. For this case, we use market-clearing prices from the CAISO wholesale market as a proxy to estimate the value of all ISO/RTO services and resource adequacy.

Figure 9 summarizes the revenues and costs of this fleet over a 20-year project lifetime, including battery replacement in years seven and fourteen.

FIGURE 9

USE CASE III MODELING RESULTS



Results

Pairing a multi-use energy storage system with rooftop PV under Salt River Project's new tariff protects the value proposition of solar PV and offers an attractive investment scenario. The storage system effectively shifts load in response to utility price signals, resulting in lower monthly electricity bills and lower utility production costs. Customer bill savings of nearly 20% per year can be accomplished with a storage dispatch factor below 10%. Put another way: customers can save 20% off their electricity bills each year while still having the battery available to collect other revenue for 90% of the battery's life. The value that end users can monetize depends heavily on the tariff structure and the load profile of the end users. Residential customers with 'peaky' loads that occur during peak load hours will realize greater savings than customers with relatively flat loads—an important distinction considering how residential customer peaks in Salt River Project territory are driven by peaky air conditioning loads.

This use case reveals several other insights:

- Stacking residential demand charge reduction and TOU optimization with additional ISO/RTO services produces enough revenue to justify investment in energy storage systems that deliver this particular stack of services
- However, for this investment to make sense when the investment tax credit goes to zero for homeowners and shrinks to 10% for businesses, the capital costs of the energy storage need to decline to $300/kWh and $1,111/kW to be cash positive
- In order for this scenario to be possible in Salt River Project's non-restructured environment (where no wholesale ancillary service market exists), changes need to occur to allow customer-owned, behind-the-meter assets to provide—and be compensated for—ISO/RTO services and resource adequacy

CASE 4: SOLAR SELF-CONSUMPTION IN SAN FRANCISCO

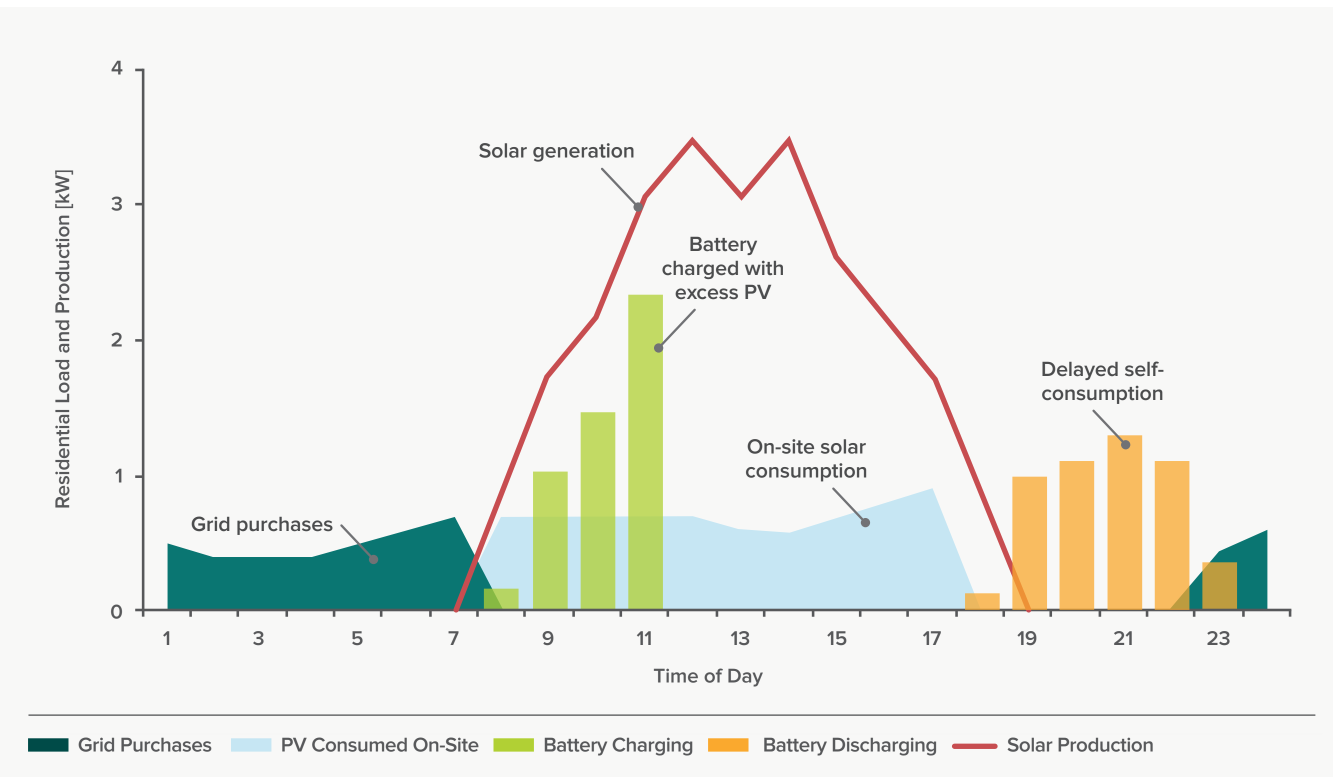
Description

Net energy metering (NEM) policies face an uncertain future in many markets for several reasons beyond the scope of this report. Although the future of NEM in most regions is unknown, for this particular use case we assume that NEM will be replaced with a modified tariff where solar PV that is not consumed on-site is sold back to the grid at a much lower value than the retail price, modeled here at 3.5 cents/kWh.

Figure 10 shows a sample day of a particular residential customer's load, again in San Francisco. When PV production exceeds on-site load, the excess power is first used to charge the battery (green bars). Only after the battery is fully charged is electricity exported back to the grid (not shown on this figure). Energy

FIGURE 10

RESIDENTIAL LOAD AND PV PRODUCTION BEFORE AND AFTER ENERGY STORAGE IS DEPLOYED



stored during the day is used in the evening (orange bars) when PV production drops off, effectively preventing a portion of the evening load from being met with power purchased from the grid. This process maximizes self-consumption of the PV system, improving the economics of PV under this hypothetical non-NEM tariff.

In this scenario we assume the customer has installed a rooftop PV system sized for annual-net-zero power purchases from the grid. Again, to be conservative, we do not share power electronics costs between the PV and energy storage systems and assume the storage system bears all of the power electronics ($/kW) costs.

Primary Service: Self-Consumption of generation from on-site solar PV

The primary function of this system is to reduce customer bills by maximizing self-consumption of solar kilowatt-hours. The value to the customer is calculated as the difference between the customer's bill with and without energy storage. Here we make the assumption that net energy metering is no longer in effect and the customer is credited for excess PV sent to the grid at the wholesale electricity rate of $0.035/kWh. In addition to capturing value by maximizing on-site PV consumption and minimizing grid purchases, this customer benefits from TOU energy management (included in self-consumption in Figure 11).

Secondary Services: ISO/RTO Services and Resource Adequacy

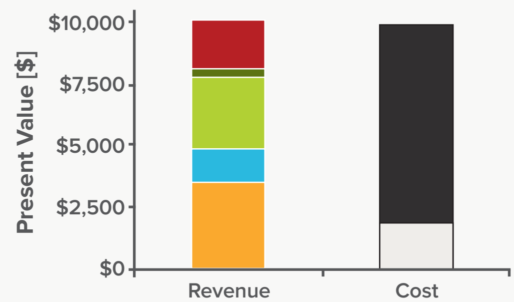
After optimizing building-level load to maximize self-consumption of generation from on-site solar PV, we assume the energy storage device is aggregated with other, similar systems and dispatched to provide a suite of services to the grid: regulation, spinning /non-spinning reserves, resource adequacy, and load following (energy arbitrage). The fractional breakdown of hours dispatched to each service is based on average hourly market-clearing prices for ancillary services, the capacity required for each service, and the availability and state-of-charge of the aggregated storage fleet.

Figure 11 summarizes the revenues and costs of this fleet over a 20-year project lifetime, including battery replacement in years seven and fourteen.

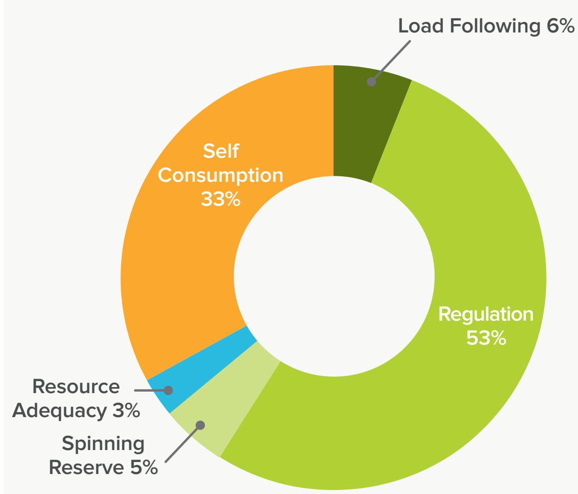
FIGURE 11

USE CASE IV MODELING RESULTS

Solar self-consumption in San Francisco



Percentage of hours energy storage is dispatched to each service



Load Following | Frequency Regulation | Spin Reserve | Resource Adequacy | Demand Charge Reduction | Capital Cost | O&M & Charging | Tax Cost | Tax Benefits

Results

Using energy storage to maximize self consumption of generation from a distributed PV system under a non-NEM rate is economically attractive if that same energy storage system is allowed to deliver a suite of ISO/RTO and utility services and thereby earn revenue. In regions without NEM, this use case makes sense if the full stack of grid services are valued, yet in areas where NEM exists this use case does not make economic sense because the utility is willing to pay the full retail rate for all exported electricity without the need for an on-site battery.

This use case also illustrates the following dynamics:

- Retail electricity rates and tariff structures are regularly subject to modification that can drastically undercut the value proposition of rooftop solar.[xiii] Energy storage systems like the one modeled above reduce PV-ownership risk by partially decoupling the value of solar from utility compensation of DERs
- With the help of the investment tax credit, an energy storage system that maximizes self-consumption under this non-NEM rate and participates in RTO/ISO services is cash-positive. Achieving costs of $300/kWh and $927/kW makes this scenario cash positive even without the investment tax credit
- A system primarily performing self-consumption is available for roughly two-thirds of the year to provide other services to the grid

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[xiii] For example, recent filings in Hawaii, California, and elsewhere have requested implementation of non-export tariffs for new solar PV customers. Under a non-export tariff, the value proposition of rooftop solar alone is reduced, while the value proposition of solar self-consumption is significantly larger than the modeling results illustrated here.

WHAT BARRIERS EXIST—AND WHAT ARE THE IMPLICATIONS?

05

IMAGE: PAVEL IGNATOV-SHUTTERSTOCK

05 WHAT BARRIERS EXIST—AND WHAT ARE THE IMPLICATIONS?

THIS SECTION ADDRESSES the last and perhaps most important question we set out to explore in this report: **what barriers—especially regulatory—currently prevent single energy-storage systems or aggregated fleets of systems from providing multiple, stacked services to the electricity grid, and what are the implications for major stakeholder groups?**

As demonstrated in the previous section, energy-storage business models that are able to provide both customer- and grid-facing services present a compelling investment opportunity—even under current behind-the-meter energy storage cost structures. However, for our modeling, **we artificially removed any regulatory barriers from the equation.** For example, our use case that considers residential bill management in Phoenix assumes an aggregator (or utility) is able to use thousands of networked residential energy storage systems to bid into a wholesale market and receive revenue for providing frequency regulation to the grid. However, wholesale electricity markets do not exist in every state. Furthermore, in restructured states where such markets do exist, regulatory barriers still largely prevent behind-the-meter systems from providing those services. As another example, the revenue we assigned to energy storage from a distribution upgrade deferral in New York depends on a rarity—there exist only a handful of similar revenue opportunities anywhere in the world where utilities are willing and/or incentivized to use distributed energy resources for such applications.

BARRIERS

In order for the scenarios modeled in this report to become reality or for energy storage to provide any other combination of stacked services to the grid at scale, many barriers must be overcome. Some of the most pressing ones are detailed below.

Overarching barriers

A number of crosscutting barriers prevent energy storage from providing many services to the electricity grid:

- **Rules and regulations that place behind-the-meter energy storage on an equal playing field with large central generators have been developed and implemented slowly.** Perhaps the most powerful example of this trend was the three-year adoption period for FERC order 755 in ISOs/RTOs across the nation. Furthermore, most state public utility commissions have yet to require utilities to consider behind-the-meter energy storage (in addition to other distributed energy resources) as a viable alternative to traditional infrastructure investments during integrated resource planning and rate filings.

- **Regulatory restrictions make it difficult or impossible for a utility to collect revenue from a behind-the-meter energy storage asset that provides value to multiple stakeholder groups.** Value created by an energy storage device or fleet of devices that delivers services at different levels of the electricity grid (transmission level, distribution level, and behind the meter) and to different stakeholders (ISOs/RTOs, utilities/grid operators, and customers) cannot be captured by utilities at present. For example, under prevailing ISO/RTO rules, a utility would not be allowed to use a fleet of batteries to participate in the wholesale electricity market while simultaneously providing distribution upgrade deferral services and collecting cost-of-service recovery payments. Furthermore, most utilities are not incentivized to invest in energy storage systems that provide multiple services, as only part of the investment can be rate-based under prevailing regulations. Using bilateral contracts, vertically integrated utilities could currently capture these disparate value streams across all classifications, though few have done so.[13]

- **Most electricity markets compensate ancillary service providers using a formula that accounts for the marginal cost of generation and opportunity costs from not participating in the wholesale energy market.** This methodology does not accurately represent the cost of providing ancillary services for a non-generating asset like energy storage. Put another way: electricity markets designed with a marginal cost in mind are not well suited to integrate capital-intensive technologies like energy storage.

Specific Market and Regulatory Barriers

More regulatory barriers exist for specific services, as discussed below.

Energy Arbitrage (Includes Load Following)

- **Regulations are currently misaligned.** System operators cannot currently dispatch energy storage as a load-serving entity for least-cost operation due to barriers that limit participation in the commercial market. In ISO/RTO regions where energy storage is deployed as a transmission and distribution asset (to deliver services like resource adequacy), storage is not allowed to participate in wholesale electricity markets.

Frequency Regulation and Spin/Non-Spin Reserves

- **Regulatory uncertainty is limiting energy storage's potential.** Energy storage has yet to be clearly classified, leading to a major lack of clarity regarding its ability to participate in various markets.
- **Widespread energy storage participation in electricity markets will dramatically alter the markets themselves under current market design.** As more energy storage is deployed to deliver some services, the relative value of the services will decline because of energy storage's ability to quickly, reliably, and predictably deliver.

Voltage Control and Black Start

- **There are no formal market structures in the U.S. for black start and voltage control—services particularly well suited to battery-based energy storage.** Instead, these services are compensated at a FERC-approved cost-of-service rate.

Distribution Upgrade Deferral

- **Currently, no standard market mechanism exists for behind-the-meter assets to collect revenue for load management,** resulting in deferred system investments, other than those for traditional demand management programs. Programs like the Brooklyn Queens Demand Management program and various behind-the-meter energy storage pilots proposed by Consolidated Edison, San Diego Gas & Electric, and Hawaii Electric Corporation do establish one-off mechanisms to compensate storage providers for deferrals, but no standard mechanism has yet to emerge.

It is beyond the scope of this report to unpack each of these barriers and recommend specific regulatory changes to overcome each of them. However, as illustrated here, behind-the-meter energy storage is capable of providing net value to the electricity system when it is allowed to deliver multiple services to different stakeholder groups at different levels of the grid. In particular, the inclusion of customer services in the stack of services that a battery can provide dramatically improves the economics of the system as a whole. It may not be a one-size-fits-all solution for the electricity system, but surely a technology capable of providing necessary services to the electricity grid should compete on a level playing field with centralized thermal power plants and distribution-/transmission-level infrastructure investments—the technologies that have provided these services since the grid was born.

Implications for Stakeholders

Energy storage is capable of providing more value at a lower cost than legacy technologies for many important services but, in order for these services to be delivered and compensated, several groups of stakeholders must enact changes. Only then will energy storage and other distributed energy resources reach their full potential.

To help energy storage become an integral part of a secure, high-renewable, low-cost, and low-carbon electricity grid of the future, we recommend the following next steps:

For Regulators

- Remove barriers that prevent behind-the-meter resources such as battery energy storage from providing multiple, stacked services to the electricity grid that benefit all stakeholder groups, including customers, ISOs/RTOs, and utilities.[xiv]

- Require that distributed energy resources (including storage) be considered as alternative, potentially lower-cost solutions to problems typically addressed by traditional "wires" investments and/ centralized peaking generation investments.

- Across all markets, require utilities to use a standardized, best-fit, least-cost benefit methodology that compares energy storage providing a full suite of stacked services to incumbent technologies.

For Utilities

- Restructure utility business models and rates to reflect the value that storage can provide to the grid via temporal, locational, and attribute-based functionality, making utilities indifferent to the distinction between distributed and centralized resources.

- Prior to considering new centralized assets, look first for opportunities to leverage existing assets, such as storage, via stacking of uses; provide education so that distribution planners, grid operators, and rate designers can work together to leverage storage's full suite of capabilities.

For the Research Community

- Develop a widely recognized modeling tool or a consistent methodology and approach capable of comparing, on an equal basis, the net cost of stacked services provided by energy storage and other distributed energy resources to incumbent technologies such as combustion turbines and traditional infrastructure upgrades.

- Develop a detailed, state-by-state roadmap that specifically identifies policy and regulatory changes that must be adapted or revised to enable widespread integration of energy storage and other distributed energy resources.

For Battery and Distributed Energy Resource Developers

- Pursue business models that fully utilize the battery.

- Pursue cost reduction efforts for all power-focused elements of energy storage systems (all $/kW components) in order to unlock more energy storage markets.

- Collaborate with utilities and regulators to help them understand what values distributed energy storage can provide and what new utility business models will be needed to scale them.

[xiv] Ongoing efforts that tend towards this outcome include New York's Reforming the Energy Vision proceeding, California's order for development of distributed resource plans, Massachusetts' Grid Modernization Plan, ERCOT's proposed rules and regulations on distributed energy resource integration, Minnesota's e21 initiative, ongoing regulatory proceedings in Hawaii, and others.

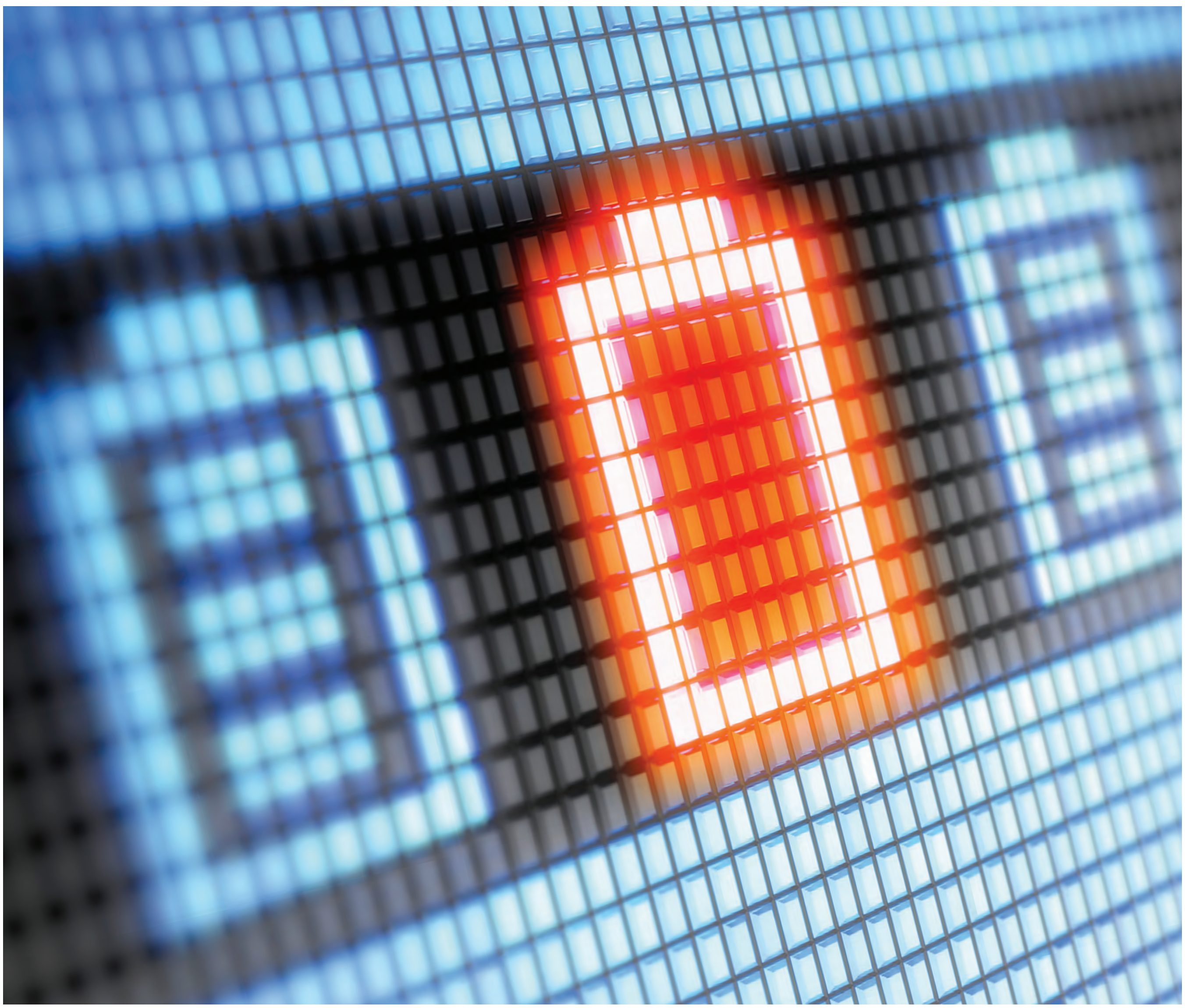
CONCLUSION

06

IMAGE: PAVEL IGNATOV-SHUTTERSTOCK

06 CONCLUSION

As illustrated in this report, energy storage is capable of providing a suite of thirteen general electricity services to the electricity grid, and **the further downstream from central generation stations energy storage is located, the more services it can offer to the electricity system at large.** Many of these downstream services, such as customer bill management, have powerful impacts on the economics of battery storage and help justify batteries that also contribute to grid services. What remains to be determined is exactly where on the grid energy storage should be deployed to maximize net value to the system. Our simple dispatch model does not definitively answer this question but, instead, illustrates how dramatically the net value of energy storage can vary based on a number of different variables. **However, even today, pending a suite of regulatory changes to unlock unfettered market participation, behind-the-meter energy-storage business models that deliver a stack of services to both customers and other electricity system stakeholders can already provide positive net value to the electricity system under prevailing energy storage cost structures.**



07 ENDNOTES

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