Sensitivity: Public

Non-Wires Solution Study to Support Friday Harbor Ferry Electrification

Technology strategy to support OPALCO's sustainable electrification vision

Hitachi Energy

Non-Wires Solution Study to Support Friday Harbor Ferry Electrification

Technology strategy to support OPALCO's sustainable electrification vision

Contents

Sensitivity: Public

List of Figures

List of Tables

Terms and Abbreviations

Terms & Abbreviations	Definition
OPALCO	Orcas Power and Light Company
NWS	Non-Wires Solution
WSF	Washington State Ferries
GES	Grid Edge Solution
IRR	Internal Rate of Return
T & D	Transmission & Distribution
CEF	Clean Energy Fund
SLD	Single Line Diagram
BPA	Bonneville Power Administration
PRDM	Public Rate Design Methodology
TRM	Tiered Rate Methodology
PoC	Provider of Choice
PNGC	Pacific Northwest Generating Cooperative
LLH	Light Load Hours
HLH	Heavy Load Hours
Fixed CC	Fixed Customer Charge
SLA	Service Level Agreement
JOE	Joint Operating Entity

Revisions

Rev.	Author	Description of Version	Date Completed/Init.
A	Grace Sadhana S	In Review	09-14-2024
B	Hamideh Bitaraf,Ph.D.	Approved	11-12-2024

1 Executive Summary

Context: Orcas Power and Light Company (OPALCO) plans to expand its grid modernization infrastructure targeting key cross-sectoral decarbonization goals to benefit Washingtonians. The primary focus is grid infrastructure development in the form of a Non-Wires Solution (NWS) in Friday Harbor that enables equitable, decarbonized transportation to the San Juan islands, particularly in consideration of "Washington State Ferries' (WSF) 2040 Long Range Plan". The NWS study focuses on the grid infrastructure to enable decarbonized electricity for the planned (hybrid) electric ferry at Friday Harbor. The NWS includes a combination of solar photovoltaic (PV), and battery energy storage systems (BESS). BESS is a key component of the potential NWS due to its ability to provide a transformative set of services to enable electrification.

Opportunity: OPALCO needs guidance on the conceptual design of BESS with distributed solar PV deferring the infrastructure upgrades of the existing utility grid. Hitachi Energy Grid Edge Solutions Advisory and Power Simulations Team provides analysis and expertise for this conceptual design.

Overview of Analysis: Project analysis for the conceptual design of the NWS study includes the following sections. 1) The Existing Infrastructure assessment consists of the current infrastructure in the Friday Harbor substation area, focusing on the grid constraints and limitations. 2) The load growth study involving the creation of baseline load and load projections captured under Business-as-usual electrification, data collection, and processing on the ferry-related transportation that may be electrified. For the baseline load projection, the historical load usage data in the Friday Harbor substation area, with the business-as-usual load growth based on the trends in load growth and guidance from OPALCO is considered. The electric transportation load projection is based on the assessment of ferry-related operations (Ferries Operating and Passenger Vehicles waiting for the Ferries). 3) The investment options study proposes key investment options to OPALCO while enabling the electrification of ferry-related transportation to ensure that Friday Harbor can support the electrification of WSF.

Major Findings: Based on the techno-economic study performed on the business case scenarios, for a 20-year project lifetime with a discount rate of 9%, the NWS with 15 MW/15 MWh BESS manages the forecasted demand growth and defers the substation upgrade. The peak demand charges of 1.72MUSD are drastically reduced by the peak shaving value provided by 15MW/15MWh BESS. The econometric indices of the proposed NWS show a 38% Internal Rate of Return (IRR) with 2.5 years of payback time. Investing in and integrating BESS for Peak shaving applications at the Friday Harbor substation saves 1.6 MUSD. This analysis is based on the BESS market pricing in 2024 and is not a price quotation from manufacturer. A detailed report on the matter is presented in the following sections.

2 Introduction

The OPALCO, a non-profit utility, provides energy services to 11,700 customers across 20 islands in San Juan County, Washington. OPALCO is planning for its grid modernization infrastructure through NWS, targeting key cross-sectoral decarbonization goals to benefit Washingtonians. The NWS study focuses on providing solutions through a combination of assets like solar photovoltaic (PV), and battery energy storage systems (BESS). OPALCO's load increases in winter, however the solar production decreases during the winter time resulting in a negative correlation.

The "WSF 2040 Long Range Plan" depends on a coordinated set of investments in WSF's fleet, terminal infrastructure, workforce, and technology over the next 20 years, focusing on building a reliable fleet that has a lighter footprint on the environment to meet CO_2 reduction targets. The report recommendations underpin investments and policy recommendations that support dependable, sustainable, and resilient ferry service through 2040 and beyond while managing growth and offering an exceptional customer experience.

WSF, a division of the Washington State Department of Transportation (WSDOT) operates the largest ferry system in the United States. The system carried 24.5 million riders (about the population of Texas) in 2017 through the operation of 10 routes and 20 terminals [1].The WSF system is an essential part of Washingtonian's transportation network, linking communities on both sides of Puget Sound with the San Juan Islands and internationally to Sidney, British Columbia (BC). The map of the San Juan Islands and Friday Harbor Substation location is presented in Figure *1* , is identified as the San Juan Island. A more efficient fleet needs to be supported by resilient terminals that support vessel charging infrastructure.

This report analyzes the impacts of ferry-related electrifications on OPALCO's Friday Harbor substation. The techno-economic evaluation of NWS provides detailed information on mitigating potential electricity supply challenges under the forecasted electrification.

(a) (b)

Figure 1 (a) San Juan Islands (b) Friday Harbor Site Location, Washington

Vision for OPALCO's Friday Harbor Ferry Electrification: Electrification of transportation is key to a clean energy future – and ferries play a big part in that initiative for the islands. OPALCO is committed to modernizing the infrastructure at island ferry landings to make it easy and cost-effective for WSF ferries to charge docked in San Juan County. Using a Clean Energy Fund grant from the Washington Department of Commerce, the early design work is in progress for a ferry charging station at the Port of Friday Harbor. The vision for Orcas Power and Light Company (OPALCO) is to expand its grid modernization infrastructure targeting key cross-sectoral decarbonization goals to benefit Washingtonians. The primary focus is grid infrastructure, in the form of a Non-Wires Solution (NWS) in Friday Harbor that enables equitable, decarbonized transportation to the San Juan islands, particularly Washington State Ferries (WSF) 2040 Long Range Plan. OPALCO is designing the infrastructure in parallel with energy storage projects that help to reduce peak charges during the high-demand events during plugged-in ferries.

Strategy for Friday Harbor Ferry Electrification and Project Statement: Project analysis performed for the Conceptual Design comprising of NWS study that has, the Existing infrastructure assessment consisting of current infrastructure in the Friday Harbor substation area, focusing on the grid constraints and limitations. The load growth study includes the creation of baseline load and load projections captured under Business-as usual electrification, data collection, and processing on ferry-related transportation. The baseline load projection considered the historical load usage data in the Friday Harbor substation area, with the business-as-usual load growth based on the trends in load growth and guidance from OPALCO. The electric transportation load projection is based on the transportation assessment for ferry-related operations (Ferries Operating and Passenger Vehicles waiting for the Ferries). Given the substantial number of services that may benefit the microgrid, the BESS will play a vital role. Figure *2* provides an overview of the range of services offered by BESS.

OPALCO has shared the following files for the study.

1. kWh Consumption data from 01-05-2022 to 01-25-2024 as kWh delivered and kWh received tabulated separately.
2. Reports on OPALCO-Decatur Island Solar and Energy Storage Project Assessment of Battery Technical Performance and Preliminary Techno-Economic Study conducted for San Juan Hybrid BESS.
3. Single Line Diagram (SLD) of Friday Harbor Substation
4. January 2024 Invoice for OPALCO's Power Utility.

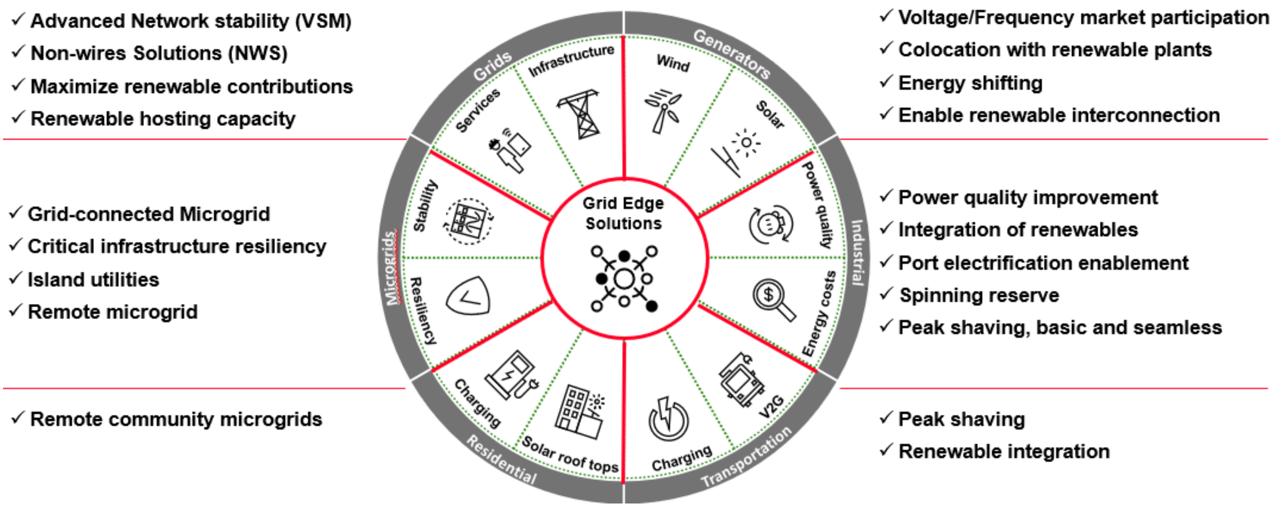


Figure 2 BESS Provides a Range of Values

3 Existing Infrastructure Assessment

3.1 Site Layout

The Single Line Diagram (SLD) of the Friday Harbor Substation is shown in Figure *3*. There are four Feeders of 27kV connecting to the 25kV main bus and one to the 69kV transmission line. The Friday Harbor substation has 6MW distributed solar PV and 2.7MW of Solar PV.

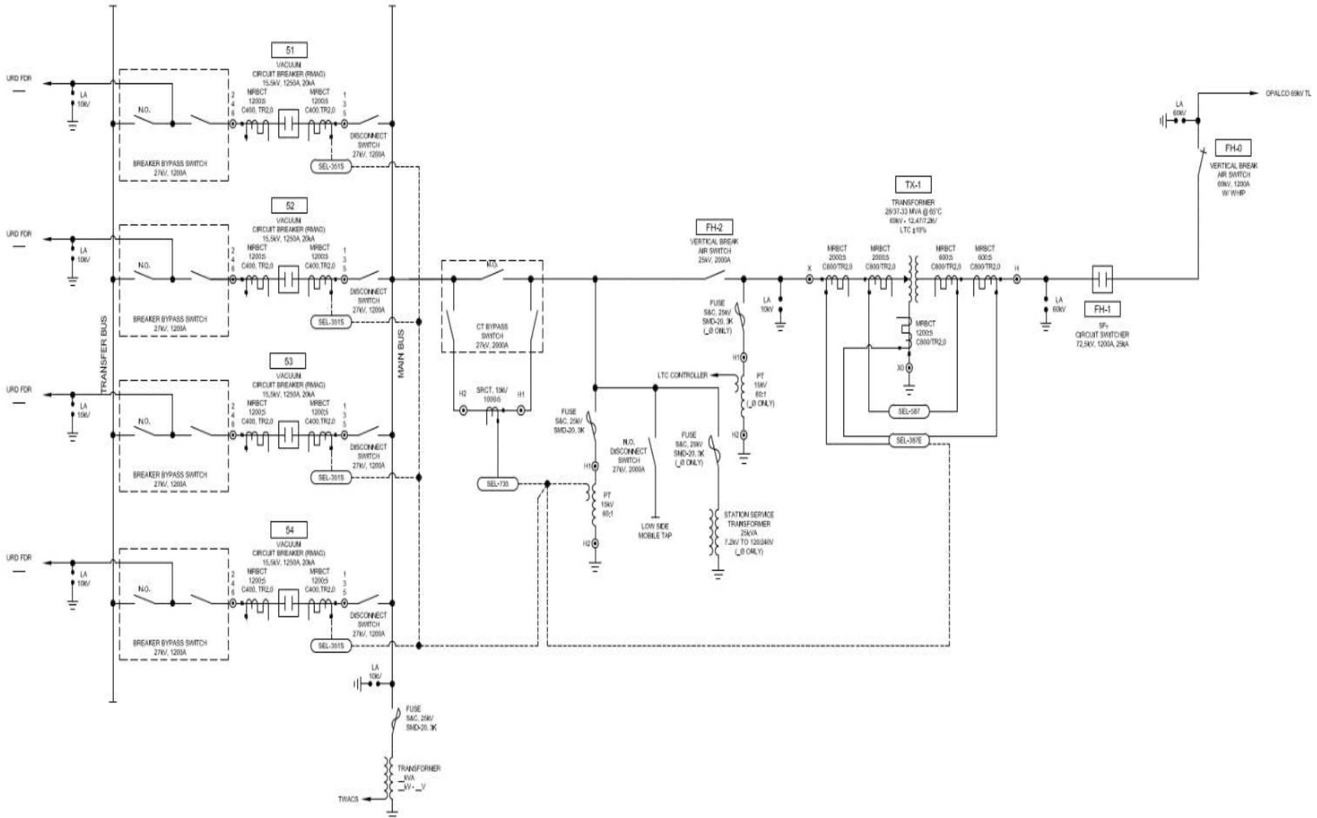


Figure 3 SLD of Friday Harbor Substation

3.2 Overview of the Friday Harbor Substation Load Profile

The hourly load profile received from (01-05-2022 to 01-25-2024) is presented in Figure *4*. This load profile includes the 6MW distributed Solar PV generation. The weekly load profile and renewable generation profile from 01-07-2024 to 01-13-2024 is given in Figure *5*, the highest load in the Friday Harbor is observed during wintertime, and the lowest load is observed during summertime. Table *1*. presents the maximum energy delivered for each year from 2022 to 2024. The average daily load profile for each month recorded in 2023 is presented in Figure *6*. The peak load observed is 14,548 kW with an average load of 136,141 kWh/day.

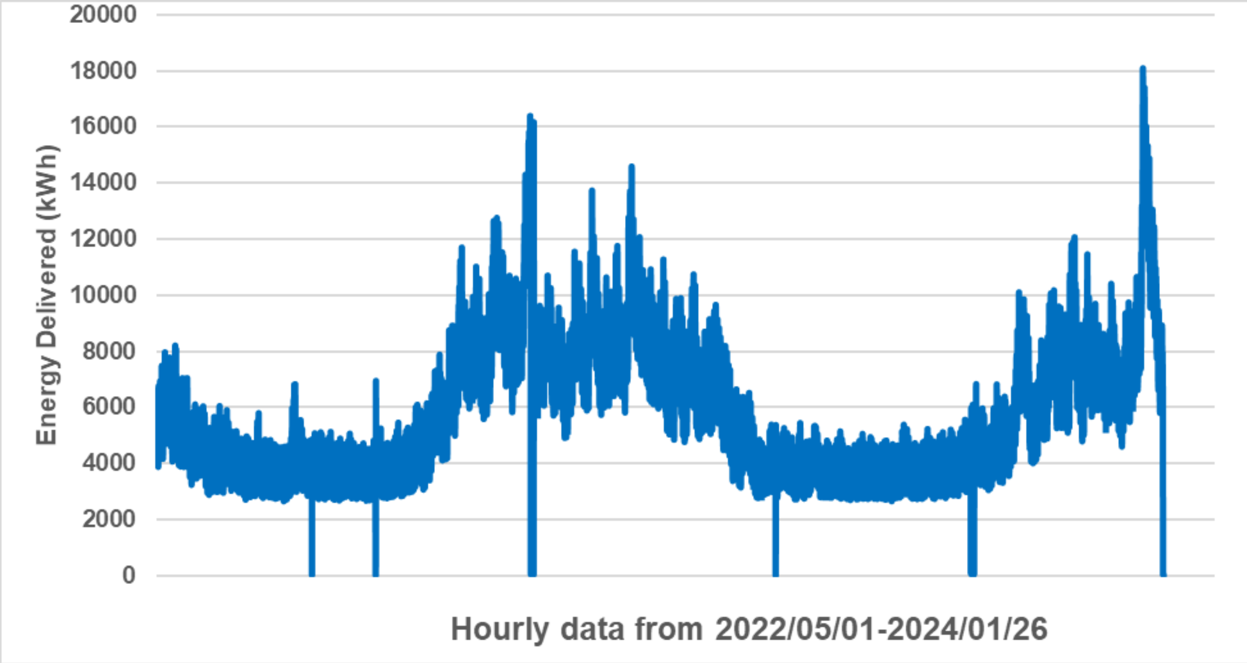


Figure 4 Hourly Load Profile for Friday Harbor Substation

Table 1 Maximum Energy Delivered from 2022-2024

Year	Date, Time	Max. Energy delivered for each year (kWh)
2022	12/22/2022, 9 AM	16,398
2023	2/24/2023, 8 AM	14,576
2024	1/12/2024, 9AM	18,088

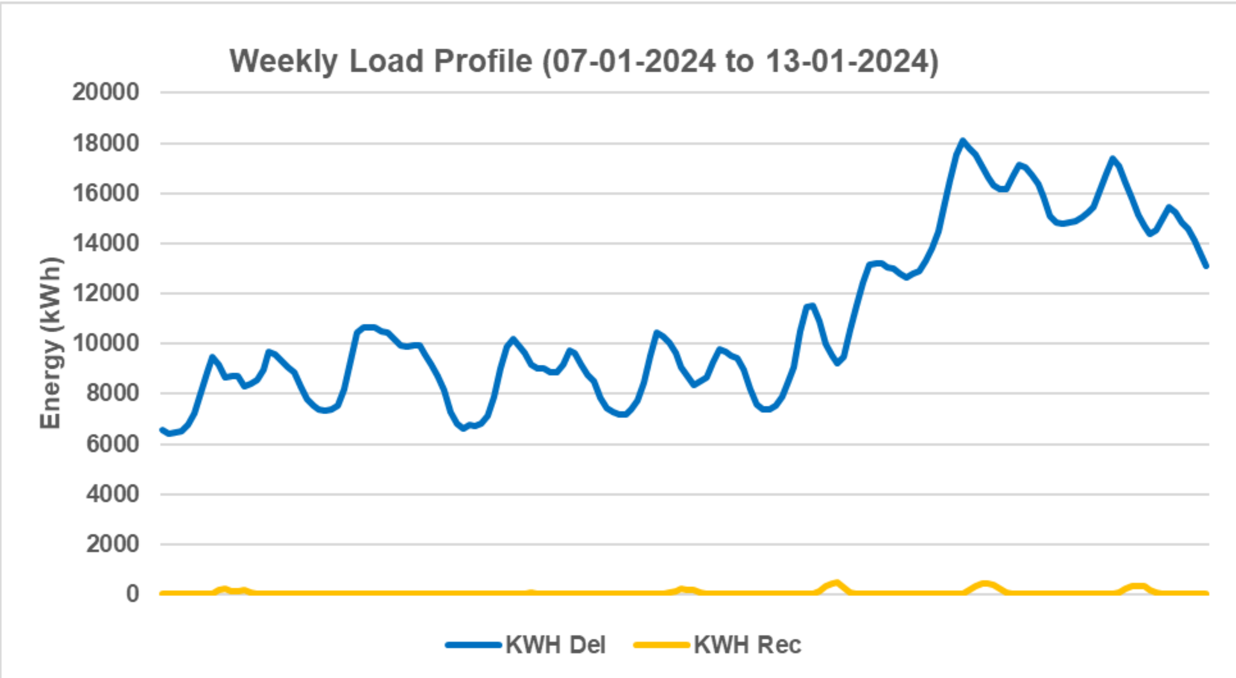


Figure 5 Weekly Load Profile(KWH Del) and weekly renewable generation (KWH Rec) (07-01-2024 to 13-01-2024)

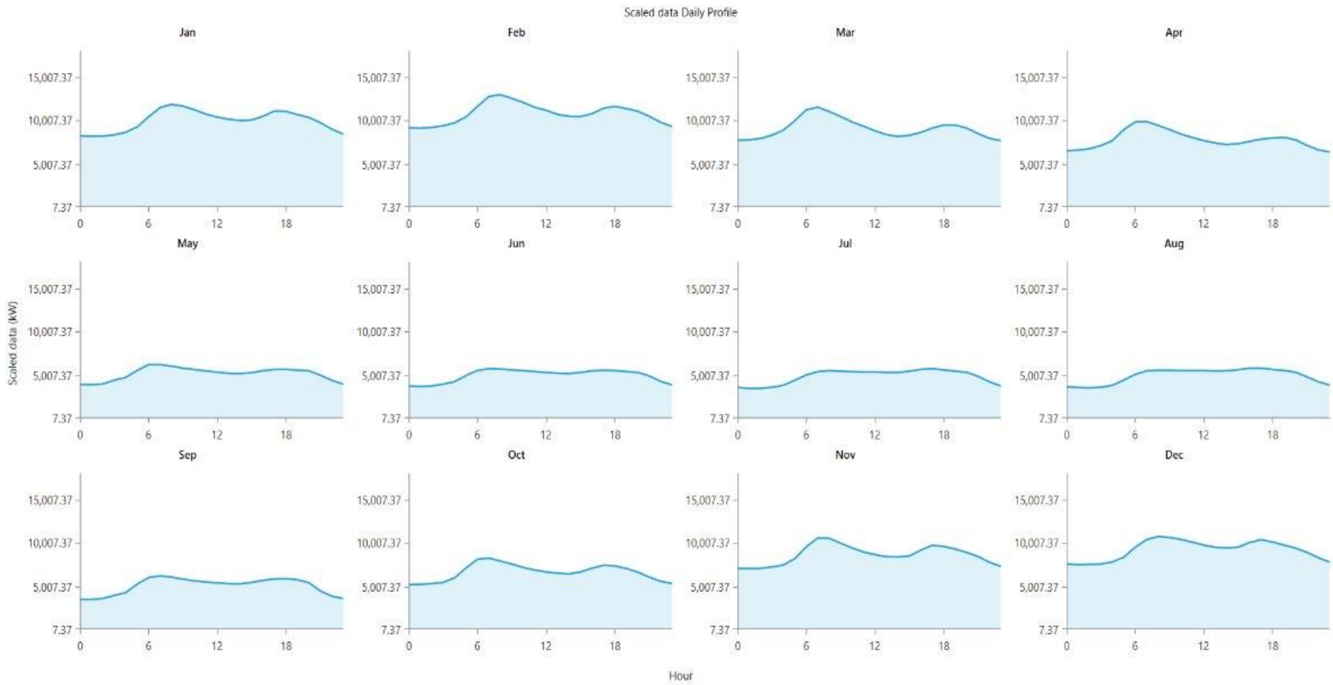


Figure 6 Average Load Profile for each Month in 2023

3.3 Operation of Ferries at Friday Harbor Substation

The Friday Harbor Substation serves the electric loads at the port for all the ferries operating daily round trips. The operation of ferries originating from Anacortes via the islands of Lopez, Shaw, and Orcas to Friday Harbor (San Juan Island) is scheduled from 4:15 AM to 11:30 PM. The daily round trip operation of ferries scheduled for the periods (03-24-2024 to 07-15-2024) and (07-16-2024 to 09-21-2024) are presented in Figure *7* & Figure *8* with the route map. The frequency of operation of ferries increases during weekends rather than weekdays

The details of ferries operating in the Friday Harbor Substation are presented in detail in Table 2. The strategies and assumptions for calculating the rating of ferries are presented below.

- Identify the power consumption by electric ferries. This has been performed by transferring the Power reported for each ferry from the HP unit to the kW unit (this has been done using a 0.7457 conversion rate)
- Obtain Ferry Schedules and estimate Power Consumption – Power ratings, Power Consumption (Using Patterns, Operating conditions), Equipment Efficiency, Load Factors, and Standby Power consumption.
- Aggregation of load events – 5 min data overlap or concurrent operation of multiple ferries, & associated activities.
- Other consumption areas – Lighting of non-ferry areas, HVAC system, EV charging stations.

Table 2 Details of Ferries

DETAILS OF FERRIES						
S.No.	**Name**	**Type of Ferry**	**Engines #**	**Power (HP)**	**Equivalent Power (kW)**	**Propulsion**
1	Chelan	Auto/ Passenger	2	5,000	3,728	Diesel
2	Yakima	Auto/ Passenger	4	8,000	5,966	Diesel-Electric (DC)
3	Samish	Auto/ Passenger	2	6,000	4,474	Diesel
4	Tillikum	Auto/ Passenger	2	2,500	1,864	Diesel-Electric (AC)

− Mar 24, 2024 - Jun 15, 2024

Leave Westbound (Daily)

	Anacortes	Lopez Island	Shaw Island	Orcas Island	Friday Harbor (San Juan Island)	Sidney B.C.
2	4:15	-----	-----	-----	5:20 ⚓	-----
1	5:30	-----	7:00 ●	6:20 ⚓	-----	-----
3	6:20	7:10	-----	-----	7:40 ⚓	-----
4	-----	6:55	7:15	7:35	8:15 ⚓	-----
2	7:30	-----	9:00 ●	8:20 ⚓	-----	-----
1	8:30	-----	-----	-----	9:35 ⚓	-----
3	9:30	-----	-----	-----	10:35 ⚓	-----
4	-----	9:55	10:15	10:35	11:15 ⚓	-----
2	10:35	11:25	12:40 ●	11:45 ⚓	-----	-----
1	11:55	12:45 ▾	-----	-----	1:20 ⚓	-----
3	12:35	1:15 ⚓	-----	-----	-----	-----
4	-----	1:05	12:20 ●	12:40 ●	2:00 ● ⚓	-----
2	1:55 FriSun	-----	-----	2:45 FriSun ⚓	-----	-----
3	2:40	-----	-----	-----	3:45 ⚓	-----
1	3:40	-----	4:35	4:45 ⚓	-----	-----
4	-----	3:50 ExSunHol	4:10 ExSunHol	4:30 ExSunHol	5:10 ExSunHol ⚓	-----
2	4:30	5:20 ▾	-----	-----	5:50 ⚓	-----
3	6:00	6:50	-----	-----	7:20 ⚓	-----
1	6:30	-----	7:25	7:35 ⚓	-----	-----
4	-----	7:30	7:50	8:05	8:45 ⚓	-----
2	8:25	9:15	-----	-----	9:45 ⚓	-----
1	8:55	-----	9:45	9:55 ⚓	-----	-----
4	11:30 Fri	12:25 Sat	-----	12:55 Sat	1:35 Sat ⚓	-----

Leave Eastbound (Daily)

	Sidney B.C.	Friday Harbor (San Juan Island)	Orcas Island	Shaw Island	Lopez Island	Anacortes
2	-----	5:45	-----	-----	6:30	7:10 ⚓
4	-----	6:05	7:35 ●	7:15 ●	6:50 ⚓	-----
1	-----	-----	6:45	7:00	7:30	8:10 ⚓
3	-----	8:05	-----	-----	-----	9:10 ⚓
4	-----	8:30	9:15	9:30	9:50 ⚓	-----
2	-----	-----	8:45 ▾	9:00 ▾	9:30	10:10 ⚓
1	-----	9:55 ▾	-----	-----	10:40	11:25 ⚓
3	-----	11:05 ★	-----	-----	-----	12:10 ⚓
4	-----	11:35 ♦	12:40 ♦	12:20 ♦	1:00 ⚓	-----
2	-----	-----	12:25	12:40	-----	1:30 ⚓
3	-----	-----	-----	-----	1:35	2:15 ⚓
1	-----	1:55	-----	-----	-----	3:00 ⚓
4	-----	2:15 SunHol	-----	-----	3:05 SunHol	3:55 SunHol ⚓
4	-----	2:20 ExSunHol	3:10 ExSunHol	3:25 ExSunHol	3:45 ExSunHol ⚓	-----
2	-----	-----	3:15 Sun	-----	-----	4:05 Sun ⚓
3	-----	4:15	-----	-----	5:00	5:40 ⚓
1	-----	-----	5:15	4:35 ●	-----	6:05 ⚓
4	-----	5:45 ♦	6:45	7:00	7:20 ⚓	-----
2	-----	6:25	-----	-----	7:10	7:50 ⚓
3	-----	7:45	-----	-----	8:25	9:05 ⚓
1	-----	-----	7:50	7:25 ●	-----	8:40 ⚓
4	-----	8:50 Fri	-----	-----	-----	10:10 Fri ⚓
1	-----	-----	10:05	9:45 ●	-----	10:55 ⚓
2	-----	10:05	-----	-----	-----	11:10 ⚓

Figure 7 Ferry Operating Schedule for March 24, 2024, to June 15, 2024

− Jun 16, 2024 - Sep 21, 2024

Leave Westbound (Daily)

	Anacortes	Lopez Island	Shaw Island	Orcas Island	Friday Harbor (San Juan Island)
2	4:05	-----	-----	-----	5:10 ⚓
3	5:55 ⊗	6:45	7:00	7:10 ⚓	-----
1	6:15	7:05 ▾	-----	-----	7:35 ⚓
2	7:20	-----	8:55 ●	8:10 ⚓	-----
4	-----	7:35	7:10 ●	6:55 ●	8:15 ⚓
3	9:05	-----	-----	-----	10:10 ⚓
1	9:40	10:20 ⚓	-----	-----	-----
4	-----	10:00	10:20	10:40	11:20 ⚓
2	10:40	-----	11:35 ▾	11:45 ⚓	-----
1	Noon	-----	-----	-----	1:05 ⚓
3	12:35	1:30	-----	1:45 ⚓	-----
4	-----	1:05	12:25 ●	12:40 ●	1:55 O ⚓
2	2:00	-----	-----	-----	3:05 ⚓
3	3:45	-----	4:40 ▾	4:50 ⚓	-----
4	-----	3:45 ExSunHol	4:05 ExSunHol	4:25 ExSunHol	5:05 ExSunHol ⚓
1	4:45	-----	-----	-----	5:50 ⚓
2	5:15	5:55 ⚓	-----	-----	-----
3	6:45 ExTueWed ✣	7:35 ExTueWed	-----	7:55 ExTueWed ⚓	-----
4	-----	7:05	7:25	7:40	8:20 ⚓
2	7:25	-----	8:20 ▾	8:30 ⚓	-----
1	8:20	-----	-----	-----	9:25 ⚓
3	9:00 ♦	9:50 ♦	10:10 ♦	10:20 ♦ ⚓	-----
3	9:50 ExTueWed	10:45 ExTueWed	11:10 ExTueWed	11:20 ExTueWed ⚓	-----
4	11:00 Fri	Midnight Sat	-----	-----	12:40 Sat ⚓

Leave Eastbound (Daily)

	Friday Harbor (San Juan Island)	Orcas Island	Shaw Island	Lopez Island	Anacortes
2	5:35 ▾	-----	-----	6:15	6:55 ⚓
4	6:00	6:55	7:10	7:30 ⚓	-----
3	-----	7:35 ▾	7:50	-----	8:40 ⚓
1	8:10	-----	-----	-----	9:15 ⚓
4	8:30	9:15	9:30	9:50 ⚓	-----
2	-----	8:40 ▾	8:55 ▾	9:30	10:10 ⚓
1	-----	-----	-----	10:50	11:30 ⚓
3	11:00	-----	-----	-----	12:05 ⚓
4	11:35 ♦	12:40 ● ♦	12:25 ♦	1:00 ⚓	-----
2	-----	12:20	12:35	-----	1:25 ⚓
1	1:55	-----	-----	2:40	3:20 ⚓
4	2:15 ExSunHol	3:05 ExSunHol	3:20 ExSunHol	3:40 ExSunHol ⚓	-----
3	-----	2:20	-----	-----	3:10 ⚓
4	2:25 SunHol	-----	-----	-----	3:55 SunHol ⚓
2	3:40 M-F ▾	-----	-----	4:15 M-F ⊗	4:55 M-F ⚓
2	3:40 SaSu	-----	-----	-----	4:55 SaSu ⚓
3	-----	5:15 ▾	5:30	-----	6:20 ⚓
4	5:30	6:20	6:35	6:55 ⚓	-----
2	-----	-----	-----	6:20	7:00 ⚓
1	6:30	-----	-----	-----	7:35 ⚓
3	-----	8:15 ExTueWed	-----	8:45 ExTueWed	9:25 ExTueWed ⚓
2	-----	8:50	8:20 ●	-----	9:40 ⚓
1	10:00	10:50	11:00	11:20	Midnight ⚓

Figure 8 Ferry Operation Schedule for June 16, 2024, to September 21, 2024

3.4 Development of Load Profile for Ferries

The Washington State Department of Transportation Ferries Division, operating as WSF is undertaking an ambitious initiative to move toward a “greener” ferry fleet with the twin goals of reducing global greenhouse gases and improving local air quality. Currently, WSF burns 19 million gallons (about 72 million liters) of diesel fuel per year, making it the largest consumer in state government. Over twenty years, the agency will convert six ferries from diesel to hybrid electric and build 16 new hybrid electric ferries. During this same time, the agency will bring medium voltage power to 16 terminals to charge these hybrid electric vessels. The impact will be a reduction in greenhouse gas emissions by 76% and toxic pollutants by 59%, exceeding the 2030 and 2040 targets established by RCW 70A.45.050 [1].

The per-day load profile development for Ferries operating at Friday Harbor Substation is performed by adopting the operation schedule of ferries presented in Figure *7* and Figure *8* as a reference. One of the key functional requirements given in [2] is the charging time to be up to 25 minutes. The desired operational charge time is 17-18 Minutes. This is kept as one of the key characteristics while developing the load profile. These characteristics informed the following assumptions for the projected per-day load profile for the ferries.

- The charging cycle for each ferry is 15 minutes.
- The charging frequency of each ferry is 14 times per day.
- The charging power for each ferry varies from 15MW to 5MW on the ferry engine details presented in Table 3.

The per-day load profile developed for ferries is presented in Figure *9* followed by Table *3* explaining the power and energy details.

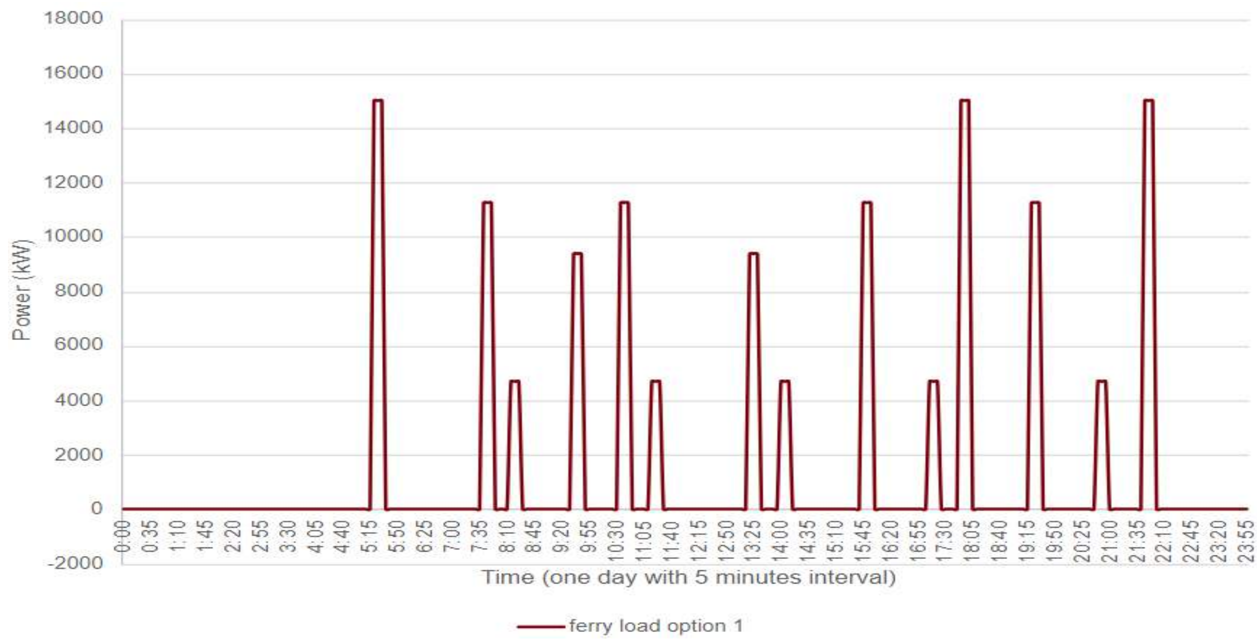


Figure 9 Per Day Ferry Load Profile

Table 3 Details of Projected Ferry Load Profile Per Day

Details of Per Day- Ferry Load Profile	
Annual Energy (kWh)	12,060,547
Average Daily Energy (kWh)	33,043
Peak Load for 15 Minutes Average (kW)	15,000

3.5 Load Growth Study at Friday Harbor Substation

The historical data for Friday Harbor Substation shared by OPALCO is used for calculating the load usage. The hourly data presented in Figure 10 shows the consolidated profile of Ferry Load, Friday Harbor Substation load, 6MW Solar PV, and 2.7 MW Solar PV capacities. From the developed ferry charging load profile of 15MW peak load for 15 minutes, the charging load averaged for one hour is 3.75MW. See the four major load and generation annual profiles plotted in Figure *10*.

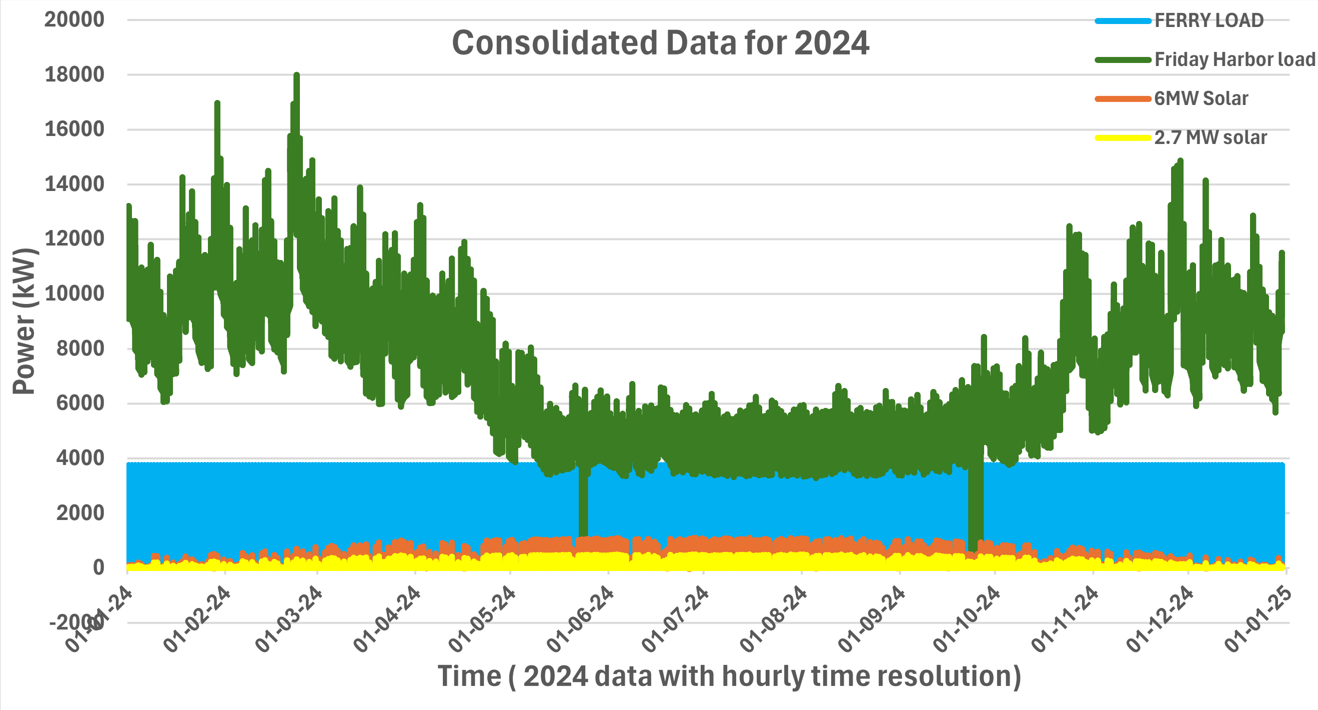
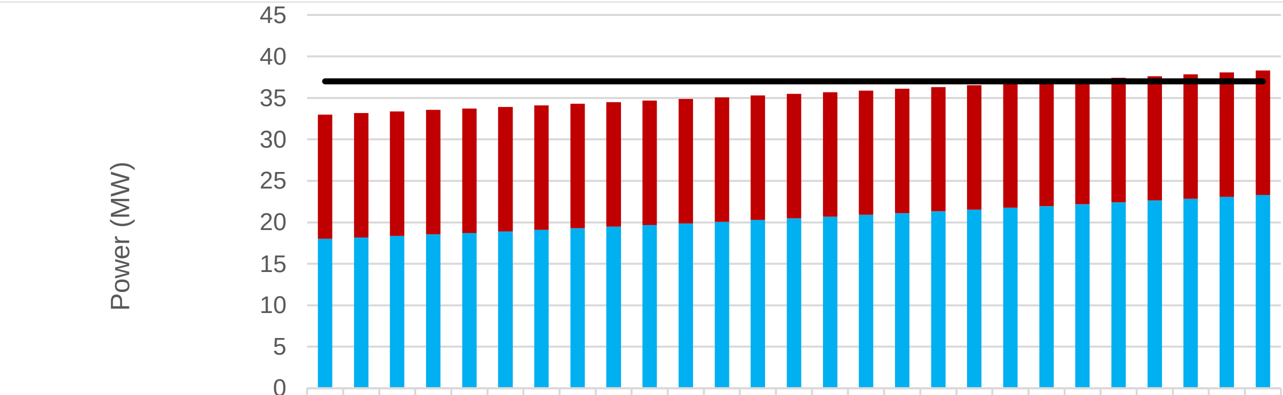


Figure 10 Consolidated Load and Generation Profiles for a year

In 2045, with assumed 1% load growth, the total peak load will exceed the substation capacity. Including both forecasted load growth and ferry charging load, the total forecasted substation load for 2050 is 38.3MW, 1.3MW more than the current 37MW substation capacity. The impact of 1% load growth on substation load every year with the addition of 15MW peak load from ferry electrification on annual projected load is presented in Figure *11*.



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
ferry peak load	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
substation load	18	18	18	19	19	19	19	19	19	20	20	20	20	20	21	21	21	21	22	22	22	22	22	23	23	23	23
substation capacity	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37

Figure 11 Impact of 1% Load Growth on Friday Harbor Substation

3.6 OPALCO Utility Invoice Analysis

OPALCO purchases its power from Bonneville Power Administration (BPA) through the electric utility company Pacific Northwest Generating Cooperative (PNGC). In 2008, PNGC Power entered a 20-year contract with BPA on behalf of its members. The distribution of charges observed from OPALO's the January 2024 PNGC utility invoice is presented as a pie chart in Figure *12*. The details on OPALCO Utility's charges and the impacts on the charges after integrating BESS is presented in Table *4*. The peak demand charges has been considered for every 15 minutes in this study.

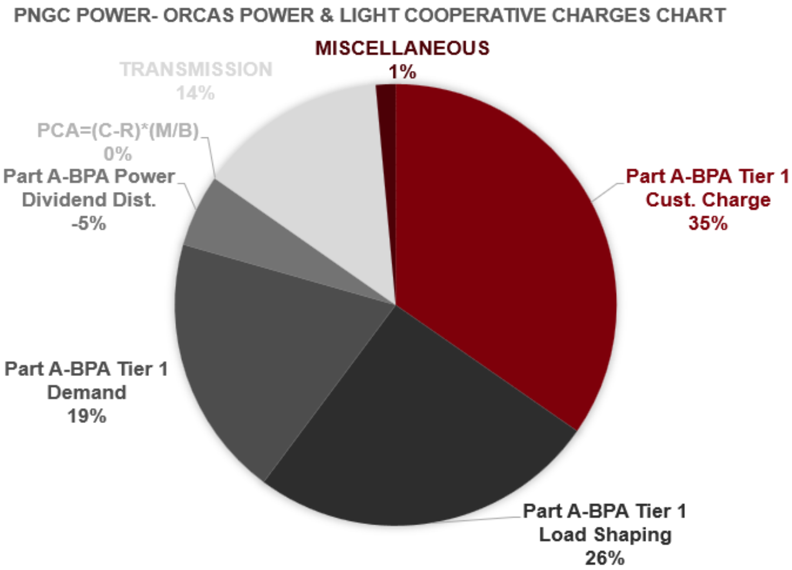


Figure 12 OPALCO's Charges

Table 4 OPALCO Utility Charges and Impacts of BESS

S.No.	Charges	Description	Impacts of BESS on Charges
1.	Customer Base Charges	Precalculated amount based on a fore-casted load and is independent of OPALCO's monthly energy consumption or peak demand.	-
2.	Load Shaping Charges	Credit OPALCO receives, depending upon whether the actual load each month is greater or less than the amount predicted by BPA. Heavy load hours (HLHs) (6:00 AM to 10:00 PM) Light load hours (LLHs). (12:00 PM to 5:00 AM and 10:00 PM to 12:00 AM)	BESS can be used for energy shifting between the ferry load from HLH to LLH.
3.	Demand Charges	Fees incurred by a customer proportional to the highest MW load they consume each month. Depends on the average HLH load.	Discharging a BESS to reduce the peak consumption reduces demand charges and can lead to a significant bill reduction.
4.	Transmission Charges	The transmission charge is based on en-ergy purchases during BPA's peak trans-mission hour.	Discharging a BESS during BPA peak transmission hours.
5.	Miscellaneous Power Cost Charges & Credits	Additional margin contribution charges for the above customer charges, load shaping, demand and PDD.	Integration of BESS contributes to the reduction of the overall charges and have negligible cost contribution.

3.7 BPA - Tiered Rate Methodology

The Tiered Rate Methodology (TRM) establishes a two-tiered rate design for sales of firm power at the Priority Firm (PF) rate under the Regional Dialogue (RD) power sales contracts [4-7]. The TRM is a 20-year rate design that is used in every biennial rate case to determine Bonneville's PF Tier 1 and Tier 2 rates. The TRM operates in conjunction with the RD contracts, also called Contract High Water Mark (CHWM) contracts. Pursuant to the RD contract and TRM, Bonneville calculates a customer's Rate Period High Water Mark (RHWM), which establishes the amount of firm power a customer can purchase at the Tier 1 PF rate each rate period. Rates are set consistent with the TRM every two years through formal rate proceedings as required under Section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act of 1980.Tiered rates preserve the cost benefits of the existing system for established customers. At the same time, customers experiencing load growth beyond their Tier 1 PF rate purchases from Bonneville can choose to serve that growth by using nonfederal power, by relying on Bonneville or by using a combination of the two. In its simplest form, this means that utilities lock in a set amount of power from the existing federal system at a cost-based rate, the Tier 1 rate. Beyond that, Tier 2 rates are for any energy a utility obtains from BPA in addition to its contractual right to power at Tier 1 rates. Each rate period, the amount of power BPA offers at Tier 1 rates is based on what the existing federal system can produce. Tier 2 rates are based on the actual or forecast price paid to acquire the additional power requested by the customers.

3.7.1 High water marks

The central feature of the TRM is the CHWM. Each customer has a CHWM that determines its initial eligibility to purchase power at Tier 1 PF rates. The TRM directs how Bonneville will calculate a customer's CHWM. The CHWMs were largely based on customer loads in FY 2010 with adjustments for weather-normalization and conservation, and adjustments to account for the economic downturn experienced throughout the region in FY 2010. Those CHWMs are fixed for the term of the Regional Dialogue contracts through 2028, with only minor exceptions such as annexations between customers, new utility formation and limited growth of tribal utilities. CHWMs are administered through Rate Period High Water Marks (RHWM), and the same for FY 2024-2025 for Tier 1 system Capability is presented in Table *5*.

Table 5 RHWM for FY 2024-2025 for RT1SC

Month	RT1SC in kWh	
	HLH	LLH
October	2,552,444,036	1,666,359,726
November	3,264,487,328	2,115,878,631
December	3,520,485,739	2,285,993,696
January	**3,735,691,715**	**2,298,138,029**
February 2024	3,299,995,879	1,889,901,959
February 2025	3,186,982,039	1,833,395,039
March	3,449,919,113	2,216,421,778
April	2,722,407,778	1,750,213,462
May	3,371,816,848	2,177,069,159
June	3,560,007,926	2,109,275,055
July	3,067,031,764	1,854,722,628
August	3,018,290,172	1,739,738,080
September	2,614,938,274	1,763,369,104

A customer's RHWM determines the average megawatt amount of energy customers can purchase at Tier 1 PF rates for a given rate period. Customers' RHWMs are calculated every two years and largely depend on the amount of Tier 1 system capability forecast for the two-year rate period. If a customer's net requirements load is greater than its RHWM, this is called Above-RHWM load and the customer must elect to serve it in one of three ways: Purchasing nonfederal resources. Purchasing an amount of firm power at Tier 2 rates from BPA. A combination of the two previous options.

3.7.2 Rate design

Among all Bonneville's RD customers and among purchasers of each product – Load Following, Block or Slice/Block – the TRM introduced various features to its rates. Most notably, the Tier 1 PF rate design consists of three elements:

- Customer Charges
- Load Shaping Charges
- Demand Charges.

3.7.2.1 Customer Charges

Most of Bonneville's costs are recovered through Customer Charges. Costs are allocated to customers using the Tier One Cost Allocator (TOCA). A customer's TOCA is calculated during the rate case and is based on the lesser of its RHWM or its forecast net requirement (a customer's hourly electricity needs, minus any non-BPA resources the customer uses to serve its own loads), and then divided by the sum of all customers' RHWMs. A customer's TOCA may be updated within a rate period due to changes to its forecast net requirement. In addition to general charges administered through TOCAs, individual Customer Charges will be adjusted by costs and credits assigned to the specific BPA products they choose, such as Slice or non-Slice charges. The monthly composite, non-slice, and customer rates are specified in Table *6*.

Table 6 Customer charges

Customer Charges Rate in $/% of Billing Determinant			
Customer Rate	**Composite Charges**	**Non-Slice Charges**	**Slice Charges**
	2,075,946	**(364,823)**	0

Customer charges are applicable to customers that purchase the following products: Load Following, Block, and Slice/Block. The composite, non-slice and slice customer billing determinants are given in Table *7* and the formulae for calcualting the same is presented for reference. An example for the customer charges and the details extracted from OPALCO's Utility's January invoice is presented here in Figure *13*.

Table 7 Customer Billing Determinants

Customer Chare Billing Determinant for Each Rate			
	Composite	**Non-Slice**	**Slice**
Load Following	TOCA	TOCA	N/A
Block Only	TOCA	TOCA	N/A
Block portion of Slice/Block	Non-Slice TOCA	Non-Slice TOCA	N/A
Slice Portion of Slice/Block	Slice %	N/A	Slice %

Where, TOCA is Tier 1 Cost Allocator (%)

For each customer, for each Fiscal Year of the Rate Period, the TOCA will be calcualted according to the following formula,

$$TOCA = \frac{Minimum\ of\ the\ Customer's{:}a)\ RHWM\ or\ b)\ Forecast\ Net\ Requirement\ for\ each\ Fiscal\ Year}{Sum\ of\ all\ Customer's RHWMs} * 100$$

The TOCA for a Joint Operating Entity (JOE) is the sum of the TOCA of the individual members of the JOE.

Slice % = The Slice Percentage for the relevant Fiscal Year as Specified in Exhibit K of the Slice Customer's CHWM contract.

Non-Slice TOCA %= TOCA – Slice %.

	Charge	Rate	Determinant	Determinant Used	Charge
1: Power					
Part A - BPA Tier 1 Cust. Charge	Composite Charge	2,075,946 $/month/%	.34845 %	TOCA	$723,363
Part A - BPA Tier 1 Cust. Charge	Composite Charge (LDD)	6.000 %	723,363 $	Composite Charge	($43,402)
Part A - BPA Tier 1 Cust. Charge	Non-Slice Charge	(364,823) $/month/%	.34845 %	TOCA	($127,123)
Part A - BPA Tier 1 Cust. Charge	Non-Slice Charge (LDD)	6.000 %	(127,123) $	Non-Slice Charge	$7,627
				Part A - BPA Tier 1 Cust. Charge	*$560,465*

Figure 13 Power/Customer Charges from OPALCO's invoice for January 2024

In this invoice shared, the TOCA Determinant is 0.34845 % and the Composite charges, Non-Slice Charges highlighted in Table 5 is applied to the invoice as well.

3.7.2.2 Load Shaping Charges

The Load Shaping Charge is applicable to customers that purchase the following products: Load Following, Block, and the Block portion of Slice/Block. In any diurnal period (HLH or Light Load Hours (LLH)), the Load Shaping Charge may be a charge or a credit, depending upon whether the Load Shaping Billing Determinant is positive or negative. The Load Shaping Rate imposed on the Utility bill is presented in Table *8*.

Table 8 Load Shaping Charges

Month	Rate in mills/kWh	
	HLH	**LLH**
October	47.71	32.91
November	40.30	31.39
December	61.63	52.69
January	**49.88**	**36.73**
February	50.32	42.01
March	35.07	35.84
April	20.42	21.67
May	18.21	16.34
June	17.87	10.33
July	55.60	36.92
August	71.52	48.93
September	58.70	44.18
October	47.71	32.91

Load Shaping Charges adjust for the difference between a customer's actual use of power from the Tier 1 system and that customer's base amount of power received for paying their TOCA share of the Tier 1 system costs. An example for the Load Shaping Charges for a Typical Utility in Two Different Months is given in Figure *14*. These base amounts are provided in the same shape as the projected Tier 1 system for a given rate period. Load Shaping rates are based on forecast market prices

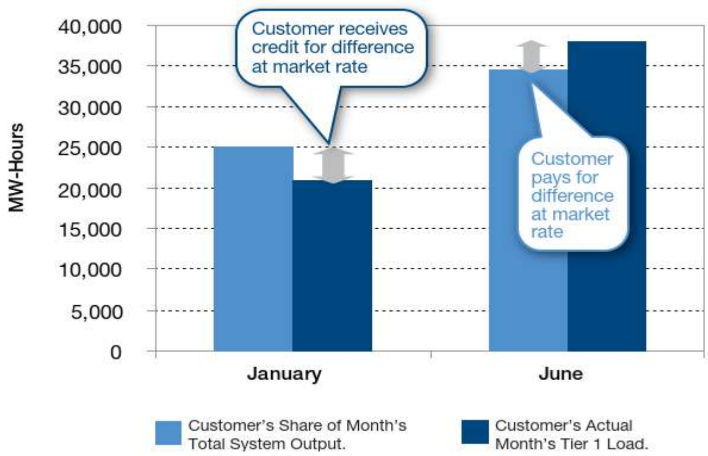


Figure 14 Load Shaping Charges for Two Different Months

Load Shaping Charges can be a charge or a credit on a customer's monthly bill depending on whether their actual power use is greater or less than their base amounts of power. Figure *15* presents the load shaping charges applied in OPALCO's Utility invoice for January 2024

Part A - BPA Tier 1 Load Shaping	HLH Energy	49.88 mills/kWh	5,352.343 MWh	load shaping HLH billing units	$266,975
Part A - BPA Tier 1 Load Shaping	HLH Energy (LDD)	6.000 %	266,975 $	load shaping charge (HLH)	($16,019)
Part A - BPA Tier 1 Load Shaping	LLH Energy	36.73 mills/kWh	4,679.085 MWh	load shaping LLH billing units	$171,863
Part A - BPA Tier 1 Load Shaping	LLH Energy (LDD)	6.000 %	171,863 $	load shaping charge (LLH)	($10,312)
				Part A - BPA Tier 1 Load Shaping	*$412,507*

Figure 15 Load Shaping Charges from OPALCO's invoice for January 2024

The Tier 1 Billing units as well as the Resource amounts recorded and calculated for January 2024 is presented in Figure *16*.

5a. Tier 1 Resource Amounts

	T1CSP (MW)	HLH (MWh)	LLH (MWh)
Total Retail Load	85.213	18,429.501	12,699.504
Less: AHWM Obligation	.000	.000	.000
Less: Decatur Solar (actual)	.000	-5.302	-1.536
Less: Decatur Battery (actual)	.000	-54.838	-11.021
Equals: Tier 1 Resource Amount	**85.213**	**18,369.361**	**12,686.947**

5b. Tier 1 Billing Units

	HLH Energy	LLH Energy	Demand	
T1 System Capacity	3,735,692	2,298,138	85.213	Tier 1 Resource
x TOCA (%)	.34845	.34845	44.157	- T1 aHLH Load
= Sys. Shaped Load	13,017.018	8,007.862	10.557	- CDQ
Tier 1 Resource - Sys. Shaped Load = Load Shaping Units	**5,352.343**	**4,679.085**	**30.499**	**= Demand Billing Units**

Figure 16 Tier 1 Resource Amounts & Billing units from Invoice for January 2024

The load shaping billing determinant for each of the two diurnal periods, HLH and LLH for each month is calculated as,

$$\text{Load Shaping Billing Determinant} = \left(\frac{Customer's\ Actual\ Monthly}{Diurnal\ Tier\ 1\ Load}\right), kWh - Customer's\ System\ Shaped\ Load\ for\ the\ relevant\ diurnal\ period, kWh$$

System Shaped Load is calculated for each diurnal period of each month. The customer's system shaped load for each diurnal period as follows,

System Shaped Load = RT1SC * TOCA

For Joint Operating Entity (JOE), the System Shaped Load = Sum of the Actual Monthly/Diurnal Tier 1 Loads of the JOE's members and the sum of the system shaped loads of the JOE's members.

3.7.2.3 Demand Charge

The Demand charge is designed to send a price signal to a limited portion of a customer's overall demand on Bonneville and applies to customers purchasing Load Following and Block with shaping capacity products. This signal can encourage activities such as demand response initiatives to help the utility manage its Demand Charges. The demand charges applied for every month is presented in Table 9.

Table 9 Demand Rate

Month	Rate in $/kW
October	10.37
November	8.75
December	13.39
January	**10.84**
February	10.93
March	7.62
April	4.43
May	3.95
June	3.88
July	12.08
August	15.54
September	12.75

The demand billing determinant is calculated using Eqn. ,

Demand Billing Determinant = Tier 1 CSP – aHLH – CDQ

Where,

Tier 1 CSP = Tier 1 Customer System Peak. (The Customer's maximum actual hourly Tier 1 Load during the HLH of the month, in kW.

aHLH = Average of the customer's actual hourly Tier 1 loads during the HLH, in kW.

CDQ = Contract Demand Quantity specified in the customer's CHWM contract, Exhibit B, Sec.c, in kW.

The maximum hourly load, as specified in the customer's contract, during the HLH of the month, in kW, less the average of the hourly loads during the HLH of the month, in kW. The example for demand charges and respective determinant values extracted from OPALCO's Utility invoice for January 2024 is presented in Figure *17*.

Part A - BPA Tier 1 Demand	Demand	10.84 $/kw-month	30.499 MW	demand billing units	$330,609
Part A - BPA Tier 1 Demand	Demand (LDD)	6.000 %	330,609 $	demand charge	($19,837)
				Part A - BPA Tier 1 Demand	*$310,772*

Figure 17 Demand Charges for January 2024

3.7.2.4 LDD Eligible Discount Percentage

This Low-Density Discount (LDD) is given to qualified BPA customers meeting the list of criteria mentioned below,

- The customer must serve as an electric utility offering power for resale to retail consumers.
- The customer must agree to pass the benefits of the discount through to its eligible consumers within the region served by BPA.
- The customer's average retail rate for the reporting year must exceed BPA's average Priority Firm Power rate for the most closely corresponding fiscal year by at least 25 percent, which is 43.59 mills/kWh for FY 2024 and FY 2025.
- The customer's kWh/Investment (K/I) Ratio must be less than 100.
- The customer's Consumers/Mile (C/M) Ratio must be less than 12.
- Each year BPA shall determine whether a customer is eligible for a discount. Such determination will not be dependent on whether the customer was determined to be eligible in the previous year. 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 6% percent smaller.
- 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.
- 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.

Table 10 presents the LDD eligible discount percentage. OPALCO also qualifies for a low-density discount (LDD) from BPA of 6% percent on its Tier 1 charges and the same is reflecting in the OPALCO's Utility invoice for January 2024.

Table 10 LDD Eligible Discount Percentage

Percentage Discount	Applicable Range for kWh/Investment (K/I) Ratio	Applicable Range for Consumers/Mile (C/M) Ratio
0.0%	35.0 < X	12.0 < X
0.5%	31.5 < X ≤ 35.0	10.8 < X ≤ 12.0
1.0%	28.0 < X ≤ 31.5	9.6 < X ≤ 10.8
1.5%	24.5 < X ≤ 28.0	8.4 < X ≤ 9.6
2.0%	21.0 < X ≤ 24.5	7.2 < X ≤ 8.4
2.5%	17.5 < X ≤ 21.0	6.0 < X ≤ 7.2
3.0%	14.0 < X ≤ 17.5	4.8 < X ≤ 6.0
3.5%	10.5 < X ≤ 14.0	3.6 < X ≤ 4.8
4.0%	7.0 < X ≤ 10.5	2.4 < X ≤ 3.6
4.5%	3.5 < X ≤ 7.0	1.2 < X ≤ 2.4
5.0%	X ≤ 3.5	X ≤ 1.2

3.7.3 Rate setting process

Although the rate design in the TRM is for the full term of the Regional Dialogue contracts, the actual applicable rates and charges, including those described above, are established every two years through formal rate proceedings as required under Section 7(i) of the Northwest Power Act of 1980. Statutorily, Bonneville's rates can be set for one to five years. The TRM and Regional Dialogue contracts provide for a two-year rate cycle, as parties determined that two-year rate periods strike a balance between the rapidly changing operating landscape and need for rate stability, while also accommodating for factors such as the two-year refueling cycle for the Columbia Generating Station.The 2012 Wholesale Power and Transmission Rate Adjustment Proceeding through which TRM was established can be found on bpa.gov.

3.7.4 Transmission Charges

The transmission charges observed from the shared invoice give details on the Co-incident (COIN) peak demand charges. For example, the NT Service Charge of 2.031 $/kW/ month and Scheduled System Control and Dispatch of 0.389 $/kW/month are for the customer demand during the BPA Transmission System Peak. The details on Transmission charges observed from the shared invoice are presented in Figure *18*.

2: Transmission

Transmission	NT Service Charge	2.031 $/kW/month	78,418 kW	kW @ BPA TX peak	$159,267
Transmission	Sched., Sys. Control, and Dispatch	.389 $/kW/month	78,418 kW	kW @ BPA TX peak	$30,505
Transmission	Reg. & Freq. Response BPAT	.44 mills/kWh	31,129.005 MWh	TRL energy [BPAT]	$13,697
Transmission	Peak Dues Charge	.04 mills/kWh	31,129.005 MWh	TRL energy [BPAT]	$1,245
Transmission	WECC Dues Charge	.04 mills/kWh	31,129.005 MWh	TRL energy [BPAT]	$1,245
Transmission	VERBS Regulating	.28 mills/kWh	384 kW	Nameplate Capacity	$108
Transmission	VERBS Following	.17 mills/kWh	384 kW	Demand Peak 2023-12-08 HE1	$67
Transmission	VERBS Imbalance	.00 mills/kWh	384 kW	Nameplate Capacity	$0
Transmission	CA Spinning Reserves	11.05 mills/kWh	2,181 kWh	3.0% TRL - gen + % losses	$24
Transmission	CA Supplemental Reserves	7.22 mills/kWh	2,181 kWh	3.0% TRL - gen + % losses	$16
Transmission	Spinning Reserves	11.05 mills/kWh	950,696 kWh	3.0% TRL - gen + % losses	$10,505
Transmission	Supplemental Reserves	7.22 mills/kWh	950,696 kWh	3.0% TRL - gen + % losses	$6,864
Transmission	NT Short Dist. Disc. [Decatur Solar	2.031 $/kW/month	5 kW	NT SDD determinant	($10)
Transmission	Oversupply Charges	4 $	1.0		$4
				2: Transmission	**$223,537**

Figure 18 Transmission Charges from OPALCO's Invoice

The BPA transmission system peak occurred at 11 am on the 13th of January 2024. Transmission energy charges for total energy consumption are calculated by Reg & Freq response BPAT of 0.44 mills/kWh, peak dues charge of 0.04 mills/kWh, and WECC dues charge of 0.04 mills/kWh. The list of charges considered and their percentage distribution in the transmission charges observed for January 2024 is given in Figure *19* as a Pie Chart.

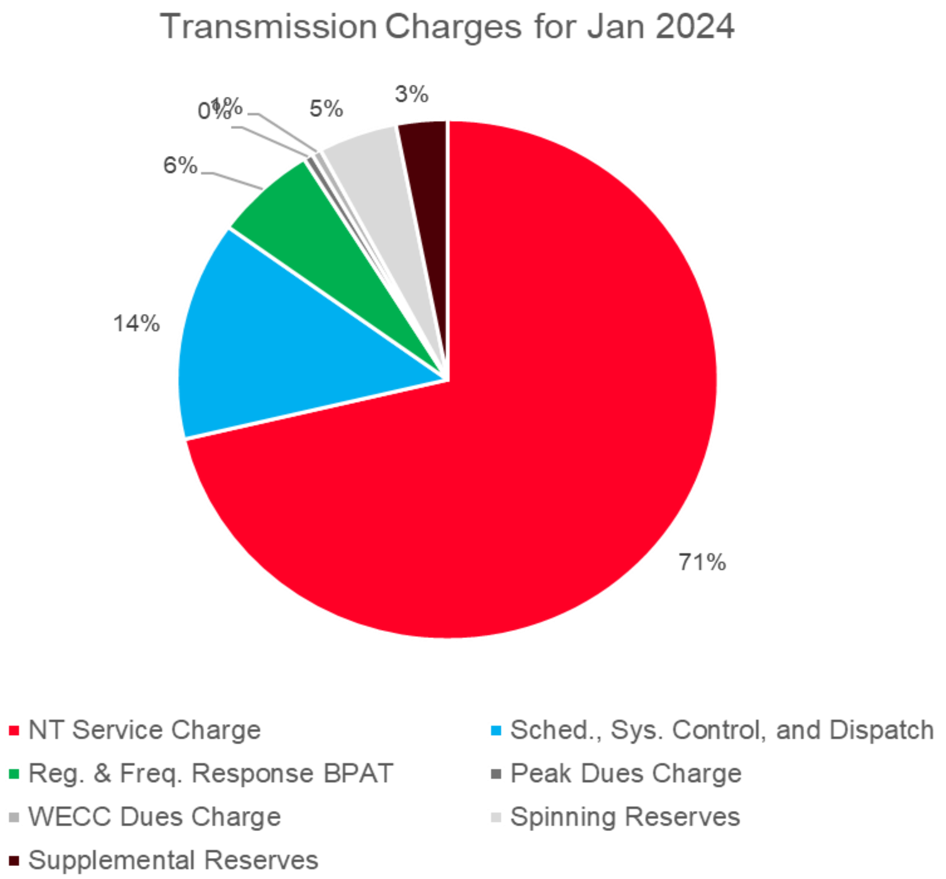


Figure 19 Pie Chart on Transmission Charges for Jan 2024

OPALCO's energy bill is calculated based on a tiered tariff structure offered by BPA. Tier 1 is the lower price level in BPA's structure and each energy customer is allocated a limited MW quantity that can be purchased at this rate. All the power OPALCO purchases fall into Tier 1. BPA is replacing the Tiered Rates Methodology (TRM), which expires Sept. 30, 2028, with the Public Rate Design Methodology (PRDM) [3]. The PRDM will work in parallel with the Provider of Choice contracts and BPA's 7(i) Rate Cases and will go into effect on Oct. 1, 2028. The development of the PRDM will be a year-long process, convening in Jan. 2024, and the final product of this process will serve as BPA's Initial Proposal in the BP-26 rate proceedings [3].

3.8 Public Rate Design Methodology (PRDM)- 2029

The Public Rate Design Methodology (PRDM) 2029, which will be in effect from October 1, 2028, is set to replace the Bonneville Power Administration's (BPA) Tiered Rate Methodology (TRM) that expires on September 30, 2028. The PRDM aims to provide a new structure for setting rates for BPA's public customers in conjunction with the Provider of Choice (PoC) contracts and BPA's bi-annual rate cases (7(i) process). PRDM is designed to offer greater flexibility and adaptability to the changing energy market and customer needs. It is more dynamic, considering factors like market conditions and new policy directions. The PRDM, status quo compared to previously chosen rate design alternatives are presented in Table *11*. The significant difference between TRM and PRDM is the changes performed to the calculation of "Demand Billing Units" and "Load Shaping Units." Additionally, the fixed charges of customer charges imposed in Tier 1 billing are eliminated. The details on the values used in TRM, PRDM Status Quo, and previously chosen rate design alternatives (1 – 4) are presented in detail in the Appendix for reference.

Table 11 BPA Market Description

<table>
<tr><th>Dependent Variables</th><th>Element 1</th><th>Element 2</th><th>Element 3</th><th>Element 4</th><th>Element 5</th><th>Element 6</th><th>Element 7</th></tr>
<tr><td rowspan="3">Status Quo</td><td rowspan="3">TOCA</td><td rowspan="3">Non-Slice TOCA</td><td rowspan="3">Slice %</td><td rowspan="3">Non-Slice HLH/LLH Load Shaping Rates</td><td>Rate = Marginal || Revenue Credit Element 2</td><td rowspan="3"></td><td rowspan="3"></td></tr>
<tr><td>Load Following Demand = Tier 1 CSP - Tier 1 aHLH-CDQ</td></tr>
<tr><td>Block w/Shaping Capacity Demand = Contract Shaping Amount - CDQ</td></tr>
<tr><td rowspan="4">Alternative 1</td><td rowspan="4" colspan="2"></td><td rowspan="4">Slice % and/or $/MWh</td><td rowspan="4">Non-Slice HLH/HLH Energy</td><td>Rate = Marginal || Revenue Credit to Element 4</td><td>Rate = Embedded Capacity Based || Revenue Credit to Element 4</td><td></td></tr>
<tr><td>Load Following Demand = Tier 1 CSP - Tier 1 aMonthly</td><td>PLV = TRL * PLVrate (Removed from Element 4)</td><td>Rate Impact Credit</td></tr>
<tr><td>Shaped Block = Tier 1 CSP - Tier 1 aMonthly</td><td>No PLV Option</td><td>Rate Impact Credit</td></tr>
<tr><td>Block w/Shaping Capacity Demand = Contract Shaping Amount</td><td>PLV Option (Same Capacity pricing as Load Following + Mkt Energy)</td><td>Rate Impact Credit</td></tr>
<tr><td rowspan="3">Alternative 2</td><td rowspan="3" colspan="2"></td><td rowspan="3">Slice % and/or $/MWh</td><td rowspan="3">Non-Slice HLH/LLH Energy</td><td>Rate = Marginal || Revenue Credit to Element 4</td><td>Rate = Embedded Capacity Based || Revenue Credit to Element 4</td><td></td></tr>
<tr><td>Load Following Demand = Tier 1 CSP - Tier 1 aHLH</td><td>PLV = TRL * PLVrate (Removed from Element 4)</td><td>Rate Impact Credit</td></tr>
<tr><td>Block w/Shaping Capacity Demand = Contract Shaping Amount</td><td>PLV Option (Same Capacity pricing as Load Following + Mkt Energy)</td><td>Rate Impact Credit</td></tr>
<tr><td rowspan="3">Alternative 3</td><td rowspan="3" colspan="2"></td><td rowspan="3">Slice % and/or $/MWh</td><td rowspan="3">63% of Non-Slice Revenue Requirement over HLH/LLH Energy</td><td>Rate = 37% of Non-Slice Revenue Requirement over capacity at TTSL & Contract Shaping Amount</td><td>Rate = Embedded Capacity Based || Revenue Credit to Element 4</td><td></td></tr>
<tr><td>Load Following and Shaped Block Demand = Load at TTSL</td><td>PLV = TRL * PLVrate (Removed from Element 4)</td><td>Rate Impact Credit</td></tr>
<tr><td>Block w/Shaping Capacity Demand = Contract Shaping Amount</td><td>PLV Option (Same Capacity pricing as Load Following + Mkt Energy)</td><td>Rate Impact Credit</td></tr>
<tr><td rowspan="4">Alternative 4</td><td rowspan="4">Fixed Customer Charge 37% of Revenue Requirement</td><td rowspan="4"></td><td rowspan="4">Slice % and/or $/MWh</td><td rowspan="4">Non-Slice HLH/LLH Energy</td><td>Rate = Marginal || Revenue Credit to Element 4</td><td>Rate = Embedded Capacity Based || Revenue Credit to Element 4</td><td></td></tr>
<tr><td>Load Following Demand = Tier 1 CSP - Tier 1 aMonthly</td><td>PLV = TRL * PLVrate (Removed from Element 4)</td><td>Rate Impact Credit</td></tr>
<tr><td>Shaped Block = Tier 1 CSP - Tier 1 aMonthly</td><td>No PLV Option</td><td>Rate Impact Credit</td></tr>
<tr><td>Block w/Shaping Capacity Demand = Contract Shaping Amount</td><td>PLV Option (Same Capacity pricing as Load Following + Mkt Energy)</td><td>Rate Impact Credit</td></tr>
</table>

The comparison between TRM (existing ate structure applied to OPALCO) and PRDM alternatives (1-4) is plotted as a bar chart in Figure *16*. This charge includes the data on Heavy Load Hours (HLH), Light Load Hours (LLH), fixed customer charges, and LDD discounts. From the observations, the overall BPA charges imposed on OPALCO increased PRDM. The significant difference between TRM and PRDM is the changes performed to the calculation of “Demand Billing Units” and “Load Shaping Units.” As shown the majority of the Tiered rates are related to fixed customer charges. While the fixed charges of customer charges imposed in Tier 1 billing are eliminated except for PDRM Alternative 4. As shown the total charges incurred from October 2023 to September 2025 for Tiered rates is $ 8,000,000 while the PDRM total charge is $16,000,000 (Alternative 2)

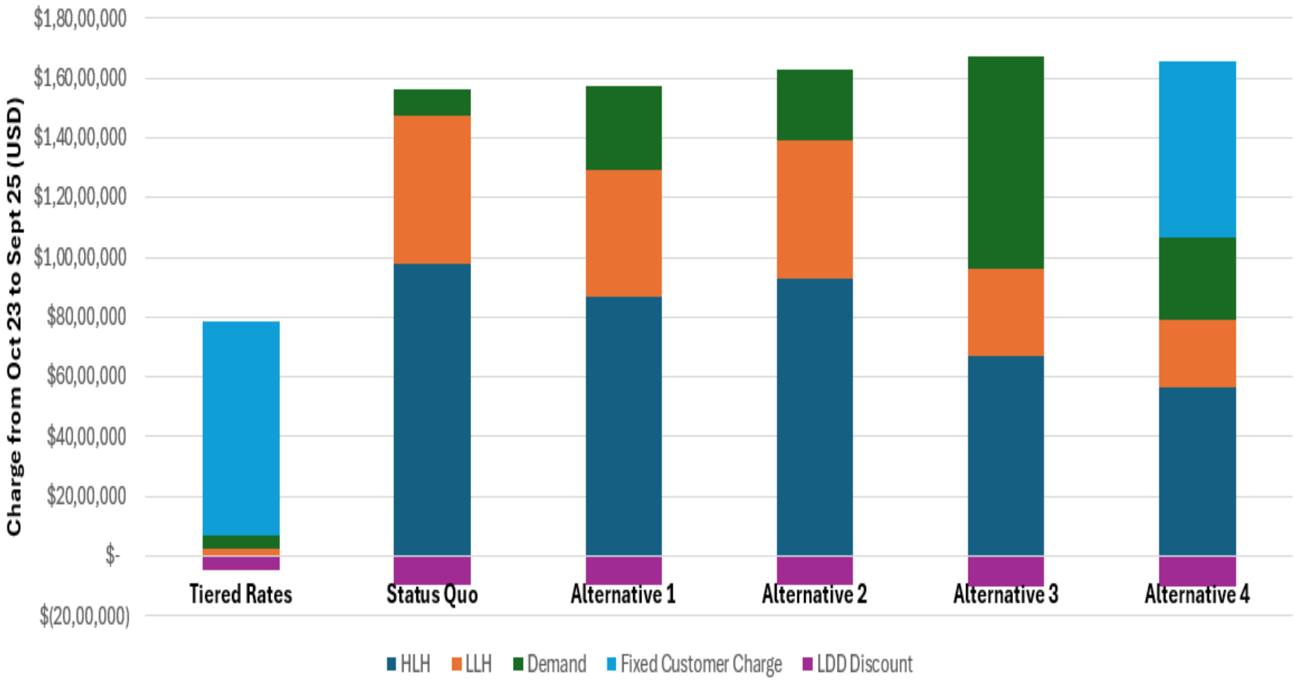


Figure 20 Comparison of TRM & PRDM Status Quo & Alternative (1-4)

4 Onsite Generation

Onsite solar PV generation combined with BESS, Automation, and an EMS with built-in smart charging provide additional value to the bus depot by maximizing renewable energy contributions, providing microgrid capabilities, and peak shaving. The solar arrays produce energy throughout the day – producing from 6 AM to 6 PM and peaking around midday, as shown in Figure *17* and BESS can store this energy and discharge during the night at peak charging loads (12 AM to 6 AM).

4.1 Solar PV Generation Profile

The 6MW distributed solar PV profile observed at the Friday Harbor substation is presented in Figure *17*. The weekly profile is presented in Figure *18*. For the period of 01-07-2024 to 01-13-2024. The maximum energy produced by 6 MW Solar PV is 1.1 MWh. The mapping of the load profile for the year 2023 with the total energy produced by 6MW distributed Solar PV for the same year showed a negative correlation proving that the lowest production of Solar PV was during the wintertime and the highest production during summertime. The same is presented in Figure *19*.

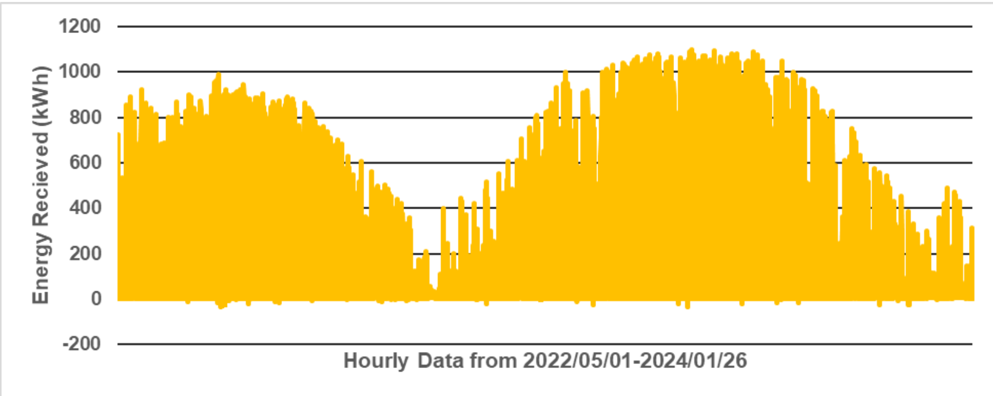


Figure 21 Data for Delivered Energy

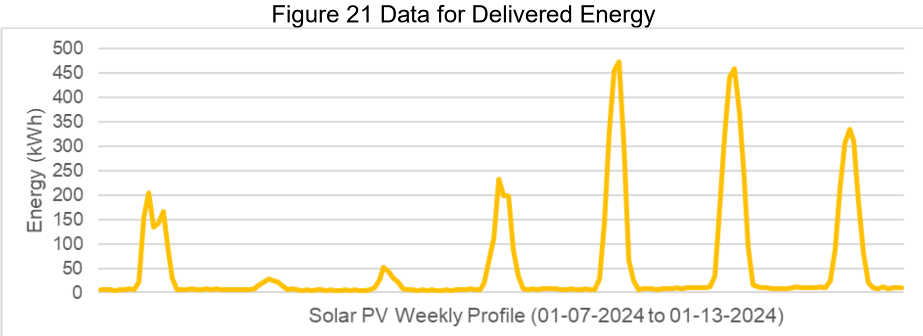
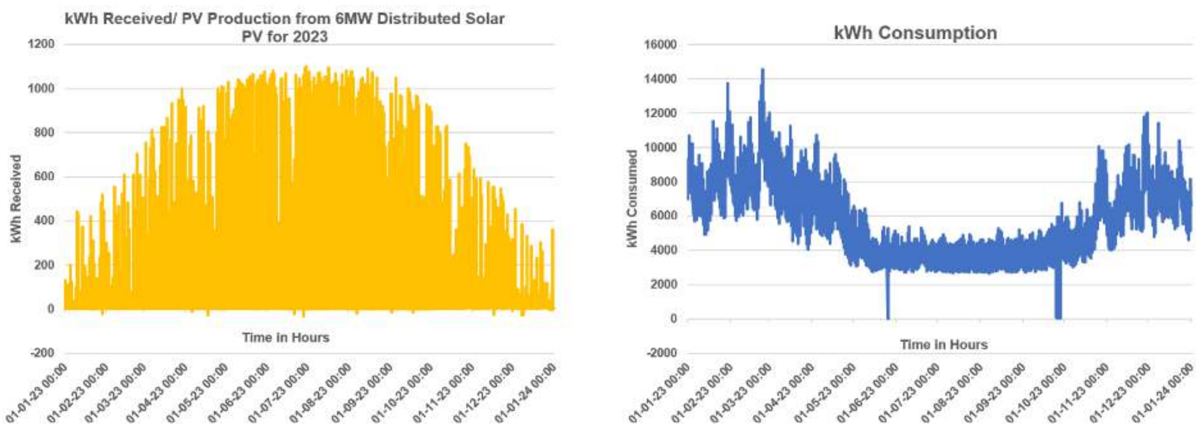


Figure 22 Solar PV Weekly Profile for Jan 7, 2024, to Jan 13, 2024



(a) (b)

Figure 23 (a) Distributed Solar PV (b) Load at Friday Harbor Substation in 2023

4.2 Battery Energy Storage Solution (BESS)

The features of BESS considered in this study are given in Table *12*. These are general market prices, is not a quote to be used for the purchase of a BESS. The CAPEX for BESS includes battery, commissioning, project management as well as installation. The OPEX for BESS includes SLA having Warranty, Performance Guarantees, Spares for BESS, and Training.

Table 12 BESS Details

Charges	BESS 1: 15MW/15MWh	BESS 2: 15MW/44MWh
Lifetime Years	10 years	10 years
Initial SoC	50%	50%
Minimum SoC	20%	20%
Power CAPEX Charges ($/kW)	189.9 $/kW	182.4 $/kW
Energy CAPEX Charges ($/kWh)	199.2 $/kWh	181.6 $/kWh
OPEX Cost	102,462 $/year	179,345 $/year
CAPEX Cost	5.8 MUSD	10.7 MUSD
Battery Replacement Cost	Battery replacement cost after 10 years of operation is considered with a 50% reduction from the energy charges.	

5 Conceptual Design

The conceptual design for the NWS study incorporates the following framework considering the ideal system functionalities received from OPALCO. The typical representation of the conceptual design framework is presented in Figure *24*.

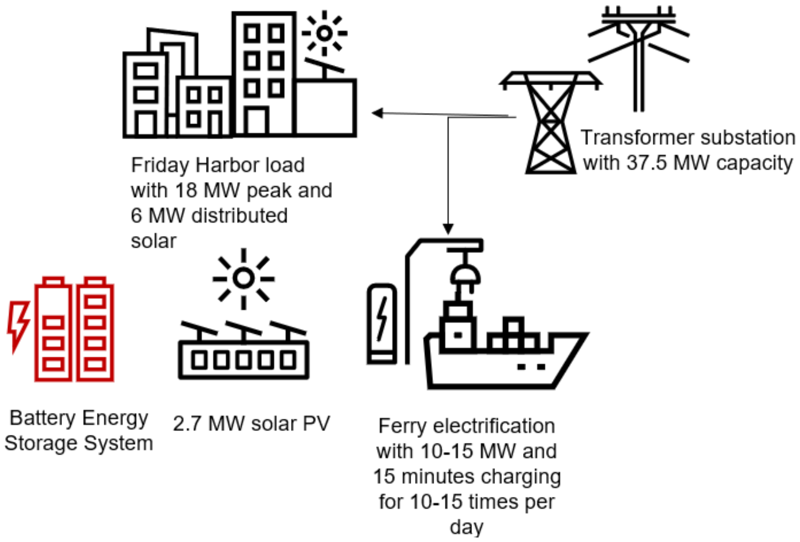


Figure 24 Conceptual Design Framework

5.1 NWS Study- Business Case Scenarios

The business case scenarios are crafted based on the evaluations and findings while assessing the existing infrastructure of OPALCO. The 1% load growth every year including electrified ferry-related transportation, benefits from the use of distributed renewable energy, and the plan on substation capacity upgradation are considered in the scenarios. The options on NWS and substation upgrade investment are represented in Figure *25* under the title, Microgrid Scenario and Distribution Capacity Upgrade Scenario.

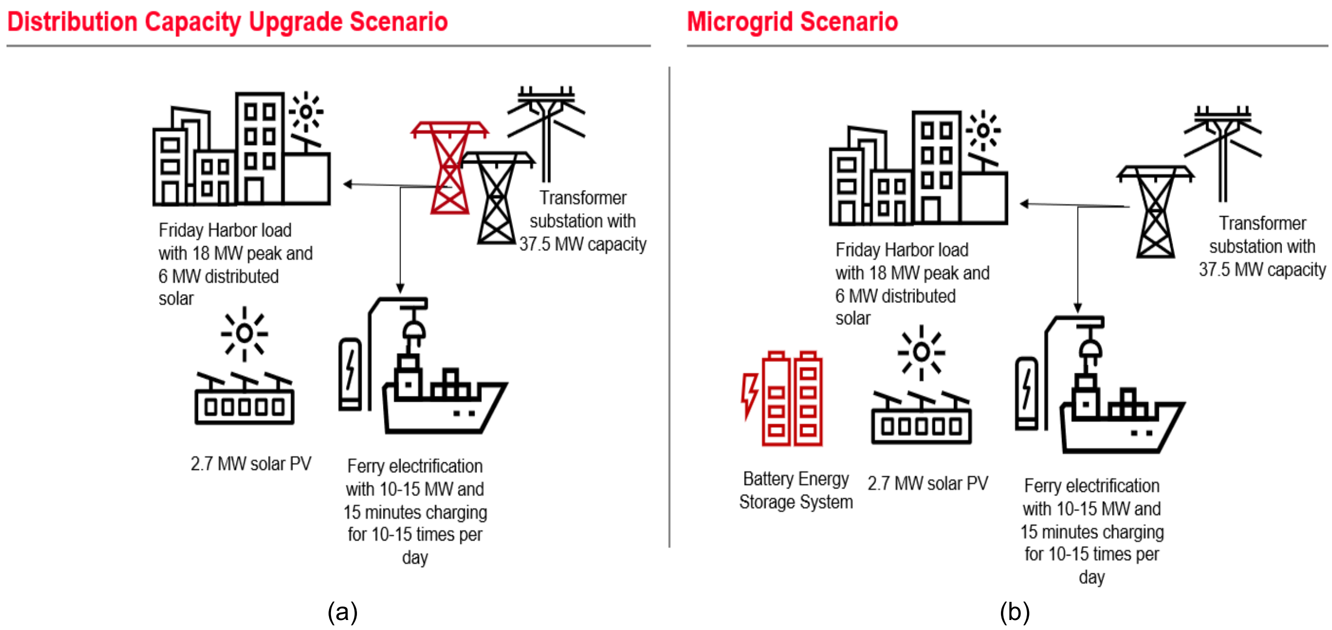


Figure 25 (a) Distribution Capacity Upgrade Scenario (b) Microgrid Scenario

The assumptions for performing the base case scenario considering the load growth and substation capacity are presented in Table *13* with the significant load growth observed in the years 2035 (start of the project), 2047 (Load exceeds the substation capacity and 2055 (end of project lifetime). The notable observation in the year 2047, highlighted in the table, is the total load exceeding the substation capacity. In the year 2055, the peak load is 39.5MW {(Load =24.5 MW) +(Ferry Load =15MW)} which is 2MW higher than the substation capacity of 37.5MW. Throughout the project's lifetime, the solar PV capacity remains fixed as there are no further plans to invest in the same.

Table 13 Details on Multi-Year Simulation and Load Data with PRDM

Year	BPA Rates	Load	Ferry Load	Solar PV	Substation Capacity
2035	PRDM	20.1 MW peak with 1% growth per year	15 MW peak in 15 minutes	6 MW and 2.7 MW Solar	37.5 MW
2047	PRDM	22.6 MW Peak with 1% growth per year	15 MW peak in 15 minutes	6 MW and 2.7 MW Solar	37.5 MW
2055	PRDM	24.5 MW Peak	15 MW peak in 15 minutes	6 MW and 2.7 MW Solar	37.5 MW

5.2 PRDM Tariff Rates

The PRDM tariff structure will be effective from October 1st, 2028, and the project starts in the year 2035, the PRDM Tariff is used for calculating the investment options. The detailed Tariff Rate structure considering the BPA rates given for PRDM design is presented in Table 14. The details of the calculations performed for PRDM Tariff Rates are presented in the Appendix section for future reference and with the details from [3].

Table 14 PRDM Tariff Rates

	PDRM Status Quo			Alternative 1			Alternative 2			Alternative 3			Alternative 4			
	HLH	LLH	Demand	HLH	LLH	Demand	HLH	LLH	Demand	HLH	LLH	Demand	HLH	LLH	Demand	Fixed Customer Charge
Month	$/MWh	$/MWh	$/kW-Mo	$/MWh	$/MWh	$/kW-Mo	$/MWh	$/MWh	$/kW-Mo	$/MWh	$/MWh	$/kW-Mo	$/MWh	$/MWh	$/kW-Mo	
Oct-23	40.9400	26.1400	10.37	36.7506	21.9506	10.37	38.9766	24.1766	10.37	29.0510	14.2510	10.37	25.0541	10.2541	10.37	13.6584
Nov-23	33.5300	24.6200	8.75	29.3406	20.4306	8.75	31.5666	22.6566	8.75	21.6410	12.7310	8.75	17.6441	8.7340	8.75	13.6584
Dec-23	54.8600	45.9200	13.39	50.6706	41.7306	13.39	52.8966	43.9566	13.39	42.9710	34.0310	13.39	38.9741	30.0341	13.39	13.6584
Jan-24	43.1100	29.9600	10.84	38.9206	25.7706	10.84	41.1466	27.9966	10.84	31.2210	18.0710	10.84	27.2241	14.0741	10.84	13.6584
Feb-24	43.5500	35.2400	10.93	39.3606	31.0506	10.93	41.5866	33.2766	10.93	31.6610	23.3510	10.93	27.6641	19.3541	10.93	13.6584
Mar-24	28.3000	29.0700	7.62	24.1106	24.8806	7.62	26.3366	27.1066	7.62	16.4110	17.1810	7.62	12.4141	13.1841	7.62	13.6584
Apr-24	13.6500	14.9000	4.43	9.4606	10.7106	4.43	11.6866	12.9366	4.43	1.76101	3.0110	4.43	-2.2359	-0.9859	4.43	13.6584
May-24	11.4400	9.5700	3.95	7.2506	5.3806	3.95	9.47666	7.6066	3.95	-0.4489	-2.3189	3.95	-4.4459	-6.3159	3.95	13.6584
Jun-24	11.1000	3.5600	3.88	6.9106	-0.6293	3.88	9.13666	1.5966	3.88	-0.7889	-8.3289	3.88	-4.7859	-12.3259	3.88	13.6584
Jul-24	48.8300	30.1500	12.08	44.6406	25.9606	12.08	46.8666	28.1866	12.08	36.9410	18.2610	12.08	32.9441	14.2641	12.08	13.6584
Aug-24	64.7500	42.1600	15.54	60.5606	37.9706	15.54	62.7866	40.1966	15.54	52.8610	30.2710	15.54	48.8641	26.2741	15.54	13.6584
Sep-24	51.9300	37.4100	12.75	47.7406	33.2206	12.75	49.9666	35.4466	12.75	40.0410	25.5210	12.75	36.0441	21.5241	12.75	13.6584

5.3 BESS Scheduling and Application

The Ferry load profile for a day is developed according to the schedule of operation, ferry ratings, and charging constraints and has a peak load of 15MW for a 15-minute average charging cycle. The same is presented in detail with suitable plots in the Existing infrastructure assessment section. The proposed NWS on integrating BESS provides services on “Peak Shaving” and “Energy Sifting (Arbitrage) applications, as explained through a plot presented in Figure *26*. A detailed explanation for the same is provided below.

Peak Shaving: BESS shaves the peak to not strike at the same time as the substation’s monthly peak. Hence, the rated power capacity of BESS needs to be equal to the peak load of ferries (15 MW). For one hour of charging duration, the BESS capacity is 15MWh. Hence for the provision of peak shaving application alone, the BESS size is calculated to be 15MW/15MWh.

Energy Shifting (Arbitrage): BESS shifts the ferry load from HLH occurring between (6 AM to 10 PM) to LLH occurring between (12 AM to 5 AM, and 10 PM to 12 AM).

$$\text{BESS Rated Energy} = \frac{\left((\text{Daily Average Ferry Load Consumption}) \times (1 + \text{SoC}_{\text{min}-\text{BESS}})\right)}{\text{Round Trip AC}-\text{AC Efficiency}} \tag{1}$$

where, $\text{SoC}_{\text{min}-\text{BESS}}$ is Minimum State of Charge of BESS = 20%.

$\text{Round Trip AC} - \text{AC Efficiency}$ = 90%

For the daily average ferry load consumption, the BESS-rated Energy is calculated to be 44MWh. Hence for both Peak shaving and energy shifting applications, the suitable BESS size is .15MW/44MWh.

Defer Substation Upgrade: BESS will defer the substation upgrade as it can provide peak shaving.

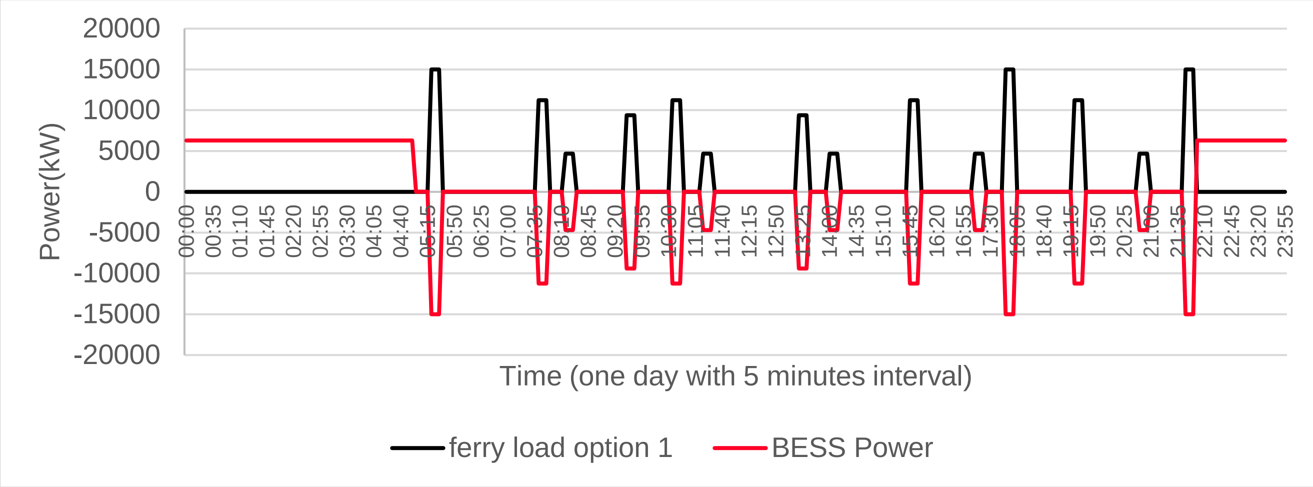


Figure 26 BESS Scheduling and Application of Peak Shaving and Energy Shifting

The PRDM tariff structure developed is applied for calculating the charges considered in the invoice of OPALCO. Here, the charges are calculated for i) Ferry Load alone, ii) Ferry Load integrated with BESS 1 (15MW/15MWh) for peak shaving application, and iii) Ferry Load integrated with BESS 2 (15MW/44MWh) for peak shaving and Energy Arbitrage. For the business case scenarios, demand charges are calculated based on BPA PDRM tariff rates presented in Table 5 charged for OPALCO for a peak load of 15 minutes. From Table *15*, the performance of option (iii) BESS 2 with Ferry load reduces the HLH charges and demand Charges to zero and provides a better savings of 1.68MUSD. Detailed calculations on the charges are given in the Appendix.

Table 15 Investment Options Study: Results

	Assets	HLH Charge	LLH Charge	Demand Charge	LDD Discount	Fixed CC	Total Charge	Savings by BESS
PDRM Status Quo	Ferry Load	$0.397M	$37.5k	$1.72M	($129.2k)	-	$2.02M	-
	Ferry Load+ **BESS 1 (15MW/15MWh)** (Peak Shaving only)	$0.397M	$37.5k	0	($26.1k)	-	$0.41M	$1.61M
	Ferry Load+ **BESS 2 (15MW/44MWh)** (Peak Shaving and Energy Arbitrage)	0	$0.367M	0	($22.02)	-	$0.345M	$1.68M

5.4 Cost Benefit Analysis

The cost-benefit analysis presented in Table 16 provides a systematic approach to estimating the advantages and disadvantages of the scenarios considered for achieving OPALCO's goal of grid modernization infrastructure development. The substation load will be 18 MW in 2024. In 2055 with 1 % load growth each year, it will be 24.5 MW.

Adding a 15 MW ferry load, the maximum substation load would be 39.5 MW in 2025. This is 2 MW higher than the substation capacity of 37.5 MW. The costs are calculated based on 189.9 $/kW for rated power and 199.2$/kWh rated energy. The battery replacement cost after 10 years of operation is considered with a 50% reduction.

Table 16 Cost Benefit Analysis

Scenario	Benefits	Costs
Scenario 1: Distribution Capacity Upgrade	1. Manage the expected demand growth by investing in distribution system upgrade 2. Peak demand charges remain high 3. Reliability performance is not improved	1. The investment cost to upgrade the distribution system is 2 MUSD. 2. The annual utility cost is 2.023 MUSD per year
Scenario 2: 15MW/15MWh BESS with Automation Control	1. Manage the expected demand growth and defer substation upgrade. 2. Reduce peak demand charges. 3. Improve reliability performance	1. The investment cost for BESS is 5.8 MUSD at year 1 and replacement cost of 2.9 MUSD at year 10 2. The 2 MUSD distribution system upgrade cost id avoided 3. The annual utility cost is reduced to 0.409 MUSD per year 4. The BESS O&M cost is $102,462/Year
Scenario 3: 15MW/44MWh BESS with Automation Control	1. Manage the expected demand growth and defer substation upgrade. 2. Reduce peak demand charges. 3. Reduce energy charges by load shifting from HLH hours to LLH hours. 4. Improve reliability performance.	1. The investment cost for BESS is 10.7 MUSD at year 1 and replacement cost of 5.3 MUSD at year 10 2. The 2 MUSD distribution system upgrade cost id avoided 3. The annual utility cost is reduced to 0.345 MUSD per year 4. The BESS O&M cost is $179,345/Year

The expected investment and operational benefits of a BESS as a potential NWS for Friday Harbor are presented in detail in Table *17* with consolidated results comparing each scenario.

Table 17 Business Case- Results

Index	Scenario 1: Distribution System Upgrade	Scenario 2: NWS with 15MW/15MWh BESS	Scenario 3: NWS with 15MW/44MWh BESS
CAPEX	2 MUSD	5.8 MUSD at year 0 for BESS	10.7 MUSD at year 0 for BESS
		2.9 MUSD at year 10 for battery replacement	5.3 MUSD at year 10 for battery replacement
OPEX	2.023 MUSD utility cost	0.409 MUSD utility cost	0.345 MUSD utility cost
		$102,462/Year BESS OPEX	$179,345/ Year BESS OPEX
Net Present Value	-	8 MUSD	2.5 MUSD
IRR	-	38%	13%
Payback Period	-	2.5 years	5.8 years

The detailed analysis for the business case scenarios considered for a project lifetime of 20 years and a discount rate of 9% shows a better econometric index with Scenario 2 as 15MW/15MWh BESS. This integration of BESS provides benefits on peak shaving and substation upgrade deferral facilitating OPALCO in achieving the grid modernization infrastructure goal enabling decarbonized electricity for hybrid electric ferries at Friday Harbor Substation. The prices considered for BESS are based on the 2024 assumptions. As the project start date for ferry electrification is estimated to be 2035, price drops on BESS technologies are likely. Hence the project econometric indices as payback time and IRR with lower CAPEX prices would have improved. The technology innovation will drive reduction in battery pack prices in the coming years to $80/kWh in 2030 based on BloombergNEF outlook. [8]

5.4.1 Cash Flow for 15MW/15MWh BESS.

The cash flow for the 15MW/15MWh BESS investment option is presented in Table *18*. This investment option results in an IRR of 38%.

Table 18 Cash Flow for 15MW/15MWh BESS

Year	Scenario 1: Distribution System Upgrade	Scenario 2: NWS with 15MW/15MWh BESS	Scenario 2 -Scenario 1 cashflow	Cumulative Cashflow
0	$ (20,00,000)	$ (58,37,025)	$ (38,37,025)	$ (38,37,025)
1	$ (20,23,644)	$ (5,11,233)	$ 15,12,411	$ (23,24,614)
2	$ (20,23,644)	$ (5,11,233)	$ 15,12,411	$ (8,12,203)
3	$ (20,23,644)	$ (5,11,233)	$ 15,12,411	$ 7,00,208
4	$ (20,23,644)	$ (5,11,233)	$ 15,12,411	$ 22,12,619
5	$ (20,23,644)	$ (5,11,233)	$ 15,12,411	$ 37,25,030
6	$ (20,23,644)	$ (5,11,233)	$ 15,12,411	$ 52,37,441
7	$ (20,23,644)	$ (5,11,233)	$ 15,12,411	$ 67,49,852
8	$ (20,23,644)	$ (5,11,233)	$ 15,12,411	$ 82,62,263
9	$ (20,23,644)	$ (5,11,233)	$ 15,12,411	$ 97,74,674
10	$ (20,23,644)	$ (34,29,746)	$ (14,06,102)	$ 83,68,572
11	$ (20,23,644)	$ (5,11,233)	$ 15,12,411	$ 98,80,983
12	$ (20,23,644)	$ (5,11,233)	$ 15,12,411	$ 1,13,93,394
13	$ (20,23,644)	$ (5,11,233)	$ 15,12,411	$ 1,29,05,805
14	$ (20,23,644)	$ (5,11,233)	$ 15,12,411	$ 1,44,18,216
15	$ (20,23,644)	$ (5,11,233)	$ 15,12,411	$ 1,59,30,627
16	$ (20,23,644)	$ (5,11,233)	$ 15,12,411	$ 1,74,43,038
17	$ (20,23,644)	$ (5,11,233)	$ 15,12,411	$ 1,89,55,449
18	$ (20,23,644)	$ (5,11,233)	$ 15,12,411	$ 2,04,67,860
19	$ (20,23,644)	$ (5,11,233)	$ 15,12,411	$ 2,19,80,271
20	$ (20,23,644)	$ (5,11,233)	$ 15,12,411	$ 2,34,92,682
		NPV	**$80,14,932.64**	
		IRR	**38%**	

5.4.2 Cash Flow for 15MW/44MWh BESS.

The cash flow for the 15MW/44MWh BESS investment option is presented in Table *19*. This investment option results in an IRR of 13%.

Table 19 Cash Flow for 15MW/44MWh BESS

Year	Scenario 1: Distribution System Upgrade	Scenario 2: NWS with 15MW/44MWh BESS	Scenario 2 – Scenario 1 cashflow	Cumulative Cashflow
0	$(2,000,000)	$ (1,07,27,525)	$ (87,27,525)	$ (87,27,525)
1	$(2,023,644)	$ (5,24,387)	$ 14,99,257	$ (72,28,268)
2	$(2,023,644)	$ (5,24,387)	$ 14,99,257	$ (57,29,011)
3	$(2,023,644)	$ (5,24,387)	$ 14,99,257	$ (42,29,753)
4	$(2,023,644)	$ (5,24,387)	$ 14,99,257	$ (27,30,496)
5	$(2,023,644)	$ (5,24,387)	$ 14,99,257	$ (12,31,239)
6	$(2,023,644)	$ (5,24,387)	$ 14,99,257	$ 2,68,018
7	$(2,023,644)	$ (5,24,387)	$ 14,99,257	$ 17,67,276
8	$(20,23,644)	$ (5,24,387)	$ 14,99,257	$ 32,66,533
9	$(20,23,644)	$ (5,24,387)	$ 14,99,257	$ 47,65,790
10	$(20,23,644)	$ (58,88,149)	$ (38,64,505)	$ 9,01,285
11	$(20,23,644)	$ (5,24,387)	$ 14,99,257	$ 24,00,542
12	$(20,23,644)	$ (5,24,387)	$ 14,99,257	$ 38,99,799
13	$(20,23,644)	$ (5,24,387)	$ 14,99,257	$ 53,99,056
14	$(20,23,644)	$ (5,24,387)	$ 14,99,257	$ 68,98,314
15	$(20,23,644)	$ (5,24,387)	$ 14,99,257	$ 83,97,571
16	$(20,23,644)	$ (5,24,387)	$ 14,99,257	$ 98,96,828
17	$(20,23,644)	$ (5,24,387)	$ 14,99,257	$ 1,13,96,085
18	$(20,23,644)	$ (5,24,387)	$ 14,99,257	$ 1,28,95,343
19	$(20,23,644)	$ (5,24,387)	$ 14,99,257	$ 1,43,94,600
20	$(20,23,644)	$ (5,24,387)	$ 14,99,257	$ 1,58,93,857
		NPV	**$24,70,460.41**	
		IRR	**13%**	

6 Data Monitoring Concept

Data monitoring is a critical aspect of optimizing the operation of a complex network with different assets in action. Hitachi Energy developed a comprehensive list of potential operational data from the NWS Study and Investment Options Study to be monitored to optimize the operation of new ferry-related electrification served by the Friday Harbor substation. It includes the concept and strategies for capturing data to optimally manage and operate the Friday Harbor network. This enhances the efficiency, reliability, and overall performance of the Friday Habor Substation facilitating the new service on ferry electrification. The schematic representation of data monitoring with assets is presented in Figure *26*Figure *27*.

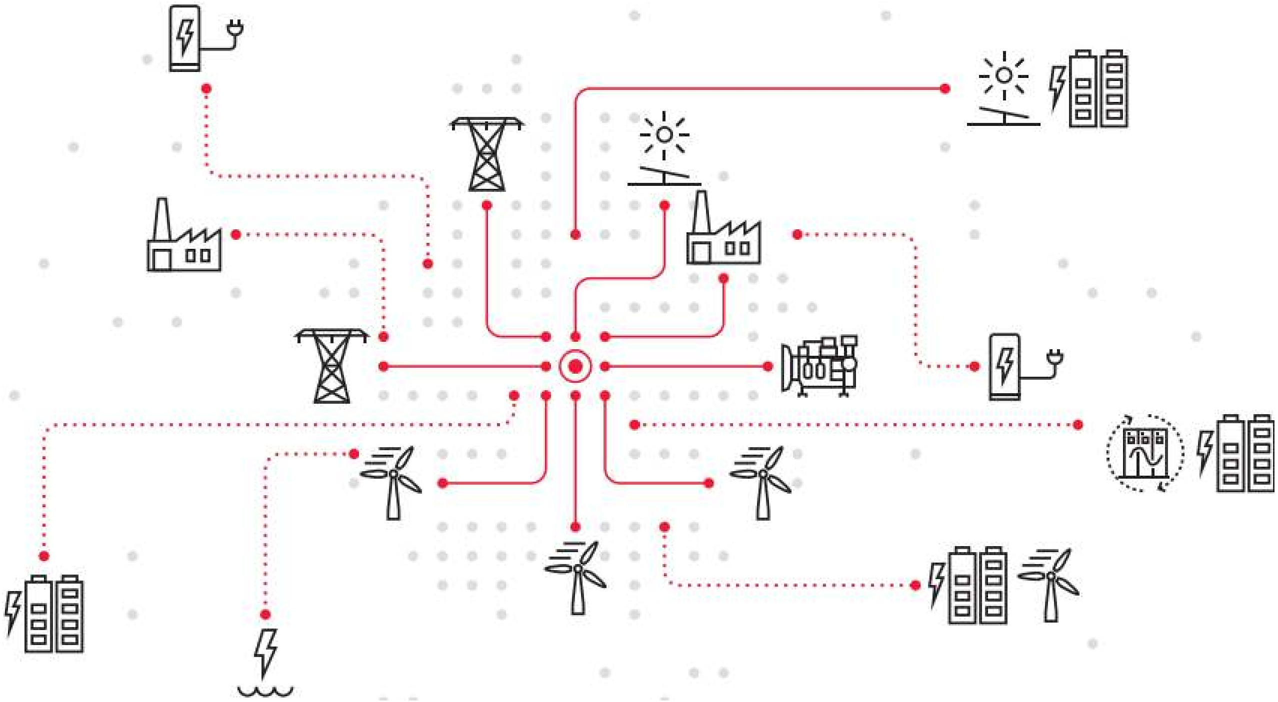


Figure 27 e-mesh™ High-level conceptual rendering of the data monitoring concept

6.1 Potential Operational Data from Friday Harbor Substation

The optimized operation of Friday Harbor Substation including the new ferry electrification infrastructure and implementation of NWS and strategy demands the following data to be monitored.

6.1.1 Energy Consumption Data at Friday Harbor Substation

The load data at Friday Harbor Substation includes the real-time power consumption of ferries for charging i.e., for about 15 mins at Friday Harbor Substation. Real-time data helps in understanding the immediate demand and adjusting the supply accordingly to avoid overloading the system. The identification and occurrences of peak load, observe the times when power consumption is at its highest and is essential for demand response strategies. By knowing the peak load time and episodes, operators can implement NWS to reduce demand during these periods, such as peak shaving and Energy Arbitrage. The impact of NWS is quantified in detail and the same is presented in Table 7 with the respective charges.

6.1.2 Data on Operation of Ferries

The operation of ferries is a critical component for the successful operation of electric ferries. This includes infrastructure requirements and environmental considerations. The operation schedule of ferries at Friday Harbor is presented in detail in Figure *7* and Figure *8*, explais the route, stops, and operations performed at each stop. The 15-minute charging schedule developed for ferries provides sufficient charging through the implementation of 15MW/15MWh & 15MW/44MWh BESS as NWS presented in the conceptual design.

6.1.3 Renewable Energy Sources (RES) Data

RES generation data is crucial for optimizing the operation of ferry-related electrification. This data helps in ensuring that the energy supply meets the demand efficiently and sustainably. Tracking the real-time output of RES helps in understanding their performance and availability. This data can be used to adjust the energy supply dynamically based on the current generation levels. By analyzing the historical data of existing Solar PV output at Friday Harbor Substation, operators can identify the patterns and trends. This information is useful for predicting future generations and planning, maintenance activities. It ensures balancing the supply and demand ensuring the grid remains stable and dependable.

6.1.4 BESS Operation Data

The operational details of BESS are highly essential to be monitored for managing the supply when working alongside an intermittent source like Solar PV. Keeping track of the charge, and discharge cycles of BESS helps in optimizing the usage, increasing their lifespan and efficient operation at Friday Harbor. Monitoring the SoC provides real-time information about the available stored energy. This data is crucial for ensuring the available backup power during peak demand periods and when RES is low. Regularly checking the health of batteries helps in identifying the need for maintenance, replacement, and prevention of unexpected failures.

6.2 e-mesh^{TM} Manager solution strategy for Friday Harbor Substation

Hitachi Energy's e-mesh Manager monitors and analyses the performance of distributed energy assets present in the Friday Harbor Substation (Distributed Solar PV). Hitachi Energy's e-mesh™ Maanger presented in Figure *28* enables energy management and optimization by generating stronger economic returns (leveraging energy price), load, and renewable forecasts to deliver optimized energy dispatch, smarter charging, improved energy efficiency, and reduced environmental footprint. This e-mesh ecosystem of solutions and products ensures power reliability and availability, grid stability, and the integration of renewable energy enabled by advanced automation technology. e-mesh^{TM} Monitor is a scalable cloud-enabled digital platform that brings information technology and operational technology together to transform data collected from different distributed energy assets into business insights. It facilitates better, more informed business decisions to maximize productivity and avoid down time. e-mesh^{TM} Monitor is a seamlessly integrated everything-as-a-service (XaaS) solution.

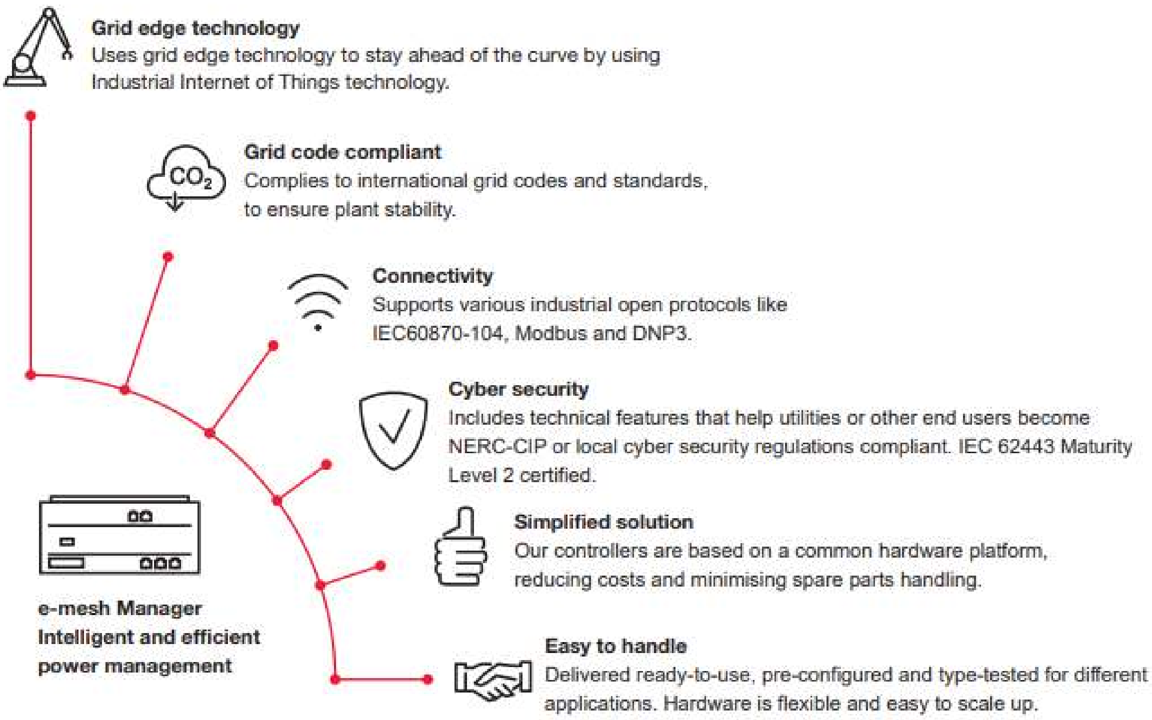


Figure 28 e-mesh^{TM} Manager

The benefits of utilizing Hitachi Energy's e-mesh Monitor are listed below.

- Real-time monitoring of distributed assets using cloud technology.
- Increases efficiency and productivity with in-depth analysis of data.
- Prevents critical asset failure and increases the reliability of site operations.

6.3 Enhanced Visibility into the distributed energy assets

Hitachi Energy's e-mesh monitor provides enhanced visibility into your distributed energy assets, a Cloud-enabled digital solution to monitor, control, and analyze the assets and site operations. Industries and utilities are moving towards distributed energy, emphasizing affordable and reliable clean energy. To comply with these demands and maximize revenue opportunities, asset owners need to continuously visualize performance trending and gain knowledge of site productivity. e-mesh™ Monitor is a cloud-based digital platform, exclusively designed to aggregate data from distributed energy assets and turn that into actionable business insights. You can monitor your assets from anywhere and anytime. e-mesh™ Monitor helps optimize performance and increase ROI from your distributed energy investments. Key features are presented below.

- Data extraction from assets using an IoT edge device.
- Data aggregation, analysis, and storage in a secure cloud environment. Real-time monitoring of distributed energy assets from anywhere, anytime
- Alarms, historical analysis, and performance analytics reporting
- High-end intuitive web interface to visualize data from the field.
- Function as a hosting environment for a set of everything-as-a-service (XaaS) e-mesh Applications.

e-mesh Applications are XaaS applications for descriptive, diagnostic, predictive, and prescriptive analytics to improve site productivity, minimize downtime, forecast renewables power generation, and increase revenue opportunities. The easy-to-deploy, scalable, and machine learning-based applications are available as four different suites: Analytics, Optimizer, Premium, and Service.

6.4 Cloud-enabled digital solutions

Hitachi Energy's e-mesh monitor provides actionable insights from the aggregate data observed from distributed energy assets. The key solutions provided by e-mesh™ monitor are given in detail below.

Cloud services and operations

To optimize the infrastructure costs, all measurements and information collected from the site are stored in a secured cloud database. Users can apply custom date ranges, visualize performance trending, and gain knowledge of on-site productivity.

Automated alarm system

All field-level critical measurements are continuously monitored with a built-in algorithm to ensure smooth operations of the site with limited outages. In case of deviation from normal operating conditions, corresponding alarms are triggered.

6.4.1 Extended functionalities

In addition to the base functionalities of e-mesh Monitor, customers can subscribe to any e-mesh Application depending on the business requirements.

Real-time monitoring of all connected assets

The monitoring includes dedicated dashboards to measure the productivity of the sites. The user-friendly design allows users to have overviews, system summaries, and any kind of detail that is important for the safe and profitable operation of assets.

Performance analytics and reporting

A set of analytics dashboards and reports are available to optimize and maximize the performance of distributed energy assets. Insights such as productivity, efficiency, CO2 emissions system uptime, etc., are measured and displayed in these reports.

6.5 Digital Enterprise Connect

Digital Enterprise Connect provides an efficient and secure way to collect and aggregate data from smart sensors or field devices for cloud-hosted applications. In Power Transmission and Distribution, it is suggested that Friday Harbor Substation adopt the Industrial Internet of Things to interface primary equipment such as transformers or circuit breakers to cloud-based applications. Those applications transform raw measurements like temperatures, pressure, current, or load into information and enable them to monitor and optimize the lifetime of assets integrated into the Friday Harbor Substation. The general overview of Digital Enterprise Connect is presented in Figure *29*. Using an open and extendible software architecture, the Digital Enterprise Connect Edge interfaces sensors or monitoring devices using industrial protocols (such as IEC 61850 or Modbus TCP) and converts the raw measurements into a common data model. This normalized model serves as a device twin representation and any updated measurement will be securely transmitted to Digital Enterprise Connect Core.

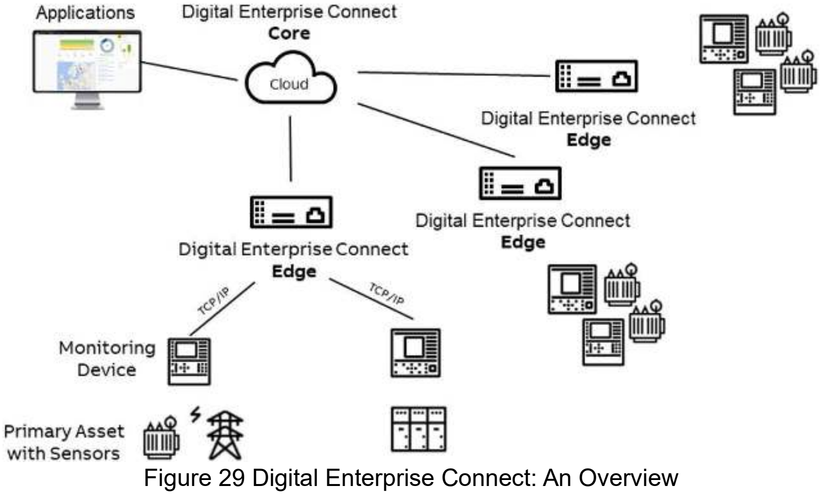


Figure 29 Digital Enterprise Connect: An Overview

The Digital Enterprise Connect Core builds the foundation for cloud-based applications. It integrates the Edge devices and provides Application Programming Interfaces (APIs) so that applications can use online and historized data. Role Based Access Control services ensure that approved applications and users can only access the data.

6.5.1 Key Features of Digital Enterprise Connect Edge

The Digital Enterprise Connect Edge provides a flexible and scalable way to integrate online measurements into cloud-based applications. The schematic representation of the Digital Enterprise Connect Edge Device is given in Figure *30*.

Figure 30 Digital Enterprise Connect Edge

The Core functionalities of digital enterprise Connect Edge are given below.

- Vendor-independent integration of existing or new monitoring devices using industry-specific protocols such as IEC 61850 and Modbus/TCP
- Flexible mapping of device-specific measurements into a generic Data Model (Digital Twin) is the basis for multiple applications reusing the same data, even if the data sources are from different vendors.
- Secure and encrypted connectivity to the Digital Enterprise Connect Core
- Wi-Fi and cellular connectivity (optional)

• 2 Ethernet Interfaces for dedicated connectivity to field device network and Cloud (external internet connectivity required)
• Buffering of data in case of communication interruption to the Digital Enterprise Connect for some days (duration depends on configuration)
• Dedicated provisioning process to ensure only legitimate Edge devices can connect to the Digital Enterprise Connect Core
• Supervision of Edge Devices from the Digital Enterprise Connect Core
• Open software architecture to allow future extensions of Edge functionality like protocol support or local applications.
• Edge software, configuration, and functionality can be updated (on demand) from the Hitachi ABB Power Grids operated and maintained Digital Enterprise Connect Core cloud platform.

6.6 Benefits of e-mesh Monitor application

The benefits of implementing e-mesh applications for monitoring the data at Friday Harbor Substation are extensive and are presented in detail in Table *20* explaining each feature with its benefits, respectively.

Table 20 Benefits of e-mesh^{TM} monitor applications.

FEATURE	BENEFITS
Return on Investment	• Reduced IT infrastructure CAPEX & OPEX • Low installation & commissioning costs • XaaS model with three subscription plans • Monetizable operational insights
Scalable and extendable	• Easy to upgrade or downgrade between different plans. • Easy to integrate new DERs as your business needs grow. • Extend to new functionalities with e-mesh Apps
Cybersecurity	• Strict cybersecurity measures • Authorization & authentication policies • Secured APIs • Secure and authenticated connections
Operational excellence	• Dedicated DevOps • Continuous delivery and support • New application's trial versions • Customer engagement • Fast response to business needs • Services over the full project lifecycle
Visibility anytime anywhere	• Single platform for DERs monitoring, management, and analysis • Secure access 24x7 • Fast corrective response to any issue • Avoid downtimes; increase productivity
Intuitive user experience	• No software setup is needed by the user. • Easy to use and navigate. • Minimal training needs • User-friendly dashboards • Clear information display

7 Conclusion

Hitachi Energy's Conceptual Design framework for OPALCO's plan to expand their grid modernization infrastructure targeting key cross-sectoral decarbonization goals. The conceptual design study considered the assessment of the existing Friday Harbor infrastructure with the distributed solar PV of 6MW and 2.7 MW of solar PV, a detailed load growth study incorporating the 1% load growth each year from the start of project time and forecasted load growth observed from the historical data .

The conceptual design includes the NWS Study and the Investment Options Study. The NWS study presented a detailed analysis of the expected investment and operational benefits of BESS and presented as a complete NWS for Friday Harbor Substation. The main applications of BESS for peak shaving and energy shifting (Arbitrage) are considered for the business case scenarios.

The Investment options study presented the summary of key investment options that provide the greatest value to OPALCO while enabling the electrification of ferry-related transportation. The results include a comparison of the business-as-usual case of distribution system upgrade with NWS investments, In the NWS scenario, 15MW/15MWh BESS and 15MW/44MWh BESS cases are analyzed. The business case results for the substation capacity of 37.5MW, and Ferry Peak load of 15MW, showed promising outcomes for the NWS Scenario with BESS of 15MW/15MWh. This investment option showed a significant econometric index of increase in IRR at 38% with a payback of 2.5 years. The CAPEX for BESS includes the battery, inverter, control system, commissioning, project management, and installation. The OPEX for BESS includes SLA having a warranty, Performance guarantees, spare parts for BESS, and Training.

The data monitoring concept presented the concepts and strategies for capturing data to optimally manage and operate the Friday Harbor network. Hitachi Energy's e-mesh Manager monitors and analyses the potential operational data derived from the NWS Study and Investment Options Study and monitors to optimize the operation of new ferry-related electrification served by the Friday Harbor substation. This e-mesh ecosystem of solutions and products integrates every asset in Friday Harbor and ensures power reliability and grid stability. It facilitates business decisions to maximize productivity and avoid downtime.

8 Appendix-PRDM Tariff Calculations

8.1 PRDM Status Quo Calculations for Table 6 (Ferry Load without BESS)

Period	HLH	LLH	Demand	PLVS	LDD Dis-count	IRD Dis-count	Fixed Cus-tomer Charge	Tier 1 True-up
Rate	**$/MWh**	**$/MWh**	**$/kW-Mo**	**$/MWh**	**%**	**$/MWh**	**-**	**$/MWh**
Oct-23	40.9400	26.1400	10.37	0	0.06	-11.57	0	6.7699
Nov-23	33.5300	24.6200	8.75	0	0.06	-11.57	0	6.7699
Dec-23	54.8600	45.9200	13.39	0	0.06	-11.57	0	6.7699
Jan-24	43.1100	29.9600	10.84	0	0.06	-11.57	0	6.7699
Feb-24	43.5500	35.2400	10.93	0	0.06	-11.57	0	6.7699
Mar-24	28.3000	29.0700	7.62	0	0.06	-11.57	0	6.7699
Apr-24	13.6500	14.9000	4.43	0	0.06	-11.57	0	6.7699
May-24	11.4400	9.5700	3.95	0	0.06	-11.57	0	6.7699
Jun-24	11.1000	3.5600	3.88	0	0.06	-11.57	0	6.7699
Jul-24	48.8300	30.1500	12.08	0	0.06	-11.57	0	6.7699
Aug-24	64.7500	42.1600	15.54	0	0.06	-11.57	0	6.7699
Sep-24	51.9300	37.4100	12.75	0	0.06	-11.57	0	6.7699
Oct-24	40.9400	26.1400	10.37	0	0.06	-11.57	0	6.7699
Nov-24	33.5300	24.6200	8.75	0	0.06	-11.57	0	6.7699
Dec-24	54.8600	45.9200	13.39	0	0.06	-11.57	0	6.7699
Jan-25	43.1100	29.9600	10.84	0	0.06	-11.57	0	6.7699
Feb-25	43.5500	35.2400	10.93	0	0.06	-11.57	0	6.7699
Mar-25	28.3000	29.0700	7.62	0	0.06	-11.57	0	6.7699
Apr-25	13.6500	14.9000	4.43	0	0.06	-11.57	0	6.7699
May-25	11.4400	9.5700	3.95	0	0.06	-11.57	0	6.7699
Jun-25	11.1000	3.5600	3.88	0	0.06	-11.57	0	6.7699
Jul-25	48.8300	30.1500	12.08	0	0.06	-11.57	0	6.7699
Aug-25	64.7500	42.1600	15.54	0	0.06	-11.57	0	6.7699
Sep-25	51.9300	37.4100	12.75	0	0.06	-11.57	0	6.7699

8.2 Billing Determinant Calculations for PRDM Status Quo – Ferry Load Without BESS

Billing Determi-nant	MWh	MWh	kW	MWh	$	MWh		MWh
Oct-23	891	114	15000	1005.046	-195008.4827	0	16766.1	0
Nov-23	891	114	15000	1005.046	-163932.9231	0	21924.54	0
Dec-23	891	114	15000	1005.046	-254967.1235	0	24717.58	0
Jan-24	891	114	15000	1005.046	-204427.6348	0	26402.84	0
Feb-24	891	114	15000	1005.046	-206771.9173	0	23364.45	0
Mar-24	891	114	15000	1005.046	-142830.6597	0	21054.25	0
Apr-24	891	114	15000	1005.046	-80311.4918	0	17222.96	0
May-24	891	114	15000	1005.046	-70534.4661	0	13939.68	0
Jun-24	891	114	15000	1005.046	-68496.0162	0	12407.35	0
Jul-24	891	114	15000	1005.046	-228145.7299	0	12866.69	0
Aug-24	891	114	15000	1005.046	-295600.0712	0	12787.44	0
Sep-24	891	114	15000	1005.046	-241776.3764	0	12738.48	-1.40248
Oct-24	891	114	15000	1005.046	-195008.4827	0	16807.52	0
Nov-24	891	114	15000	1005.046	-163932.9231	0	21978.63	0
Dec-24	891	114	15000	1005.046	-254967.1235	0	24778.53	0
Jan-25	891	114	15000	1005.046	-204427.6348	0	26467.93	0
Feb-25	891	114	15000	1005.046	-206771.9173	0	22669.91	0
Mar-25	891	114	15000	1005.046	-142830.6597	0	21106.22	0
Apr-25	891	114	15000	1005.046	-80311.4918	0	17265.53	0
May-25	891	114	15000	1005.046	-70534.4661	0	13974.2	0
Jun-25	891	114	15000	1005.046	-68496.0162	0	12438.09	0
Jul-25	891	114	15000	1005.046	-228145.7299	0	12898.57	0
Aug-25	891	114	15000	1005.046	-295600.0712	0	12819.09	0
Sep-25	891	114	15000	1005.046	-241776.3764	0	12769.98	-1.40248

8.3 Total Charges Calculations for PRDM Status Quo – Ferry Load without BESS

Charges	HLH	LLH	De-mand	PL VS	LDD Discount	IRD Dis-count	Fixe d CC	
Oct-23	36476.8843	2981.5984	155550	0	-11700.5089	0	0	0
Nov-23	29874.6997	2808.2234	131250	0	-9835.9753	0	0	0
Dec-23	48879.3688	5237.7547	200850	0	-15298.0274	0	0	0
Jan-24	38410.3176	3417.3172	162600	0	-12265.6581	0	0	0
Feb-24	38802.3501	4019.5672	163950	0	-12406.3150	0	0	0
Mar-24	25214.8581	3315.8015	114300	0	-8569.8396	0	0	0
Apr-24	12161.9559	1699.5359	66450	0	-4818.6895	0	0	0
May-24	10192.8833	1091.5828	59250	0	-4232.0679	0	0	0
Jun-24	9889.94906	406.06721	58200	0	-4109.7609	0	0	0
Jul-24	43506.7408	3438.9890	181200	0	-13688.7437	0	0	0
Aug-24	57691.1914	4808.8797	233100	0	-17736.0042	0	0	0
Sep-24	46268.7883	4267.0828	191250	0	-14506.5825	0	0	-9.4947
Oct-24	36476.8842	2981.5984	155550	0	-11700.5089	0	0	0
Nov-24	29874.6996	2808.2234	131250	0	-9835.9753	0	0	0
Dec-24	48879.3687	5237.7547	200850	0	-15298.0274	0	0	0
Jan-25	38410.3175	3417.3172	162600	0	-12265.6580	0	0	0
Feb-25	38802.3501	4019.5672	163950	0	-12406.3150	0	0	0
Mar-25	25214.8581	3315.8015	114300	0	-8569.8395	0	0	0
Apr-25	12161.9559	1699.5359	66450	0	-4818.6895	0	0	0
May-25	10192.8833	1091.5828	59250	0	-4232.0679	0	0	0
Jun-25	9889.9490	406.06721	58200	0	-4109.7609	0	0	0
Jul-25	43506.7408	3438.9890	181200	0	-13688.7437	0	0	0
Aug-25	57691.1914	4808.8797	233100	0	-17736.0042	0	0	0
Sep-25	46268.7883	4267.0828	191250	0	-14506.5825	0	0	-9.4947
Total--->	**$3,97,369.99**	**$ 37,492.40**	**$17,17, 950.00**	**$ -**	**$(1,29,168.17)**	**$ -**	**$ -**	**$ (9.49)**

8.4 PRDM Status Quo Calculations for Table 6–Ferry Load with BESS 2 (15MW/44MWh)

	HLH	LLH	Demand	PLVS	LDD Dis-count	IRD Dis-count	Fixed Cus-tomer Charge	Tier 1 True-up
Rate	**$/MWh**	**$/MWh**	**$/ kW-Mo**	**$/MWh**	**%**	**$/MWh**	**-**	**$/MWh**
Oct-23	40.9400	26.1400	10.37	0	0.06	-11.57	0	6.7699
Nov-23	33.5300	24.6200	8.75	0	0.06	-11.57	0	6.7699
Dec-23	54.8600	45.9200	13.39	0	0.06	-11.57	0	6.7699
Jan-24	43.1100	29.9600	10.84	0	0.06	-11.57	0	6.7699
Feb-24	43.5500	35.2400	10.93	0	0.06	-11.57	0	6.7699
Mar-24	28.3000	29.0700	7.62	0	0.06	-11.57	0	6.7699
Apr-24	13.6500	14.9000	4.43	0	0.06	-11.57	0	6.7699
May-24	11.4400	9.5700	3.95	0	0.06	-11.57	0	6.7699
Jun-24	11.1000	3.5600	3.88	0	0.06	-11.57	0	6.7699
Jul-24	48.8300	30.1500	12.08	0	0.06	-11.57	0	6.7699
Aug-24	64.7500	42.1600	15.54	0	0.06	-11.57	0	6.7699
Sep-24	51.9300	37.4100	12.75	0	0.06	-11.57	0	6.7699
Oct-24	40.9400	26.1400	10.37	0	0.06	-11.57	0	6.7699
Nov-24	33.5300	24.6200	8.75	0	0.06	-11.57	0	6.7699
Dec-24	54.8600	45.9200	13.39	0	0.06	-11.57	0	6.7699
Jan-25	43.1100	29.9600	10.84	0	0.06	-11.57	0	6.7699
Feb-25	43.5500	35.2400	10.93	0	0.06	-11.57	0	6.7699
Mar-25	28.3000	29.0700	7.62	0	0.06	-11.57	0	6.7699
Apr-25	13.6500	14.9000	4.43	0	0.06	-11.57	0	6.7699
May-25	11.4400	9.5700	3.95	0	0.06	-11.57	0	6.7699
Jun-25	11.1000	3.5600	3.88	0	0.06	-11.57	0	6.7699
Jul-25	48.8300	30.1500	12.08	0	0.06	-11.57	0	6.7699
Aug-25	64.7500	42.1600	15.54	0	0.06	-11.57	0	6.7699
Sep-25	51.9300	37.4100	12.75	0	0.06	-11.57	0	6.7699

8.5 Billing Determinant Calculations for PRDM Status Quo – Ferry Load with BESS 2

Billing Determinant	MWh	MWh	kW	MWh	$	MWh		MWh
Oct-23	0	1117	0	1117	-29191.03727	0	16766.1	0
Nov-23	0	1117	0	1117	-27493.62692	0	21924.54	0
Dec-23	0	1117	0	1117	-51279.70612	0	24717.58	0
Jan-24	0	1117	0	1117	-33456.89748	0	26402.84	0
Feb-24	0	1117	0	1117	-39353.165	0	23364.45	0
Mar-24	0	1117	0	1117	-32463.01905	0	21054.25	0
Apr-24	0	1117	0	1117	-16639.13444	0	17222.96	0
May-24	0	1117	0	1117	-10687.03105	0	13939.68	0
Jun-24	0	1117	0	1117	-3975.559882	0	12407.35	0
Jul-24	0	1117	0	1117	-33669.07377	0	12866.69	0
Aug-24	0	1117	0	1117	-47080.84895	0	12787.44	0
Sep-24	0	1117	0	1117	-41766.94685	0	12738.48	-1.40248
Oct-24	0	1117	0	1117	-29191.03727	0	16807.52	0
Nov-24	0	1117	0	1117	-27493.62692	0	21978.63	0
Dec-24	0	1117	0	1117	-51279.70612	0	24778.53	0
Jan-25	0	1117	0	1117	-33456.89748	0	26467.93	0
Feb-25	0	1117	0	1117	-39353.165	0	22669.91	0
Mar-25	0	1117	0	1117	-32463.01905	0	21106.22	0
Apr-25	0	1117	0	1117	-16639.13444	0	17265.53	0
May-25	0	1117	0	1117	-10687.03105	0	13974.2	0
Jun-25	0	1117	0	1117	-3975.559882	0	12438.09	0
Jul-25	0	1117	0	1117	-33669.07377	0	12898.57	0
Aug-25	0	1117	0	1117	-47080.84895	0	12819.09	0
Sep-25	0	1117	0	1117	-41766.94685	0	12769.98	-1.40248

8.6 Total Charge Calculations for PRDM Status Quo – Ferry Load with BESS 2

Charges ($)	HLH	LLH	De-mand	PL VS	LDD Discount	IRD Dis-count	Fixe d CC	
Oct-23	0	29191.0372	0	0	-1751.4622	0	0	0
Nov-23	0	27493.6269	0	0	-1649.6176	0	0	0
Dec-23	0	51279.7061	0	0	-3076.7823	0	0	0
Jan-24	0	33456.8974	0	0	-2007.4138	0	0	0
Feb-24	0	39353.1650	0	0	-2361.1899	0	0	0
Mar-24	0	32463.0190	0	0	-1947.7811	0	0	0
Apr-24	0	16639.1344	0	0	-998.34806	0	0	0
May-24	0	10687.0310	0	0	-641.22186	0	0	0
Jun-24	0	3975.5598	0	0	-238.53359	0	0	0
Jul-24	0	33669.0737	0	0	-2020.1444	0	0	0
Aug-24	0	47080.8489	0	0	-2824.8509	0	0	0
Sep-24	0	41776.4416	0	0	-2506.0168	0	0	-9.4947
Oct-24	0	29191.0372	0	0	-1751.4622	0	0	0
Nov-24	0	27493.6269	0	0	-1649.6176	0	0	0
Dec-24	0	51279.7061	0	0	-3076.7823	0	0	0
Jan-25	0	33456.8974	0	0	-2007.4138	0	0	0
Feb-25	0	39353.1650	0	0	-2361.1899	0	0	0
Mar-25	0	32463.0190	0	0	-1947.7811	0	0	0
Apr-25	0	16639.1344	0	0	-998.3481	0	0	0
May-25	0	10687.0310	0	0	-641.2218	0	0	0
Jun-25	0	3975.5598	0	0	-238.5335	0	0	0
Jul-25	0	33669.0737	0	0	-2020.1444	0	0	0
Aug-25	0	47080.8489	0	0	-2824.8509	0	0	0
Sep-25	0	41776.4416	0	0	-2506.0168	0	0	-9.4947
Total ---->	**$ -**	**$ 3,67,065.54**	**$ -**	**$ -**	**$(22,023.36)**	**$ -**	**$ -**	**$ (9.49)**

Sensitivity: Public

8.7 e-mesh monitor - Datasheet

GRID EDGE SOLUTIONS

e-mesh™ Service

Cloud-enabled monitoring

A cloud-based services platform, exclusively designed to aggregate data from distributed energy assets and turn it into actionable business insights.

Solution at a glance

Monitor, manage and analyse your distributed energy resources for optimal performance:

Connectivity, aggregation & centralisation

- Secure data collection from all DERs using Hitachi Energy Digital Enterprise Connect Edge
- Southbound over Modbus TCP/IP
- Northbound secure web connectivity
- 3G/4G connectivity optional
- Data ingestion and processing
- Secure data storage on cloud side
- Custom web application protocol interfaces (APIs) developed on demand
- Cybersecurity services

e-mesh Service monitoring

- Real-time & historical data processing
- Intuitive web interface accessible from PC, laptop, tablet or mobile phones
- Three subscription plans: Standard, Pro and Expert

e-mesh Service applications

- Transforms data into insights to help improve business performance
- Four suites: Analytics, Optimiser, Service and Premium

Site IoT Edge		Digital Energy Connect Edge
Hardware	CPU	Intel E3826 dual-core Atom, operating at 1.46GHz Integral GPU
	RAM	4GB DDR3L 1333MHz SO-DIMM
	Ethernet	2 x GbE Ethernet ports (each is a discrete GbE solution)
	Serial Interface	1 x RS-232 or RS-422/485 serial port (BIOS configurable)
	USB	2 x USB 2.0 ports and 1 x USB 3.0 port
	Display	1 x VGA and 1 x HDMI
	Disk	32GB SATA
	Wi-Fi	2x2 11ac Wi-Fi / BT
	Mobile communication	3G Modem (available only in 1KHW003477P0002) SIM card not provided
	External Antenna Kit	Accessory with dedicated separate ordering number
	Dimensions	Width: 140mm, Height: 36, Depth: 117
	Din Rail Mounting	Mounting Kit included
	Power Supply	12V DC, with total consumption, 10.5 Watts typical Universal power kit- USA, UK, Euro, JPN
	Shock and Vibration	3 Grms, IEC 60068-2-64, random, 5 – 500 Hz, 1 hr/axis 30 G, IEC 60068-2-27, half sine, 11 ms duration
	EMC	CE/FCC Class B (RF), PTCRB, GCF with Intel AC7260 WIFI Card and Telite HE910G 3G module) CE/FCC Class B (w/o RF) with bare bone only
	Safety Certifications	CB, UL, CCC, BSMI, KCC
Digital Enterprise Connect Edge Software	Southbound connectivity	Modbus TCP/IP master
	Northbound connectivity	Mutual Transport Layer Security (TLS)
	Data buffering in case of lost connectivity	Up to 4,000,000 messages for e-mesh Monitor standard plan
	Provisioning Service	Device Provisioning Service (DPS) dedicated to ensure only legitimate Edge devices can connect to the cloud side
	Services	Remote software and configuration updates for site edge (Optional)
	Extensions	Flexible edge architecture allowing future extensions (on demand)
Security	Secure Storage	Trusted Platform Module
	Isolation of Interfaces	Using firewall rules
	Outbound connections	All communications are device initiated and no direct access from public internet
	Secure and Authenticated connections	Server authentication for edge to cloud communications
Environmental	System Inlet Temperature - Extended Operating	-20°C to 60°C (-4° to 140°F) at sea level with extended temperature peripherals
	System Inlet Temperature – Non Operating	-40° to 60°C (-40° to 140°F)
	Relative Humidity – Operating	5 to 95% relative humidity (Rh), 40°C (104°F) maximum wet bulb temperature, non-condensing
	Relative Humidity – Non Operating	5 to 95% relative humidity (Rh), 40°C (104°F) maximum wet bulb temperature, non-condensing
	Acoustic Noise	None - Passively cooled solution with solid state drives

e-mesh Service Cloud Instance		
Device Twin	Compatible information models	Fully Integrated with e-mesh Manager and e-mesh Energy Storage
		Generic information models solar PV, wind energy, battery energy storage system, conventional generators, power meter, utility connection and weather station
	Additional information models	Easy to extend to other equipment information representation (on demand)
Compatibility	Supported browsers	Chrome, Firefox, Safari, Microsoft Edge
	Devices with supported browsers	PC, Laptops, Tablets, and Mobile phones
Data archiving	Historical data archiving	Standard plan up to 18 months at 10 mins averages – extra durations on demand
Security	Authentication policies	Tokens for user and applications authentication
	Authorisation policies	Role-based access control (RBAC) system, and Active Directory Integration
	REST APIs Security	Exposed only over HTTPS protocol
Localisation	Display Language	English, other languages on demand
DevOps	Services	Remote support and updates, remote edge services (on demand)
	Continuous Integration and Delivery	Automatic upgrades while subscribed

8.8 e-mesh^{TM} Manager – Energy Management & Optimization Datasheet

	Element	Details		
Managed assets	PCC	All assets are virtually connected to a single or multiple points of common coupling		
	Diesel Generators	Continuous setpoint		
	Energy Storage	Continuous setpoint		
	PV plant	Controllable and non-controllable PV plants. Continuous setpoints		
	Wind plant	Controllable and non-controllable Wind plats. Only continuous setpoints		
	Loads	Controllable and non-controllable loads. Continuous and discrete setpoints		
	EV Supply Equipment (EVSE)	Continuous and discrete setpoints, with integrated smart charging, including support for fleet schedules and VDV261-compliant battery recharge and preconditioning.		
Optimization	Intra-day	Synchronous optimization automatically executed every 15 minutes according to a 24 hours receding horizon framework Compute economic dispatch		
	Day-ahead	Asynchronous optimization requested by the user		
	Offline	Asynchronous optimization requested by the user Helps in planning and schedule maintenance activities		
Forecasting	e-mesh Manager integrated load forecast module engine and/or external data import			
	Renewable energy production forecast import			
	Energy price data import			
	Asset availability forecast import			
	Vehicle (e.g. bus) schedule import			
Connectivity	Plant SCADA	Modbus TCP/IP (slave)		
	Power Management	Modbus TCP/IP (master) IEC 61870-104		
	3rd party / customers' applications	Modbus TCP/IP (slave)		
	Forecast provider (e.g., renewable, load and energy price)	Secured and authenticated Web APIs		
	Element	EV Charging Infrastructure Details: OCPP 2.0.1 and Modbus TCP		
Users	Guest	4 default user roles with specific permissions Possibility to modify both user roles and permissions	Read and view data	
	Operator		Read and view data, enable disable workflow and commands, view parameters	
	Engineer		Read and view data, enable disable workflow and commands, run offline optimization, view and edit parameters	
	Administrator		Full access	
SW & HW Requirements	Hardware	e-mesh Manager runs on an Industrial PC	CPU	Intel Core i7-6820EQ Processor
			RAM	32 GB DDR4 2133 MHz RAM
			Hard disk	256 GB SSD
			Ethernet adapter	Any adapter supported by the operating system
			Input	Keyboard/mouse
			Output	Display
			Installation	USB port
	Software and OS	e-mesh Manager relies on microservices and containers technology	OS	Linux Ubuntu Server 18.04.X LTS
			Docker CE	LSB stable release
			Web browser	Chrome with support to TLS 1.2 or TLS 1.3

9 References

Sl.No.	Details
1.	Washington State Ferries - System Electrification Plan - December 2020
2.	001 RFI For Vessel Charging System - 2024-02-02_AF_RFI HE-VCS_Final_Rev03
3.	public-rate-design-methodology-2029 - Bonneville Power Administration (bpa.gov)
4.	Appendix B.Final Proposal Power Rate Schedules and GRSPs.BP-24-A-02-AP01 (bpa.gov)
5.	Appendix B - BPA Tiered Rate Methodology (smartgrid.gov)
6.	Appendix B.Final Proposal Power Rate Schedules and GRSPs.BP-24-A-02-AP01 (bpa.gov)
7.	https://www.bpa.gov/-/media/Aep/about/publications/fact-sheets/fs-202009-Tiered-Rate-Methodology.pdf
8.	https://about.bnef.com/blog/lithium-ion-battery-pack-prices-hit-record-low-of-139-kwh/#:~:text=Miners%20and%20metals%20traders%20surveyed,(in%20real%202023%20dollars).