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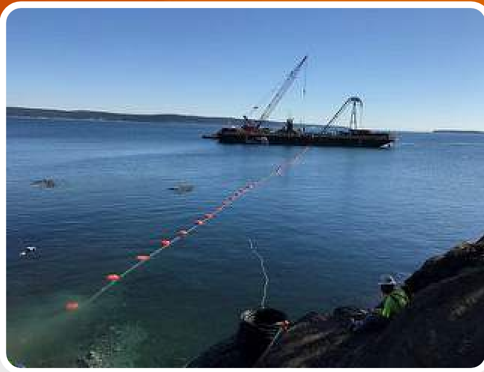

Decatur Island Community Solar and Energy Storage Project – Preliminary Economic Assessment

July 2018

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Pacific Northwest National Laboratory
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Executive Summary

The Washington State Clean Energy Fund (CEF) provides grants in support of the development of clean energy technologies in Washington State, and is administered by the Washington Department of Commerce. Since 2013, the Washington State Legislature has authorized $122 million for the fund, with the third round of funding reaching $46 million (Kirchmeier 2018). To date, CEF funds have been distributed to electric utility companies, vendors, universities, and research organizations to fund projects that integrate intermittent renewables, improve grid reliability, expand grid modernization activities, reduce the costs associated with distributed energy resource deployments, and lower emissions.

In 2016, as part of the second round of CEF funding, the Orcas Power & Light Co-Op (OPALCO) received a $1 million modernization grant in support of a project that will deploy a community solar array in combination with an energy storage system (ESS) on Decatur Island, Washington. As proposed, the project would include a 0.5 megawatt / 2 megawatt-hour ESS at the Decatur Island Substation alongside a 504 kW LG community photovoltaic (PV) system. The Decatur Island Substation is essential to ensuring reliable energy to the residents of the San Juan Islands as it is the point of interconnection with the mainland transmission system. The proposed ESS, in combination with the community solar array, will deliver an innovative method to both defer the costly upgrade of the transmission system as well as allow for other high-value applications intended to benefit the utility and the customers it serves.

OPALCO is a non-profit utility that provides energy services to approximately 11,200 customers across 20 islands in San Juan County, Washington. A map of the San Juan Islands, including Decatur Island where the project will be located, is presented in Figure ES.1. The island network is located off the northwestern coast of Washington State.

Figure ES.1. Map of the San Juan Islands, Washington

This report documents the results of the preliminary economic analysis conducted by the Pacific Northwest National Laboratory for the Decatur Island Community Solar and Energy Storage Project. The following key lessons and implications can be drawn from the analysis.

1 – Based on its Initial Design and Cost Documents Prepared by OPALCO, the Community Solar and ESS Project Generates Positive Net Benefits to OPALCO under the Base Case Scenario

Benefits calculated for the project under the base case ($3.3 million) exceed associated costs ($2.9 million), producing a benefit cost ratio of 1.13 (Figure ES.2). The most valuable application is transmission deferral, which generates nearly $2 million in 20-year present value benefits. The second most valuable application is demand charge reduction, which generates over $700,000 in benefits over the life of the system.

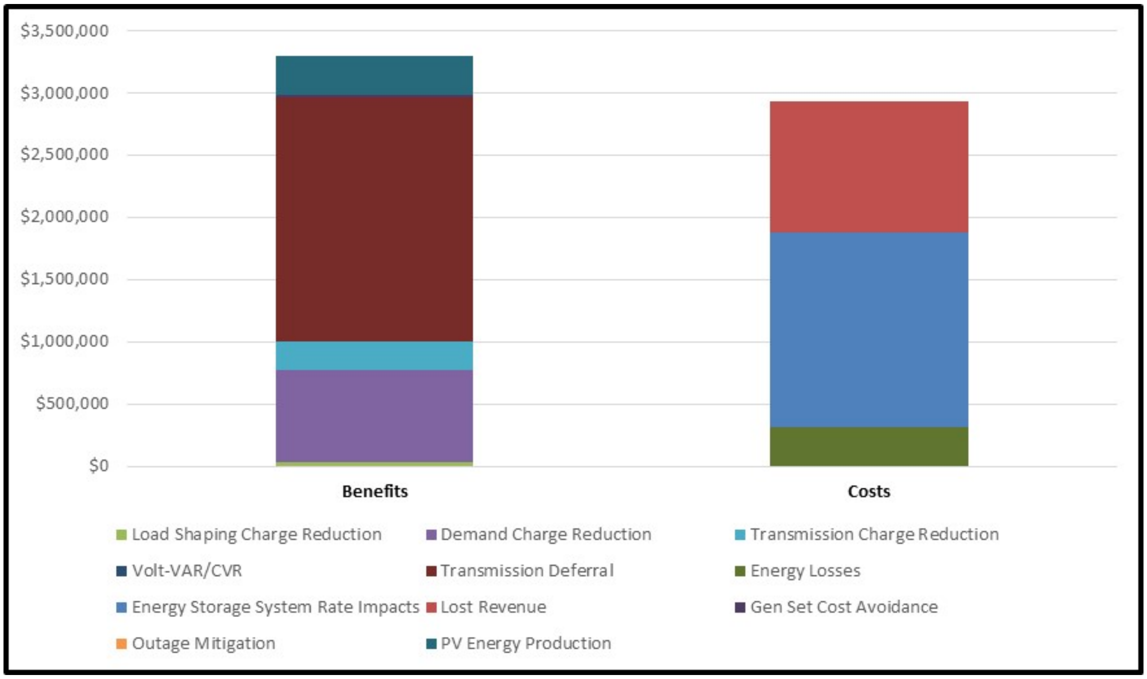


Figure ES.2. Base Case Benefits and Costs for the Decatur Island Community Solar and Energy Storage Project

2 – Isolating the ESS from the PV System Results in a Lower Benefit Cost Ratio Unless Outage Mitigation is Included among the Benefits

When ESS costs and benefits are analyzed in isolation, net benefits fall to $146,607 and the benefit-cost ratio is 1.08. This scenario reduces load shaping and transmission deferral benefits but has little effect on demand and transmission charges. With outage mitigation benefits included within this scenario, net benefits increase to $0.5 million and the benefit-cost ratio rises to 1.27.

3 – The Presence of the Energy Storage System and Community Solar Assets Defers Submarine Cable Replacement by Nearly Four Years

By reducing stress on the submarine transmission cable that distributes power to the San Juan Islands, replacement of the estimated $40 million transmission cable is deferred by 3.65 years, generating approximately $2 million in benefits in present value terms. This is the most valuable application of all use cases analyzed.

4 – Outage Modeling Indicates that the PV and ESS Used in Combination Could Mitigate All Power Outages Affecting Decatur and Center Island Customers

Modeling conducted for this assessment indicates that all outages occurring on Decatur and Center Islands over the past eight years could have been eliminated with the presence of both the PV system and the ESS. The average annual benefit of avoiding these outages is approximately $21,000.

5 – The Presence of the ESS and PV Systems Reduces OPALCO's Energy Bill

By evaluating data from 2017, the effects of the PV and the ESS together would have reduced OPALCO's costs associated with demand, transmission, and load shaping charges by approximately $60,000. The energy storage device is effective at reducing transmission and demand charges; however, it was found that the community solar increases demand charges due to the structure of the rates paid by OPALCO. Between the two assets, the battery is responsible for 82 percent of these estimated benefits.

6 – Sensitivity Analysis Results Show a Range of 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. Two of the five evaluated scenarios resulted in negative impacts to the economic results compared to the base case. The most negative impact resulted from lowering the discount rate by one percentage point. While counterintuitive as lower discount rates typically increase present value benefits, in this case the lower discount rate greatly reduced the present value benefits of deferring a future investment in a submarine transmission cable. The 2nd worst return on investment ROI was found in the scenario in which the 2nd round benefits from transmission cable deferral were excluded from the analysis. Under this scenario, the first cable replacement is deferred by 3.65 years; however, the benefits derived from the deferral of the subsequent replacement cable are not included and the net present value benefits drop by approximately $700,000 as a result. Adjusting the inflation rate to three percent increased net benefits by approximately $400,000. Increasing the discount rate by one percent improved net benefits by approximately $356,000 in present value terms. Also on the positive side, including outage mitigation as a benefit increased total present value by over $350,000.

Acknowledgements

We are grateful to Dr. Imre Gyuk, who is the Energy Storage Program Manager in the Office of Electricity Delivery and Energy Reliability at the U.S. Department of Energy, and Bob Kirchmeier, who is a Senior Energy Policy Specialist in the Clean Energy Fund Grid Modernization Program of the Washington State Energy Office. Without their organizations' financial support and their leadership, this project would not be possible.

Acronyms and Abbreviations

AC	alternating current
aHLH	average heavy load hour
AHWM	Above High Water Mark
BPA	Bonneville Power Administration
BSET	Battery Storage Evaluation Tool
CDQ	contract demand quantity
CEF	Clean Energy Fund
CSP	customer system peak
CVR	conservation voltage reduction
DC	direct current
DER	distributed energy resources
DOE	U.S. Department of Energy
ESS	energy storage system(s)
FCC	Federal Communications Commission
HLH	heavy load hour
kW	kilowatt(s)
kWh	kilowatt hour(s)
LDD	low density discount
LF	life fraction
LLH	light load hour
MW	megawatt(s)
MWh	megawatt hour(s)
O&M	operations and maintenance
OPALCO	Orcas Power & Light Co-Op
PNNL	Pacific Northwest National Laboratory
POI	point of interconnection
PSM	physical solar model
PV	photovoltaic(s) and present value
ROI	Return on Investment
RTE	round trip efficiency
SAM	System Advisor Model
SOC	state of charge
SnoPUD	Snohomish Public Utility District
SOLPOS	Solar Position and Intensity Calculator
UET	UniEnergy Technologies
TOCA	Tier One Cost Allocator

VAR	Volt-ampere reactive
VFB	vanadium flow battery
WUTC	Washington Utility and Transportation Commission
XLPE	cross linked poly-ethylene

Contents

Figures

Tables

1.0 Introduction

The Washington State Clean Energy Fund (CEF) is a publicly funded program that 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 (Figure 1.1), with the third round of funding reaching $46 million (Kirchmeier 2018). To date, CEF funds have been distributed to electric utility companies, vendors, universities, and research organizations to fund 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. In 2016, as part of the second round of CEF funding, the Orcas Power & Light Co-Op (OPALCO) received a $1 million modernization grant in support of a project that will deploy a community solar array in combination with an energy storage system (ESS) on Decatur Island, Washington.

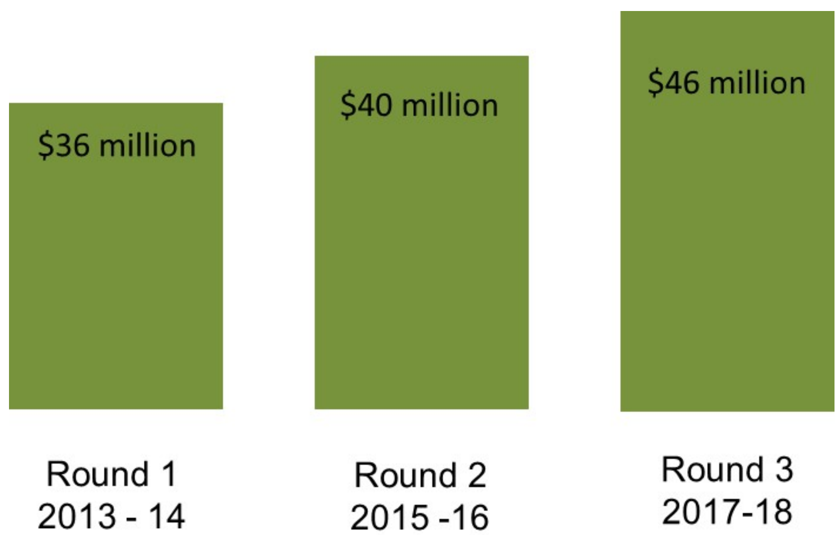


Figure 1.1. Washington Clean Energy Fund Biennial Funding Levels

OPALCO is a non-profit utility that provides energy services to approximately 11,200 members across 20 islands in San Juan County, located off the northwestern coast of Washington State. A map of the San Juan Islands, including Decatur Island where the ESS is set to be located, is shown in Figure 1.2.

OPALCO receives its energy from the Bonneville Power Administration (BPA) by way of submarine transmission cables through a point of interconnection (POI) located at the Decatur Island Substation. The installation of the ESS at OPALCO's Decatur Island Substation is expected to extend the life of a 69 kV transmission submarine cable and provide substantial additional monetary benefits through bill-reducing activities tied to shaving peaks and shaping loads. The Decatur Island Substation is a highly important POI, as approximately 200 million kWh of energy is transferred through it to the islands from the mainland on an annual basis. This POI also includes systems for voltage, frequency regulation, and switching (OPALCO 2016).

Figure 1.2. Map of the San Juan Islands, Washington

The specifications of the energy storage project include the proposed deployment of a 0.5 megawatt (MW) / 2 megawatt-hour (MWh) ESS at the substation alongside a 504 kilowatt (kW) LG community photovoltaic (PV) system. The proposed ESS, in combination with the community solar array, will deliver an innovative method to both defer the costly upgrade of the transmission system as well as allow for other high-value applications intended to benefit the utility and the customers it serves.

Pacific Northwest National Laboratory (PNNL) was engaged by the U.S. Department of Energy (DOE) and the Washington Department of Commerce to work with OPALCO in evaluating the economic and technical performance of the ESS. This report presents the results of the economic assessment.

1.1 Project Synopsis

PNNL has worked closely with OPALCO to evaluate the potential benefits that the ESS and the 504 kW community solar installation can bring to their system. Tasks performed by PNNL to date are presented in a task flow diagram in Figure 1.3.

Early tasks included definition of use cases or services provided by the ESS, the development of methods for evaluating the benefits of each use case in isolation and when co-optimizing bundled services, and data collection activities.

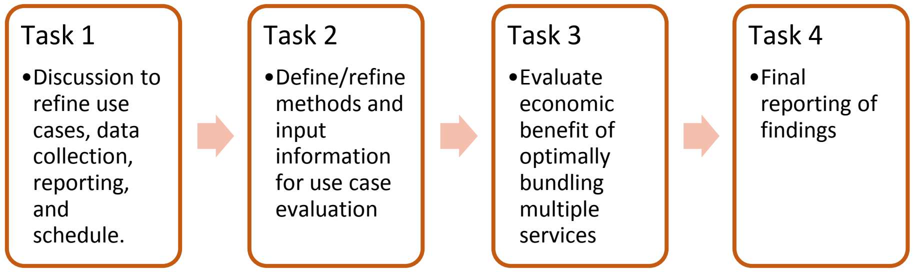


Figure 1.3. Task Flow Diagram

This report documents the value of the ESS when engaged in single or bundled use cases. It also evaluates the impact of solar energy production on OPALCO revenue and costs. It defines the approaches used in monetizing the economic benefits associated with ESS services and documents the modeling techniques used to optimize values. Lastly, it identifies which use cases are the most economically viable for the ESS and under what circumstances the overall value can be maximized.

Understanding of the technical features and limitations of each key asset is essential to performing economic evaluations of the ESS, the community solar array, and the submarine cable connecting the islands to the mainland. Thus, the following section presents an overview of each component. For modeling purposes, we assume the ESS will be a UniEnergy Technologies (UET) vanadium flow battery (VFB).

1.2 UET Vanadium Flow Battery

VFBs offer a scalable energy storage solution with the ability to retain capacity for 20 years or more. Over the past few decades, a number of companies and research labs have further developed the technology with demonstration and commercial deployment at utility scale. UET, with its Uni System vanadium-based mixed acid battery technology, is one such company.

UET is a Washington State-based energy storage technology company that provides grid-scale energy storage solutions for both commercial and industrial applications. The UET VFB uses an electrolyte solution that is passed through a membrane in a container-based design. The chemistry underlying this technology was initially developed at PNNL, funded through the energy storage research & development program at DOE's Office of Electricity Delivery and Energy Reliability. Figure 1.4 shows a UET VFB that is currently deployed in Pullman, Washington for Avista Utilities.

Figure 1.4. Turner Energy Storage Project Located in Pullman, Washington

The battery planned for deployment at the Decatur Island Substation would be a 0.5 MW / 2 MWh system. The Decatur Island Substation is the first POI between OPALCO and BPA, and stands as a critical site to the island chain's grid system. The POI has a critical load of 45 kW and includes switching and other vital equipment.

Based on the battery documentation provided from UET, it is assumed that the battery system can provide 0.5 MW for a 4-hour duration. Battery specifications indicate a peak shaving efficiency of 70 percent alternating current (AC). It is further assumed that all energy losses are split evenly between charging and discharging, which results in an 83.7 percent efficiency rate being applied to both operations (UET 2016).

1.3 Photovoltaic System

A 504 kW community solar facility is also planned for deployment at the Decatur Island Substation. The system will include 1,260 power-dense LG400 Watt monocrystalline modules provided by Puget Sound Solar (Puget Sound Solar 2017). The estimated heat mapping of the solar installation at the Decatur Substation site is shown in Figure 1.5 (Puget Sound Solar 2017).

Figure 1.5. Shading Heat Map of PV Installation at Decatur Island Substation

To evaluate the estimated energy production from PV panels deployed in that location, a number of solar profiles were used with an established solar PV production model. The solar data was gathered from the National Solar Radiation Database, specifically the Physical Solar Model (PSM) dataset. This dataset provides both a large temporal coverage with 18 years of data as well as relatively fine spatial resolution (4 km by 4 km) for all locations in the continental US. The data used in this evaluation is hourly.

The data itself is not measured data, but rather modeled data based on satellite observations and models that estimate the impact on solar parameters due to atmospheric conditions. A comprehensive evaluation of the modeling techniques can be found at Habte et al. 2017, which shows that this modeled PSM data has a mean bias error of ±5 percent to ±10 percent.

Given the necessary solar data, to calculate what a given solar PV panel would produce requires a calculation of the position of the sun in the sky. This calculation is used by the model of the solar PV panel to determine its electrical production value. The Solar Position and Intensity (SOLPOS) calculator was used to calculate the position of the sun. The solar panel production model is commonly referred to as the Perez model (Perez et al. 1990). These models were chosen for their simplicity and are appropriate for the fidelity of this analysis.

Table 1.1 shows the specific parameters used in the solar PV production analysis.

Table 1.1. Solar Analysis Parameters

Variable	Value
Latitude (degrees)	48.51 N
Longitude (degrees)	122.81 W
Tilt angle (degrees)	20
Azimuth angle (degrees)	180 (south)
Shading/degradation/soiling factor	0.90
Inverter efficiency	0.95

There was no accounting for any specific shading due to nearby trees or buildings; it is assumed that the entire solar array has a clear view of the sky year-round. The inverter is assumed to contain a perfect power-point tracking algorithm and converts all the available direct current (DC) energy produced by the panel to AC energy at the indicated efficiency. Because the solar data is only updated each hour, it is assumed the solar array operates at a constant rate throughout the entire hour.

Running the 18 years of PSM data through the SOLPOS/Perez production model resulted in an annual average production of 545,956 kWh with a standard deviation of 21,541 kWh. On a per-kW of installed solar capacity basis, the average was 546 kWh per kW installed with a standard deviation of 21 kWh/kW installed. The lowest annual value across all 18 years was 512 kWh per kW installed and the most productive year was 580 kWh per kW installed.

To validate these results, the National Renewable Energy Laboratory's System Advisor Model (SAM) was run using similar input values and typical meteorological year solar data (effectively a composite, single-year of hourly solar parameters most closely matching a mathematically defined average year). SAM's analysis found a value of 583 kWh of annual energy per kW of solar PV installed, a difference of 6 percent when used as the reference case.

1.4 Submarine Cable

OPALCO delivers power to thousands of customers through an automated distribution system that includes 15 distribution submarine cables and 11 transmission submarine cables, which together cover 16 miles between the islands. Their system also encompasses 11 substations, including the one located on Decatur Island where the ESS and community solar will be sited (OPALCO 2018).

Power for the islands is purchased from BPA, a federal agency under the DOE that serves the Pacific Northwest. For OPALCO, there are two submarine transmission cables covering a six-mile distance that both deliver power from BPA's Fidalgo Substation located in Anacortes, Washington. The first cable is an oil-filled submarine transmission cable rated at 115 kV. The second, referred to as Cable Number 5, is a 69 kV 3 core Cross Linked Poly-Ethylene (XLPE) insulated cable manufactured by Nexans. A map showing the path of the cables across Rosario Strait is presented in Figure 1.6.

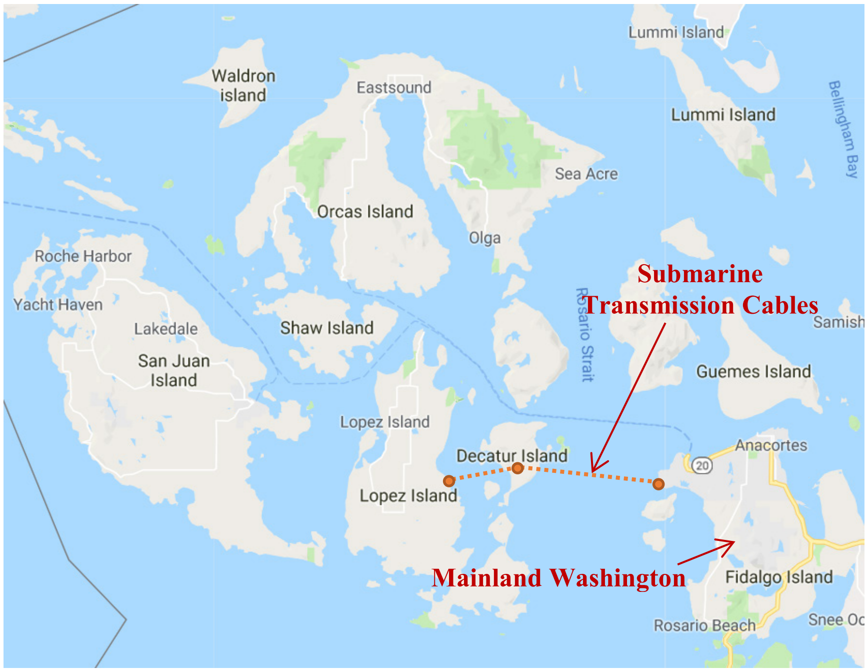


Figure 1.6. Transmission Cable Map from Fidalgo Substation in Anacortes to Decatur and Lopez Islands

These transmission cables connect the San Juan Islands to the BPA system and, from the Decatur Island POI, OPALCO is able to distribute energy to its customers. A one-line diagram showing the OPALCO transmission and distribution system across the islands, including 43.6 miles of transmission and over a thousand miles of distribution lines, is shown in Figure 1.7.

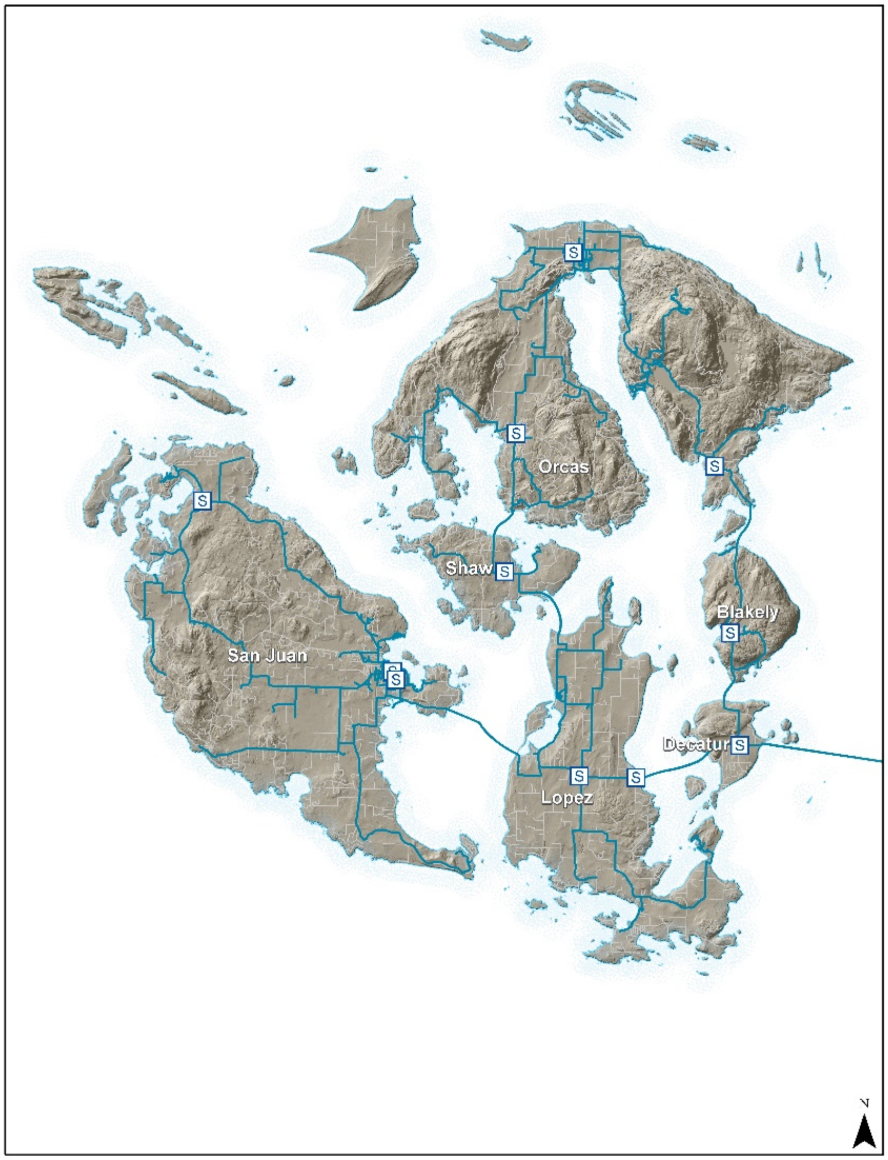


Figure 1.7. One Line Diagram of OPALCO's Transmission and Distribution System

2.0 Energy Storage Valuation Methodology and Cost Estimates

2.1 Use Cases

PNNL began its assessment of community solar and energy storage benefits by meeting with OPALCO and developing a list of use cases or services that could be offered by the ESS and PV systems. The following use cases were defined for further evaluation:

1. Load Shaping Charge Reduction;
2. Demand Charge Reduction;
3. Transmission Charge Reduction;
4. Submarine Transmission Cable Replacement Deferral;
5. Volt-VAR/Conservation Voltage Reduction;
6. PV Production; and
7. Outage Mitigation.

Each of these use cases will be defined in the next sections along with the methodology used to estimate the associated value. The value of each use case is presented in Section 2.1.

2.1.1 Load Shaping and Demand Charge Reductions

Load shaping and demand charges are components of OPALCO's energy bill from BPA that fluctuate on a monthly basis. Load shaping appears as either a charge or a credit that is dependent upon whether OPALCO purchases more or less energy than the amount expected by BPA. The demand charge, on the other hand, is a fee OPALCO incurs that is tied to energy purchases during the utility's most load-intensive hour each month. The battery and community solar have the potential to impact both of these charges and, therefore, it is important to understand how they are derived.

To be able to accurately calculate the full benefits that the ESS can derive by mitigating these charges, it is necessary to first understand the structure of BPA's rates.

Though OPALCO pays its bill through the electric utility company PNGC Power, its energy is ultimately purchased from BPA and is, therefore, subject to BPA's rate structure. BPA offers a tiered tariff structure to its customers within which there are multiple levels, differentiated by a MW demand quantity, and each individually priced. The cutoff at which it crosses over from the lower level to the next is established to align with the current generation capabilities of BPA's system.

Tier 1 is the lower price level in BPA's structure and each energy customer is allocated a limited MW quantity that they may purchase at this rate. The reasoning behind the purchase cap is that Tier 1 is constrained by BPA's total current generation capability and the level of MW demand it can readily meet with available resources. Tier 2 rates, on the other hand, are established to cover any remaining customer demand beyond what is covered under Tier 1 and are higher as they are priced according to the cost of BPA obtaining more generation to meet the additional demand.

Tier 1, which accounts for almost all of the power OPALCO purchases, includes four separate charges:

1. The customer base charge;
2. The load shaping charge;
3. The demand charge; and
4. The transmission charge.

The first component, the customer base charge, is not dependent on either OPALCO's monthly peak demand or the time at which it consumes energy, but rather is a pre-calculated amount based on a forecasted load. For this reason, the base customer charge remains unaffected regardless of the ESS's activity and therefore will not be described in detail here as it is simply a previously established charge OPALCO must pay each month. Each customer is assigned a tier one cost allocator or TOCA, which defines the portion of BPA generation costs that should be paid by OPALCO. In 2017, OPALCO's TOCA was 0.35 percent. PV production would affect future year TOCAs and, therefore, the base charges allocated to OPALCO. The load shaping and demand charges, however, would be affected by ESS operations.

For the amount of power that OPALCO is unable to purchase at Tier 1 rates, it must pay at the higher, Tier 2 rates. This is incorporated into its bill from PNGC under what is called the Above High Water Mark (AHWM) Power Cost. This MWh quantity is set as a fixed amount based on a forecast of how much Tier 2 power BPA expects OPALCO to require. Like the customer base charge described previously, the ESS will not be able to affect the AHWM power cost, as the value is fixed and not dependent on OPALCO's time-of-use or peak energy usage. Nevertheless, the AHWM load that OPALCO makes the obligation to purchase is important, as it allows us to determine the Tier 1 amounts each month that the battery has the ability to impact.

The monthly AHWM obligations, shown in Table 2.1 below, are the MWh load amounts that OPALCO has agreed to pay for at Tier 2 rates through PNGC, specific to the category in the first column. As previously mentioned, these amounts are determined by a forecast of OPALCO's load and are then further determined for each of the variables in the first column based on hours per year that variable occurs. The obligation amounts remain unchanged month-to-month throughout 2018 but are important as they each factor into the Tier 1 equations through the variables in column one. Each of these variables and their functions will be described in the next sections.

Table 2.1. OPALCO above High Water Mark Obligations

Variable	Monthly AHWM Obligation (MWh)
Customer System Peak	0.487
Total Heavy Load Hour	202.592
Total Light Load Hour	159.736
Average HLH	0.487

As an example of how these values work, the first variable in Table 2.1, customer system peak (CSP), factors into the equation for the demand charge. The CSP is the highest MWh load OPALCO purchases from BPA in any hour in any given month. Only a portion of that peak load, however, can be charged at Tier 1 amounts due to the cap described previously. To obtain the Tier 1 CSP, therefore, the determined monthly AHWM obligation from the table, specific to the CSP, must be subtracted from OPALCO's total MWh CSP that month. For example, if OPALCO's highest load quantity was 35 MWh in a month, the Tier 1 component of that would be 35 - 0.487 = 34.513. The 34.513 MWh is the Tier 1 amount of peak load that factors into determining the demand charge for that month.

As stated previously, the energy storage system will only be able to impact the load shaping and demand charge portions of the three Tier 1 charges OPALCO faces. The methods for determining these charges, as well as how the AHWM obligations factor in to each of them, is described in greater detail in the sections that follow.

2.1.1.1 Load Shaping Charge

Load shaping is a Tier 1 charge or credit OPALCO receives that is dependent on whether their actual retail load each month is greater or less than the amount BPA predicted it would purchase. Load shaping is split into two categories: heavy load hours (HLHs) and light load hours (LLH). A different charge/credit is determined for each that fluctuates depending on energy purchased during set hours.

HLHs include all hours between 6:00am and 10:00pm, Monday through Saturday. LLHs include all other hours on those same days as well as all hours on Sundays and holidays. For simpler modeling, holidays are excluded from the analysis as they would have a minimal impact on the formulation.

If OPALCO's power purchases are less than expected, they receive a credit on their bill. Conversely, if they purchase more power than expected, they must pay an additional charge.

For HLHs, the load shaping charge/credit for each month in 2018 is determined by the following formula:

$$\begin{aligned} &HLH\ Load\ Shaping\ Charge \\ &\qquad = [(Total\ HLH\ actual\ retail\ load \\ &\qquad - 202.592)\ -\ OPALCO\ HLH\ System\ Shaped\ Load] \\ &\qquad \times\ HLH\ Load\ Shaping\ Rate \end{aligned} \tag{1a}$$

For LLH it is:

$$\begin{aligned} &LLH\ Load\ Shaping\ Charge \\ &\qquad = [(Total\ LLH\ actual\ retail\ load \\ &\qquad - 159.736)\ -\ OPALCO\ LLH\ System\ Shaped\ Load] \\ &\qquad \times\ LLH\ Load\ Shaping\ Rate \end{aligned} \tag{1b}$$

where *Total HLH (LLH) actual retail load* is the MWh quantity that OPALCO purchases each month; *HLH (LLH) system shaped load* is BPA's forecast of OPALCO's MWh retail load for that month; and *HLH (LLH) load shaping rate* is the mills/kWh rate that BPA charges for these bill components.

Note the two differing values that are subtracted from the total actual retail load for the respective hours. These values, originally provided in Table 2.1, are the AHWM obligations that OPALCO has agreed to pay each month that cannot be charged at the lower, Tier 1 rates. By subtracting them from the total actual retail load, we are left with the HLH tier 1 load and LLH tier 1 load, respectively.

The second component of the equations above, the system shaped load, is the total monthly amount of energy BPA expects OPALCO to purchase during the indicated hours across the entire month. These values are predetermined for OPALCO for each month of 2018 for both HLH and LLH and are provided in Table 2.2 below.

Table 2.2. OPALCO 2018 System Shaped Load by Month (MWh)

Month	HLH (MWh)	LLH (MWh)
January	10,590.94	6,551.59
February	8,877.34	5,176.21
March	10,521.94	6,116.95
April	10,284.79	5,707.60
May	14,957.24	8,510.47
June	12,112.66	6,402.74
July	10,629.20	5,628.88
August	12,046.44	5,960.03
September	10,428.00	5,885.15
October	10,687.01	5,744.09
November	12,796.04	7,511.54
December	12,498.70	7,565.01

The difference between the tier 1 loads and the system shaped loads, as shown in the equation, gives the deviation in energy consumption for which OPALCO will be additionally charged or rewarded. This deviation is charged/credited at the appropriate load shaping rate shown below in Table 2.3.

Table 2.3. HLH and LLH Load Shaping Rates Set by BPA for 2018 (mills/kWh)

Month	HLH Rate	LLH Rate
January	29.30	23.94
February	28.54	23.94
March	23.75	20.80
April	19.67	17.54
May	16.63	11.25
June	17.71	9.31
July	24.66	19.05
August	28.11	22.61
September	27.94	22.19
October	26.74	22.49
November	27.27	24.74
December	30.28	26.60

The sum of the HLH and LLH load shaping charges/credits is the total load shaping charge/credit for the month.

OPALCO also qualifies for a low density discount (LDD) from BPA of 5.61 percent on its Tier 1 charges. This discount is given to qualified BPA customers who meet a list of criteria including: low kWh/investment and low consumers/mile of line ratios. During months in which OPALCO purchases more energy from BPA than expected, this discount is applied to the cost it faces. In months in which OPALCO purchases less energy than expected, this discount works against it and any credit it receives is 5.61 percent smaller (BPA 2011).

The potential monetary savings that can be gained through the usage of the ESS is through the shifting of energy consumption away from the pricier HLHs and towards the LLHs. As shown in Table 2.3, the LLH load shaping rate is consistently lower each month. By charging up the battery during these hours and discharging during HLH, the price differential generates the potential for benefits. These benefits, however, are typically low for ESS operations due to the cost associated with round trip efficiency (RTE) losses.

2.1.1.2 Demand Charge

The second Tier 1 charge that the ESS has the potential to impact is the demand charge paid by OPALCO. Demand charges are fees incurred by a customer proportional to the highest MWh load they consume each month. This charge can be reduced by shaving peak loads throughout the month. This service can be provided by the ESS discharging energy when a specific load threshold is surpassed, thereby reducing peaks and can amount in substantial savings for OPALCO.

The demand charge is determined by three factors: (1) OPALCO's Tier 1 customer system peak (CSP), (2) OPALCO's Tier 1 average HLH load, and (3) OPALCO's contract demand quantity (CDQ). These three components come together in the following equation each month:

$$\begin{aligned} Demand\ Charge &= [(CSP - 0.487) - (average\ HLH\ load - 0.487) - CDQ\ ] \\ &\times Demand\ Charge\ Rate \end{aligned} \tag{2}$$

where *CSP* is OPALCO's peak MWh energy load for the given month; *average HLH load* is the average load across all HLH hours for the month; and *CDQ* is the CDQ (MW) set by BPA that is preset for each month.

OPALCO's CDQs are shown for each month in Table 2.4 below.

Table 2.4. OPALCO Contract Demand Quantities (MW)

Month	CDQ
January	10.557
February	9.877
March	9.049
April	8.336
May	5.661
June	2.964
July	3.04
August	1.537
September	3.725
October	8.608
November	11.397
December	5.808

As before, note the 0.487 that is subtracted from both the CSP and the average HLH (aHLH) in the equation. By subtracting these Tier 2 amounts from the total load, we are ensuring that only the portion of the total retail load that applies to Tier 1 rates is being used in the equation. CDQs are set independently and only for Tier 1 equations, therefore they do not require any adjustment and are already Tier 1 amounts.

The resulting value is charged at the appropriate demand rate for the given month, provided below in Table 2.5.

Table 2.5. BPA Demand Rate for 2018

Month	Rate ($/kW)
January	11.45
February	11.15
March	9.28
April	7.68
May	6.49
June	6.92
July	9.63
August	10.98
September	10.91
October	10.45
November	10.65
December	11.83

The demand charge is also subject to the same LDD discount that applied to the load shaping charge. Therefore, this final calculated value benefits from a 5.61 percent reduction each month (BPA 2011).

2.1.2 Transmission Charge Reduction

OPALCO incurs a small transmission charge each month of $2.103/ kW that is dependent upon its energy purchases during BPA's peak transmission hour in that same month. By using the battery system to reduce the load during predicted peak transmission load hours, costs can be reduced.

To estimate the benefit gained from this use case, we collected historical monthly peak transmission values from BPA for three years. From these historical peaks, the timing of the peaks were defined and built into PNNL's Battery Storage Evaluation Tool (BSET) as a 488 kWh reduction in load during the indicated hours. While the proposed ESS could be discharged at 0.5 MW for four hours, some power capacity is reserved for providing emergency backup power for the telecommunications hub at the Decatur Island Substation. This constraint limits power output to 488 kW. The discharging of the battery along this schedule recovers approximately $1,026 a month and $12,315 annually.

2.1.3 Transmission Submarine Cable Replacement Deferral

Traditionally, Decatur Island has been powered by electricity imported from the BPA system through a 69 kV cable across Rosario Strait with its sending end connected to a BPA substation at Anacortes on Fidalgo Island and receiving end at Lopez Island, crossing over Decatur Island with an overhead line portion. The submarine portion from Anacortes to Decatur Island is shown in the left side of Figure 2.1. OPALCO is now planning to tap from the overhead portion of the BPA 69 kV cable, also identified as Cable 5, to serve the Decatur Island load. The 69 kV line runs adjacent to the Decatur Substation as shown in the right side of Figure 2.1. Once the ESS is installed at the Decatur Island Substation, it could be used to serve loads which will reduce power flow and hence, stress on the submarine cable, resulting in the potential extension of cable life. This extended cable life will apply to both the first cable that is installed as well as a subsequent cable, thereby offering two rounds of benefits that will be included in the base case of this analysis. The following sections present the methodology used for cable lifetime estimation and its application to infer potential lifetime extension of Cable 5 contributed by ESS power discharge.

Figure 2.1. Cable 5 Between Anacortes and Decatur Island (left); ESS Site at Decatur Substation (right)

2.1.3.1 Cable Electrothermal Life Model

The purpose of an electrothermal life model is to estimate the remaining life of an insulated cable when subjected to a given loading cycle that exposes the cable to electrical and thermal stress. A multistress model (Mazzanti 2007) that considers the impact of thermal and electrical stress simultaneously is applied in this work. The model also incorporates a probability of cable failure in the estimation and determines the life at a given design failure probability. A Weibull distribution function is used for the life model. Accelerated aging tests are performed on mini-cable samples to estimate life model parameters that are then factored into the actual cable. The life model used in this work is presented in equation (3) and introduced below.

$$t_P = \left[-\log\left(1 - P_T\right)\right]^{\frac{1}{\beta}} \alpha_0 \left(\frac{E}{E_0}\right)^{-\left(n_0 - bcT\right)} \exp\left(-BcT\right) \tag{3}$$

where,

t_P = the life of the mini-cable sample;
P_T = the failure probability at which the test specimen life is determined;
βI = the shape of the Weibull distribution;
α_0 = the life at 63.2% failure probability;
E = the electric field;
E_0 = the electric field below which aging is negligible;
n_0 = the voltage endurance factor at $T = T_{0;}$
B = the ratio of activation energy of the main thermal degradation reaction to the Boltzman's constant;
b = a parameter that rules the synergism between electrical and thermal stress; and,
cT = the thermal stress determined using $(1/T_0)$-$(1/T)$.

This estimated life determined using (3) can be translated to the actual cable's life (L_D) using the expression below.

$$L_D = t_P \left[\frac{-\log(1-P_D)}{-D\log(1-P_T)} \right]^{\frac{1}{\beta}} \tag{4}$$

where D is the enlargement factor to extrapolate life estimation from test specimen to actual cable and P_D is the design failure probability.

The factor D could be approximated as shown in equation (5) below where l_D, r_D, and l_T, r_T are the length and radius of the actual conductor, and the mini-cable sample, respectively.

$$D \approx \left(\frac{l_D}{l_T} \right) \times \left(\frac{r_D}{r_T} \right)^2 \tag{5}$$

Given that these cables are exposed to a loading cycle at a given time duration (typically 24 hours or daily load cycle), a loss of life fraction (LF) of a cable is estimated for each segment within the loading cycle. Consider the loading cycle of width t_D (24, if daily cycle) contains N number segments. Then, LF for the i-th segment of can be expressed as given below.

$$LF_i = \frac{t_D}{L_D \times N} \tag{6}$$

According to Miner's cumulative damage theory, the sum of all life fractions lost should yield 1 at failure. Therefore, the total number of cycles before failure could be estimated using the equation below.

$$K = \left[\sum_{i=1}^{N} LF_i \right]^{-1} \tag{7}$$

Equations (3)-(7) were used for life curve modeling of Cable 5 and estimation of the life time extension as a result of reducing peak load on the cable using ESS discharge.

2.1.3.2 Cable 5 Case Study

Cable 5 is a 69 kV 3 core XLPE insulated cable manufactured by Nexans. The cable installation has both submarine and land portions with different current ratings specified for different portions of the cable. The lowest of the specified current ratings is used in the analysis. The submarine portion of Cable 5 and its proposed tapping to the Decatur Substation is shown in the single line diagram of Figure 2.2 (left side).

Investigation of cable life time using the electrothermal life model essentially involves assessment of thermal stress on the cable exerted by the loading cycles and electrical stress caused by applied voltage. Temperature variation in a cable as a result of loading could be estimated in a number of ways ranging from transient models (Stojanovic 2013) based on detailed physical parameters (e.g., thermal resistance, capacitance, surrounding medium, cable laying and installation method) of the cable to a more simplistic curve fitting technique (Yenchek 1993) providing steady state temperature.

To work with the present level of information available on the cable installation, a curve-fitting approach is used in this version of this work. Given that the cable is short (7.55 km), analytical modeling shows that voltage rise across the cable is not very significant. Therefore, electric stress calculated based on rated applied voltage is considered in the life model. With the availability of sending and receiving end voltage of the cable in the future, further analysis will be performed to study the impact of increased electric field stress on the feeder and possible mitigation using volt-ampere reactive (VAR) power compensation from ESS inverters. Information on cable parameters used for electric field stress is obtained from the cable cross section diagram (right side of Figure 2.2) provided by OPALCO. Cable parameters and ratings, as extracted from the information provided by OPALCO, is listed in Table 2.6.

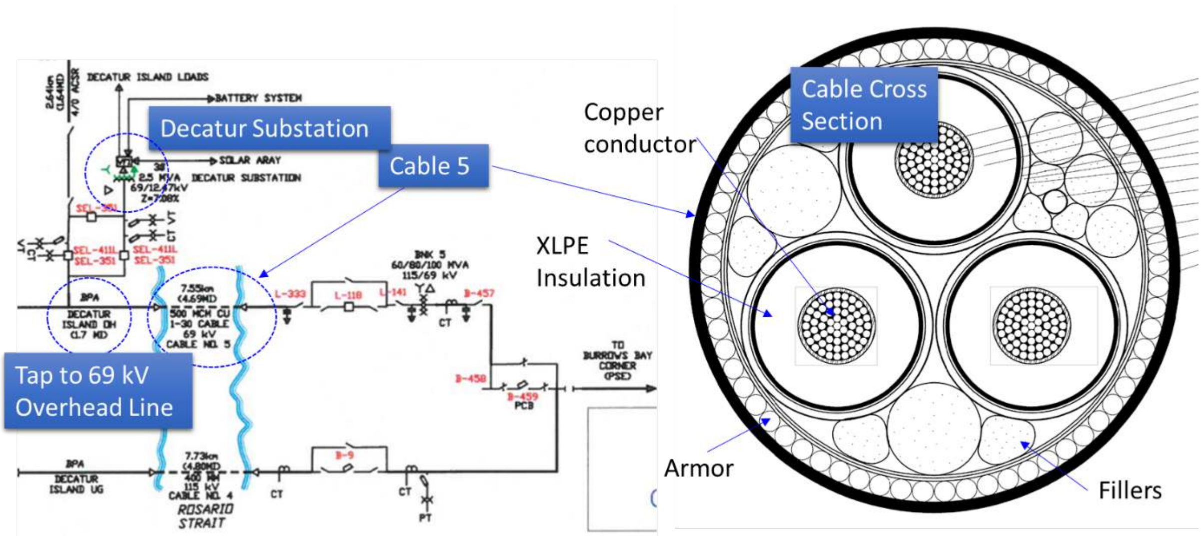


Figure 2.2. Cable 5 and ESS site at Decatur Substation in the OPALCO Single Line Diagram (left); Cable 5 Cross Section (right)

Table 2.6. Cable Specifications

Parameter	Value
Length	7.55 km
Conductor Cross Section	500 mm^2
Conductor Radius	12.75 mm
Insulation Thickness	12 mm
Minimum Current Rating	460 A

2.1.3.3 Fitting a Life Model

The electrothermal life model described using Equations (3)-(5) is fitted using the parameters listed in Table 2.7. As the life parameters used are extracted from the accelerated aging test results obtained using mini-cable samples of a 145 kV cable of specifications, adjustment of some parameters values is performed to fit the model. The per-unit (with respect to a rated life of 30 years) life curve using the parameters in Table 2.7 is shown in Figure 2.3. The curve shows that life at 293 degrees K (or 20 degrees C) is approximately 1,200 times the rated life at 90 degrees C and exponentially reduces as operating temperature increase and converges to rated life at 90 degrees C or 363 degrees K. With ESS discharging, cable loading and operating temperature will decrease and contribute to extending cable life.

Table 2.7. Electrothermal Life Model Parameters

Parameter	Values
E_0	3.04 kV/mm
E	4.35 kV/mm
T_0	293 deg. K
α_0	9.5×10^{14}
β	2
b	4420
B	12430
n_0	15
P_D	0.05
P_T	0.632

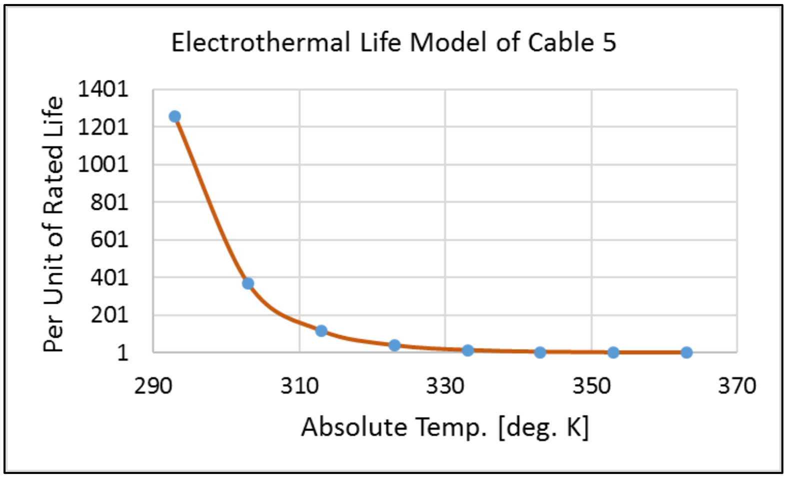


Figure 2.3. Electrothermal Life Model of Cable 5

2.1.3.4 Estimate Life Extension with ESS Discharge

For this step, it is first required to determine a suitable load cycle for the cable. Examining the cable load data provided by OPALCO for three weeks in December 2017, it was found that the daily load cycles vary substantially among adjacent days. Therefore, a two-week duration was considered as a cycle instead of a daily load cycle, as shown in the left side of Figure 2.4. In the future, cable loading data will be collected for a longer duration from OPALCO to determine a more representative loading cycle. Generally, the cable load profiles show two peaks, morning and evening. Therefore, ESS discharge profile for this application was constructed using four hours of discharge at 0.488 MW. Although the proposed ESS is able to discharge at 0.5 MW for four hours, some power capacity is reserved for providing emergency backup power for the telecommunications hub at the Decatur Island Substation. One of the days within the two-week cycle is shown in the right side of Figure 2.4, which identifies the two peak periods and the load reduction by ESS discharge. Based on this discharge strategy, cable life is inferred for the given load cycle with and without ESS as 50.73 and 47.08 years, respectively, producing an estimate of 3.65 years of life extension.

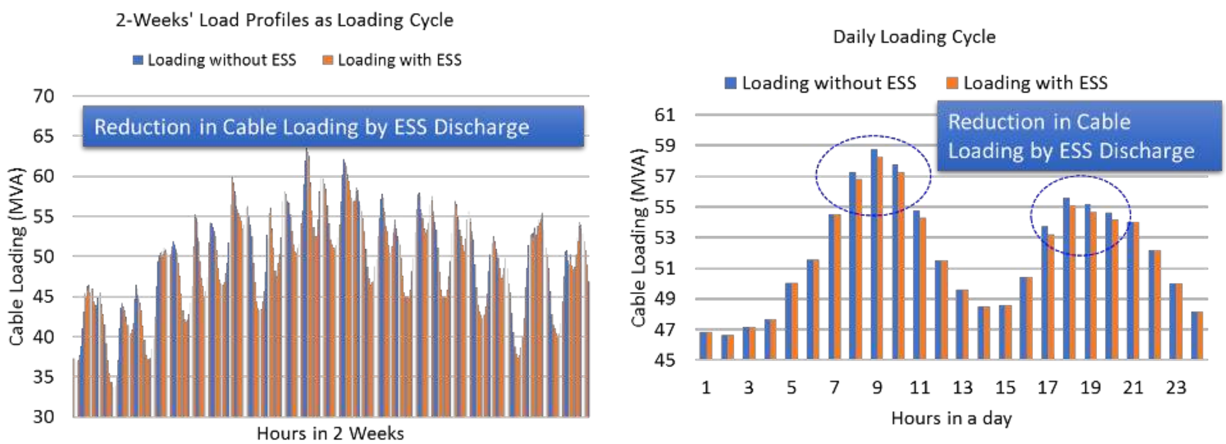


Figure 2.4. Two-Weeks Load Profile as Loading Cycle (left); Daily Load Profile Showing Reduction in Loading Due to ESS Discharge (right)

Estimation of Cable 5 lifetime using the electrothermal life model in the current version of this work relies on aging test parameters of a different cable specimen available from literature. In the future versions, efforts will be given to obtain aging test parameters of a cable of similar or closer specification. PNNL will further engage with OPALCO and BPA to obtain currently unavailable data and will incorporate it into the life estimation model.

2.1.4 Volt-VAR/Conservation Voltage Reduction

Conservation Voltage Reduction (CVR) is an approach to intentionally reduce the system voltage in such a way that the customers' voltage stays within allowable bounds but at the same time reduces the power and energy consumption due to the existence of voltage-dependent loads. A number of utilities have exercised this approach in some way or other in their network 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. An ESS 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 degree depending on the location of the ESS, available VAR capability of the ESS inverter, and VAR to voltage sensitivity of the feeders.

The general expression used for assessment of CVR benefits is shown in Equation (8) 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 percent reduction in voltage, determined experimentally/ empirically/ or, otherwise) for active power, ΔV 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 engagement area, and k is a given time instant when the benefit is being assessed.

$$P_{red}\left(k\right) = \sum_{i=1}^{n} CVR_{fP} \times \Delta\left|V\left(k\right)\right|_i \times P_i\left(k\right) \tag{8}$$

PNNL, as a part of its economic evaluation effort, conducted an analysis using 2017 load data from the Decatur Substation serving Decatur and Center Islands by deploying the ESS inverter capacity for CVR operations. CVR factor and voltage sensitivity data determined from previously conducted tests at

Portland General Electric was used as a basis for estimation. Based on these inputs and considering the most optimistic assumption that the entire inverter capacity is available for VAR operation, the CVR factor benefits for the entire year was estimated to be $226, which is negligible. Therefore, CVR benefit analysis is currently excluded from further assessment.

2.1.5 PV Production

The methods and models used to estimate PV production are detailed in Section 1.3. The analysis of PV production completed for this study resulted in hourly production values, which we used to evaluate the associated impacts on load shaping charges, demand charges, transmission charges, and transmission submarine cable replacement deferral benefits using the methods outlined previously in this section. The energy value of PV production was monetized using the valuation approach outlined in Section 2.2. We also include the value of lost revenue as a cost to OPALCO based on current OPALCO rates for residential customers at 10.7 cents/kWh.

2.1.6 Outage Mitigation

In the event of an outage, the ESS would have the capacity to effectively operate in an islanded mode on Decatur and Center Islands. This benefit would result in benefits accruing to OPALCO customers located in the area of the outage and are monetized in terms of avoided loss of load. Because these benefits accrue to the customers and not OPALCO, associated benefits are excluded from the base case.

For the Decatur Island Substation, there are two components that must be considered to evaluate the full benefit of mitigating outages. Co-located with the battery is an array of communication network equipment that relies on power to stay operational. A map of the communications system is shown in Figure 2.5. A loss of power to the substation would simultaneously result in a loss of the communications system across multiple islands.

Figure 2.5. Fiber Cable Network that Provides Communication Services to the San Juan Islands

In the past there have been occurrences of long communication system outages. The longest outage occurred in November of 2013 that resulted in a loss of local calls and data communications on San Juan, Lopez, Orcas, Blakely, Decatur, and Shaw Islands for 10 days. The outage affected a total of 15,921 access lines and 11,000 voice customers and caused a total loss of approximately $175,000 to 50 local businesses (Wehrly 2013). During the first two days of the outage, customers on three of the islands (Orcas, Decatur, and Lopez) were unable to contact other islands, disabling their ability to reach 911 for emergency services given that their connection to the Friday Harbor Central Office host switch was severed. The outage was also responsible for impacting cellular service (WUTC 2014).

The Federal Communications Commission (FCC) has recently changed the requirement associated with backup power at certain communication sites. Rather than requiring eight hours of backup (the previously established requirement), they now require 24 hours of emergency power (FCC 2015). To meet this new requirement, 48 kWh of energy must be held in reserve in the battery specifically for this purpose at all times and cannot be used for other use cases.

As part of the total benefit calculation for avoiding a communication system outage, the cost of generation equipment that would otherwise be purchased to meet the 24-hour requirement needs to be taken into consideration. OPALCO has estimated the capital cost of a backup generator to be approximately $8,500, with an additional $500-$1,000 in annual maintenance costs.

In addition to the communication system outage mitigation, the battery has the potential to "island" customers on both Decatur and Center Islands in the case of total system power loss. By working with the community solar available at the substation location, the possibility of totally eliminating outage impacts is plausible.

To estimate the benefits that can be derived from outage mitigation, historical events were examined at the Decatur Island substation site. From these historical occurrences, the timing and duration of the outages were defined. This historical data is presented below in Table 2.8:

Table 2.8. Historical Outage Affecting Customer on Decatur and Center Islands (2009-2017)

Date	Outage Start Time	Outage Duration (Minutes)
04/23/2009	17:44	179
04/2/2010	09:38	171
09/15/2011	23:24	363
05/09/2014	00:04	329
11/17/2015	13:34	128
11/26/2017	12:02	48

Based on the historical data above, we estimate that customers on Decatur and Center Islands face, on average, one unplanned outage per year lasting 152 minutes.

Though the ESS system will be deployed on Decatur Island, an outage at the substation affects customers on both Decatur and Center Islands and the avoided cost of an outage to both must be included in the analysis. The breakdown of types of customers at each location is shown in Table 2.9 where small commercial customers are those with loads of 50,000 kWh or less per year.

Table 2.9. Customer Breakdown by Type on Decatur Island & Center Island

Description	Decatur Customers	Center Customers
Residential	397	218
Small Commercial	16	4
Total	413	222

In order to assign monetary values to reducing or eliminating potential outages, the findings of Sullivan et al. (2015) from Lawrence Berkeley National Laboratory are used. This process estimates costs based on customer group (residential, commercial, or industrial), the duration of the outage, the time of year the outage occurred, and the time of day the outage began.

A scenario was run in which every historic outage (data, time duration) shown in Table 2.8 struck in one year (2017). Therefore, the evaluation herein assumes that the projected annual 152-minute outage can be mitigated in its entirety.

The savings to customers on Decatur and Center Islands is estimated to be $21,093 annually based on the Sullivan et al. (2015) cost assumptions and the customer profiles of both islands. As mentioned previously, this benefit is not included in the base case economic evaluation due to the fact that the value does not accrue to OPALCO directly.

2.2 Valuation Modeling Approach

BSET was used to run a one-year simulation of energy storage operations. The model performed an hourly look-ahead optimization to determine the battery base operating point. 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).

BSET was used to define the potential economic benefit of the ESS on an annual basis and determine the number of hours the system would be actively engaged in the provision of each service under optimal conditions and in combination with the PV production. BSET also determined the annual number of hours the ESS would be optimally engaged in the provision of each use case.

2.3 Estimating Energy Storage Costs and Revenue Requirements

The CEF is a matching grant program; that is, part of the cost of the project is incurred directly by OPALCO. Individual cost components of the project are presented in Table 2.10. Table 2.10 also presents the cost allocation for each of the participating parties. Note that 100 percent of the costs associated with the community solar project are allocated to participating customers. That cost is, therefore, not included in this assessment. What is included is the approximately $1.0 million in lost revenue resulting from PV production. Also note that although OPALCO received a $1 million grant for the project from the CEF, $95,000 of that amount was assigned to analytics support provided by PNNL. That leaves $905,000 for engineering, design, and equipment purchases.

Table 2.10. Estimated Costs for the Decatur Island Community Solar and ESS Project

Cost by Item		Cost Allocation		
Item	**Cost**	**OPALCO**	**WA CEF**	**Community Solar Participants**
PV System	$828,146			$828,146
Battery	$1,500,000	$595,000	$905,000	
Installation costs	$300,000	$300,000		
Electrical	$90,000	$90,000		
Site/Civil	$110,000	$110,000		
Overheads	$70,000	$70,000		
WA Sales Tax	$160,000	$160,000		
Contingency	$100,000	$100,000		
Total	**$3,158,146**	**$1,425,000**	**$905,000**	**$828,146**

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 the ESS was prepared to estimate revenue requirements. Major parameters used in the pro forma are presented in Table 2.11.

Table 2.11. Major Parameters Used in Estimating ESS Revenue Requirements

Parameter	Value	Source
Energy Storage Book Life	20 years	UET Proposal
Annual Battery O&M	$30,000	UET Proposal
Insurance Rate	0.271%	OPALCO
Borrowing Rate	3%	OPALCO
Cost of Capital	5.47%	OPALCO
Property Tax Rate	.345%	OPALCO
Inflation Rate	3.25% for the next five years followed by 4% in all subsequent years	OPALCO

Based on the combination of costs and assumptions outlined previously in this section, we were able to produce revenue requirements that accounted for full system costs, including all taxes, debt, and insurance costs. The cost to OPALCO customers for the ESS is estimated at $1.6 million. That value includes the effect of the subsidy provided through the CEF grant.

3.0 Economic Results

3.1 Introduction

This report presents the findings of a study not only designed to enhance the value that the Decatur Island Community Solar and Energy Storage Project can provide to OPALCO, but to also aid in the development of a framework for evaluating the technical and financial benefits that energy storage can deliver to Washington utilities and the customers they serve more broadly. In doing so, the analysis could be useful to other utilities facing similar investment decisions and those trying to extract maximum value from existing energy storage assets. This report represents the final technical output of the first phase of a three-phase project. Future phases will focus on implementing a detailed testing program for the ESS on Decatur Island, which as of July 2018 had not been deployed, and then reevaluating the financial performance of the project using a detailed characterization of the performance of the ESS.

3.2 Energy Cost Assumptions

BPA, the federal agency that provides power to the San Juan Islands, relies on a unique tariff structure. Rather than charging a $/kWh rate for hourly consumption, BPA instead charges each of its customers a pre-calculated, flat charge for all energy usage each month that is independent of their actual, real-time demand. The monthly energy charge is instead dependent on past energy consumption and a forecast of the customer's load for each month made on a two-year basis. Through this forward-looking process, BPA defines the energy it anticipates provided to each of its customers. This load forecast is then evaluated as a proportion of the total amount of energy BPA will have to provide to all customers in total. This ratio, distinct for each customer, is called the TOCA, and it represents that customer's "share" of BPA's cost base.

For OPALCO, which makes up a very small portion of BPA's system, its calculated TOCA value for 2018 is 0.35 percent. For much larger customers, this value is much higher. Snohomish Public Utility District (SnoPUD), BPA's largest customer, for example, has a TOCA value greater than 11 percent (BPA 2018).

As an example of how this process determines OPALCO's energy charge, suppose that BPA estimates that it will incur a cost of $200 million to provide energy to all its customers in a particular month. If it projects that for the given year OPALCO will account for 0.35 percent of its entire demand, then OPALCO is charged 0.35 percent of that total $200 million cost that month, or approximately $740,000.

Both the total expected cost of BPA's system, as well as OPALCO's TOCA, are values that are adjusted on a bi-annual basis. Due to this structure, changes to OPALCO's energy consumption do not have immediate effects on costs incurred, but rather result in effects in the years that follow. As a result, all activity associated with an ESS pulling energy from BPA's grid to charge up will appear as if it does not result in a direct energy cost for the co-op. This activity will, however, contribute to the next forecast BPA makes of OPALCO's expected load and future costs OPALCO will pay.

Evaluating energy storage costs on a per-hour basis is necessary to appraise the expected economic value it can provide to a system. Not incorporating a cost of charging energy would lead to a large inflation of the net benefits the ESS brings to OPALCO's system. For this reason, we devised a way to conduct the analysis as if there were an hourly cost through an estimated energy price. By doing so, real time analysis is possible and a more accurate estimation of total ESS benefits is provided.

The hourly energy price was estimated through a simple calculation. By taking the energy cost OPALCO incurred in 2017[1] and dividing that value by its total kWh load for the same year, an average $/kWh rate is obtained. This calculated value was 3.2 cents/kWh for the year. The model described later in this section also accounts for the round-trip efficiency losses associated with the charging and discharging of the ESS, and the impact of those losses on energy costs.

3.3 Evaluation of Project Benefits and Revenue Requirements

There is a multi-dimensional competition for the energy stored in the battery at all times. This competition has an intertemporal component in that the use of energy in the present hour limits the ability of the ESS to provide a service in the next. In addition, there is competition for ESS energy between use cases. 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 usage conflicts, the research team employed BSET. The model co-optimizes the benefits under the base case, limiting the value to what is technically achievable by the ESS.

Battery and community solar benefits for the base case ($3.3 million) exceed the costs ($2.9 million) for the Decatur Island Community Solar and Energy Storage Project (Table 3.1 and Figure 3.1). The most valuable application is transmission submarine cable deferral, which generates nearly $2 million in present value (PV) benefits. The second highest value application is demand charge reduction at $0.74 million, followed by energy production from the PV system at just over $313,000. The remaining values are, in descending order, transmission charge reduction, load shaping charge reduction, generator cost avoidance, and CVR. Total costs include those associated with revenue lost as a result of PV production for community solar members, energy losses resulting from ESS operations, and the energy storage rate impacts defined in Section 2.3.

Table 3.1. Benefits Estimates by Use Case

Element	Benefits	Costs
Load Shaping Charge Reduction	$36,404	
Demand Charge Reduction	$739,802	
Transmission Charge Reduction	$227,331	
Outage Mitigation	$-	
Volt-VAR/CVR	$3,380	
Transmission Deferral	$1,957,878	
Gen Set Cost Avoidance	$19,706	
PV Energy Production	$313,434	
Lost Revenue		$1,048,0146
Energy Losses		$315,457
Energy Storage System Rate Impacts		$1,567,144
Total	$3,297,936	$2,930,647

[1] The total energy cost includes the customer composite charge and PNGC AHWM power costs, which account for Tier 2 costs.

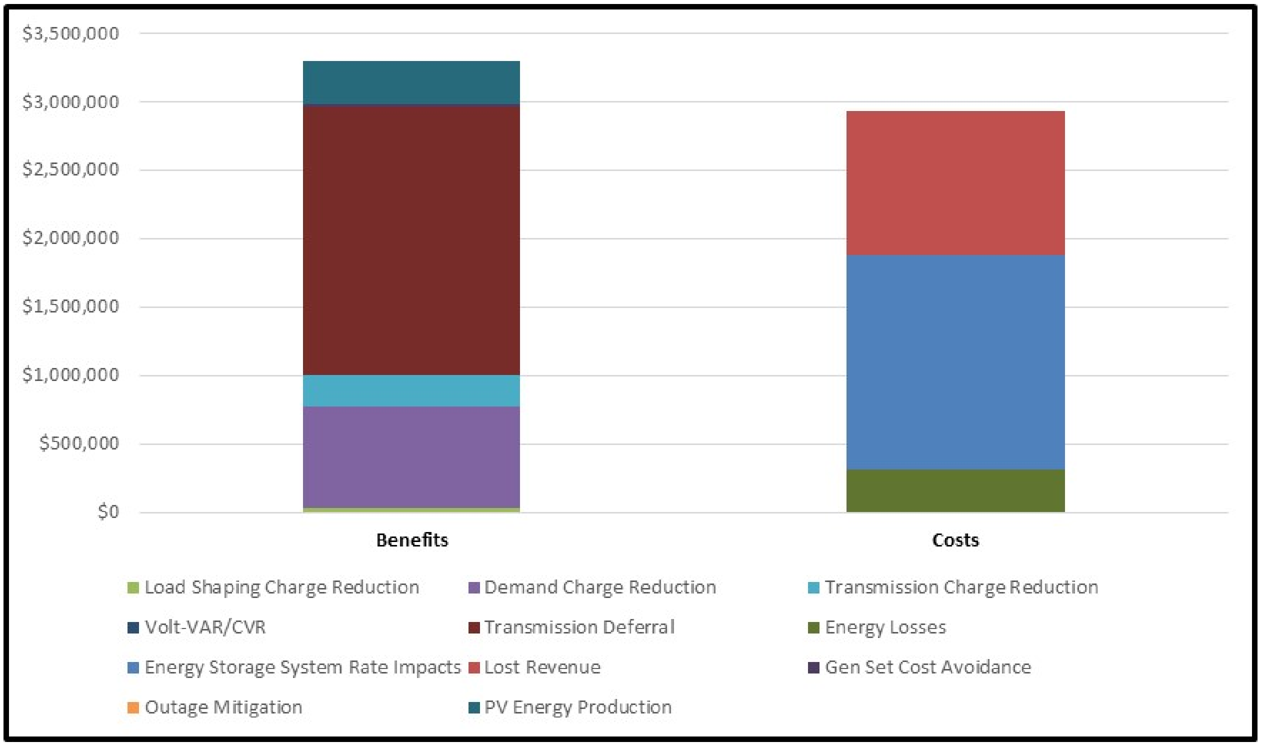


Figure 3.1. 20-Year Present Value Benefits vs. Cost

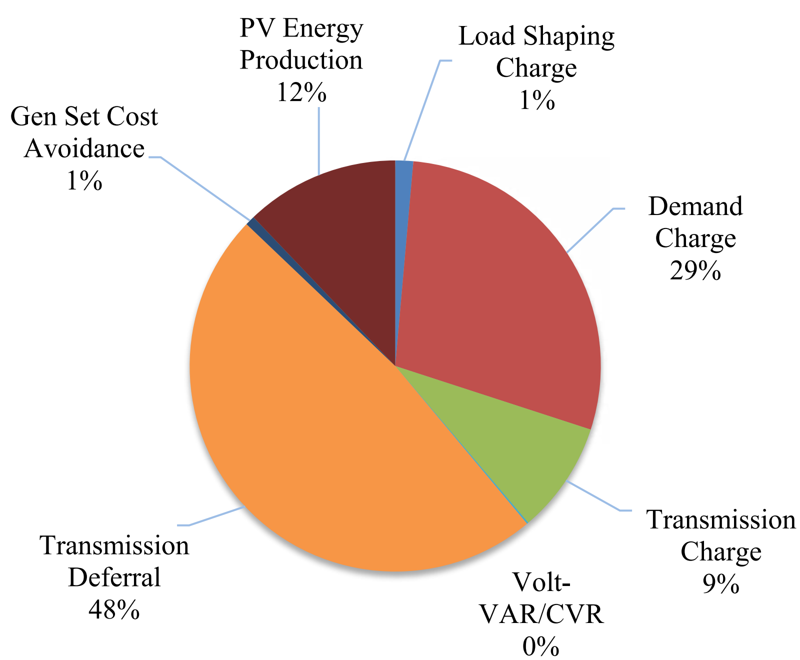


Figure 3.2. 20-year Present Value Percentage Breakdown by Benefit Type

3.4 Impact of PV and ESS on OPALCO Bill

By reviewing the effects of PV generation and the ESS together, we were able to discover the impact of the assets on OPALCO's energy bill each month. These values are shown in Table 3.2.

In 2017, the annual bill could have been reduced by $59,375 with the inclusion of the assets at the Decatur Island Substation. From this analysis, it is possible to determine that the energy storage device is effective at reducing transmission and demand charges, but that the community solar actually increases demand charges by reducing loads during heavy load hours. This latter impact is due to the presence of the aHLH component in the demand charge equation described in Section 2.1.1.2 where a lower aHLH value leads to a greater deviation between customer system peaks and the aHLH value. Between the two assets, the battery is responsible for 82 percent of the estimated benefits associated with the components of the OPALCO bill highlighted in Table 3.2. Note that in addition to these benefits are those tied to submarine transmission cable deferral and the avoided energy costs associated with PV production.

Table 3.2. Impacts of the PV and ESS on OPALCO's Monthly Bill, Excluding TOCA Impacts

	Demand Charge	Load Shaping Charge	Demand Charge + Load Shaping Charge	Transmission Charge	Total
January	($4,234)	$617	($3,617)	($1,026)	($4,643)
February	($4,042)	$355	($3,687)	($1,026)	($4,713)
March	($3,204)	$10	($3,194)	($1,026)	($4,220)
April	($2,311)	($374)	($2,685)	($1,041)	($3,726)
May	($2,046)	($824)	($2,870)	($1,440)	($4,310)
June	($2,385)	($1,200)	($3,584)	($1,295)	($4,879)
July	($4,737)	($1,248)	($5,985)	($1,155)	($7,140)
August	($5,360)	($914)	($6,273)	($1,178)	($7,451)
September	($3,386)	($441)	($3,827)	($1,183)	($5,010)
October	($3,667)	$303	($3,364)	($1,026)	($4,390)
November	($3,855)	$619	($3,235)	($1,026)	($4,261)
December	($4,547)	$942	($3,605)	($1,026)	($4,631)
Total	**($43,773)**	**($2,155)**	**($45,928)**	**($13,448)**	**($59,376)**

3.5 Energy Storage System Benefits and Costs in Isolation

When the benefits and costs of the community PV system are removed from the analysis, the following impacts are experienced:

- Load shaping benefits are reduced;
- Transmission deferral benefits are reduced;
- There is little effect on either demand or transmission charges; and,
- All associated lost revenue from PV are eliminated.

Figure 3.3 below shows the PV benefits versus costs of the 20-year energy system in isolation. The net benefits of the ESS system are approximately $2 million while total cost, exclusive of PV system costs, is

$1.9 million, resulting in a benefit-cost ratio of 1.09. Under this scenario, the load shaping charge is higher as a result of increased battery activity in replacement of the PV generation during heavy load hours and leads to a negative benefit for that application. The $1.9 million total present value costs exceed the revenue requirements identified in Section 2.3 because total costs include those associated with energy losses and $30,000 in annual operations and maintenance (O&M) costs.

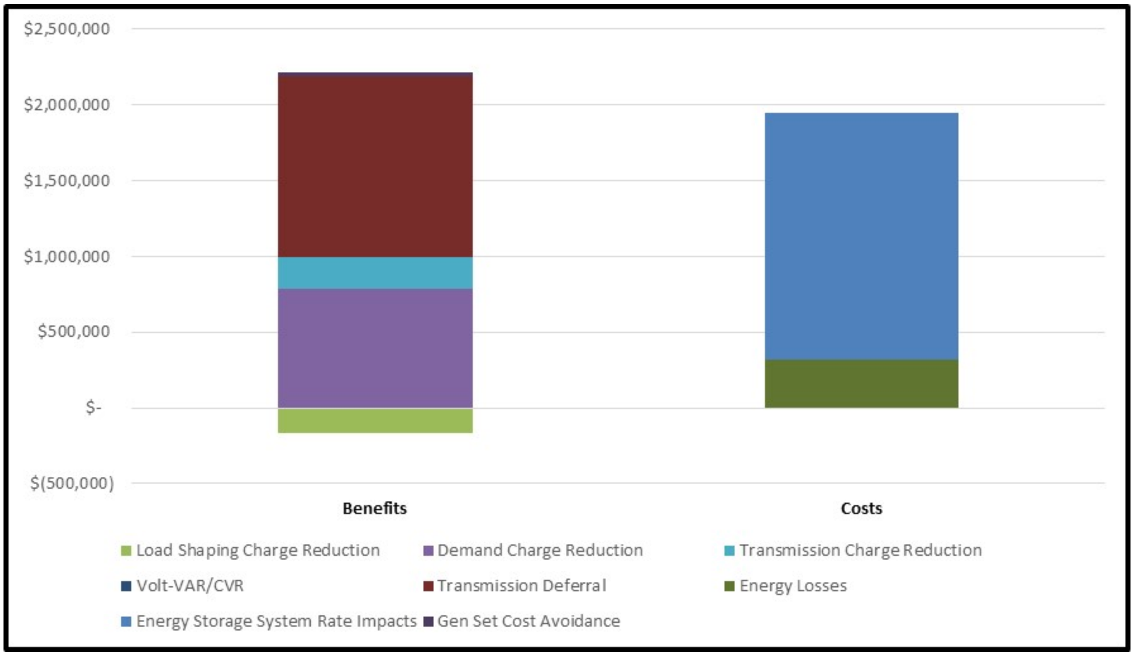


Figure 3.3. 20-year Present Value Benefits vs. Costs with Battery in Isolation

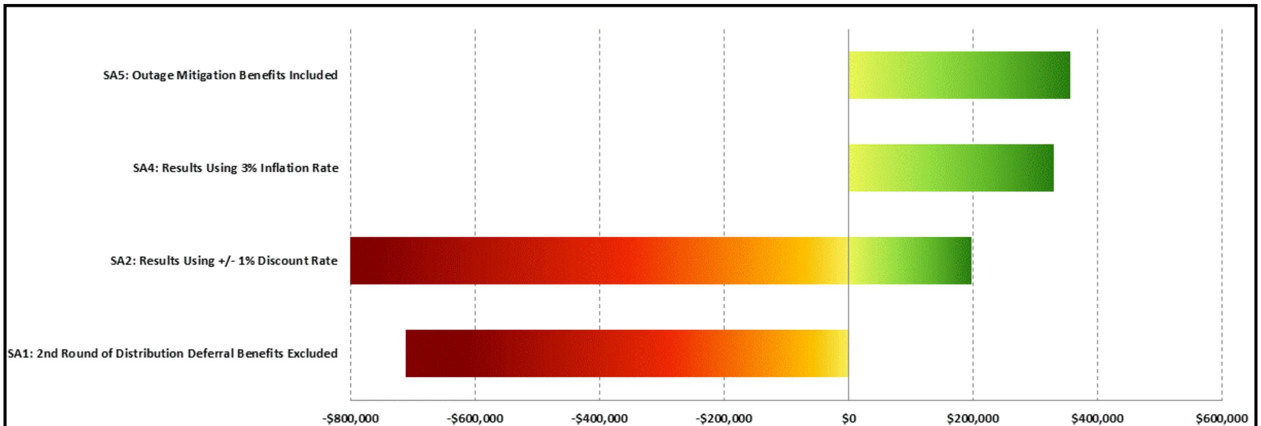
3.6 Evaluation of Alternative Scenarios and Sensitivity Analysis

To explore the sensitivity of the results to varying a number of key assumptions, the research team conducted a series of sensitivity analyses. The various scenarios are outlined below and their impacts were measured in comparison to the base case. Sensitivity analysis was performed by making the following adjustments to the assumptions:

- SA 1: 2nd Round of Distribution Deferral Benefits Excluded
- SA 2: +/- 1% Discount Rate Used
- SA 3: 3% Inflation Rate Used
- SA 4: Outage Mitigation Benefits Included

The results of each sensitivity analysis are presented in Figure 3.4. Note the table that appears below the figure. As shown, the changes in discount 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 return on investment equation.

Two of the five evaluated scenarios resulted in negative impacts to the economic results compared to the base case. The most negative impact resulted from lowering the discount rate by one percentage point. While counterintuitive as lower discount rates typically increase present value benefits, in this case the lower discount rate greatly reduced the present value benefits of deferring a future investment in a submarine transmission cable. The 2nd worst return on investment ROI was found in the scenario in which the 2nd round benefits from transmission cable deferral were excluded from the analysis. Under this scenario, the first cable replacement is deferred by 3.65 years; however, the benefits derived from the deferral of the subsequent replacement cable are not included and the net present value benefits drop by approximately $700,000 as a result (Figure 3.4). Adjusting the inflation rate to three percent increased net benefits by approximately $400,000. Increasing the discount rate by one percent improved net benefits by approximately $356,000 in present value terms. Also on the positive side, including outage mitigation as a benefit increased total present value by over $350,000.



	SA1: 2nd Round of Distribution Deferral Benefits Excluded	SA2: Results Using +/- 1% Discount Rate	SA4: Results Using 3% Inflation Rate	SA5: Outage Mitigation Benefits Included
High-End		$197,401	$329,873	$356,490
Low-End	(711,136)	$(879,306)		

Figure 3.4. Sensitivity Analysis Results

Figure 3.5 presents the ROI ratio for the various scenarios defined as part of the sensitivity analysis. The ROI ratio is defined as present value benefits divided by present value costs under each defined scenario. Note that cells shaded yellow have ROI ratios between 0.5 and 1.0 and cells shaded green represent scenarios with ROI ratios in excess of 1.0. When the cost estimates presented by OPALCO are used in the denominator of the ROI calculations, the majority of the scenarios yield ROI ratios in excess of 1.0, meaning that present value benefits exceed present value costs. The only scenarios that did not result in an ROI greater than 1.0 were the sensitivity analysis in which the 2nd round transmission cable deferral benefits were excluded and the scenario using a lower 4.47 percent discount rate. Typically, lowering the discount rate would result in a higher ROI due to a lower impact on future year benefits. In this case, however, the lower discount rate significantly reduces the benefits of deferring a future investment in a transmission submarine cable.

Base Case	2nd Round of Deferral Benefits Excluded	Results Using 4.47% Discount Rate	Results Using 6.47% Discount Rate	Results Using 3% Inflation Rate	Outage Mitigation Benefits Included
1.13	0.86	0.74	1.26	1.25	1.22

Figure 3.5. Return on Investment Ratios for Alternative Scenarios

4.0 Conclusions

This assessment examined the financial feasibility of a battery energy storage system co-located with a community solar PV system at a substation on Decatur Island, Washington. The analysis conducted was done so by monetizing the values derived from several services the project could provide to OPALCO and the customers it serves. The battery and the grid conditions in which it will operate were modeled and an optimization tool was employed to explore tradeoffs between services and to develop optimal control strategies.

These results provide crucial insights into the practical application of the energy storage and solar project. The following lessons were drawn from this analysis.

5. Based on its initial design and cost documents prepared by OPALCO, the Decatur Island Community Solar and ESS Project generates positive net benefits under the base case scenario. OPALCO energy storage and community solar benefits for the base case ($3.3 million) exceed associated costs ($2.9 million), producing a BCR of 1.13.
6. When ESS costs and benefits are analyzed in isolation, net benefits fall to $146,607 and the BCR is 1.08. This scenario reduces load shaping and transmission deferral benefits but has little effect on demand and transmission charges. With outage mitigation benefits included within this scenario, net benefits increase to $0.5 million and the benefit-cost ratio rises to 1.27.
7. By reducing stress on the 69 kV submarine transmission cable that distributes power to OPALCO from the mainland, the high-cost replacement of the cable is deferred by 3.65 years. This use case generates nearly $2 million in benefits in present value terms, making it the most valuable application of those modeled in the analysis. The next most valuable application is the demand charge reduction, which generates over $700,000 in present value benefits.
8. Outage modeling indicates that all power loss events occurring on Decatur and Center Islands over the past eight years could have been mitigated with the presence of both PV and the ESS. The average annual benefit of avoiding these outages is approximately $21,000. This benefit was not included in the base case analysis, however, as it is a value that only accrues to OPALCO members and not to the utility itself.
9. By evaluating data from 2017, it was discerned that the effects of PV generation and the ESS together reduces OPALCO's energy bill by $59,375 annually, excluding impact on the OPALCO TOCA. The energy storage device would be effective at reducing transmission and demand charges. Community solar actually increases demand charges by reducing average high load hour loads. This latter impact is true due to the presence of the aHLH component in the demand charge equation where a higher deviation between the customer system peak and the aHLH value leads to a higher demand charge. The ESS would be responsible for 82 percent of the estimated benefits.
10. Two out of five sensitivity analysis scenarios evaluated in this report would result in negative impacts to the economic results compared to the base case. The most negative impact was found by reducing the discount rate by one percentage point. Doing so significantly reduces the present value benefits associated with deferring investment in the submarine transmission cable. The other scenario that results in negative impacts to net benefits was the one where the 2nd round of benefits from transmission cable deferral were excluded. Under this scenario, the first cable replacement is deferred by 3.65 years; however, the benefits from the deferral of the subsequent cable are not included and the present value net benefits drop by approximately $700,000. Adjusting the inflation rate to 3 percent increased net benefits by $300,000. Also on the positive side, including outage mitigation as a benefit increased total present value benefits by over $350,000 and increasing the discount rate by one percent caused benefits to rise by approximately $356,000.

This report represents the output of the preliminary economic analysis for the Decatur Island Community Solar and Energy Storage Project as part of Washington CEF II. The next phases will include battery acquisition and installment, battery testing procedures, and a final economic evaluation.

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Appendix A

Supplemental Data Tables

Appendix A

Supplemental Data Tables

Table A.1. Benefits Estimates by Use Case for Base Case, 2nd Round of Deferral Benefits Excluded, and Results Using 4.47% Discount Rate

Use Cases	Base Case	2nd Round of Deferral Benefits Excluded	Results Using 4.47% Discount Rate
Load Shaping Charge Reduction	$36,404	$36,404	$40,234
Demand Charge Reduction	$739,802	$739,802	$817,619
Transmission Charge Reduction	$227,331	$227,331	$251,244
Outage Mitigation	$-	$-	$-
Volt-VAR/CVR	$3,380	$3,380	$3,736
Transmission Deferral	$1,957,878	$1,246,742	$938,309
Gen Set Cost Avoidance	$19,706	$19,706	$21,086
PV Energy Production	$313,434	$313,434	$346,403
Net Value	$3,297,936	$2,586,800	$2,418,630

Table A.2. Benefits Estimates by Use Case for Results Using 6.47% Discount Rate, Results Using 3% Inflation Rate, and Outage Mitigation Benefits Included

Use Cases	Results Using 6.47% Discount Rate	Results Using 3% Inflation Rate	Outage Mitigation Benefits Included
Load Shaping Charge Reduction	$33,077	$33,674	$36,404
Demand Charge Reduction	$672,183	$684,322	$739,802
Transmission Charge Reduction	$206,553	$210,283	$227,331
Outage Mitigation	$-	$-	$356,490
Volt-VAR/CVR	$3,071	$3,127	$3,380
Transmission Deferral	$2,277,166	$2,364,042	$1,957,878
Gen Set Cost Avoidance	$18,499	$18,926	$19,706
PV Energy Production	$284,786	$313,434	$313,434
Net Value	$3,495,337	$3,627,809	$3,654,426

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