PNNL-33107

Avista's Shared Energy Economy Model Pilot

A Techno-economic Assessment

July 2022

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Pacific Northwest National Laboratory
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Executive Summary

Avista Utilities is an operating division of Avista Corporation, providing electricity to 402,000 customers and natural gas to about 369,000 customers across 30,000 square miles in eastern Washington, northern Idaho, and parts of southern and eastern Oregon, with a population of 1.5 million. In 2017, as part of the second round of the Clean Energy Fund (CEF) program[1] administered by the Washington State Department of Commerce, Avista received a $3.5 million matching grant in support of a shared energy economy model pilot project to demonstrate and test the integration of energy assets–from rooftop solar and battery storage to building energy management systems–that can be shared and used for multiple purposes. Partners in the model pilot include Washington State University (WSU), McKinstry, Schweitzer Engineering Laboratories, Spirae, Itron, and Pacific Northwest National Laboratory. The goal is to demonstrate how both the customer and the utility can benefit from this shared energy economy model and demonstrate that the electric grid can become more reliable, efficient, resilient, and flexible.

The shared energy economy model consists of two battery energy storage systems (BESSs), two rooftop photovoltaic (PV) systems, and flexible building loads with advanced building management systems on the Spokane Health Sciences Campus. Both BESSs are Li-ion batteries, one rated at 500 kW/1506 kWh and the other rated at 168 kW/335 kWh for a combined total of 668 kW/1841 kWh. The two rooftop PV systems are identical, each rated 100 kW. Through proper coordination and control, these distributed energy resources (DERs) will allow for high-value applications intended to benefit the utility and the customer they serve, including:

- Utility applications for Avista[2]
  - Resource adequacy
  - Energy arbitrage
  - Ancillary services including frequency response, regulation, load following, and contingency reserve

- End-user applications for WSU
  - Energy charge reduction
  - Demand charge reduction
  - Demand response
  - Resilience improvement

A critical aspect of the joint analytic work is to develop sets of analytic assumptions for these applications that correspond to planned or potential changes in the retail tariff and/or wholesale market. This project focuses more on end-user applications than grid applications, which have been extensively studied in previous CEF projects,[3] including the Avista Turner energy storage project. This report documents the techno-economic assessment methods and results for the

[1] Washington State Department of Commerce, Clean Energy Fund Grid Modernization Program, https://www.commerce.wa.gov/growing-the-economy/energy/clean-energy-fund/energy-grid-modernization/

[2] Energy storage can also provide other grid services, including critical infrastructure upgrade deferral and volt/var management. The first one is not applicable in this project as there is sufficient feeder capacity compared to the projected load growth. The second one is excluded because there are limited economic benefits from volt/var management considering other low-cost alternatives.

[3] Balducci, P. J., K. Mongird, J. E. Alam, D. Wu, V. Fotedar, V. V. Viswanathan, A. J. Crawford, Y. Yuan, G. Labove, S. Richards, X. Shane, and K. Wallace 2020, October. Washington Clean Energy Fund Grid Modernization projects: Economic analysis (final report). Technical Report PNNL-30594, Pacific Northwest National Laboratory.

shared energy economy model. The following key lessons and implications can be drawn from the analysis.

1. The total benefits of the shared energy economy model from applications in grid-connected mode are about one third of the total cost in the base scenario. The investment is not cost-effective for applications considered in grid-connected mode. Among all applications, demand charge reduction offers the most value and ancillary service offers the least value, representing 31% and 3% of the total benefits, respectively.

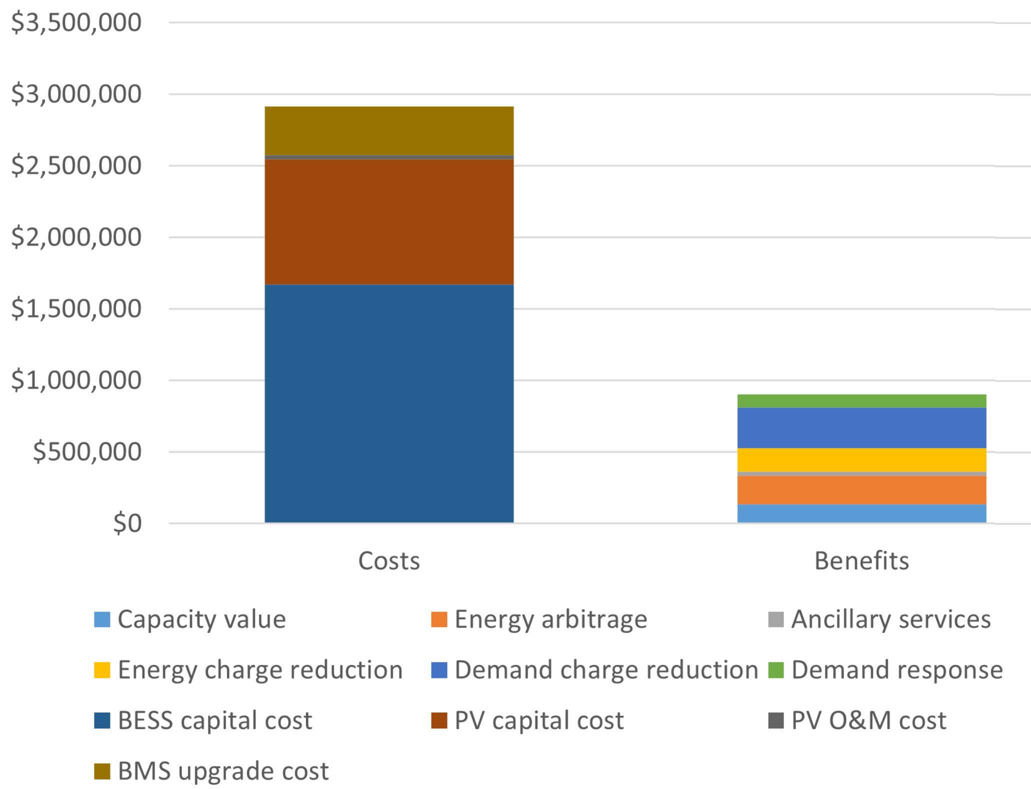

Figure ES.1. Present value costs vs. benefits in the base scenario.

2. The shared energy economy model generates positive net benefits in a low-cost and high-benefits scenario. In this scenario, BESS and PV capital costs are reduced to reflect the latest technology and some value streams are increased to reflect the growing need for flexibility in the evolving power grid. In particular, the BESS and PV costs are reduced by 30% from the base scenario. The BESS capacity credit is increased to 65% and ancillary service value is increased to $47/kW-yr. It is also assumed that demand response program is offered 8 months a year instead of the 2 summer months.

3. The shared energy economy model can be operated as an islanded microgrid to mitigate impacts of outages from the main grid and thereby reduce the cost of outages. Outage mitigation is often the most valuable use case. The exact economic benefits depend on numerous factors, such as region, number of outages per year, starting time and duration of outages, and number and type of customers being affected. The dollar value is often difficult to quantify and is not as tangible as other use cases. In this project, due to lack of historical outage information and specific outage cost, resilience is not treated as a monetary value

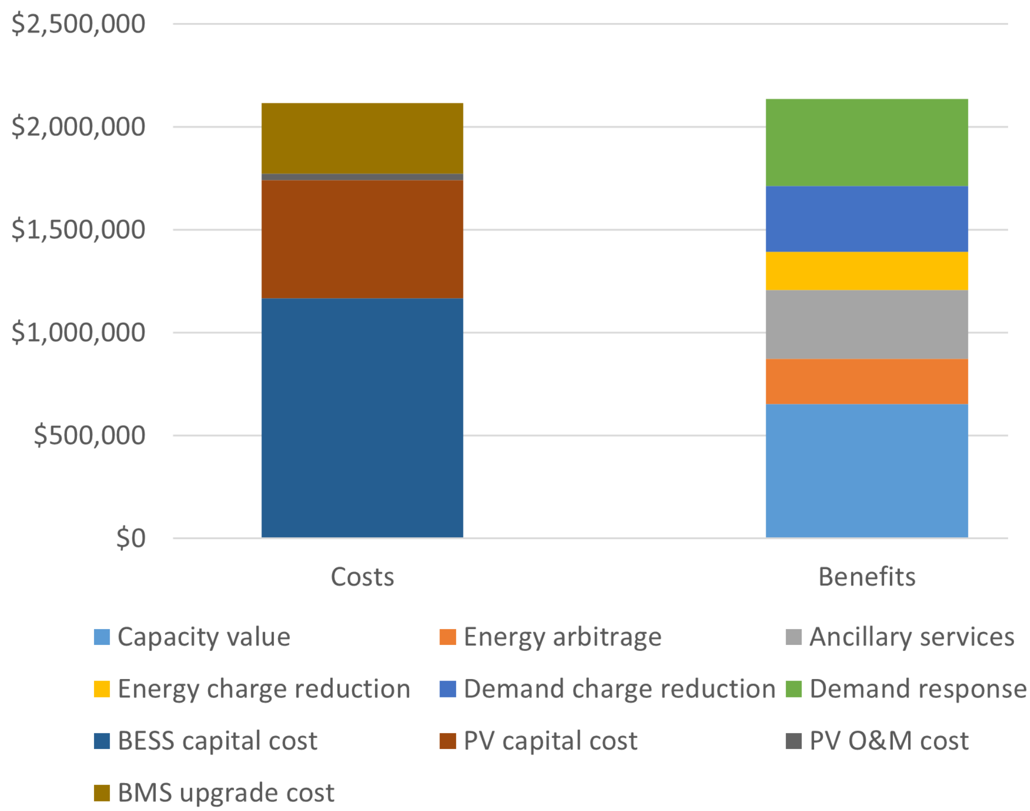

Figure ES.2. Present value costs vs. benefits in a reduced cost and increased benefit scenario.

stream but is quantified using survivability, which is defined as the probability that the system can survive a random outage.

4. With the shared energy economy model, the survivability is above 20% for outages with a duration of 2–8 hours with a random state of charge when an outage occurs. For 2-hour outages, the survivability is 80% in winter and 60% in summer. When energy storage assets are fully charged as an outage occurs, the survivability is significantly improved, especially in non-summer months. The chance to survive an outage with a duration of 4 hours or less is above 90% in non-summer months. Load shedding and/or additional DER capacity are required to further improve resilience.

5. The proposed framework and assessment results in this work not only enhance the understanding of how both Avista and a customer can benefit from this shared energy economy model, but are also useful for other utilities that are interested in this kind of model to make the electric grid more reliable, efficient, resilient, and flexible.

6. Because the BESS and PV in this project are front-of-meter assets owned and operated by Avista, the actual customer bills are not impacted by BESS and PV. In the real world, when a utility and a customer co-develop a shared energy economy model, they may want to operate energy assets differently to maximize their own benefits. Coordinating energy assets to improve one party’s benefits may compromise the other one’s benefits. One interesting area of future work is to develop advanced methods to effectively explore different coordination strategies to optimally utilize the energy assets considering the different allocation of benefits

between the two parties, and to support decision-making by finding the preferred Pareto optimal solution according to subjective preferences.

Acknowledgments

We are grateful to Dr. Imre Gyuk, Director of Energy Storage Research in the Office of Electricity at the U.S. Department of Energy, Mr. Bob Kirchmeier, former Program Manager for the Clean Energy Fund (CEF) Grid Modernization Program, and Mr. Jeremy Berke, Senior Commerce Specialist and Program Manager for the CEF Grid Modernization Program at the Washington State Department of Commerce. Without their organizations' financial support and their leadership, this project would not be possible.

Acronyms and Abbreviations

ADS	Anchor Data Set
BESS	battery energy storage system
BMS	building management system
BTM	behind-the-meter
CCRS	Center for Clinical Research and Simulation
CEF	Clean Energy Fund
DER	distributed energy resource
DR	demand response
DX	direct expansion
ESS	energy storage systems
HSB	Health Sciences Building
HVAC	heating, ventilation, and air conditioning
IRP	Integrated Resource Plan
MPPT	maximum power point tracking
O&M	operations and maintenance
PNNL	Pacific Northwest National Laboratory
PV	photovoltaic
SOC	state of charge
VAV	variable air volume
VB	virtual battery
WECC	Western Electricity Coordinating Council
WSU	Washington State University

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CHAPTER 1

Introduction

The Washington State Clean Energy Fund (CEF) is a publicly funded program administered by the Washington State Department of Commerce. The CEF provides grants in support of the development of clean energy technologies in Washington state. Since 2013, the Washington State Legislature has authorized $122 million for the fund (Kirchmeier, 2018), including Energy Revolving Loan Fund Grants, Smart Grid and Grid Modernization Grants to Utilities, Federal Clean Energy Matching Funds, and Credit Enhancement for Renewable Energy Manufacturing. Additional information on the CEF and the Grid Modernization Program can be found in Washington State Department of Commerce (2017, 2021). To date, CEF funds have been distributed to electric utility companies, vendors, universities, and research organizations for projects that integrate intermittent renewables, improve grid reliability, expand grid modernization activities, reduce the costs associated with distributed energy resource (DER) deployments, and lower emissions.

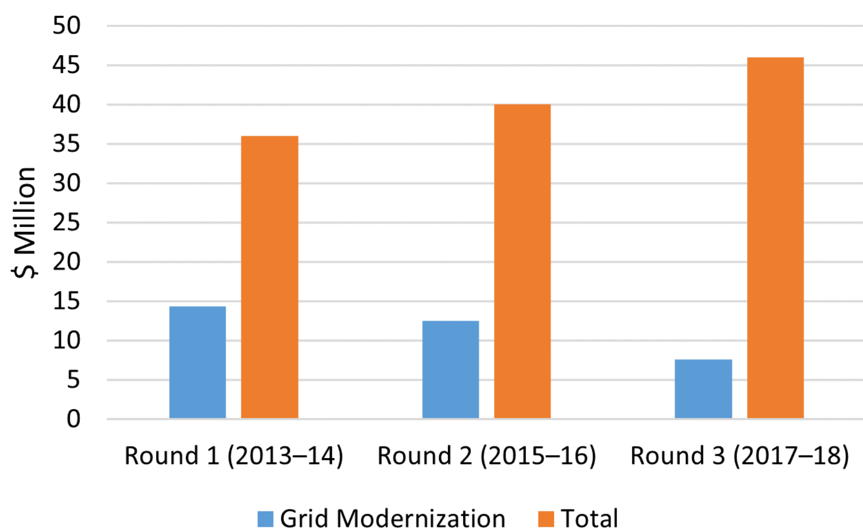


Figure 1.1. Washington Clean Energy Fund funding levels.

In 2017, as part of the second round of CEF, Avista Corp received a $3.5 million matching grant in support of a shared energy economy project to test the integration of energy assets–from rooftop solar and battery storage to building energy management systems–that can be shared and used for multiple purposes. The goal of this project is to demonstrate how both the customer and the utility can benefit from this shared energy economy model and demonstrate that the electric grid can become more reliable, efficient, resilient, and flexible. The specifications of the shared energy economy model include two battery energy storage systems (BESSs) (500 kW/1506 kWh and 168 kW/335 kWh) and two 100-kW rooftop photovoltaic (PV) units connected to two buildings with advanced building management systems (BMSs) on the Spokane Health Sciences Campus, as shown in Figure 1.2.

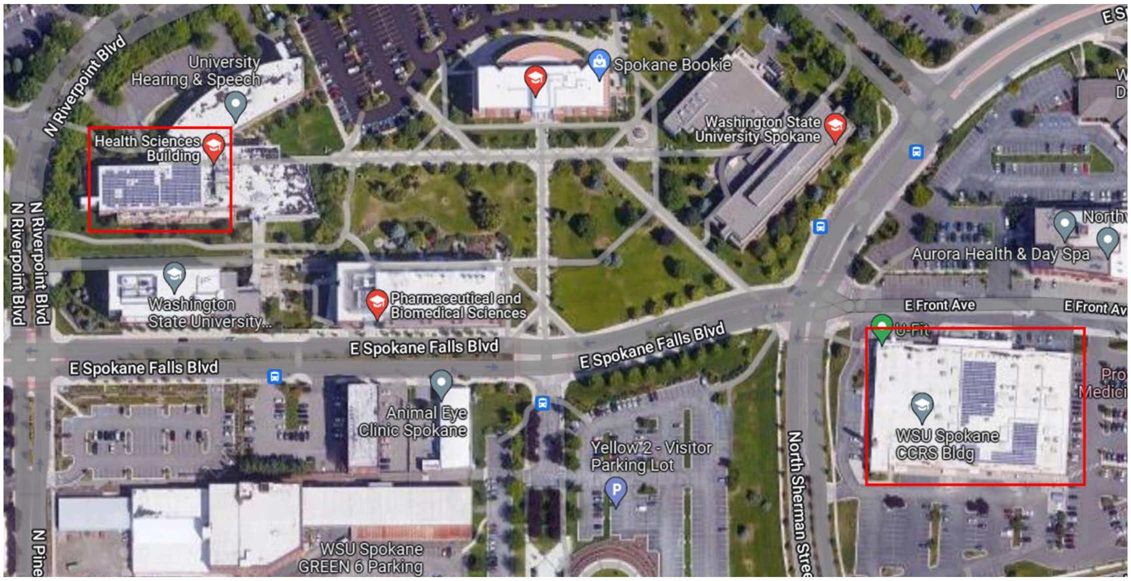


Figure 1.2. Two buildings on Spokane Health Sciences Campus with advanced building management systems, PV, and BESS.

Pacific Northwest National Laboratory (PNNL) was engaged by the U.S. Department of Energy and Avista to assess the benefits of the shared energy economy model. This report documents the techno-economic assessment of the shared energy economy model, including the definition of use cases and applications, collection and preparation of data and input parameters, development of modeling and optimization methods, and case studies and analysis results.

CHAPTER 2

System Configuration and Use Cases

There are numerous factors that affect the assessment of the shared energy economy model. The cost and benefits highly depend on system design and configuration, including operational characteristics and physical capabilities of individual components, deployment options and use cases, grid infrastructure and operational cost, as well as distribution system capacity and load growth rate. This chapter details system configuration and use cases for the techno-economic assessment of the shared energy model.

2.1 System Configuration

The shared energy model is illustrated in Figure 2.1. The U.S. Department of Energy defines a microgrid as “a group of interconnected loads and DERs with clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and can connect and disconnect from the grid to enable it to operate in both grid-connected or island modes” (Ton and Smith, 2012). With the capability to form a microgrid, these DERs not only can generate economic benefits by providing grid and/or behind-the-meter (BTM) services in grid-connected mode under normal conditions, but can also improve system resilience by enabling islanded microgrid when a power outage occurs. Individual components and their specifications are described as follows.

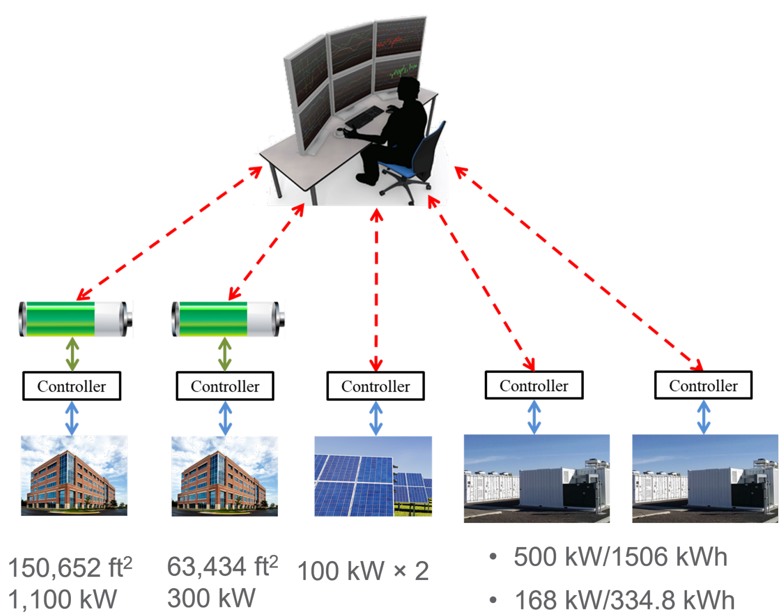


Figure 2.1. Illustration of energy assets in the shared energy economy project.

2.1.1 Battery Energy Storage Systems

The two BESSs are Li-ion nickel manganese cobalt produced by Samsung SDI. Manufacturer information and parameters are listed in Table 2.1. Note that for BESS 1, while the battery rated power is 756 kW, the inverter rated power is only 500 kW. As a result, the system charging/discharging power is limited to 500 kW. The recommended state of charge (SOC) range for both BESSs is 5-95%. The round trip efficiency is 94.5%. The performance guarantee ensures at least 85% of rated energy capacity can be discharged at the rated power at the end of 5 years, with one full cycle (based on the total energy throughput) per day on average. Note that the performance guarantee has a 5-year period, but there is a 13-year maintenance and warranty agreement for the system. The investment cost is $1.67 million, including both installed cost and operations and maintenance (O&M) costs.

Table 2.1. BESS Chemistry, Manufacturer, and Parameters

	BESS 1	**BESS 2**
Battery cell and management system	Samsung SDI	Samsung SDI
Inverter manufacturer/model	EPC PD500	EPC PD250
Inverter AC voltage (Volt)	480 3PH	480 3PH
Site controller	ELM Fieldsight	ELM Fieldsight
AC power rating (kW)	756 (500)*	168
AC energy rating (kWh)	1506	334.8

* BESS 1 is limited to 500 kW by inverter capacity.

2.1.2 Photovoltaic Systems

The two 100-kW PV units are identical—REC TwinPeak 2S 72 Series solar panels with SMA Sunny Tripower inverter. The total installed cost is $1.075 million, which is higher than industry average because the provision for any work with Washington state funding is required to pay prevailing wage. In addition, the work to install the solar was sub-contracted to a solar installer, and the main contractor who Avista hired charged a percentage of the dollar value of the work as their fee. The estimated annual O&M cost is $3,000. The economic life is about 20 years. Locational normalized PV generation profiles are generated for the Spokane Health Sciences Campus using the pvlib library (Holmgren et al., 2018), which is a community-supported tool for simulating the performance of PV systems. The required input parameters of pvlib include PV module and inverter parameters, PV installation parameters, as well as parameters that depend on weather conditions. All input parameters except the ones depending on weather conditions are deterministic and can be specified based on selected models. The parameters such as hourly clear sky global horizontal irradiance, direct normal irradiance, ambient temperature, and wind speed are generated using a stochastic model with historical weather data from National Solar Radiation Database (Wilcox, 2012) as inputs.

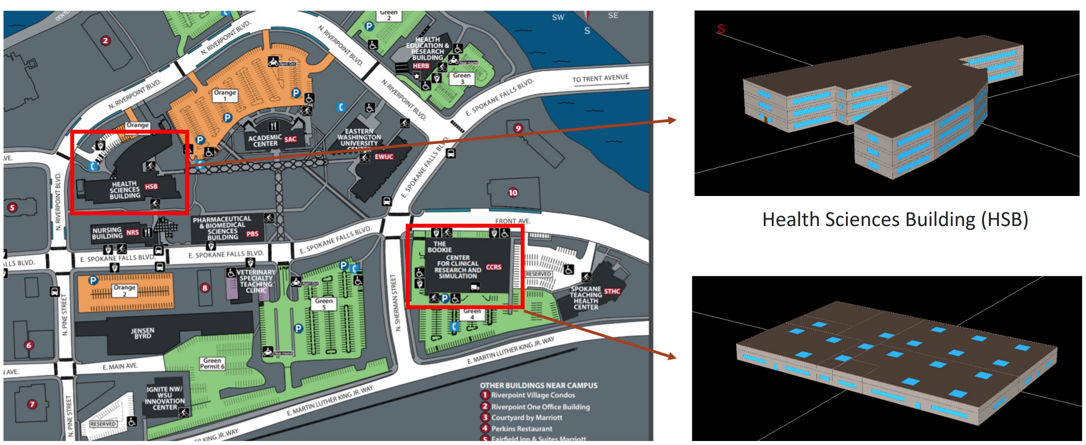
2.1.3 Flexible Building Loads

We considered two buildings in this study: the Health Sciences Building (HSB) and the Center for Clinical Research and Simulation (CCRS). Both buildings are located on the Washington State University (WSU) Spokane Campus. The site view and building geometry of the two buildings are provided in Figure 2.2.

- HSB is a mixed-use building with a floor area of 150,652 ft^2 for office and laboratory. The peak power demand is around 1,100 kW. It is served by a variable air volume (VAV) system with a rated power of 800 kW to supply conditioned air to rooms in the building with supply fans. Electric-powered chillers and gas-powered boilers are employed to provide cooling and heating energy, respectively. The supply air flow rate of the VAV system is modulated to maintain the zonal temperature around the setpoint under varying thermal loads.

- CCRS is a laboratory building with a floor area of 63,434 ft^2. The peak power demand is around 300 kW. It is served by a rooftop direct expansion (DX) system with a rated power of 263 kW. The cooling and heating energy are mainly provided by DX coils. Under extreme weather conditions, furnaces are used as auxiliary heating devices. DX coils are switched on and off to maintain the zone temperature around the setpoint.

In this project, the BMS was upgraded to enable the control and monitoring of the buildings' mechanical and electrical equipment, such as heating, ventilation, and air conditioning (HVAC) systems, fire systems, and security systems. The associated upgrade cost is $342 thousand. For HSB, electric heating is much smaller than gas heating. The electric heating in CCRS is also small compared with the total load of the two buildings. In addition, flexibility is most valuable during summer peak hours. Therefore, in this analysis, only the HVAC load in cooling mode in summer months is modeled and assessed.



Health Sciences Building (HSB)

Washington State University, Spokane Campus

Center for Clinical Research and Simulation (CCRS)

Figure 2.2. Two building assets on the Spokane campus of Washington State University.

2.2 Use Cases

Energy storage systems (ESSs) including BESSs and flexible building loads as storage assets paired with PV can be used to provide a broad range of grid and end-user services. PNNL has developed an energy storage valuation taxonomy that includes bulk energy, ancillary, transmission, distribution, and customer energy management services (Balducci et al., 2018). The potential use cases and applications vary by stakeholder and typically require different modeling and solution methods (Wu and Ma, 2021). In this project, PNNL has worked with Avista to identify a list of high-value applications intended to benefit Avista and/or WSU.

The utility applications for Avista include capacity and resource adequacy, energy arbitrage, and ancillary services, including frequency response, regulation, load following, and contingency reserve. Note that energy storage and flexible building loads can also provide other grid services, including critical infrastructure upgrade deferral and volt/var management. The procedure to estimate the value of critical infrastructure upgrade deferral using energy storage can be found in Wu et al. (2022). The application is excluded in this analysis as there is sufficient feeder capacity compared to the projected load growth. Volt/var management using energy storage is excluded because there are limited economic benefits from volt/var management considering other low-cost alternatives.

Because the BESS and PV are front-of-meter assets owned and operated by Avista, the actual customer bills are not impacted by BESS and PV. Nevertheless, one main objective of this project is to understand how these DERs can benefit end-users in scenarios where they are deployed as BTM assets Therefore, four end-user services are also studied, including energy charge reduction, demand charge reduction, demand response (DR), and distribution resilience. Each of these applications is briefly described as follows.

2.2.1 Utility Applications for Avista

- Capacity value to meet resource adequacy
  An important issue in power system planning is to ensure sufficient resources to meet future demand, either through capacity markets or integrated resource planning. Capacity is not actual electricity, but rather the ability to produce electricity in future years. While dispatchable generators can be controlled to respond to varying demand, there could be generator outages due to mechanical failures and planned maintenance or unexpected high demand, leaving a power system with insufficient capacity to meet the load. The two BESSs can be used to provide peaking capacity since they are flexible and can be quickly dispatched with a high ramp rate to meet peak demands. While PV assets are not as dispatchable as conventional generators, they also contribute to system capacity. The corresponding economic rewards are capacity payments for market participants or capacity charge reduction in a market environment or through bilateral contracts. For vertically integrated utilities, the economic benefits are the savings from replacing or reducing the need for new peaking resources.

- Energy arbitrage
  Energy arbitrage or energy shifting refers to the operation of energy storage that generates electricity when the demand and/or electricity prices are high and consumes electricity when the demand and/or prices are low. Both BESSs and flexible building loads can be used for energy arbitrage. The energy arbitrage analysis in this project also includes the energy production from PV, which is assumed to be operated in the maximum power point tracking (MPPT) mode. Note that storing PV energy in BESSs and building thermal mass during low price/cost periods for later use is also captured in this use case. The operation can be performed in an electricity market to pursue revenue from energy trading or in a vertically integrated utility to reduce production cost. The economic reward is the price or cost differential between charging and discharging electrical energy, considering losses during charging

and discharging. For flexible building loads, it is also important to model heat leaking effects for energy arbitrage.

- Ancillary services (frequency response, regulation, load following, and contingency reserve)

  The electric power system must maintain a near-real-time balance between generation and load. Balancing generation and load instantaneously and continuously is difficult because loads and generation are constantly fluctuating. Frequency response is one of the important reserve services used by grid operators to uphold steady frequency, and is called in response to a system contingency that leads to a decline in frequency. Frequency regulation is required to continuously balance generation and load within a control area and thereby maintain system frequency and to manage differences between actual and scheduled power flows between control areas. Frequency regulation is the most valuable ancillary service. To provide regulation services, energy storage needs to respond rapidly to system-operator requests for up and down movements by following automatic generation control signals. Contingency or operating reserves are called to restore the generation and load balance in the event of a contingency such as a sudden, unexpected loss of a generator. Any resource that can respond quickly and long enough can supply contingency reserves. The economic benefits from ancillary services can be defined based on ancillary service prices in electricity markets or reduced costs of operating generators in vertically integrated utilities.

  Note that with deloading control, PV deviates from the MPPT to preserve reserve power during steady state and contributes to system inertia following a disturbance. However, such a control strategy is sub-optimal for energy production. Flexible building loads are technically capable of providing ancillary services, but require communication infrastructure and advanced controllers to receive and follow grid control signals. Such capability is not deployed yet. Therefore, ancillary services from PV and flexible building loads are excluded from this analysis.

In this analysis, the results from the 2021 Avista Electric Integrated Resource Plan (IRP) (Kalich et al., 2021) are used to estimate the capacity value for BESS and PV and ancillary services for BESS. The IRP looks 24 years into the future to determine the energy needs of customers, and evaluates several different generation, storage, and hybrid solar/storage supply-side resource options to meet future resource deficits.

Energy arbitrage benefits are estimated based on energy prices obtained using ABB GridView and Western Electricity Coordinating Council (WECC) Anchor Data Set (ADS) 2030, which provides the best available projection of new generation, generation retirements, transmission assets, and load growth in the 10-year planning horizon within the WECC grid planning community. WECC ADS 2030 provides a detailed representation of the power grid topology, including about 22,000 nodes and 26,000 transmission lines in 37 balancing authorities in WECC.

2.2.2 End-user Applications for WSU

- Energy charge reduction

  Energy charge is based on the amount of energy consumed and the time when energy is consumed. It reflects the operational cost of electricity generation and delivery. Energy production from BTM PV reduces an end-user’s energy consumption and energy charge. Energy storage and flexible building loads can be used for energy shifting to take advantage of time-of-use tariff structures. Other bill components such as transmission charge depend on the energy consumption during specific hours that are given or can be forecasted. Such kinds of charges can also be captured by adding the corresponding rates to the energy charge rate to generate a lumped “energy” charge rate.

- Demand charge reduction

  Demand charge is based on the maximum power consumption and during certain times on weekdays and weekends within a billing period (typically a month). It is mainly designed to recover the investment in electricity generation and transportation infrastructure. Typically, demand charge only applies to medium and large commercial and industrial customers. Separating demand charge from energy charge helps fairly distribute power system’s operation and investment cost to customers. Energy storage, PV, and flexible building loads can be used to lower the peak load and thereby reduce demand charge.

- Demand response

  Energy storage and flexible building loads may participate in a utility’s DR program, which compensates customers for curtailing their energy use when the demand is forecasted to be at its peak. A participating customer would be compensated for the amount of energy curtailed on a pay-for-performance basis. The rules and incentives vary by DR program. Energy storage and flexible building loads can adjust their power output relative to a baseline calculated by the applicable program administrator.

- Resilience improvement

  Resilience is a system’s ability to prepare for and adapt to changing conditions and to withstand and recover rapidly from deliberate attacks, accidents, or naturally occurring threats or incidents (Anderson et al., 2017). Resilience has become a high priority for federal, state, and local governments, and is moving into the industrial and commercial sectors. With the development and advancement of renewable generation and energy storage, their deployment in distribution systems has increased considerably in recent years (Horowitz et al., 2019). These emerging DERs not only provide economic benefits, but also strengthen the resilience of distribution systems and reduce power interruptions of critical facilities (Parhizi et al., 2015). Increasing attention is being given to the use of distributed renewable generation and/or energy storage in addition to conventional distributed generators for cost-effective and resilient system operation, magnitude of affected load, and/or duration of interruption. In many existing studies, such as Wu et al. (2015) and Alsaidan et al. (2018), distribution resiliency is modeled in a simple manner where financial losses are expressed as a function of unserved energy and then included in the objective function. The same formulation for economic analysis of DERs is used to capture resilience. Resilience or outage mitigation is often the most valuable use case. The exact economic benefits depend on numerous factors, such as region, number of outages per year, starting time and duration of outages, and number and type of customers being affected. The dollar value is often difficult to quantify and is not as tangible as other use cases. In practice, it is difficult for a facility manager or system operator to quantify the value of resilience and estimate the cost associated with an outage occurring at different times with different durations and magnitudes. More importantly, economic and resilience performance are two different metrics. Resilience performance and requirements, in general, cannot be fully captured as a monetary value. An improved method is required to simultaneously model economic and resilience performance of the shared energy economy model without simply treating resilience as another monetary value stream in conventional economic analysis.

Avista’s Schedule 21 Large General Service tariff in Washington state (Avista, 2021) is used to calculate the energy and demand charge and estimate economic benefits of the energy assets for bill reduction. The monthly energy consumption is charged based on a two-tier rate structure: 7.535 cents per kWh for the first 250,000 kWh and 6.742 cents per kWh for additional energy consumption. The demand charge consists of fixed charge and variable charge: $550 for the first 50 kW or less and $7 per kW for each additional kW of demand. If customers have reactive kilovolt-ampere meters, they are also subject to a power factor adjustment charge, which is not considered in this analysis. The tariff structure is illustrated in Figure 2.3.

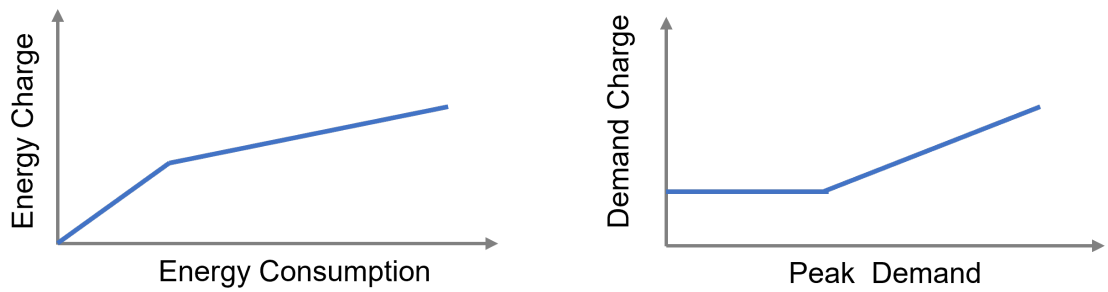


Figure 2.3. Illustration of Avista's Schedule 21 Large General Service tariff.

DR is not currently offered by Avista, but Avista is considering a DR program that is similar to Idaho Power Flex Peak (Idaho Power, 2021). The program offers cash incentives to commercial and industrial customers who can reduce their electric load when summer demand for energy is high or for other system needs. The program operates in the summer months. The exact DR start and end dates, time window, notification time in advance, and incentive rates vary by year, although the DR structure remains the same. For example, the DR program operates from June 15 to August 15, 2021. Three events is the minimum that will occur during the season from 2 p.m. to 8 p.m., Monday through Friday. Events last between 2 and 4 hours, and customers are notified 2 hours before each event. Incentive payments consist of a fixed payment and a variable payment. The fixed payment is $3.25 per kW per week. Customers will get paid this amount even for weeks when an event is not called, up to their nominated amount. For weeks when an event is called, customers will receive the $3.25 payment based on the amount of actual kW reduction achieved during the event. The variable payment is $0.16 per kWh. This amount is only provided after the first four events of the season and is based on the amount of kW reduced during the event, multiplied by the length of the event in hours. For simplicity, this analysis assumed that Avista's DR program is the same as Flex Peak except that only fixed payment is offered and all DR events last for 4 hours.

For resilience assessment, historical outage information is not available. Therefore, survivability is estimated for random outages that are characterized by duration and season.

CHAPTER 3

Modeling and Evaluation Methods

Economic and resilience benefits of the shared energy economy model highly depend on the technical characteristics and physical capabilities of individual energy assets. Appropriate models need to be developed and used to capture the characteristics and capabilities with a good balance between fidelity and simplicity. This modeling and analysis in this project leverage PNNL's capabilities developed in previous projects. including BESS and PV models developed in previous CEF projects and virtual battery (VB) models (Wu et al., 2020) for flexible building loads in previous building-to-grid integration projects. The VB model is a scalar linear system that models the inherent ability of buildings to store heat in thermal mass, vary their power consumption, and shift electric energy consumption to an earlier or later time, subject to customer requirements for comfort and convenience.

A microgrid can be operated in grid-connected mode under normal conditions and island mode during an outage. In grid-connected mode, the energy assets are optimally coordinated to provide grid or end-user services to maximize the economic benefits. During an outage, a microgrid is operated in island mode and all DERs are used to meet the demand from the two buildings. The following sections present the modeling methods for individual energy assets as well as optimal dispatch and assessment methods.

3.1 Modeling of Individual Energy Assets

3.1.1 PV

PV hourly energy output is capped at the hourly energy in MPPT mode:

$$0 \le p_{i,t}^{\text{pv}} \le r_{i,t}^{\text{pv}} P_i^{\text{pv}}, \quad \forall i \in \{1,2\}, \forall t, \tag{3.1}$$

where $p_{i,t}^{\text{pv}}$ is the power output from PV i at time step t, $r_{i,t}^{\text{pv}}$ is the normalized power output in MPPT mode from PV i at time step t, and P_i^{pv} is the rated power of PV i.

3.1.2 Battery Energy Storage System

The dynamics of a BESS i can be expressed as

$$e_{i,t+1}^{\text{batt}} = e_{i,t}^{\text{batt}} - \Delta e_{i,t}^{\text{batt}}, \quad \forall i \in \{1,2\}, \ \forall t \tag{3.2a}$$

where $e_{i,t}^{\text{batt}}$ is the energy state of BESS i at the beginning of time step t, and $\Delta e_{i,t}^{\text{batt}}$ is the change of energy stored in BESS i at time step t (discharging if positive), which can be expressed as

$$\Delta e_{i,t}^{\text{batt}} = \begin{cases} p_{i,t}^{\text{batt}} \Delta T / \eta_i^{\text{dis}} & \text{if } p_{i,t}^{\text{batt}} \ge 0 \\ p_{i,t}^{\text{batt}} \Delta T \eta_i^{\text{chg}} & \text{if } p_{i,t}^{\text{batt}} < 0 \end{cases}, \quad \forall i \in \{1,2\}, \forall t, \tag{3.2b}$$

where $p_{i,t}^{\text{batt}}$ is the BESS power at the point of coupling, ΔT is the time step size, and η_i^{dis} and η_i^{chg} are the discharging and charging efficiencies, respectively. The BESS power output is limited by rated power, while the energy state is constrained by SOC limits and energy capacity:

$$-P_i^{\text{batt}} \le p_{i,t}^{\text{batt}} \le P_i^{\text{batt}}, \quad \forall i \in \{1,2\},\ \forall t\,, \tag{3.2c}$$

$$s_i^{\text{min}} E_i^{\text{batt}} \le e_{i,t}^{\text{batt}} \le s_i^{\text{max}} E_i^{\text{batt}}, \quad \forall i \in \{1,2\},\ \forall t\,, \tag{3.2d}$$

where P_i^{batt} is the rated power of BESS i, E_i^{batt} is the energy capacity of BESS i, and s_i^{min} and s_i^{min} are the minimum and maximum SOC limits, respectively. The boundary SOC condition equations are omitted here to conserve space.

3.1.3 Flexible Building Loads

Flexible building loads represent a significant but largely untapped resource that can greatly enhance the flexibility and reliability of power systems (Wu et al., 2018; Huang et al., 2020). Detailed dynamic models and various operational constraints at the device level can be used to coordinate flexible building loads with BESS and PV units. However, such methods are computationally expensive and inefficient yet unnecessary for coordinating building devices with other DERs and transmission-level assets (Wang et al., 2021). Therefore, simplified models are desired to represent the aggregate flexibility from building loads at a level of detail adequate for utility planning and regulatory consideration purposes. In this work, the aggregate flexibility of individual buildings is characterized and modeled using the VB method (Wu et al., 2020), leveraging PNNL's load modeling capabilities developed in previous building-to-grid integration projects.

The VB model is a scalar linear system that resembles simplified battery dynamics parameterized by charging/discharging power limits, energy limits, and self-discharging rate, as given in (3.3):

$$e_{i,t+1}^{\text{vb}} = (1-\alpha) e_{i,t}^{\text{vb}} - p_{i,t}^{\text{vb}} \Delta T, \quad \forall i \in \{1,2\},\ \forall t \tag{3.3a}$$

$$\underline{P}_{i,t}^{\text{vb}} \le p_{i,t}^{\text{vb}} \le \overline{P}_{i,t}^{\text{vb}}, \quad \forall i \in \{1,2\},\ \forall t \tag{3.3b}$$

$$\underline{E}_{i,t}^{\text{vb}} \le e_{i,t}^{\text{vb}} \le \overline{E}_{i,t}^{\text{vb}}, \quad \forall i \in \{1,2\},\ \forall t \tag{3.3c}$$

where $p_{i,t}^{\text{vb}}$ is the charging/discharging power of VB i at time step t, $e_{i,t}^{\text{vb}}$ is the energy state, α is the self-discharging rate, $\underline{P}_{i,t}^{\text{vb}}$ and $\overline{P}_{i,t}^{\text{vb}}$ are power limits, and $\underline{E}_{i,t}^{\text{vb}}$ and $\overline{E}_{i,t}^{\text{vb}}$ are energy limits. Reserve marge can be introduced in the power and energy limits to improve control performance when frequency regulation from VB is considered. In VB model, the charging/discharging power corresponds to the deviation of total power consumption from the baseline, the energy state corresponds to the average energy state of the HVAC load, and the self-discharging rate captures the leaking energy. This model captures the inherent ability of buildings to store heat in thermal mass, vary their power consumption, and shift their electric energy consumption to an earlier or later time, subject to customer requirements for comfort and convenience.

Unlike a BESS for which power and energy limits are given parameters, the power and energy limits of VB are time-varying and need to be estimated considering numerous factors, including resource type, building floor areas, thermal parameters such as thermal resistance and capacitance, and external drivers (e.g., ambient temperature, water draw, and usage patterns). Simulation-based (Huang et al., 2020) and optimization-based methods (Hao et al., 2018) can be used to estimate VB parameters for commercial buildings. In this work, VB parameters were estimated using the simulation-based method through EnergyPlus™, which is a whole building energy simulation program that engineers, architects, and researchers use to model both energy consumption—for heating, cooling, ventilation, lighting, plug and process loads—and water use in buildings (Department of Energy, 2022). It provides an integrated and simultaneous approximation of thermal zone conditions and HVAC system response, and heat balance-based solution of radiant and convective effects. Detailed methodology for modeling building energy consumption in EnergyPlus™ can be found in Fumo et al. (2010).

We first obtained building models from McKinstry Consulting in the format of eQuest, which is a freeware building energy use analysis tool that provides professional-level results with an affordable level of effort. eQuest models were converted into EnergyPlus™ models so that we could modify the thermostat settings in runtime. All model parameters were extracted from eQuest, including building geometry, envelope thermal, schedules, and internal heat gains. Only the HVAC systems were modeled from scratch in EnergyPlus™.

The baseline power was first estimated with the existing supervisory control. The feasible power consumption range was then estimated by simulating a building by setting zone temperatures to the maximum or minimum of the deadband around the desired temperature. For example, to obtain the maximum (or minimum) power consumption during the period from 13:00 to 13:30, the zone temperature setpoint remains the same before 13:00 and is increased (or decreased) by 2°F for that period. With two simulations per period, 96 simulations are needed to repeat the same process for all half-hour periods throughout the day. It was found that with the cooling temperature setpoint adjusted by 2°F, the change in HSB cooling load is up to 380 kW (increased) and 300 kW (decreased), representing an operating range of 62.5–147.5% of the baseline power. The change in CCRS cooling load is up to 25 kW in both directions, representing an operating range of 90–110% of the baseline power.

3.2 Optimal Dispatch and Assessment Methods

3.2.1 Grid-connected Mode

The energy assets in the shared energy model can be dispatched differently in grid-connected mode, depending on the objective function. In this work, we evaluated the economic benefits in different scenarios: i) maximize benefits from grid services for Avista and ii) maximize benefits from end-user services for WSU.

3.2.1.1 Utility Applications for Avista

Capacity credit needs to be estimated to quantify the economic benefits of BESS and PV for resource adequacy. Capacity credit can be estimated based on loss of load probability analysis (Sioshansi et al., 2014). The required inputs include system load profile and generation fleet information. Due to the lack of the required information, the capacity value for BESS and PV is calculated based on the results of the 2021 Avista Electric IRP (Kalich et al., 2021). The capacity credit for a 4-hour BESS and PV are 15% and 2%, respectively. With an estimated levelized cost of $140/kW-yr for a reciprocating engine facility, the corresponding capacity values for BESS and PV are around $21/kW-yr and $2.8/kW-yr, respectively.

The 2021 Avista IRP results were also used to estimate the benefits of BESSs for ancillary services, including frequency response, regulation, load following, and contingency reserves. Avista must hold a 24 MW frequency response to provide instantaneous response to correct system frequency variations. Avista is also required to hold capacity to help control intermittent resources and load variance and hold generating reserves of 3% of load and 3% of online generation. The aggregate value was estimated to be $4.74/kW-yr for a lithium-ion BESS.

To estimate energy arbitrage benefits, the energy prices are obtained using ABB GridView and WECC ADS 2030 (the latest WECC version). With the energy price λ_t, the optimization problem $\mathbf{P}_{\text{grid}}$ was formulated and solved to optimally dispatch the energy assets and assess the corresponding benefits from energy arbitrage:

$$
\begin{aligned}
\mathbf{P}_{\text{grid}} : \max \quad & \sum_t \left(\lambda_t \sum_i \left(p_{i,t}^{\text{batt}} + p_{i,t}^{\text{pv}} + p_{i,t}^{\text{vb}} \right) \right) \\
\text{subject to} \quad & \\
\text{PV:} \quad & (3.1), \\
\text{BESS:} \quad & (3.2), \\
\text{Flexible HVAC loads:} \quad & (3.3).
\end{aligned}
$$

The objective function and all constraints in $\mathbf{P}_{\text{grid}}$ are linear except the conditional expression in (3.2b). One common method to work around this is to introduce two non-negative auxiliary variables representing charging and discharging power and thereby capture losses associated with charging and discharge separately. Simultaneous charging and discharging leads to "fictitious" consumption of energy in a BESS with non-ideal efficiencies. These kinds of solutions are physically unrealizable. To address this problem, studies such as Fang et al. (2016) and Correa-Florez et al. (2018) introduce binary variables to avoid charging and discharging at the same time. An alternative method is to add complementarity constraints where the product of charging and discharging power at any time must be equal to zero, as shown in Fang et al. (2018). Therefore, the formulation in Wu et al. (2016) is used in this analysis.

3.2.1.2 End-user Applications for WSU

To optimally coordinate the energy assets to minimize the electricity bill for an end-user through mathematical programming, the energy charge, demand charge, and DR need to be expressed as functions of power output from individual energy assets. The net load L_t^{net} can be expressed as

$$
L_t^{\text{net}} = L_t - \sum_{i=1}^{2} \left(p_{i,t}^{\text{batt}} + p_{i,t}^{\text{pv}} + p_{i,t}^{\text{vb}} \right), \quad \forall t \tag{3.4}
$$

where L_t is the native load.

- **Energy Charge**

  The energy charge expression is nonlinear and non-convex because of the two-tier energy rate structure. In addition, the monthly energy consumption can be negative in the extreme case where PV generation is more than the native load. An innovative method is proposed in this project to generate a mixed integer linear programming formulation, as shown in (3.5):

$$
\begin{aligned}
\text{Monthly energy charge:} \quad & C_m^{\text{energy}} = \left(-\lambda^0 E_m^- + \lambda^1 E_m^1 + (\lambda^1 - \lambda^2) E^{\text{tp}} (b_m^+ - b_m^1) + \lambda^2 E_m^2 \right) && \text{(3.5a)} \\
\text{Monthly energy:} \quad & \sum_{t \in \mathcal{T}_m} L_t^{\text{net}} \Delta T = -E_m^- + E_m^1 + E_m^2 && \text{(3.5b)} \\
\text{Negative energy:} \quad & 0 \le E_m^- \le M(1 - b_m^+) && \text{(3.5c)} \\
\text{Tie 1 energy:} \quad & 0 \le E_m^1 \le b_m^1 E^{\text{tp}} && \text{(3.5d)} \\
\text{Tie 2 energy:} \quad & E^{\text{tp}} (b_m^+ - b_m^1) \le E_m^2 \le M(b_m^+ - b_m^1) && \text{(3.5e)} \\
\text{Binary variable condition:} \quad & b_m^1 \le b_m^+ && \text{(3.5f)}
\end{aligned}
$$

where m is the month index, $\mathcal{T}_m$ is a set that contains all time step index in month m, E^{tp} is the turning point between tier 1 and tier 2 (E^{tp} = 250,000 kWh for the tariff structure described in Section 2.2.2), E_m^- is used to represent the negative energy consumption, E_m^1 and E_m^2 are used to represent energy consumption for tiers 1 and 2, respectively, λ^- is the energy charge rate for negative energy consumption, λ^1 and λ^2 are the tier 1 and 2 rates, respectively, b_m^+ is a binary variable that indicates whether the monthly energy consumption is positive (1 if the monthly energy consumption is positive and 0 otherwise), b_m^1 is a binary variable that indicates whether the monthly energy consumption is on tier 1 or 2 (1 if the monthly energy consumption is on tier 1 and 0 if on tier 2), and M is a large positive number. The three cases are provided as follows to explain how the proposed formulation works.

- With $b_m^+ = 0$, the monthly energy consumption should be negative. According to (3.5f), $b_m^1 = 0$. According to (3.5c)–(3.5e), we have $0 \leq E_m^- \leq M$ and $E_m^1 = E_m^2 = 0$. According to (3.5b), $\sum_{t\in\mathcal{T}_m} L_t^{\text{net}}\Delta T = -E_m^-$. The monthly energy charge in (3.5a) becomes $C_i^{\text{energy}} = -\lambda^0 E_m^-$.
- With $b_m^+ = 1$, the monthly energy consumption should be positive.
  - With $b_m^1 = 1$, the monthly energy consumption should be on tier 1. According to (3.5c)–(3.5e), we have $0 \leq E_m^1 \leq E^{\text{tp}}$ and $E_m^- = E_m^2 = 0$. According to (3.5b), $\sum_{t\in\mathcal{T}_m} L_t^{\text{net}}\Delta T = E_m^1$. The monthly energy charge in (3.5a) becomes $C_i^{\text{energy}} = \lambda^1 E_m^1$.
  - With $b_m^1 = 0$, the monthly energy consumption should be on tier 2. According to (3.5c)–(3.5e), we have $0 \leq E_m^2 \leq M$ and $E_m^- = E_m^1 = 0$. According to (3.5b), $\sum_{t\in\mathcal{T}_m} L_t^{\text{net}}\Delta T = E_m^2$. The monthly energy charge in (3.5a) becomes $C_i^{\text{energy}} = \lambda^1 E^{\text{tp}} + \lambda^2(E_m^2 - E^{\text{tp}})$.

- **Demand Charge**

  The monthly demand charge can be expressed as

$$\text{Monthly demand charge:} \quad C_m^{\text{demand}} = \beta^0 + \beta^1 d_m^1 \tag{3.6a}$$
$$\text{Monthly demand:} \quad L_t^{\text{net}} \leq d^0 + d_m^1, \quad \forall t \in \mathcal{T}_m \tag{3.6b}$$
$$\text{Demand above threshold:} \quad d_m^1 \geq 0 \tag{3.6c}$$

  where β^0 is the fixed demand charge, β_m is the demand charge for each additional kW above the threshold, d^0 is the threshold (d^0 = 50 kW for the tariff structure described in Section 2.2.2), and d_m^1 is the demand above the threshold.

- **Demand Response**

  The DR capability of the shared energy economy model is time varying, depending the scheduled baseline power and SOC level upon a DR event. In this work, the nominated kW per week is calculated as the weekly average DR capability. DR events are not simulated due to the lack of historical data. The DR incentives received in week w can be calculated as

$$I_w^{\text{DR}} = \gamma^{\text{dr}} p_w^{\text{DR}}, \tag{3.7a}$$

  where γ^{dr} is the DR incentive rate per week, and p_k^{dr} is the average nominated kW of the week, which can be expressed as

$$p_w^{\text{DR}} = \frac{1}{|\mathcal{T}_w^{\text{DR}}|} \sum_{t\in\mathcal{T}_w^{\text{DR}}} \sum_{i=1}^{2} \left(p_{i,t}^{\text{batt,DR}} + p_{i,t}^{\text{vb,DR}}\right), \tag{3.7b}$$

where $p_{i,t}^{\text{batt,DR}}$ is the DR kW from BESS i at time step t, $p_{i,t}^{\text{vb,DR}}$ is the DR kW from VB i at time step t, and $\mathcal{T}_w^{\text{DR}}$ is a set that contains all possible time steps a DR event may start with in week w. For $\forall t \in \mathcal{T}_w^{\text{DR}}$ and any BESS i, the DR kW is constrained by both power flexibility in (3.7c) and available energy (3.7d):

$$p_{i,t}^{\text{batt,DR}} + p_{i,k}^{\text{batt}} \le P_i^{\text{batt}}, \quad \forall k = t, t+1, \ldots, t+K^{\text{DR}}-1, \tag{3.7c}$$

$$e_{i,t}^{\text{batt}} - \sum_{k=t}^{t+K^{\text{DR}}-1} \left(p_{i,k}^{\text{batt,DR}} \Delta T + \Delta e_{i,k}^{\text{batt}}\right) \ge s_i^{\min} E_i^{\text{batt}}, \tag{3.7d}$$

where K^{DR} is the number of time steps within the duration of a DR event. Note that we can take the advantage of the time window between a notification being received and a DR event starting to increase the energy stored in BESS. The maximum energy state should be no more than the case in which a BESS is charged at the rated power for the entire time window:

$$e_{i,t}^{\text{batt}} \le e_{i,t-K_{\text{ntf}}}^{\text{batt}} + P_i^{\text{batt}} K_{\text{ntf}} \Delta t\,. \tag{3.7e}$$

Similarly, we have the following constraints for VB:

$$p_{i,t}^{\text{vb,DR}} + p_{i,k}^{\text{vb}} \le \overline{P}_i^{\text{vb}}, \quad \forall k = t, t+1, \ldots, t+K^{\text{DR}}-1, \tag{3.7f}$$

$$e_{i,t}^{\text{vb}} - \sum_{k=t}^{t+K^{\text{DR}}-1} \left(p_{i,k}^{\text{vb,DR}} + \Delta p_{i,k}^{\text{vb}}\right) \Delta T \ge \underline{E}_{i,t}^{\text{vb}}, \tag{3.7g}$$

$$e_{i,t}^{\text{vb}} \le e_{i,t-K_{\text{ntf}}}^{\text{vb}} - \underline{P}_{i,t}^{\text{vb}} K_{\text{ntf}} \Delta t\,. \tag{3.7h}$$

The optimization problem $\mathbf{P}_{\text{BTM}}$ can be formulated and solved to optimally dispatch the energy assets and assess the corresponding benefits from BTM services.

$$\begin{aligned}
\mathbf{P}_{\text{BTM}} : \min \quad & \sum_{i=1}^{12} \left(C_m^{\text{energy}} + C_m^{\text{demand}}\right) - \sum_{w=1}^{9} I_w^{\text{DR}}, \\
\text{subject to} \quad & \\
\text{Individual energy assets:} \quad & (3.1), (3.2), (3.3), \\
\text{Net load:} \quad & (3.4), \\
\text{Energy charge:} \quad & (3.5), \\
\text{Demand charge:} \quad & (3.6), \\
\text{Demand response:} \quad & (3.7).
\end{aligned}$$

3.2.2 Island Mode

In this analysis, resilience is quantified using survivability, which is defined as the probability that the system can survive a random outage. When modeling system operation in island mode, in addition to meeting load at each time step, instantaneous peak demand must be met considering variability from load and PV within each time step. Moreover, there must be enough flexibility from ESS to balance fast changes from the load and PV in both up and down directions. The microgrid cannot survive an outage unless all these requirements are met.

To quantify survivability, we generated a large number of outage scenarios characterized by outage duration and season. In each outage, the power balance must be maintained all the time:

$$L_t = \sum_{i=1}^{2} \left(p_{i,t}^{\text{batt}} + p_{i,t}^{\text{pv}} + p_{i,t}^{\text{vb}} \right) + L_t^{\text{us}} , \quad \forall t \tag{3.8a}$$

where L_t^{us} denotes the unserved load. In island operation, there must be enough power capacity from ESS to meet the instantaneous net load considering fluctuation in load and PV:

$$\sum_{i=1}^{2} \left(P_i^{\text{batt}} + P_i^{\text{vb}} + (1 - f_{\text{pv}}) p_{i,t}^{\text{pv}} \right) + L_t^{\text{usp}} \geq (1 + f_L) L_t , \quad \forall t \tag{3.8b}$$

where f_{pv} and f_L are the PV and load fluctuation, respectively, around the average power at each time step as a percentage of the average power, and L_t^{usp} is the unserved peak load. In addition, operational reserves are required to maintain power balance all the time:

$$\sum_{i=1}^{2} \left(p_{i,t}^{\text{batt,r+}} + p_{i,t}^{\text{vb,r+}} \right) + p_t^{\text{us,r+}} \geq f_{\text{pv}} \sum_{i=1}^{2} p_{i,t}^{\text{pv}} + f_{\text{L}} L_t , \quad \forall t \tag{3.8c}$$

$$\sum_{i=1}^{2} \left(p_{i,t}^{\text{batt,r-}} + p_{i,t}^{\text{vb,r-}} \right) + p_t^{\text{us,r-}} \geq f_{\text{pv}} \sum_{i=1}^{2} p_{i,t}^{\text{pv}} + f_{\text{L}} L_t , \quad \forall t \tag{3.8d}$$

where $p_{i,t}^{\text{batt,r+}}$ and $p_{i,t}^{\text{batt,r-}}$ are the regulation-up and regulation-down reserves from BESS i, respectively, $p_{i,t}^{\text{vb,r+}}$ and $p_{i,t}^{\text{vb,r-}}$ are the regulation-up and regulation-down reserves from VB i, respectively, and $p_t^{\text{us,r+}}$ and $p_t^{\text{us,r-}}$ are regulation-up and regulation-down reserve shortage, respectively. The operational reserves from BESSs are constrained as follows:

$$p_{i,t}^{\text{batt}} + p_{i,t}^{\text{batt,r+}} \leq P_i^{\text{batt}} , \quad \forall t \tag{3.8e}$$

$$-P_{i,t}^{\text{batt}} + P_{i,t}^{\text{batt,r-}} \leq P_i^{\text{batt}} , \quad \forall t \tag{3.8f}$$

$$e_{i,t+1} - \frac{p_{i,t}^{\text{batt,r+}} \Delta T}{\eta_i^{\text{dis}}} k_i^{\text{batt}} \geq s_i^{\text{min}} E_i^{\text{batt}} , \quad \forall t \tag{3.8g}$$

$$e_{i,t+1} + p_{i,t}^{\text{batt,r-}} \Delta T \eta_i^{\text{ch}} k_i^{\text{batt}} \leq s_i^{\text{max}} E_i^{\text{batt}} , \quad \forall t \tag{3.8h}$$

where k_i^{batt} is the required energy reserve per kW regulation from BESS i. The operational reserves from VB are constrained as follows:

$$p_{i,t}^{\text{vb}} + p_{i,t}^{\text{vb,r+}} \leq \overline{P}_{i,t}^{\text{vb}} , \quad \forall t \tag{3.8i}$$

$$-P_{i,t}^{\text{vb}} + P_{i,t}^{\text{vb,r-}} \leq -\underline{P}_{i,t}^{\text{vb}} , \quad \forall t \tag{3.8j}$$

$$e_{i,t+1} - p_{i,t}^{\text{vb,r+}} \Delta T k_i^{\text{vb}} \geq \underline{E}_{i,t}^{\text{vb}} , \quad \forall t \tag{3.8k}$$

$$e_{i,t+1} + p_{i,t}^{\text{vb,r-}} \Delta T k_i^{\text{vb}} \leq \overline{E}_{i,t}^{\text{vb}} , \quad \forall t \tag{3.8l}$$

where k_i^{vb} is the required energy reserve per kW regulation from VB i. The optimization problem $\mathbf{P}_{\text{res}}$ can be formulated and solved to minimize the total unserved load and reserve shortage:

$$\begin{aligned} \mathbf{P}_{\text{res}} : \min \quad & \sum_{t \in \mathcal{T}_n} \left(L_t^{\text{us}} + L_t^{\text{usp}} + p_t^{\text{us,r+}} + p_t^{\text{us,r-}} \right) , \\ \text{subject to} \quad & \\ \text{Individual energy assets:} \quad & (3.1), (3.2), (3.3), \\ \text{Island mode operation:} \quad & (3.8), \end{aligned}$$

where $\mathcal{T}_n$ is the set of time steps during outage n, and L_t^{us}, L_t^{usp}, $p_t^{\text{us,r+}}$, $p_t^{\text{us,r-}}$, $p_{i,t}^{\text{batt,r+}}$, $p_{i,t}^{\text{batt,r-}}$, $p_{i,t}^{\text{vb,r+}}$, and $p_{i,t}^{\text{vb,r-}}$ are all non-negative. For an outage, if the objective function of $\mathbf{P}_{\text{res}}$ can be optimized to zero, the system survives the outage without any load shedding. Otherwise, the islanded microgrid fails to serve all the local load during the outage.

CHAPTER 4

Assessment Results

This chapter presents techno-economic assessment results for both grid and end-user use cases, along with key findings and insights. Although resilience or outage mitigation could be the most valuable use case, due to lack of historical outage information and specific outage cost, resilience was not treated as a monetary value stream but is quantified using survivability. For the other use cases in grid-connected mode, co-optimization was performed to maximize the total benefits from bundling applications considering their trade-offs in grid-connected mode. The present value cost-benefit analysis was carried out to understand the cost-effectiveness of the shared energy economy model. In addition to the base scenario using the cost and input data presented in Chapter 2, the shared energy economy model was also evaluated in an alternative scenario with reduced BESS and PV capital cost to reflect the technology development and increased benefits to reflect the growing needs of flexibility in the evolving power grid. For resilience analysis, a large number of Monte Carlo simulations were carried out to estimate the system survivability against a random outage with different starting times and durations by season considering different initial SOC conditions. The proposed framework and assessment results in this work not only enhance the understanding of how both Avista and a customer can benefit from this shared energy economy model, but are also useful for other utilities that are interested in this kind of model to make the electric grid more reliable, efficient, resilient, and flexible.

4.1 Economic Assessment

4.1.1 Annual Economic Benefits

4.1.1.1 Utility Economic Benefits

The economic benefits from utility applications were estimated using the methods and input data presented in Section 3.2.1.1. Note that capacity value and ancillary services from flexible building loads are not considered in this analysis, as explained in Section 2.2.1. Flexible building loads were evaluated for energy arbitrage, which was found to be not profitable because the difference in hourly energy prices in summer is not high enough for energy shifting using building thermal mass considering the associated losses. The annual benefits for different applications are listed in Table 4.1 and plotted in Figure 4.1.

As can be seen, BESS accounts for 85% of the total benefits from utility applications. Benefits from BESS for capacity value and energy arbitrage are close to each other, each representing 36-40% of the total benefits. PV rated power is much smaller than BESS, and the two PV units only account for 15% of the total benefits. Most PV benefits come from energy production. The PV capacity value is very small because of the low capacity credit.

Table 4.1. Annual Economic Benefits from Utility Applications

	Capacity Value	Energy Arbitrage	Ancillary Services	Total
BESS	$14,028	$15,867	$3,166	$33,061
PV	$560	$5,017		$5,577
Total	$14,588	$20,884	$3,166	**$38,638**

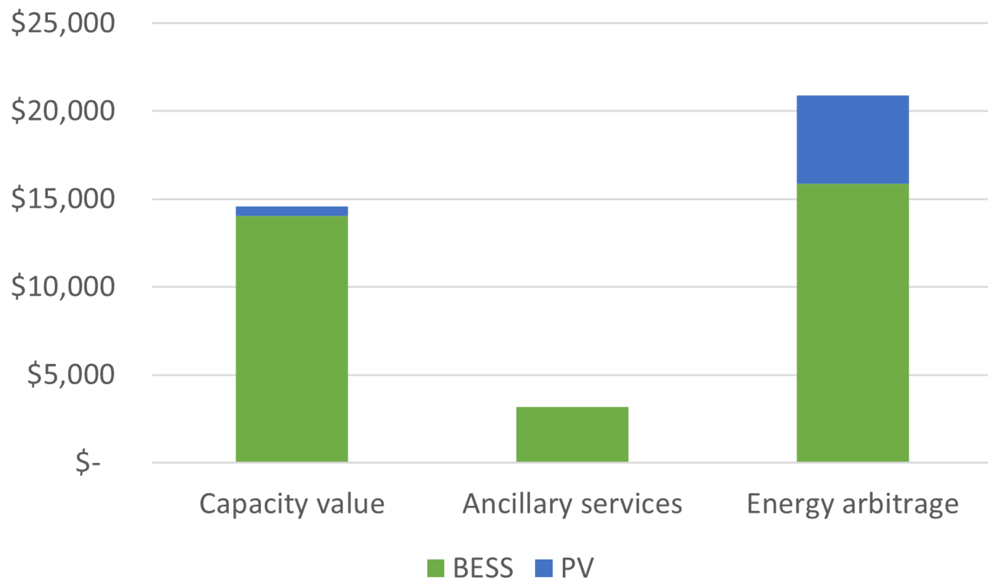


Figure 4.1. Annual economic benefits from utility applications.

4.1.1.2 End-user Economic Benefits

To understand the economic benefits of different energy assets for different end-user applications, we first calculated the electricity bill for the two buildings using the tariff structure described in Section 2.2.2 in the base case without any DERs. We then evaluated another three cases considering different DERs with and without DR. The four cases are:

- No DER (base case)
- PV only
- PV and ESS (including both BESS and VB from flexible building loads) for bill reduction without DR
- PV and ESS for bill reduction and DR

By comparing the results in different cases, we can quantify the value of energy assets for reducing energy and demand charges as well as the economic benefits from the BESSs and flexible building loads for DR. Note that in the last two cases, optimization is performed to maximize the total benefits, considering the trade-off among different applications.

We first present the results of energy consumption and energy charge, which are plotted in Figure 4.2 and Figure 4.3, respectively. The monthly energy consumption from the two buildings varies from 100 to 270 MWh, while the monthly energy charge varies from $7,000 to $20,000. The two building load peak occurs in summer months, which is mainly driven by cooling needs. The energy consumption and energy charge in the last three cases are close to each other. Almost all reduction in energy consumption and energy charge comes from PV. PV reduces monthly energy consumption in a range of 0.5 to 30 MWh, more in summer and less in winter due to varying solar irradiation. The corresponding energy charge reduction is proportional to energy saving. The impacts of BESSs and flexible building loads are not energy sources and are only used to shift energy. Therefore, their impacts on energy consumption and energy charge are very small. Energy consumption and energy charge slightly increase in the last two cases due to cycling losses of BESSs for demand charge reduction and DR.

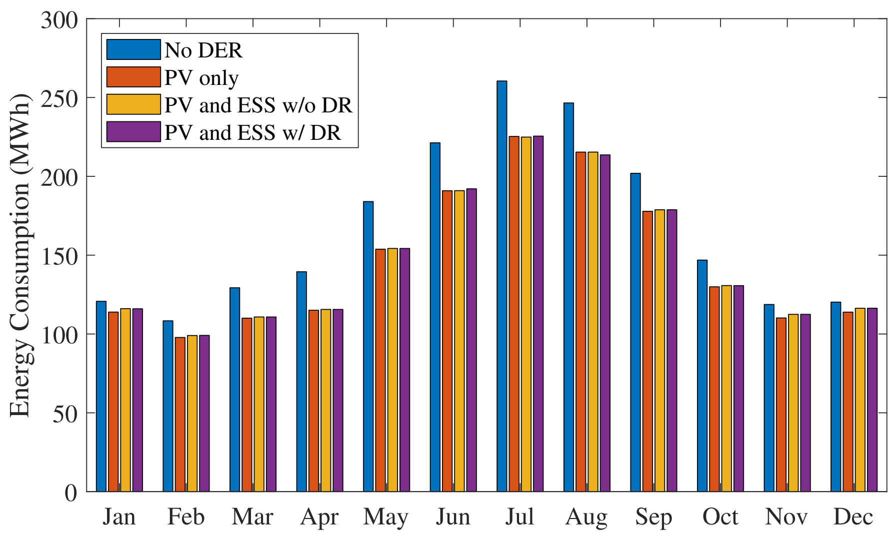


Figure 4.2. Monthly energy consumption.

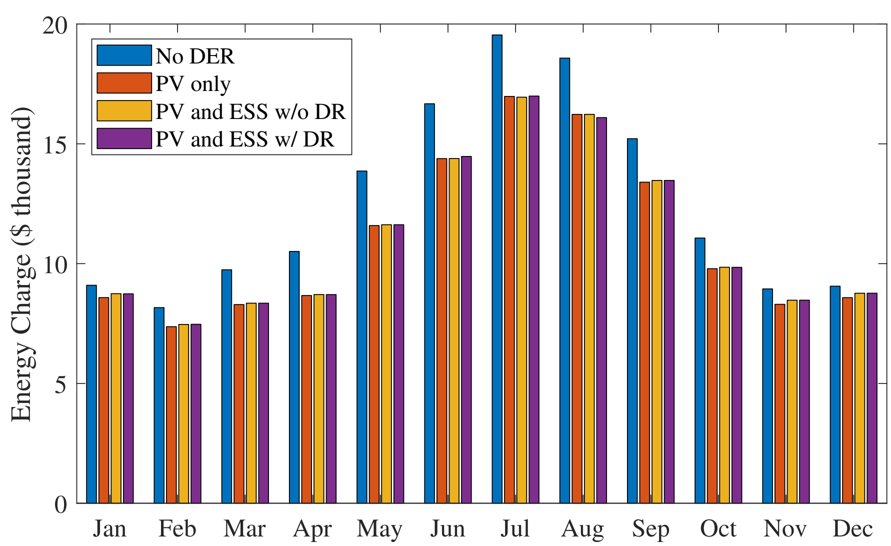


Figure 4.3. Monthly energy charge.

The peak demand and demand charge results are plotted in Figure 4.4 and Figure 4.5, respectively. By comparing the PV-only case to the base case with no DERs, we can see that

PV slightly reduces the peak demand, more in summer and less in winter. In the last two cases with BESS and VB, peak demand is reduced by 300–400 kW by discharging storage assets during peak hours, more in winter mainly due to narrow peak hour windows. This corresponds to 29-65% of the monthly peak demand in the base case. The monthly demand charge is reduced by $2000–3000. DR may slightly affect peak demand reduction, because some BESS energy is reserved for DR and less energy is available for peak demand reduction.

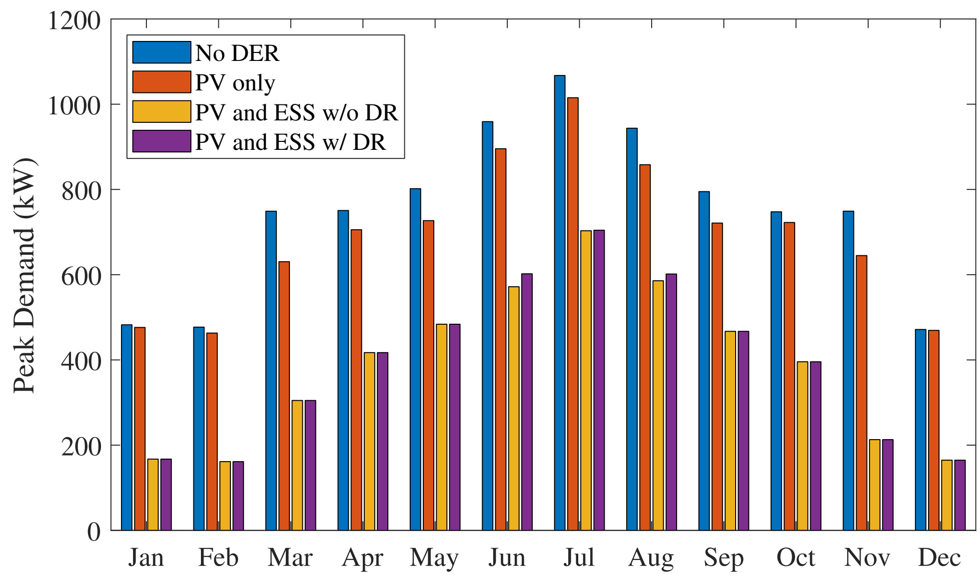


Figure 4.4. Monthly peak demand.

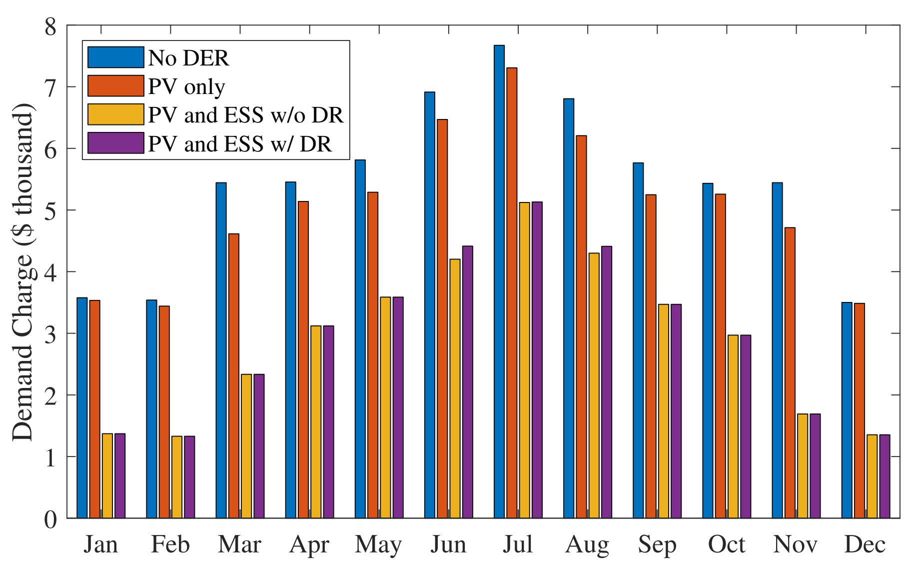


Figure 4.5. Monthly demand charge.

Figure 4.6 plots the total monthly cost excluding the fixed charges. Because the DR program is available from June to August, the electricity bill is further reduced in those 3 months compared to other months. For example, the total cost is reduced from $27,000 in the base case to about $17,000 in the last case with DR, representing a 37% reduction. While in

December, the total cost is reduced from $12,000 in the base case to about $10,000 in the last case with DR, representing a 17% reduction.

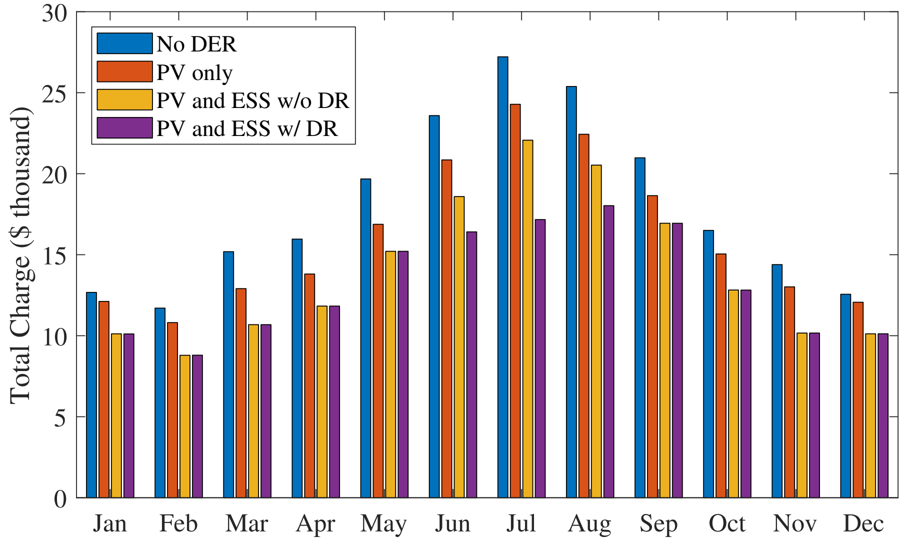


Figure 4.6. Monthly total cost (excluding fixed charges).

The annual saving on electricity bills are plotted in Figure 4.7 for the last three cases in comparison with the base case. Annual electricity bill savings vary within a range of $20,000-60,000. PV can effectively reduce the energy charge by about $20,000, leading to 10% savings. On the other hand, energy storage can effectively reduce the demand charge by about $25,000, leading to 12% savings. PV also reduces demand charge by about $4,000. While energy and demand charges represent about 70% and 30% of the total electricity bill, respectively, demand charge reduction is higher than energy charge reduction. DR incentives are about $10,000, representing about 4.5% of the annual electricity bill in the base case.

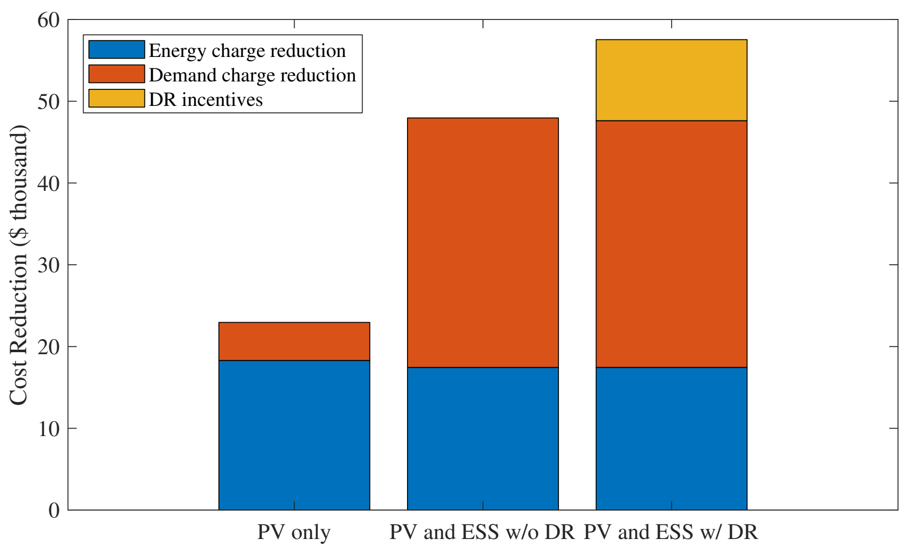


Figure 4.7. Annual cost saving.

4.1.2 Present Value Analysis

Present value analysis was performed to understand the cost-effectiveness of the shared energy economy model. The installed cost, O&M cost information, and economic lifetime described in Section 2.1. Note that the economic lifetime of PV is different from BESS and BMS. There are different strategies for performing the present value analysis (Wu et al., 2021). One method is to set the present value analysis time horizon to the maximum lifetime among all energy assets. For energy assets with a lifetime shorter than the planning horizon, an augmented equivalent cost can be used to capture the additional cost associated with augmentation, replacement, or extended warranty. An alternative is to set the time horizon for present value analysis to the minimum lifetime among all energy assets. For energy assets with a lifetime longer than the planning horizon, residual value is calculated at the end of the planning horizon and extracted from the capital cost. In this analysis, the second strategy is used and we set the analysis time horizon to 13 years.

Two scenarios are considered. In the base scenario, cost and input data presented in Chapter 2 are used without any modification. In the alternative scenario, BESS and PV capital costs are reduced to reflect the technology development and some value streams are increased to reflect the growing need for flexibility in the evolving power grid.

4.1.2.1 Base Scenario

The present value costs versus benefits in the base case are summarized in Table 4.2, where the real discount rate is assumed to be 5%. Note that BESS O&M services are included in maintenance agreement, which accounts for a portion of the installed cost. The cost and benefit bar plots are shown in Figure 4.8. As can be seen, the total benefits are only about one third of the total cost. Therefore, the investment is not cost-effective for applications considered in grid-connected mode. Among all applications, demand charge reduction value is the highest and ancillary service value is the lowest, representing 31% and 3% of the total benefits, respectively.

Table 4.2. Present Value Costs vs. Benefits in The Base Scenario

	Costs	Benefits
Capacity value		$137,033
Energy arbitrage		$196,175
Ancillary services		$29,743
Energy charge reduction		$163,906
Demand charge reduction		$283,462
Demand response		$93,082
BESS capital cost	$1,670,000	
PV capital cost (excluding residual)	$875,467	
PV O&M cost	$28,181	
BMS upgrade cost	$342,000	
Total	$2,915,648	$903,402

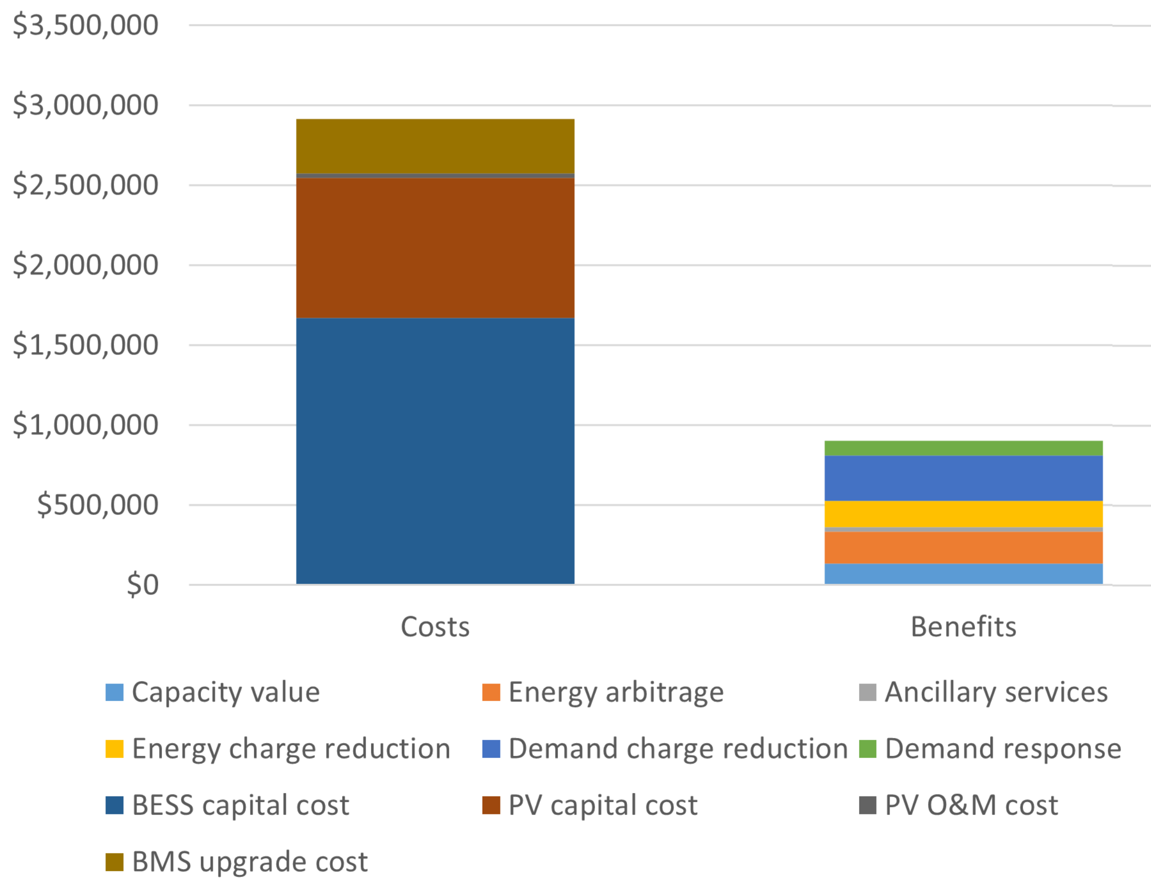


Figure 4.8. Present value costs vs. benefits in the base scenario.

4.1.2.2 Low-Cost High-Benefit Scenario

The real discount rate is assumed to be 3% in this scenario. The BESS and PV costs in this project are higher than the numbers reported in Mongird et al. (2020) and Feldman et al. (2020), and are reduced by 30% from the base scenario to reflect the latest technology. In addition, the capacity credit for BESS is increased to 65% according to the analysis in Sioshansi et al. (2014). The BESS value for ancillary services in Avista's IRP is lower than the survey results reported in Balducci et al. (2018), and is increased to $47/kW-yr in this scenario. Moreover, it is assumed that the DR program is offered 8 months instead of the 2 summer months only. The updated numbers are listed in Table 4.3 and plotted in Figure 4.9.

In this case, the present value benefits are slightly higher than the cost. The cost is reduced by 27% while the benefits increase by 136% compared with the base scenario. In particular, capacity value, ancillary services, and DR account for 42%, 25%, and 27% of the increment in present value benefits, respectively. The results indicate that the shared energy economy model can improve distribution resilience at a zero net cost (the investment cost is fully recovered from the applications in grid-connected mode). The shared energy economy model could offer lower net cost than conventional diesel generators for distribution resilience, because the latter generate no or little economic benefits in grid-connected mode due to emission restrictions.

Note that there exists double-counting in benefits from utility and end-user applications. For example, demand charge is designed to recover the investment in electricity generation and

Table 4.3. Present Value Costs vs. Benefits in a Reduced Cost and Increased Benefit Scenario

	Costs	Benefits
Capacity value		$652,433
Energy arbitrage		$222,100
Ancillary services		$333,895
Energy charge reduction		$185,566
Demand charge reduction		$320,922
Demand response		$421,530
BESS capital cost	$1,169,000	
PV capital cost (excluding residual)	$573,154	
PV O&M cost	$31,905	
BMS upgrade cost	$342,000	
Total	$2,116,059	$2,136,448

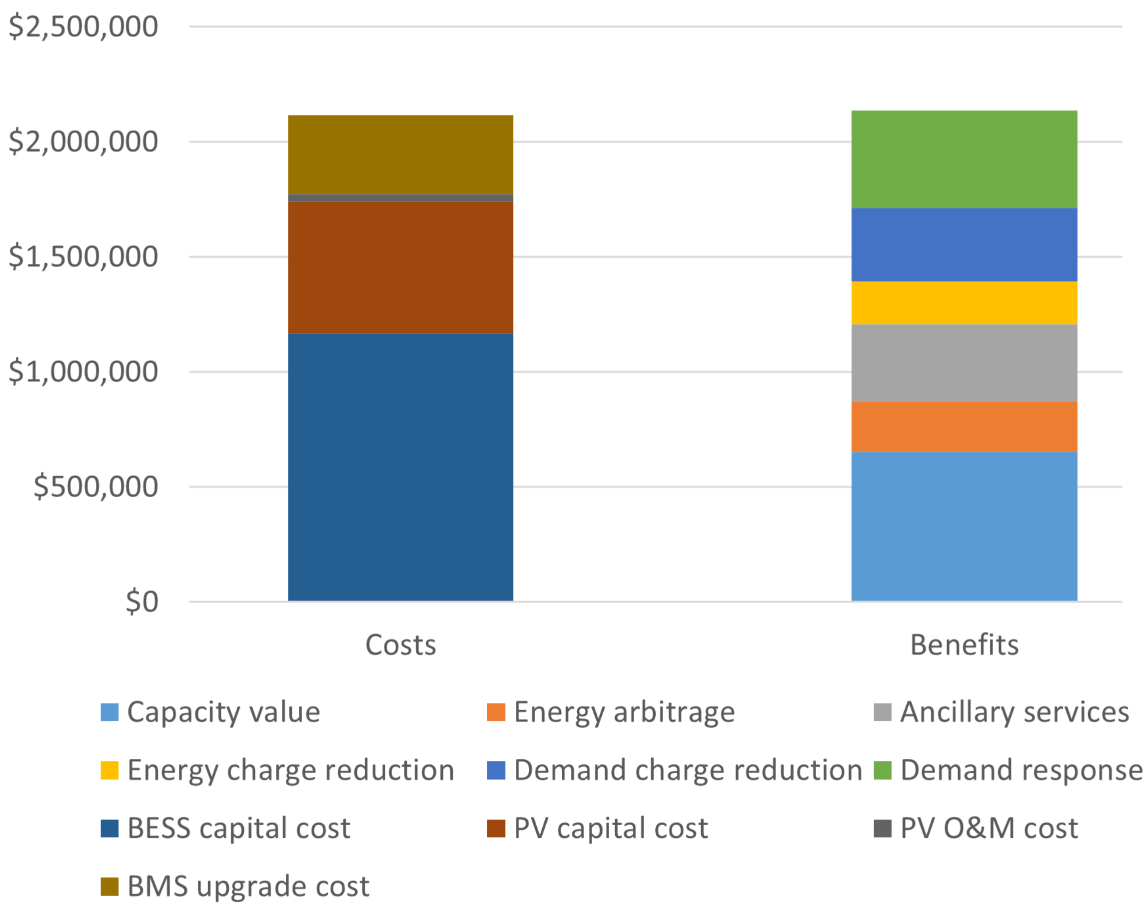


Figure 4.9. Present value costs vs. benefits in a reduced cost and increased benefit scenario.

transportation infrastructure. DR is called when there is insufficient generation capacity or electricity prices are extremely high. A portion of benefits in capacity value for resource adequacy is captured in demand charge reduction and DR. In addition, in the real world, when a utility and a customer co-develop a shared energy economy model, they may desire to operate energy assets differently to maximize their own benefits. Coordinating the energy assets to improve one party's benefits may compromise the other one's benefits. Therefore, methods are required to effectively explore different coordination strategies to optimally utilize the energy assets considering the different allocation of benefits between the two parties. A multi-objective optimization formulation could be formulated to explore how energy assets can be coordinated, thereby supporting decision-making by finding the preferred Pareto optimal solution according to subjective preferences.

4.2 Resilience Assessment

The shared energy economy model is also evaluated for improving system resilience by serving the two buildings upon a power outage. Monte Carlo simulations were performed to quantify survivability against outages with a duration of 2-24 hours in winter and summer seasons. In particular, 1000 Monte Carlo simulations were performed in each case. Two scenarios are considered to represent different control strategies.

In the first scenario, it is assumed the SOC can be any value between 5% and 95% following a uniform distribution when an outage occurs. This represents a control strategy where BESS assets are fully and freely used to maximize the economic benefits in grid-connected mode. The survivability is plotted in Figure 4.10, where summer months are between June and September, and October through May are winter months. As expected, the survivability is higher in winter than in summer due to higher load in summer. In particular, the survivability is above 20% for outages with a duration of 2–8 hours. For 2-hour outages, the survivability is 80% in winter and 60% in summer.

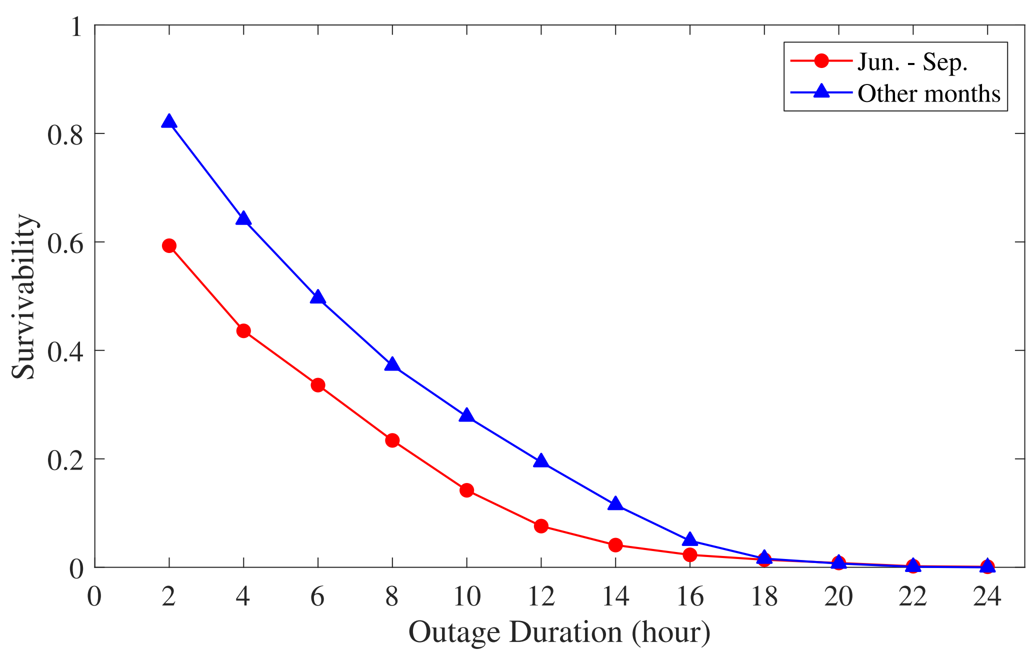


Figure 4.10. Survivability with a random BESS SOC when an outage occurs.

In the second scenario, it is assumed the SOC is 95% when an outage occurs. This represents the theoretical upper bound of system resilience, assuming we have perfect foresight of outages or the BESS is dedicated to system resilience and is not used under normal conditions. The results are plotted in Figure 4.11. In this case, the survivability is significantly improved, especially in non-summer months. The chance to survive an outage with a duration of 4 hours or less is above 90% in non-summer months. Note that we assume the energy assets are used to support all building loads when there is an outage of the main grid for resilience assessment in both scenarios. Shedding of all or part of non-critical load can also be implemented to further improve survivability.

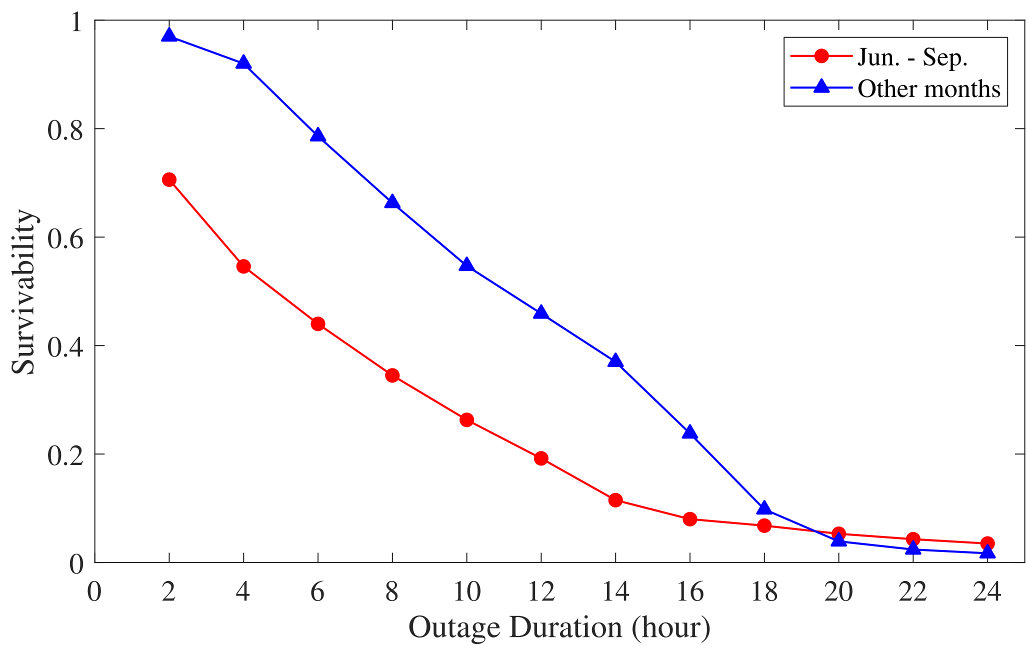


Figure 4.11. Survivability with a fully charged BESS when an outage occurs.

CHAPTER 5

Conclusions and Future Work

This report presented techno-economic assessments of the shared energy economy model deployed on the WSU Spokane Campus, considering a variety of utility and end-user applications in grid-connected mode and islanding operation upon an outage to improve distribution resilience. The system configuration and use cases were detailed. To define technically achievable benefits, advanced modeling and optimal dispatch were developed to capture the techo-economic characteristics of individual energy assets, system operational constraints, rules and requirements of different applications, and their couplings. Comprehensive analyses were performed to understand the cost-effectiveness and resilience enhancement of the shared energy economy model, as well as the potential of individual value streams.

It was found that the present value benefits only represent one third of the cost in the base scenario. With the reduced cost to reflect technology development and increased benefits to reflect the growing need for flexibility in the evolving power grid in an alternative scenario, the benefits are slightly higher than the cost, yielding positive net benefits. Most of the increment of benefits comes from capacity value, ancillary services, and DR. The results indicate that the shared energy economy model could offer lower net cost than conventional diesel generators for distribution resilience.

With the shared energy economy model, the survivability is above 20% for outages with a duration of 2–8 hours with a random SOC when an outage starts. For 2-hour outages, the survivability is 80% in winter and 60% in summer. When energy storage assets are fully charged when an outage occurs, survivability is significantly improved, especially in non-summer months. The chance to survive an outage with a duration of 4 hours or less is above 90% in non-summer months. Load shedding or additional DER capacity is required to further improve resilience.

In this project, the BESS and PV are deployed as front-of-meter assets that are owned and operated by Avista, end-user applications were assessed to understand how these DERs can benefit a customer in scenarios where they are deployed as BTM assets. In the real world, when a utility and a customer co-develop a shared energy economy model, they may desire to operate energy assets differently to maximize their own benefits. Coordinating the energy assets to improve one party's benefits may compromise the other one's benefits. One interesting area of future work is to develop advanced methods to effectively explore different coordination strategies to optimally utilize the energy assets considering the different allocation of benefits between the two parties, and support decision-making by finding the preferred Pareto optimal solution according to subjective preferences.

CHAPTER 6

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