Energy Storage System Performance Impact Evaluation

Final Report

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1 Introduction

This section presents a program description and a summary of the evaluation objectives and methods.

1.1 Program description

In 2018, the Public Service Commission of New York set an ambitious target of 3 GW of qualified energy storage capacity by 2030. Moreover, NYSERDA's most recent Energy Storage Roadmap, filed in December 2022, doubles that target to 6 GW.[1] This target dovetails with the Climate Leadership and Community Protection Act, which calls for 70% of electricity to be sourced from renewables by the end of the decade. According to the Roadmap, 1.3 GW of storage projects have been deployed, contracted, or rewarded.

To meet the goals, New York has thus far pursued a suite of incentive programs. Sites totaling 811 MW of the 1.3 GW achieved so far received funding from NYSERDA's Market Acceleration Bridge Incentive program. Of that portion, 480 MW comes from bulk storage sites over 5 MW that participate in the wholesale electricity market. The Bridge program provided an up-front incentive scaled to the kWh capacity of the system. Another 320 MW was procured via the Retail Storage Incentive Program, which targeted distribution-connected projects, and 11 MW from the Long Island Residential Storage program. The state's Utility Bulk Storage Dispatch Rights Procurement program also yielded 120 MW of storage capacity by directing utilities to meet certain targets via their own procurement process. Finally, the state's Clean Energy Standard[2] and the NY Green Bank have contributed to the growing pipeline of projects by incentivizing the co-location of storage with generation and providing loans to support the project development, construction, and operation of storage systems.

Sites covered in this analysis are participants in the Bulk and Retail Storage programs, as well as the Emerging Technologies and Accelerated Commercialization for the Commercial/Industrial Sector (ETAC-CI) program. Collectively, these sites have 128 MW and 322 MWh in energy storage capacity. Thirty-one of the 42 sites in the data participate in the Value of Distributed Energy Resources (VDER) compensation system. VDER replaced net metering in 2017 and

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[1] New York Department of Public Service & NYSERDA, New York's 6 GW Energy Storage Roadmap, 2022: https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/Energy-Storage/ny-6-gw-energy-storage-roadmap.pdf

[2] For more information on New York's Clean Energy Standard: New York's Clean Energy Standard (CES)

provides site operators with credits based on a Value Stack that includes energy, capacity, environmental, reliability, locational, and community benefit components. Per the rules of the compensation scheme, these VDER sites are 5 MW or less in capacity. Besides VDER, two sites in the data provide ancillary power-balancing services for NYISO, five assisted with demand reduction and response, and two supplied back-up power to the facilities on-site.

With 200 storage projects currently in the New York Independent System Operator (NYISO) interconnection queue[3] and policy pressure to increase this number and bring projects through the procurement, contracting, and construction process faster, it is important that all stakeholders have insight into how the storage systems currently in operation are contributing to the energy transition. This report provides that insight and documents the challenges faced in doing so.

1.2 Evaluation objectives and methods

This report synthesizes an overview of the energy storage sector, a survey of system installers, battery degradation modeling, site-level performance and operational strategy insights, and Value of Distributed Energy Resources (VDER) vs. non-VDER site benefits. Market and qualitative research is combined with quantitative analysis to arrive at findings of how storage systems are currently contributing to the New York grid and offer recommendations for the program.

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[3] NYISO Interconnection Queue, October 13th, 2023: https://www.nyiso.com/documents/20142/1407078/NYISO-Interconnection-Queue.xlsx/f615d83e-eea6-ccf6-ec07-b4ecbe78d8ef

Table 1-1. Study objectives, research questions, and methods

Objective	Purpose	Method
Identify main drivers and obstacles to market adoption of energy storage systems	To understand barriers for market adoption, state of technology within the industry so as to benchmark for comparing systems in study	Market research & web surveys
Model battery degradation and expected lifespan of BESS systems	To understand how design factors like battery technology and performance characteristics like round-trip efficiency affect the longevity of the battery	Battery AI model[4]
Investigate technical operational performance	To understand how site characteristics like primary use case, system size, and meter position relate to performance and operational strategies of systems	Review of AMI interval data, largely from 2020 through 2022, for 42 NYSERDA incentivized sites + contextual program tracking data
Investigate benefits for BESS and hybrid DERs	To understand the system and site benefits provided by BESS and co-located solar PV + BESS systems—to both system owners and the grid—across different revenue streams	Review of AMI interval data, largely from 2020 through 2022, for 42 NYSERDA incentivized sites + contextual program tracking data + utility electric rates and other market information

A detailed review of the methodology used in this report is covered in Section 2. Analysis and results of the various components of the study are presented in Section 3, followed by a table of findings and a list of conclusions and recommendations for the program.

1.3 Overview of modern energy storage systems

This section gives an overview of current energy storage systems. This information is based on a literature review of reliable industry information and consultation with energy storage experts. It is meant to give an overview of how non-NYSERDA-incentivized storage systems perform, as context for the following section (and results to come in later reports), which describes the performance of incentivized systems. Metrics covered here include:

- Efficiency
- Degradation rates
- Lifetime
- Energy/power density

The following descriptions focus on lithium-ion batteries, which currently make up most of the energy storage market and which compose the entirety of the NYSERDA-incentivized storage

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[4] DNV's Battery AI tool: Battery AI (dnv.com)

systems for which there is data to evaluate. In addition to describing the characteristics of current storage systems, a section is devoted to the discussion of trends in grid-serving storage, including storage types and costs. It is important to note that the data in Table through Table 1-, on efficiency and degradation, are largely from controlled, testing environments. Battery storage systems deployed in a "real-world" setting may have slightly different performance numbers depending on a variety of factors such as cycle frequency and duration.

1.3.1 Efficiency

The first metric discussed here is battery round-trip efficiency (RTE), or the percentage of power used to charge the battery that is later available to discharge. Round-trip efficiency is extremely important in determining how effectively a storage system can shift load/generation and the economic viability of the system.

The primary sources used as references for the RTE of currently produced lithium-ion batteries were DNV's Battery Scorecard, the Environmental and Energy Study Institute, and two confidential reports from previous battery storage projects. All sources are comprised of reputable primary and secondary research practices. Across all sources, lithium-ion batteries are reported to have a RTE of 77% to 95%. Table shows how reported RTE varies by source and by lithium-ion battery chemistry.

Table 1-2. Round-trip efficiency for lithium-ion batteries reported by different sources

Source	Year Published	Lithium titanate (LTO)	Lithium iron phosphate (LFP)	Nickel manganese cobalt (NMC)	Lithium-ion Batteries in General
Environmental and Energy Study Institute (EESI) [a]	2019	N/A	N/A	N/A	85 – 95%
DNV Battery Scorecard [b]	2022	N/A	N/A	N/A	≥90%
Confidential 1 [c]	2019	77% – 85%	79% – 83%	77% – 85%	77% – 85%
Confidential 2 [d]	2021	N/A	N/A	N/A	85 – 92%

[a] EESI, Fact Sheet: Energy Storage, 2019. https://www.eesi.org/papers/view/energy-storage-2019

[b] DNV, 2022 Battery Scorecard. https://www.dnv.com/power-renewables/energy-storage/2022-battery-scorecard.html

[c] Confidential DNV Project, 2019

[d] Confidential DNV Project, 2021

Non-lithium-ion technologies have quite different RTE values but may become more valuable because of lower costs and/or longer-term storage abilities. The round-trip efficiency of various storage technologies is shown in Table 1-. Pumped hydroelectric storage refers to a large-scale storage system in which water is pumped to an elevated reservoir, stored, and then released to a lower reservoir, generating power through turbines on the way down. Hydrogen refers to the generation of electricity by combining hydrogen and oxygen. Lead-acid batteries use the chemical reaction between lead and acid to generate electricity. Lastly, flow batteries leverage the exchange of ions between electrolyte solutions to convert liquid chemical energy into electricity.[5]

Table 1-3. Round-trip efficiency of non-lithium-ion storage technologies[a]

Source	Technology	Round-Trip Efficiency
EESI	Pumped hydroelectric storage	70 – 85%
EESI	Hydrogen	25 – 45%
EESI	Lead-acid battery	80 – 90%
EESI	Flow battery	60 – 85%
Confidential 1	Pumped hydroelectric storage	70 – 85%
Confidential 1	Flow battery	65 – 80%

[a] EESI, Fact Sheet: Energy Storage, 2019. https://www.eesi.org/papers/view/energy-storage-2019

1.3.2 Degradation rates and lifetime

Degradation rates, and the associated battery metric – lifetime – are important for storage system economic viability. The biggest factor causing degradation is battery cycling, or how many times the battery is charged and discharged. If operated effectively, each cycle is associated with some economic benefit, so the more cycles a battery can perform during its lifetime determines its return on investment.

Table shows lifetime expectations of lithium-ion batteries, as reported by different sources. Although lifetime is not explicitly defined within the sources, the analysis team defines lifetime of individual lithium-ion batteries, in typical applications, to be between 10 to 20 years or when the batteries have degraded to 60% – 65% of their initial energy capacity, whichever comes first.￼ This range, of course, is highly dependent upon how the batteries are used.

Table 1-4. Lifetime expectations (number of cycles)

Source	Year Published	Lithium titanate (LTO)	Lithium iron phosphate (LFP)	Nickel manganese cobalt (NMC)	Lithium-ion batteries in general
EESI	2019	N/A	N/A	N/A	1,000 – 10,000
Confidential 1	2019	15,000	3,000	3,500	3,000 – 15,000
Confidential 2	2021	3,000 – 7,000	1,000 – 2,000	1,000 – 2,000	1,000 – 7,000

In addition to cycle life, batteries also have time-associated degradation rates which are also dependent upon the use case of the battery system. In this report, degradation rates are shown as

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[5] Flow batteries for grid-scale energy storage. (2023, April 7). MIT News | Massachusetts Institute of Technology. https://news.mit.edu/2023/flow-batteries-grid-scale-energy-storage-0407

the percentage of the battery's initial capacity that is lost after a 10-year period. The range of degradation rates from the Battery Scorecard is specifically related to a two-hour grid support use case. The range of degradation rates from Confidential 1 is not related to a specific use case and is, instead, an aggregate of various use cases.

Table 1-5. Degradation rates over a 10-year period

Source	Year Published	Lithium titanate (LTO)	Lithium iron phosphate (LFP)	Nickel manganese cobalt (NMC)	Lithium-ion batteries in general
DNV Battery Scorecard	2022	N/A	N/A	N/A	11% – 32%
Confidential 1	2019	15% – 20%	20% – 25%	20% – 25%	15% – 25%

1.3.3 Energy and power density

Energy and power density represent how much energy or power a battery contains per pound (weight-based) or liter (volumetric). Lithium-ion batteries (such as those typically used in electric vehicles and other weight/size critical applications) tend to have the highest power densities of storage systems. However, relative to batteries used for electric vehicles, stationary storage systems designed to serve the grid have less need to be power dense. Therefore, lower power density batteries may provide future opportunities for lower-cost grid-serving storage systems.

Table shows the energy density of various types of battery storage systems. NMC is the most commonly used chemistry and most economically viable option among lithium-ion batteries. NMC's high energy density makes it a popular option among manufacturers. LFP's energy density, while less than NMC's, is still considered high. LTO energy density is much lower than LFP and NMC and LTO costs are much higher than LFP and NMC.

Table 1-6. Energy density by battery type

Source	Year published	Lithium titanate (LTO)	Lithium iron phosphate (LFP)	Nickel manganese cobalt (NMC)
Confidential 1: energy density (Wh/kg)	2019	50 – 80 (low)	90 – 120 (high)	150 – 220 (high)

2 Methods

2.1 Primary data methodology

2.1.1 Program staff interviews

The analysis team interviewed several NYSERDA program staff to understand the state of programs, program data, changes to rules, incentives, and efforts to advance CEF initiatives. Interviewees included staff from Retail and Bulk Storage, NY-Sun (including CDG and SFA), Clean Energy Siting and Soft Cost Reduction, Standards and Quality Assurance, Clean Energy Communities, and NYGB.

2.1.2 Installer engagement interviews

To engage solar PV and energy storage installers, the analysis team conducted in-depth telephone interviews with 49 installers of 80 attempted (61% response rate). The interview objectives were to (a) identify the correct respondent for each section of the web survey, (b) gather subscriber contact lists and project information from CDG installers, and (c) collect performance data for the solar PV persistence study. A**Error! Reference source not found.** disposition table for the installer engagement interviews, is in Section **Error! Reference source not found.Error! Reference source not found.** of **Error! Reference source not found.Error! Reference source not found.**.

2.1.3 Installer web surveys

The analysis team developed a detailed installer web survey to gather insights from solar PV and energy storage installers that address this evaluation's research objectives. The team fielded the survey to 66 installer contacts and obtained 18 completed surveys and 15 partial completes. A disposition table for the installer web survey is in Section **Error! Reference source not found.Error! Reference source not found.** of **Error! Reference source not found.**.

2.1.4 Community solar subscriber web survey

The team developed a web survey for CDG subscribers and obtained CDG subscriber data, including mailing addresses, from NYGB, for a total of 9,501 usable contacts—8,587 residential subscribers and 914 non-residential subscribers (reflecting re-assignment of subscriber types based on CDG subscriber survey response). The analysis team fielded the CDG subscriber survey September 2022 through January 2023 and obtained completed surveys from 338 residential respondents and 26 nonresidential respondents, for a response rate of 6% and 3%, respectively. **Error! Reference source not found.**, a disposition table for the community solar subscriber web survey, is in Section **Error! Reference source not found.** of the Methods appendix (**Error! Reference source not found.**).

2.2 Interval data

The team received 15-minute interval data for 42 BESS sites from the program's data aggregator. The interval data includes gross charge, discharge, solar generation, and net facility kWh. Nine of the sites' data include interval readings for state of charge percentages.[6] Across sites, the interval data ranges from November 2016 through February 2023, though most sites' data covers the 22 months of operations between April 2021 and February 2023. Additionally, the team used a site-level dataset obtained directly from NYSERDA, which includes site location, facility category, battery specifications, and the primary use case for that storage system. These variables were important in identifying anomalies and creating data cleaning rules, as well as analyzing and interpreting battery performance.

2.2.1 Data coverage

Before any analysis of battery performance, the team assessed the quality of the 15-minute interval data and implemented a sequence of data cleaning steps. Overall, completeness of data was a significant obstacle to a meaningful analysis of operational performance at multiple sites. Data uncertainty can be split into two categories: missing data and outliers. Section 2.2.1.1 and 2.2.1.2 detail them respectively.

2.2.1.1 Missing values in data

To identify the prevalence of missing data points, the team first checked the number of missing data within the timeseries data across all sites.

> *Given this high proportion of* ***missing data****, the team chose* ***not to drop*** *the records that contain null values, otherwise there would be* ***insufficient data*** *left for subsequent analysis.*

There are a significant number of missing values, with "State of Charge" having the highest percentage of nulls at 66.0%. "Net Facility kWh" has the second highest percentage of missing values at 15.8%. The "Charge kWh," "Discharge kWh," and "Solar kWh" columns have missing values ranging from 7.2% to 10.3%. Furthermore, when combining any of the four main columns – Charge, Discharge, Solar, and Net Facility load – 19.9% of the records have at least one null value in

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[6] State of Charge (SoC) is an instantaneous measurement of available capacity in the battery. It is defined as the amount of kWh available in the system divided by the nameplate kWh capacity.

these fields. The situation is very similar for the 60-minute interval data, which is the 15-minute interval data aggregated to the hour for analysis purposes.

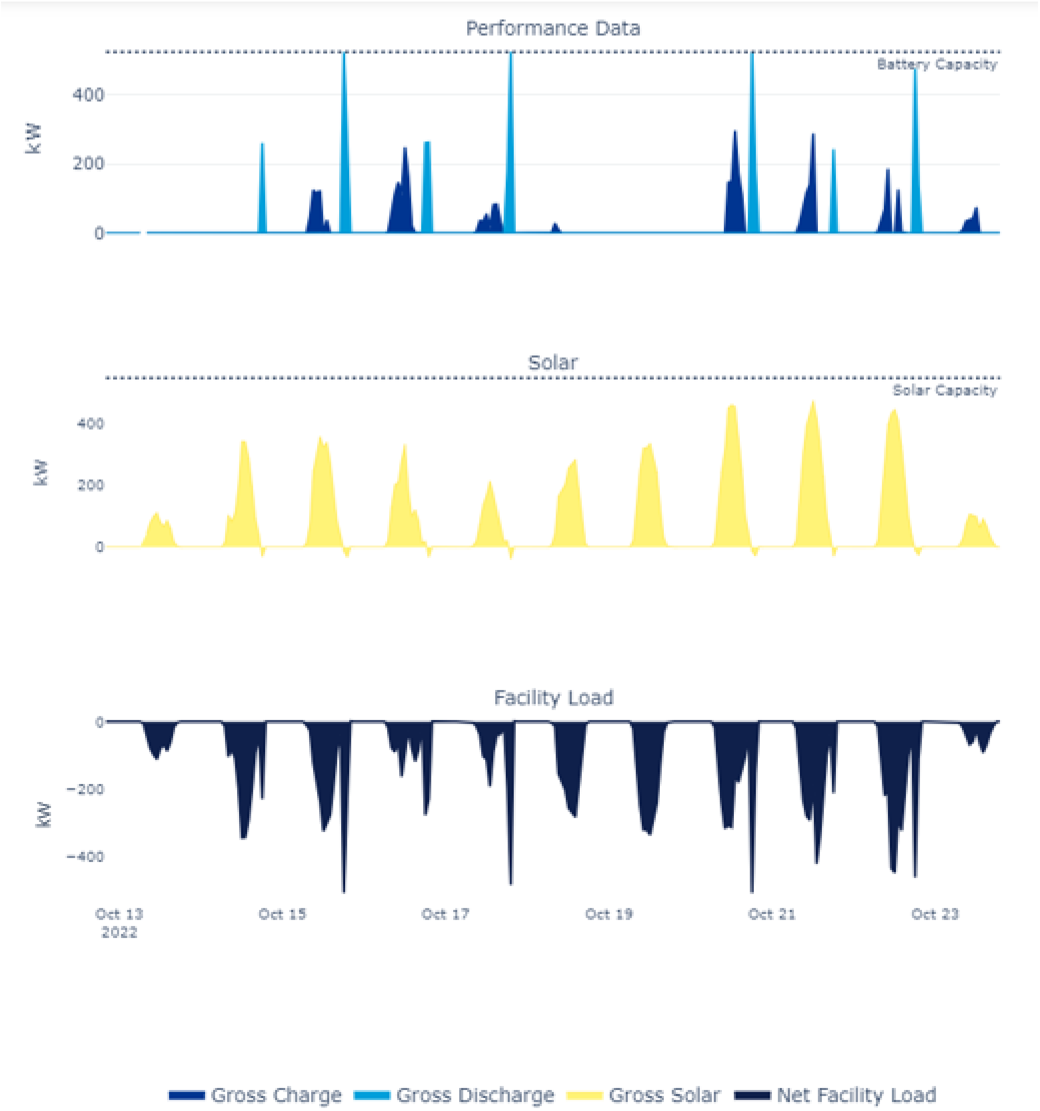
Given this high proportion of missing data, the team chose not to drop the records that contain null values, otherwise there would be insufficient data left for subsequent analysis. One consequence of keeping records with null values is that it may result in an anomalous record to evade the outlier detection rules. Specifically, the load discrepancy and rolling charge flags are calculated fields that use the relationship between two or more fields to identify unrealistic system performance. For example, the load discrepancy flag looks for instances where the battery charge and discharge and solar generation data streams are out of sync with the net facility load field, where one would expect them to be approximately equal. For example, consider the case where the solar generation field is null but net charge is high and net facility load is near zero. This is an anomalous record, but the flag will not be "tripped" because the calculation behind it is not possible without all data streams present. It is uncertain how often this occurs, but it illustrates another case where data quality might compromise this analysis.

Furthermore, the team checked the integrity of the time-series for each site and found no instances of a missing interval. However, there were a significant number of null values in the four primary data streams (battery charge and discharge, solar generation, and net facility load). Missing values were more common at certain sites (for a summary of missing data at all sites). Sites 4, 24, 26, and 52 had significant portions of missing data. In most cases, missing data appears in "chunks," with one or more data streams presenting as nulls or zeroes at a given site for an extended period. The team cannot explain the cause of the missing data. It is possible, in some cases, that the missing data reflects a period in which the facility was shut down. But in other cases, it may reflect an issue with the metering and/or data feed.

2.2.1.2 Outlier values in data

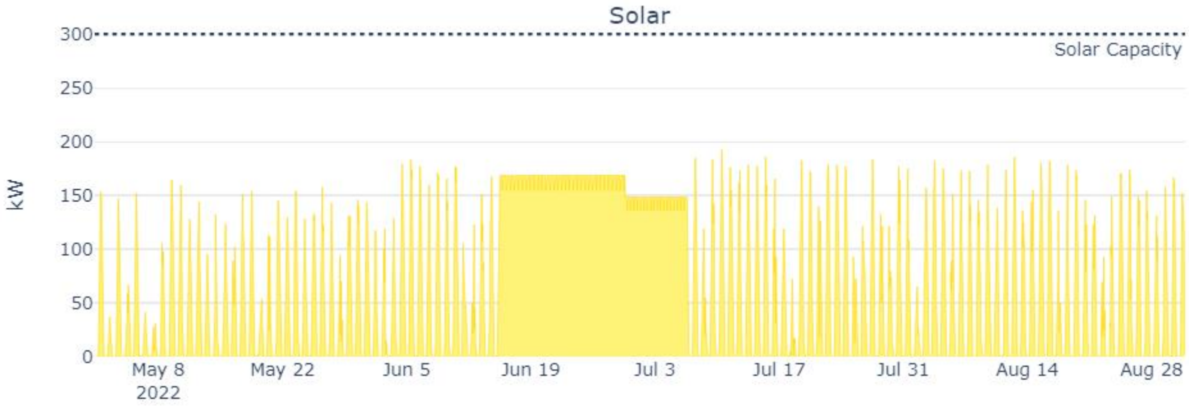
To identify outliers and anomalous site performance, the review of the data was overseen by battery performance subject matter experts who evaluated the data streams against the expected bounds of normal operation. The team created a list of outlier detection and removal rules based on these expectations, as well as a close visual inspection of the interval data using plots like Figure 22-1. Ultimately, it is not in the scope of this analysis to investigate where the outliers come from and if they are "real," but rather to arrive at a dataset clean enough to lend itself to meaningful visualization, which would be used to identify trends in battery performance.

Figure 22-1. Example of interval analysis visualization



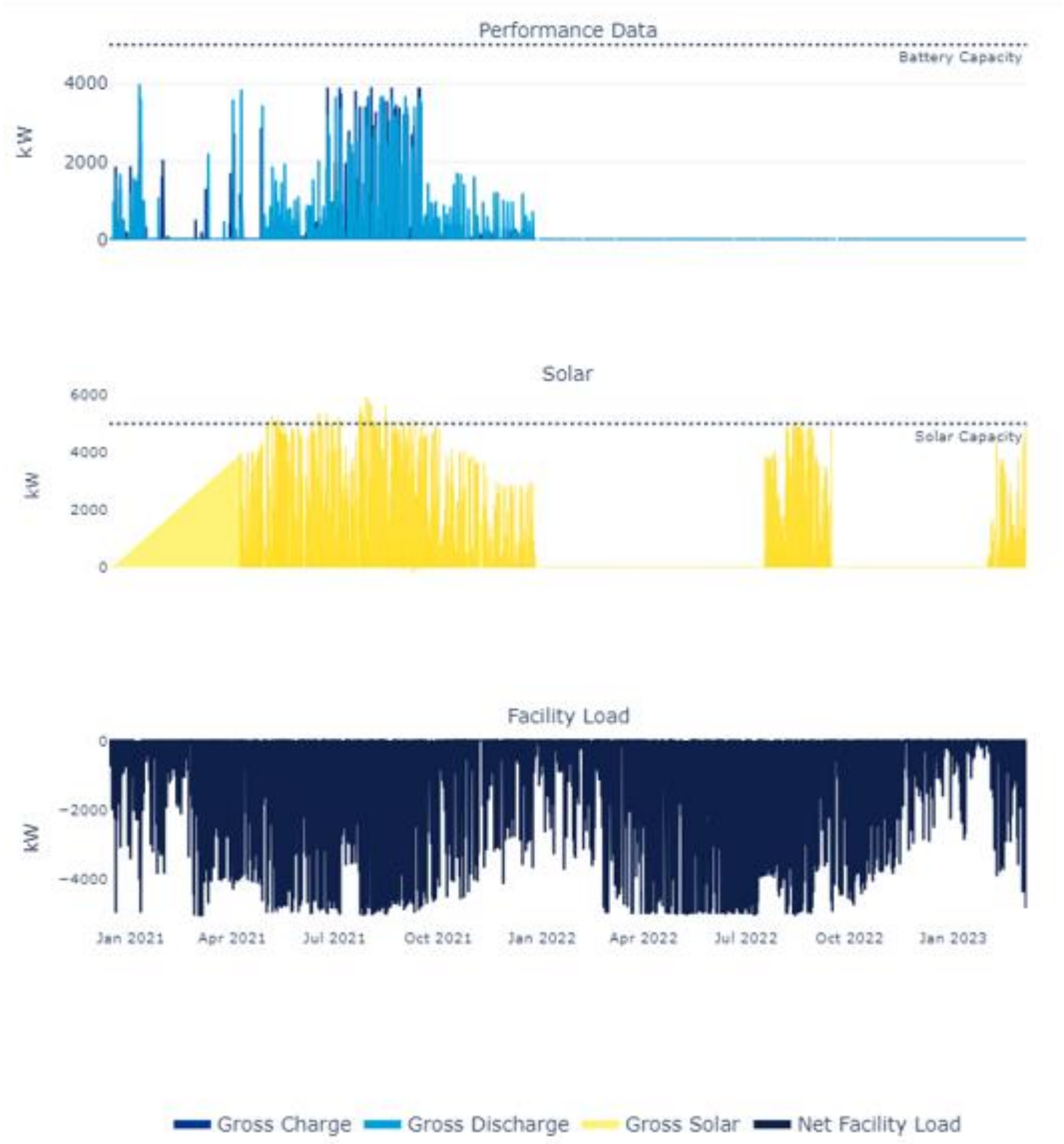
Reviewing the interval data site by site, the team was able to spot site-specific anomalies, which were then added to its data cleaning procedure. For example, Figure 22-2 shows the solar generation at site 21, which had anomalous solar generation between June 14 and July 7, 2022, with high solar output maintained throughout the night.

Figure 22-2. Solar generation at Site 21



There were some anomalous phenomena in the interval data that showed up in multiple sites. For example, the team observed a pattern where net facility load reflected site generation (through solar plus battery discharge minus charge) greater than observed via those data streams (i.e., “phantom” generation). It appears this occurs for one of two reasons: There is a lag between data streams due to the different metering technologies used for the net facility load versus generation assets, or there is an interruption in one of the generation data feeds. In these cases, the net facility load continues to show a net export level indicative that the power from that source continues to flow. In the case of the former, there should not be an issue when the data is aggregated; in the case of the latter, the phantom generation will persist after aggregating the data. Indeed, the net facility data stream can be used to spot issues in the battery and/or solar streams, like in Figure 22-3.

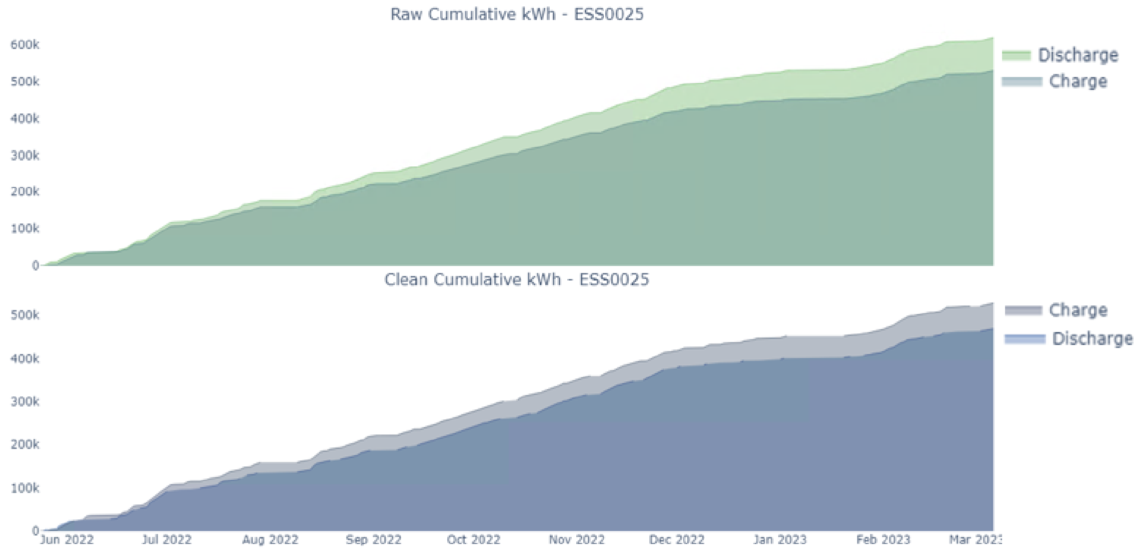
Figure 22-3. Example of "phantom" generation



> *Since it is **impossible** for cumulative discharge to exceed cumulative charge, observing this phenomenon at multiple sites **undermines** the ability to draw meaningful insights from their interval data – removing outliers helps, but the data loss can **obscure patterns** and **impact analysis accuracy.***

Additionally, the team observed an anomalous pattern at 5 sites, where cumulative discharge over the timeseries was significantly higher than cumulative charge. However, cumulative discharge is expected to be lower than cumulative charge, by approximately the round-trip efficiency of the battery. For example, Figure 22-4 shows the cumulative charge and discharge of site 25 before and after applying the data cleaning rules. The team alerted the program's data aggregator about this anomaly, and they said it was due to known metering issues at those sites. The issue usually manifests as an erroneously non-zero level of discharge when the system is idle. The data aggregator suggested using the net import data stream as the ground-truth against which to evaluate the validity of the charge and discharge amounts, as that is the only revenue-grade data stream. This was incorporated into the data cleaning rules. Since it is impossible for cumulative discharge to exceed cumulative charge, observing this phenomenon at multiple sites undermines the ability to draw meaningful insights from their interval data – removing outliers helps, but the data loss can obscure patterns and impact analysis accuracy.

Figure 22-4. Cumulative charge/discharge at site 25 before and after data cleaning rules applied



Overall, as in the example above, the consistency of data feeds from the various metering and control systems introduces varying levels of uncertainty in the results that should be addressed moving forward. Currently, it is difficult to parse what is real activity and what is an issue with the data feed, which complicates the effort to understand how these sites are operating and how they respond to the market incentives.

Lastly, only 9 of 42 sites report state of charge information. This is an important data point in assessing the performance of the battery over time; as these systems age, having this data point will become increasingly valuable in understanding their longevity.

2.2.2 Data cleaning procedure

To address the issues detailed in Section 2.1 and to prepare the interval dataset for analysis, the team implemented a sequence of data cleaning steps. In a few cases where anomalous data was observed, the team altered the raw values to correct for issues with the data stream. Additionally, given the volume of data, the team implemented pre-emptive outlier detection flags for all sites to identify records to be removed from analysis. The data cleaning and outlier removal rules were then applied prior to the site-level performance and site benefits analyses.

Note that though it did not contain outliers, per se, the charge and discharge data streams for site 52 were missing more than 50% of the time, compromising any characterization of that system’s performance. It was not removed from the following analysis, however.

For 15-minute interval data, the team identified outliers that account for 2.6% of whole dataset. The most significant outlier type is “Delta Outlier Flag,” which accounts for 2.0% of total records (around 40,000 instances). Other outlier categories like “Charge Outlier Flag” and “Rolling Charge Outlier Flag” were also identified, but in smaller proportions – representing 0.6% (around 11,000 instances) and 0.3% (around 7,000 instances) respectively. Post the necessary data cleaning and outlier removal processes, a total of 1.9 million records remains, marking a 97.4% retention rate of the original dataset.

Similarly, for 60-minute interval data, the team identified outliers that account for 2.2% of the whole dataset. This ratio is smaller than that in 15-minute interval data because the data has been smoothed from 15 minutes to 60 minutes. The identification and subsequent removal of these outliers are critical to the analysis because outliers can skew results and distort true patterns. Removing outliers strengthens the robustness of subsequent results and findings in this report. Though it prepares the data for aggregation and broad trend-finding, removing outliers can obscure the picture when viewing load shapes on specific days, which is a useful temporal grain for understanding the strategy site operators are using for their BESS.

2.3 Battery degradation analysis

Battery degradation is a key factor in the operation of any BESS. As will be seen in the installer web survey (Section 3.1.2), capacity degradation is the biggest challenge to maintaining BESS. It can also be observed in batteries’ operational profile (Section 3.4.1). Therefore, understanding the degradation impacts of the different battery operational strategies is critical for programs looking to incentivize Energy Storage adoption.

The analysis team gathered metadata on 42 Battery Energy Storage Systems (BESS) projects through tracking data and ran the batteries through the *BatteryAI* tool—its in-house AI model trained on lab data—to evaluate battery degradation and produce an estimate of their future degradation.

To do so, the team identified cell chemistries of each project from the information publicly available online. The BESS technologies in the various projects include both Lithium Iron Phosphate (LFP) and Nickel Manganese Cobalt (NMC) cell chemistries. Notably, the majority of the BESS were based on NMC technology. In general, although the LFP technologies are academically known to have better life performance, there are no such generalized expectations for commercial products. Engineering solutions are integrated within a BESS technology, such as those that limit the operating voltage of NMC cells, to significantly improve life performance and de-risk chemistry-specific concerns.

2.3.1 Factors in battery degradation

Design characteristics such as cell chemistry and Max P-rate can impact battery degradation. Max P-rate is determined by rated power (kW) divided by rated energy (kWh) of a BESS. For example, a 4-hour BESS would have a P-rate of 0.25 and a 2-hour BESS would have a P-rate of 0.5. In general, a higher P-rate indicates a faster charge and discharge capability. However, it is important to consider that high P-rates can lead to increased degradation of the battery system compared to systems with lower P-rates. This degradation occurs due to factors such as higher internal resistance, increased heat generation, and potential acceleration in electrolyte breakdown.

Within a given battery cell technology and P-rate design, degradation expectation can still vary significantly depending on how the BESS is cycled. These operational characteristics of a BESS include State-of-Charge (SOC) swing range, equivalent full cycles (EFC), resting period SOC, and operating temperature of the BESS. Generally, the more EFC a BESS goes through, the more quickly the BESS degrades.

SOC swing range denotes the upper and lower bounds SOC at which the BESS is operated. EFC denotes the number of times annually the BESS charges and discharges the full storage amount. Resting period SOC looks at how batteries also suffer capacity loss over time when sitting idle and is commonly known as the calendar degradation effect. Given the importance of SOC in degradation modeling, the team recommends collecting SOC data as part of any BESS project.

For the NYSERDA BESS degradation modeling, the team has referred to the individual project’s BESS design parameters and historical performance data to create usage conditions that are representative of the actual operation of the batteries. As BESS operating temperatures were not available, the degradation modeling assumes that battery thermal management systems are capable of maintaining battery cell temperatures at or near 25°C. If a BESS operates at elevated temperatures (above 40°C), or at very cold temperatures (below 10°C), the BESS may result in accelerated degradation.

2.3.2 Metrics used for degradation modeling

A key metric used in the battery degradation modeling is a battery's P-rate—a measure of the maximum charge/discharge rate of the battery. A P-rate of 0.25 indicates a four-hour battery: a battery that would take four hours to charge completely, and four hours to discharge the entire energy stored within it. Conversely, a rating of 0.5P would indicate that the battery would take at least two hours to completely discharge its capacity.

The analysis team leveraged the performance interval data for the 42 BESS projects as an input for the degradation modeling. After applying data cleaning steps similar to those described in Section 2.2.2, the BESS discharge energy measurements were used to calculate the aggregate annual throughput in Equivalent Full Cycles (EFC). In addition, average cycles per day are calculated by dividing EFC by the number of days of data.

2.3.3 Grouping storage projects

The 42 BESS projects were segmented into four groups based on design and operational characteristics including Max P-rate and average cycles per day.

Grouping projects provides a convenient reference to understand the key characteristics of each project and allows for easy comparison between groups and their associated BESS systems. The degradation modeling groups are as defined below. These groups were selected by the analysis team as a reasonable categorization based on the design and operation of the 42 BESS and are further discussed in the following sections.

For example, a BESS in Group 2 charges and discharges at a rate of 0.25P, has a throughput of 0.5 equivalent full cycles per day and spans one 0% – 100% – 0% state of charge cycle over two days.

Table 2-1 summarizes the number of projects that fit into each group. Roughly half of projects were designed with a P-rate of 0.25 (e.g., four-hour battery) while the other half were designed with a P-rate of 0.5 (e.g., two-hour battery). Note that two of the 42 projects (05 and 91) were excluded from the grouping as their designed P-rates were much higher at 0.71 and 1.2 and could not be accurately modeled. A majority of the projects were not cycled often, with an average cycle per day of 0.25, meaning a full cycle every four days.

Table 2-1. Number of projects in each group

Grouping	P-rate	Avg cycle per day	Number of projects
Group 1	0.25	0.25	15

Group 2	0.25	0.50	2
Group 3	0.50	0.25	19
Group 4	0.50	0.50	4

Note that two of the 42 projects (05 and 91) were excluded as their designed P-rates of 0.71 and 1.2, which were above the rates of what Battery AI could model.

2.4 VDER benefits analysis methods

The Value of Distributed Energy Resources (VDER) mechanism aims to accurately compensate Distributed Energy Resources (DER) (such as solar, storage) owners in New York for the value they provide to the grid. The hourly unit prices are reflective of multi-stream, location-specific benefits to the grid.

For both solar exports and storage exports, the VDER compensation is based on six different unit prices: Energy Value, Capacity Value, Environmental Value, Demand Reduction Value (DRV), Locational System Relief Value (LSRV), and Community Credit. The six contributing components to the VDER rate's 'Value Stack' are briefly summarized in Table 2-2**Error! Reference source not found.**. A publicly available VDER calculator—available on the NYSERDA website—helps site owners/installers conduct a *prospective* modeling of VDER compensation for their systems[7]. The calculator provides a comprehensive breakdown of compensation across the six value stack streams under different scenarios and configurations.

Table 2-2. Summary of VDER value stack

Value Type	Description [a]
Energy Value	Determined by the NYISO's location-based marginal price of energy, which updates each hour based on the supply and demand of energy on the grid
Capacity Value	Based on the value the asset provides in helping mitigate strain and meet demand for energy during peak time periods (e.g., hot summer afternoons)
Environmental Value	Reflects the value of load shifting when power is generated via a carbon-free source instead of fossil fuels. Determined by the social cost of carbon calculated by the New York Department of Public Service
Demand Reduction Value	Represents the value of the avoided cost of utility grid upgrades that would have been necessary in the absence of the resource
Locational System Relief Value	Value stream for systems located in utility-designated areas where demand reduction and capacity provided by distributed generation and energy storage are particularly valuable
Community Credit	Additional credit available to Community Distributed Generation sites

a NYSERDA VDER Value Stack Fact Sheet, 2020: https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/NY-Sun/value-stack-overview.pdf

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[7] NYSERDA VDER Calculator, Phase Two Version: https://www.nyserda.ny.gov/All-Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources/Solar-Value-Stack-Calculator

2.4.1 Analysis method

Thirty-one (of the 42) incentivized sites that are being analyzed reported VDER as a primary use case for their Energy Storage system. For this analysis, the team used the *Value Stack Calculator v2.7*, accessible through the NYSERDA website, applicable for projects qualifying for VDER after July 2018.[8] The calculator uses contextual parameters such as utility, NYISO zone, energy rate code, etc. to identify the applicable *Value Stack* compensation.

The team inputted site-specific contextual parameters and combined it with the interval data stream to conduct a retrospective modeling of the *estimated* VDER compensation in the applicable sites.

The VDER calculator ingests hourly time-series data for three key metrics: Final Discharge (kWh), Final Charging (kWh), and Solar Generation (kWh). From these inputs, the calculator derives two fundamental metrics: Export Solar Discharge (kWh) and Export Storage Discharge (kWh). See the equations below:

$$\mathit{Export\ Solar\ Discharge}\ (kWh) = \max\left(\mathit{Solar\ Generation} - \frac{\mathit{Final\ Charge}}{\mathit{storage\ efficiency}} - \mathit{Onsite\ Load}, 0\right)$$

$$\mathit{Export\ Storage\ Discharge}\ (kWh) = \max\left(\mathit{Final\ Discharge} - \max(\mathit{Onsite\ Load} - \mathit{Solar\ Generation}, 0)\,, 0\right)$$

Export Solar Discharge (kWh) approximates the amount of solar energy exported to the grid. It is calculated by taking the solar generation and subtracting the amount used for charging storage (adjusted for the storage efficiency, which is set as 80%) and the onsite load. Onsite load is assumed to be 0 for VDER sites, as it is our understanding there is no co-located facility for these sites that draw power, unlike sites primarily used for demand response or backup power, for example. If Export Solar Discharge is negative, meaning a solar device has no surplus energy to export, this is set to 0.

Export Storage Discharge (kWh) represents the energy exported to the grid from the storage system. It is derived by subtracting the part of onsite load that exceeds solar generation from the energy discharged from storage. If the result is negative, meaning storage has no surplus energy to export, this is set to 0.

By multiplying the Export Solar Discharge (kWh) and Export Storage Discharge (kWh) with the respective hourly rate of these six value stack rates yields the six revenue streams.

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[8] Accessed from NYSERDA website June 2023, https://www.nyserda.ny.gov/All-Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources/Solar-Value-Stack-Calculator

2.4.2 Analysis considerations and assumptions

The VDER calculator has over 50 individual inputs that inform the compensation mechanism. The program data collection does not track all the necessary inputs at the specificity required. In particular, there are three fundamental bottlenecks that prevent the team from calculating the actual DER compensation for the 31 sites.

- **Unknown exact system utility configurations**

While the team was able to look up and identify up some of inputs required using site addresses—like Electric Utility, Substation, NYISO zones, and CSRP zones—other inputs (such as utility rate code) could not be found out accurately. Also unavailable are factors like electricity supply costs, for which a site can contract with an Energy Services Companies (ESCO) and can have time-of-use varying rates.

- **Unknown system configuration and physical parameters.**

The VDER configuration—i.e., Community Distributed Generation (CDG) vs Projects with onsite load vs Remote crediting vs Mass Market—in which a site is enrolled under the VDER program materially impacts the applicable VDER compensation. While the metadata received from program's data aggregator provide notation for some (nine of the 31) sites indicating that they are configured as CDG, this information is not available for all sites.

Furthermore, there are metrics such battery round-trip efficiency (RTE) that are transient (as they are a function of duty cycles and battery life) and for which only an approximate value can be calculated from the operational timeseries data.

- **Missing data and data quality impacts**

Phantom generation, or negative net facility load unaccounted for by the data streams available to DNV (detailed in Section 2.2.1.2) severely limited the team's ability to incorporate on-site load into the VDER analysis.

Despite these bottlenecks, the analysis team was able to compile an analysis that proceeds by using reasonable best-guess analysis. The following section details the team's analysis methodology and assumptions therein.

2.4.2.1 VDER-methodology specific considerations

VDER's capacity value (ICAP) stream accrues benefits through one of three distinct mechanisms (Alternative 1,2, and 3), each with a distinct set of pricing signals and therefore requiring different operational strategies[9]. A BESS system can elect into one of the three ICAP options. While it was unknown which of the ICAP alternatives was in-effect for each system, ICAP Alternative II would appear to be a good fit for an energy storage system (as discharge is limited to fixed windows in summer months only, leading to limited impact on battery life). Therefore, the team assumed that all the sites were based on the Alternative 2 structure. Hence, each utility's historic Alternative 2 rates ($/kWh) for all hours between June 24 and August 31 for years 2020, 2021, and 2022 were derived from VDER statements of each utility and applied for the analysis.

Day-ahead zonal Location-Based Marginal Prices (LBMP) inform the Energy Price portion of the value stack in the VDER tool. The analysis team used actual historical LBMP values from NYISO (without any calendar year escalation) in the analysis.[10]

The applicable E-value for VDER is re-calculated annually; a project locks in the E-value that is in effect (when the project becomes eligible) for 25 years.[11] However, the VDER tool uses a constant Environment Value (E-value) for all sites regardless of the year in focus. Therefore, the analysis team used the applicable historical E-values (0.027 $/kWh until April 2021, and 0.03103 $/kWh thereafter) for all the VDER sites. Note that while standalone storage systems do not qualify for E-value, each of the 31 sites had a co-located solar PV system; therefore, E-value was applied to all the VDER sites.

The team had to make an estimated determination of LSRV eligibility for each of the 31 sites in the cohort. To do so, each site's date of registration (recorded under the field "*Payment Received Date*") was used to check if the LSRV credit was available to the substation associated with that site prior to its registration.[12] Of the cohort, two sites were deemed to eligible for LSRV value stream.

To estimate applicability of Community Credit (CC) at each site, the team researched the historical availability of community credit tranches for each applicable sites' utility at the time of "*Payment Received Date*" for each site. If community credits were open at that time, the site was considered eligible for CC value stream.

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[9] The Value Stack Reference Guide for Energy Storage Developers, NYSERDA: https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/Energy-Storage/Value-Stack-Reference-Guide-for-Storage-Developers.pdf

[10] http://mis.nyiso.com/public/P-2Alist.htm

[11] A project becomes eligible when the interconnection agreement is fully executed or when it pays 25% of the interconnection costs to the utility. (Source: The Value Stack Reference Guide for Energy Storage Developers)

[12] For the sites whose "Payment Received Date" was missing, a date was estimated using the average duration between payment receipt and data receipt across projects.

As information on VDER configuration is not available across projects, the project team assumes that all projects are structured as Community Distributed Generation projects.

2.4.2.2 Modeling assumptions

As mentioned in Section 3.5.1.1, as RTE for the systems were not known, the team assumed an average round-trip efficiency of 80% across all sites.

As electricity supply cost was not known, the team assumed an average electricity supply cost of 8 ¢/kWh across all sites.

To make a reasonable and directionally accurate VDER revenue estimate, the onsite load is assumed to be always zero. As such, the team also excluded any applicable demand ($/kW) and energy charges ($/kWh) for the system. As a second-order effect, the analysis methodology did not include the value of reduced onsite demand due to battery storage.

2.5 Site benefits

This section includes the following two parts of analysis: energy charge ($/kWh) financial benefits, and demand charge ($/kW) financial benefits. In this analysis, the team only looked at the sites with a BESS in a Behind-the-Meter (BTM) configuration, going after one of the following use cases: Demand Reduction, Demand Response, Ancillary Services, or Backup Power. Because rates were not provided in the site-level program tracking info received from NYSERDA, the team used the utilities’ filed tariffs to make a best-guess assumption about the applicable retail electric rate based on site characteristics. These assumptions were made using the site’s utility information, building type, and maximum demand. For example, for a site in Con Edison territory, a multifamily site is assumed to be under SC8 service classification whereas a commercial site is assumed to be in SC9 service classification. Additionally, if the site has a maximum demand of less than 1,500kW in the period of data coverage, it can be reasonably assumed to be in SC8 R1 rate (as opposed to being in SC8 R2 rate if it had a maximum demand greater than 1,500 kW).

Seven sites meet the use-case requirement listed above, and among those seven, one site had Nulls in the *net facility load* column in timeseries data. Therefore, the team included only the remaining six sites for the site benefits analysis. The team made a reasonable assumption about the electric rates to estimate site benefits from demand reduction. For demand reduction, BESS sites accrue benefits from both energy charges and demand charges.

In the analysis of annual energy charge benefits for specific sites, the team calculated the energy charges for scenarios both with and without battery integration. The charges with battery were computed by multiplying the net facility energy charge (kWh) values by their respective rate. The charges without battery were determined by multiplying the imputed kWh usage without battery (calculated by the equation below) by the designated rate. The financial benefit in terms of energy charge ($/kWh) was then derived by subtracting the charges with battery from the charges without. This methodology enabled the team to assess the potential financial savings associated with battery deployment at the respective sites.

$$Usage\ without\ battery(kWh) = Net\ Facility(kWh) + Discharge(kWh) - Charge(kWh)$$

The energy rates applicable were calculated by adding the site-specific delivery charges (from the assumed electric rates) with an assumed electricity supply charge of 8 ¢/kWh across all sites.

To assess the monthly demand charge savings, the team aggregated the peak monthly demand (kW) to ascertain the maximum demand both with and without the battery. Some of the estimated electric rates involved Time-Of-Use (TOU) tariffs. When the rates involved TOU demand tiers (e.g., a demand tier applicable only on weekdays, between 8a and 7p), demand *with* and *without* battery was assessed independently for each demand tier. Subsequently, demand charge savings were independently calculated for each demand tier by multiplying the identified peak demand by the applicable demand rate ($/kW). Finally, monthly demand charge savings were computed by aggregating demand charge savings across all demand tiers within the month.

3 Results

3.1 Installer web survey – standalone energy storage systems

The analysis team conducted an installer web survey to, in part, gain insight into the system performance of installed storage systems.[13] No more than six responses were obtained for any of the relevant questions. Consequently, the reported results are generally more anecdotal than quantitative metrics.

3.1.1 Residential standalone energy storage systems

Survey results were only received for non-incentivized residential standalone BESS. Results revealed that regularly scheduled inspections never take place, or only take place when a problem is suspected.[14] System performance issues were identified, with charge/discharge cycling frequency, state of charge when inactive, control technology, ambient temperature, and battery type as factors reported to contribute to system degradation or underperformance.

3.1.2 Commercial/retail standalone energy storage systems

Responses indicated that commercial BESS inspections are conducted every year—regardless of whether projects are NYSERDA-incentivized or non-incentivized.[15] The biggest challenge to maintaining these systems was reported to be capacity degradation. When asked to rank equipment from most likely to fail to least likely to fail, rankings listed the thermal management system, followed by the internet, controllers, inverter, and finally the battery system. A similar inquiry was made regarding equipment most likely to degrade, and the battery system was ranked as most likely, followed by the inverter, then the thermal management system, and finally controllers. Responses indicated that other factors contributing to commercial/retail standalone energy storage system degradation or underperformance include charge/discharge frequency cycle, depth of discharge, battery type, and calendar degradation. Respondents reported that no warranties are offered for these systems.

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[13] The survey instrument is not appended in this document due to its length, but is available upon request. Please contact Dana.Nilsson@nyserda.ny.gov, requesting access to the Installers Web Survey (file name: January_7_2023_Installers_WebSurveyGuide_FINAL).

[14] For this, and all following instances, the team asked respondents how often, on average, regularly scheduled (non-NYSERDA) inspections were conducted. Responses did not indicate the type of inspection (e.g., maintenance vs. preventative).

[15] NYSERDA requires that 100% of systems are inspected. Additional detail regarding inspections can be found on the NYSERDA website.

3.1.3 Bulk standalone energy storage systems

Similar to commercial BESS, bulk standalone energy storage system inspections are conducted every year. Capacity degradation was indicated as the biggest challenge to maintaining these systems. When asked to rank equipment from most likely to least likely to fail, rankings listed the thermal management system, followed by the internet, then controllers, the inverter, and finally, the battery system. When asked about equipment most likely to degrade, rankings revealed that the battery system is most likely to fail, followed by the inverter, then the controllers, and finally, the thermal management system. When asked about other factors contributing to degradation or underperformance, responses cited charge/discharge cycling frequency, depth of discharge, battery type, and calendar degradation all playing a role. No respondents said that warranties are offered.

3.2 Installer web survey – project-specific energy storage systems

Five respondents provided project-specific information for 10 unique co-sited solar and storage systems. Three of the 10 systems were reported to have experienced unexpected downtime or nonperformance. No projects were reported to have any warranty claims filed. Of the 10 projects, respondents indicated only four were providing the anticipated financial benefits.[16] For two projects, it was noted that repairs have been necessary every year. For two other projects, repairs were said to take place every five years or less often. Four other projects were reported to never (i.e., not yet) need repair. On average, for six projects, repairs were said to have been completed in less than two months. For three projects, respondents indicated that downtime and repairs impacted the expected revenues from the projects. For three systems, the unit is configured in a way for backup power to be provided during an outage.

Respondents indicated the following mechanisms being responsible for providing value to the project(s): wholesale market capacity, NYISO demand response, ancillary services, VDER energy value (LBMP), VDER capacity value (ICAP) – Option 1, 2, or 3, VDER environmental value (only storage with solar), VDER demand reduction value, VDER locational system relief value, and VDER community credit. However, at least one respondent indicated having challenges with the following mechanisms: NYISO demand response, VDER energy value

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[16] Of the six projects not providing anticipated financial benefit, three were impacted by unexpected downtime or nonperformance. Additional data were not provided regarding why the three other projects were not meeting anticipated financial benefit.

(LBMP), VDER capacity value (ICAP) – Option 1, 2, or 3, VDER environmental value (E), VDER demand reduction value, and VDER locational system relief value. Additionally, respondents indicated considering but not enrolling in wholesale market energy (price arbitrage for standalone solar) as a value due to too many rules and regulations, or the project not being eligible for the benefit.

3.3 Installer web survey – combined solar and energy storage systems

Installer web survey respondents were also asked a series of system performance questions pertaining to combined solar and energy storage systems. No more than six responses were obtained for any of the relevant questions. Consequently, the reported results are generally more anecdotal than quantitative metrics.

3.3.1 Residential combined solar and energy storage systems

Combined residential solar and storage system performance issues are identified with monitoring platforms. On average, regularly scheduled inspections are rarely conducted. However, respondents said that repairs are made to combined residential systems, on average, either yearly or more than once a year. When it came to addressing major degradation, responses indicated that repairs are made in less than two months. There were multiple contributing factors resulting in underperformance or degradation of the systems: depth of discharge, control technology, battery type, and hardware issues. Warranties are generally provided for these systems—respondents indicated that either five- or ten-year warranties are most common. Few warranty claims are filed, with responses indicating that fewer than 20% of projects file claims.

3.3.2 Commercial combined solar and energy storage systems

Responses indicate that system performance issues are identified via active or online monitoring. Inspections are common for these systems, with most respondents saying they are performed once a year. When asked about the biggest challenge with maintaining these systems, capacity degradation was found to be the biggest challenge. Other challenges include availability/downtime, vegetation maintenance (specifically for the solar PV), and hardware. All respondents said that either the internet or thermal management equipment was most likely to fail. However, other equipment was also cited as being likely to fail, namely controllers, inverters, battery systems, modules, panels, and surrounding utility infrastructure.

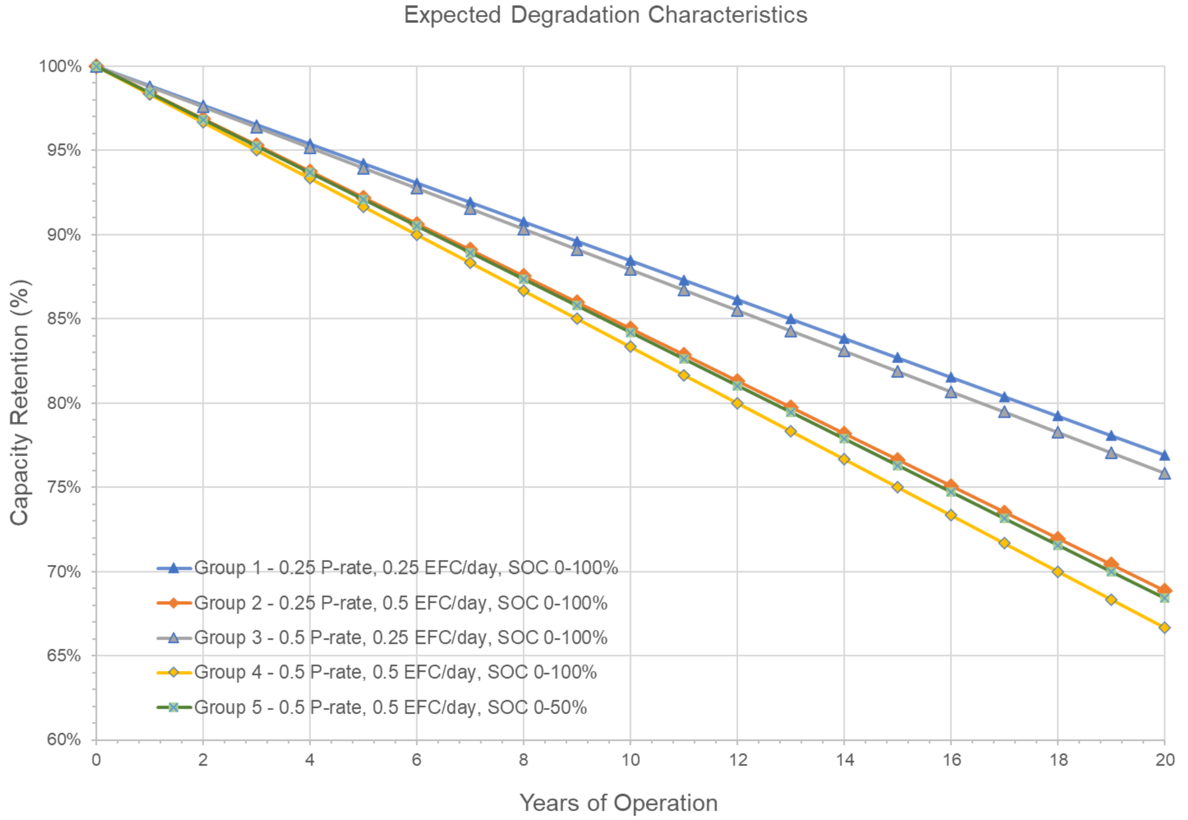
In order from ***most likely to degrade*** *to* ***least likely to degrade****, respondents indicated:* ***battery systems****, inverters, controllers, modules/panels, and the* ***thermal management system****.*

Respondents who only work on NYSERDA-incentivized systems provided insight into which equipment is most likely to degrade. In order from most likely to degrade to least likely to degrade, respondents indicated the battery systems, inverters, controllers, modules/panels, and the thermal management system. Respondents who install both NYSERDA-incentivized and non-incentivized systems ranked the order of degradation (from most likely to least likely) in the following order: battery system, thermal management system, inverter, controller, then modules/climate. Further, respondents who install only NYSERDA-incentivized systems said a variety of factors may lead to system degradation or underperformance: charge/discharge cycling frequency, state of charge when inactive, depth of discharge, control technology, ambient temperature, and battery type. No respondents who install non-incentivized systems provided information regarding factors leading to system degradation or underperformance. Warranties are commonly offered for these systems—including either a five-year workmanship warranty or a manufacturer’s warranty. Warranty claims are not common, with respondents indicating no more than 10% of projects have filed claims. Respondents report system repairs are needed, on average, between more than once a year to once every three years.

3.4 Storage degradation findings

The results of the analysis team’s storage degradation modeling are presented in Figure 33-1. The figure details capacity retention over time in years. General industry knowledge is that a BESS has reached its end of life when it reaches either 60% capacity retention or 20 years. Based on this degradation analysis, none of the BESS projects are expected to reach end of life based on capacity retention by year 20.

Figure 33-1. Battery degradation modeling using Battery AI Degradation Model



By comparing Group 1 (0.25 P-rate, 0.25 equivalent full cycles (EFC/day)) and Group 2 (0.25 P-rate, 0.5 EFC/day), the impact of battery cycling on battery degradation can be isolated. Group 1 and Group 2 share similar design characters in being four-hour batteries with a P-rate of 0.25, but Group 2 is cycled twice as often as Group 1. After 20 years, Group 1 retains 77% of the system's original capacity, whereas Group 2 retains 69% of the system's original capacity. The degradation in Group 2 retains 8% less capacity than Group 1, highlighting that increased cycling does increase battery degradation. Groups 3 and 4 show a similar comparison, where Group 4 is cycled twice as often and retains 9% less of the system's original capacity than Group 3. Group 2 and Group 4 show a similar comparison of P-rates, where Group 4 retains 1% less of capacity than Group 2.

3.4.1 Alternate degradation cycle

Analysts also created a new, simulated, Group 5 that is similar to Group 4 in having the same P-rate at 0.5 and average cycles per day at 0.5. The difference in Group 5 is that this system follows an operating cycle with less degradation over time where the BESS spans from 0% to 50% SOC, whereas Group 4 spans from 0% to 100% SOC. Group 5 can be treated as a more optimal way to operate BESS for reducing battery degradation, though limiting battery to 50% can reduce potential revenue for the project. As shown in the results in Figure 33-1, Group 5 retains 1% more capacity at 20 years compared to Group 4. even with a less degrading operation cycle (0% to 50% range of state-of-charge (SOC)).

This Battery AI Tool underwent model training using a generic NMC model that was built on laboratory test data which includes and represent the different usage conditions. An NMC chemistry-specific model was used in this analysis as a majority of the 42 BESS utilize NMC technology.

Disclaimer: The Battery AI Degradation Model was trained on laboratory test data from accelerated battery cell testing under various cycling and resting conditions. For the purpose of this analysis, a generic model for the NMC chemistry was used, which was built based on testing data from multiple cells. The following points should be considered when using predictions made by the Battery AI system:

- Predictions are generally constrained to within the bounds of the testing data. Fields with little or missing data may result in unexpected predictions with higher levels of uncertainty. This can be especially true for high and low temperatures where there may be limited testing data available.
- Individual erroneous cells or test error may cause unexpected or erroneous predictions under certain conditions. The project team attempts to minimize the effects caused by potential outliers through a quality control process of model training.
- Due to the time-limited nature of the cell testing, the end-of-life (EOL) performance of cells is not explicitly captured in the predictions. The team considers 60% capacity retention to be the EOL condition, as is accepted in the stationary battery storage industry.

In the upcoming year, in addition to modeling battery degradation by grouping sites, the evaluation can use the state of charge data from the nine sites for which this data is available to generate battery-level model outputs if this of interest to NYSERDA.

3.5 System technical performance findings

The analysis team received 15-minute interval data for 42 BESS sites from the program’s data aggregator. The interval data includes gross charge, discharge, solar generation, and net facility kWh. Nine of the sites’ data includes state of charge percentages. Across sites, the interval data ranges from November 2016 through February 2023, though most sites’ data covers the 22 months of operations between April 2021 and February 2023. Additionally, the team used a site-level dataset obtained directly from NYSERDA, which includes site location, facility category, battery specifications, and the primary use case for that storage system. These variables were important in identifying anomalies and creating data cleaning rules, as well as analyzing and interpreting battery performance. For details on data cleaning issues and the rules implemented before analysis, please see Section 2.

3.5.1 Site-level storage system performance trends

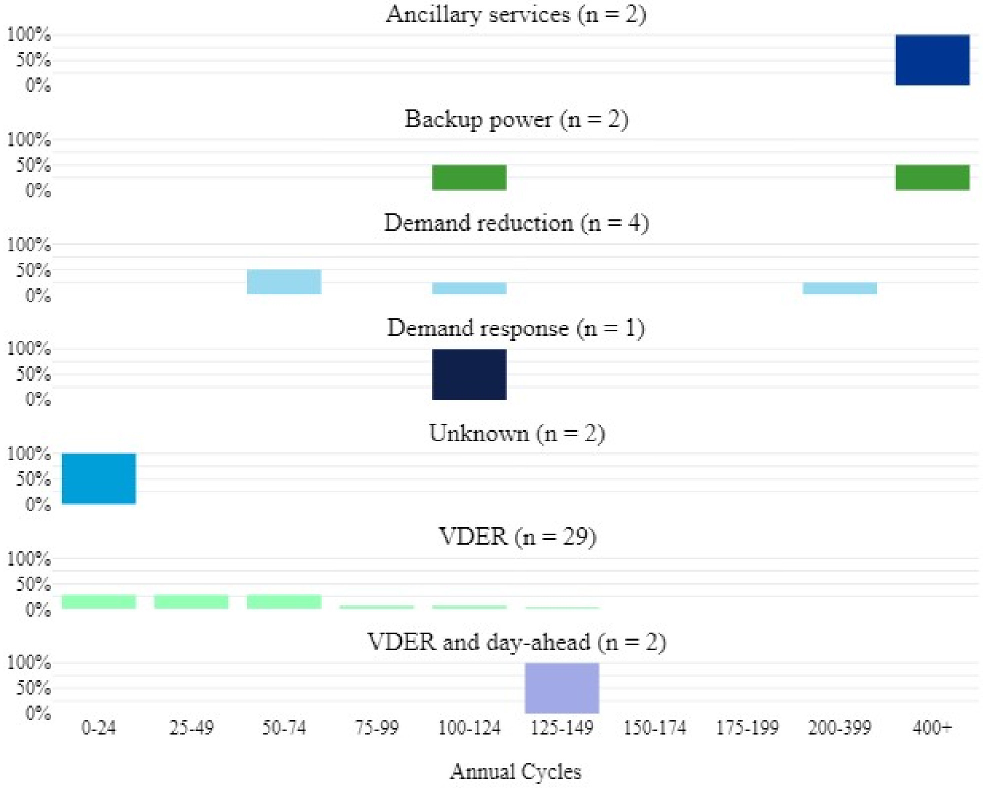
Aggregating the 15-minute interval data for each site, six key indicators of battery performance are reported: number of cycles per year, share of active discharge days, share of high performance intervals, roundtrip efficiency, maximum discharge, and low battery frequency When coupled with site-level characteristics, like the reported primary use of the BESS and facility category, these indicators provide insights into how BESS operators are utilizing their systems. The metrics can help NYSERDA understand how the storage systems improve grid operation and facilitate the integration of renewables onto the grid. Sections 3.5.1.1 through 3.5.1.6 provide a summary of these indicators and selected figures.

3.5.1.1 Number of cycles

For each site, total kWh charged was divided by the rated battery size, and then that value was annualized against the number of intervals for that site. This metric approximates how often a battery system cycles each year, which correlates with battery degradation.

Batteries cycled between 1 and 1,109 times per year, and the median number of cycles was 64. Figure summarizes the number of cycles by primary use case. Sites on the VDER tariff cycled fewer than 175 times each year (mean of 50), while sites designed to provide ancillary services (e.g., frequency regulation) cycled the most. VDER systems cycle far less than the 700+ and 100+ cycles averaged by the two Ancillary Services sites and four Demand Reduction sites, respectively. This may be in part due to VDER site operators dispatching power only when the financial incentive is strongest.

Figure 3-2. Percentage of sites by annual cycles and primary use case



3.5.1.2 Active days

The team calculated the percentage of days with significant charge and discharge activity. The team defines “active” as charge or discharge at a rate that is 25% or more than the rated capacity of the battery. If a day has four or more intervals with activity, then that day is classified as an active day. This metric describes how often battery systems perform, even if not performing close to their rated capacity values.

The percentage of active discharge days ranges from zero to 80%, and the median percentage of active discharge days is 18%. Likewise, percentage of active discharge days ranges from zero to 79%, and the median percentage of active discharge days is 13%. Sites primarily used for ancillary services and sites with large batteries had the highest shares of active discharge days. Figure and Figure summarize active discharge days by primary use case and facility category, respectively.

Figure 3-3. Sites by high discharge activity days and primary use case

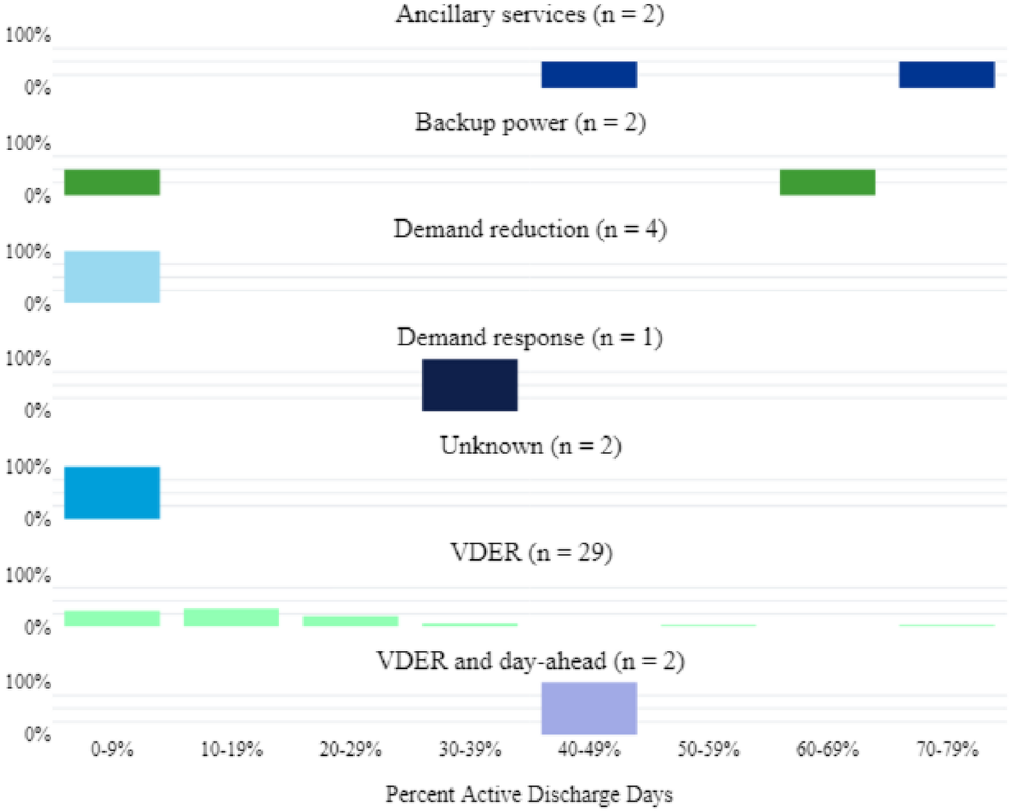
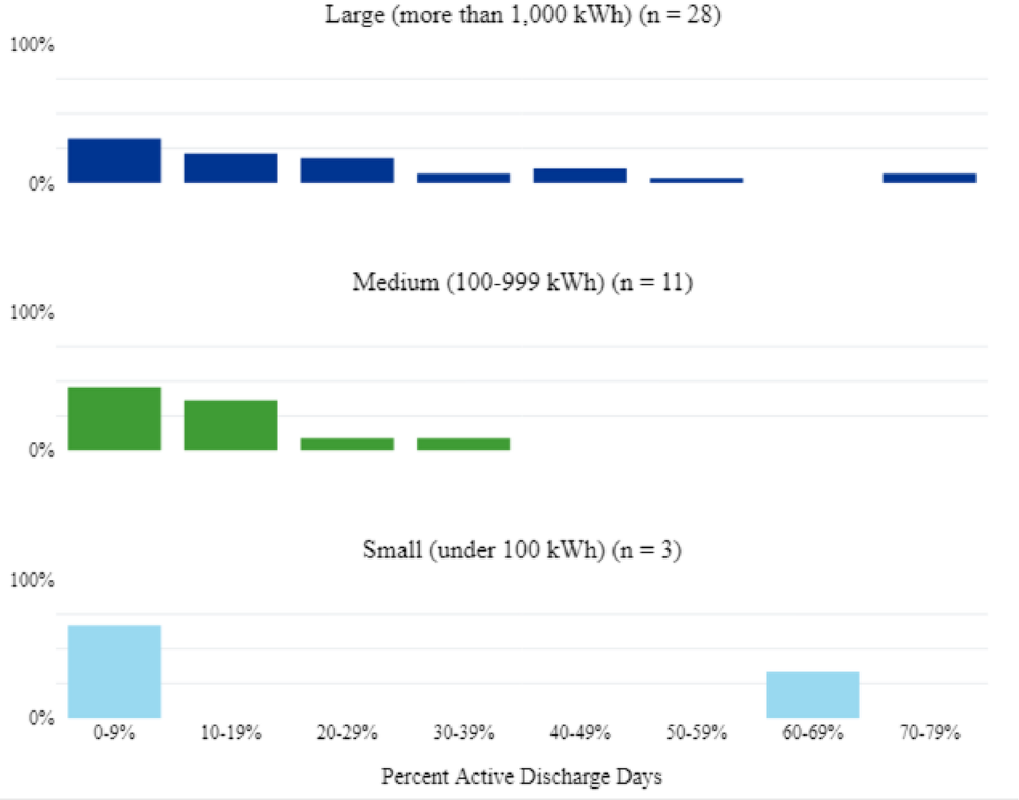


Figure 3-4. Sites by high discharge activity days and battery size

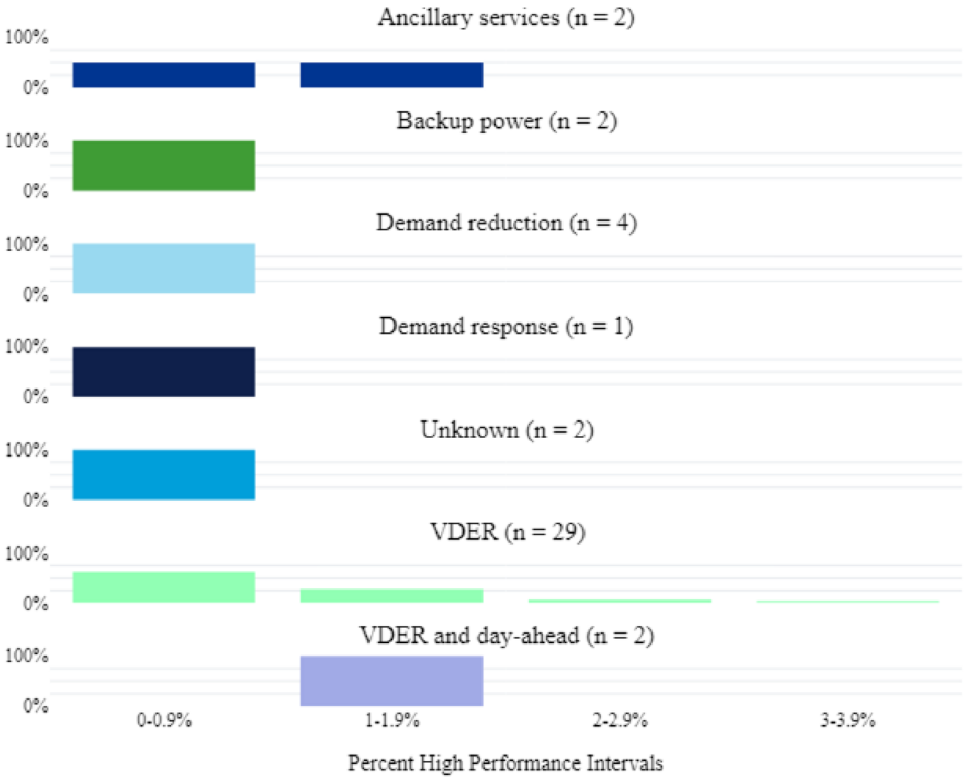


3.5.1.3 Intervals with high performance

Next, the analysis team calculated the percentage of intervals with high discharge performance. High performance was defined as an interval with a discharge at a rate that is 75% or more than the rated kWh capacity of the battery. This metric describes how often battery systems are performing close to their rated discharge capacity.

Overall, the batteries rarely discharge close to their capacity. The percentage of intervals with high discharge performance ranges from zero to 3.3%, and the median percentage is 0%. Large batteries (greater than 1,000 kWh) discharged close to the rated capacity more frequently than small and medium batteries. Also, the only batteries with more than 2% high performance intervals were on the VDER tariff (see Figure 33-5). The takeaway from this metric and the previous one is that batteries NYSERDA has incentivized typically have additional capacity that can be dispatched. Many sites could be cycling their batteries more often and at a higher rate of discharge. This may be because site operators are using their systems conservatively to prolong the life of their battery.

Figure 33-5. Share of sites by high performance intervals and primary use



3.5.1.4 Round-trip efficiency

The team calculated round-trip efficiency by dividing total kWh discharged by total kWh charged for each site. This metric approximates the amount of useful energy a battery system can provide, accounting for losses from system operation.

Round-trip efficiency ranges from 16% to 100%, and the median efficiency achieved is 84%. For sites 13, 36, 37, 40, 41, and 52, round-trip efficiency was above 1, even after removing outliers according to the rules above; these sites were subsequently excluded from this metric.

Round-trip efficiency for large batteries was above 90% for more than half of sites. Sites used primarily for demand reduction have the lowest round-trip efficiencies. Figure 33-6 and Figure 33-7 summarize round-trip efficiency by battery size and primary use. Average round-trip efficiency across the 37 batteries with valid estimates was 79%, which is lower than the expected range of 3 of 4 cited in Table . However, 20 of the 37 had RTE values above 85%, and it is possible data completeness issues suppressed the RTE estimate for some sites.

Figure 33-6. Share of sites by round-trip efficiency and battery size

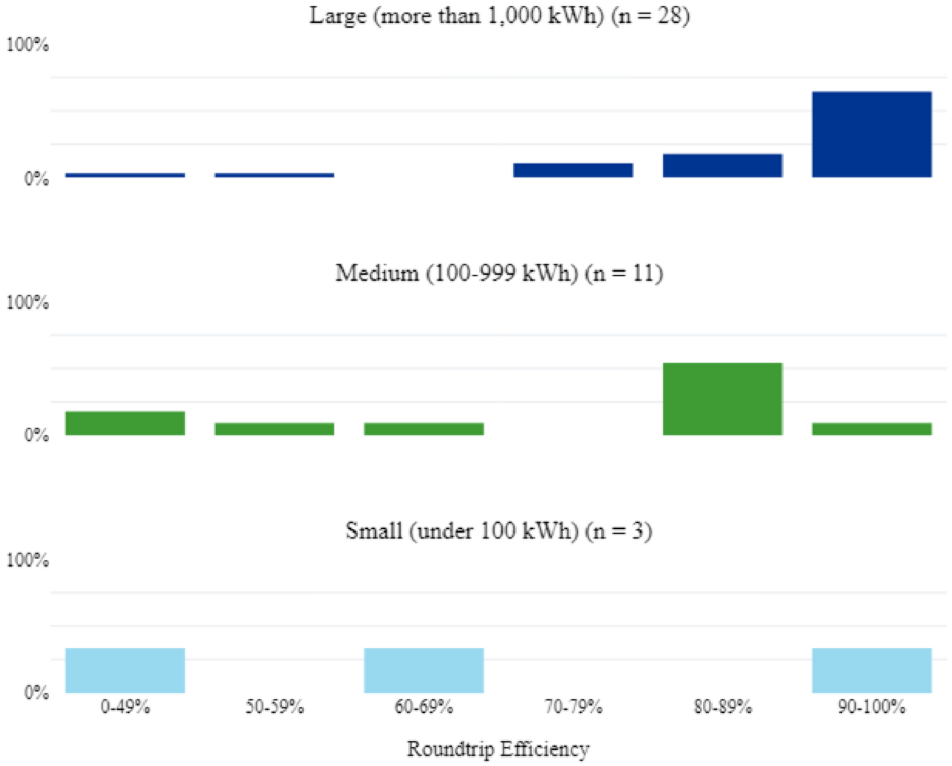
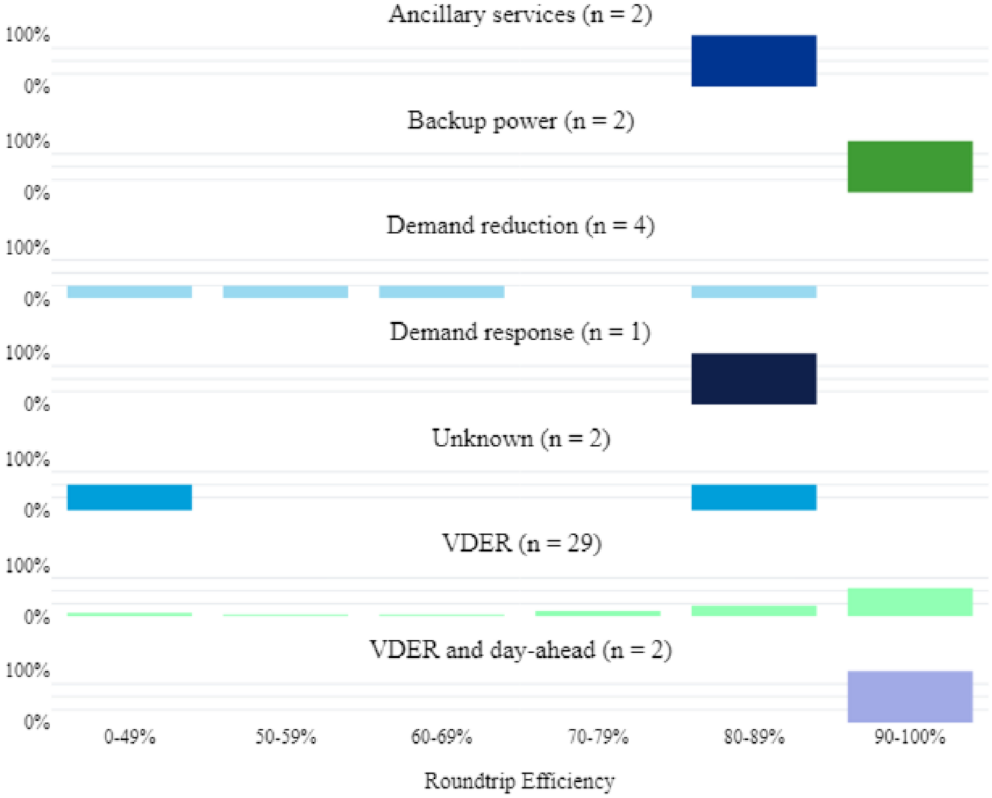


Figure 33-7. Share of sites by round-trip efficiency and primary use

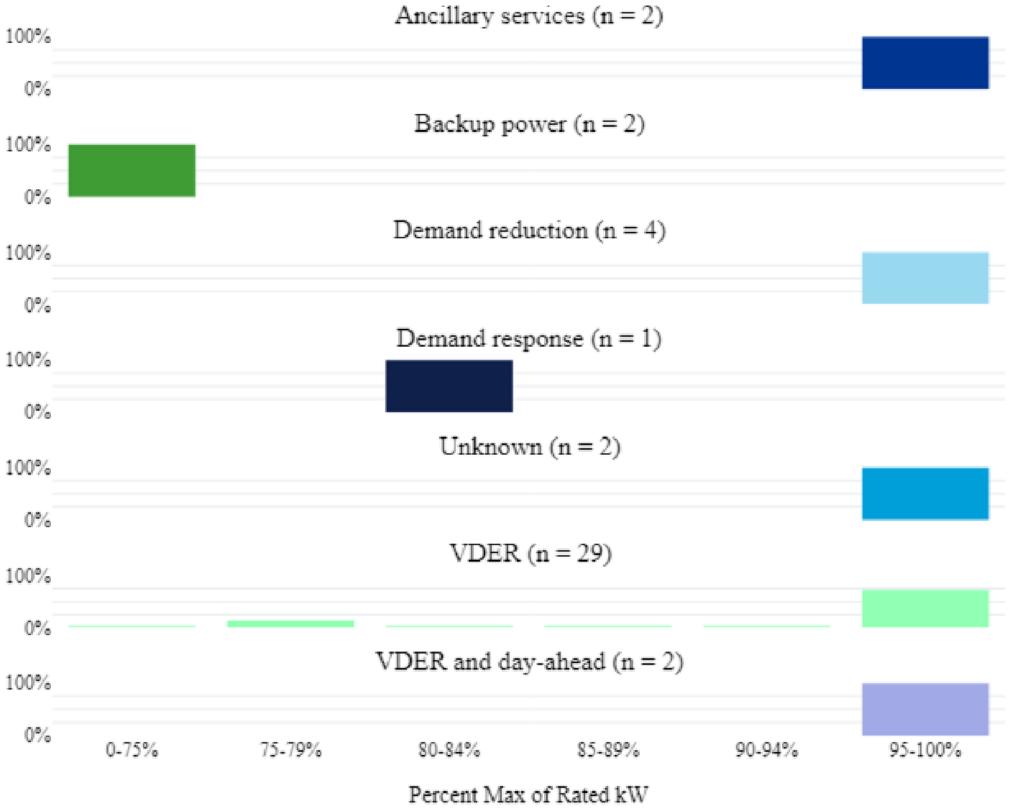


3.5.1.5 Maximum discharge

The team calculated the percentage of rated kW capacity achieved at the interval with the battery system’s maximum rate of discharge. This metric describes the extent to which battery systems achieve the rated discharge capacity.

Batteries achieved between zero and 107% of rated discharge capacity, and the median percentage achieved is 100%. While the figure 107% might initially seem perplexing as it exceeds the standard 100%, it is a result of a typical practice amongst BESS system installers/developers to intentionally overbuild the battery, vis-à-vis design specifications, to counteract degradation over time. Batteries lose capacity due to time and usage, and by initially overbuilding beyond nominal capacity, the system installers ensure that the battery system will maintain a performance above the nominal capacity for extended period of time. The three lowest percentages achieved were from sites 3 and 52, which are behind the meter systems that are designed for backup power or demand response, and site 54, which is a VDER site but appears to have been idle for long periods of time. Figure 33-8 summarizes percentage of rated discharge capacity achieved by primary use case. It is interesting to note that six VDER sites had maximum kW discharge intervals less than 90% of capacity. This could be for many reasons – It would be valuable to hear directly from the site operators on their strategy for power dispatch and whether there was intention behind this.

Figure 33-8. Share of site by max kW discharge as percentage of rated capacity and primary use

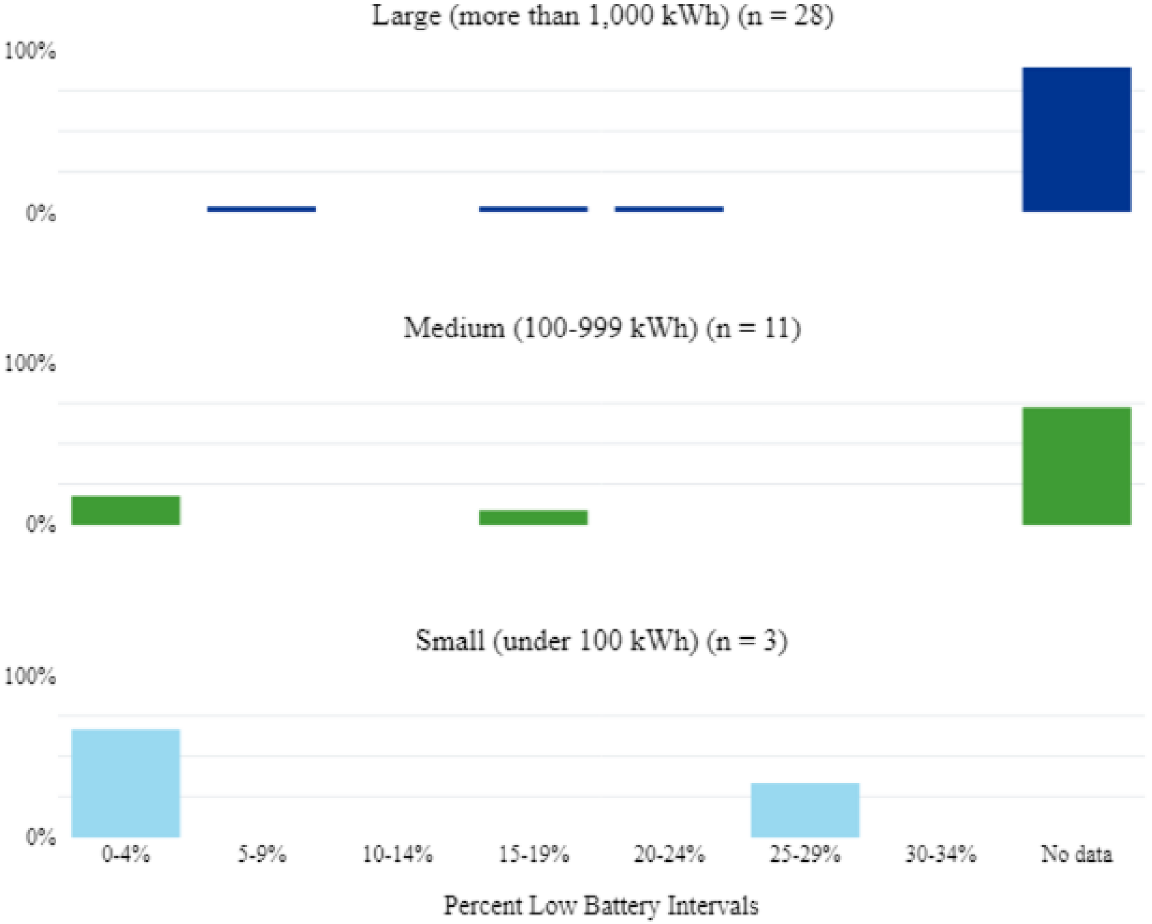


3.5.1.6 Low battery

The team calculated the percentage of intervals with low battery. “Low battery” was defined as state of charge below 20%. This metric approximates how often battery systems stay in a state of low charge, which correlates with battery degradation. However, only 9 of the 42 sites had state of charge data.

Batteries range from having zero to 29% of low battery intervals; and the median percentage is 6%. Small and medium battery systems (less than 1,000 kWh) that are behind the meter spent the least percentage of time in a state of low battery. Figure 33-9 summarizes percentage of low battery intervals by battery size. Given that only nine sites had state of charge data, little insight can be drawn from these aggregations due to sample size issues.

Figure 33-9. Share of sites by low battery intervals and battery size



3.5.2 Battery discharge patterns

3.5.2.1 Seasonal and diurnal trends

The visualizations in Figure 33-10 through Figure 33-12 show the seasonal and diurnal battery performance patterns at select sites. These are shown to give examples of the diverse ways energy storage is used depending on the nature of the site and the motivations of operators. In the chart, green areas represent when the battery is discharging, and blue areas represent charging. Darker colors represent when the battery is discharging or charging close to its max capacity.

At Site 66, the team observed discharge activity in the evenings increase from the spring to summer of 2022. As a VDER site, it is likely site operators are responding to the financial incentive to dispatch power at times of peak load. This pattern reflects what was observed when aggregating the interval data for all VDER sites, shown in Figure . This view provides insight into the overall role VDER sites play as grid resources motivated by energy price arbitrage.

Figure 33-10. Hourly discharge as % of capacity at site 66: an example of summer season increases in discharge

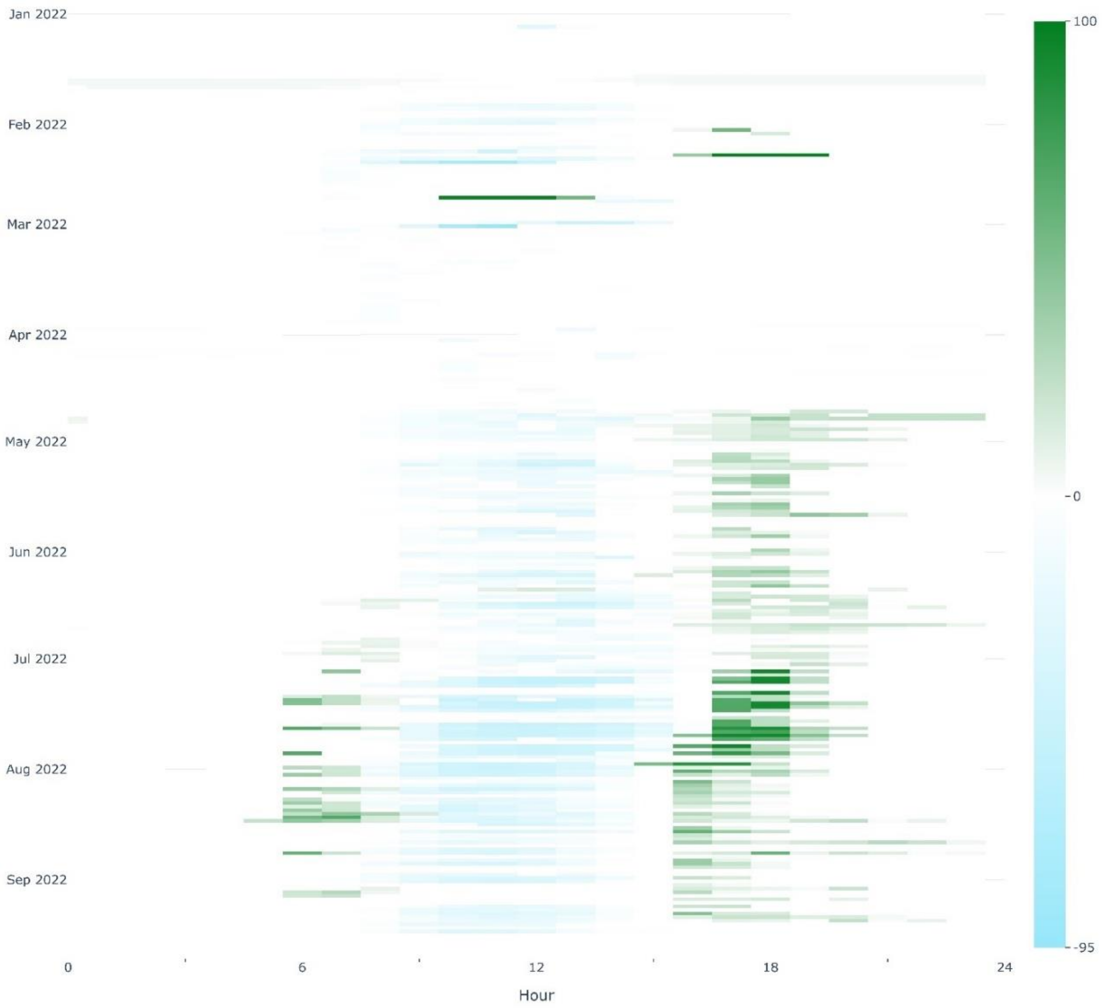
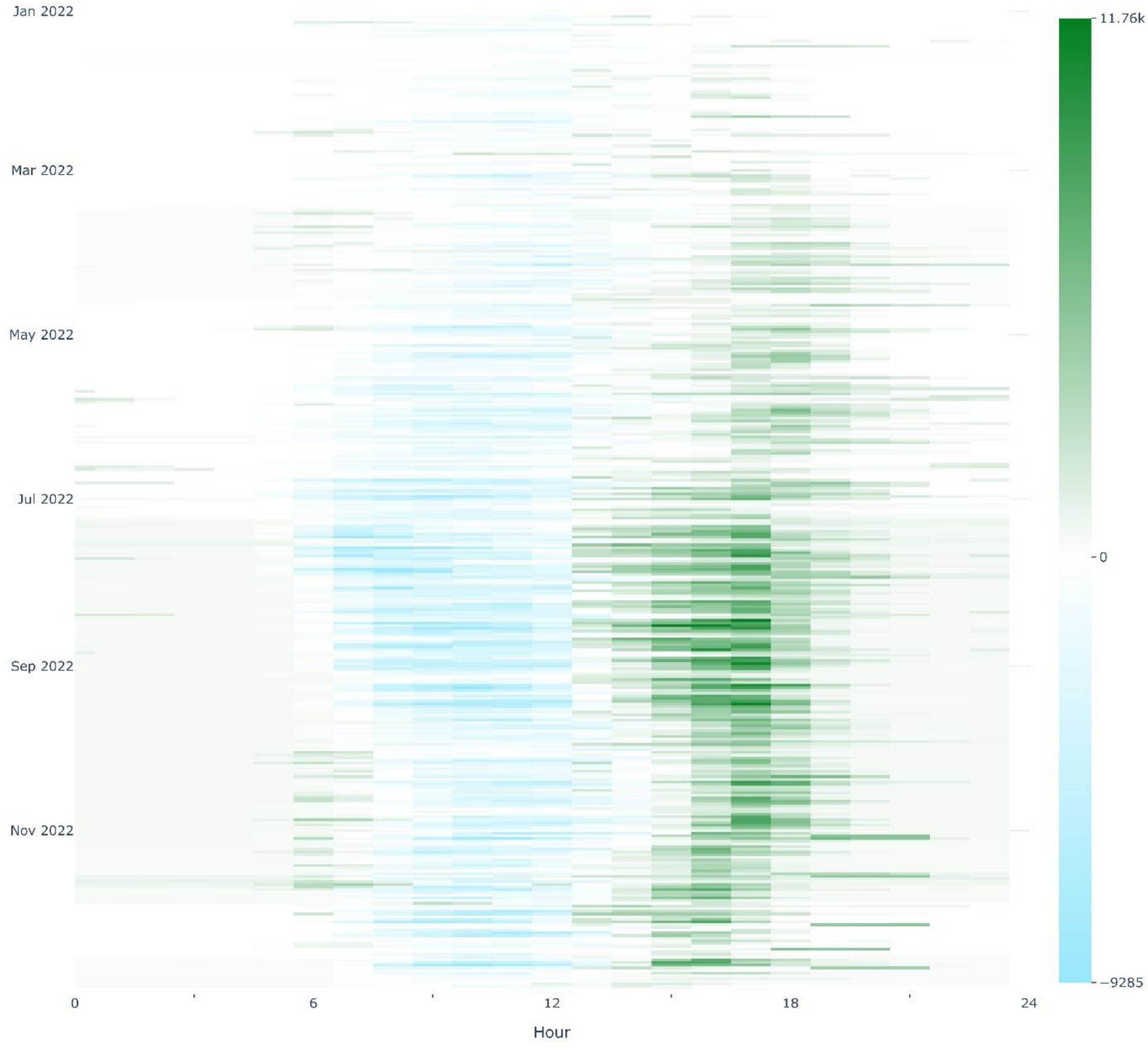


Figure 3-11. Aggregated hourly net discharge at VDER sites



At site 15, which does not have solar generation, the site was observed charging in the late evening and early morning hours (Figure 33-12). This aligns with the site operator’s intention to use the battery system for demand reduction at the co-located multifamily residential building, where residents use the most power in the late afternoon and early evening. At site 21, the team observed long, even discharge cycles from the early evening through the morning (Figure 33-13). The site has solar generation which helps charge the battery in the middle of the day. The purpose of the site, which has a refrigerated warehouse, is demand reduction. Since refrigeration requires a steady supply of power at all times, the steady use of battery power throughout the night is evidence of that purpose in action. The patterns at sites 15 and 21 align with what was seen across demand reduction sites.

Figure 33-12. Hourly discharge as % of capacity at site 15: an example of overnight charging

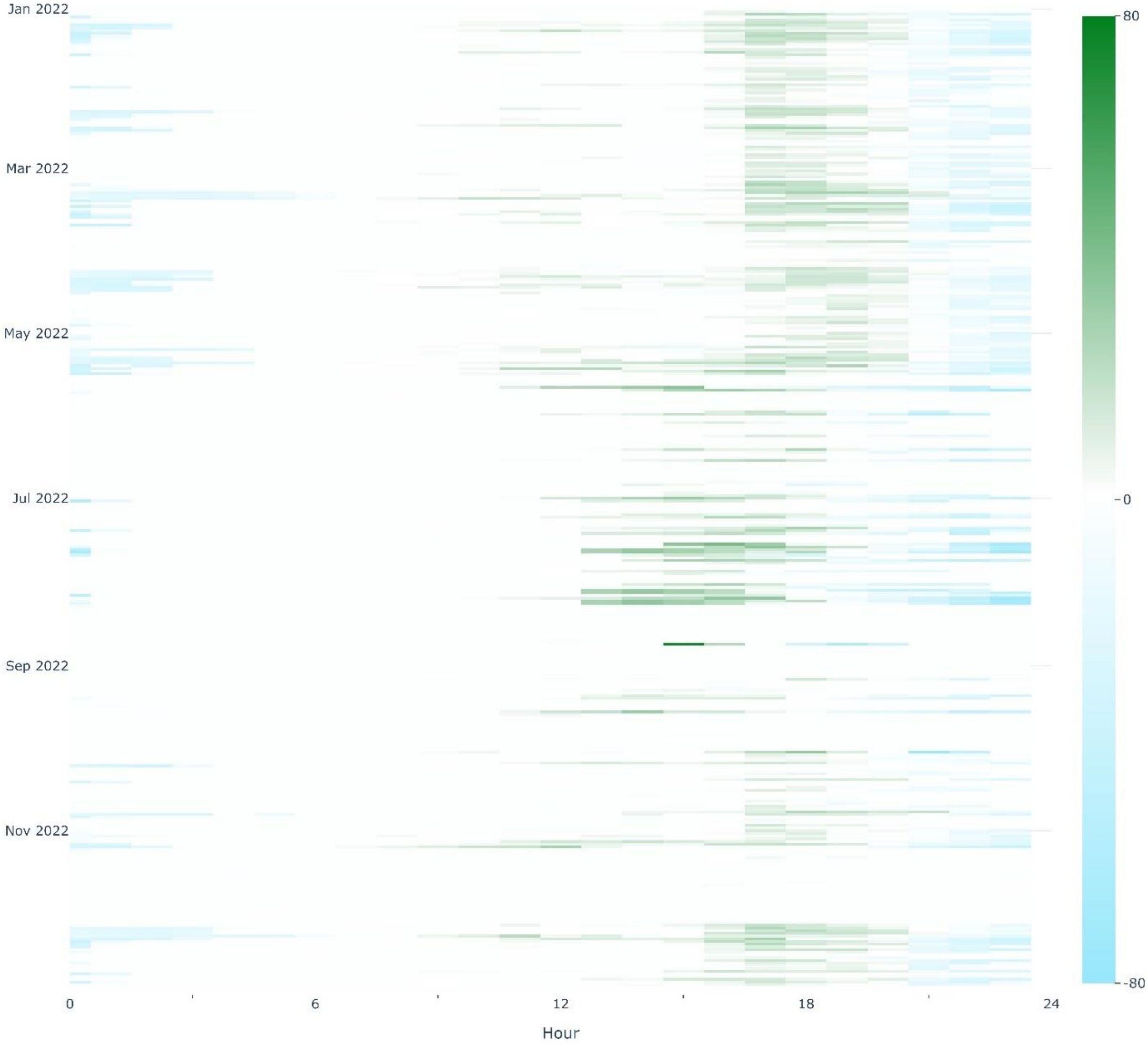


Figure 33-13. Hourly discharge as % of capacity at site 21: an example of a long overnight discharge cycle

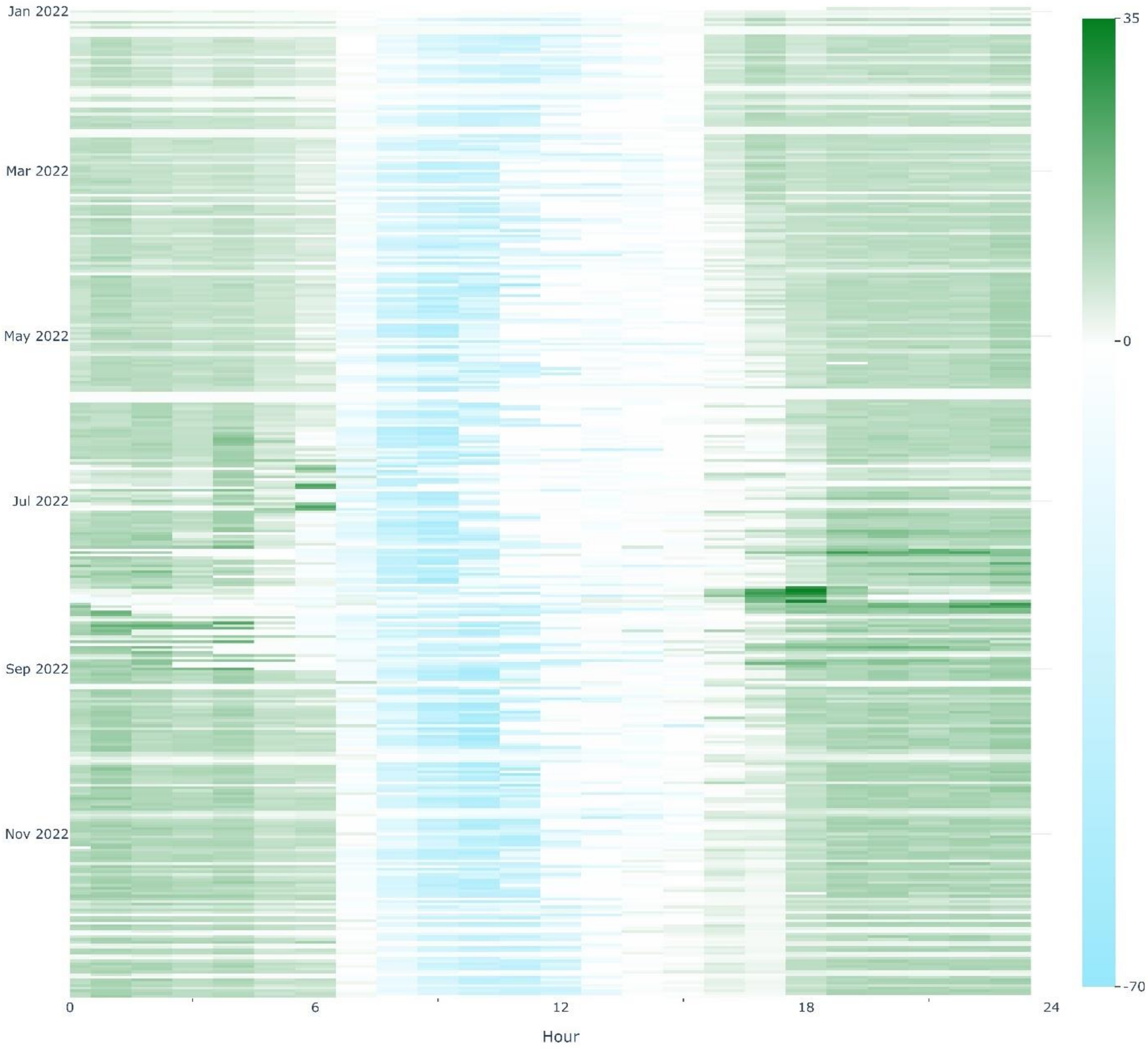
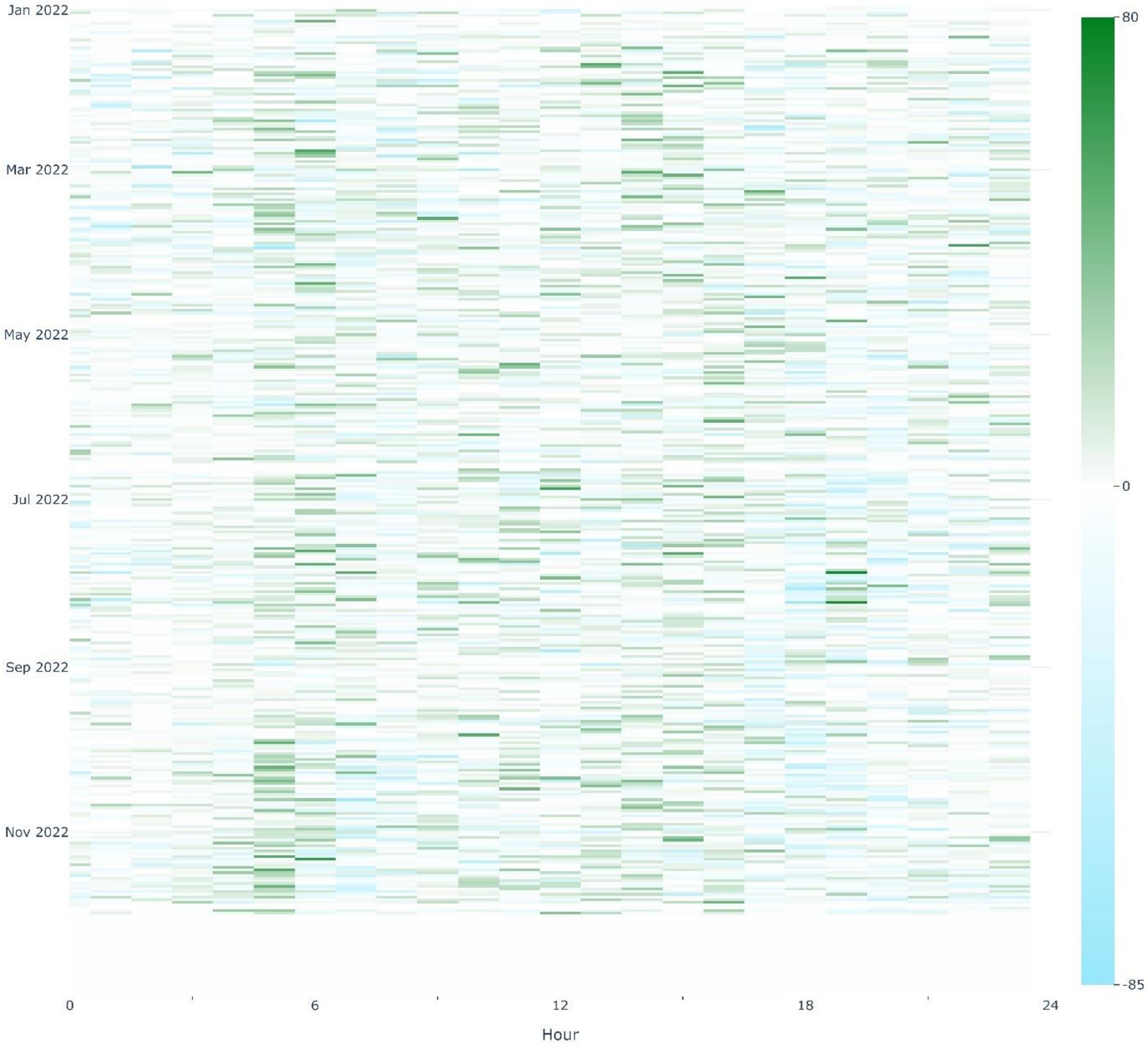


Figure 3-14. Hourly discharge as % of capacity at site 5: an example of battery dispatch for ancillary services

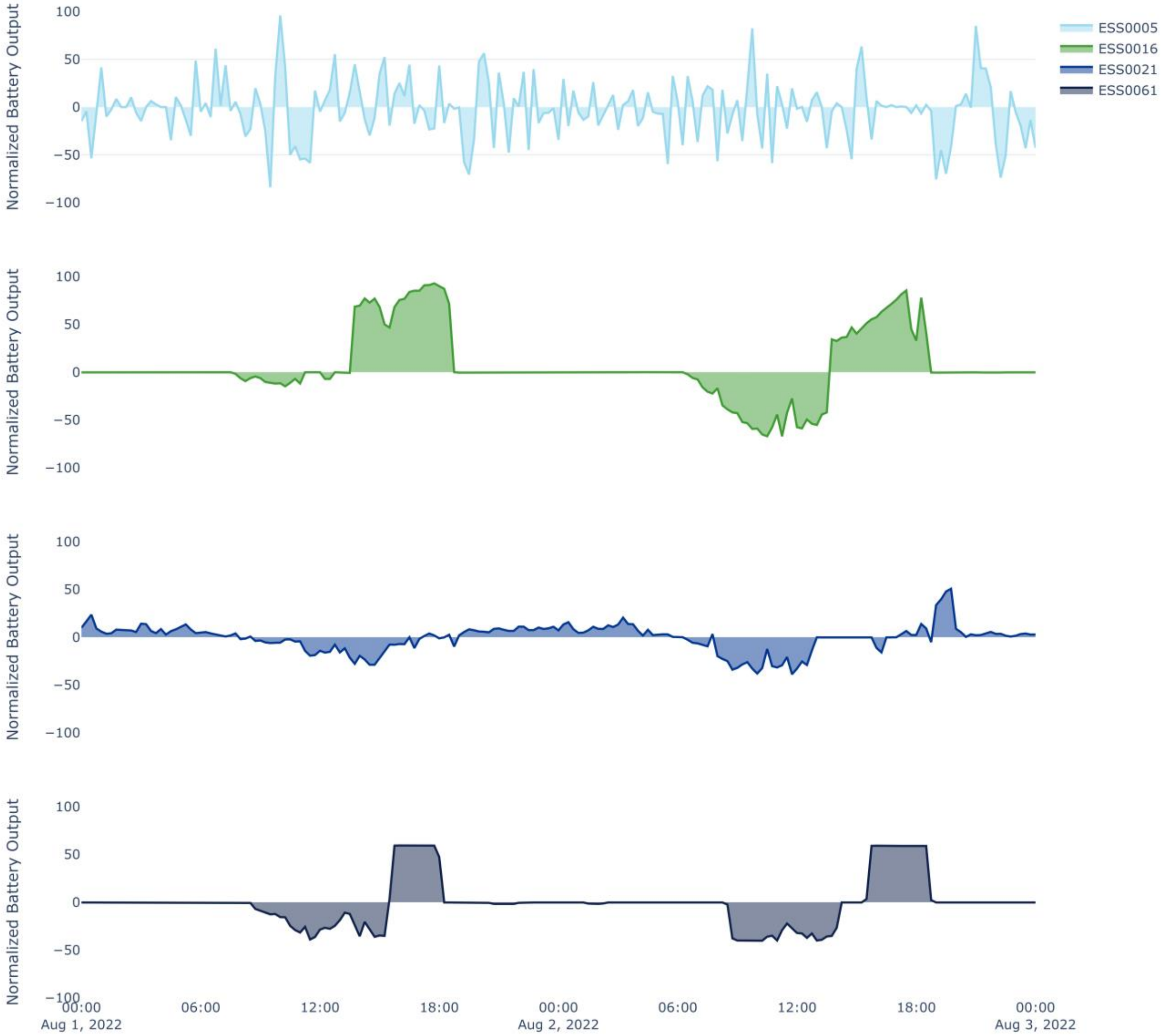


At site 5, which provides ancillary power support to the utility, the team observed little seasonal or diurnal pattern in how battery is used (Figure 3-14). The lack of a discernable pattern reflects how the battery is likely used as a tool to provide frequency regulation support (i.e., an ancillary service) to the NYISO grid, absorbing and discharging power as needed.

3.5.2.2 Intra-day variations in dispatch strategy

Figure shows the battery system charging and discharging pattern for two days in August 2022, for the four example sites. The bottom site (in grey) has a consistent strategy—it charges from mid-morning until afternoon, then discharges in the early evening, which aligns with typical peak hours. Site 16 (in green) had a similar strategy. Site 21(in blue) is charging and discharging at a lower rate over a longer period, and the discharging time is from late night to early morning. Site 5 (in light blue) is an ancillary services site that provides and absorbs power from the grid to balance load, which is evident in this figure as it is charging and discharging back and forth rapidly.

Figure 3-15. Charging and discharging patterns at select sites from August 1–3, 2022



3.6 VDER benefits

This section details the results of the team's VDER benefits analysis. Figure 3-16 (top) shows yearly compensation in total and the comparison between compensation from solar and from storage. The number on top of each bar indicates the number of sites that have compensation from either storage or solar. A huge increase in total compensation can be seen from 2020 to

2022, going from 0.06 million to 10.0 million. The ratio of solar exports rose from 2020 to 2022, reaching 82% in 2022.

Figure 3-16. Annual compensation (top) and normalized compensation (bottom) split by year

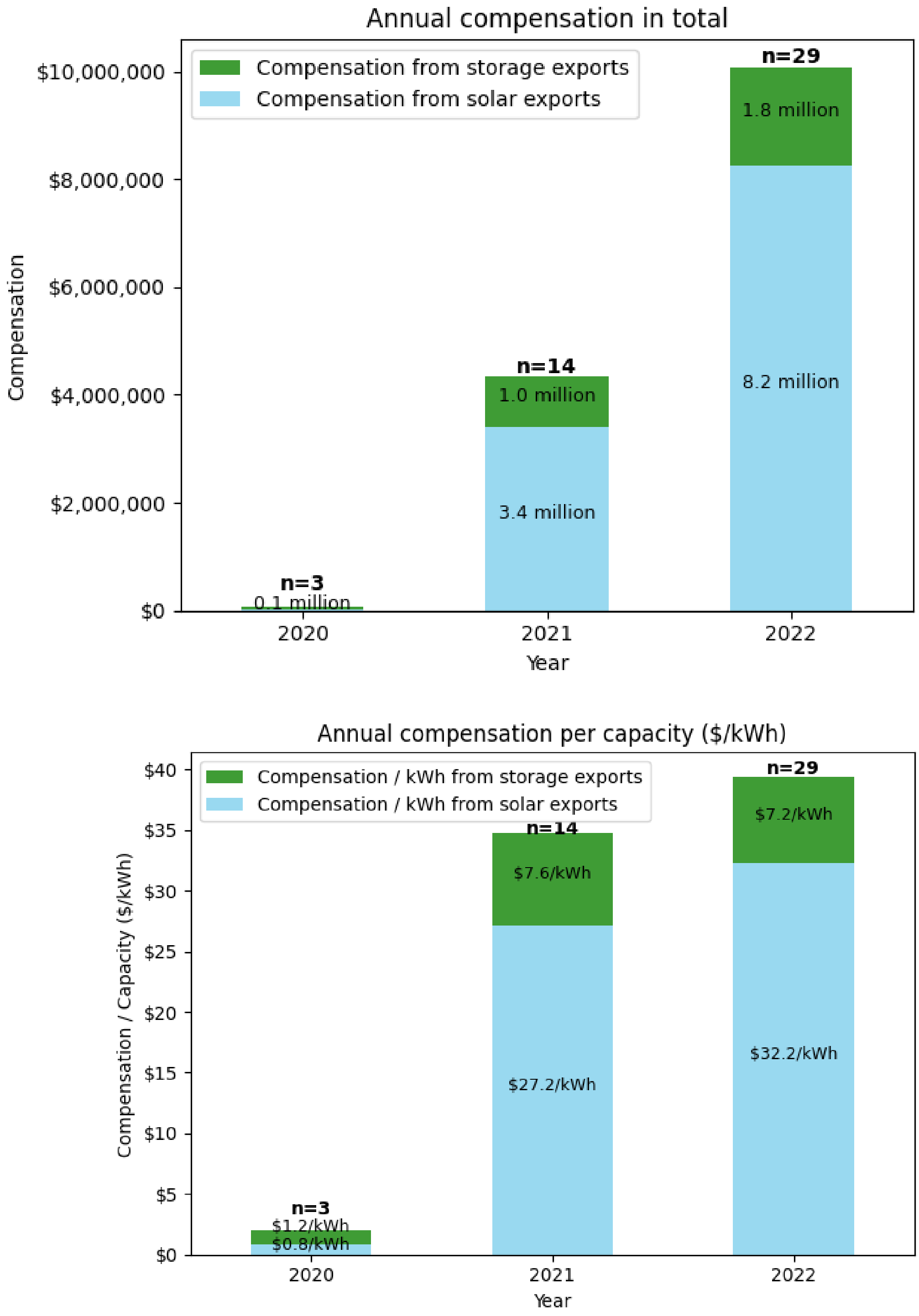
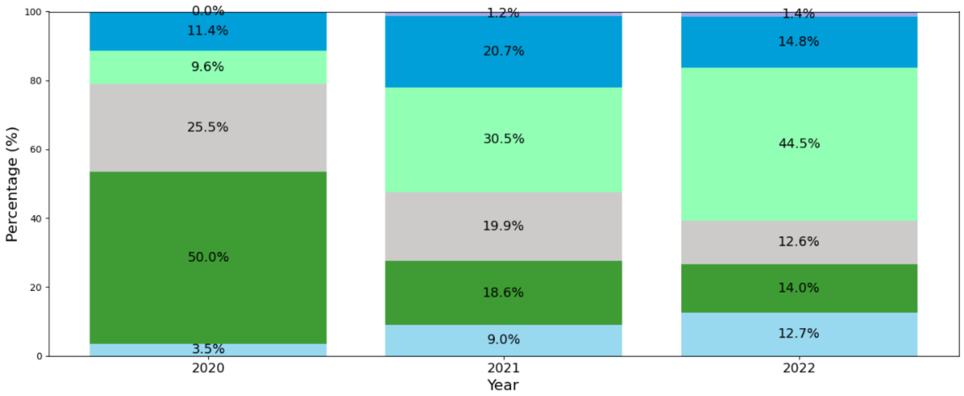


Figure 3-16 (bottom) shows yearly compensation normalized by installed system capacity. The value is low in 2020 due to limited operational data (one out of the three sites began operation in 2020 Aug, and the other two sites started in 2020 Dec, resulting in small annual compensation). From 2021 to 2022, the normalized compensation from storage export has a minor reduction of 5%, while that from solar export increased 18%.

The annual revenue split for solar exports is depicted in Figure 3-17. The upper section of the plot shows the proportional distribution of compensation across the six streams; the percentage of energy value has increased from 9.6% in 2020 to 44.5% in 2022, while the proportion of community credit to total revenue has declined from 50% in 2020 to 14% in 2022. The lower section of the plot shows the magnitude of compensation distribution across six streams, which all have exhibited considerable growth from 2021 to 2022. The energy value stream has shown the most substantial growth, escalating from 1 million dollars to 3.8 million dollars. It should be noted that the data for 2020 is not presented in the lower plot due to the minimal value and breakdown figures, rendering them not easily discernible.

Figure 3-17. Annual revenue split for solar exports for 2020–2022



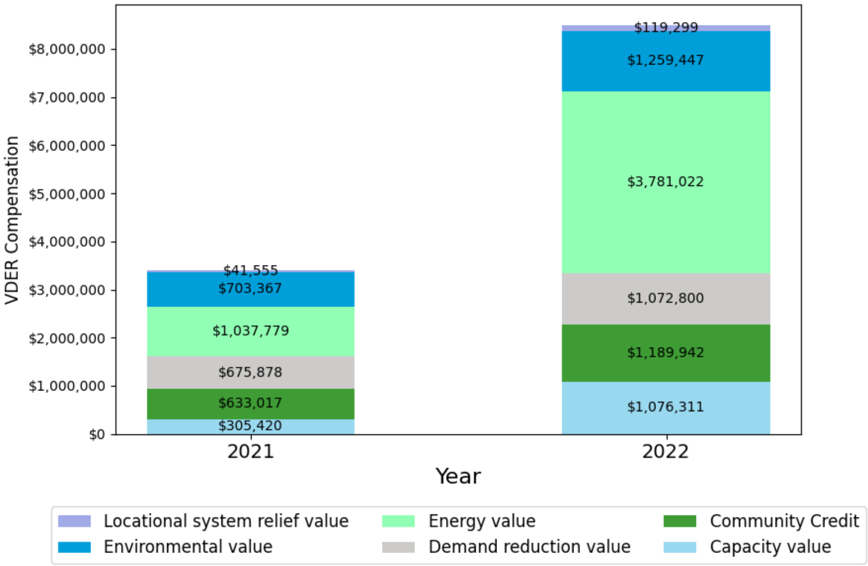
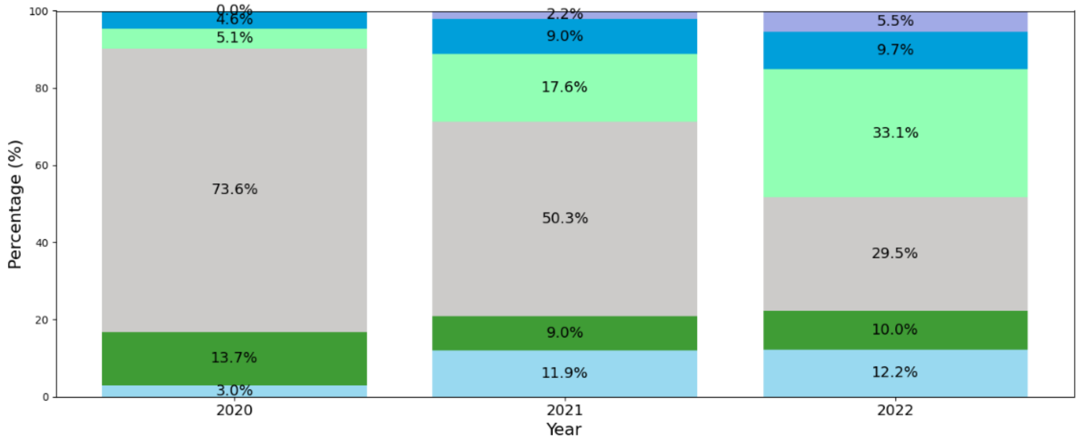
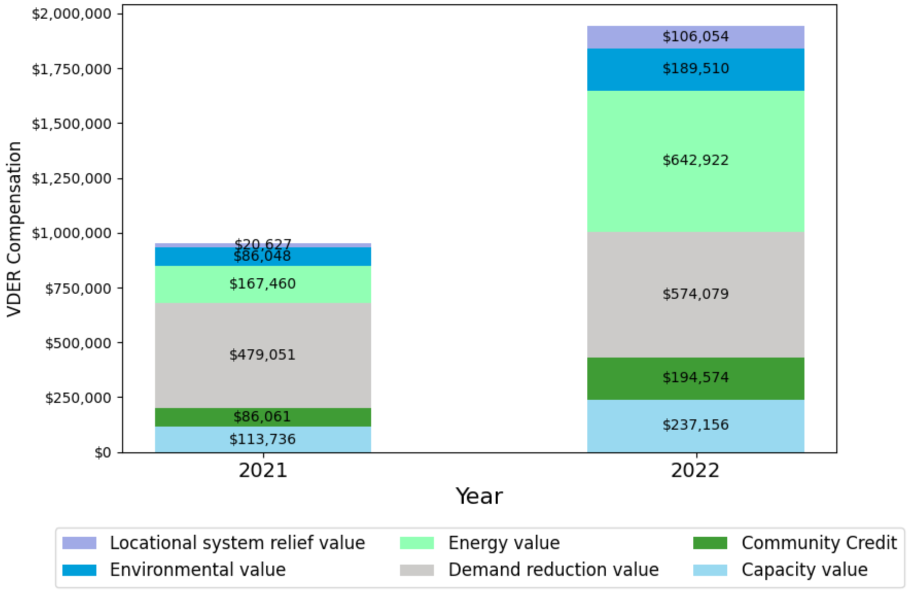


Figure 3-18 (top) shows the annual revenue breakdown for storage exports. Similar to solar exports, the ratio of energy value to total revenue in storage exports had a significant increase, rising from 5.1% in 2020 to 33.1% in 2022, while the proportion of demand reduction value to total revenue has declined from 73.6% in 2020 to 29.5% in 2022. Regarding compensation (illustrated in the lower plot), all six streams again registered growth from 2021 to 2022. Notably, the locational system relief value, despite being a minor component among the six streams, increased from $21,000 to $106,000. Similarly, the energy value nearly quadrupled from $167,000 to $643,000.

Figure 3-18. Annual revenue split for storage for 2020–2022



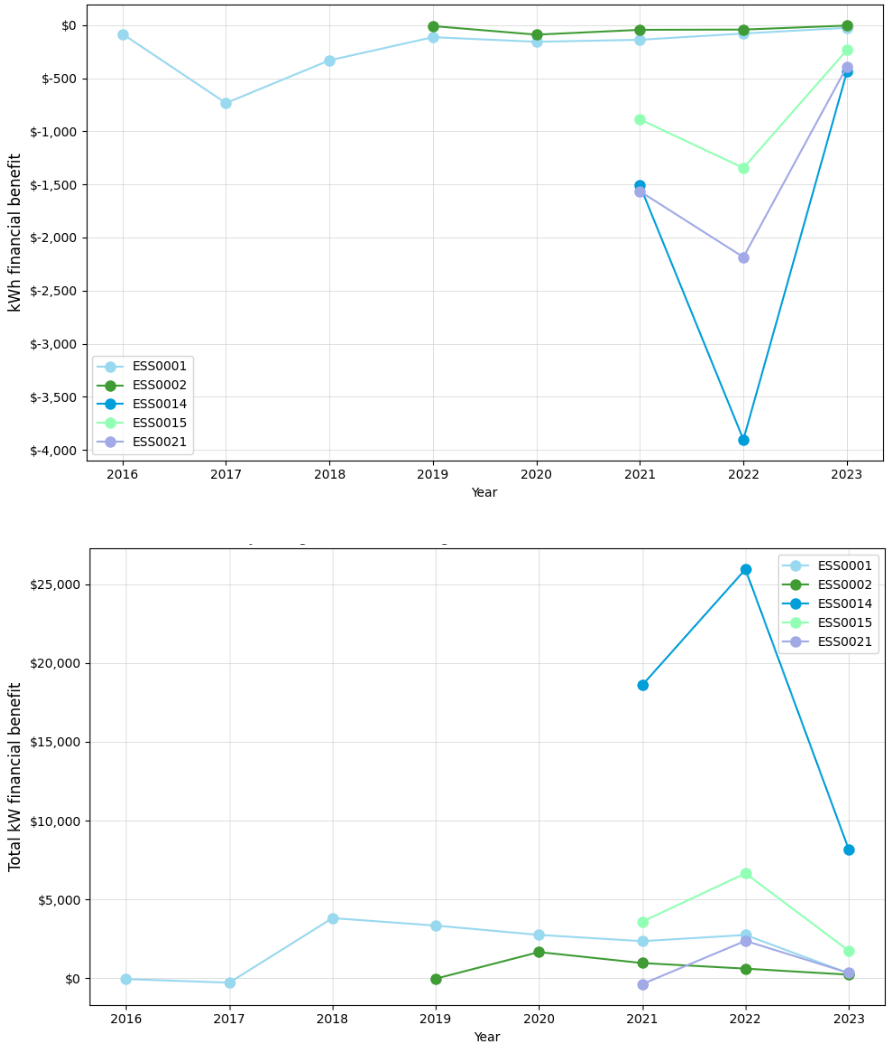


3.7 Site benefits

This section details the results from the team's site benefits analysis. The team looked at kWh savings and kW savings based on the comparison between site usage with battery and site usage without battery.

Figure 3-19 illustrates the annual energy charge (kWh) and demand charge (kW) financial benefits, expressed in US dollars. It is noteworthy that energy charge benefits are marginally negative across all the sites under study, with batteries actually costing site operators between $4,000 and $0 per year (data was only available through March for 2023). Negative energy savings occur due to the battery's RTE: when energy is transferred to the battery and later dispatched, some energy is lost in the process, leading to a reduction in dispatched kWh. These losses are summarized in the round-trip efficiency metric in Section 3.5.1.4. In financial terms, that loss might be offset if the site operator could sell the power at a higher rate than when it was purchased (or reduce site consumption by an equivalent amount). However, none of the sites analyzed are on a time-variant energy rate. The analysis is the same even if the battery was charged via on-site generation because it is assumed the site operator could have instead exported that power to the grid.

Figure 3-19. Annual energy charge (top) and demand charge (bottom) financial benefit ($) across sites



As shown in Figure 3-19 (bottom)**Error! Reference source not found.**, the total demand charge (kW) savings are mostly positive, with annual values ranging between $0 and $5,000, and one site reached more than $25,000 saving in 2022. Again, the demand charge savings for 2023 are lower because only data from the first quarter of 2023 were included in the analysis.

Figure 3-2020. Annual total site impact ($)

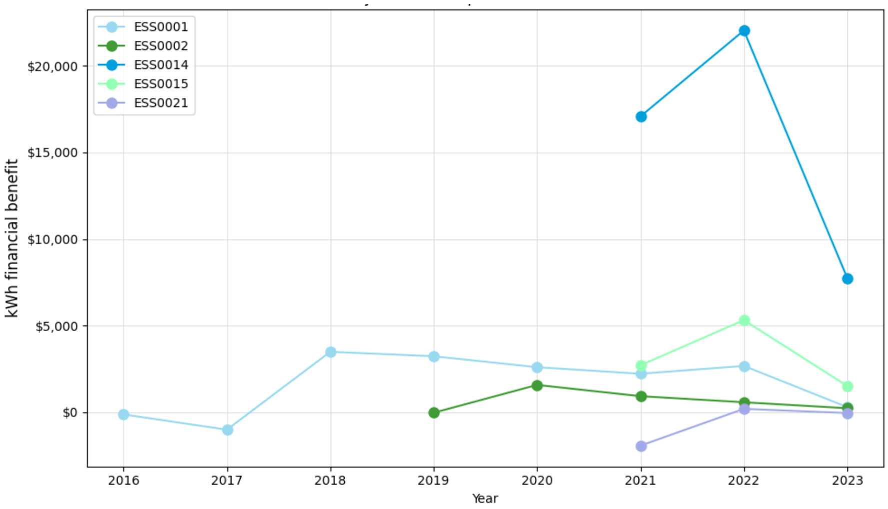


Figure 3-20 indicates the total site impact, which is the sum of financial benefits from energy savings and demand charge. Site 14 reached the highest site impact of $22,000 in year 2022, while most sites have an annual site impact below $5,000.

The team notes that while there are instances of negative savings from energy charges, the magnitude of positive demand charge savings is significantly more pronounced. This observation underscores the efficacy of leveraging battery storage for demand reduction. Importantly, the revenue generated from this source pales in comparison to the revenue from VDER. For context, VDER benefits in 2022 averaged revenue of over $300,000 per site (combining both solar and storage compensation).

4 Findings

This section sums up the main takeaways from each component of this analysis.

Table 4-1. Table of findings

Topic	Main Takeaways
Installer Surveys	- Respondents indicated a wide range of components can contribute to degradation/underperformance of storage systems and, in some instances, lead to non-performance. - There are a variety of mechanisms which may provide value to projects, and respondents were aware of and utilize many. - Respondents self-reported that issues with systems are, on average, able to be addressed quickly, and few projects file warranty claims.
Battery Degradation	- Per this study's modeling of battery degradation, none of the 42 BESS projects evaluated for battery degradation are expected to reach end of life by year 20, where end of life is defined as when the BESS has 60% or less of capacity retention remaining. - An increase in battery cycling has the greatest impact on battery degradation as compared to designed P-rates (e.g., Inverter kW / Battery kWh ratio). An increase from 0.25 cycles per day to 0.5 cycles per day saw 8 to 9% more degradation over the course of 20 years, whereas an increase in P-rate from 0.25 to 0.5 saw 1% more degradation over the course of 20 years
Site-level System Performance	- VDER systems cycle 50 times a year on average, far less than the 700+ and 100+ cycles averaged by the two Ancillary Services sites and four Demand Reduction sites, respectively. This may be in part due to VDER site operators dispatching power only when the financial incentive is strongest. - Average round-trip efficiency across the 37 BESS with valid estimates was 79%, which is lower than the expected range of 3 of 4 cited in Table 1-2. However, 20 of the 37 had RTE values above 85%, and it is possible data quality issues suppressed the RTE estimate for some sites.
VDER Benefits	- Total compensation increased significantly from 2020 to 2022, going from $60,000 to $10 million. In 2022, the average VDER compensation per site was $345k. - Increasing from 5% in 2020 to 33% in 2022, energy value has displaced demand reduction value as the largest revenue stream for VDER sites' storage exports. This mirrors the trend on the solar export side.
Other Site Benefits	- Site benefits from cumulative energy savings and demand reduction were calculated for the five sites for which rate information was available. These benefits were modest when compared to VDER compensation. For example, $22,000 was the largest annual sum of site benefits, accrued at site 14 in 2022. Other sites were mostly in the <$5,000 range.

5 Findings and recommendations

Based on these analyses, the analysis team provides the following conclusions and related recommendations for the program team.

Finding 1: Market signals. For the majority of systems in this study, market opportunities and their economic incentives drive operational strategy. The review of the system performance data suggests two general trends: 1) site operators try to minimize the cycling of the battery to minimize degradation and preserve its lifecycle, and 2) dispatch only when there is a significant incentive to do so, which appears to be mostly in summer, particularly for VDER sites. Given sufficient market signals, many sites could be cycling their batteries more often and at a higher rate of discharge—further bolstering the case for batteries as a flexible grid resource. For example, VDER sites, which make up 29 of the 42 sites, cycled only 50 times per year on average.

Recommendation 1: As most of the battery usage is focused on the summer months, NYSERDA can evaluate opportunities for winter-targeting programs that have defined hours of needs (e.g., winter DR programs), to which the batteries can contribute.

***NYSERDA response to recommendation**: Implemented. NYSERDA routinely monitors system performance and tailors the program according to situational needs.*

Finding 2: Underutilization. The analysis team finds that it is common for sites to have extended periods of no discharge activity. In some cases, this may be a metering issue, but to the extent it reflects real idle time, it signals that these grid assets are sometimes underutilized. For example, 7 of 42 sites cycled fewer than 20 times per year.

Recommendation 2: NYSERDA should continue routine engagement with site operators, with additional focus on gathering data points throughout the life of the system on how it is being used and why. NYSERDA might consider enhanced outreach to sites identified in this report as having extended period of inactivity.

NYSERDA response to recommendation: Rejected. Based on individual site economic tolerances and site desire to optimize VDER incentives as described in Finding 1.

Finding 3: VDER revenue is driving the market currently. Estimated VDER revenues are meaningfully greater than those from other revenue streams, with an average of $345k per VDER-participating site in 2022. They also represent the revenue stream that most systems are targeting. Survey responses recognized that all six components of the VDER Value Stack provide value to projects: energy value (LBMP), capacity value (ICAP, Option 1, 2, or 3), environmental value (E) – only storage with solar, demand reduction value, locational system relief value, and community credit.

Recommendation 3a: NYSERDA should consider alternative outreach methods with stakeholders (e.g., target workshops, focus groups, etc.) to drive continued adoption of these systems.

NYSERDA response to recommendation: Pending. NYSERDA will consider alternative and/or additional outreach methods as opportunities arise with key stakeholders, and with guidance by evaluators.

Recommendation 3b: If opportunities exist to refine the VDER modeling tool, one option would be to allow vendors to look at how much they earned from VDER in order to more easily calibrate projected and actual VDER performance, further bolstering their confidence in their projected earnings.

NYSERDA response to recommendation: Implemented. NYSERDA maintains a value stack calculator to help contractors better estimate compensation for projects.

Finding 4: Normal degradation. Per this study's operational and time-based modeling of battery degradation, all of the 40 BESS projects evaluated for battery degradation are expected to have remaining useful life after 20 years of operation, where end of life is defined as when the BESS has 60% or less of capacity retention remaining. However, this finding relies on modeling and lacks important inputs, like state of charge and operating temperature. State of charge information is only collected for 9 of 42 sites and operating temperature is not tracked. Both measurements are important in accurately estimating battery degradation.

Recommendation 4: In the upcoming year, the evaluation can use the state of charge data from the nine sites for which this data is available to generate battery-level model outputs if this is of interest to NYSERDA. Ideally, however, state of charge and operating temperature would be available for all sites. Since these metrics are typically collected by the system vendors as part of the routine operational data collection, NYSERDA should consider adding this as a data collection requirement for program participants.

NYSERDA response to recommendation: Pending. This will be considered as part of upcoming retail energy storage program manual updates.

Finding 5: Consistency in interval data. Electric inputs and outputs from the battery, solar system, and grid must each be captured separately and at high rigor to enable analysis and modeling of hybrid DERs. Varying levels of data feed consistency from metering and control systems introduces uncertainty into the results that the program should address moving forward. Currently, it is difficult to parse what is real activity and what is an issue with the data feed, which complicates the effort to understand how these sites are operating and how they respond to the market incentives.

Recommendation: Moving forward, the program should put into place regular validations of control system data streams (charge and discharge) against on-site revenue-grade metering (net facility load). Such validations can alert both site operators and program staff to issues in data collection. In addition to the validations, the program could consider making addressing data collection issues' a requirement for continued participation in the program.

NYSERDA response to recommendation: Implemented. A component of program participation includes a requirement to install a revenue grade meter to directly record the net energy charged and discharged from the energy storage system. NYSERDA routinely performs validation of energy storage system performance.

Finding 6: Program information. Contextual information collected as part of the program—specifically in utility rate classes and VDER configurations applicable for each site—is key to accurately calculating site benefits (both VDER and otherwise). When this data is unavailable, assumptions must be made that can lead to inaccurate estimates of site benefits.

Recommendation: Require the provision and consistently collect site-level characteristics, like engineering specifications, facility characteristics, and utility rates. All contextual information about the site aids in understanding system performance.

NYSERDA response to recommendation: Implemented. This is now a standard component of program participation.