PNNL-30594

Washington Clean Energy Fund Grid Modernization Projects: Economic Analysis

Final Report

October 2020

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Prepared for the U.S. Department of Energy under Contract DE-AC05-76RL01830

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Executive Summary

In the rapidly evolving state of today's electrical grid, energy storage is a highly valuable resource that is capable of providing a wide array of services. Utilities and states have explored how to capitalize on this expanding technology and have developed new funding opportunities in recent years to support it. The Washington State Clean Energy Fund (CEF) is one such program and provides grants in support of the development of clean energy technologies in Washington State. The CEF is administered by the Washington Department of Commerce. To date, CEF grant funds have been dispersed to electric utility companies, vendors, universities, and research organizations to support projects that work to integrate intermittent renewable sources of energy, improve grid reliability, expand grid modernization activities, reduce the costs associated with distributed energy resource (DER) deployments, and lower emissions.

Since 2013, the Washington State Legislature has authorized $122 million for the fund (Figure ES 1). The total funding amount has grown each consecutive iteration with the third round of funding reaching $46 million.[1] The wide selection of projects covers a broad scope of use cases and includes different battery technologies across a range of locations within the state.

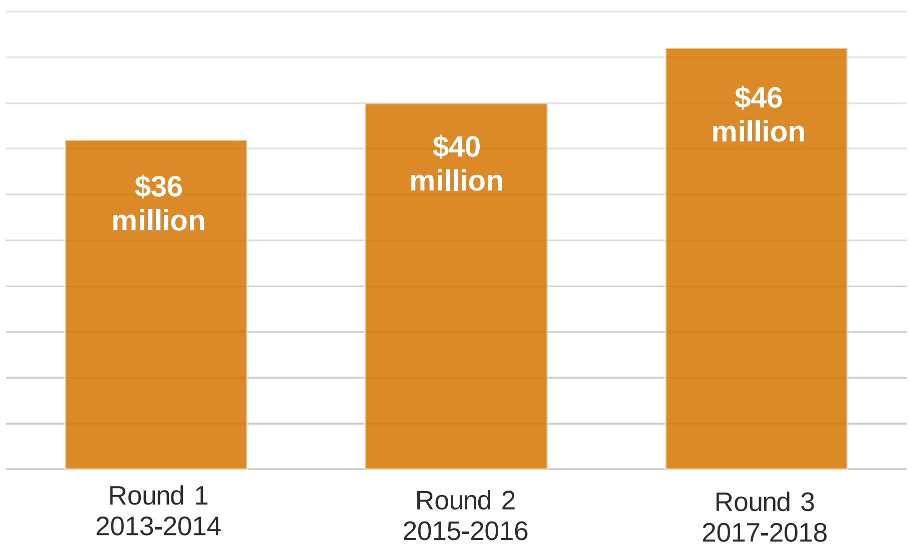

Figure ES 1 Washington CEF Biennial Funding Levels

As part of CEF Round 1 funding, Pacific Northwest National Laboratory (PNNL) was engaged by the U.S. Department of Energy (DOE) and the Washington Department of Commerce to work with Puget Sound Energy (PSE), Avista, and Snohomish Public Utility District (SnoPUD) in evaluating the economic and technical performance of each of their battery energy storage systems (BESSs). This report presents the final results of the economic assessment.

The location of each of the three BESS projects PNNL evaluated is shown in Figure ES 2 below.

[1] Kirchmeier, B. 2018. Clean Energy Funds: 2013-2017-Overview of Grid Modernization Program. Presented at the Pacific Northwest Regional Economic Conference. Tacoma, WA.

CEF Round 1 Projects

(1) Puget Sound Energy:
Glacier, Washington
2 MW / 4.4 MWh Lithium-ion BESS

(2) Snohomish Public Utility District:
Everett, Washington
2 MW / 1 MWh Lithium-ion BESS
2.2 MW / 8 MWh Vanadium-Redox Flow BESS

(3) Avista:
Pullman, Washington
1 MW / 3.2 MWh Vanadium-Redox Flow BESS

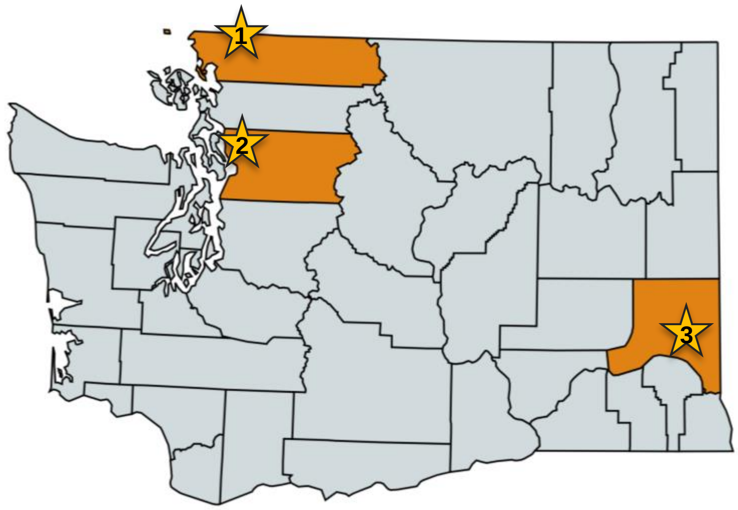

Figure ES 2. Map of Washington CEF Round 1 Projects

PNNL worked closely with each of the three utilities to determine the economic viability of each of their projects. The following key lessons and implications can be drawn from the multi-year analysis.

1 – Based on Design and Cost Documents Prepared by Each of the Utilities, all Three Projects Fall Short of Generating Positive Net Benefits to each Utility under the Base Case Scenarios.

The base case analyses provide results from the perspective of the utilities only (i.e., they do not incorporate any benefits that would be directly gained by other parties). Benefits calculated for the projects under the base case for all projects fall below associated revenue requirements with the CEF grant funds included for each of the projects (Figure ES 3). The return on investment (ROI) ratios (total benefits divided by revenue requirements, present value terms) for each of the projects are: 0.43 for PSE, 0.26 for Avista, and 0.11 for SnoPUD.

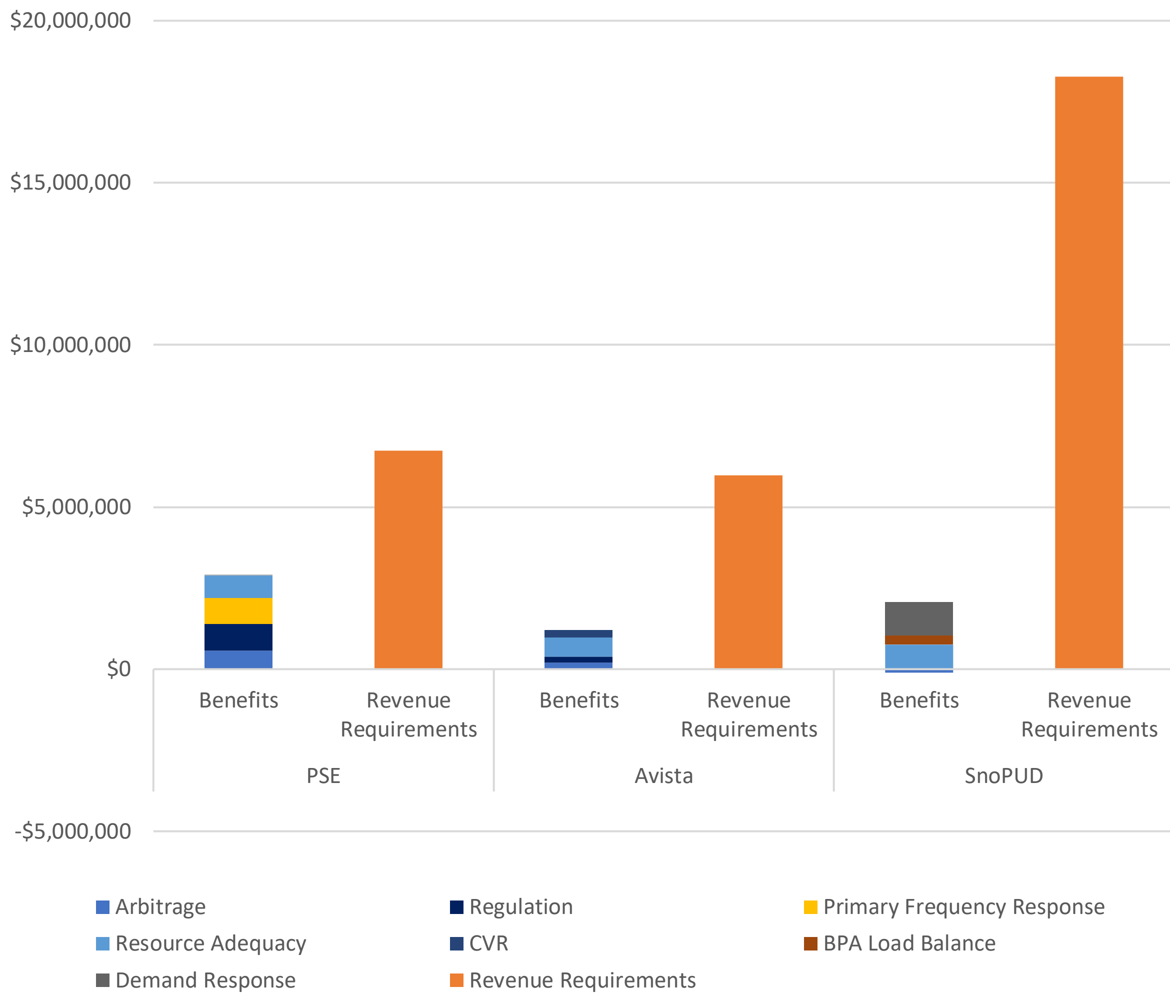

Figure ES 3. Base Case Present Value Benefits and Revenue Requirements by Project and Use Case

2 – When Outage Mitigation is Included in the Analysis, the Avista Turner BESS Project Generates Positive Net Benefits and the PSE BESS Project Shows a Large Increase in Benefits.

When outage mitigation is included in the analysis, a benefit measured in terms of value of lost load to customers for the Avista and the PSE projects are included, and total benefits for both projects rise (Figure ES 4). For Avista, the ROI increases to 1.85, and for PSE the ROI nearly doubles to 0.84. This use case is not included in the base case because the benefits do not yield tangible economic benefits to the utilities incurring the costs of the deployed BESSs.

While the Avista Turner BESS demonstrated the capacity for significant value, it later became non-operational and was removed from the facility. <u>The results presented within this report, therefore, represent the potential benefits that could have been derived had the battery operated as tested and remained in place for its entire usable life.</u>

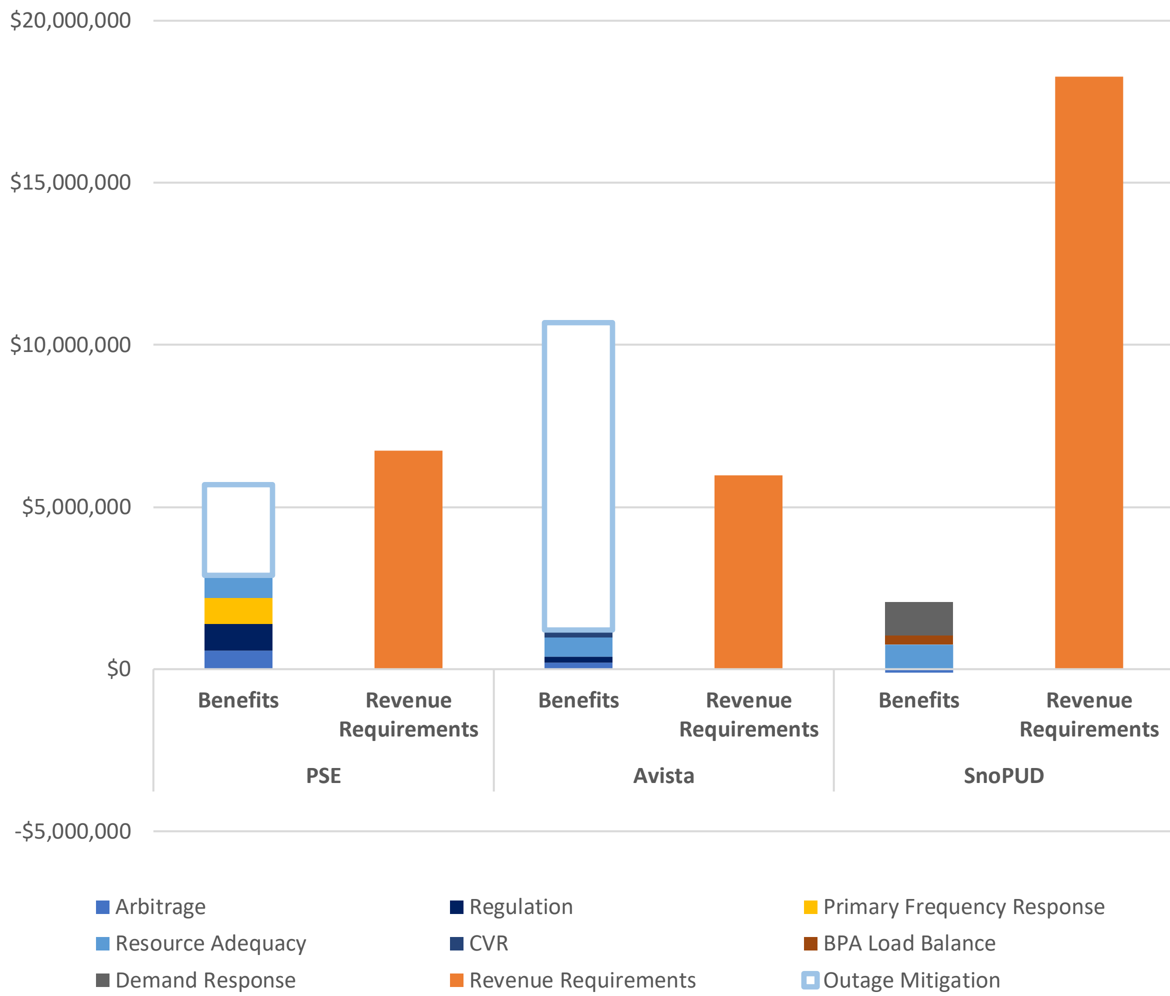

Figure ES 4. Present Value Benefits and Revenue Requirements by Project and Use Case – Outage Mitigation Included

3 – Outage Modeling for the Avista Project Indicates that the BESS Could Have Mitigated All Voltage Sags Affecting Schweitzer Engineering Laboratories (SEL) in Pullman, WA.

Modeling conducted for this assessment indicates that all voltage sag-created outages occurring at SEL could have be mitigated with the Avista BESS. The facility contains manufacturing processes which are sensitive to power quality disturbance-related interruptions. The interruptions lead to significant financial damage as there is a minimum of three hours of downtime for the facility. The average annual benefit of avoiding these outages is approximately $150,000 per hour to SEL, totaling roughly $9.5 million over the life of the battery as shown in Figure ES 4.

4 – A Survey of the Effects of Using the Modular Energy Storage Architecture (MESA) Standardization Shows a Wide Range of Benefits from Implementing Standards in Energy Storage.

The MESA specifications were developed to promote scalable energy storage that can provide cost and time saving benefits to the industry. SnoPUD was one of the first utilities to implement the standard and provided information regarding the benefits they have experienced or expect to experience with standards in place (Table ES 1). Equipment procurement and electrical design both showed the potential for up to a 50% reduction in cost with MESA. Electrical design, as well as commissioning, showed a potential 50% reduction in time with standardization. Responses indicated that other components would be expected to experience 5-25% reductions in either cost or time.

Table ES 1 Estimated Reduced Time and Cost to Complete Due to Standardization

Component	Reduced Time to Complete	Reduced Cost to Complete
Electrical Design	50%	50%
Engineering	25%	25%
Equipment Procurement		25-50%
Construction	10%	10%
Factory Acceptance Test	15-20%	
Commissioning	50%	
Acceptance Testing	15-20%	
Quality/Quality Assurance & Reliability		5%
Operations & Maintenance	10%	10-15%

5 – Battery Systems Testing Allowed for the Development of a State of Charge (SOC) Model to More Accurately Represent Battery Operation Over Time.

After all testing was completed for the BESSs, nonlinear SOC models were developed to be used in economic modeling and to aid in developing power profiles for future testing. The purpose of the SOC model is to come up with a form for describing how the SOC changes with respect to time, allowing for more complete and accurate representation within battery modeling. Testing results indicated that round trip efficiency (RTE) differs based on several parameters, including the SOC range within which the BESS is operating, temperature, power output level, and whether the BESS is charging or discharging. The nonlinear SOC models greatly enhance our ability to predict battery performance when engaged in economic operation.

6 – Sensitivity Analysis Results Show a Range of Positive and Negative Results Compared to the Base Case for Each Project.

Several scenarios for each project were examined to determine the sensitivity of results with respect to varying a small number of key parameters. For the PSE project, incorporating societal benefits and costs led to a lower return for PSE as removing the impact of the grant funds led to a large decline in net benefits even when outage mitigation was included. Grant funds are eliminated in a societal analysis because these funds did represent a cost to taxpayers. The existence of the grant funds, therefore, do not reduce costs to society, they simply shift their source to other taxpayers. For Avista, the large benefit from including outage mitigation for SEL far outweighed the negative impact of excluding the grant funds under the same scenario. On the positive side, extending the PSE analysis from a 10-year battery to a 20-year battery with major maintenance and upgrades included led to an increase in benefits of over $866 thousand. All sensitivity analysis scenarios for SnoPUD and the remainder of the analyses for PSE and Avista had little impact on the overall return of each project.

Acknowledgments

We are grateful to Mr. Bob Kirchmeier, Senior Energy Policy Specialist at the Washington Department of Commerce, for providing CEF program leadership and support to PNNL and our utility partners. We are also grateful to Dr. Imre Gyuk, who is the Energy Storage Program Manager in the DOE Office of Electricity, for providing financial support and leadership on this and other related work at PNNL. We wish to acknowledge Philip Craig from BlackByte Cyber Security, the team members from Avista, including Matt Michael, Robert Cloward, James Gall, Reuben Arts, John Gibson, Clint Kalich, Curt Kirkeby, and Kenny Dillon; Uni Energy Technologies team members Chauncey Sun, Brad Kell, and David Ridley; and the team members from SnoPUD, including Bob Anderson, Arturas Floria, Kevin Lavering, Nick Peretti, Mike Shapley, and Jason Zyskowski; and Kelly Kozdras from PSE.

Acronyms and Abbreviations

AC	alternating current
ACE	area control error
ADSS	Avista’s Decision Support System
AM	Advanced model
AP	Actual price
BESS	Battery energy storage system
BPA	Bonneville Power Administration
BSET	Battery Storage Evaluation Tool
CAISO	California Independent System Operator
CBEMA	Computer Business Equipment Manufacturers Association
CEF	Clean Energy Fund
CVR	Conservation Voltage Reduction
DAM	day ahead market
DER	distributed energy resource
DERO	Distributed Energy Resource Optimizer
DG	Doosan Gridtech®
DNP3	distributed network protocol
DOE	U.S. Department of Energy
EA	Energy arbitrage
EI	Energy Imbalance
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FP	Forecast price
GBM	gradient boosting machine
ICE	incremental capacity equivalent
IEC	International Electrotechnical Commission
IRP	Integrated Resource Plan
ISO	independent system operator
ISONE	Independent System Operator for New England
IT	information technology
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
LADWP	Los Angeles Department of Water and Power
LMP	locational marginal price
LOLP	loss of load probability
LVRT	low voltage ride through
MESA	Modular Energy Storage Architecture
MISO	Midcontinent Independent System Operator
mSec	milliseconds
MW	megawatt

MWh	megawatt-hour
NERC	North American Electric Reliability Corporation
NPS	Northern Power Systems
NYC	New York City
NYISO	New York Independent System Operator
O&M	operations and maintenance
OPET	Optimization Performance Evaluation Tool
OT	operational technology
PCS	power conversion system
PJM	Pennsylvania/Jersey/Maryland Power Pool
PNNL	Pacific Northwest National Laboratory
PSE	Puget Sound Energy
PV	present value and photovoltaics
RMSE	root mean square error
ROI	return on investment
RTE	round trip efficiency
RTM	real time market
SCADA	supervisory control and data acquisition
SCL	Seattle City Light
SEL	Schweitzer Engineering Laboratories
SM	Simple model
SnoPUD	Snohomish Public Utility District
SOC	state of charge
SSPC	Salem Smart Power Center
T&D	transmission and distribution
TCC	transmission congestion contracts
TOU	time of use
UET	UniEnergy Technologies
VAR	volt-ampere reactive
WA	Washington
WSU	Washington State University

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1.0 Introduction

BESSs have the potential to improve the operating capabilities of the electrical grid. Their ability to store energy and deliver power can increase the flexibility of grid operations while also providing the reliability and robustness that will be necessary in the grid of the future. The technology has received a great deal of attention in recent years and entrepreneurs are working to commercialize a myriad of promising technologies. Venture capitalists, as well as the U.S. government, are investing in this space. The technologies show promise, but it oftentimes remains difficult to evaluate and measure the benefits that BESSs could provide.

The CEF provided $14.3 million toward the deployment and demonstration of energy storage in an effort to explore the role storage could play and the value it could deliver to Washington State's utilities and to its citizens as consumers. The first round of funding for the Washington CEF Grid Modernization Program (CEF 1) supported deployment of five battery systems located at three utilities. Avista Utilities deployed a 1-megawatt (MW) / 3.2 megawatt-hour (MWh) UniEnergy Technologies (UET) vanadium-flow battery system in Pullman, Washington. PSE deployed a 2 MW / 4.4 MWh lithium-ion/phosphate BESS at a substation in Glacier, Washington. SnoPUD deployed two 1 MW / 500 MWh lithium-ion battery systems (MESA 1a and MESA 1b) at a substation in Everett, Washington. At another substation in Everett, SnoPUD also deployed a 2.2 MW / 8 MWh vanadium-flow battery (MESA 2) built by UET. The installation and operation of the battery systems for SnoPUD was also part of a multi-year effort to advance MESA and transform how the utility manages grid operations. MESA is a standardization framework for battery systems that is described in greater detail later in this report.

To maximize the value of the CEF, the Washington Department of Commerce worked with PNNL to design an assessment framework for the demonstration based on a consistent set of use cases and measurements that does not constrain, but rather enhances the diverse scope of applications for energy storage. This framework, and its application for these demonstration projects, will inform and empower other utilities, storage technology developers, and state regulators to prudently and confidently pursue the deployment of energy storage.

This document outlines the modeling and analytical methods used to evaluate the economic performance of the BESSs at all three utilities and the financial and non-financial performance of the MESA standardization at SnoPUD.

2.0 Background on CEF 1 Projects

This section serves as a guide to the projects in the demonstration and provides background information on each.

2.1 PSE Glacier Energy Storage Project

PSE's battery project is located in Glacier, Washington—a remote part of northern Washington State, just south of the U.S.-Canadian border in the North Cascade foothills. A 55-kilovolt (kV) radial transmission line serves the small town as shown in Figure 2.1. The area is heavily forested, which leads to interference on the lines and has historically caused frequent transmission outages.

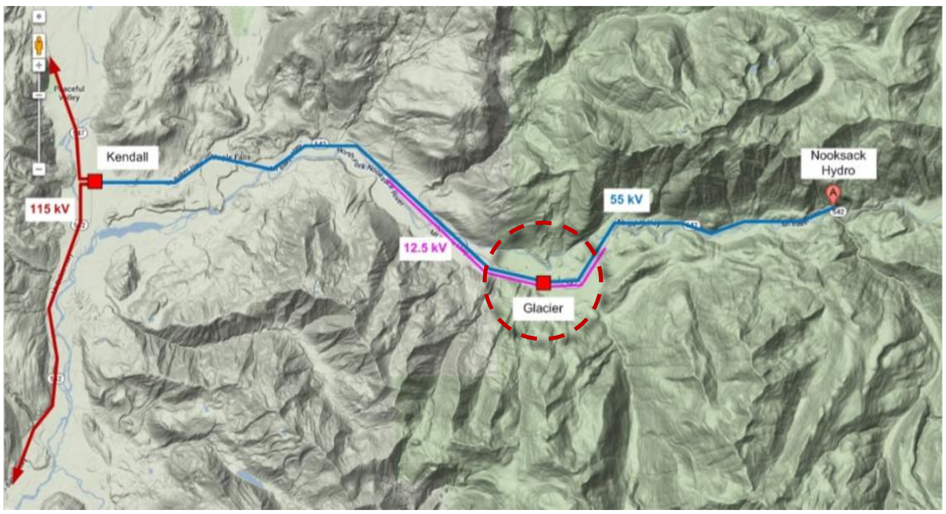

Figure 2.1. Glacier Location on the 55 kV Transmission Line

The remote locality of the transmission line and substation has historically made it difficult for repair crews to solve electrical problems when storms occur, leading to extended outages on the system. PSE submitted their CEF grant application with the hopes that a battery system would serve to mitigate these power loss intervals, generating large value to the PSE customers that reside in the core downtown area.

The system installed consists of four 500-kilowatt (kW) lithium-ion batteries produced by Renewable Energy Systems America, which together form a 2 MW / 4.4 MWh lithium-ion system. It is currently operational and located adjacent to the Glacier substation in Whatcom County, Washington.

Lithium-ion batteries are prevalent across a variety of industries due to their high energy density and performance. The battery chemistry is used across a wide scope of applications and grid-level systems have the ability to retain their capacity for approximately 10 years. With major maintenance and replacement of battery components, the lifespan of the system is capable of being extended to 20 years.[1]

Major components of the PSE battery include the following:

- **Battery**: sealed 200AH UL-listed, lithium iron phosphate battery cells in 8-cell packs, mounted in racks, complete with a hierarchical battery management system
- **Power Conversion System (PCS)**: four BYD model BEG500KTL-U 500kW inverter systems, one per container
- **Transformer**: 2.2MVA 480VAC/12.xkV pad mount
- **Environmental Operating Range**: -27F to 106F
- **Operating Characteristics**: System will respond within 50 milliseconds (mSec) and can swing from full charge to full discharge within 50 mSec. The maximum ramp rate consists of a full swing from 2 MW charge to full 2 MW discharge within 50 mSec, or a rate of 1,200 MW/minute.
- **Monitoring and Controls**: full supervisory control and data acquisition (SCADA) control of all operations; full remote monitoring of all alarms, breakers, cell and container temperatures, cell, module, ad bus voltages, bus currents, and other parameters (PSE 2013)

Figure 2.2 shows the lithium-ion battery system deployed by PSE along with the interior of one of the storage units.

Figure 2.2. Exterior and Interior of PSE Glacier Battery System

The Glacier battery has the capability, along with the substation and distribution system, to switch between grid-tied configurations or islanding either manually or automatically (PSE 2016a).

Physical testing of the battery was conducted in 2016 through 2018 and has provided valuable information regarding its capabilities and RTE values with respect to each use case it may be performing. These RTE values are shown in Table 2.1.

[1] A 20-year battery lifespan scenario is included as a sensitivity analysis within this report in Section 8.0.

Table 2.1 PSE Glacier Battery RTE Values

Low Rate		Moderate Rate		High Rate	
RTE	RTE without aux power	RTE	RTE without aux power	RTE	RTE without aux power
88%	90%	83%	85%	86%	88%

2.2 SnoPUD MESA 1 and MESA 2 Energy Storage Project

SnoPUD received a $7.3 million grid modernization grant in support of a project that deployed battery systems at two substations in Everett, Washington. MESA 1a and MESA 1b include a pair of lithium-ion battery systems with a total power to energy ratio of 2 MW/1.0 MWh. MESA 1a was procured from Mitsubishi Electric and MESA 1b was procured from LG Chem. MESA 2 includes a 2.2 MW/8.0 MWh vanadium redox-flow battery system from UET. The project was part of a multi-year effort to transform how the utility manages grid operations through the advancement of the MESA standard. The MESA Standards Alliance is an industry group whose purpose is to accelerate energy storage adoption by developing “open, non-proprietary methods and standards” (SnoPUD 2018a). More information on MESA and an analysis of the benefits of MESA is included in Section 8.3.

2.2.1 MESA 1

MESA 1 consists of two lithium-ion batteries—one manufactured by GS Yuasa International Ltd. and supplied by Mitsubishi Electric (MESA 1a) and the other manufactured by LG Chem (MESA 1b). Both batteries are 1 MW/0.5 MWh in size, giving a total installed capacity of 2 MW/1 MWh. The batteries utilize a PCS by Parker Hannifin Power (SnoPUD 2018b).

Figure 2.3 below shows MESA 1 being installed and Figure 2.4 shows MESA 1 post-installation with both battery units.

Figure 2.3. Installation of MESA 1 Battery System at Everett, WA Substation

Figure 2.4. MESA 1 Battery Systems After Installation

2.2.2 MESA 2

MESA 2 is a 2.2 MW/8.0 MWh vanadium redox flow battery system that was deployed in 2017. Flow batteries are comprised of two tanks of electrolyte solutions, one for the cathode and the other for the anode, with the electrolyte being passed by a membrane to store and generate energy. Compared to lithium-ion, the technology is still in the early phases of commercialization. However, redox flow batteries offer advantages, such as longer usable lives and lower operating temperature ranges (Aquino et al. 2017). The battery provided for MESA 2 was procured by UET, a Washington-based redox flow battery company, and consists of four strings of batteries.

Figure 2.5. below shows the installation of MESA 2 at the Everett substation.

Figure 2.5. UET Vanadium Redox Flow Battery Installation in Everett, Washington

Table 2.2 below shows the MESA 1 and MESA 2 RTE values found in testing of the battery systems.

Table 2.2 SnoPUD MESA 1 and MESA 2 Battery RTE Values

	Low Rate		Moderate Rate		High Rate	
	RTE	RTE without aux power	RTE	RTE without aux power	RTE	RTE without aux power
MESA 1	69%	82%	83%	90%	77%	89%
MESA 2	58%	75%	60%	71%	59%	68%

2.3 Avista Pullman Energy Storage Project

The system installed is part of the Avista Turner Energy Storage Project and consists of a 1 MW/3.2 MWh vanadium redox flow battery from UET. Figure 2.6 and Figure 2.7 show the vanadium redox battery system deployed adjacent to the SEL facility in Pullman, WA. The location was chosen due to SEL being a power-sensitive customer located at the end of two feeders that require ride-through capabilities to avoid costly outages.

When the BESS became operational in April 2015, it was the largest vanadium flow battery system across both North America and Europe. After installation, however, the battery system became non-operational and was removed from the facility. <u>The results presented within this report, therefore, represent the potential benefits that could have been derived had the battery operated as tested and remained in place for its entire usable life.</u>

Figure 2.6. Avista Turner Battery System at SEL, Pullman, WA

Figure 2.7 Avista Pullman Battery System, Pullman, WA

Table 2.3 below shows the RTE values found for the Avista Turner BESS through testing of the battery system.

Table 2.3 Avista Battery RTE Values

Low Rate		Moderate Rate		High Rate	
RTE	RTE without aux power	RTE	RTE without aux power	RTE	RTE without aux power
64%	74%	64%	73%	57%	63%

3.0 Taxonomy of Energy Storage Benefits

Energy storage has a number of attributes that collectively differentiate it from traditional forms of power generation. Its capacity to provide distributed, highly responsive energy means it can address the flexible operations required to integrate renewables and increase grid reliability. Characteristics that drive the value of BESSs include the following:

- The capacity to act as both generation and load;
- The ability to provide benefits at the transmission-, distribution- and customer-levels;
- The ability to be housed in mobile units and moved between sites to address specific system needs, such as avoiding customer interruptions during extended maintenance operations, or deferring investment in distribution assets;
- The capacity to be more effective than conventional generation in meeting ramping requirements and responding to regulation signals at the sub-second level (Masiello et al. 2010);
- The modular nature of energy storage, which allows it to scale up as needed to reduce the risk and present value (PV) costs of investments; and
- The capability to avoid startups of least-efficient peaking plants.

These unique characteristics enable energy storage to provide extensive value to the grid and should be reflected in the set of use cases evaluated for each project. Services provided by energy storage have differing purposes, and vary based on grid topology, benefitting parties and markets in which they are realized. Further, there are varying rules, requirements, and capabilities tied to value-capture. To monetize the value of energy storage, these services must be co-optimized in a manner that accounts for the fact that at any given time, a BESS cannot provide all services to all parties.

PNNL conducted an extensive literature search and made note of several use case matrices developed for energy storage. The individual use cases or services offered by BESSs can be segmented into five categories as defined in Akhil et al. (2015). PNNL has slightly refined the use cases presented in Akhil et al. (2015) based on its review of valuation literature, as presented in Table 3.1.

Table 3.1. Services Provided by BESSs

Category	Service	Definition
Bulk Energy	Capacity or Resource Adequacy	The BESS is dispatched during peak demand events to supply energy and shave peak energy demand. The BESS reduces the need for new peaking power plants.
	Energy Arbitrage	Trading in the wholesale energy markets by buying energy during low-price periods and selling it during peak high-price periods.
Ancillary Services	Regulation	A BESS operator responds to an area control error (ACE) in order to provide a corrective response to all or a segment portion of a control area.
	Load Following	Regulation of the power output of a BESS within a prescribed area in response to changes in system frequency, tie line loading, or the relation of these to each other, so as to

Category	Service	Definition
		maintain the scheduled system frequency and/or established interchange with other areas within predetermined limits.
	Spin/Non-Spin Reserve	Spinning reserve represents capacity that is online and capable of synchronizing to the grid within 10 minutes. Non-spin reserve is offline generation capable of being brought onto the grid and synchronized to it within 30 minutes.
	Frequency Response	The energy storage system provided energy in order to maintain frequency stability when it deviates outside the set limit, thereby keeping generation and load balanced within the system.
	Flexible Ramping	Ramping capability provided in real time, financially binding in five-minute intervals in California Independent System Operator (CAISO), to meet the forecasted net load to cover upwards and downwards forecast error uncertainty.
	Voltage Support	Voltage support consists of providing reactive power onto the grid in order to maintain a desired voltage level.
	Black Start Service	Black start service is the ability of a generating unit to start without an outside electrical supply. Black start service is necessary to help ensure the reliable restoration of the grid following a blackout.
Transmission Services	Transmission Congestion Relief	Use of a BESS to store energy when the transmission system is uncongested and provides relief during hours of high congestion.
	Transmission Upgrade Deferral	Use of a BESS to reduce loading on a specific portion of the transmission system, thus delaying the need to upgrade the transmission system to accommodate load growth or regulate voltage.
Distribution Services	Distribution Upgrade Deferral	Use of a BESS to reduce loading on a specific portion of the distribution system, thus delaying the need to upgrade the distribution system to accommodate load growth or regulate voltage.
	Volt-VAR Control	In electric power transmission and distribution (T&D), volt-ampere reactive (VAR) is a unit used to measure reactive power in an alternating current (AC) electric power system. VAR control manages the reactive power, usually attempting to get a power factor near unity (1).
Customer Services	Power Reliability	Power reliability refers to the use of a BESS to reduce or eliminate power outages to customers.
	Time-of-Use Charge Reduction	Reducing customer charges for electric energy when the price is specific to the time (season, day of week, time-of-day) when the energy is purchased.
	Demand Charge Reduction	Use of a BESS to reduce the maximum power draw by electric load in order to avoid peak demand charges.

Source: Modified from Akhil et al. 2015.

This list is by no means comprehensive and it aligns imperfectly with the Washington CEF value matrix as originally designed; however, it captures the bulk of the values generated by BESSs as well as DERs. Further, the matrix aligns well with studied literature. It is important to note that only a subset of these use cases is likely to be relevant for energy storage at any given site.

Existing production cost and capacity expansion tools fail to provide a complete and accurate characterization of the potential value that energy storage can provide to the electrical grid. These system models rarely capture benefits at the sub-hourly level, do not address location-specific benefits, and often fail to characterize distribution- and customer-level benefits. Further, control strategies that can be integrated into grid operational software and supervisory control of the storage unit exists in limited form. The lack of knowledge on the part of utilities, system operators, legislators, and regulators about the technical capabilities of energy storage is still a significant barrier to BESS penetration in the marketplace.

The lack of knowledge concerning energy storage capabilities and the ability to generate value at multiple points in the grid results in an incomplete assessment of BESS value. By failing to capture full energy storage capabilities, nearly all utility models underestimate potential value streams, which dampens investment. Underinvestment in energy storage due to an inability to fully account for the services it provides can lead to sub-optimal outcomes during the resource planning process. For example, some models do provide 5-minute capabilities in tracking energy storage output, but even that level of detail undervalues the ability of energy storage to provide services at the second or even sub-second level. No models are currently capable of evaluating the full range of values described in this section and performing a co-optimization routine to estimate the maximum value provided by each service. Further, markets often fail to fully reward energy storage operators, even when value is well defined.

Figure 3.1 documents the results of numerous energy storage valuation studies conducted within the past 11 years. The values estimated for each service, which are tied to market revenue or avoided costs, were modeled by the various research teams. In many cases, these values are not well documented or necessarily captured through a market or ratemaking process.

When reviewing Figure 3.1, the following should be noted:

- All values have been transformed into the dollars per kW (measured in terms of power capacity) per year ($/kW-year) metric. Thus, if a 1 MW system generates a value of $50/kW-year for arbitrage, its operator could expect to receive $50,000 in annual arbitrage revenue. In many cases, these values were not present in the literature; but with the total value of the service, the economic life of the battery system, the scale of the battery system, the discount rate, and the value could be calculated.
- All values were adjusted for inflation using the Producer Price Index for Electric Power Generation, Transmission, and Distribution published by the U.S. Bureau of Labor Statistics (BLS 2019).
- Findings are color coded by Federal Energy Regulatory Commission (FERC) Power Markets as identified in the figure legend.

The studies capture a broad array of values and cover many regions throughout the United States. Results vary widely based on a number of factors, including:

- **Market Structure:** presence or lack thereof with some markets exhibiting higher prices than others
- **Utility Type:** vertically integrated investor-owned utility, municipal, public utility district or utility operating in organized market
- **Battery Energy Capacity**

- **Battery Characteristics**: including RTE
- **Regional Electricity Price Differences**
- **Methodology**: are services co-optimized; are they evaluated at a sub-hourly level; do they include T&D-level benefits; are the benefits location-specific?
- **Characterization of the Marginal Unit**: in terms of cost for next-best alternatives for a specific service (e.g., combustion turbine for capacity) being replaced by storage
- **Assumptions:** governing load and price growth

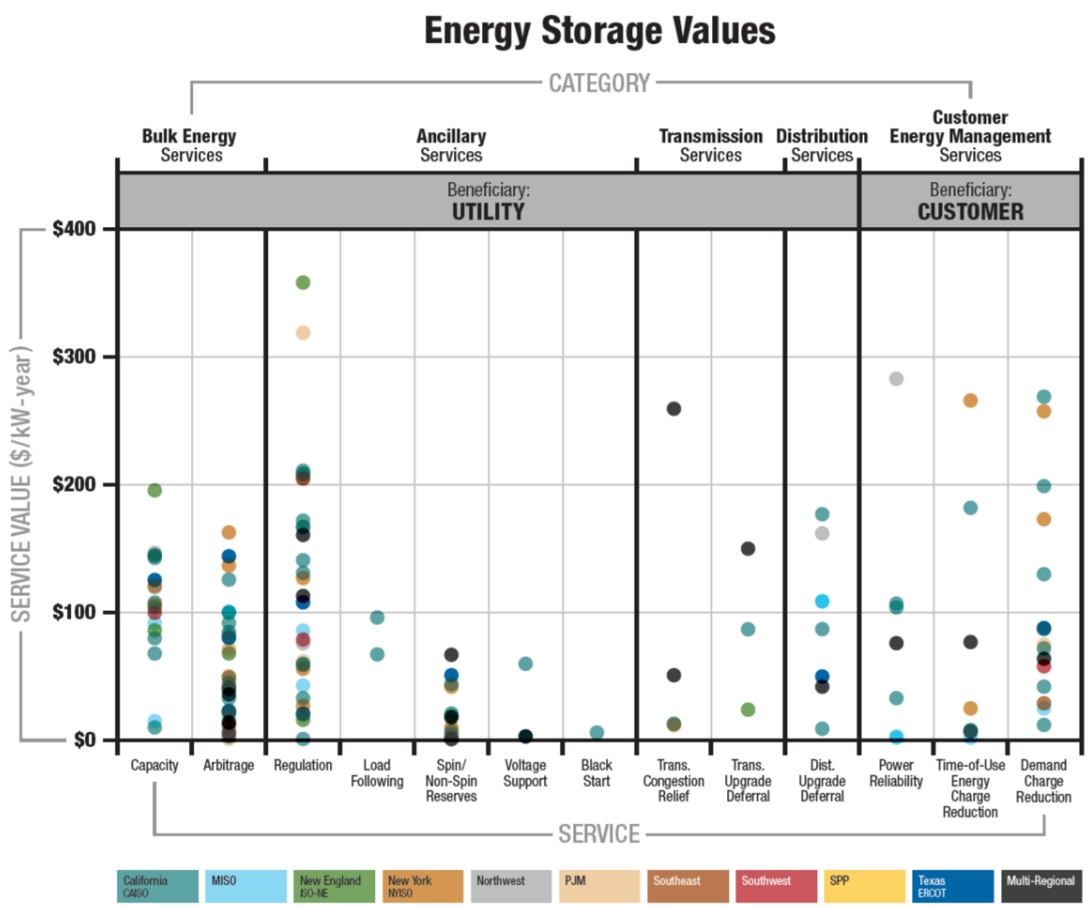

Figure 3.1. Estimated Values of Energy Storage Services[1]

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[1] Figure 3.1 was modified from Fitzgerald et al. (2015) but the values for Kirby (2007), Sayer (2007), Eyer and Corey (2010), EPRI (2013), Denholm (2013) and Brattle (2014) were provided to PNNL through a personal communication with Garrett Fitzgerald on March 11, 2016. Additional references added by PNNL include: Avendano-Mora and Camm (2015), Balducci et al. (2013), Balducci (2015), Bradbury et al. (2014), Byrne and Silva-Monroy (2012), Byrne and Silva-Monroy (2015), Byrne et al. (2015), Cutter et al. (2014), Dahlke (2016), Danley et al. (2014), Del Rosso and Eckroad (2014), DiOrio et al. (2015), Edgette et al. (2013), Fox (2015), Hibbard et al. (2016), Kleinschmidt Group et al. (2015), Maitra et al. (2014), Massachusetts Department of Energy Resources (2016), Narula et al. (2012), Neubauer et al. (2012), Olinski-Paul (2015), Salles (2014), Schenkman (2015), Sioshansi et al. (2009), Walwalkar et al. (2007), Wood et al. (2014), and Wu et al. (2016).

The results of the literature review are further summarized in Table 3.2 and Figure 3.2. More confidence can be taken from the results for more well-studied services (e.g., arbitrage, regulation). The results vary significantly by region and energy storage characteristics, including energy capacities, but the value for regulation tends to exceed those for other ancillary services and arbitrage. Capacity or resource adequacy, which is tied to the incremental cost of the next best alternative for providing peaking resources, generally coalesces around $80-$140/kW-year. T&D deferral benefits vary significantly between studies ($9-$233/kW-year) depending on the cost of the deferred asset and the discount rates used to calculate PV benefits. Customer-level services can be significant because they reflect the full cost of electricity supplied to customers, as opposed to a specific service supporting the grid at the transmission or distribution level.

Table 3.2. Value of Services Provided by BESSs in Literature ($/kW-year)

Category	Service	Num	Mean	Min	25th Percentile	75th Percentile	Max
Bulk Energy	Capacity or Resource Adequacy	21	$106	$10	$86	$134	$196
	Energy Arbitrage	39	$52	$1	$14	$82	$163
Ancillary Services	Regulation	34	$123	$1	$58	$180	$359
	Spin/Non-spin Reserve	17	$20	$1	$3	$39	$67
	Frequency Response	4	$54	$37	439	$74	$81
	Voltage Support	3	$22	$3	$3	$60	$60
	Black Start Service	1	$8	$8	$8	$8	$8
Transmission Services	Transmission Congestion Relief	5	$72	$12	$12	$155	$260
	Transmission Upgrade Deferral	5	$124	$24	$40	$212	$233
Distribution Services	Distribution Upgrade Deferral	8	$93	$9	$44	$148	$177
Customer Services	Power Reliability	9	$77	$2	$18	$106	$283
	Time-of-Use Charge Reduction	9	$65	$2	$7	$130	$266
	Demand Charge Reduction	16	$104	$12	$46	$163	$269

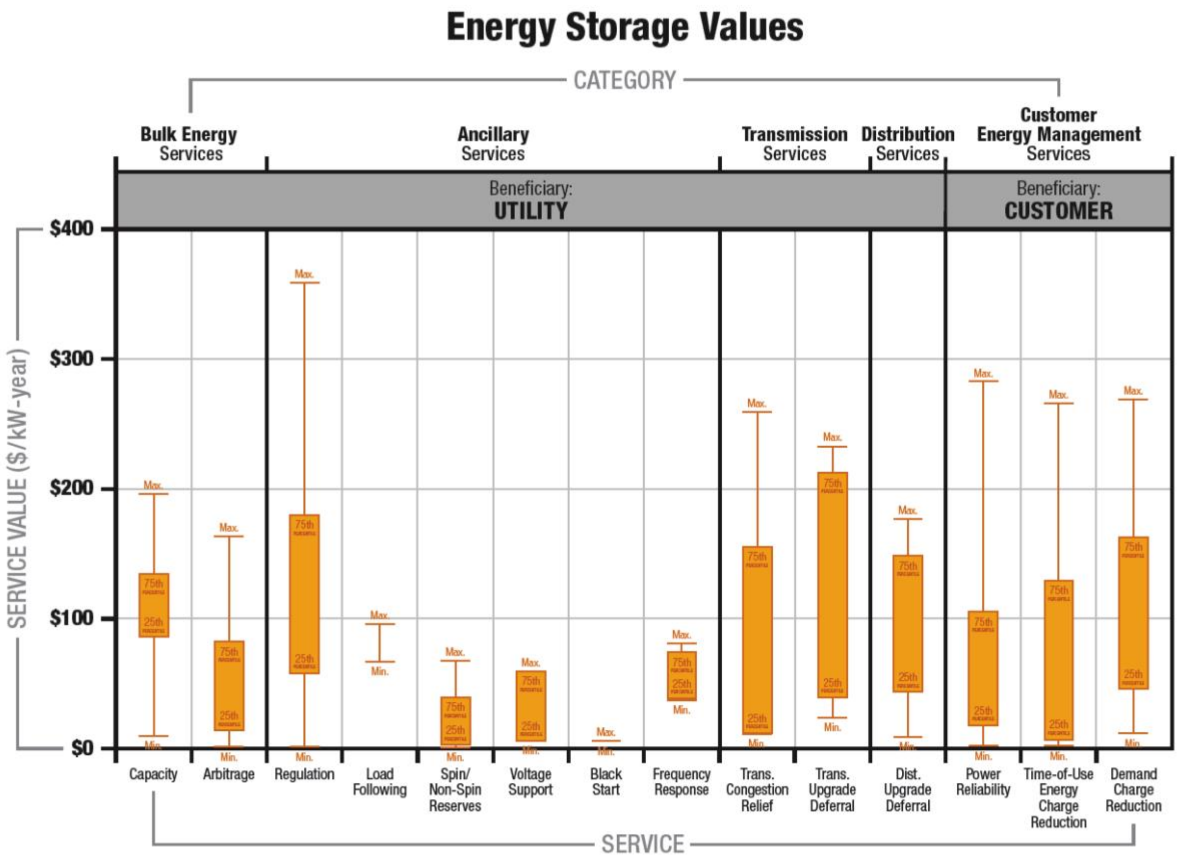


Figure 3.2. Descriptive Statistics for Energy Storage Valuation Studies

The remainder of this section discusses the value of energy storage on a service-by-service basis.

3.1.1 Energy Arbitrage

Energy arbitrage benefits are derived from buying low and selling high in wholesale energy markets. Profits are therefore dependent on peak and off-peak price differentials, which vary by region and market, and storage characteristics. For example, low RTE rates with battery systems reduce arbitrage profits due to higher energy losses. Within the literature, dispatch strategies for storage devices are based on optimization approaches for maximizing revenue. Studies reviewed cover the main system operators in the U.S., including the CAISO, Electric Reliability Council of Texas (ERCOT), Independent System Operator for New England (ISONE), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), and the Pennsylvania/Jersey/Maryland Power Pool (PJM). Electricity price data used in reviewed studies covered periods ranging from 2005 to 2015.

The research team found 39 estimates of arbitrage value for BESSs in the literature, ranging from $1/kW-year to $163/kW-year. Findings in the 25th percentile registered at $14/kW-year, while $82/kW-year represented the 75th percentile. Bradbury et al. (2014) assessed arbitrage in six major independent system operators (ISO)s across the U.S., and the estimated arbitrage benefit varied from a low of $69/kW-year in ISONE to $146/kW-year in ERCOT. Denholm et al.

(2013), which evaluated arbitrage potential using a multi-regional approach, found that beyond a certain storage capacity in the system, marginal net benefits fell due to declining peak and off-peak price differentials.

Technical assumptions governing energy storage size (discharge power and energy capacity), RTE, and variable operating cost played a critical role in defining value and, therefore, these factors cause total benefit estimates to vary. Byrne and Silva-Monroy (2014) showed how arbitrage benefit estimates could vary based on the foreknowledge of energy prices. Arbitrage benefit with perfect foreknowledge yielded a benefit of $47/kW-year while using last year's average price and the previous day's price. An estimate of $42/kW-year and $45/kW-year was found—which is 88% and 95%, respectively—of the benefit with perfect knowledge. Some studies co-optimize arbitrage benefit with regulation. Analysis performed by Byrne et al. (2015) showed co-optimizing arbitrage with regulation on a system at times can generate negative arbitrage benefit because of energy purchased to keep the storage charged for regulation services. Price volatility is another market parameter that contributes to varied results. The market type (day ahead market or DAM vs. real time market or RTM) can also effect results due to price volatility. An analysis conducted by Salles et al. (2014) showed at the same location (PJM) and year (2014), arbitrage benefit could potentially double within the RTM ($50/kW-year) as compared to the DAM ($25/kW-year).

Table 3.3 presents summary information on each of the energy arbitrage studies reviewed (e.g., when was it conduced, data source and year, financial assumptions, details about storage device, and the benefit estimate) for this report.

Table 3.3. Literature Review Summary on Energy Arbitrage

Year, Authors	Data Year, Region	Lifecycle, Discount Rate, Escalation Rate	BESS Size, Discharge Hour, Efficiency, Variable Op. Cost	Benefit ($/kW-yr)
2007, Walawalkar et al.	2001-2005, New York City (NYC)	10 Yr, 10%	1 MW, 4 MWh, 83%	162
	2001-2005, New York East			50
	2001-2005, New York West			42
2007, Sayer et al.	2005 Locational Marginal Price (LMP) in DAM, NYC	10 Yr, 10%, 2.5%	NA, 1-8 h, 70-90%, 0-4 c/kWh	28-42
2009, Sioshansi et al.	2007, PJM		NA, 4 h, 80%, NA	58
2010, Eyer and Corey	2009 LMP in DAM, CAISO	10 Yr, 10%, 2.5%	NA, 1-8 h, 70-90%, 0-2 c/kWh	60-100
2010, Rastler.	2006-2008, USA	15 Yr, 10%, 2.5%	1 MW/2 MWh, NA, NA	13
2011, Narula et al.	2009 LMP in DAM, CAISO	10 Yr, 10%, 2.5%	NA, 1-8 h, 70-90%, 0-2 c/kWh	86
2012, Byrne and Silva-Monroy	2010-2011 CAISO LMP	Annual revenue	8 MW/32 MWh, 80%, NA	25 (2010) 42 (2011)
2013, Denholm et al.	2006, Colorado (PSCO, WACM)	Annual revenue	300 MW, 8 Hours, 75%, NA	35

Year, Authors	Data Year, Region	Lifecycle, Discount Rate, Escalation Rate	BESS Size, Discharge Hour, Efficiency, Variable Op. Cost	Benefit ($/kW-yr)
2013, Kaun	2020, Bulk, CAISO	20 Yr, 11.47%, 2%	50 MW, 100 MWh, 83%	82
	2020, Ancillary Service-Only, CAISO	20 Yr, 11.47%, 2%	20 MW, 5 MWh, 83%	21
	2020, Substation, CAISO	20 Yr, 11.47%, 2%	1 MW, 4 MWh, 83%	97
2013, Edgette et al.	2013, Minnesota (modified CPUC data); no wholesale market participation	20 Yr, 11.47%, 2%	1 MW/4 MWh, 83%, 0.25	96
	Same data, with MISO market participation			47
2014, Byrne and Silva-Monroy	2011-2012, ERCOT	Annual revenue	8 MW/32 MWh, 80%, NA (Not Available)	132 (2011) 47 (2012)
	2011, ERCOT			42 (2012)
	2011-2012, ERCOT			126 (2011) 45 (2012)
2014, Brattle.	2020, ERCOT	15 Yr, 8%	1,000 MW – 8,000 MW	24
2014, Salles et al.	2014, PJM DAM	Annual revenue	1 – 14 MWh, 95%, NA	25 (1 MWh) 100 (14 MWh)
	2014, PJM RTM			50 (1 MWh) 140 (14 MWh)
2014, Bradbury et al.	2008 LMP ERCOT	Average daily revenue	1 MW/ 2 Hr, 90-98%, NA	146
	2008 LMP NYISO			139
	2008 LMP CAISO			128
	2008 LMP MISO			102
	2008 LMP PJM			73
	2008 LMP ISONE			69
2014, Wood et al.	2013, Los Angeles Department of Water and Power (LADWP) (Beacon, Mount Cotton and Q09 solar farm)	15 Yr, 4%, 1%	20-35 MW, 10-17.5 MWh, NA, 0.2 c/kWh	33
2014, Maitra et al.	2013, LADWP (NR-CHA-5 Feeder),		2.5 MW, 3.5 Hr, NA, NA	22
2015, Byrne et al.	2014-2015, PJM	Annual revenue	20 MW/15 min, 85%, NA	1
2015, Fitzgerald.	Case I, CAISO	20 Yr, 6.77%	140 kW-560kWh	6
	Case II, NYISO	20 Yr, 6.77%	26MW	12

Year, Authors	Data Year, Region	Lifecycle, Discount Rate, Escalation Rate	BESS Size, Discharge Hour, Efficiency, Variable Op. Cost	Benefit ($/kW-yr)
	Case III, Southwest	20 Yr, 6.77%	4kW-4kWh	6
	Case IV, CAISO	20 Yr, 6.77%	5kW-5kWh	3
2015, Kleinschmidt Group.	2025, Pacific Northwest	40 Yr., 4%, 2%	1,000 MW	19
2016, Olinksky-Paul.	2017-2018, Sterling Municipal Light Department in Sterling, Massachusetts.	Annual revenue	1 MW/1 MWh, NA, NA	41
2016, Dahlke.	2015, MISO	Annual revenue	2 MW/4 MWh, 90%, NA	14
2017, Balducci et al.	2017, Pacific Northwest	20 Yr, 6.32%, 2.25%	5MW-10MWh, 78-85%	26
2018a, Balducci et al.	2018, Pacific Northwest	20 Yr, 5.5%, 2.25%	5MW-30MWh, 67%	16

3.1.2 Regulation

Regulation services result from a BESS operator responding to an ACE to provide a corrective response to all or a segment of a control area. That is, regulation services involve intra-hour balancing responses to deviations between load and generation. In general, the benefits of regulation services are evaluated based on the price of those services in a specified region, with value defined based on historic market data. In regions with no organized markets, the focus is on avoided costs estimated through production cost model runs that define the most efficient generation schedule given utility portfolio of assets. Production cost models can define the influence of additional energy storage capacity on overall regulation costs. The amount of energy lost due to storage RTE losses also needs to be considered in evaluating benefits.

Within organized energy markets, energy storage can generate revenue by providing energy and ancillary services (e.g., frequency regulation, load following, spin/non-spin reserves). Recent FERC orders have served to level the playing field for energy storage in frequency regulation markets, but challenges remain for other services.

At the transmission level, two FERC orders address the market design of certain grid services (e.g., frequency regulations) that BESSs are well suited to provide. FERC Order 784 requires transmission providers to consider both speed and accuracy in the determination of regulation and frequency response requirements, and FERC Order 755 ensures that providers of frequency regulation are paid just and reasonable rates based on system performance. In providing frequency regulation, organizations are required to include both a capacity payment that considers the marginal unit's opportunity cost and a pay for performance component based on the mileage or the sum of the up and down signal followed by the provider. Table 3.4 summarizes select market features in U.S. ISOs (Kintner-Meyer 2014). Note that ERCOT is not under FERC jurisdiction.

Table 3.4. Summary of Select Market Features in U.S. RTOs/ISOs

Service	RTO/ISO					
	PJM	MISO	CAISO	NY ISO	ISONE	ERCOT
Capacity Payment	Yes	Yes	Yes	Yes	Yes	No
Mileage Payment	Yes	Yes	Yes	Yes	Yes	Yes
Accuracy Payment	No	No	Yes	Yes	No	No
Basis of Mileage Payments	DA and real-time	Real-time	DA and real-time			

In addition to the traditional regulation signal obtained by low-pass filtering of ACE, PJM generates a high-pass filtered version of ACE for fast-responding regulation assets like energy storage. The low-pass filter signal is referred to as Regulation A and is sent to traditional regulation sources. The low-pass filter results in a slower signal designed to address larger, longer fluctuations in grid conditions. The Regulation D signal based on the high-pass filter requires a near instantaneous response and is a faster, more dynamic signal. Ratio of the high-pass filtered signal to the low-pass filtered signal is defined as the mileage and is used to determine the performance-based component of the regulation payment. While PJM has historically attracted a significant degree of market participation from energy storage providers due to the design of its market, which more accurately compensates energy storage for its performance, there is evidence that market saturation has significantly affected profit potential in the PJM regulation market.

The literature reviewed for this report provided 34 estimates of regulation benefits. The 25th percentile of the values was found to be \$58/kW-year while \$180/kW-year was obtained as the 75th percentile. Among the ISO cases studied in the references, ISONE corresponds to the highest estimate of regulation benefit (\$364/kW-year with 2012 data), which is closely followed by PJM (\$319/kW-year with 2014-2015 data). Studies conducted on ERCOT derived benefit estimates in the range of \$104-\$295/kW-year with contributors for variations being year of data (2011/2012) and knowledge of price (perfect knowledge/previous day's price). A study conducted on CAISO by Eyer and Corey (2010) showed the effect of regulation service duration on benefit calculations. Operating for 50% and 80% of a year provided an estimate of \$109 and \$210/kW-year, respectively. The lowest estimate of regulation benefit (\$1/kW-year) was obtained from a study conducted on a distribution feeder in the LADWP area by Maitra et al. (2014). This is attributed to the low regulation services price in the LADWP area, which registered a peak regulation price of \$0.31/MWh and off-peak regulation price of \$0.15/MWh. Excluding this LADWP estimate, the lowest benefit among the studies was found to be \$15/kW-year in ISONE using 2015 data on a statewide 1,766 MW deployment of energy storage in Massachusetts.

Apart from energy price, different market mechanisms established for payment of ancillary services may impact benefit estimation. Avendano-Mora and Camm (2015) discussed performance score-based payment for regulation services in PJM and showed ± 3% variation can result in a change of ± \$3 million in project net present value for 50MW of energy storage capacity. This study also found storage replacement cost as another important cost assumption that could potentially impact benefit estimation—each additional replacement cost can reduce the net present value by 20%. A summary of the literature covering regulation service benefits is provided in Table 3.5.

Table 3.5. Literature Review Summary on Regulation

Study Year, Authors.	Data Year, Region	Lifecycle, Discount Rate, Escalation Rate	BESS size, efficiency, Variable cost	Benefit ($/kW-yr)
2007, Walawalkar et al.	2001-2005, NYC, New York East, New York West	10 Yr, 10%	1 MW, 4 MWh, 83%	203
2007, Sayer et al.	2005, NYISO	10 Yr, 10%, 2.5%	NA, 1-8 h, 70-90%, 50 $/MWh	150
2010, Eyer and Corey.	2009, CAISO	10 Yr, 10%, 2.5%	NA, 1-8 h, 70-90%, NA	195 (avg. of 50% and 80% hours a year)
2010, Rastler.	2006-2008, US	15 Yr, 10%, 2.5%	1 MW/2 MWh	145 (fast 1 hr) 65 (1 hr) 128 (15 min)
2012, Byrne and Silva-Monroy.	2010-2011, CAISO LMP,	Annual revenue	8 MW/32 MWh, NA, NA	117 (2010) 161 (2011)
2011, Narula et al.	2009, CAISO	10 Yr, 10%, 2.5%	1-40MW	195
2013, Denholm et al.	2011, CAISO	Annual revenue	100 MW, 8 Hours, 75%, NA	110
2013, Kaun.	Bulk, CAISO	20 Yr, 11.47%, 2%	50 MW, 100 MWh, 83%	161
	Ancillary Service-Only, CAISO	20 Yr, 11.47%, 2%	20 MW, 5 MWh, 83%	204
	Substation, CAISO	20 Yr, 11.47%, 2%	1 MW, 4 MWh, 83%	161
2013, Balducci.	2018, Pacific Northwest	20 Yr, 7.8%, 2.5%	4 MW/16MWh	59
2013, Edgette et al.	2013, MISO	20 Yr, 11.47%, 2%	1 MW/4 MWh, 83%, 0.25	41
2014, Byrne and Silva-Monroy.	2011-2012, ERCOT LMP, Perfect Knowledge, Regulation and Arbitrage bundled	Annual revenue	8 MW/32 MWh, NA, NA	295 (2011) 116 (2012)
	2011-2012, ERCOT LMP, Previous Day's Price			253 (2011) 104 (2012)
2014, Wood et al.	2013, LADWP (Beacon, Mount Cotton and Q09 Solar Farm)	15 Yr, 4%, 1%	20-35 MW, 10-17.5 MWh, NA, 0.2 c/kWh	133
2014, Maitra et al.	2013, LADWP		2.5 MW, 3.5 Hr, NA, NA	1
2014, Cutter et al.	2011, CAISO	Annual revenue	NA, 4 h, 75%, NA	143
2014, Hibbard et al.	2012, ISONE	20-year, NA, NA, 10% and 2.5% assumed	4 MW/16 MWh, 75%, NA	364
2015, Byrne et al.	2014-2015, PJM	Annual revenue	20 MW/15 min, 85%, NA	319

Study Year, Authors.	Data Year, Region	Lifecycle, Discount Rate, Escalation Rate	BESS size, efficiency, Variable cost	Benefit ($/kW-yr)
2015, Fitzgerald.	Case I, CAISO	20 Yr, 6.77%	140 kW-560kWh	33
	Case II, NYISO	20 Yr, 6.77%	26MW	56
	Case III, Southwest	20 Yr, 6.77%	4kW-4kWh	79
	Case IV, CAISO	20 Yr, 6.77%	5kW-5kWh	60
2015, Balducci.	2014, CAISO	20 years, 3.9%, 2.5%		73
2015, Fox.	2013, ERCOT	Annual revenue	1 MW/2 MWh, NA, NA	107
2015, Avendano-Mora and Camm.	2012-2014, PJM	20 Yr, 11.47%, 2%	50 MW/12.5 MWh, NA, NA	62
2016, Dahlke.	2013-2015, MISO	Annual revenue	2 MW/4 MWh, 90%, NA	86
2016, Massachusetts Department of Energy Resources	2015, MA (ISONE)	Annual revenue	1766 MW state-wide deployment	15
2017, Byrne et al.	2017, MA (ISONE)	Annual Revenue	1MW/1MWh, 85-90%	60
2017, Balducci et al.	2017, Pacific Northwest	20 Yr, 6.32%, 2.25%	5MW-10MWh, 78-85%	147
2018a, Balducci et al.	2018, Pacific Northwest	20 Yr, 5.5%, 2.25%	5MW-30MWh, 67%	137

3.1.3 Capacity

The basis for estimating the capacity benefit of energy storage is typically either the reduced or avoided cost of a new peaking plant, or a capacity price set through a regional market. Capacity is often referred to as resource adequacy.

The capacity addition cost is calculated based on an increment of an installed cost of the next best alternative – e.g., a simply cycle or combined cycle combustion turbine technology. An annual fixed charge rate is used to determine the installation cost in terms of a $/kW-year metric. Annual fixed operations and maintenance (O&M) cost would also typically be included in the benefit estimation. When estimating the capacity benefit of an energy storage system, one must also determine its incremental capacity equivalent (ICE), or the availability of the resource in relation to the next best alternative against which it is being compared. Thus, if an energy storage device has only 60% of the reliability of a combustion turbine, it would only be assigned 60% of the benefit. ICE is typically calculated by performing a loss of load probability (LOLP) analysis or through some form of a performance test.

Denholm et al. (2013) suggested these costs would vary depending on equipment costs, location, and financing terms, with estimates ranging from a low of $77/kW-year (PSCO 2011) and a high value $212/kW-year (CAISO 2012). For capacity price markets, ISOs publish relevant capacity market data, which is used for benefit estimation and vary depending on location and market. In highly populated urban areas, it may be difficult and expensive to augment generation and transmission capacity, which leads to high capacity prices and by transfer a high benefit to energy storage when providing capacity services. For example, in NYISO, the capacity price for NYC is higher than the rest of the system. Among the studies reviewed, 21 different capacity benefits were found with $86 and $134/kW-year as the 25th and 75th percentile values, respectively. A summary on the literature review findings of capacity benefits of energy storage is provided in Table 3.6.

Table 3.6. Literature Review Summary on Capacity

Study Year, Authors	Price Data Year, Region	Benefit ($/kW-yr)
2007, Sayer et al.	2006, NYISO	105
2010, Eyer and Corey	2009, CAISO	120
2010, Rastler	2006-2008, CAISO, ERCOT, ISONE, NYISO, PJM	84 (Local) 15 (System)
2013, Denholm et al.	2013, PJM	90
	2011, PSCO	77
	2012, CAISO	212
2013, Kaun	Bulk, CAISO	65
	Substation, CAISO	104
2013, Balducci	2018, Pacific Northwest	142
2013, Edgette et al.	2013, MISO	88
2014, Wood et al.	2014, LADWP	9
2014, Hibbard et al.	2013, ISONE	199
2015, Fitzgerald	Case I, CAISO	145
	Case II, NYISO	106
	Case III, Southwest	100
	Case IV, CAISO	145
2015, Kleinschmidt Group	2015, Pacific Northwest	120
2016, Olinksky-Paul	2016, Sterling Municipal Light Department in Sterling, Massachusetts.	115
2016, Dahlke	2015, MISO, Minnesota	2
	2015, MISO, Illinois	15
Balducci et al., 2018a	2018, Pacific Northwest, Oregon	86
Schoenung, 2017	2017, ISONE, Vermont	120

3.1.4 Spinning/Non-Spinning Reserve

Estimation of spin/non-spin reserve benefits is tied to either prices evident in regional ancillary service markets or the cost of the next best alternative available to provide the service as estimated through production cost model runs conducted by electricity service providers operating in regions without markets. The research team found 17 studies that estimated the value of spin/non-spin reserve, ranging from $1/kW-year to $67/kW-year. At the 25th percentile, the value was estimated at $3/kW-year. At the 75th percentile, the value was estimated at $39/kW-year. These studies covered the NYISO, MISO, ERCOT, CAISO, and Southwest regions. This service is a lower value benefit when compared to others presented thus far in this review.

Sayer et al. (2007) analyzed 2005 Eastern New York market data and found a $2/MWh reserve price when storage was used for other more valuable applications. Based on an assumption of $30/MWh variable O&M cost and 3,000 hours of annual service hours, a net benefit of $36/kW-year was estimated. Using CAISO data, Eyer and Corey (2010) estimated a reserve price of $40/kW-year, which is an average of a low-end estimation of $7.9/kW-year with $3/MWh of reserve price while providing services for 30% of the hours in a year and a high-end estimation of $31.5/kW-year with $6/MWh of reserve price and providing services for 60% of the hours in a year.

Rastler (2010) estimated spinning/non-spinning reserve benefits of $14 and $2/kW-year, respectively. Denholm et al. (2013) estimated spinning reserve benefit of $65/kW-year based on a reduction of production cost by adding a 100 MW storage system. Edgette et al. estimated a spinning/non-spinning reserve price for a 1 MW / 4 MWh system in Minnesota (MISO) at $4/kW-year, while Wood et al. estimated a reserve price of $1/kW-year when studying battery storage installations at three solar farms in Los Angeles (Wood et al. 2014).

3.1.5 Voltage Support

Voltage support benefit of energy storage is typically valued by assessing the contribution made by storage to reduce the use of centrally located large generating plants to provide reactive power during region-wide voltage emergencies. This essentially relates to the value of electric service reliability. Eyer and Corey (2010) estimated the low-end estimate of voltage support benefits at $400/kW and a high-end estimate of $800/kW for a 10-year lifecycle, which translate to $56/kW-year to $112/kW-year value. Using the price of shunt capacitors, the most common technology for providing voltage support, Rastler (2010) estimated a benefit of $3-$17/kW-year. Based on an assumption of $5/kVAR-year of voltage support cost, Wood et al. (2014) estimated a transmission voltage support benefit of $3/kW-year. The three studies summarized in this section were the only ones found by the research team to have evaluated the benefit of energy storage in providing voltage support.

3.1.6 Black Start

Benefits are estimated based on the payments by ISOs for procuring black start services, which could be through competitive market processes or strategically procured through bilateral agreements. Only one study was found that estimated the value of energy storage when providing black start capacity. Based on 2006 CAISO data, Rastler (2010) estimated a black start benefit of $8-$38/kW-year.

3.1.7 Frequency Response

North American Electric Reliability Corporation (NERC) Standard BAL-003-1 requires that balancing authorities maintain sufficient frequency response capacity to maintain interconnection frequency within predefined bounds. In compliance with NERC Standard BAL-003-1, NERC establishes frequency response obligation allocations for each of the four interconnections in the U.S., and those obligations are in turn transferred onto balancing authorities within each interconnection. BESSs can provide energy in order to maintain frequency stability when it deviates outside the set limit, thereby keeping generation and load balanced within the system.

The 5 MW/1.25 MWh lithium-ion battery system referred to as the Salem Smart Power Center (SSPC), which is operated by Portland General Electric, is set to automatically respond to unexpected frequency excursions. Based on set points (high and low) established by a frequency response screen, the SSPC responded 181 times over 13 months for an average of 13.9 times per month. The SSPC is programmed to respond to frequency response events over a six to seven-minute duration while providing 300 kilowatt-hour (kWh) of energy. The value of this service was estimated at $52.80 per kW-year (Balducci et al. 2017).

CAISO has contracted with two entities for primary frequency response: Seattle City Light (SCL) and Bonneville Power Administration (BPA). The SCL contract transfers 15 MW/0.1 Hz of frequency regulation to SCL at a contract price of $1.22 million or $81/kW-year (CAISO 2016a). The BPA contract transfers 50 MW/0.1 Hz of frequency regulation to BPA at a contract price of $2.22 million or $44.40 per kW-year (CAISO 2016b).

3.1.8 Transmission and Distribution Upgrade Deferral

Eyer and Corey (2010) determined the cost of T&D upgrade deferral combined by estimating the cost of the T&D upgrade to be deferred based on $/kW to be added, or the T&D marginal cost. The value of cost deferral can be significant due to the nature of utility cost accounting. For example, if an energy storage system could be used to shave local load peaks, resulting in deferral of a $10 million substation for five years, the benefit would be $3.2 million. PV costs are estimated by dividing the future cost of the asset, while accounting for inflation, by one plus the discount rate raised to the number of deferral years. If the cost inflation rate was 2% and the discount rate was 8%, moving the deferral out five years reduced the present value cost of the asset to $7.4 million ($10 million*1.02^5 / 1.08^5).

Balducci et al. (2013) evaluated the benefits of deferring investment in a substation located on Bainbridge Island, Washington by nine years, estimating the deferral value at $162/kW-year. Sayer et al. (2007) estimated deferral benefits associated with 375 kW of storage capacity at $445/kW or $55/kW-year. Rastler (2010) estimated a $135/kW-year benefit for transmission upgrade deferral and $37/kW-year benefit for distribution upgrade deferral.

Brattle (2014) estimated transmission upgrade deferral benefits at $36/kW-year based on average annual transmission cost for every unit of reduced peak demand. This estimate is consistent with the average annual transmission cost per kW of summer coincident peak load in ERCOT. On distribution upgrade deferral, Brattle (2014) noted that distribution system costs are driven by non-coincident, local peak loads. Brattle estimated distribution investment deferral benefit at $14/kW-year.

Edgette et al. (2013) estimated a distribution upgrade deferral benefit of $104/kW-year based on a Minnesota case study involving local peak shaving services. A Massachusetts energy storage initiative report (2016) assessed a T&D upgrade deferral benefit of $24/kW-year (Massachusetts Department of Energy Resources). Based on an analysis performed on a distribution feeder (NR-CHA-5) in the LADWP area, Maitra et al. (2014) estimated a distribution upgrade deferral benefit of $9/kW-year; the goal was to limit transformer loading up to 90% using a 2.5 MW, three-hour storage device. These findings suggest that the value of T&D deferral is highly situational and location dependent.

Balducci et al. (2018b) demonstrated the breadth of benefits associated with energy storage by using an electro thermal life model to evaluate how energy storage could be used to defer investment in a 7.55 kilometer, 69 kV submarine transmission cable that connects mainland Washington State near Anacortes and Lopez Island in the San Juan Islands. PV and energy storage will be used to reduce loading stress on the cable and have a potential life extension benefit. Using the electro thermal life model and the selected load cycle, potential life extension was estimated to be 3.3 years. With the cable cost estimated at $40 million in 2018 dollars, the value of the deferral was estimated at $2 million.

3.1.9 Transmission Congestion Relief

Sayer et al. (2007) reported that congestion is a growing concern for NYC and is managed by transmission congestion contracts (TCC), which reimburse the holders when there is congestion. The TCC effectively provides a way for energy buyers to manage the risk associated with uncertain energy congestion charges. Storage can reduce congestion charges as long as it is charged by the energy generated within NYC or with energy transmitted when there is little or no congestion. Benefits of reduced energy congestion is estimated based on the congestion price signals and TCC. According to NYC 2005 data, avoided congestion charges average $10/kW-year. Eyer and Corey (2010) reported excessive congestion exists for 10-15% time of the year in California. Assuming a congestion charge is possible and would be more likely with the addition of renewable generation, a range of value was estimated at $4.38-$19.71/kW-year. Rastler (2010) estimated transmission congestion benefits at $46/kW-year. Del Rosso and Eckroad (2014) studied the impact of energy storage on transmission congestion relief using a modified version of the IEEE Reliability Test System with a 50 MW / 25 MWh battery storage, deriving a benefit estimate of $258/kW-year based on a 15-year project lifecycle and 7% discount rate.

3.1.10 Power Reliability

Power reliability benefits can be evaluated based on utility costs or interruption costs to customers. When evaluating the benefits to utilities, avoided costs could include undelivered energy, restoration costs, costs associated with reliability-associated investments (e.g., voltage regulators) or penalties paid for non-compliance with reliability targets. Interruption costs to customers are logged by studies that evaluate the impact of electricity disruptions to residential, commercial, and industrial customers.

Eyer and Corey (2010) evaluated the benefit of storage in providing electric power reliability based on an assessment of the annual number of hours when energy is not delivered. Based on standard assumptions of a 2.5-hour annual outage and $20/MWh of unserved energy, a $50/kW-year annual reliability benefit could be obtained from storage. Rastler (2010) estimated a benefit of $67/kW-year for power reliability enhancement by storage applications. Neubauer et al. (2012) reported a combined power quality and reliability benefit of $135/kW-year in California based on a 200-kW system with approximately five reliability events and 10 power quality events annually. Edgette et al. (2013) studied two cases in Minnesota. In the 0.5 MW, 2 MWh customer owned and controlled storage case, the value of storage was estimated at $3/kW-year, while a 1 MW / 4 MWh utility-owned and controlled storage system yielded a $2/kW-year benefit. Balducci et al. (2013) evaluated reliability benefits from a customer perspective, finding that a 4 MW / 16 MWh could significantly reduce the cost of outages on a feeder serving a small community in Washington State experiencing roughly 20 outages annually. Based on an assessment of interruption costs to customers located on Bainbridge Island, Washington, reliability benefits were estimated at $273/kW-year.

3.1.11 Time of Use Charge Reduction

Time of use (TOU) benefits associated with energy storage are typically derived from the difference between the peak time savings resulting from supplying electricity from storage and cost of the electricity used to charge the storage during the off-peak period. Energy storage can be used to store energy during low-price, off-peak periods and then avoid higher-cost peak energy. Note that the peak and off-peak price differential must be sufficient to more than counterbalance the typical 15-30% RTE losses associated with charging and discharging energy storage systems.

Eyer and Corey (2010) used the Pacific Gas and Electric A-6 tariff to evaluate TOU benefits. Based on peak and off-peak energy prices of 37 cents/kWh and 11 cents/kWh, respectively, a storage battery of 1 MW at 80% efficiency could generate an annual benefit of $167/kW-year. Based on Con Edison's tariff structure, a benefit of $50/kW-year was found. Rastler (2010) estimated a benefit of $272/kW-year for TOU application. Based on Xcel Energy's GS-TOU (S) tariff, Edgette et al. (2013) estimated a TOU benefit of $2/kW-year with a customer owned and controlled 0.5 MW, 2 MWh storage system in Minnesota. Wu et al. (2016) studied TOU benefits for an office building case using a 0.2 MW / 0.8 MWh BESS in several cities across the U.S. and found the following benefit values: San Francisco ($7/kW-year), Chicago ($7/kW-year), Houston ($7/kW-year), and NYC ($24/kW-year).

3.1.12 Demand Charge Reduction

Demand charges accrue based on a customer's peak loads. By reducing demand during those peak load periods, the basis of the demand charge is reduced. Figure 3.3 presents the load for one day at a U.S. military base located in California. The first pane shows the load without energy storage. The second pane shows that with energy storage operated in an optimal manner, load can be shifted and dispersed over the three hours following the original peak hour. The third and final pane of the figure, shows energy input/output while pane 4 shows the energy storage system's SOC. The benefits to this base in California were estimated in Balducci et al. (2015) at $130/kW-year. The study found that the vast majority of benefits associated with behind-the-meter storage were tied to demand charge reduction, with relatively few benefits associated with TOU charge reduction. Using PGE's E-19 tariff, Eyer and Corey (2010) estimated demand charge reduction benefits of $54/kW-year. Rastler (2010) conducted a multi-regional assessment that estimated the value of demand charge reduction at $230/kW-year. Neubauer et al. (2012) estimated a combined demand charge and TOU benefit of $185/kW-year using Southern California Edison's TOU-GS-3-SOP tariff.

In Minnesota, Xcel Energy's GS-TOU (S) tariff structure was used to estimate a $24/kW-year benefit for demand charge reduction (Edgette et al. 2013). Maitra et al. (LADWP-EPRI, 2014) studied 39 loads in a distribution feeder (NR-CHA-5) in the LADWP area and estimated the maximum potential benefit at $80/kW-year from demand charge reduction for a load with 796 kW peak demand and a 300 kW, 4-5 hour battery storage. A study conducted on behind-the-meter energy storage projects by Danley et al. (2014) in the Wright-Hennepin Cooperative Electric Association area estimated a demand charge reduction benefit of $4/kW-year using a 9.2 kW, 2-hour battery with 60% efficiency and 5 cycles per month.

DiOrio et al. (2015) evaluated the benefits associated with demand charge reductions in two cities - Los Angeles, California and Knoxville, Tennessee. Financial evaluations were conducted using assumptions of a 25-year lifecycle, 2.5% inflation rate, and 8.14% nominal discount rate. Based on the Southern California Edison TOU-GS-2 rate structure, a demand charge reduction benefit was estimated at $42/kW-year with a 110 kWh/55 kW 92% efficient li-ion storage system. Using the Knoxville Utility Board general power rate schedule, a benefit of $29/kW-year was estimated based on a 300 kWh/150 kW storage system. Schenkman (2015) reported a demand charge reduction of $51/kW-year from a commercial 3 kW, 4 kWh, 80% efficient li-ion system. Using a common office building load profile and a 0.2 MW/0.8 MWh energy storage system, demand charge reduction benefits in four U.S. cities were determined by Wu et al. (2016) as: San Francisco ($72/kW-year), Chicago ($75/kW-year), Houston ($87 /kW-year), and NYC ($256/kW-year).

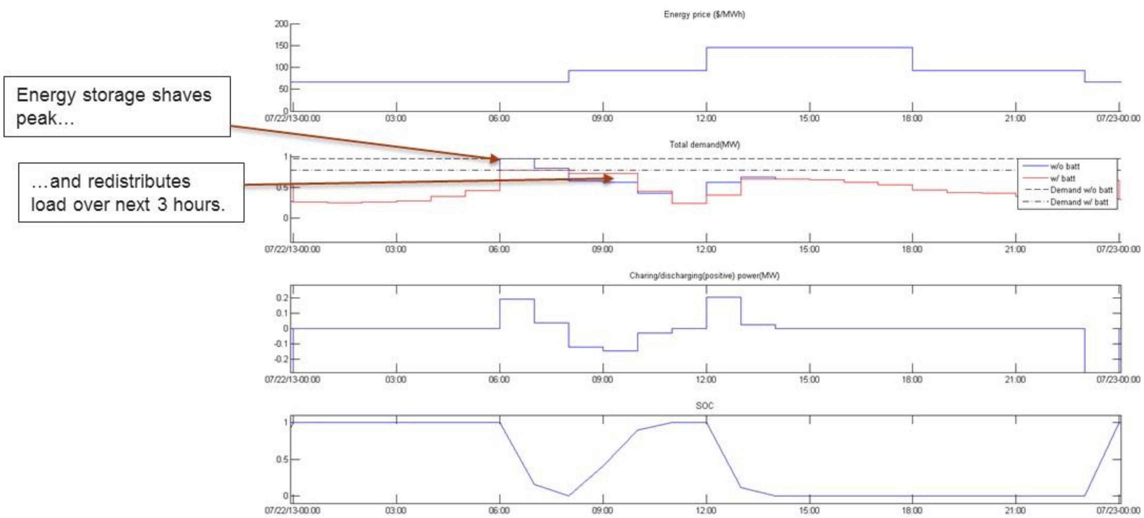


Figure 3.3. Base Load and Battery Operation for an Illustrative Day

4.0 CEF Economic Methodology

As part of the Washington CEF analytics effort, PNNL and the utility sponsors identified a broad range of use cases for evaluation. Table 4.1 presents an overview of the use cases and applications performed and measured/analyzed. “X” means the service is included as part of the use case analysis project. The use-cases are grouped according to their intended target benefits within the electric infrastructure topology (e.g., transmission vs. distribution). Although a BESS may be located on the low-voltage side of a substation that provides power to a distribution feeder, a use case that addresses bulk power services could still be provided and would be grouped under the transmission or bulk-power benefits. Use cases for BESSs for applications deep into the distribution circuit would be categorized under the distribution system cases.

Table 4.1. Washington CEF Use Case Matrix

Use Case and Application	Avista	PSE	Sno-MESA 1	Sno-MESA 2	Sno-Controls Integration
UC1: Energy Shifting					
Energy shifting from peak to off-peak on a daily basis	X	X	X	X	
System capacity to meet adequacy requirements	X	X	X	X	
UC2: Grid Flexibility					
Regulation services	X	X		X*	
Load following services	X	X		X*	
Real-world flexibility operation	X	X		X*	
UC3: Improving Distribution Systems Efficiency					
Volt/VAR control with local and/or remote information	X		X	X	
Load-shaping service	X	X	X	X	
Deferment of distribution system upgrade	X	X			
UC4: Outage Management of Critical Loads					
Outage management of critical loads		X			
UC5: Enhanced Voltage Control					
Volt/VAR control with local and/or remote information and during enhanced Conservation Voltage Reduction (CVR) events	X				
UC6: Grid-connected and islanded micro-grid operations					
Black start operation	X				
Micro-grid operation while grid-connected	X				
Micro-grid operation while in islanded mode	X				
UC7: Optimal Utilization of Energy Storage					
Optimal utilization of energy storage	X	X			X

*Use case relies on simulated signals because these services are not provided by SnoPUD

The remainder of this section presents the methods used for each use case.

4.1 Use Case 1 – Energy Shifting

4.1.1 Energy Shifting from Peak to Off-Peak on a Daily Basis

Energy shifting, commonly referred to as arbitrage, is the practice of taking advantage of differences between two prices. In the context of electric energy markets, energy storage can be used to charge during low-price periods (i.e., buying electricity) in order to discharge the stored energy during periods of high prices (i.e., selling during high-priced periods). The economic reward is the price differential between buying and selling electrical energy, minus the cost of RTE losses during the full charging/discharging cycle and variable O&M costs.

Figure 4.1 shows hourly energy prices for one day from the Mid-Columbia energy market, which serves the Pacific Northwest. As shown below, the average price on the day shown is approximately $37/MWh, with fairly minor fluctuations offering few opportunities for arbitrage profit.

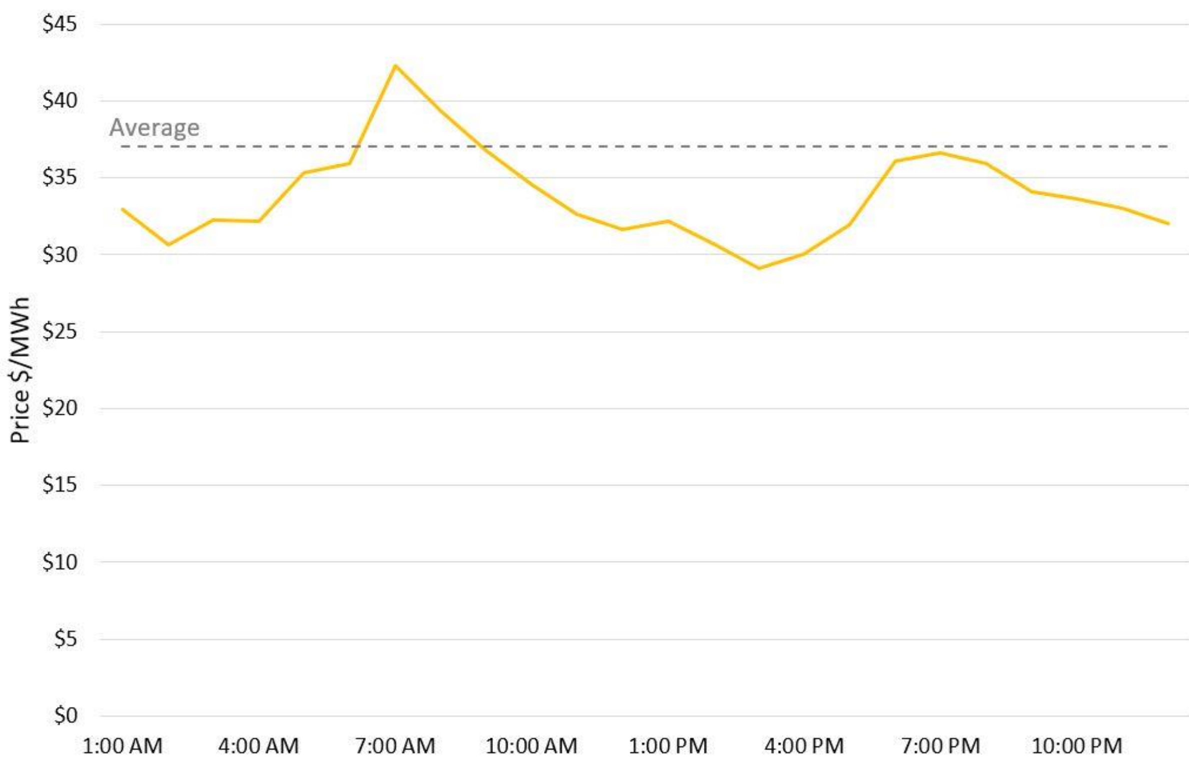


Figure 4.1. Mid-Columbia Energy Price Over a Single Day

Figure 4.2 demonstrates an example duty cycle output in which the battery is charging and discharging energy to capture price differentials. The dotted line shows the SOC of the battery while the orange line shows the battery output on an hourly basis.

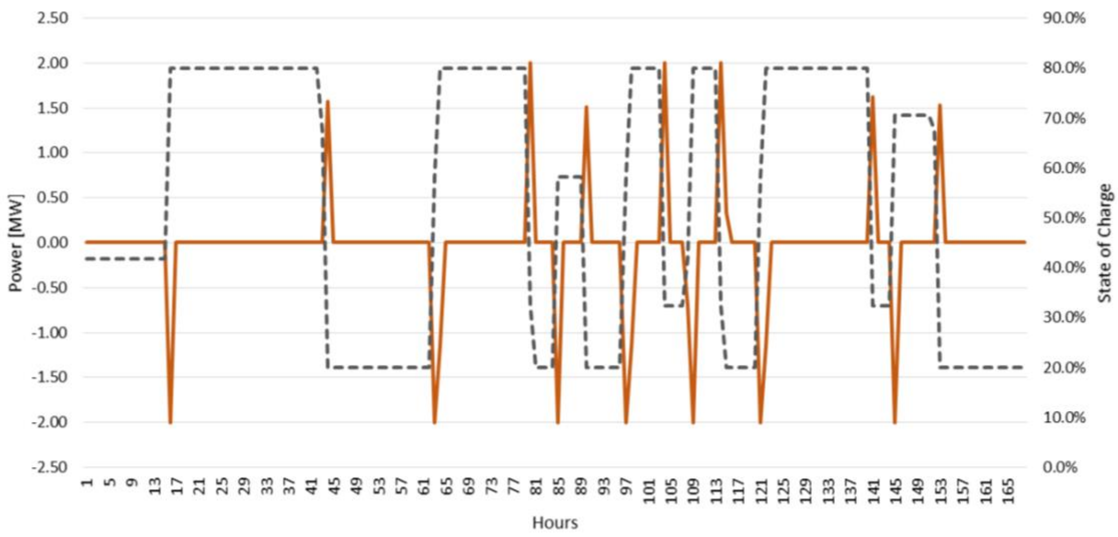


Figure 4.2. Arbitrage Duty Cycles of Battery by Hour

While arbitrage is one of the first recognized use cases for energy storage, it typically yields small value that is closely tied to RTE. Accurate characterization of the battery performance development of real-time control strategies, are essential to maximizing value to the electrical grid. Based on battery testing, PNNL was able to find an estimated relationship between annual revenue and RTE shown in Figure 4.3 below.

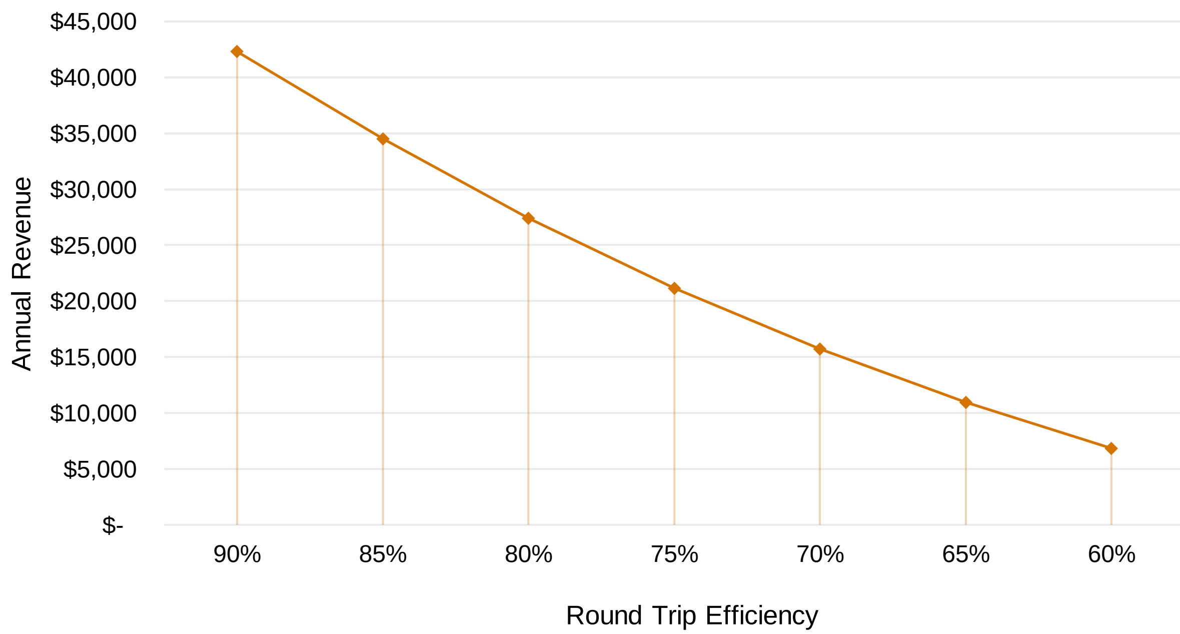


Figure 4.3 Annual Arbitrage Revenue Based on Battery RTE

4.1.1.1 Avista

For arbitrage value at Avista, price values were incorporated into the optimization process and the total arbitrage revenue was captured by the battery. The volatility of the energy prices has a large impact on the results of the evaluation.

The value for this use case was generated through Avista's Decision Support System (ADSS) model which is discussed in higher detail later in this report. All energy and ancillary services for the project were estimated at $21/kW-year in the base case. It should be noted that the Avista flow battery BESS suffered from low RTE.

4.1.1.2 PSE

For PSE, ancillary service prices/requirements were obtained from the PSE-managed PLEXOS model and then shadow prices were used as input for PNNL's Battery Storage Evaluation Tool (BSET), which is discussed in Section 5.1. The total arbitrage revenue was captured by the battery, assuming the price structure per-hour remained the same for each year of the battery's usable life.

4.1.1.3 SnoPUD

Mid-Columbia index prices for 2011-2018 were used together with a characterization of the capacity and performance of the MESA 1 and MESA 2 BESSs to estimated arbitrage value of $5-$10/kW-year. Arbitrage value is low because MESA 2 suffers from low RTE.

4.1.2 System Capacity to Meet Resource Adequacy Requirements

When providing capacity or resource adequacy, the battery is dispatched during high demand events to supply energy and shave peaks that are present on the system. By doing so, the battery reduces the need for new peaking power plants and other peaking resources that would be required to handle the spikes in customer load. Resource adequacy requirements are in place to ensure that energy providers have sufficient assets and capacity to meet their peak demand and can be required on both a local- and regional-level.

Figure 4.4 shows a demonstration of top peak load days for a utility and the times in which the battery system would be dispatched to mitigate the highest loads within the day.

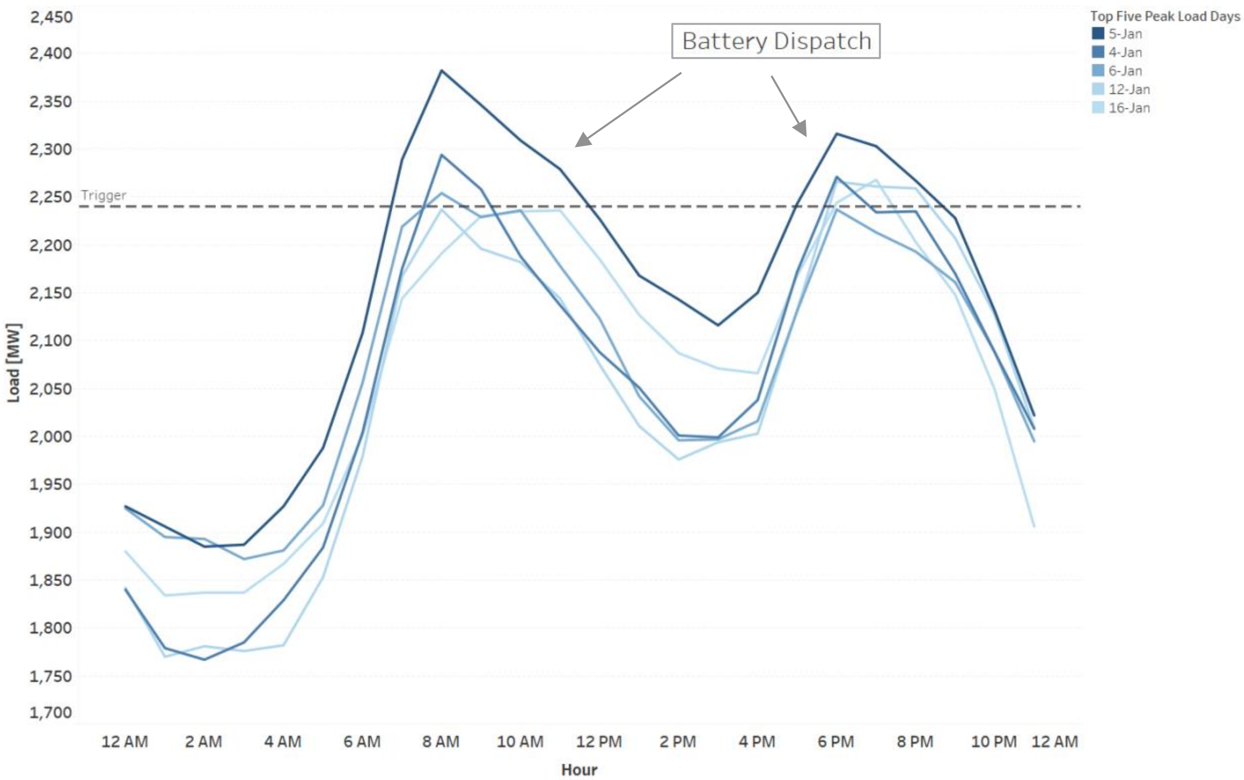


Figure 4.4. Example of Top Five Peak Load Days and Battery Dispatch for Capacity Benefit

4.1.2.1 Avista

Figure 4.5 shows the hourly 2017 load for the Avista control area. The battery would be triggered to dispatch energy above specific load amounts to flatten the peaks shown in winter and summer, generating value by displacing the need for a generation unit to meet the high demand.

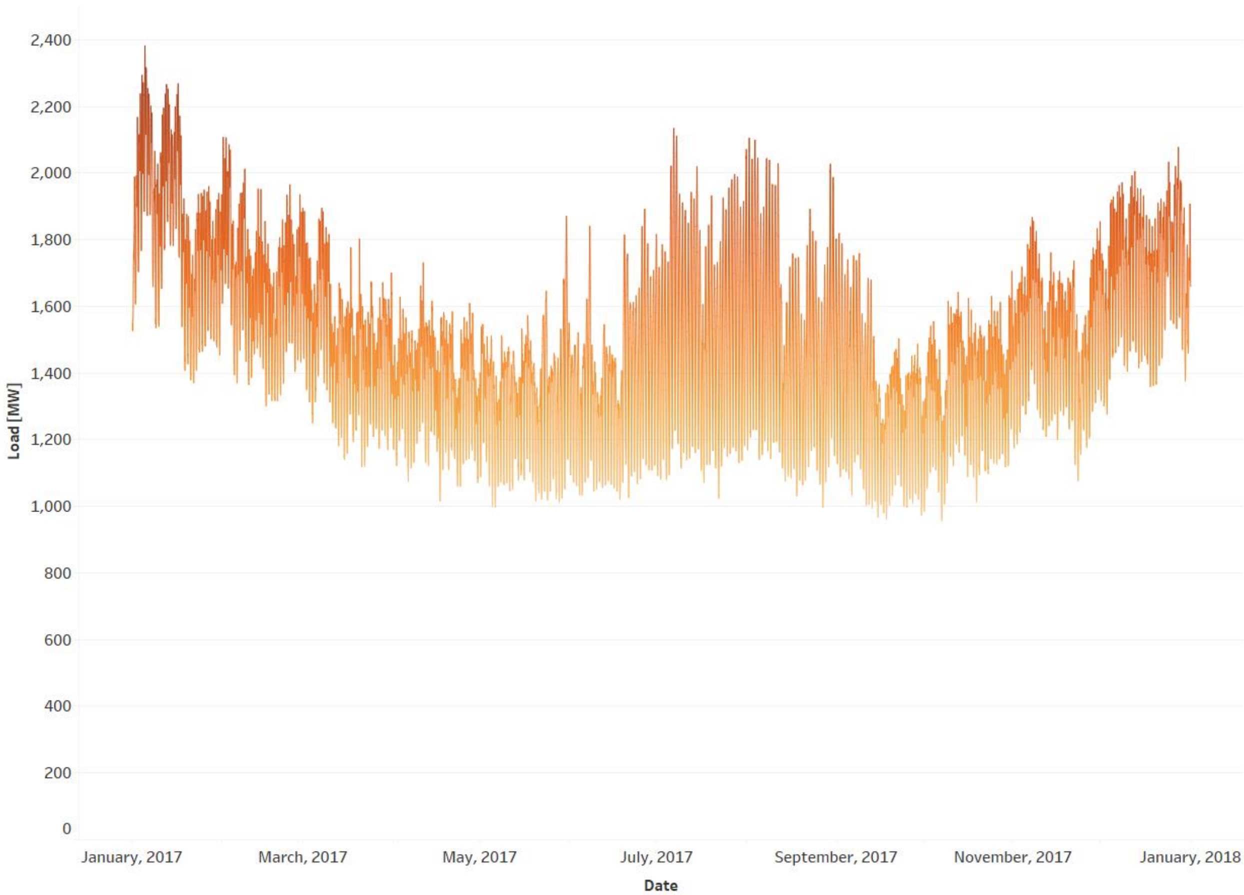


Figure 4.5. Avista Control Area Hourly Load, 2017

To determine the hours when the energy storage would be needed to provide capacity services, hourly system-wide load data was obtained for 2011 through 2015. The capacity trigger is set at the peak load point for each year. Capacity is required over a three-day period that includes the annual peak load day and the days immediately before and after the peak load day. The capacity must be available during the 18 peak hours over the course of the three-day peak: three hours in the morning peak and three hours in the evening peak each day. Based on the data provided by Avista, PNNL defined an hourly duty cycle that provided six hours of capacity each day, discharging during the peak loads for the day. A unique schedule was formed for three consecutive days according to Avista's capacity requirements. It was found that the maximum energy output for a 3-hour window was 700 kW, not the 1 MW nameplate capacity.

The capacity value is based on the amount of total revenue requirement the facility does not recover from the energy market or ancillary services. This use case, however, does not begin accruing benefits to Avista until 2027 as the utility is “capacity-long” and will only require additional reserves starting at that time.

4.1.2.2 PSE

For PSE, the battery is triggered to dispatch energy above specific load amounts to supply energy and flatten the peaks, generating value by displacing the need for a generation unit to meet the high demand. The load from the Glacier substation for 2015 is shown in Figure 4.6. As shown, the load peaks during the winter months.

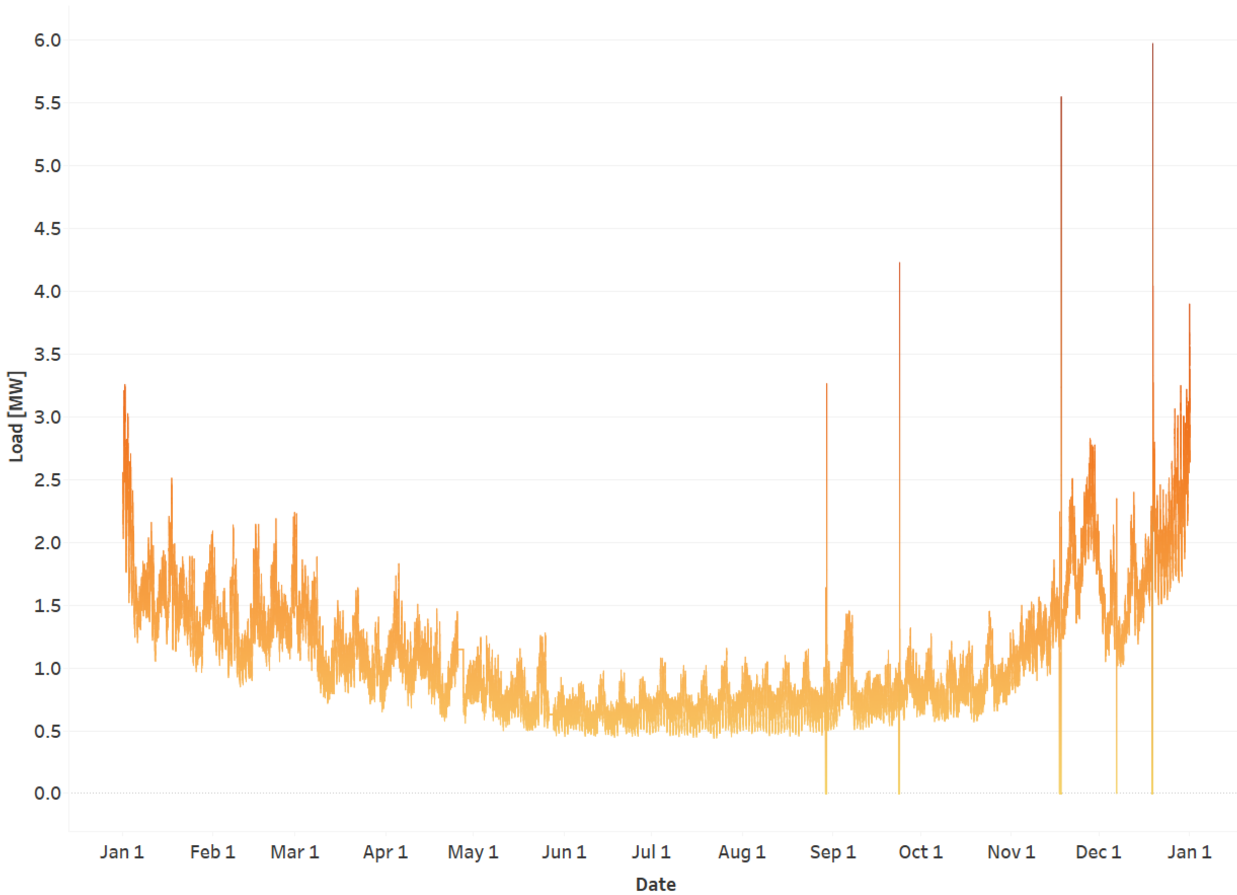


Figure 4.6 PSE Glacier Substation Load, 2015

For PSE, the capacity value is based on the incremental cost of the next best alternative investment which would be a peaking combustion turbine. The incremental cost as estimated for the economic analysis, however, includes adjustments for the following:

1. Energy and flexibility benefits of the alternative asset;
2. The ICE of energy storage (0.6x based on LOLP analysis completed by PSE); and
3. Capacity hours modeled using 2016 PSE capacity call data (described further below).

LOLP analysis consists of determining the quantity of capacity required to meet a set reliability target. Prior to incorporating the ICE of energy storage based on the LOLP conducted by PSE, the value of capacity was $64/kW-year after also incorporating energy/flexibility benefits. After including the additional LOLP analysis assumption that the battery has 40% less availability than a conventional peaking resource, this value was reduced to $38/kW-year, or $76,590 annually.

Figure 4.7 shows the ICE for varying hours of energy storage for PSE.

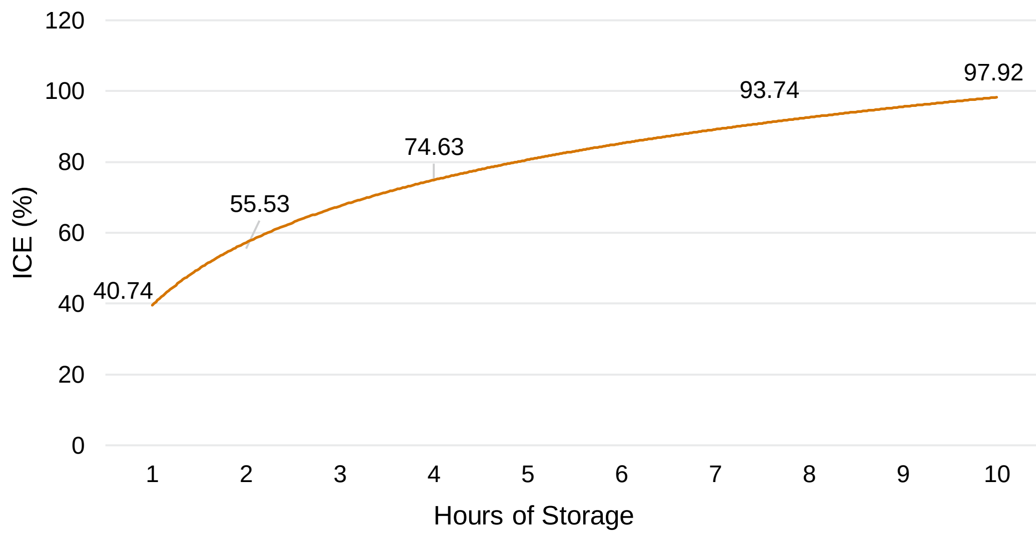


Figure 4.7 ICE for Varying Hours of Storage

From capacity data provided by PSE it was determined that there were 131 hours that could be targeted for capacity procurement from the battery system. Table 4.2 below shows the supply of energy necessary on behalf of the battery to mitigate peaks for each of the peak days found in the call data. It should be noted that while some days require more than 12 hours of constant output, a majority of the days require the battery to act between 2pm and 10pm, which aligns with the higher daily peak.

Table 4.2. Peak Load Days and Corresponding Hours of Battery Output, 2016

Date	Hours	Output (MW)
6/27/2016	3pm-8pm	0.67
7/20/2016	5pm-9pm	0.80
7/21/2016	11am-9pm	0.36
7/25/2016	3pm-8pm	0.67
7/27/2016	12pm-9pm	0.40
7/28/2016	1pm-11pm	0.36
7/29/2016	3pm-7pm	0.80
8/12/2016	2pm-10pm	0.44
8/29/2016	2pm-9pm	0.50
9/26/2016	5pm-9pm	0.80
12/5/2016	5pm-8pm	1.00
12/8/2016	5pm-9pm	0.80
12/9/2016	6am-9pm	0.25
12/10/2016	5pm-9pm	0.80
12/12/2016	5pm-7pm	1.33
12/14/2016	6am-10pm	0.24

Date	Hours	Output (MW)
12/18/2016	5pm-9pm	0.80

4.1.2.3 SnoPUD

Figure 4.8. SnoPUD Hourly Load (MW)Figure 4.8 below shows SnoPUD's 2017 hourly load, which displays the higher winter peaks and times in which they would need to mitigate peak demand.

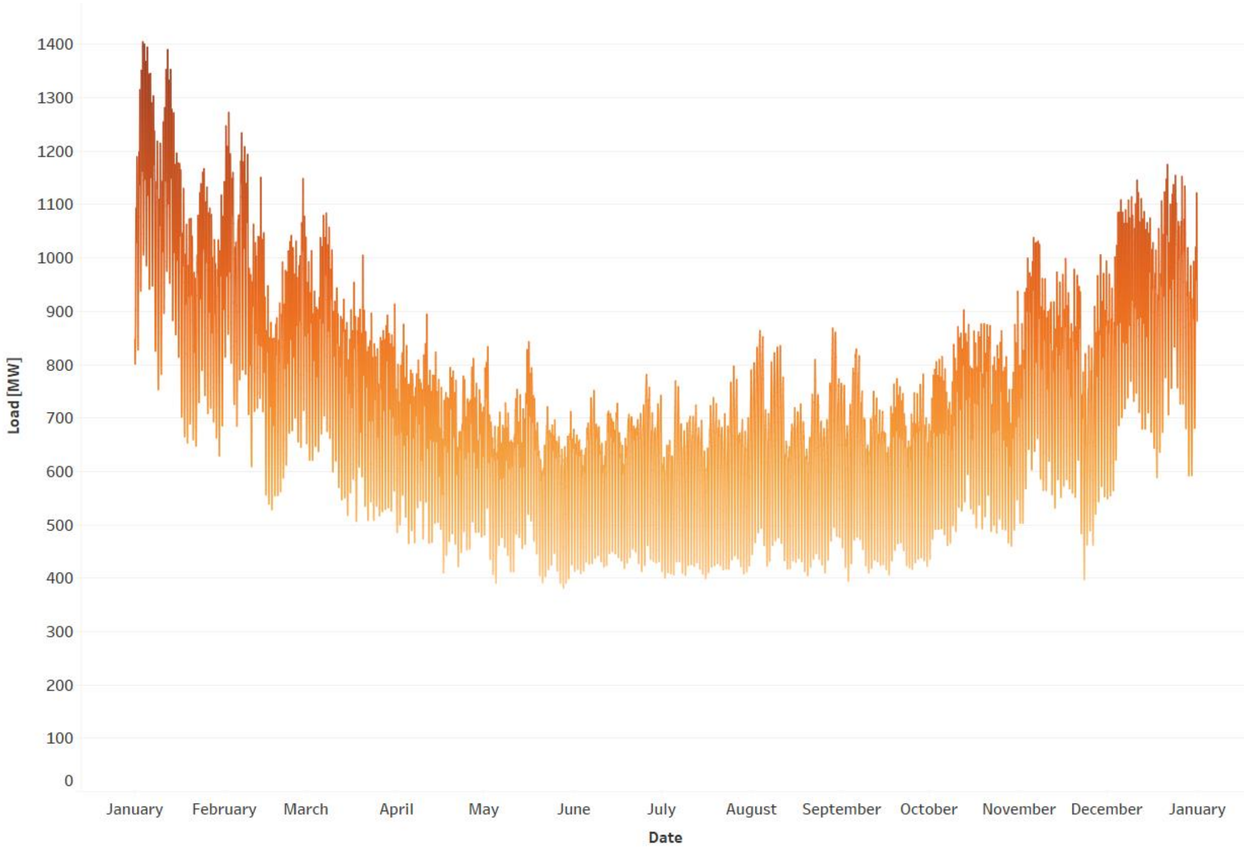


Figure 4.8. SnoPUD Hourly Load (MW)

For SnoPUD, assets are allocated a capacity credit that is associated with that demand reduction which is then valued at SnoPUD's portfolio implied price for capacity. Given that the Pacific Northwest does not have an accessible capacity market with known pricing, the implicit capacity price forecast based on the cost of building a new capacity resource is used. This implied price is calculated through the average capital and dispatch costs required for a cycle turbine over its annual peak availability over a 30-year life (SnoPUD 2018c). These prices were provided by SnoPUD and were used to calculate the value that the battery systems can provide with capacity.

To obtain the capacity benefit, the asset must discharge power within a 16-hour window each day of a 5-day annual peak that typically takes place at the beginning of January. The peak hours within those days correspond to the high load hours of 6am to 10pm, Monday through Friday.

The capacity incentive obtained each year is based on the average MW the battery systems would be capable of providing over the 80 applicable hours during that week with 95% confidence. There is no penalty for not discharging during a span of the window, however the battery cannot charge during this window and only during the off-peak hours (10pm to 6am). The optimal discharge rate (Figure 4.9) was calculated to extract the maximum combined energy out of MESA 1 and MESA 2 with 95% confidence. Based on battery testing, this was found to be 7,150 kWh across 7.5 hours within the 80-hour window. Because the capacity value is based on the average amount that could be provided over the 16-hour window, the value is based on a 447 kW (7.2 MWh / 16 hours) capacity.

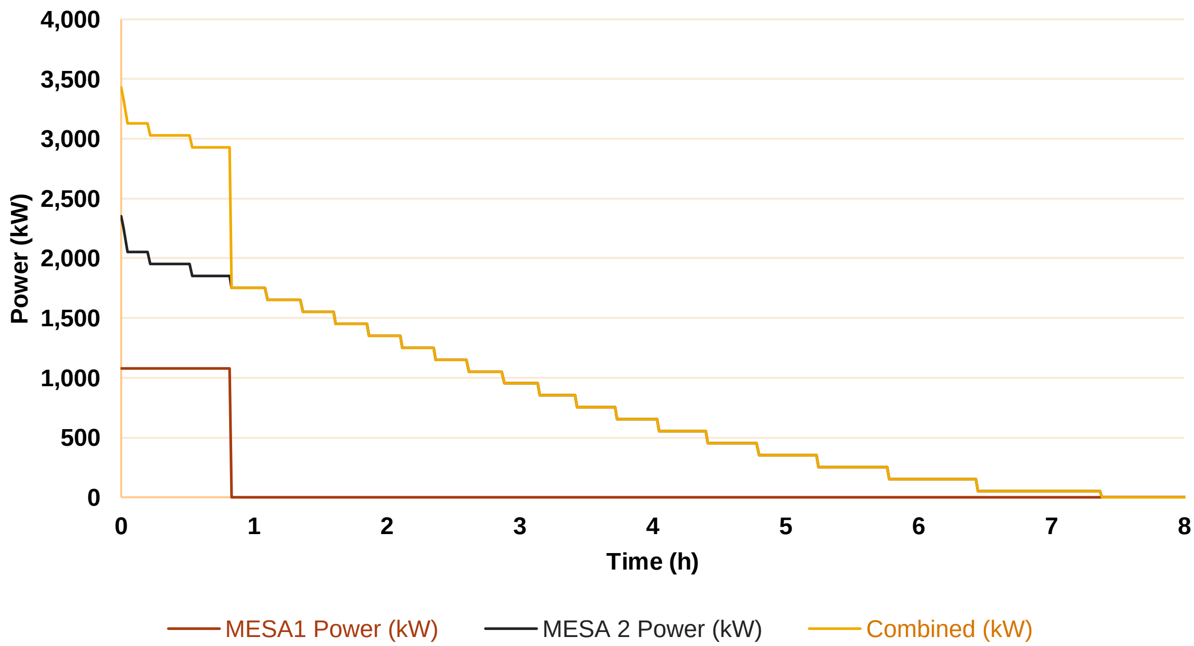


Figure 4.9 Maximum Output of MESA 1 and MESA 2 Within Capacity Period with 95% Confidence

Based on the above, the batteries are expected to generate approximately $40,000 each year for providing the peak capacity use case.

4.2 Use Case 2 – Provide Grid Flexibility

4.2.1 Regulation Services

Battery storage technologies are capable of filling short-term gaps between supply and demand. This service has the capability of generating value, as well as reducing costs and emissions associated with fossil-fuel burning plants.

Regulation up/down can be served by online generation, load, or storage equipped with automatic generation control and the ability to track fluctuations in load and change output quickly. This allows the system frequency to remain steady and differences between scheduled power and actual power flows within a control area to be managed. Figure 4.10 below demonstrates the difference between supply and demand that drives grid imbalances and requires regulation services.

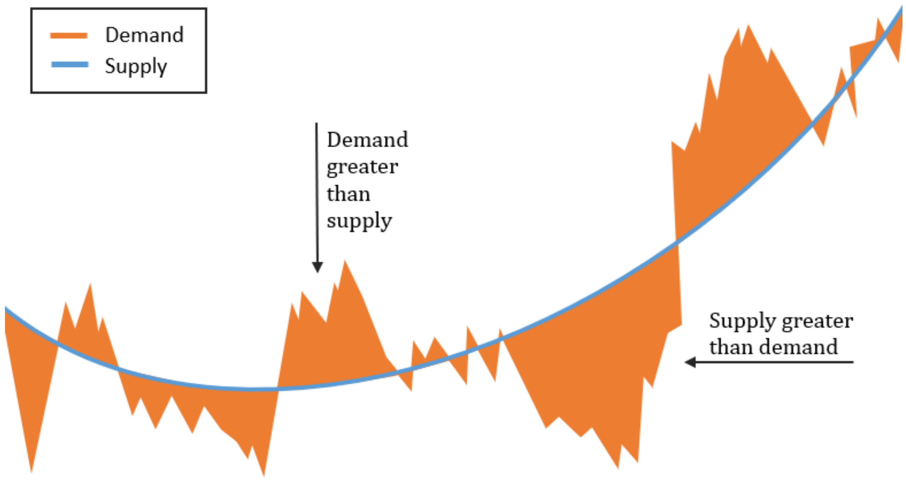


Figure 4.10. Imbalance between Energy Supply and Demand

Balance between generation and load must be maintained in near real-time on the electric power system. The constant load variability that arises from the fluctuation in loads that are connected to the system leads to a requirement for instantaneous and continuous balancing. The services that accomplish this are known as "ancillary services," and they are necessary to support the basic functions of generation, energy supply, and the delivery of power. Energy storage can be used to fill these minute-to-minute gaps between supply and demand, keeping power running for customers while maintaining a balanced electric system.

The Glacier battery is capable of generating value for spin/non-spin, regulation, and arbitrage as flexibility benefits. Spin/non-spin, however, was found to provide negligible value and was removed from the analysis.

PSE's production cost model provided prices and service requirements, such as balancing signals for the PSE balancing area in order to generate duty cycles for regulation. With energy storage, PSE can balance out the regional electric system by quickly reacting to a sudden change in customer demand or to a sudden change from generation output. For example, PSE operates the Wild Horse Wind and Solar Facility in central Washington that is capable of providing up to 273 MW of power. If energy output decreases in that location, a portion of the load can be picked up in Glacier and the battery can assist in bringing balance back to the overall system (PSE 2017a).

Calculating the value of balancing services requires two inputs. The first is the price of balancing service and the second is the balancing signal. The balancing signal is required in order to determine the output of the BESS when it is providing this service.

The perfect balancing signal is the one that is able to minimize deviations of ACE from zero when a certain threshold is met. The objective of the power system control is to minimize the ACE such that it follows NERC's control performance standards. Data to determine the balancing reserve requirement and signal for this analysis was sourced from the output of a prior analysis conducted of PSE's system by PNNL. Within the analysis, PSE provided 1-minute load and generation data from which a Monte Carlo simulation was run and determined the actual output of the energy storage for every MW of balancing service bid. The Monte Carlo simulations were run in order to cover uncertainty associated with generation and load forecast errors. Figure 4.11 below demonstrates the 1-minute balancing signal of PSE for the month of January 2018 and Figure 4.12 shows the balancing reserve requirements of PSE for the same time period. The detailed formulation of this method can be found in Balducci et al. (2016).

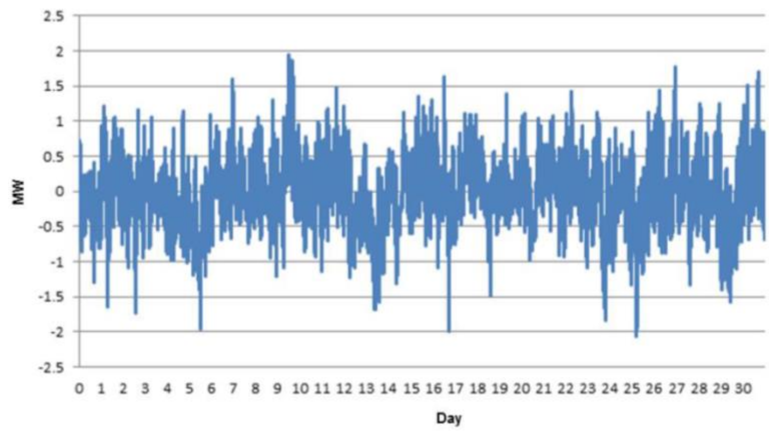


Figure 4.11. 1-minute Balancing Signal of PSE for the Month of January 2018

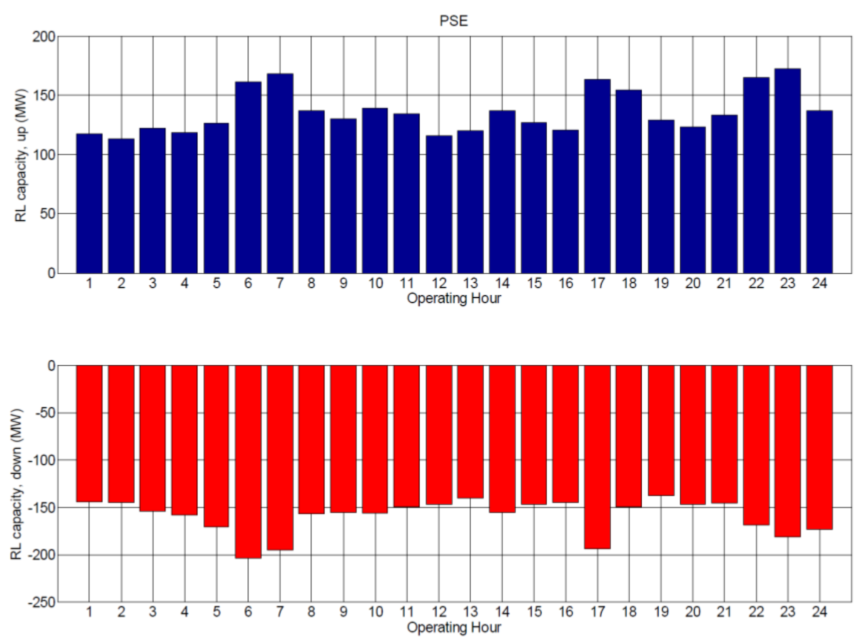


Figure 4.12. PSE Balancing Reserve Requirement for January 2018

Overall, the total value for flexibility services from the Glacier battery was estimated to be $81/kW-year through PSE's production cost model ($51/kW-year from regulation services, $30/kW-year from energy arbitrage).

4.2.2 Primary Frequency Response

Primary frequency response involves a generation or storage unit reacting to a drop-in system frequency so that the system as a whole may remain in balance. Under this use case, a Western Electricity Coordinating Council-wide frequency response event triggers a required response from PSE to provide resources to quickly recover from system frequency changes. In compliance with NERC Standard BAL-003-1 — Frequency Response and Frequency Bias Setting, utilities must provide generation capacity when required. Figure 4.13 demonstrates the NERC frequency response initiative in which primary frequency response would work to restore the system over time (CAISO 2015).

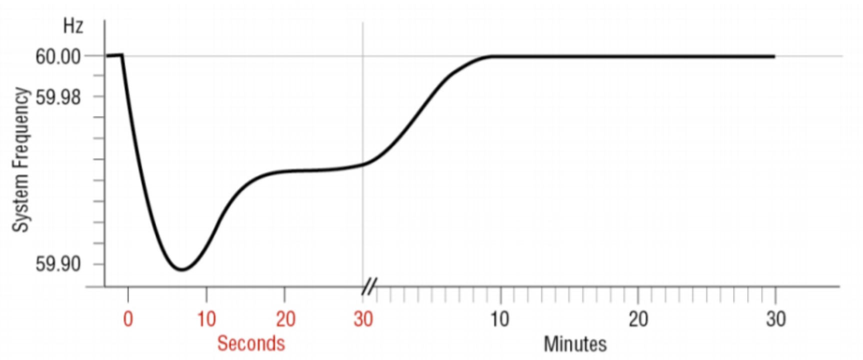


Figure 4.13. NERC Frequency Response Initiative

Figure 4.14 illustrates an example of a reaction to a frequency response event by the SSPC in Salem, Oregon. The green line represents the power output level by the battery during the event and the red line represents system frequency. In this example, the power output level was approximately 4 MW over the first four minutes of the event before tapering to zero. The drop in the red line provides a clear demonstration of the frequency droop that caused the event (Balducci et al. 2017).

Figure 4.14. SSPC Battery System Reacting to Frequency Drop

Neither the Western Electricity Coordinating Council nor NERC provide notifications for frequency response events. Rather, the battery must be set to automatically respond to unexpected frequency changes and react accordingly.

PSE is the only utility of the three included in the CEF that is considering using the battery to provide this service. Discussions with the utility indicated that events typically last 100 seconds, during which the battery must provide a burst of energy. For this analysis, an assumption was made that the battery must provide 2 MW of output for the full 100-second duration, providing a total of 56 kWh per event. To be conservative, however, it was further assumed that some events might require an additional 100 seconds of tapering, meaning a total of 84 kWh must be provided.

The dates and response requirements for the PSE Glacier BESS from 2016 are provided in Table 4.3. It was assumed that for each year of operation, the battery would attempt to provide power for each of these frequency events. Given the fact that primary frequency response events are of short duration and are unpredictable due to the lack of notification, under the base case of analysis it is assumed that energy, in this case 84 kWh, must be held in reserve at all times.

Table 4.3. Dates and Durations of Responses Required

Date	Average Duration (sec)	Response (MW/0.1Hz)	Requirement (MW/0.1Hz)	Battery Contribution (kW)	Reserve Requirement (kWh)
1/21/2016	100	-51.233	-19.7	(2,000)	-55.56
1/26/2016	100	-16.286	-19.7	(2,000)	-55.56
3/8/2016	100	-10.027	-19.7	(2,000)	-55.56
3/8/2016	100	2.924	-19.7	(2,000)	-55.56
3/28/2016	100	-14.088	-19.7	(2,000)	-55.56

Date	Average Duration (sec)	Response (MW/0.1Hz)	Requirement (MW/0.1Hz)	Battery Contribution (kW)	Reserve Requirement (kWh)
3/19/2016	100	-15.544	-19.7	(2,000)	-55.56
4/10/2016	100	-13.891	-19.7	(2,000)	-55.56
5/4/2016	100	-21.413	-19.7	(2,000)	-55.56
5/18/2016	100	-12.415	-19.7	(2,000)	-55.56
5/22/2016	100	-1.943	-19.7	(2,000)	-55.56
6/2/2016	100	-16.468	-19.7	(2,000)	-55.56
7/21/2016	100	-3.865	-19.7	(2,000)	-55.56
8/16/2016	100	-20.276	-19.7	(2,000)	-55.56
9/6/2016	100	-4.282	-19.7	(2,000)	-55.56
9/7/2016	100	-10.967	-19.7	(2,000)	-55.56
9/16/2016	100	-10.458	-19.7	(2,000)	-55.56
9/19/2016	100	-14.061	-19.7	(2,000)	-55.56
9/21/2016	100	-9.622	-19.7	(2,000)	-55.56
10/25/2016	100	-13.277	-19.7	(2,000)	-55.56
10/28/2016	100	-12.744	-19.7	(2,000)	-55.56

Due to confidentiality constraints, PSE was unable to provide the exact cost of a contract whereby PSE has transferred its obligation to a third party. PNNL, therefore, estimated the value based on a frequency response contract between CAISO and BPA. The contract transfers 50 MW / 0.1 Hz of frequency regulation to BPA at a total contract price of $2.22 million or $44.40/kW-year. This value was confirmed by PSE to be within a reasonable range of PSE's actual cost and was therefore used as the basis of value within this analysis.

4.3 Use Case 4 – Outage Management of Critical Loads

Outage mitigation refers to the use of a BESS to reduce or eliminate the costs associated with power outages to utilities.

4.3.1 Avista

Avista's battery system located at SEL is powered by two redundant feeders (regular feeder TUR117, and alternate feeder TUR116) from Avista's Turner substation located nearby. The SEL facility contains sensitive manufacturing processes that are prone to power quality disturbances, such as voltage sag. Discussions with SEL personnel revealed that voltage sags exceeding a certain magnitude and sustaining beyond a certain period can cause interruptions in the manufacturing process leading to financial damage worth hundreds of thousands of dollars. The BESS's ability to mitigate these sags, therefore, provides an opportunity of tremendous value.

PNNL analyzed voltage sag data from 2014-2017 provided by SEL, shown in Figure 4.15. Applying the Computer Business Equipment Manufacturers Association (CBEMA) defined power quality curve, over 40 voltage sag events (<70% in voltage magnitude, >20 millisecond in duration) were identified by PNNL and matches the finding of SEL's power quality monitoring system. Only three events caused power interruption during this period, all having over four seconds duration and zero minimum voltage. With an energy storage system on-site, a solution is to engage the fast real and reactive power control capability of its power electronic converters to mitigate the voltage sags and avoid interruptions. However, the effectiveness of the real and reactive power capability for mitigation of voltage sag will depend on the battery's response characteristics, and impact on the SEL connection point's voltage.

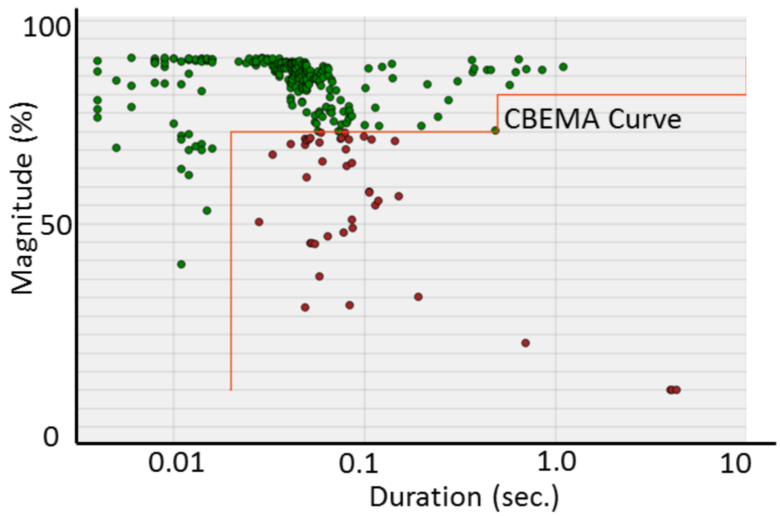


Figure 4.15. SEL Voltage Sag Events

The following sections review and analyze the Turner battery's real and reactive power capabilities, response characteristics, and sensitivity of the feeder voltage with respect to its real and reactive power to perform a high-level assessment of its ability to counteract voltage sags.

4.3.1.1 Avista BESS Inverter Capabilities

The Avista BESS contains 2x600 kVA Northern Power Systems (NPS) FlexPhase PCS Type 6LI inverters with grid compliance features, such as high and low voltage ride through (LVRT), voltage/frequency response, and full reactive power capability (100% of inverter capacity). LVRT test results from NPS literature show that in the event of low voltage in the grid, inverters can increase reactive current very fast, which will act against the voltage sag. Voltage waveforms during a 20% voltage sag event are presented in the left side of Figure 4.16 and reactive current waveforms to mitigate that are shown in the right side. The time required to attain high reactive current is marked in the figure and does not appear to exceed 20 mSec.

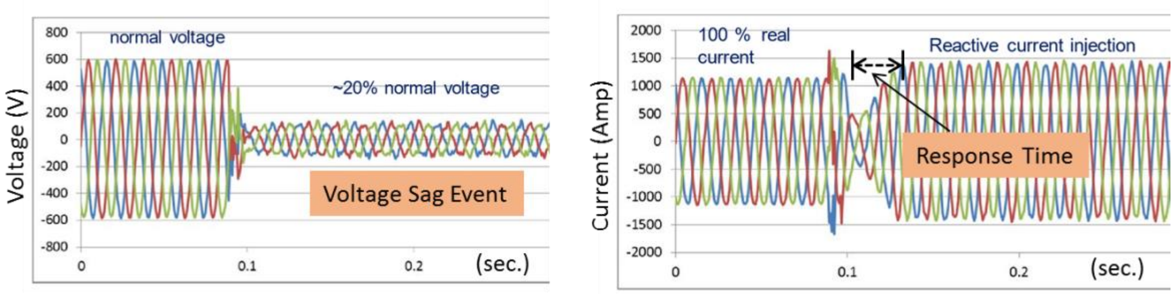


Figure 4.16. Voltage Waveforms During a Voltage Sag Event

4.3.1.2 Impact of BESS Real and Reactive Power SEL Voltage

While it is observed that the Avista BESS inverters can provide fast current response to a voltage sag event, its actual effectiveness for mitigation of voltage sag at the SEL facility will depend on the voltage sensitivity with a real and reactive current injection. A research team at Washington State University (WSU) performed network studies of the Turner substation feeders to assess voltage profile improvement by reactive power support from the BESS. Time series power flow simulation results presented in Figure 4.17 suggest that reactive power output from BESS inverters can improve the BESS bus voltage. WSU studies did not perform voltage sensitivity analysis with respect to real power. Since distribution networks are more resistive in nature than reactive, it could be anticipated that the voltage improvement by real power support will be equal to greater than the improvement by reactive power. Therefore, a combination of real and reactive power support can be provided by the inverters to support feeder voltage.

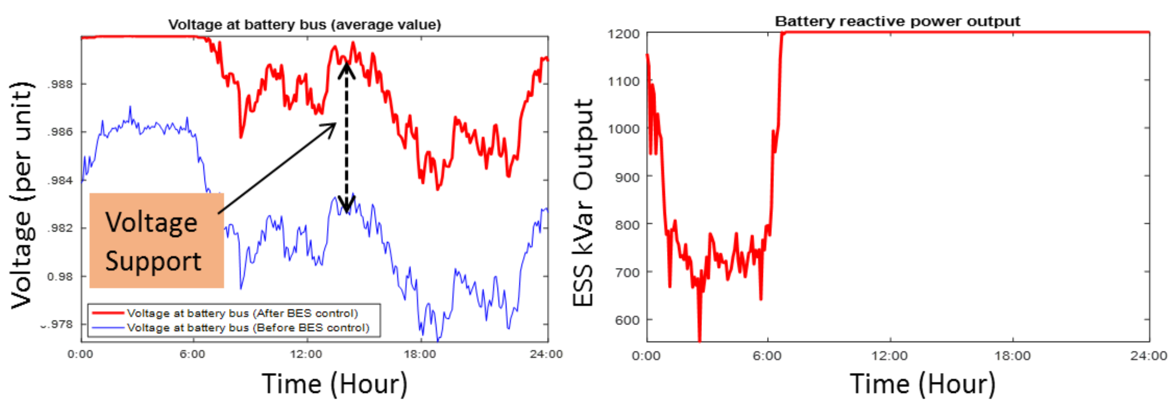


Figure 4.17. Voltage Profile at BESS Bus (Left); Reactive Power from BESS Inverters (Right)

4.3.1.3 Voltage Sag and Interruption Mitigation Using the BESS

By reviewing the BESS inverter reactive current profiles during voltage sag events (Figure 4.16), it is apparent that the response time of a reactive current is lower than the time criteria (>20 mSec) for defining voltage sag using the CBEMA curve. However, the magnitude of improvement by reactive power would depend on the voltage sensitivity. The analysis and results performed by WSU shows voltage improvement for scenarios where base case voltage (i.e., without reactive power support) did not sag below 95%, which is higher than the voltage sag definition criterion (<70% of nominal voltage). The three interruption events recorded in the 2014-2017 data showed the minimum voltage during those events was 0% of nominal voltage, and each of the events sustained over 4 seconds. Therefore, a voltage sag scenario that could cause a potential interruption was not observed from the WSU presented results. However, it should be noted that voltage profile analysis performed by WSU was a steady-state analysis conducted through time series power flow simulation which is not able to capture dynamic voltage events occurring in the mSec time scale. Also, the voltage sag records from SEL data show only the total duration of a sag event and the minimum voltage during that event. Without studying a time series profile of voltage variations during a sag event, and protection system settings that initiate a power supply interruption in response to that event, it is difficult to pinpoint the exact conditions of interruption. However, based on the LVRT features and fast current control capabilities, it is assumed that the inverters would be able sustain operation and boost voltage during sag events—that will ideally reduce the risk of a voltage sag driven interruption. Depending on the situation—real, reactive, or a combination—both types of power could be used for sag mitigation. Using a very conservative assumption 50-second long burst of real power at 1 MW (rated power capacity), the energy discharged amounts to 14 kWh, which is negligible in comparison to the BESS rated energy capacity (3.2 MWh).

The analyses presented here supports the idea of mitigating voltage sag by fast real/reactive power control of the BESS purely based on generic test results found in inverter supplier's literature, steady-state simulation studies of Turner feeders, and technical assumptions. Field tests by creating artificial disturbances would be useful and recommended to assess the actual effectiveness of BESS capabilities for this application.

Overall, due to the extensive down time caused by each outage of a minimum of three hours, which relates to a $150,000/hour cost to SEL, the benefits from voltage sag mitigation are substantial. Over the course of the battery life, the PV benefit from this use case is nearly $10 million.

4.3.2 PSE

In the event of an outage, the BESS has the capability to effectively operate in an islanded mode to the customers in the core downtown area of the town of Glacier. This operation would result in benefits accruing to PSE customers located in the islanded area and are monetized in terms of the value of lost load.

A map of the islanded area in the event of an outage is shown in Figure 4.18.

Figure 4.18. Islanded Area in Glacier, WA

To estimate the benefits that can be derived from outage mitigation, historical events were examined at the Glacier substation site. From these historical outage occurrences, the timing and duration of the outages were defined. Based on the historical data, it was found that customers face, on average, four unplanned outages per year lasting approximately 6.5 hours each.

An outage at the substation affects customers across the entire town; however, the battery has sufficient capacity to mitigate power loss for only the core downtown area of the city and its residents. The breakdown of types of customers within that area is shown in Table 4.4 where small commercial customers are those with loads of 50,000 kWh or less per year.

Table 4.4. Customer Breakdown by Type in Downtown Glacier Area

Description	Number of customers
Residential	38
Small Commercial and Industrial	20
Total	**58**

In order to assign monetary values to reducing or eliminating potential outages, the findings of Sullivan et al. (2015) from Lawrence Berkeley National Laboratory were used. This process estimates costs based on customer group (residential, commercial, or industrial) and the duration of the outage. Figure 4.19 shows an example of the trendline used to estimate the cost for different lengths of outage for residential customers. The cost to commercial and industrial customers is similarly upwardly sloped but quickly reaches costs into thousands for each consecutive hour of power loss.

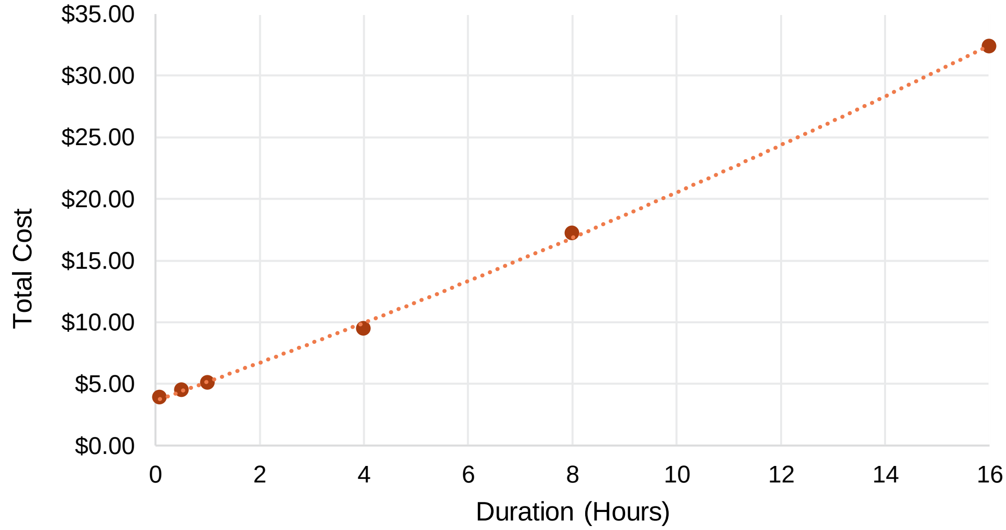


Figure 4.19. Cost by Outage Duration for Residential Customers

Using historic outage data, PNNL constructed a statistically average outage year. The outages were randomly selected and scaled to reach the average outage duration for the year. The outages were then built into the optimization analysis without foreknowledge, and the energy on-hand at the moment each outage struck was then used to mitigate the outage. The with and without battery conditions were then compared to determine the marginal benefit of mitigation offered by the BESS.

The savings to customers served by the substation are estimated to be $310,000 annually based on the Sullivan et al. (2015) cost assumptions and the customer profiles provided by PSE.

4.4 Use Case 5 – Enhanced Voltage Control

CVR is an approach designed to reduce the system voltage in such a way that customers' voltage stays within allowable bounds but at the same time the power and energy consumption, due to the existence of voltage-dependent loads, is reduced. A number of utilities have exercised this approach in some way or another in their networks to achieve economic benefits of reduced power demand and energy consumption. Typically, CVR is implemented as a large area-wide project consisting of multiple feeders containing tap-changing transformers, voltage regulators, and capacitor banks. A BESS connected to a substation or at another location within the area of the CVR project may be directed for sinking VAR by the distribution automation system or a Volt/VAR controller at the substation. This will reduce the voltage in the feeders in varying degrees depending on the location of the BESS, available VAR capability of the BESS inverter, and VAR to voltage sensitivity of the feeders.

The general expression used for assessment of CVR benefits is shown in equation (1) for active power demand reduction where, P_{red} is the reduction in active power demand, CVR_{fP} is the CVR factor (percent reduction in active power demand per 1% reduction in voltage, determined experimentally/ empirically/ or, otherwise) for active power, DV is the reduction in voltage resulting from CVR, P is the amount of active power flow in the feeder, n is the total number of feeders in the CVR deployment area, and k is a given time instant when the benefit is being assessed.

$$P_{red}(k) = \sum_{i=1}^{n} CVR_{fP} \times \Delta |V(k)|_i \times P_i(k) \qquad (1)$$

PNNL, as a part of its economic evaluation effort for Avista, conducted an analysis of CVR benefit using one-year (September 2016 to August 2017) load data from the Turner substation. CVR factor value (0.881) was taken from a study conducted by Navigant Consulting, Inc for Avista (Navigant 2014). Voltage reduction by VAR consumption was determined using an analytical expression developed from previously conducted test results at Portland General Electric. The BESS real power profile obtained from Avista, generated by their production cost modeling tool, was used to determine the inverter capacity available for VAR consumption. The substation load data provided by Avista was from September 2016 to August 2017. Using 2015-2016 Powerdex price data available to PNNL, the estimated CVR benefit was found to be \$5,488, whereas the benefit is found to be \$16,315 when using 2013-2014 price data. The higher price in 2013-2014 resulted in a higher benefit.

Providing VAR locally from a BESS, as shown in the left side of Figure 4.20, would relieve the upstream network from the burden of supplying VAR and the released capacity could be used to supply additional loads. In an electricity market, capacity service is priced based on a per-kW cost estimate of installing peaking power generation resources (e.g., combustion turbine generator). An approach to estimate the amount of capacity released by supplying VAR locally could be to map the VAR supplied by the BESS on an AC system's capability curve and determining the release of equivalent active power capacity, as illustrated in Figure 4.20.

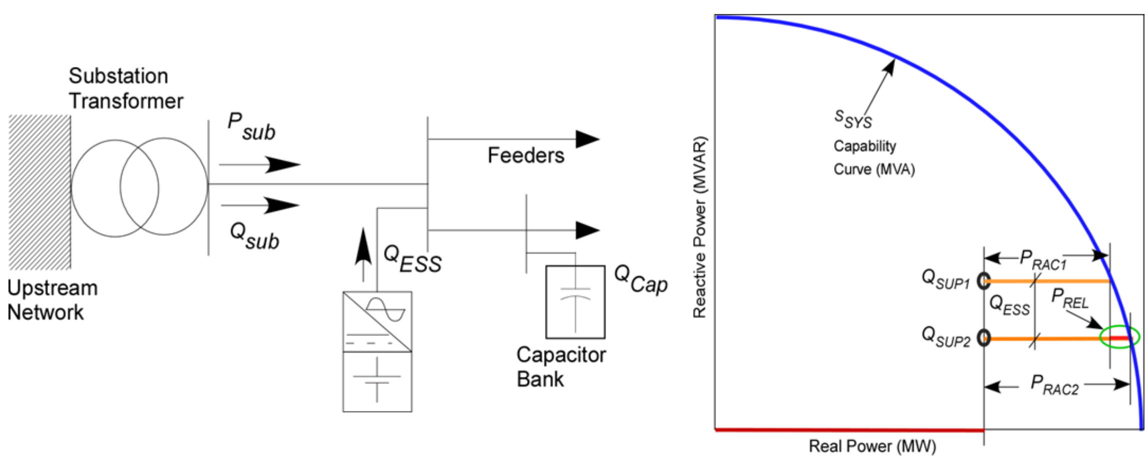


Figure 4.20. Release of Upstream Network Capacity in Terms of AC System Capability

Assume an upstream AC source with a capacity of S_{SYS} MVA is supplying P_{SUP1} MW and Q_{SUP1} MVAR at a given hour to the feeder where a BESS is installed. If the local BESS inverter now supplies Q_{ESS} MVAR, the MVAR supplied by the upstream AC source will be reduced from Q_{SUP1} to Q_{SUP2} MVAR. Assuming a lossless ideal circuit, Q_{SUP2} could be roughly estimated by subtracting Q_{ESS} from Q_{SUP1}. The difference between remaining active power capacity of the AC source (P_{RAC1}) when it was supplying Q_{SUP1} MVAR and the remaining active power capacity (P_{RAC2}) when it is supplying Q_{SUP2} is considered as capacity released (P_{REL}) by supplying VAR locally and used for capacity benefit calculation. Expression for determining P_{REL} is given in equation (2).

$$
\begin{aligned}
&P_{REL} = P_{RAC2} - P_{RAC1} \\
&P_{RAC1} = \left(\sqrt{{S_{SYS}}^2 - Q_{SUP1}^2} \right) - P_{SUP1}, P_{RAC2} = \left(\sqrt{{S_{SYS}}^2 - Q_{SUP2}^2} \right) - P_{SUP1} \\
&Q_{SUP2} = Q_{SUP1} - Q_{ESS}
\end{aligned}
\tag{2}
$$

Assumptions on the capacity of the upstream AC source (S_{SYS}) can be made based on the maximum demand of the feeder being supplied by the AC source over a given period. A safety factor (e.g. 10%) could be introduced to overrate the capacity.

The Avista Turner BESS is capable of providing this use case. According to Avista, capacity benefit can be achieved by providing capacity support during certain hours in a certain month (06:00-09:00 and 17:00-20:00 on January 4, 5, and 6). Therefore, the upstream capacity release benefit is estimated based on the minimum capacity release achieved during those hours, based on the approach described in Figure 4.20 and equation (3.3.2). Available VAR capacity for local VAR support (Q_{ESS}) is obtained from the rated MVA capacity of the inverters (1.2 MVA) and the real power output of the BESS, which is generated by Avista production cost modeling tool.

According to Avista's 2017 Integrated Resource Plan (IRP), capacity benefit achievement will commence from 2027 and valued at $171/kW-yr for that year (Avista 2017). Using this value, and the minimum capacity release (9 kW) achieved during the hours under consideration, annual benefit is estimated at $1,551.

5.0 Evaluation Tools

5.1 BSET

To accurately capture the value of a storage system, the analysis must recognize that there is a multi-dimensional competition for the energy stored in the battery at all times. This competition has an intertemporal component in that all usage of the energy in the battery in the current hour, and affects the opportunities in the next hour. Following the intertemporal condition, there is also competition within each hour between the use cases themselves. Understanding the individual characteristics of the battery system as well as the landscape of economic opportunities is a fundamental component of deriving optimal value. To resolve these usage conflicts, PNNL's BSET was engaged. The model co-optimizes the benefits under the base case, limiting the value to what is technically achievable by each of the BESSs.

BSET was used to run a one-year simulation of energy storage operations in which the model performed the optimization process on an hourly basis. The simulation was then used to determine the actual battery operation. The detailed modeling and formulation of this method can be found in Wu et al. (2013). Figure 5.1 shows an example of the model interface to which price, load, and other data can be input and battery operations extracted.

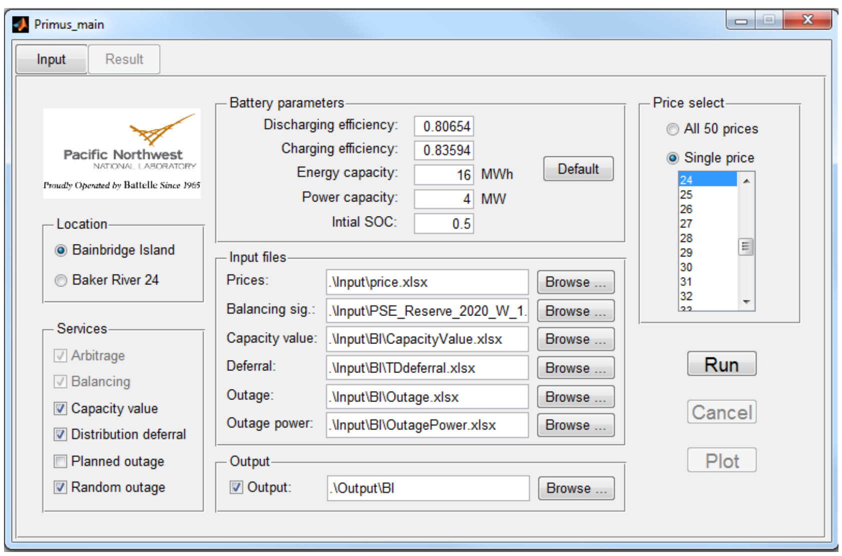


Figure 5.1. BSET Interface

5.2 ADSS

In order to accurately co-optimize the value of energy and ancillary services, the ADSS tool was used in addition to BSET for the Avista Turner Energy Storage Project. ADSS is a model that utilizes a "mixed-integer hydrothermal decision support solution that emulates utility generation and transmission portfolio assets" (Avista 2018b).

ADSS was used to run a simulation of energy storage operations in which the model performed the optimization process on an hourly basis. The simulation was then used to determine the actual battery operation.

Figure 5.2 presents an example of battery output activity from the model for a week for energy and ancillary services (Avista 2018b).

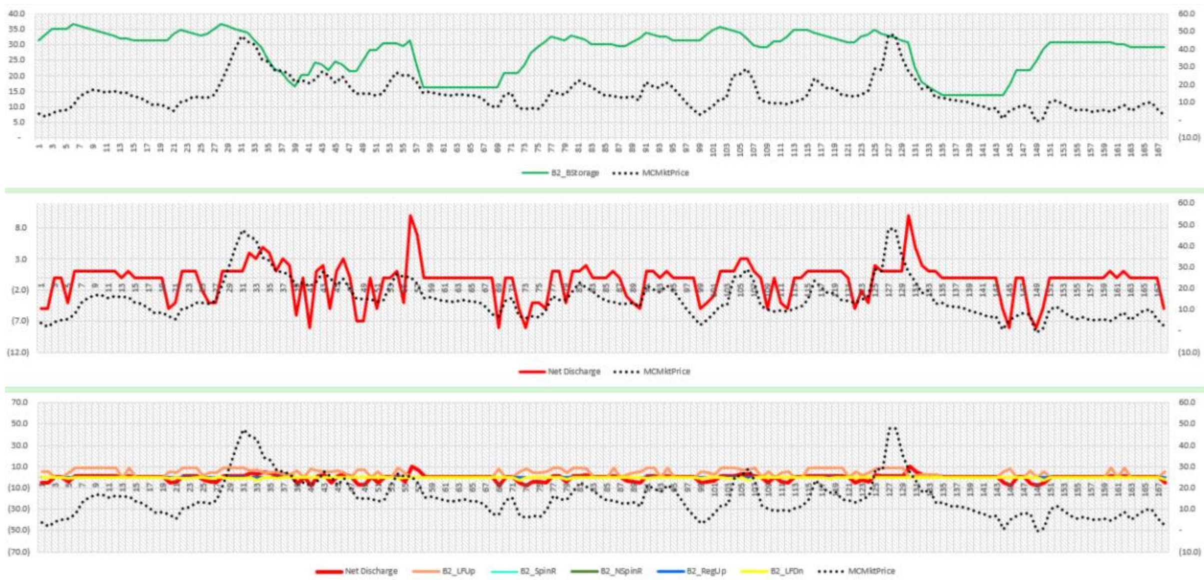


Figure 5.2 Turner Battery Dispatch with ADSS Model, April 9th – April 15th

6.0 SOC Modeling

6.1 Introduction

Battery testing and analysis was completed as a component of PNNL's work with the CEF projects. The BESSs were run through a set of tests to determine their capability of carrying out the use cases outlined through preliminary economic analysis. After all testing was completed for the PSE, SnoPUD MESA 1, and SnoPUD MESA 2 BESSs, nonlinear SOC models were developed to be used in economic modeling and to aid in developing power profiles for future testing. The approach evolved throughout the CEF project, becoming more refined.

Ultimately, the goal of any SOC model is to come up with a form for describing how the SOC changes with time, as described in Equation (3).

$$\frac{dSOC}{dt} = f(Power, SOC) \tag{3}$$

Where power is the power the battery exchanges with the grid, and SOC is the SOC of the battery. This allows us to determine how the battery SOC changes over operation in an easily interpretable manner. For all three cases, the data (consisting of time series data for power and SOC) was cleaned by taking charge or discharge half-cycles by which the SOC changed by at least 30%, and where the power was roughly constant throughout the half-cycle.

6.2 Modeling Approach

In order to make a model that is easily interpretable and testable, the equation form was set up as a series of predictors as described in equation (4).

$$\frac{dSOC}{dt} = \sum c_i X_i \tag{4}$$

Where X_i is a predictor and c_i is a coefficient of regression, X_i are chosen based on knowledge of the chemistry and statistical significance of the predictors when applied in a model. The benefit from setting up the model as in equation (4) is that both sides can be integrated with respect to time, obtaining equation (5) .

$$\Delta SOC = \int \sum c_i X_i \, dt \tag{5}$$

The benefit of doing this is twofold—first, no smoothing step is required. This can utilize noisy data or low-resolution data, as there is no differentiation step to amplify the noise. In fact, the integration step will naturally smooth out some of the noise in any of the predictors without losing any information. Secondly, it means that when we do the regression, the model will be minimizing error in predicting the change in SOC. This means our model is built around giving the best estimate for the SOC, rather than the dSOC/dt. However, the equation we get in the end still gives dSOC/dt, giving the convenience of that approach.

Furthermore, what we are really interested in is how SOC changes with the charge or discharge of energy rather than the passage of time. In order to do this, each point was weighted by the absolute value of the change in SOC for a given timestep. Without doing this weighting, the model was found to perform much worse for extreme powers. As we are using time series data at high discharge or charge rates, there are fewer time points and so they have less influence on the regression.

To use equation (5), each predictor is integrated with respect to time, giving the cumulation of that predictor. The change in SOC from the original SOC is linearly regressed vs. each of these predictors, using the weighing previously described.

In order to validate a given model, it is important to evaluate it on its predictive capability. To test how well a model can predict a given half-cycle, it is allowed to train only on previous cycles. The error is then calculated by seeing how well it predicts the change in SOC of a given cycle. For calculating cumulative error, the error is weighted by the absolute value of the change in SOC of each time step, using the same reasoning as weighing the absolute value of change in SOC for regression.

6.3 Linear Modeling

In order to come up with a linear model, the two predictors used in equation (4) are power discharged, power charged, and an intercept, resulting in equation (6).

$$\frac{dSOC}{dt} = k_{chg}P_{chg} + k_{dis}P_{dis} + k_0 \tag{6}$$

When regressed, the coefficients for each utility are given in Table 6.1.

Table 6.1 Linear Coefficients for All Utilities, Standard Error in Brackets

Utility	k0 (1/h)	kchg (1/kWh)	kdis (1/kWh)
PSE	-6.326e-03 (1.2e-05)	2.297e-04 (4.2e-08)	-2.590e-04 (5.5e-08)
SnoPUD MESA 1	-2.516e-02 (1.1e-05)	8.948e-04 (7.2e-08)	-9.216e-04 (9.3e-08)
SnoPUD MESA 2	-1.189e-02 (2.1e-05)	1.017e-04 (4.4e-08)	-1.215e-04 (7.4e-08)

The cumulative out of sample root mean square error (RMSE) is given in Figure 6.1. As PSE and SnoPUD MESA 1 are both lithium-ion batteries with consistent performance across their SOC range, their linear models do quite well with an out of sample RMSE of 2-2.5%. By contrast the RMSE of the flow battery SnoPUD MESA 2 is quite a bit higher at 4.5%, due to its performance depending being more variable depending on the SOC and power.

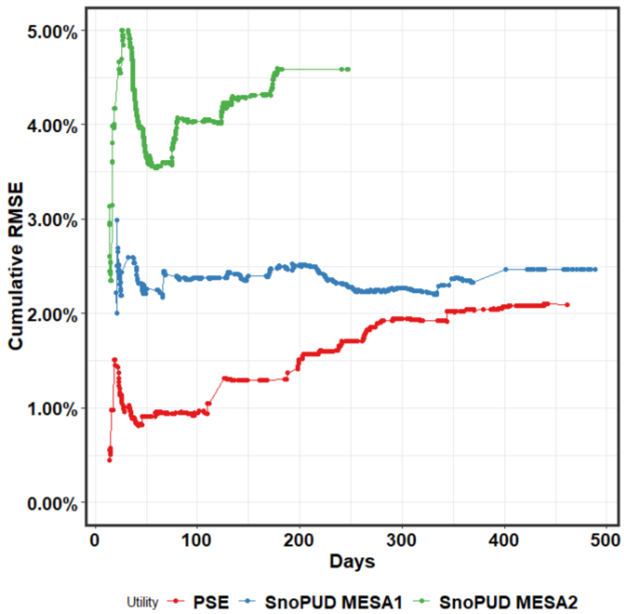


Figure 6.1 Cumulative Out of Sample Error for Linear Models

6.4 Non-Linear Modeling

In order to test nonlinear models, several more predictors based on SOC and power were considered. Based on the knowledge that performance can vary a lot based on different SOCs (especially at extreme SOCs for the flow battery), the SOC and the reciprocal of the SOC were considered, as well as their squares to account for nonlinearity. To account for the efficiency falling off at higher powers (i.e. the performance being non-linear with power), the power squared was also considered. To account the interactions, all first order interactions were also considered. The total list of predictors is given in Table 6.2.

Table 6.2 List of Predictors

Predictor
P
P^2
SOC
SOC^2
SOC^{-1}
SOC^{-2}
$P\ SOC$
$P\ SOC^2$
$P\ SOC^{-1}$
$P\ SOC^{-2}$
$P^2\ SOC$
$P^2\ SOC^2$
$P^2\ SOC^{-1}$
$P^2\ SOC^{-2}$

Using all these predictors at the same time would be problematic and would immediately run into issues of overfit, with high out of sample prediction error, as well as the equation being hard to interpret and complicated to use. Therefore, for each utility this list is pruned to get only the most important ones.

In order to do this, a gradient boosting machine (GBM) algorithm was utilized, due to previous success of the algorithm in detecting predictor performance and ease of use. The GBM was given each of the predictors in Table 6.2, predicting how the SOC changed for each cycle using only the knowledge of previous cycles. This was used to tune the GBM's hyperparameters of interaction depth and number of trees. After tuning, the GBM was run on the data, and the importance metric of each predictor was returned, giving a ranking of most to least importance.

The next step was to choose the number of predictors. When choosing n predictors, the first through nth most important as determined from the GBM were considered. The model was then evaluated on its out of sample prediction error. The results are given in Figure 6.2.

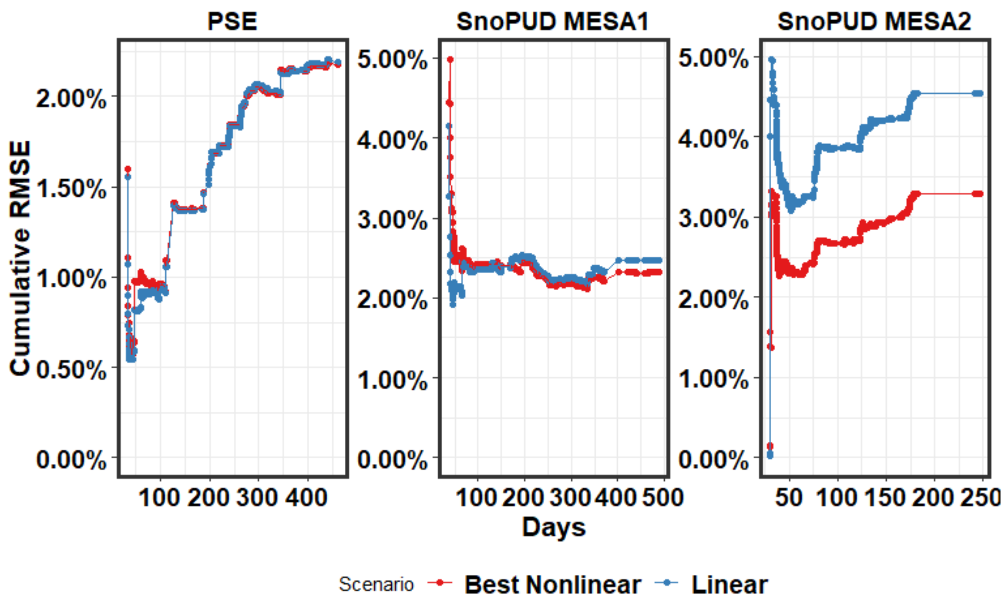


Figure 6.2 Best Nonlinear out of Sample Cumulative RMSE for each Utility, with the Linear Model for Comparison

As expected, only minor gains were made for PSE and SnoPUD MESA 1, while a large drop of about 1.5% RMSE was made for SnoPUD MESA 2, as the nonlinearity of performance was accounted for. Due to the small reductions in error and high model complexity required to get any gain in performance (the best PSE model required four predictors, and the SnoPUD MESA 1 model required nine), it is recommended to stick to the linear models described in the previous section.

From the trend of the cumulative RMSE vs time, SNOPUD MESA 1 flattened out almost immediately, showing we can understand how the battery operated after only 50 days of testing. Ignoring the high error period at the start of testing, PSE and SnoPUD MESA 2's cumulative RMSE typically increased with time, implying the model might be overfitting (or there might have been unresolved balancing issues that resulted in the battery's performance changing over time).

The model developed for SnoPUD MESA 2 is given in Table 6.3, with the graph of performance vs SOC and power given in Figure 6.3

Table 6.3. SnoPUD MESA 2 Regression Coefficients

Predictor	Estimate	Std. Error	Units
$P\ SOC^{-2}$	2.703e-06	2.912e-08	$kW^{-1}h^{-1}$
$P\ SOC^{-1}$	-6.044e-05	1.997e-07	$kW^{-1}h^{-1}$
SOC^{-2}	-1.051e-03	4.799e-06	h^{-1}
P	-1.755e-05	2.534e-07	$kW^{-2}h^{-1}$
P^2	-1.590e-08	2.765e-11	kW^{-1}
k_0	-9.242e-03	2.101e-05	h^{-1}

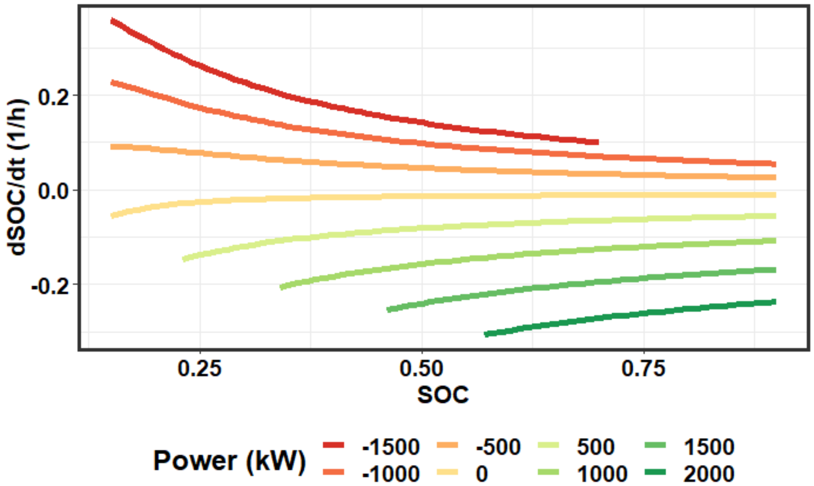


Figure 6.3. SnoPUD MESA 2 Performance as Function of Power and SOC

7.0 Data Requirements and Financial Inputs

To run the battery simulation using BSET, various data and other parameters must be acquired in order to accurately evaluate the economic potential of the battery systems. This includes items, such as specific costs/values for services within the utility's specific service territory, financial parameters, and other values of importance. Given that the CEF is a matching fund program, a portion of the costs of each project are directly incurred by the utility partners and a breakdown of each of these costs must be collected as well.

For energy storage to be cost competitive, its benefits must not only exceed its costs, but all associated revenue requirements, including all taxes and debt payments. A detailed pro forma for each BESS was prepared to estimate revenue requirements using the data in Table 7.1.

Table 7.1. Financial Data Requirements

Item	Avista	PSE	SnoPUD
BESS Capital Cost	Installed cost of each BESS, including site/civil, electrical, installation, communications, information technology (IT), transportation, sales tax, and other relevant costs.		
BESS O&M costs	Estimated annual fixed and variable O&M costs for each BESS. Long-term O&M cost inflation rates.		
Insurance Premiums	Rate for insurance premiums and other taxes (as fraction of capital investment).		
Cost of Capital	Before-tax weighted cost of capital.		
Property Tax	Property tax rates on the BESS (if applicable for determining rate recovery).		
Income Tax	Marginal income tax built into revenue requirements calculations.		
Other Taxes/Fees	Other taxes or fees required to calculate levelized capital costs as defined by the utility.		
Operating Life	Operating lifetimes for BESSs in terms of number of cycles and years.		
Price Data	Forecast day-ahead hourly price data during testing period and hourly real-time energy price data for 2012-2014. For SnoPUD, high load hour and low load hour average hourly market index prices by month.		
Capacity Value	Capacity value ($/kW-year) in 2015 IRP.	Cost ($/kW-year) of next best alternative for meeting capacity reserve.	Powerdex super peak hourly market index prices for 2014.
Regulation/Balancing Prices	ADSS weekly marginal prices for 2011-2015.	Hourly prices for flexibility operations based on PSE production cost model for 2011-2015.	Identification and discussion of the persistent deviation rates applied in the energy imbalance payment structure.
Distribution Equipment Costs	Cost and life, in terms of number of operations, for each equipment type that might benefit from peak shifting, load shaping, and power factor correction.		
Outage Costs	Power reliability/quality benefits to SEL.	Outage costs by customer type.	None. The BESSs are located at substations and there is no capacity to island feeders for mitigating outages.

8.0 CEF Project Economic Results

This section individually documents the economic valuation results of each of the three Washington CEF BESS projects. The findings of these studies were intended to not only report the value that the individual storage projects can bring to the utilities and their customers, but also to aid in the development of a framework regarding the benefits energy storage can more broadly bring to the State of Washington. This analysis may provide insight for other utilities looking to make similar investments as the ones in these projects and also for those who are attempting to maximize the value of the assets they have already procured.

8.1 Avista Turner Energy Storage Project

8.1.1 Project Costs and Financial Parameters

Given that the CEF is a matching grant program, a portion of the costs of the project are directly incurred by Avista. Table 8.1 shows the itemized cost component breakdown for the Avista Turner Energy Storage Project.

Table 8.2 Estimated Costs for the Turner Energy Storage Project

Item	Cost	Avista	WA CEF
Battery Purchase and Shipping/Placement	$3,600,000	$400,000	$3,200,000
Construction and Interconnection	$940,000	$940,000	
Communication Costs	$40,526	$40,526	
Software/Optimizer Development Costs	$784,000	$784,000	
NPS Inverters / Transformer Repair / Site Cleanup / AFUDC / Consultant Costs	$2,344,564	$2,344,564	
Total	**$7,709,000**	**$4,509,090**	**$3,200,000**

For energy storage to be cost competitive, its benefits must not only exceed its costs, but all associated revenue requirements, including all taxes and debt payments must be considered. A detailed pro forma for the BESS was prepared to estimate revenue requirements. Major parameters used in the pro forma are presented in Table 8.3.

Table 8.3. Major Parameters Used in Estimating BESS Revenue Requirements

Parameter	Value	Source
Energy Storage Book Life	20 years	UET Battery Proposal
O&M Escalation Rate	3%	Avista
Federal and State Income Tax Rate	23.65%	Avista
Property Tax Rate	1.50%	Avista
After-Tax Weighted Cost of Capital	6.85%	Avista
Benefit Growth Rates		
Capacity	2%	Avista
Energy Arbitrage and Ancillary Services	5%	Avista
Outage/Voltage Sag Mitigation	2.5%	Avista

Parameter	Value	Source
CVR	5%	Avista

Based on the combination of costs and assumptions outlined previously in this section, PNNL was able to produce revenue requirements that accounted for full system costs, including all taxes, debt, and insurance costs.

8.1.2 Evaluation of Project Benefits and Revenue Requirements

After running the model to demonstrate a year of activity, it was found that, for the Avista Turner Battery Project, battery benefits for the base case ($1.2 million), under which outage/voltage sag mitigation is not included, fall short of meeting costs ($5.98 million) (Table 8.4 and Figure 8.1). Overall, this produces a benefit cost ratio of 0.20 under the base case. Of the benefits included in the base scenario, the most valuable application is capacity, which generates just under $600 thousand in PV benefits. The second highest value application is the combination of arbitrage and regulation at approximately $381,000, followed by CVR at $221 thousand in PV terms.

Table 8.4. Benefits Estimates by Use Case vs Revenue Requirements for Base Case

Element	Benefits	Revenue Requirements
Capacity / Resource Adequacy	$599,762	
Energy Arbitrage + Regulation	$381,473	
CVR	$220,935	
SEL Outage/Voltage Sag Mitigation	-	
Total	**$1,202,170**	**$5,982,768**

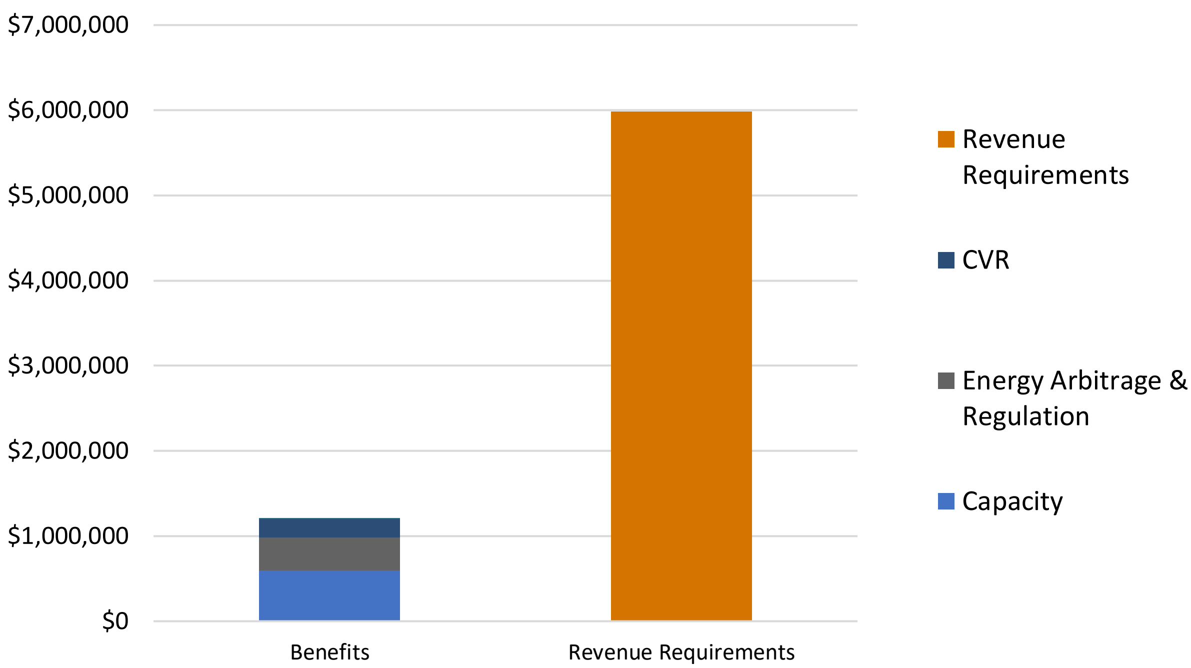


Figure 8.1. Avista 20-Year Present Value Benefits vs. Revenue Requirements

Figure 8.2 shows the percentage breakdown by benefit type in PV terms.

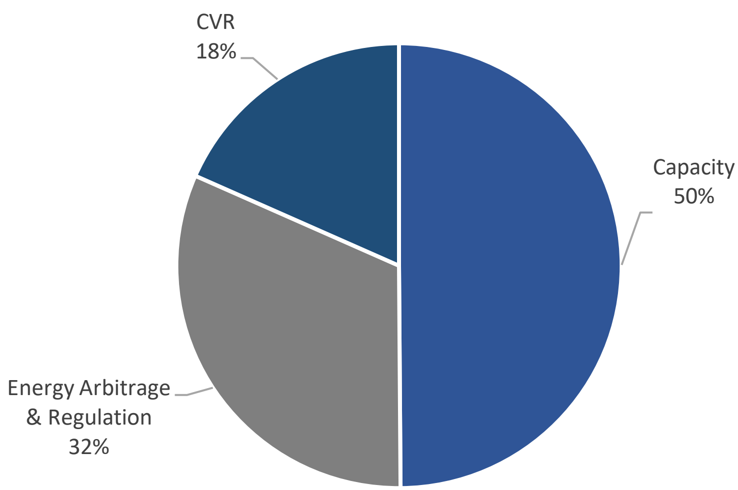


Figure 8.2. Avista 20-year Present Value Percentage Breakdown by Benefit Type

8.1.3 Evaluation of Analysis with Outage Mitigation Benefits Included

While the financial repercussions of voltage sag related outages to SEL is a high value use case, the benefits from eliminating power loss are not included in the base case of this economic analysis. The reasoning behind this is that the analytics take the perspective of the utility, not its customers.

Despite this, the value of outage mitigation is important to understand given the value it provides to SEL and the Avista customer base. By using the respective methodology and calculating the value of eliminating the outages to the customer, it was found that 20-year present value benefits increase by nearly $9.5 million when this use case is included in combination with the other applications. Table 8.5 and Figure 8.3 show these results. Overall, this scenario offers the highest return of any of the scenarios examined in this report with a benefit cost ratio of 1.78—a vast improvement on the base case. While the Avista Turner BESS demonstrated the capacity for significant value, it later became non-operational and was removed from the facility. <u>The results presented within this report, therefore, represent the potential benefits that could have been derived had the battery operated as tested and remained in place for its entire usable life.</u>

Table 8.5. Benefits Estimates by Use Case vs. Revenue Requirements, Outage Mitigation Included

Element	Benefits	Revenue Requirements
Capacity / Resource Adequacy	$599,762	
Energy Arbitrage + Regulation	$381,473	
CVR	$220,935	
SEL Outage/Voltage Sag Mitigation	$9,487,911	
Total	**$10,690,081**	**$5,982,768**

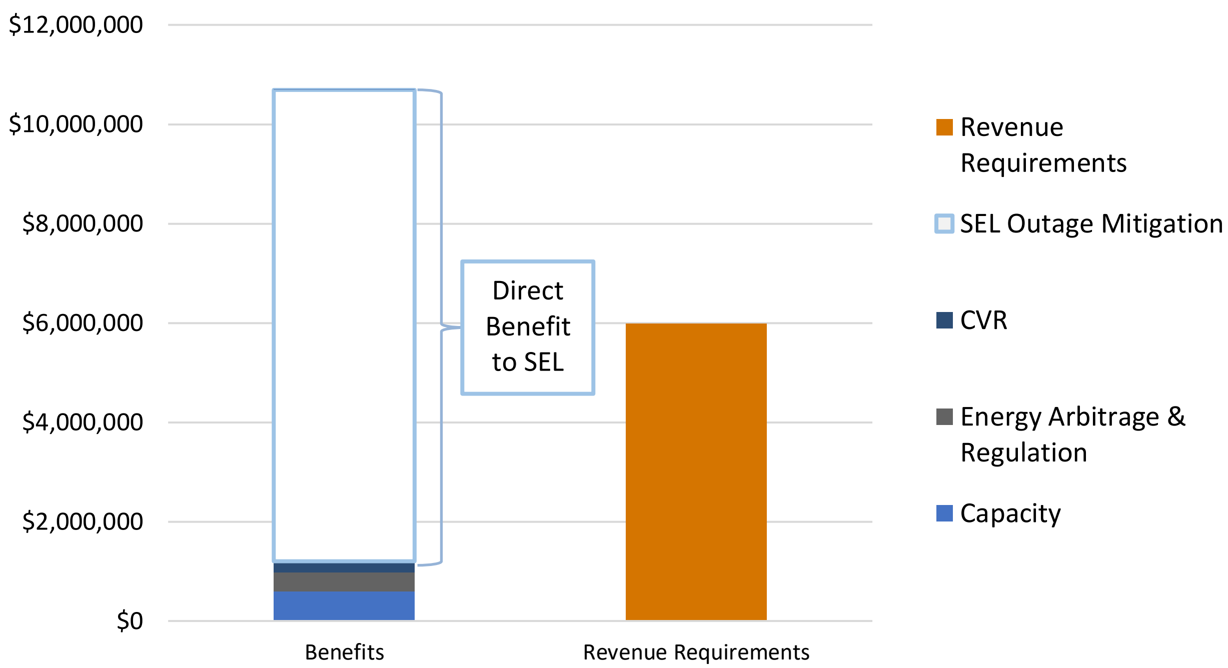


Figure 8.3. Avista 10-year Present Value Costs vs. Revenue Requirements, Outage Mitigation Included

8.1.4 Evaluation of Alternative Scenarios and Sensitivity Analysis

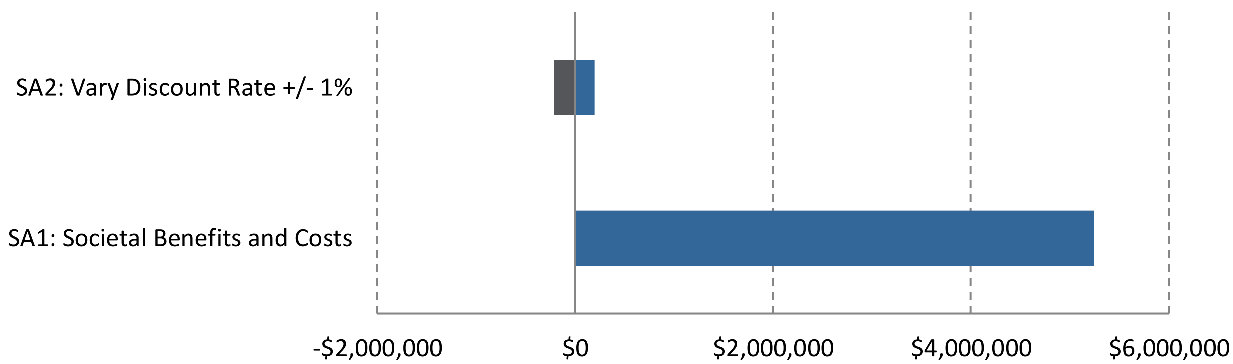
A variety of analyses were conducted to explore the sensitivity of the results to changes in a number of key assumptions and parameters. These scenarios and their impacts are outlined below as measured in comparison to the base case. The following adjustments to the assumptions were made:

– SA 1: Societal Benefits and Costs Use as Focus of Analysis

– SA 2: +/- 1% Discount Rate Used

The results of each sensitivity analysis are presented in Figure 8.4. Note the table that appears below the figure. As shown, the change in discount rate used accounts for impacts on both the benefit and cost side of the analysis. All other scenarios evaluate changes on only one side of the ROI equation.

One of the evaluated scenarios resulted in negative impacts to the economic results compared to the base case. The lowest ROI was found in the scenario in which the discount rate was increased by 1%. This scenario dropped total benefits by approximately $215,000 in present value terms. Adjusting the discount rate down by 1%, on the other hand, increased net benefits by approximately $197,000. Also, on the positive side is the scenario in which only societal benefits and costs were considered. This involved the inclusion of the outage/voltage sag mitigation benefit to SEL but eliminated the CEF grant funds. In total, this scenario provided an increase of just over $5.2 million in benefits in present value terms over the life of the battery.



	SA1: Societal Benefits and Costs	SA2: Vary Discount Rate +/- 1%
Low-End		$(215,015)
High-End	$5,241,640	$197,413

Figure 8.4. Sensitivity Analysis Results

Table 8.6 presents the ROI ratios for the various scenarios defined in the base case and as part of the sensitivity analysis. The ROI ratio is defined as PV benefits divided by PV costs under each defined scenario. When the cost estimates presented by Avista are used in the denominator of the ROI calculations, all of the examined scenarios yield ROI ratios that fall short of 1.0, meaning that PV benefits fail to exceed PV costs. The only scenarios that exceeds an ROI of 1.0 are the scenarios in which outage mitigation benefits were included, with or without the grant included.

Table 8.6. Return on Investment Ratios for Alternative Scenarios

	Base Case	Outage Mitigation Included	+1% Discount Rate	-1% Discount Rate
Base Case	0.20	1.58	0.19	0.21
Grant Excluded	0.13	1.05	0.32	0.33

8.2 PSE Glacier Energy Storage Project

This section presents the economic results of the PSE Glacier Energy Storage Project.

8.2.1 Project Costs and Financial Parameters

Table 8.7 shows the itemized cost component breakdown for the Glacier Energy Storage Project.

Table 8.7 Estimated Costs for the Glacier Energy Storage Project

Item	Cost	PSE	WA CEF
Engineering, Procurement, and Construction Contract	$6,500,000	$2,700,000	$3,800,000
Permitting and Landscaping	$225,000	$225,000	
Site/Civil Prep	$450,000	$450,000	
IT/SCADA/Comms	$400,000	$400,000	
Control System	$475,000	$475,000	
Project Management	$160,000	$160,000	
Line Reclosers and System Interconnection	$485,000	$485,000	
Overheads	$1,105,000	$1,105,000	
Total	**$9,800,000**	**$6,000,000**	**$3,800,000**

For energy storage to be cost competitive, its benefits must not only exceed its costs, but all associated revenue requirements, including all taxes and debt payments related to the BESS. A detailed pro forma for the BESS was prepared to estimate revenue requirements. Major parameters used in the pro forma are presented in Table 8.8.

Table 8.8. Major Parameters Used in Estimating BESS Revenue Requirements for the Glacier Energy Storage Project

Parameter	Value	Source
Energy Storage Book Life	10 years	Lithium-ion Battery Proposal
Annual Battery O&M	$22,500	Lithium-ion Battery Proposal
O&M Escalation Rate	2.5%	PSE
Insurance Rate	0.479%	PSE
Federal and State Income Tax Rate	24.873%	PSE

Parameter	Value	Source
Property Tax Rate	.56%	PSE
After-Tax Weighted Cost of Capital	7.6%	PSE
Benefit Growth Rate	5.7%	PSE

Based on the combination of costs and assumptions outlined previously in this section, PNNL was able to produce revenue requirements that accounted for full system costs, including all taxes, debt, and insurance costs.

8.2.2 Evaluation of Project Benefits and Revenue Requirements

After running the model to demonstrate a year of activity, it was found that battery benefits for the base case for PSE ($2.46 million), under which outage mitigation is not included, fall short of meeting costs ($6.7 million) for the Glacier Energy Storage Project (Table 8.9 and Figure 8.5). Overall, this produces an ROI ratio of 0.36 under the base case. Of the benefits included in the base scenario, the most valuable application is Regulation Up/Down, which generates just over $859 thousand in PV benefits. The second highest value application is primary frequency response at just above $800 thousand, followed by resource adequacy at approximately $691 thousand in PV terms. Arbitrage provides the lowest value overall.

Table 8.9 PSE Benefits Estimates by Use Case vs Revenue Requirements for Base Case

Element	Benefits	Revenue Requirements
Capacity / Resource Adequacy	$691,499	
Primary Frequency Response	$801,843	
Regulation Up/Down	$828,634	
Arbitrage	$563,548	
Outage Mitigation	-	
Total	**$2,885,525**	**$6,748,775**

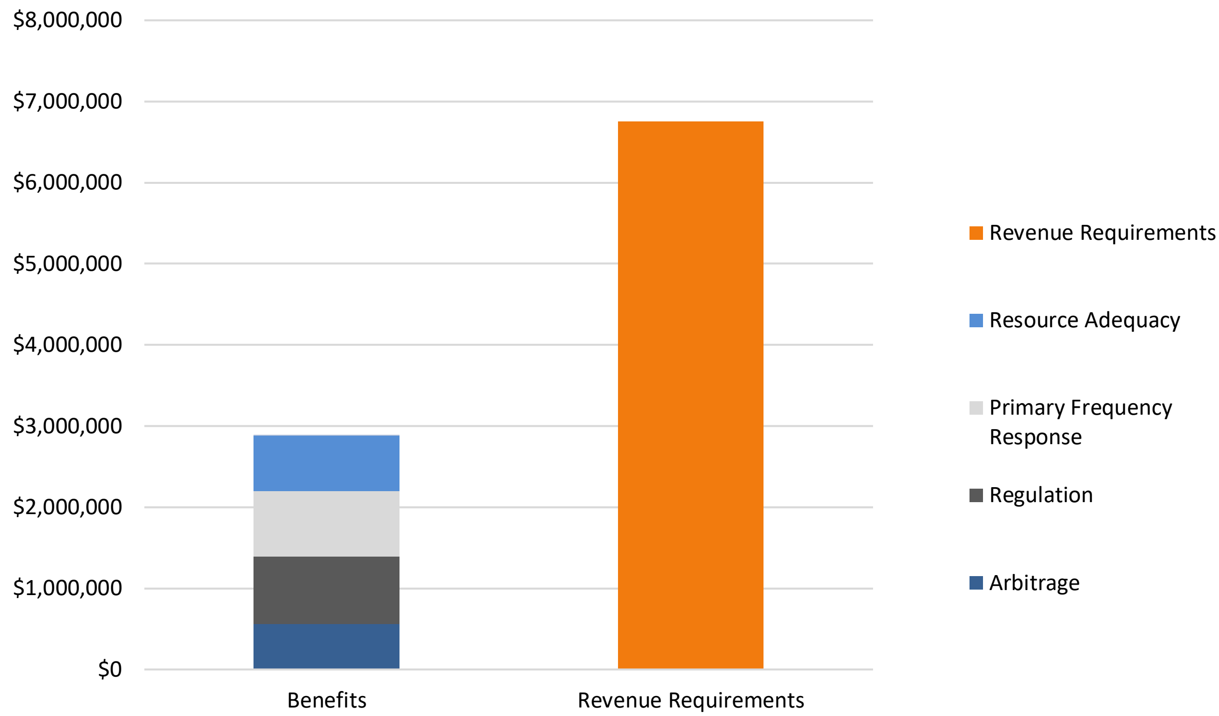


Figure 8.5. PSE 10-Year Present Value Benefits vs. Revenue Requirements

Figure 8.6. shows the percentage breakdown of each use case.

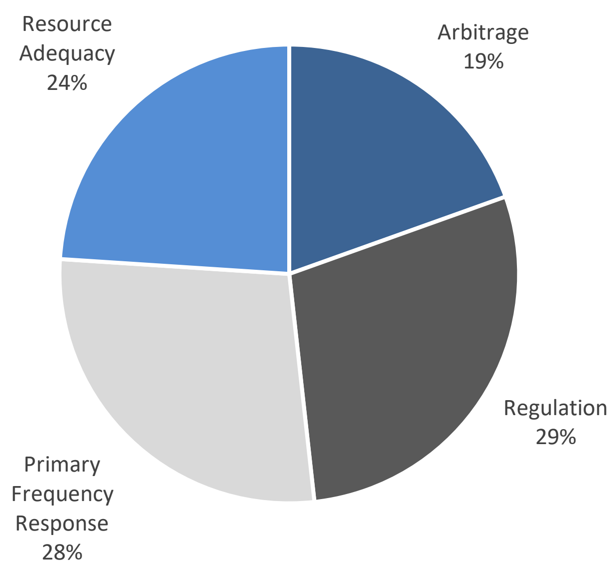


Figure 8.6. 10-year Present Value Percentage Breakdown by Benefit Type

8.2.3 Evaluation of Analysis with Outage Mitigation Benefits Included

While the high frequency of long duration outages in the Glacier area was one of the largest considerations when PSE chose the site, the benefits from eliminating power loss are not included in the base case of this economic analysis. The reasoning behind this is that the analytics take the perspective of the utility, not its ratepayers.

Despite this, the value of outage mitigation is important to understand given the frequency and duration of outages that strike each year in the Glacier area. By calculating the value of eliminating the outages to the customers described, it was found that 10-year PV benefits increase by nearly $2.8 million when this use case is included in combination with the other applications. Figure 8.7 and Table 8.10 show these results. Overall, this scenario offers one of the highest returns of any of the scenarios examined in this report with an ROI ratio of 0.84—more than double that of the base case.

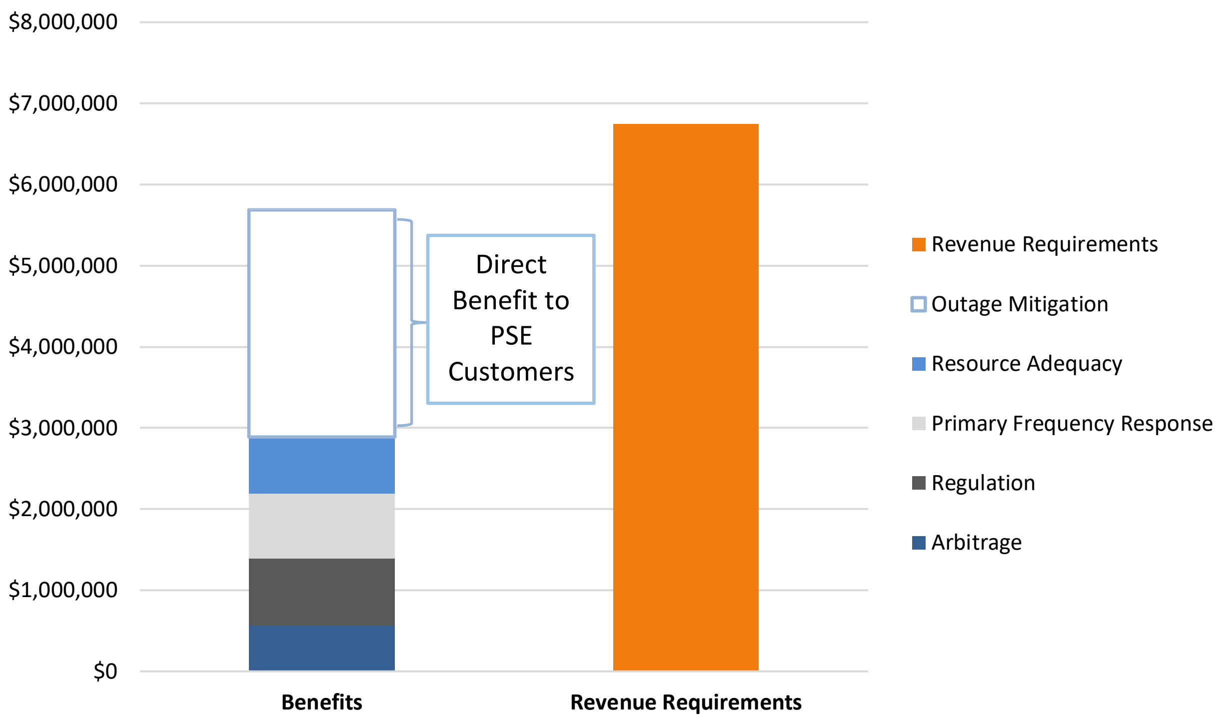


Figure 8.7. PSE 10-year Present Value Costs vs. Revenue Requirements, Outage Mitigation Included

Table 8.10. PSE Benefits Estimates by Use Case vs. Revenue Requirements, Outage Mitigation Included

Element	Benefits	Revenue Requirements
Capacity / Resource Adequacy	$691,499	
Primary Frequency Response	$801,843	
Regulation Up/Down	$828,634	
Arbitrage	$563,548	
Outage Mitigation	$2,799,227	
Total	**$5,684,751**	**$6,748,775**

8.2.4 Evaluation of Alternative Scenarios and Sensitivity Analysis

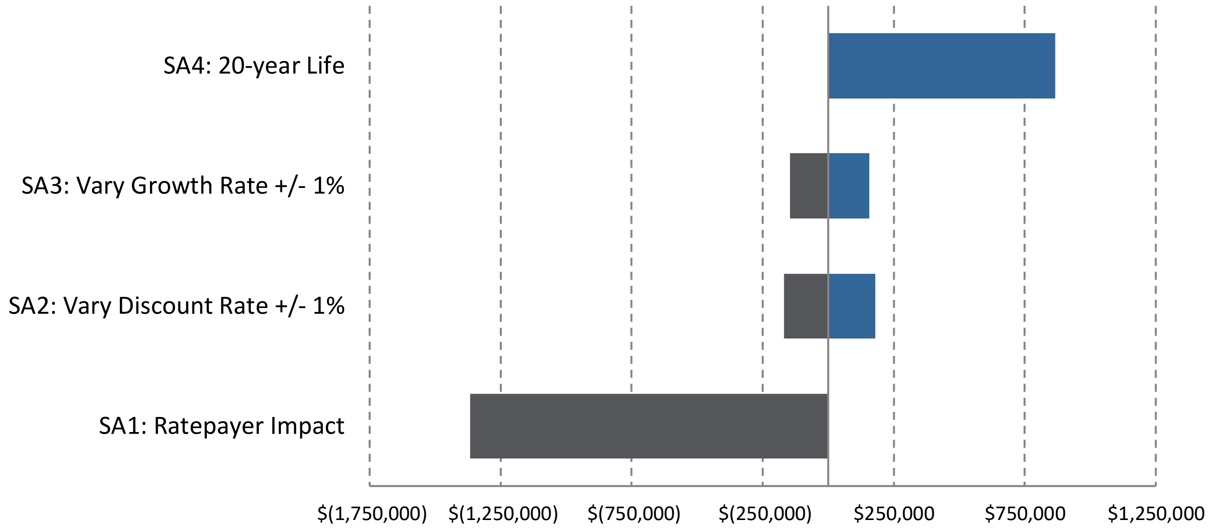
A variety of analyses were conducted to explore the sensitivity of the results to changes in a number of key assumptions and parameters. These scenarios and their impacts are outlined below as measured in comparison to the base case. The following adjustments to the assumptions were made:

- SA 1: Societal Benefits and Costs Used as Basis of Analysis
- SA 2: +/- 1% Discount Rate Used
- SA 3: +/- 1% Benefit Growth Rate Used
- SA 4: 20-year Battery Life

The results of each sensitivity analysis are presented in Figure 8.8. Note the table that appears below the figure. As shown, the changes in discount rate and growth rate used account for impacts on both the benefit and cost side of the analysis. All other scenarios evaluate changes on only one side of the ROI equation.

Three of the four evaluated scenarios resulted in negative impacts to the economic results compared to the base case. The greatest negative impact resulted from approaching the analysis from the societal perspective. For this scenario, the benefits of outage mitigation are included; however, the $3.8 million grant from the CEF fund is not put towards total costs. The difference between this scenario and the base case is a drop in benefits of $1.37 million in 10-year PV terms. Other negative effects were found with the two scenarios including the increase in the discount rate by one percentage point and dropping the benefit growth rate by one percentage point. These analyses revealed a decrease of approximately $167,000 and $146,000, respectively, in 10-year PV terms.

On the positive side, decreasing the discount rate by one percentage point leads to an increase in total benefits over the 10-year lifespan of the battery of approximately $180k. Increasing the yearly benefit growth rate by one percentage point has an increase of about $157,000 over the base case. The last sensitivity analysis showed that increasing the useable life of the battery to 20 years by conducting major maintenance in years 7 and 14 and replacing the battery module in year 11 leads to an increase of $866,178 in PV terms compared to the base case.



	SA1: Ratepayer Impact	SA2: Vary Discount Rate +/- 1%	SA3: Vary Growth Rate +/- 1%	SA4: 20-year Life
Low-End	$(1,367,519)	$(167,873)	$(145,674)	
High-End		$180,517	$157,397	$866,178

Figure 8.8. PSE Sensitivity Analysis Results

Table 8.11 presents the ROI ratios for the various scenarios defined as part of the sensitivity analysis. When the cost estimates presented by PSE are used in the denominator of the ROI calculations, all of the examined scenarios yield ROI ratios that fall short of 1.0, meaning that PV benefits fail to exceed PV costs. The only scenario that begins to approach an ROI of 1.0 is the scenario in which outage mitigation benefits were included and the grant was also included to offset costs, giving an ROI of 0.84. The second highest value was that of the 20-year battery analysis, which yielded a 0.64 ROI.

Table 8.11. Return on Investment Ratios for Alternative Scenarios

	Base Case	Outage Mitigation Included	+1% Discount Rate	-1% Discount Rate	+1% Growth Rate	-1% Growth Rate	20-Year Life
Base Case	0.43	0.84	0.41	0.45	0.45	0.41	0.64
Grant Excluded	0.26	0.52	0.25	0.28	0.28	0.25	0.48

8.3 SnoPUD MESA 1 and MESA 2

8.3.1 Project Costs and Financial Parameters

Given that the CEF is a matching grant program, a portion of the costs of the project are directly incurred by SnoPUD. Table 8.12 shows the itemized cost component breakdown for the MESA

1 & 2 Energy Storage Project. Note that a $500,000 grant for controls development was broken out proportionally between MESA 1 and MESA 2.

Note that unlike the Avista or PSE energy storage projects, the SnoPUD MESA battery systems are not expected to generate outage mitigation. Both BESSs are located at substations and there is no current capacity to isolate feeders to mitigate outages.

Table 8.12 Estimated Costs for the SnoPUD MESA 1 and MESA 2 Energy Storage Project

Item	Cost	MESA 1	MESA 2	WA CEF
Engineering Costs w/ Overheads	1,354,116	1,354,116		
Construction	576,487	576,487		
Equipment and Material	275,681	275,681		
Site Construction w/ tax	269,285	269,285		
Equipment, Installation, and Commissioning	13,541,274	2,173,911	4,067,363	7,300,000
Site/Civil Prep	686,327		686,327	
Project Management	50,920		50,920	
Engineering Design	201,202		201,202	
Line Reclosers and System Interconnection	430,328		430,328	
Labor Overhead	331,930		331,930	
Overheads	1,622,592		1,622,592	
Total	**$19,340,142**	**$4,649,480**	**$7,390,662**	**$7,300,000**

For energy storage to be cost competitive, its benefits must not only exceed its costs, but all associated revenue requirements, including all taxes and debt payments must also be considered. A detailed pro forma for the BESS was prepared to estimate revenue requirements. Major parameters used in the pro forma are presented in Table 8.13.

Table 8.13. Major Parameters Used in Estimating BESS Revenue Requirements

Parameter	Value	Source
Lithium-ion Energy Storage Book Life	13 years	Lithium-ion Battery Proposal
Redox Flow Energy Storage Book Life	20 years	UET Battery Proposal
Lithium-ion Annual Battery O&M	$60,000	Lithium-ion Battery Proposal
Redox Flow Annual Battery O&M	$200,000	UET Battery Proposal
O&M Escalation Rate	3.0%	SnoPUD
Insurance Rate	0.07%	SnoPUD
Privilege Tax Rate[(a)]	2.14%	SnoPUD
After-Tax Weighted Cost of Capital	4.2%	SnoPUD

(a) SnoPUD pays a privilege tax in lieu of a property tax

Based on the combination of costs and assumptions outlined previously in this section, PNNL was able to produce revenue requirements that accounted for full system costs, including all taxes, debt, and insurance costs.

8.3.2 Evaluation of Project Benefits and Revenue Requirements

Data for the years 2011 through 2018 was available for SnoPUD. For this reason, those years were individually run using BSET for the use cases presented previously. The results of these individual evaluations are presented in Table 8.14 below.

Table 8.14 SnoPUD Use Case Value for Modeled Years 2011-2018

	2011	2012	2013	2014	2015	2016	2017	2018
Arbitrage	-$2,622	-$5,220	-$10,522	-$8,295	-$8,172	-$8,509	$304	-$1,798
BPA Balancing	$22,326	$14,106	$12,359	$19,794	$8,009	$7,650	$22,073	$20,862
Demand Response	$52,864	$54,411	$55,278	$56,151	$56,101	$56,871	$58,293	$59,500
Capacity	$44,306	$44,306	$44,306	$44,241	$44,306	$44,306	$44,306	$44,306
Total	**$116,875**	**$107,603**	**$101,421**	**$111,892**	**$100,244**	**$100,318**	**$124,976**	**$122,870**

To calculate the total 20-year value for the MESA 1 and MESA 2 systems, the values from the 2011-2018 modeled years were individually adjusted to 2018 values using the BLS Consumer Price Index and then averaged to form the base year, 2018 value. From there the results were cast out 20 years, subject to growth rates based on the Mid-C price index and then discounted back to PV terms.

From this analysis, it was found that battery benefits for the base case ($1.97 million) fall significantly short of meeting costs ($18.29 million) for the MESA 1 and MESA 2 BESS projects (Figure 8.9 and Table 8.15). Overall, this produces an ROI ratio of 0.11 under the base case. Of the benefits included in the base scenario, the most valuable application is demand response, which generates just over $1.02 million in PV benefits. The second highest value application is capacity at approximately $761k. BPA load balance provides just over $289k, and arbitrage provides the lowest value overall at -$103 thousand in PV terms. This negative amount results from all charging costs being embedded in arbitrage. Thus, if the BESS is charging to reduce balancing costs, all charging costs are debited to arbitrage. Arbitrage in this case is effectively the value of any energy sold into the Mid-C market minus the costs of energy used for any purpose. Despite this value being negative, the overall $1.8 million is the optimally generated value when all use cases are considered.

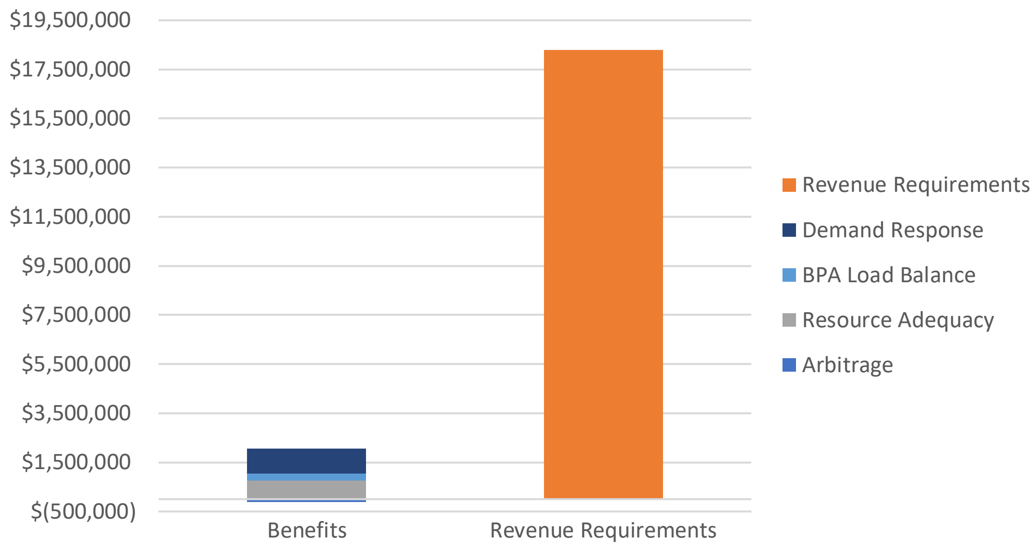


Figure 8.9 SnoPUD 20-year Present Value Costs vs. Revenue Requirements

Table 8.15 SnoPUD Benefits Estimates by Use Case vs. Revenue Requirements

Element	Benefits	Revenue Requirements
Arbitrage	-$102,823	
BPA Load Balance Reduction	$289,470	
Capacity / Resource Adequacy	$760,968	
Demand Response	$1,021,924	
Total	**$1,969,540**	**$18,282,512**

Figure 8.10 shows the percentage breakdown of each use case generating positive benefits.

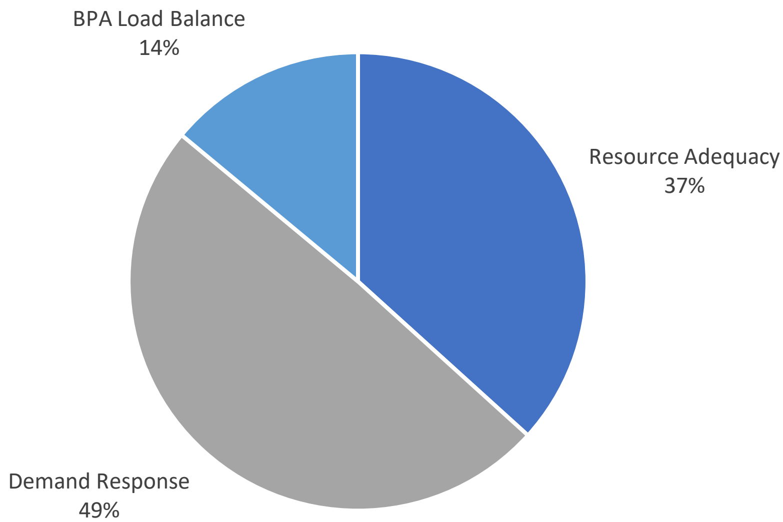


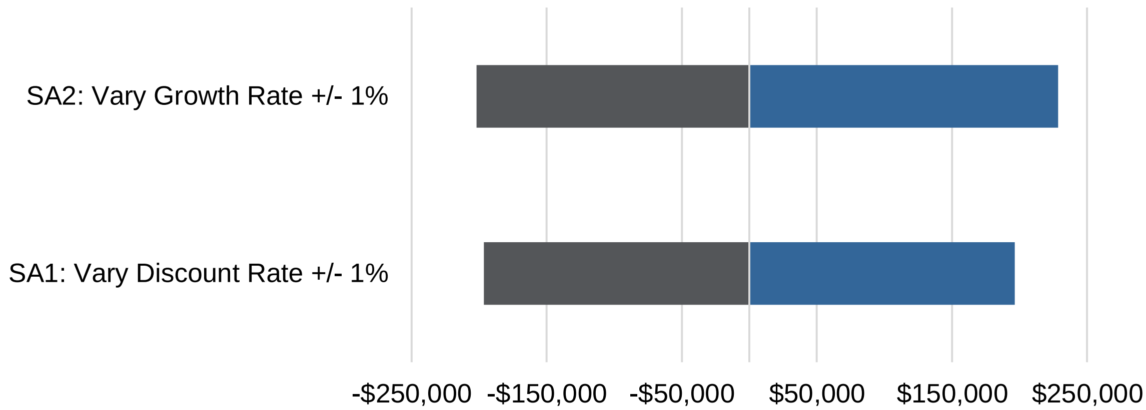
Figure 8.10 SnoPUD MESA 1 and MESA 2 Percentage Values by Use Case

8.3.3 Evaluation of Alternative Scenarios and Sensitivity Analysis

A variety of analyses were conducted to explore the sensitivity of the results to changes in key assumptions and parameters. These scenarios and their impacts are outlined below as measured in comparison to the base case. The following adjustments to the assumptions were made:

- SA 1: +/- 1% Discount Rate Used
- SA 2: +/- 1% Benefit Growth Rate Used

The results of each sensitivity analysis are presented in Figure 8.11. Note the table that appears below the figure. As shown, the changes in discount rate and growth rate used account for impacts on both the benefit and cost side of the analysis. The ROIs for each of the scenarios are presented in Table 8.16.



	SA1: Vary Discount Rate +/- 1%	SA2: Vary Growth Rate +/- 1%
High-End	$196,387	$228,612
Low-End	$(196,267)	$(202,089)

Figure 8.11 SnoPUD Sensitivity Analysis Results

Table 8.16 SnoPUD Return on Investment Ratios for Alternative Scenarios

	Base Case	+1% Discount Rate	-1% Discount Rate	+1% Growth Rate	-1% Growth Rate
Base Case	0.11	0.09	0.13	0.12	0.10
Grant Excluded	0.08	0.06	0.09	0.09	0.07

8.4 Comparison of Results

This section aims to provide a comparison of the final economic results of each CEF round 1 project.

Figure 8.12 shows a comparison of the stacked use cases and revenue requirements for each project side by side. Of the three projects, the PSE Glacier Project has the highest return under the base case; however, the Avista Pullman project has the highest return when customer benefits are included in the analysis. Note again that benefits calculated for the Avista Pullman project are based on the battery system tested by PNNL. That system later became non-operational and was subsequently removed from the SEL site. Overall, SnoPUD MESA 1 and MESA 2 show the lowest return with the lowest amount of co-optimized benefits in total and the highest cost at just over $18 million with grant funds included. It should be noted that, for Avista, given that the ADSS model estimated benefits for regulation and arbitrage as a single use case, their value was split equally for graphical representation here.

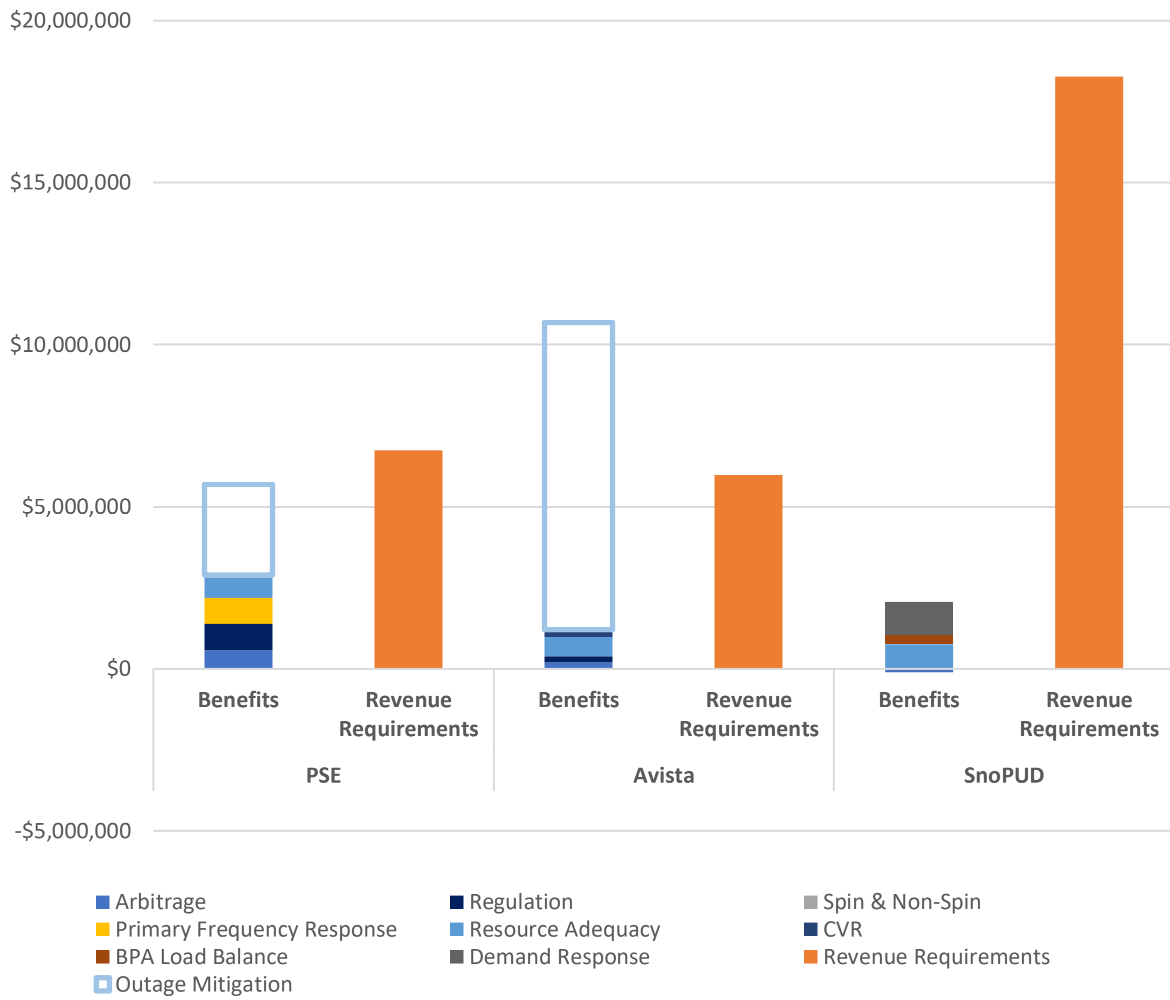


Figure 8.12 Comparison of Final Results of CEF 1 Projects

Figure 8.13 shows a comparison of each use case in $/kW with the averages laid across. Outage mitigation, at an average of $5,444/kW between the two projects, is not included in the chart in order to better differentiate between the other benefits. The chart shows that regulation has a similar total value for both the PSE and Avista projects. BPA load balance and CVR show the lowest benefits across all three projects. Just as in the last chart, the values for arbitrage and regulation for Avista have been formed by their combined benefit being divided in half.

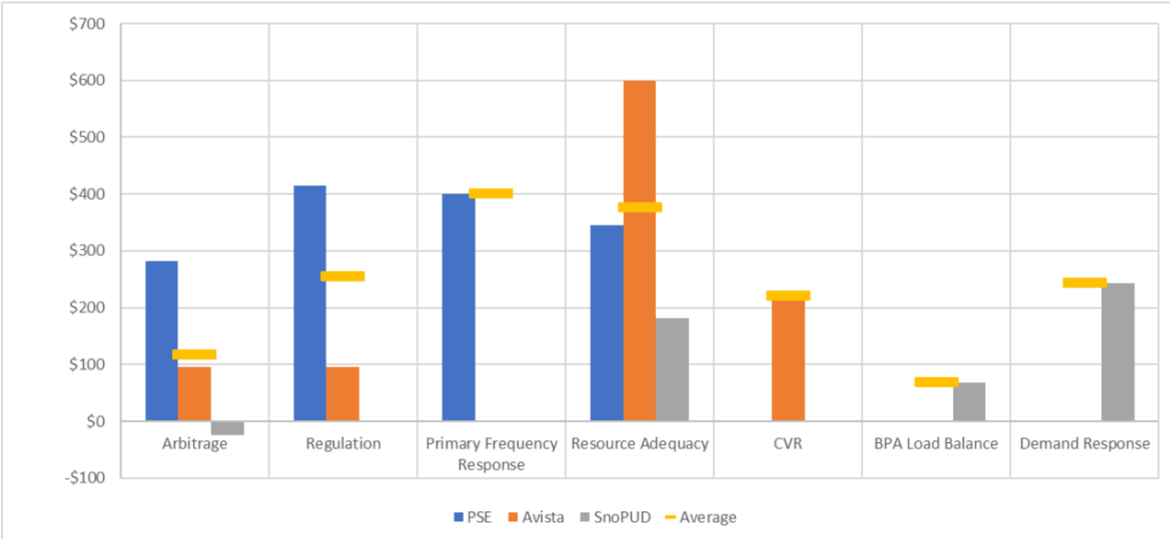


Figure 8.13 Comparative $/kW Use Case Value by Project, Outage Mitigation Not Included

9.0 MESA Standardization

9.1 Background

Due to their relative nascence as grid assets, large-scale BESSs do not have a set of industry-wide standards for utilities to rely upon. For the technology to be deployed widely and effectively, it needs to be organized on a scale that can be implemented quickly without the need for new research and engineering with each installation. The MESA alliance's purpose is to eliminate the need for project-specific energy storage solutions and customized systems by establishing a non-propriety set of standards and specifications in order to accelerate the adoption of energy storage onto the grid.

The SnoPUD CEF energy storage project is one of the first to be based on MESA. The MESA architecture was originally developed by SnoPUD in coordination with 1Energy but is now managed independently (SnoPUD 2017).

The MESA specifications were developed to promote scalable energy storage that can provide cost and time saving benefits to the industry. Its key goals include:

- Developing a standardized communication specification for energy storage systems;
- Expediting the development and industry deployment of BESSs;
- Enabling technology suppliers to focus on their core competency rather than a multitude of protocols;
- Providing electric utilities with their preferred SCADA protocol of distributed network protocol (DNP3);
- Reducing project-specific engineering costs; and,
- Reducing training costs and improve safety for field staff (MESA 2018).

There are three MESA device standards for energy storage: Energy Storage, Power Meter, and PCS. The standards are driven by SunSpec alliance models for the three systems. Figure 9.1 below shows an overview of MESA specifications in which the gray portions were developed by MESA and SunSpec and components in orange were developed by MESA Alliance (MESA 2018).

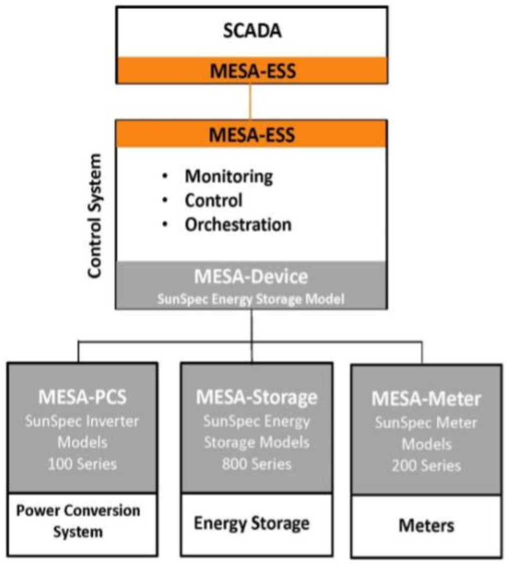


Figure 9.1. Overview of MESA Specifications

The MESA-Storage standard is the SunSpec Alliance Energy Storage Model and can be used to describe the base requirements for any storage technology including PV systems with energy storage. The MESA standards are based upon SunSpec models (MESA 2014). SunSpec models are used by software developers, hardware manufacturers, and integrators for a “plug-and-play” interoperability between grid applications and batteries (SunSpec 2019).

The communication standards for MESA were developed so that each component of the three required (battery, meter, and inverter) can communicate through a controller. In addition, the BESS must communicate with both the operational technology (OT) of electricity grid infrastructure, as well as the IT part of the grid. BESS-Devices standards connect BESSs to substation and distribution automation, relays and smart meters, or the OT portion of the grid. IT standards allow communication between distribution management systems, SCADA, as well as market trading and power scheduling applications (MESA 2014).

Two sets of standards are developed to communicate between the BESS and the electricity grid, one each for OT and IT. The MESA device standards use Modbus tcp protocol, and to a certain extent the DNP3 protocol. The MESA-ESS standards for IT connections specify how the energy storage system components will communicate with the utilities’ grid control and power scheduling systems and use the DNP3 protocol (MESA 2014).

MESA standards will directly relate to the International Electrotechnical Commission (IEC) 61850 standard for DER type even though the draft standard indicates that the coordination with IEC is still underway. For example, the battery type maps to ZBAT in IEC 61850 as does voltage. DC charge current and DC discharge current nearly map to ZBAT values (MESA 2014).

9.2 The Value of MESA Standardization

With so few projects currently built to MESA standards and utility-scale battery storage only recently taking off, the way the economic benefits of MESA are evaluated and quantified will evolve as data for these projects becomes more readily available. This section will first discuss the direct benefits to project developers. It will conclude with a section that provides an overview of benefits to the industry as a whole.

9.2.1 Direct Benefits to Storage Developers

SnoPUD has implemented the MESA standard within the MESA 1 and MESA 2 projects and will use it in the future for a third project (MESA 3). PNNL surveyed the utility for estimated savings experienced due to MESA standards in terms of percentages of both time and cost for different components of their project development (SnoPUD 2019).

Percentages were used in place of hours saved or dollars saved for three primary reasons:

1. The savings from MESA standardization are based on the projections for a project that is currently under development and its scale is currently unknown;
2. These percentages can be applied to known costs for other estimations; and,
3. Percentage estimates were simpler for SnoPUD when comparing past to current projects.

The sections that follow include a breakdown of benefits that have been found for the different aspects of implementing a standardization technique collected from industry and literature. Where SnoPUD was able to provide a cost and/or time reduction percentage, the value is included. These values are also summarized later in Table 9.1.

9.2.1.1 Conceptualization

Conceptualization is defined as the process consisting of generating the idea to install a battery through exploring its potential configurations. It may also include research and development efforts, as well as the time and labor necessary to request and evaluate proposals from battery manufacturers. A standardized system may streamline this step by reducing the cost of innovation, research, and the need for a battery system that is specific to a site. A “plug and play” system would allow a developer to forgo a vast number of hours spent towards this component of battery development.

According to SnoPUD, implementing MESA reduced their electrical design conceptualization stage by 50% in both time and cost to complete. This reduction in time/cost is dependent on the system’s customization requirements. Additionally, MESA allows them to meet the communication interface requirements, which are pre-defined and which all battery systems must meet.

9.2.1.2 Siting and Permitting

A comparison between the costs and time associated with acquiring a permit for a project with and without the standards should be performed to evaluate this category. The implementation of standards should streamline the process since processing authorities will become familiar with the specifications of the systems and how they are interconnected over time. However, literature from the solar industry suggests that the permitting processes currently in place for energy storage systems could negate any value generated from standards implementation.

In line with these suggestions, SnoPUD reported that permitting is still subject to the local planning department associated with the location of the BESS and for this reason the MESA standard has no expected benefits in this subcategory directly to them.

9.2.1.3 Installation and Commissioning

According to Mackiewicz (2006), before plug and play standards were developed, power system engineers needed to manually configure substation components and map them to index numbers, low-level register numbers, and I/O modules each time a new device was installed. With the introduction of the standard, a model was developed that indicated how each device should organize data and the process was consistent across all devices. In the case of substation standards, having a substation configuration language allowed offline development tools to generate configuration files automatically, which reduces labor associated with manual configuration. The files can also be shared with other suppliers, further reducing inconsistencies. Because all the components are defined with standard definitions, the standards lower installation costs, commissioning costs, and lower equipment migration costs.

Labor time for manually mapping system communications and labor time for installing a project with MESA standards are utilized to determine the associated costs. If data is incomplete or unavailable for projects with MESA standards, a progress ratio could also be utilized. For each time the number of installations double, a learning curve or progress ratio could be used to determine the labor to install and commission. Assumptions would need to be made regarding improvements based on non-standardized installations.

SnoPUD has estimated that the MESA standard reduces the time for BESS commissioning by 50%.

9.2.1.4 Engineering, Procurement, and Construction

Engineering, procurement, and construction consists of efforts made to bring a BESS project online and into operation. Less time and effort are expected to be needed for engineering design of the systems that are standardized and modular. More to that effect, standardized systems will require less effort to prepare technical specifications for procurement of system components and less costly construction and system integration as a result.

SnoPUD estimated that engineering costs and time would be reduced by 25% while procurement of equipment would see a cost reduction between 25-50% but no time reduction. The reduction in time for engineering will depend on the customization required for the project. Procurement timing is based on the lead time necessary for large utility equipment and is only manufactured once an order has been placed. For this reason, standardization may have little to no impact on timing. Lastly, construction is expected to see 10% time and cost reductions due to standardization.

9.2.1.5 Testing

Labor time for manually testing the system and labor time for testing a project with MESA standards are utilized to determine the associated costs. Alternatively, if the values are unknown for testing the BESS with a standard, then the values of labor over time associated with testing labor could be estimated using a progress ratio. For each time the number of installations double, a learning curve or progress ratio could be used to determine the labor to test. Similar to installation and commission cost reductions, reduced testing cost would also drive increased installations of batteries.

According to SnoPUD, applying the MESA standard is not expected to have any direct impact on the cost of testing but will have an impact on the timing. It is projected that for the factory acceptance test, which tests whether the battery has been built to design specifications, will take 15-20% less time. Acceptance testing, which tests the system for compatibility and compliance, will also be reduced by 15-20%.

9.2.1.6 Quality and Quality Assurance and Reliability

The value of quality and quality assurance with regards to implementation of standards is determined through the long-term frequency of rework for faulty installations. A comparison should be made between the number of components that are rejected between projects that were built to MESA standards and those that were not. Because the standards would reduce the costs of rework, the value of the reduced rework would be a range of reduced costs for rework over time.

Reliability is the percent of the time the BESS is available for operation. Some anecdotal evidence indicates that plant availability can be increased with standardization. One study in Thailand indicated with introduction of standards, plant availably increased from 94% to 99.66% (ISO 2013).

An analysis of the battery's availability is used to determine the effect that the MESA standards have on battery reliability. Comparing the available time of the battery for projects with and without the MESA standard provides a range of increased or decreased reliability. If the battery is available more often and can provide services to the electric grid, there is an opportunity for increased revenue.

SnoPUD predicts that including standards will reduce costs associated with this category by approximately 5%.

9.2.1.7 Operation and Maintenance and Upgrades

To determine if there is a benefit associated with maintenance and upgrades when MESA standards are implemented, the labor associated with maintaining and upgrading BESS projects over the course of their lives is evaluated. The costs of hazards and safety may be incorporated into this category as well. The total cost of an electrical accident as calculated by the Occupational Safety and Health Administration would total $190,000. The direct costs are over $90,000 and indirect costs are over $100,000. In addition, to maintain the companies' profits (at a 3% profit margin), the company would need $6.5 million in increased sales to cover the loss (Ruttenberg 2013). The key is to estimate how many accidents the standards would reduce over specified lifetime of the standard and the quantity of BESS installations over that period.

Overall, it is expected by SnoPUD that the time spent conducting O&M on a battery system will be 10% lower than if no standard was in place. Costs are expected to reduce by an even greater amount between 10-15%.

9.2.1.8 Decommissioning

The decommissioning stage of a battery involves all steps and procedures to successfully take the asset offline. This could include recycling or disposing of components as necessary or as possible. Standardization could streamline this process or introduce more opportunity for parts to be recycled into systems following the same or similar standards. SnoPUD has estimated that the MESA standard will not provide any cost or time benefits for this category, however.

9.2.2 Summary Results

Table 9.1 shows a summary of the effects described in the previous subsections that the MESA standard is expected to have on an energy storage development by SnoPUD. Actual values may differ as the MESA 3 project moves forward and as the industry continues to develop.

Table 9.1. Summary of Time and Cost Reduction Percentages from MESA Standardization

Component	Reduced Time to Complete	Reduced Cost to Complete
Electrical Design	50%	50%
Engineering	25%	25%
Equipment Procurement		25-50%
Construction	10%	10%
Factory Acceptance Test	15-20%	
Commissioning	50%	
Acceptance Testing	15-20%	
Quality/Quality Assurance & Reliability		5%
Operations & Maintenance	10%	10-15%

9.2.3 Industry Benefits

Beyond the direct benefits of utilizing a standard to a specific project, there are additional benefits that can be realized across the industry as a whole. While difficult to quantify directly, these can be discussed qualitatively.

The following list provides some of the conceptual benefits of standardization to the industry:

- **Job Creation:** Standards provide significant macroeconomic impacts in terms of job creation. For example, energy efficiency standards for U.S. appliance, equipment, and lighting have generated about 340,000 jobs through 2010. The macroeconomic effects occur because reduced expenditures in the electric utility industry shifts jobs to sectors where job intensity is higher (Gold et al. 2011). Blind et al. (2011) indicated that macroeconomic impacts of standardization have provided a boost 0.7-0.8% to gross domestic product in Germany and France while it has been much lower in Canada and the UK with a range of 0.2-0.3% added to gross domestic product.
- **Increased Trade:** Econometric evidence indicates that increased standardization in Europe increased trade. The study indicates that while standards could provide negative impacts, the empirical evidence indicates that standards increase trade. The study indicated that trade increased 4.7 times when Europe implemented a set of standards. The path to increasing trade through standardization occurred because of lower transactions costs and the compatibility of parts (ISUG 2002). The ISUG study also noted the impact on costs due to increased competition through standards showing the costs of simple parts dropping by ½ to $^{1}/_{125}$ of the original costs. The standard is the basis for quality control and assurance systems. For batteries, the effects ratio is 49:1 after standardization. The effects ratio is how much price fell from pre-standardization to post standardization. Newer industries have a higher ratio (10:1-20:1) than more mature industries (7:1). They note the typical effects ratio is 5:1.

- **Promotion of Innovation:** A study of companies pre-categorized into innovators, follower innovators, and novel innovators indicated the more innovative a company was, the more they used standards. Novel companies were about 2.5 times more likely to use standards than those categorized as non-innovative (ISUG 2002). The ISUG study notes how hard it is to predict the impact of standardization. For example, Organization for Economic Co-operation and Development indicates that calculating the impacts on non-tariff trade barriers is complex and requires a significant amount of information.
- **Increased Competition:** By assuring availability of multiple sources for nearly identical products (Tilton 2010), competition is fostered, driving down prices. More to that effect, standardized communication interfaces provide for more alternatives and thus more competition which drives prices down (MESA 2014). A range analysis could be used to estimate the value of the competitiveness. Historical evidence indicated costs decline from ½ to $^{1}/_{125}$ of the original cost due to competitiveness.
- **Increased Environmental Benefits:** To the extent that standardization reduces the cost of BESSs and increases the quantity of BESSs installed, the net benefits of reduced emissions through reducing the amount of time that peaking plants operate could be evaluated. The difference in the quantity of emissions with and without standards needs to be quantified and the discounted PV of the reduced emissions calculated. The estimate would reflect reduced emissions from reduced peaking plants, reduced congestion, and time shifting of increased renewables which will also reduce electricity grid emissions.

Overall, standards have the potential to improve both project cost and execution time, particularly in efforts that are recurring or would otherwise require extensive research and development for project developers. MESA, and other standards like it, can also help wide-scale adoption with less investment in the long run. The benefits to each stage of development, from conceptualization through decommissioning, differ both in cost and time saved. According to the SnoPUD, savings ranged from 10-50% in reduced time and 5-50% in reduced costs. For energy storage systems which are costly investments typically, this can lead to substantial amounts (millions of dollars and months of time). These savings and benefits may also continue to develop and advance as standards are implemented across a wider proportion of the industry. Industry-wide benefits as a whole are more difficult to quantify compared to the direct project benefits. However, whether it is increased competition in storage development or promoting environmental benefits in the long run, there are additional benefits to standardization to those experienced directly by project developers.

10.0 Conclusions

This assessment examined the economic viability of three Washington CEF projects—PSE's Glacier Energy Storage Project, Avista's Turner Energy Storage Project, and SnoPUD's MESA 1 and MESA 2 Energy Storage Project. The analysis involved the monetization of values derived from several services the storage systems could provide to each of the utilities and the customers they serve. The batteries and the grid conditions in which they operate were modeled and optimization tools were employed to explore tradeoffs between services.

The Washington State CEF provided $14.3 million toward the deployment and demonstration of energy storage in an effort to explore the role storage could play in Washington State and the value storage could deliver to Washington State's utilities and to its citizens as consumers and workers. The first round of the Washington CEF projects is comprised of five battery systems located at three utilities. Avista Utilities deployed a 1 MW / 3.2 MWh vanadium-flow battery system in Pullman, Washington. PSE deployed a 2 MW / 4.4 MWh lithium-ion/phosphate BESS at a substation in Glacier, Washington. SnoPUD deployed two 1 MW / 500 MWh lithium-ion battery systems at a substation in Everett, Washington. At another substation in Everett, SnoPUD deployed a 2.2 MW / 8.0 MWh vanadium-flow battery built by UET. The installation and operation of the battery systems for SnoPUD was part of a multi-year effort to transform how the utility manages grid operations through the advancement of the MESA alliance.

PNNL was enlisted by the Washington State Department of Commerce and DOE to design an assessment framework for the demonstration that is based on a consistent set of use cases and measurements during the demonstrations that does not constrain, but rather enhances, the diverse scope of applications for energy storage. The results of this analysis provide critical insights into the practical application of the energy storage projects installed and the following lessons were drawn from this analysis:

1. Based on the design and cost documents prepared by each utility, all three BESS projects fail to generate positive net benefits under the base case scenario.
2. When outage mitigation is included as a benefit, both the Avista Turner Energy Storage Project and the PSE Glacier Energy Storage Project see an increase in benefits. Under this scenario, however, only the Avista project returns a positive ROI. The high return for Avista is due to the large benefit of mitigating voltage sags for SEL—a very high cost issue that the battery system was capable of mitigating. Modeling conducted for this assessment indicates that all voltage sag-created outages occurring to SEL can be mitigated with the BESS. The facility contains sensitive manufacturing processes which are prone to power quality disturbance related interruptions. The interruptions lead to significant financial damage as there is a minimum of three hours of downtime for the facility. The benefit of avoiding these outages is approximately $150,000 per hour to SEL and nearly $9.5 million over the life of the battery in total. Note that while the BESS demonstrated the capacity to provide this benefit, since testing was completed it became non-operational and has been removed from the SEL site. For Glacier, the outage mitigation benefit derived from the benefit seen by customers residing in the core downtown area who can be successfully islanded in the event of a power loss incident to the town.
3. The voltage analyses presented within this report supports the idea of mitigating voltage sags using fast real/reactive power control of the BESS. PNNL analyzed voltage sag data from 2014-2017 provided by SEL. Applying the CBEMA defined power quality curve, over 40 voltage sag events (<70% in voltage magnitude, >20 millisecond in

duration) were identified by PNNL and this result matches the findings of SEL's power quality monitoring system.

4. After all testing was completed for the PSE, SnoPUD MESA 1, and SnoPUD MESA 2 BESSs, nonlinear SOC models were developed and used in economic modeling and to aid in developing power profiles for future testing. The purpose of the SOC models is to come up with a form for describing how the SOC changes with time, allowing for more complete and accurate representation within battery modeling.

5. Information collected from SnoPUD indicated that there is a wide range of benefits that can be derived from using the MESA alliance standards for a BESS project. Of the affected categories, electrical design yields the highest overall benefit with a 50% reduction in both time to complete and cost to complete. Equipment procurement and commissioning are also expected to experience a large benefit from standardization with a 25-50% cost reduction, and 50% time reduction, respectively. Other factors involved in the installation and operation of a battery system saw between a 5% and 25% time and/or cost reduction.

6. Sensitivity analysis results showed a range of both positive and negative results compared to the base case. Several scenarios were examined to determine the sensitivity of results with respect to varying a small number of key parameters for each project. For the PSE project, incorporating societal benefits and costs led to a lower return for PSE as removing the grant funds led to a large decline in net benefits even when outage mitigation was included. For Avista, the large benefit from including outage mitigation for SEL far outweighed the negative effect introduced by removing the grant funds. Also, on the positive side, extending the PSE analysis from a 10-year battery to a 20-year battery with major maintenance and upgrade costs incorporated led to an increase in benefits. All sensitivity analysis scenarios for SnoPUD and the remainder of the analyses for PSE and Avista had little impact on the overall return of each project.

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