TECHNICAL AND ECONOMIC FEASIBILITY OF A MICROGRID FOR A FIRE STATION IN HUMBOLDT COUNTY, CALIFORNIA.

By

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ABSTRACT

TECHNICAL AND ECONOMIC FEASIBILITY OF A MICROGRID FOR A FIRE STATION IN HUMBOLDT COUNTY, CALIFORNIA.

Nishaant Kumar Sinha

Microgrids are emerging as a promising solution to unreliable grid energy. Today, California is not only witnessing grid resiliency challenges from natural disasters such as wildfires, earthquakes, floods and heatwaves, but it is also seeking to green the grid and bring more renewables online. For example, Humboldt County, where this project is focused, has recently experienced an earthquake of 6.4M (on December 20th, 2022), which shut down the regional grid for ~20 hours.

Microgrid adoption enables critical facilities to operate seamlessly. The Humboldt Bay Fire Station (HBFS) No.1 is one such example, where first responders work to protect citizens against emergencies, be it emergency medical services (EMS) operations or fire rescue or even helping in restoration of power lines. This study involves a techno-economic analysis of a microgrid design that could support efficient and seamless operations for the fire station as it serves the people of Humboldt County during emergencies.

A clean energy microgrid for the station aligns with the Humboldt County GHG emission target to reach net zero by 2030, and could provide resilient power to their general and critical loads during regular operations and emergencies. The recommended

microgrid for the HBFS No. 1 facility includes a 70-kW photovoltaic (PV) array and a 90 kW/360 kWh battery energy storage system (BESS). The project cost ranges from $300k to $600k (depending upon the level of investment tax credits (ITC) the microgrid project would get). It provides 51-day resiliency in the best case and 28-hour resiliency in the worst case depending upon the weather condition. The system would also reduce greenhouse gas emissions from electricity use at the station by over 98% annually.

Considering the potential availability of incentives and the value of resiliency (VoR), the microgrid project for HBFS No.1 demonstrates promising economic feasibility results. The next steps involve further evaluation of the project's financial viability, engaging with relevant stakeholders to secure funding, and proceeding with the detailed design and implementation phases of the microgrid.

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INTRODUCTION

The duration of power outages in the United States between the years 2013 and 2016 averaged around 3 to 4 hours per customer per year. However, a notable increase was observed from the year 2017 to 2020, with the average duration rising to 4 to 6 hours per year per customer, as depicted in Figure 1. This rise in power outages can be attributed to various significant events and occurrences (U.S EIA, 2021). The prolonged duration of outages per customer is a concerning situation, particularly for critical facilities such as fire stations. These facilities rely on uninterrupted power supply to carry out their essential operations, including emergency response and public safety.

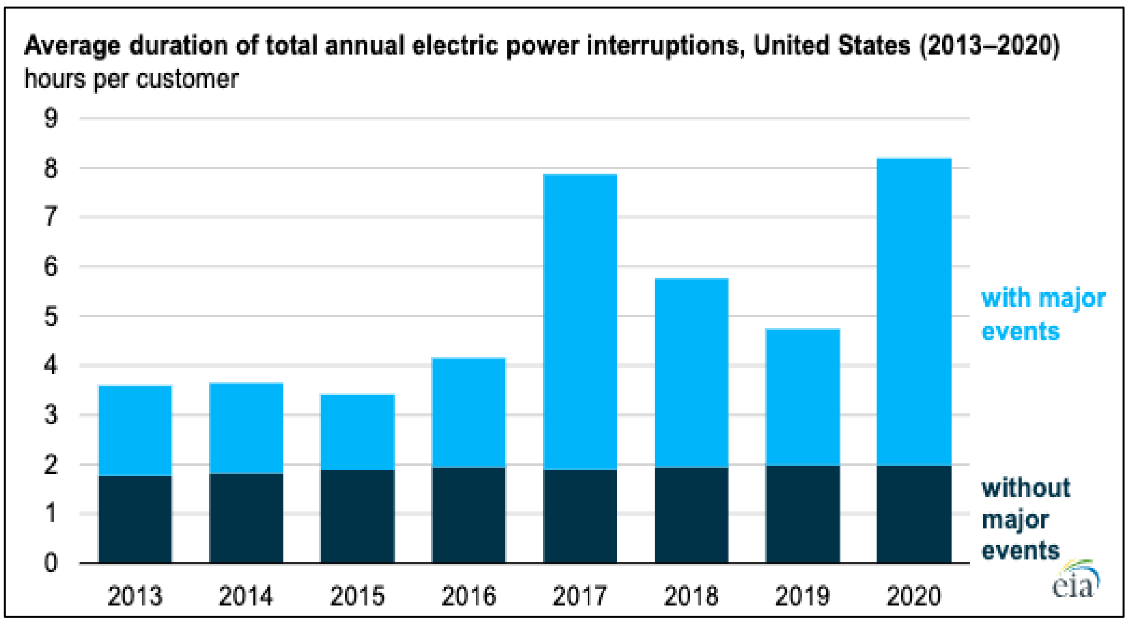


Figure 1: Historical power interruptions in U.S (U.S EIA, 2021)

This study aims to evaluate the potential implementation of a resilient and clean energy-based microgrid at the Humboldt Bay Fire Station (HBFS) No. 1 in Eureka, California, USA. This forward-thinking solution not only enhances the facility's ability to withstand power outages, but also tackles environmental concerns by curbing greenhouse gas (GHG) emissions. Furthermore, while the implementation of the microgrid offers significant benefits to the facility, it is essential to consider the associated costs of installation and maintenance. Alongside the improved resilience and reliability, the microgrids provide substantial economic advantages through reduced energy costs, enabling savings that can be allocated to further enhance operational efficiency and sustainability.

Fire stations' responsiveness depends upon a number of technologies that require uninterrupted and reliable power sources. To cope with possible power outages, most critical facilities have backup generators (gensets) that run on fossil fuel which may serve as a resiliency tool but comes with operation and maintenance (O&M) costs (fuel supply, maintenance, and parts replacement), exposure to risk from high fuel prices or shortages, harmful GHG emissions, and may experience cold start non-operational failure risks for fire station personnel when switching to the genset while critical operations are underway.

By 2050, the US wants to have an economy with zero net emissions of greenhouse gases (GHG). In January 2021, President Biden stated this objective as part of his executive order on "Tackling the Climate Crisis at Home and Abroad" (White House, 2021). California has also established a target to become carbon neutral by 2045 by enacting a number of laws and initiatives. The state has put in place a number of policies to cut greenhouse gas emissions, such as a cap-and-trade system, a renewable portfolio standard, and incentives for zero-emission automobiles through legislation such as SB 32 (Senate Bill No. 32, 2016), SB 100 (Senate Bill No. 100, 2018), and AB 398 (Assembly Bill No. 398, 2017). Humboldt County has similarly high climate targets. The county approved a climate action plan in 2019 with the objective of becoming carbon neutral by 2030. In order to minimize greenhouse gas emissions from a variety of sectors, including transportation, buildings, and energy, the Humboldt County climate action plan specifies specific methods and measures (Humboldt County, 2022). Some of the methods adopted by Humboldt County are building electrification through the Redwood Coast Energy Authority's (RCEA) energy efficiency targets and decarbonizing electricity sources through widespread deployment of solar and storage. By 2030, RCEA plans to install renewable energy backup systems and a network of community microgrids in all crucial buildings around the county. These distributed energy systems seek to reduce greenhouse gas emissions, improve energy resilience, and provide a steady supply of electricity in case of emergencies (Humboldt County, 2022).

California's wildfires, floods, earthquakes, and heat waves have catastrophic impacts on the lives of humans, wildlife, and the environment. As per a report by California Public Utilities Commission CPUC, around half of such attributed destructive wildfires originated due to power lines and tree contact. To reduce such wildfire risk, public safety power shutoffs (PSPS) are used by various power utility firms (CPUC, 2021a). Utility providers utilize PSPS events, which are a preventative action in severe weather conditions that have potential to start wildfires. For example, strong winds and dry vegetation are one of the many things that might endanger electrical transmission and distribution lines and cause fires to start (CDE, 2023). Due to their liabilities of causing wild fires caused by power lines (CPUC, 2020a), electric utility firms such as PG&E have paid more than $25 billion and filed Chapter 11 bankruptcy, which is nothing next to loss of approximately 100 lives across California in the year 2019 (Balaraman, 2020).

Decentralized power sources, such as microgrids, present a potential remedy to reduce the challenges of power outages caused by wildfires, earthquakes, PSPS, and in case of system failure caused due to excessive demand (Bowen, 2016). Microgrids increase resilience, lessen reliance on centralized systems, and guarantee dependable electricity supply in business as usual as well as in difficult conditions by offering localized energy generation and delivery to a particular facility or a community.

Microgrids strategically placed in areas prone to Public Safety Power Shutoff (PSPS) events offer a solution that mitigates the fire risk associated with high-voltage transmission lines and trees. This not only enhances safety for public utilities but also provides critical facilities with increased resilience. By adopting a proactive approach, these facilities can avoid outages during PSPS situations and ensure the availability of potential Red Cross shelters during emergencies or other major event days (MEDs). As a result, both the community and critical infrastructure can operate with greater confidence and preparedness. MEDs could be defined as days when the daily system average interruption duration index (SAIDI) of an event surpasses a statistically determined threshold based on the preceding 5 years of SAIDI data (CPUC, 2021). These events are caused due to catastrophic events such as storms, floods, earthquakes and other natural calamities which are relatively infrequent but can have significant repercussions.

Microgrids are robust and intelligent power systems that use a combination of distributed energy resources such as solar photovoltaics (PV) and battery energy storage systems (BESS). It provides backup power during grid outages caused due to PSPS, MEDs and routine power outages. Microgrids also minimize the energy procurement from the conventional grid through the utilization of solar resources for electricity generation and battery charging during periods of surplus energy generation. This enables the BESS to discharge power to the load during peak demand periods and when solar energy is unavailable, ensuring a reliable and sustainable energy supply. When microgrids use clean renewable energy sources as the distributed energy resources (DERs), it also reduces greenhouse gas emissions.

The need for microgrids serving fire stations is significant since they are a vital operation facility open 24x7 to respond to emergencies like structure fires, rescue missions, medical services or wildland fires. They safeguard a region's resources and properties and save human lives (Cal Fire, 2023). The seamless operation of fire stations depends significantly on uninterrupted communication and vital activities performed in a day-to-day manner. Therefore, it is crucial to guarantee a regular and stable power supply. Given the emergence of microgrids, the increasing need for resilient power, and the specific needs of critical facilities like fire stations, the research intends to thoroughly assess the potential of installing a microgrid system for HBFS No. 1 from a technical, economic, and environmental standpoint.

BACKGROUND

The Humboldt Bay Fire Department was formed in 2011 through an amalgamation of the City of Eureka Fire Department and Humboldt No.1 Fire Protection District. The Humboldt Bay Fire Department operates a total of five fire stations in Eureka. The first responders deal with all kinds of incidents and serve almost 50,000 people residing within the boundaries of Eureka (Reynolds, 2013). The HBFS No.1 was built in the year 1975 and occupies a total area of 25,000 sq feet as shown in Figure 2. The total number of staff working at the HBFS No. 1 is around 12 individuals, whereas the stationed staff which serve round the clock is around 5 individuals.

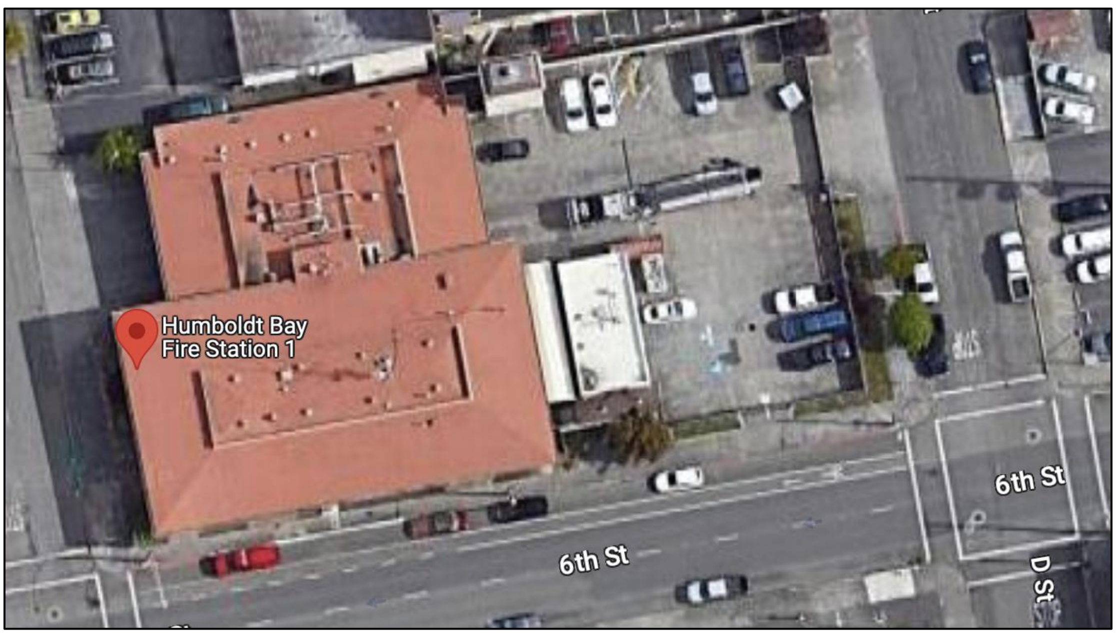


Figure 2: Aerial view of the HBFS No.1 located at Eureka, California (Google Maps, 2023).

The department is entirely dependent upon an advanced communication system. One example is an emergency responder radio communication system (ERRCS), which is a wireless technology and intended to increase public safety by receiving radio signals from outside and transmitting them within a structure. Its objective is to guarantee dependable cellular coverage and signal penetration across the whole facility, even remote or generally unreachable places (Delaney, 2022). Such equipment requires an uninterrupted power supply to be online and serving the people of Humboldt County.

Other needs for reliable electric power include an alarm system that ensures immediate notification of emergencies, automatic door openers that enable quick access for fire trucks and personnel, and Personal Protective Equipment (PPE) kit washing machines that sanitize and maintain the safety of protective gear. Additionally, vehicle exhaust removal systems help remove harmful emissions (from fire engines and trucks) from the station, while proper lighting is essential for visibility and efficient operations. Other systems that require reliable power include air compressors, which ensure an adequate supply/refilling of oxygen for emergency medical situations and firefighting, and a security and surveillance system, which is crucial for monitoring the premises, protecting valuable assets, and ensuring the safety of personnel and visitors. These various equipment and systems, along with other necessary components, depend on a reliable and uninterrupted electric power source to support the firefighting and emergency response operations of the fire station.

The occurrences of wildfires, heat waves, earthquakes, PSPS and other MEDs, have increased rapidly and could impact the life of the local residents as they threaten the functioning of the critical facilities.

As depicted in Figure 3, a statistical incident map reveals a notable spike in incidents during the month of December, reaching approximately 800 incidents. This increase can be attributed to a significant event, specifically the earthquake that took place on December 20th, 2022. By comparing these numbers with the incidents recorded in November (approximately 650 incidents) and January (approximately 580 incidents), a clear contrast of increase in the number of incidents emerges, highlighting the impact of the earthquake on the total number of incidents (Humboldt Bay Fire, 2023). This observation provides a deeper understanding of how major events, such as earthquakes, can significantly influence the frequency of incidents.

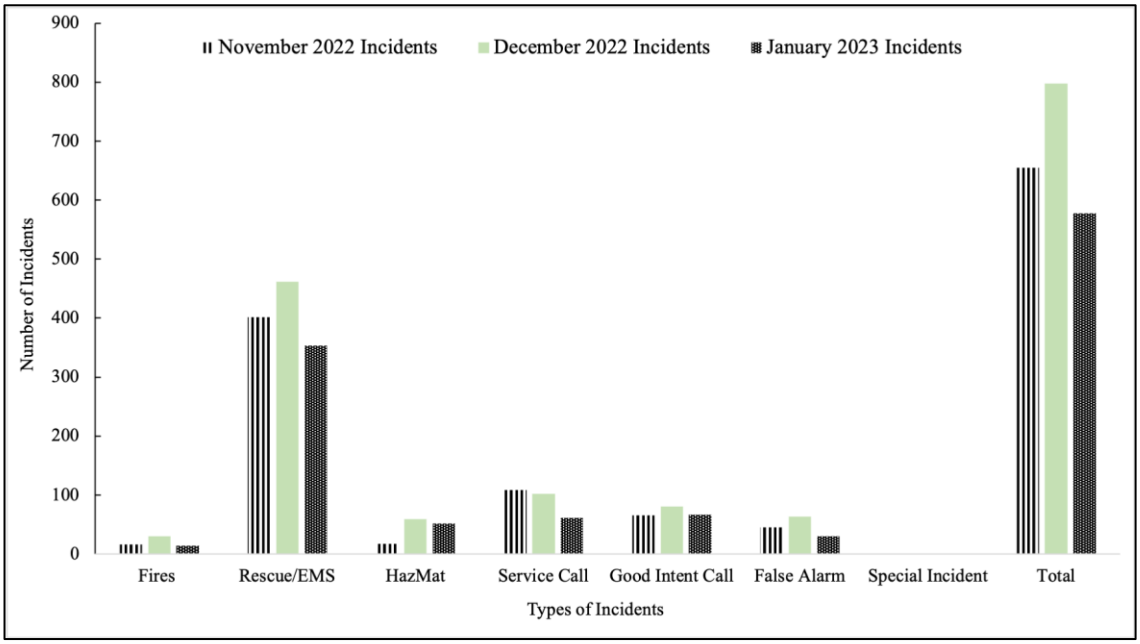


Figure 3: Incident map statistics of Humboldt Bay Fire Department from November 2022 to January 2023 (Humboldt Bay Fire, 2023).

The HBFS No. 1 has responded to numerous incidents, including serious rescue operations and other emergency fire situations in the past. For example, in the year 2020 and 2021, Humboldt Bay Fire responded 13,000 incidents, which were mainly rescuing/EMS operations. HBFS No.1, within the Humboldt Bay Fire department, stands out with the highest number of emergency responses (Humboldt Bay Fire, 2023). This distinction is depicted in Figure 4 below, showcasing the response numbers specifically for the month of December 2022. During this period, an earthquake of 6.4 magnitude struck Humboldt County, resulting in a power outage that endured for approximately twenty hours (Beam & Antczak, 2022).

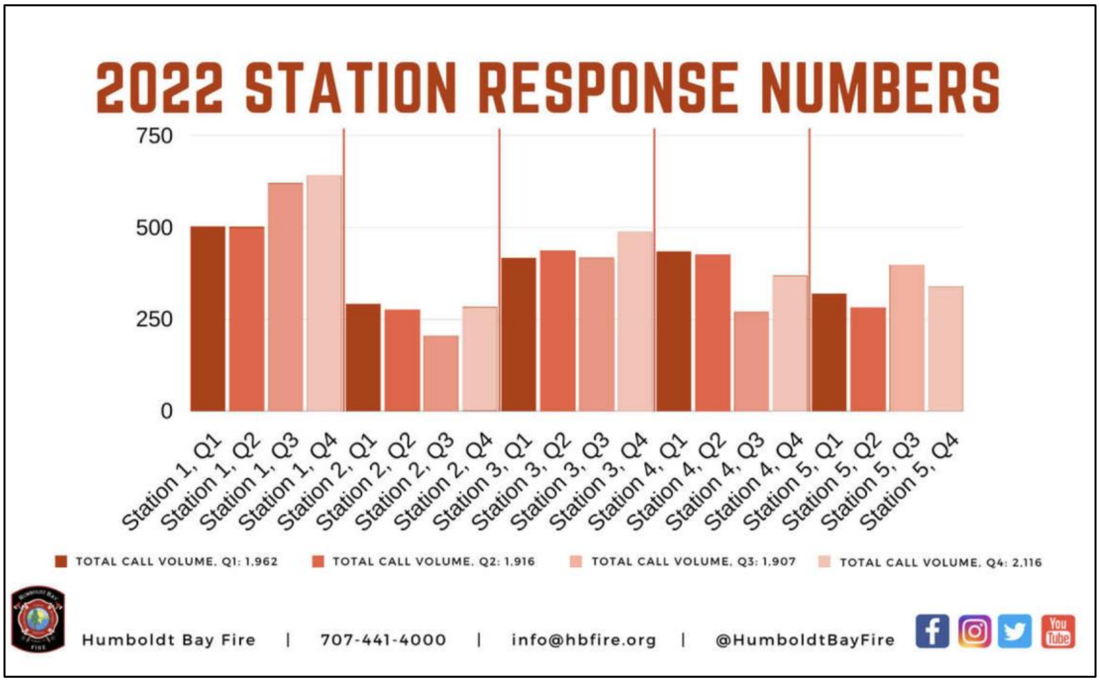


Figure 4 : Response numbers of all the fire stations for the Humboldt Bay Fire Department (Humboldt Bay Fire, 2023).

As per the Lexipol 2019 study on "Understanding and Measuring Fire Department Response Times", the total response time of a fire station is composed of three important parameters. The first parameter, "call processing time," is the time taken by the fire department public safety answering point (PSAP) to receive and respond to the call and provide notification to the first responding unit. The second parameter is the "turnout time," which is the time taken by the fire unit to change their status to "responding." The third parameter is the "travel time," which is time elapsed for the responding unit to travel and address the situation (Moore-Merrell, 2019).

If fire station operations get affected due to a vulnerable power supply, the response time could be seriously hampered, thereby reducing their effectiveness. The outcomes could involve severe consequences, such as delay in the call processing and the turnout time, which further results in ineffective operations. So, a resilient power system that can provide uninterrupted power supply during power outages is an imperative for fire station facilities.

Moving in the direction of RE-based microgrids will not only help to improve resilience and contribute to peak shaving, but it will also help achieve climate emission targets by curbing GHG emissions for California as a whole and Humboldt County in particular. In alignment with the “Humboldt County Climate Action Plan” (CAP), the County, in collaboration with the Redwood Coast Energy Authority (RCEA), has established a goal of installing solar photovoltaic (PV) systems on approximately 37 commercial facilities annually from the year 2020 to 2030 (Humboldt County, 2022). This ambitious target aims to promote renewable energy adoption and contribute to the county's efforts to mitigate climate change. By implementing solar PV on these commercial sites, Humboldt County and RCEA are taking proactive steps towards achieving their climate targets and transitioning to a more sustainable energy future.

Also, in the CAP they noted that municipal facilities such as fire stations commonly rely on diesel-powered backup generators for emergency power supply. However, an alternative solution to meet their backup generation requirements is to combine rooftop solar installations with battery storage. The City of Rio Dell has successfully implemented this approach, replacing diesel generators at crucial facilities by incorporating battery systems alongside solar power (Humboldt County, 2022).

I had discussions with the HBFS No. 1 team to understand the operational challenges due to power outages, critical loads and existing electrical infrastructure information. Some of the critical loads which were observed in the HBFS No.1 facility during the site visit are as follows:

Medical Equipment: Vital medical devices like cardiac monitors and air compressors are frequently used at fire stations and need a consistent and dependable power source to work properly. These tools are essential for offering emergency medical care to those who require it. For the purpose of keeping track of patients' heart activity and spotting any irregularities or crises, cardiac monitors are crucial. They make it possible for first responders and medical professionals to evaluate the patient's status and take prompt actions as needed.

Air compressors: Air compressors, like the one shown in the Figure 5 below, are also crucial in fire stations. They are in charge of replenishing oxygen cylinders, which are essential for patients who need oxygen assistance and for firefighting operations. To ensure that there is enough oxygen available for usage when needed, air compressors help maintain a consistent flow of compressed air to replenish the cylinders.

Figure 5: Air compressors at the HBFS No. 1 facility for oxygen refilling.

Vehicle Exhaust Removal System: During the site visit with to HBFS No. 1, I have witnessed the vehicle exhaust removal system, as shown in Figure 6 below. It was identified as one of the most critical pieces of equipment that needs an uninterrupted power supply. These systems remove pollutants like carbon monoxide (CO) emitted from the fire trucks. Exhaust emitted from the vehicles can be hazardous to firefighters' respiratory health and must continuously be removed while the vehicles are operated inside the fire house.

Figure 6: Vehicle exhaust removal system at the HBFS No. 1 facility.

Automatic Door Openers: There are automatic door openers at the fire station, shown in Figure 7 below, that allow for quick and efficient opening and closing of gates for fire trucks. This ensures that the doors can be operated swiftly and seamlessly, allowing fire trucks to move in and out of the station without any delays or obstacles. The uninterrupted power supply ensures that there is always a clear right-of-way for the movement of fire trucks, ensuring their readiness to respond to emergencies at all times.

Figure 7: Automatic door opening system at the HBFS No. 1 facility.

Communication System and Computers: As previously mentioned, the HBFS No. 1 heavily relies on its advanced communication system to effectively respond to emergency situations. The communication system, as depicted in the accompanying Figure 8, was observed during a site visit and is crucial for facilitating seamless communication and coordination among the firefighting personnel. To ensure continuous and reliable communication, the communication system and the computers at HBFS No. 1 requires an uninterrupted power supply. These systems operate around the clock, 24x7, and any disruption in the power source can significantly impact the station's ability to receive and transmit critical information in real-time.

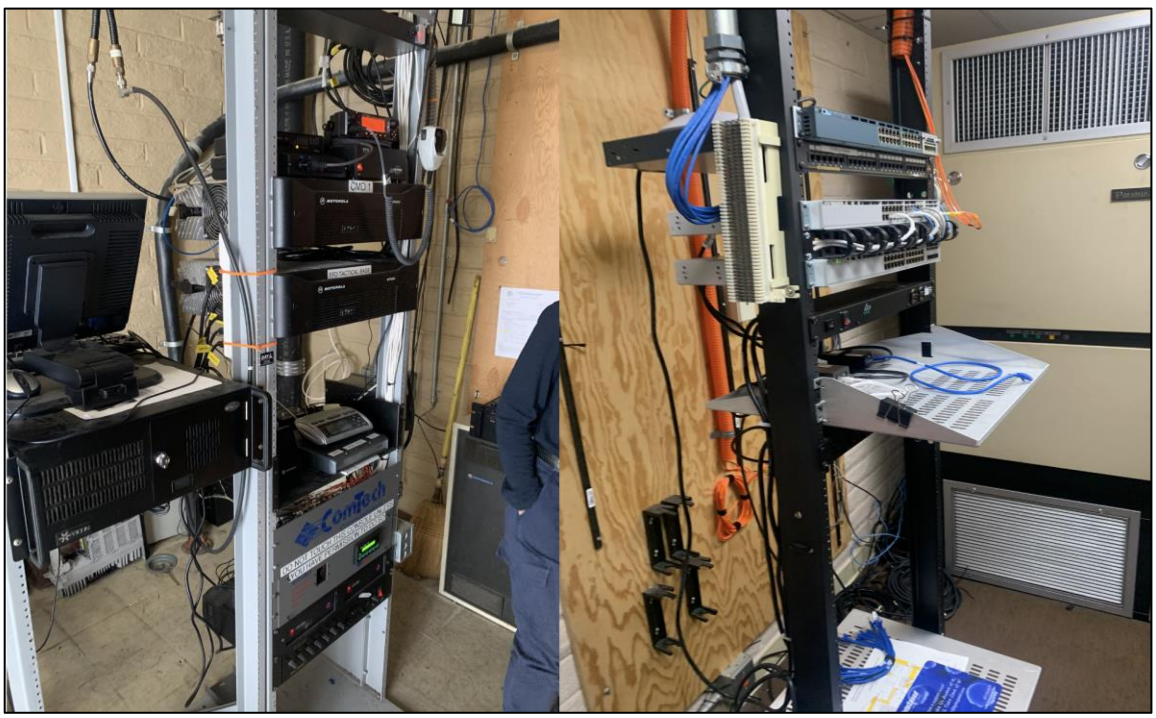


Figure 8: Communication systems at the HBFS No. 1 facility.

Due to the need for reliable power to maintain operations, there are standards established by National Fire Protection Association (NFPA) and National Institute of

Standards and Technology (NIST) in relation to the need for consistent and stable power supply for fire stations. These ensure consistent functioning of the facility and a microgrid would need to be able to meet these needs and are described below:

Emergency Response: Effective emergency response requires dependable electricity for powering communication systems, lighting, ventilation, and other essential apparatus that is required to ensure the safety and security of the firefighters and the general public (National Fire Protection Association, 2022).

Life Safety Systems: Life safety systems, such as fire alarms, sprinkler systems, and oxygen refilling equipment, are frequently found in fire stations and need dependable electricity to function. These systems must be able to function even in the event of a power failure in order to protect the public and firefighters (National Fire Protection Association, 2021).

Training and Simulations: Equipment used in training and simulation in fire stations, such as fire simulators, needs dependable power to work. These resources are crucial for giving firemen the instruction they require to efficiently handle situations (National Fire Protection Association , 2019). However, these are generally not critical to power during outages, as trainings can generally occur during other periods.

Overall Resiliency and Continuity of Operations: To maintain public safety, fire stations must be able to function even in the event of power outages or other electrical grid interruptions. When fire stations have a dependable energy source, like a microgrid, they can continue to offer vital services even when the electricity goes out (National Institute of Standards and Technology, 2020).

LITERATURE REVIEW

This section provides a concise introduction to microgrids, encompassing key aspects that are important for this work such as microgrid definition, controllers, classification, standards, case studies, benefits incentives, value of resiliency (VoR), markets for critical facilities, and the concept of operation. By exploring these elements, readers can develop a comprehensive understanding of microgrid systems and their significance in the energy landscape.

Microgrid Definitions

Microgrids have emerged as a promising solution to unreliable grid energy, and there are many different ways they are defined. Following are the definitions of microgrids by several important agencies:

Definition as per U.S. Department of Energy:

The U.S Department of Energy defines a microgrid as a network of dispersed energy resources and loads that may independently disconnect from and reconnect to the main utility grid (Ton & Smith, 2012).

Definition as per Institute of Electrical and Electronics Engineers (IEEE):

The IEEE standards association defines microgrids as the localized grids which can function independently by isolating their connections to the main grid. Microgrids can increase grid resilience, assist in reducing grid disturbances, and serve as a grid resource for quicker system resiliency and responsiveness since they can run even when the main grid is down (Hayland, 2023).

Definition as per National Electric Code:

The 2020 National Electric Code defines the microgrid system as a type of building wiring that comprises generation, energy storage, and loads, or any combination of these, as well as the capability to operate independently of and in parallel with the main source of power (Hannahs, 2021)

These definitions all share common elements and the differences between them highlight the range of applications for microgrids. Microgrids are versatile systems that utilize a combination of distributed energy sources, including solar photovoltaic (PV) arrays, battery energy storage systems (BESS), and the conventional grid. These systems are designed to provide power to a facility both in normal operation and in islanding mode, where the microgrid operates independently from the main grid. In addition to serving the facility's energy needs, microgrids can also engage in energy arbitrage and offer various other benefits. Therefore, microgrids can be likened to a "Swiss-Army Knife" due to their ability to fulfill multiple functions and provide a range of services.

A graphical typical representation of microgrid can be seen in the Figure 9 shows the various components of the microgrid and how they work collectively to ensure reliable power supply to the loads. However, Figure 9 is not a complete description of the components of the microgrid. I have included Figure 10, below, which is a detailed single line diagram (SLD) which shows how the different components of microgrids work together.

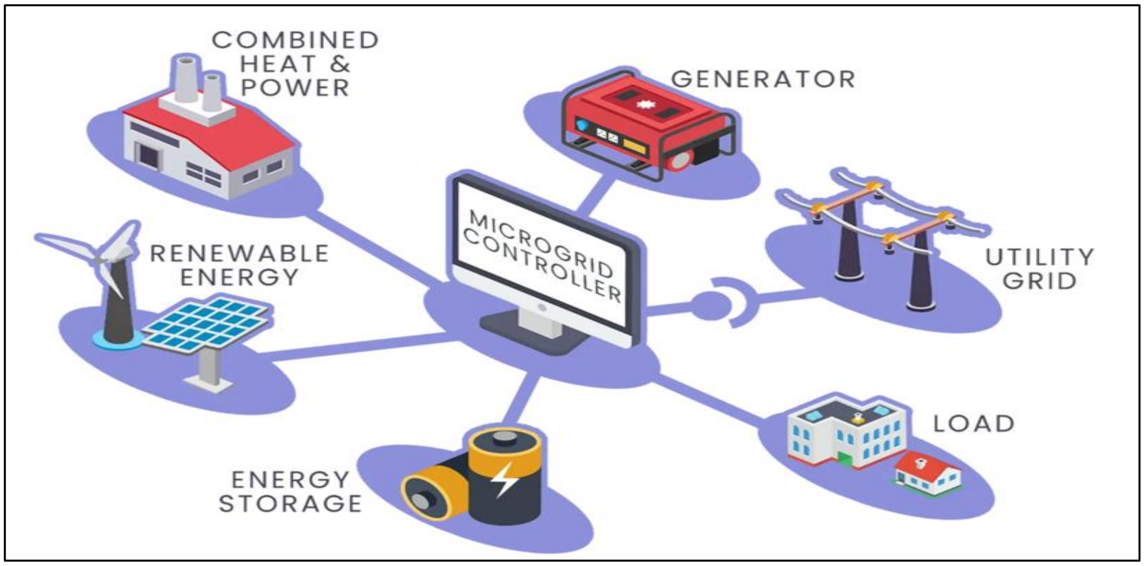


Figure 9: Graphical representation of a microgrid technology and its features (Meier, 2022).

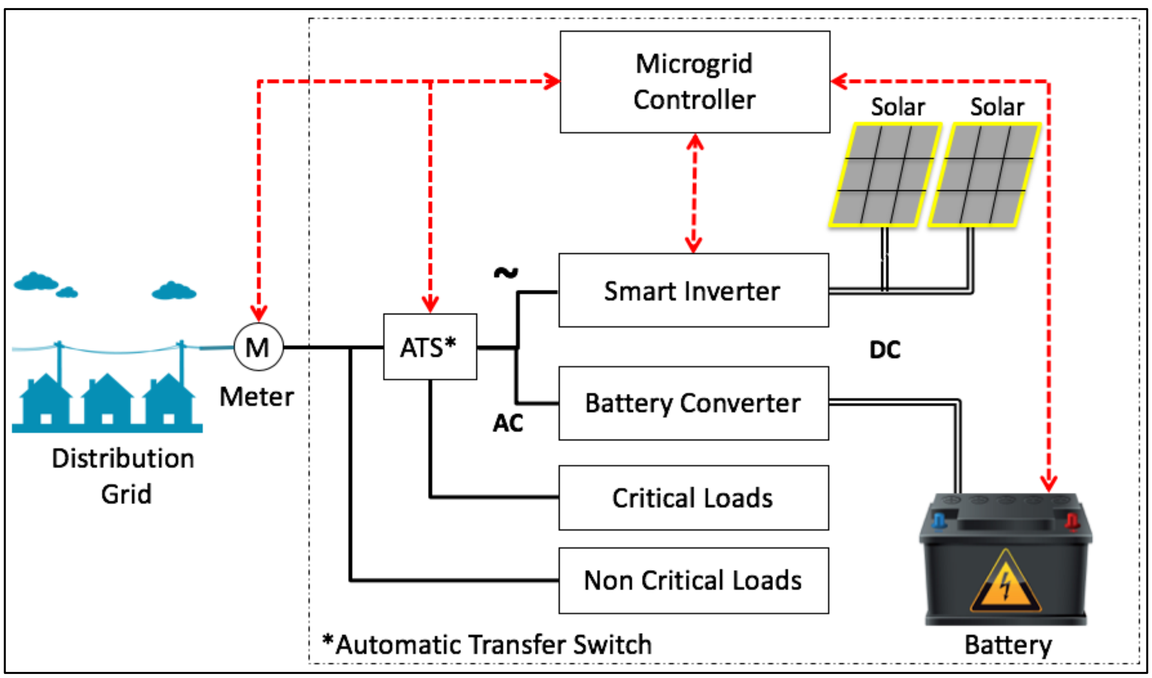


Figure 10: Single line diagram of a microgrid depicting various components (Clean Coalition, 2023).

Some of the characteristics of the components of the microgrids as per Figure 9 & Figure 10 are as follows:

Energy Generation

By using generating sources such as solar PV and a fuel generator, the microgrid installed at the facility ensures an un-interrupted power supply to serve the customer.

Battery Energy Storage System (BESS)

The microgrid uses the BESS to serve the load and manage peak demand charges. Also, the BESS ensures backup power at the time of a grid outage.

Conventional Grid

In grid connected mode, the microgrid procures power from the grid to serve the load and charge the BESS. The microgrid also isolates from the grid during power outages, and, with the help of a bi-directional meter (shown as M symbol in Figure 10), the microgrid exports surplus energy produced from the PV.

Electric Load

The electric load is the demand of the facility. The microgrid ensures that both critical and non-critical loads are served during the normal grid connected mode. When the controller senses an outage, it automatically directs the automatic transfer switch (ATS) to supply backup power either from the BESS, PV, or genset.

Smart Inverters

Smart inverters are a developing innovation with the potential to facilitate the integration of solar energy and other DERs into the electricity grid. Similar to conventional inverters, smart inverters convert the direct current (DC) produced by solar panels into alternating current (AC), which is suitable for use by consumers in residential and commercial settings. However, smart inverters offer additional capabilities beyond this primary function. They are equipped to provide support to the grid by regulating voltage, offering frequency support, and ensuring uninterrupted operation during grid disturbances (IREC, 2023).

Automatic Transfer Switch (ATS)

An automatic transfer switch is an intelligent power switching device that operates automatically based on pre-programmed control logic. Its primary function is to ensure uninterrupted electrical power supply to a connected load circuit, such as lights, motors, computers, and other electrical equipment, by seamlessly transferring power between two different power sources (Eaton, 2023).

Microgrid Controllers

A microgrid controller operates and manages all the microgrid assets and dispatches the power generated from the system. Microgrid controllers are crucial systems that effectively coordinate several elements inside a microgrid, such as renewable energy sources, energy storage systems, and loads. Their primary responsibilities include maximizing resource usage, decreasing energy losses, and cutting costs associated with operations. This calls for ongoing resource availability, usage monitoring, and subsequent energy distribution adjustments. Additionally, microgrid controllers regulate the charging and discharging of energy systems to guarantee their best use (Mesa Solutions, 2023).

Controlling the relationship between the microgrid and the primary power grid is another key duty of microgrid controllers. They help the microgrid and the main grid transfer energy seamlessly while upholding adherence to predetermined operational restrictions. Microgrid controllers could switch the microgrid into islanded mode in the case of a power loss or other main grid interruptions, enabling autonomous operation. After the main grid is back online, the controllers manage reconnection and synchronization (Mesa Solutions, 2023).

The functioning of distributed energy resources (DERs) can also be optimized using microgrid controllers to reduce operating expenses. For instance, they may plan the charging of energy storage devices for times when energy prices are low and the discharging of them for times when energy prices are high, lowering total energy costs (Mesa Solutions, 2023).

Successful seamless islanding necessitates close collaboration between relays and microgrid controllers, deterministic data, and rapid communication among relays. Microgrid controllers based on programmable logic controllers (PLCs) encounter challenges in achieving smooth islanding transitions, whereas relay-based microgrid control systems accomplish this with ease. Following the disconnection of the microgrid through the opening of the point of interconnection (POI) relay, a swift response from a high-speed load-shedding system may be necessary to restore voltage and/or frequency (Edward & Manson, 2018).

Microgrid controllers communicate to all the connected components of the microgrid power system and control the key components of the system, including solar

PV systems, inverters, generators and battery management systems. Microgrid controllers have the capability to sense an outage from the grid and respond by isolating the whole microgrid system from the conventional grid.

The comprehensive structure of the Grid Management Controller (GMC), which is further divided into five different classes of distributed components, is shown visually in Figure 11. These parts include layered microgrid integration tools including the Microgrid Management Controller (MMC), Generation Controllers (GC), Storage Controllers (SC), Load Controllers (LC), and Breakers Controllers (BC). Collectively, these parts are in charge of managing the entire microgrid system. They handle critical duties like managing storage systems such as batteries, dispatchable loads, distributed generation units like solar panels and diesel generators, circuit breakers, and switchgear. They also facilitate the sequential management of nested microgrids (Razeghi, Gu, Neal, & Samuelsen, 2018).

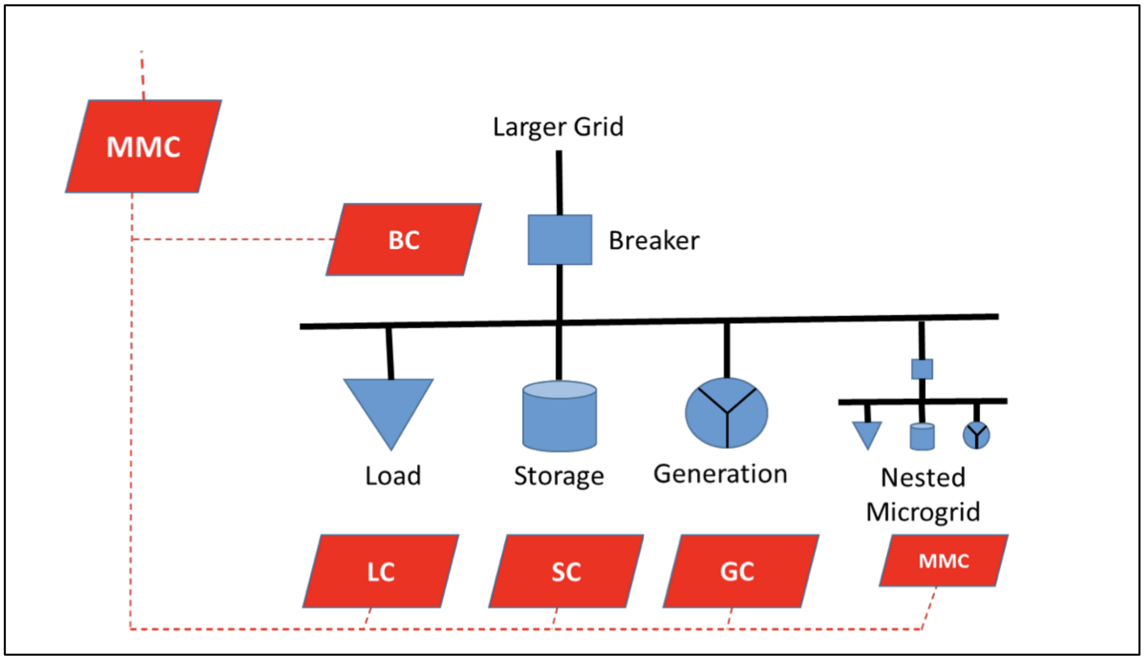


Figure 11 : Generic microgrid controller (GMC) modular architecture showing microgrid management controller (MMC), generation controllers (GC), storage controllers (SC), load controllers (LC), breakers controllers (BC) (Razeghi, Gu, Neal, & Samuelsen, 2018)

Microgrid Classification

Microgrids could be classified based on broadly three functions: demand, capacity and the type of circuits, as shown in Figure 12. Considering the energy demand as the frame of reference there are three broad classifications: (i) simple microgrids having a single source of distributed energy generation whereas, (ii) multi-DG microgrids that accommodate multiple distributed energy resources for power supply, and (iii) utility-scale microgrids which focuses on the reliability needs of the customer (Cabana-Jiménez, Candelo-Becerra, & Sousa Santos, 2022).

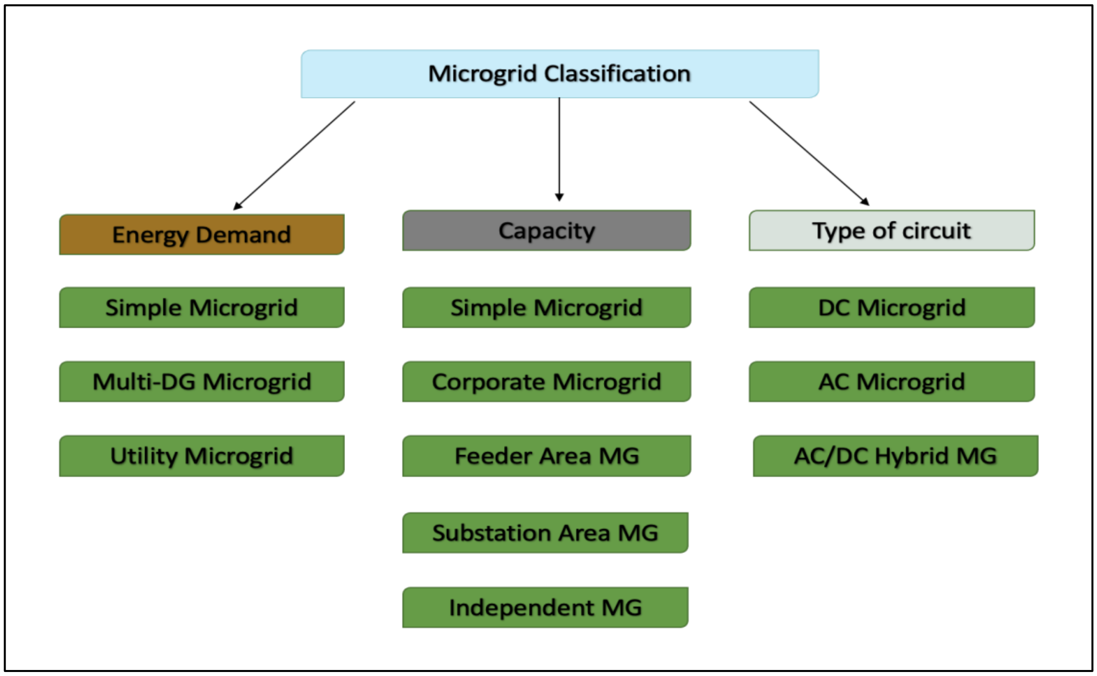


Figure 12: Microgrid classification by energy demand, capacity and type of circuit (Cabana-Jiménez, Candelo-Becerra, & Sousa Santos, 2022)

Microgrids can be categorized based on their capacity and circuit classification, each with distinct characteristics and considerations. When classified by capacity, microgrids are grouped into several types. Simple microgrids have a capacity below 2 MW, catering to smaller-scale energy needs. Corporate microgrids, on the other hand, range from 2 to 5 MW, providing power to medium-sized entities. Feeder area microgrids exceed 20 MW in capacity and serve larger regions, while substation area microgrids also surpass 20 MW and focus on supplying electricity to specific substation areas. Independent microgrids vary their capacity depending entirely on the magnitude of the load they need to support (Cabana-Jiménez, Candelo-Becerra, & Sousa Santos, 2022).

In terms of circuit classification, microgrids are further divided into three categories, taking into account the characteristics of the electric current produced, distributed, and consumed. These classifications help determine the specific requirements and configurations of the microgrid. The circuit classifications consider factors such as power flow direction, load types, and integration with the main grid. This approach enables a more precise understanding of how the microgrid operates and interacts within the broader electrical system (Cabana-Jiménez, Candelo-Becerra, & Sousa Santos, 2022).

DC microgrids exhibit higher efficiency than the AC microgrids by reducing the number of conversion steps between DC and AC power (Cabana-Jiménez, Candelo-Becerra, & Sousa Santos, 2022). DC microgrids also demonstrate higher effectiveness and reliability of transferring electric power to the end use devices or loads since they do not have reactive current. They can offer greater power supply reliability, even in remote locations. DC microgrids can also require relatively smaller cabling due to the use of high voltage at low amperages. The controllability of DC microgrids is convenient and sufficient, without causing complexities such as synchronization, harmonics, reactive power control, and frequency control (Veckta, 2021).

AC microgrids offer several advantages due to their capability to integrate with the conventional utility grid or operate in islanded mode, providing versatility in their operation. They are compatible with AC appliances and equipment, including widely available loads such as AC-based loads like pumps, lights and AC based motors. AC microgrids also demonstrate cost efficiency in power protection systems and provide higher load availability for AC loads (Veckta, 2021). AC microgrids have an upper hand in the widespread adoption by customers due to ease in interoperability with commercially available equipment. AC microgrids also face some technical challenges, such as distributed generation timings and reactive power control (Cabana-Jiménez, Candelo-Becerra, & Sousa Santos, 2022). AC/DC hybrid microgrids reduce the multiple power conversion which are found in individual AC or DC MGs, and they can also enable simultaneous connection of AC and DC sources and loads (Kaushik & Pindoriya, 2014).

A recent project was carried out in the City of Fremont at Fire Stations No. 6 and No. 11 by Gridscape Solutions (a Fremont-based engineering firm), where AC linked microgrid systems were put in place and are now effectively operational (Gore, 2019) . I have suggested an AC-linked microgrid for HBFS No. 1 in response to these developments. The installation of an AC-coupled microgrid at HBFS No. 1 offers a number of advantages, building on the lessons learned from other microgrid projects.

Microgrid Standards

To support the development and deployment of the microgrids, various “agencies having jurisdiction” (AHJs), standard bodies, and research agencies have defined rules, specifications, and regulations. The standards setup by these agencies for microgrid deployment help utilities, developers, and customers to safely integrate and operate microgrids. These guidelines and rules also helped establish constraints for the design of a microgrid for HBFS No. 1. Some of the standards set by CEC, CPUC, IEEE, and NFPA, are as follows:

CEC and CPUC standards and regulations

Rule 21. Electric Rule 21 in accordance with the California Public Utilities Commission (CPUC), specifies the interconnection, operating, and metering criteria for integrating producing facilities with a utility's distribution system. Rule 21 gives consumers the option to link their own generating or storage facilities to the electrical grid while still preserving the integrity and dependability of both local distribution networks and the larger transmission system. However, it is the Investor-Owned Utilities' (IOUs') obligation to implement and enforce Rule 21 (CPUC, 2017). This rule governs the solar PV generation and the inverters at the facility to ensure there is no back feeding during the time of power outage (CPUC, 2017).

Title 24. Building energy efficiency requirements are governed by a set of laws that have been put in place by the California Energy Commission (CEC). Every three years, these requirements are updated; the most recent version is the 2022 Energy Code. The emphasis of this revised building code is on encouraging the use of heat pumps, increasing the specifications for solar photovoltaic (PV) systems, and including battery storage criteria, which can be key components in a microgrid. The regulations also stipulate certain electrical specifications that newly built dwellings must adhere to (CEC, 2021). The criterion for combining solar photovoltaic (PV) systems and battery storage in California across the different building types listed in the table below was expanded by these code modifications beginning on January 1st, 2023. The modifications also include a requirement that newly built low-rise multifamily buildings provide the required electrical infrastructure in order to be prepared for future battery installation as shown in

Figure 13. Aiming to maximize the use of on-site solar power and reduce dependency on gas-powered plants, the addition of solar and battery regulations for low and high-rise multifamily and non-residential building types intends to lower electricity consumption during peak hours (CalSolarInc, 2023).

Building Type	Requirement
Low Rise Multifamily	New projects must install solar PV and be "battery ready" by installing either a subpanel or a split-bus main panel with four backed-up circuits.
High Rise Multifamily & Non-Residential Buildings including: • Apartments/Condos 4 stories and above • Hotels • Tenant Space • Offices & Clinics • Retail & Grocery Stores • Restaurants • Schools • Civic Buildings (Theaters, Auditoriums & Convention Centers)	New Projects must install both solar PV and energy storage. System size requirements are determined by the formulas below: PV Size Requirements kW = (CFA x A)/ 1000 CFA = Conditioned Floor Area A = Capacity factor determined by the building type and climate zone Battery Size Requirements kWh Batt = (kW PV x B)/√D B = Building energy capacity factor determined by building type D = Round trip efficiency of the battery OR The PV System size in kW shall not be less than the smallest of the PV system sizes determined by the formula or SARA* *SARA – Solar Access Roof Area includes any roof space on newly constructed buildings including covered parking, does not include occupied roof areas

Figure 13: Solar PV and BESS sizing requirements as per California Title 24 (CalSolarInc, 2023).

IEEE Standards

IEEE 1547. The technical specifications for seamlessly connecting distributed energy resources (DERs) to the traditional power grid are provided by IEEE Standard 1547. The foundation for voltage management, frequency response, and islanding prevention is also furnished by IEEE 1547. The standard intends to encourage DERs' compatibility and interoperability with the current infrastructure of the electricity grid. To guarantee correct operation and compliance with standards for voltage and frequency control, protection coordination, and other dimensions of grid integration, it sets rules for DER equipment, such as inverters and protective devices (IEEE, 2018).

IEEE 1547 strives to preserve power quality and reliability while DERs are operating. In order to make sure that DERs do not have a detrimental effect on the overall quality and dependability of the electric power system, it establishes standards and limitations for voltage and frequency deviations, harmonics, and other power quality metrics (IEEE, 2018).

The standard places a strong emphasis on safety while connecting DERs. For the purpose of preventing electrical risks and ensuring safe operation in grid-connected and islanded modes, it provides provisions for grounding, overcurrent prevention, and isolation requirements. The objective is to safeguard DER integration-related hazards for utility staff, consumers, and the power system. IEEE 1547 acknowledges that DERs may be able to offer grid support and control capabilities. It provides rules for the control of active power, reactive power, and voltage functions of DERs. The standard intends to improve the dependability and performance of the electricity system by allowing DERs, including microgrids, to contribute to grid stability and operation (IEEE, 2018).

IEEE 1547.1. IEEE 1547.1 is a testing protocol that establishes adherence to IEEE 1547 standards. Manufacturers, utilities, and independent testing organizations can utilize the IEEE standard 1547.1 testing methods to assess whether a specific interconnection system or component is suitable for connecting distributed resources (DR) with the electric power system (EPS). This certification procedure can make it easier for relevant parties to acknowledge the equipment as acceptable for the intended service (Basso & DeBlasio, 2011). This standard furnishes the requirements for the interconnection with the conventional electric utility grid, maintains the power quality and voltage regulation, specifies protection and safety considerations, and promotes interoperability and communications for seamless coordination and control for the components of the microgrid (IEEE, 2020).

IEEE 2030.7. This standard specifies the technical criteria and specifications for microgrid controllers. Additionally, it has valuable annexes that outline the microgrid, create functional requirements, show how microgrid control functions are organized, and present a bibliography. The microgrid energy management system (MEMS), which comprises control features that allow the microgrid to govern itself, run independently, or link to the grid, is one of the essential elements of microgrid operation, and it is described in this standard (IEEE, 2018).

NFPA Standards

NFPA 110. The NFPA 110 standard covers the requirements for operating standby and emergency power systems for fire stations. These systems offer a backup electricity supply if the primary power source fails. These systems' components comprise the necessary power sources, transfer equipment, controllers, supervisory equipment, and auxiliary equipment to supply electricity to the specified circuits. As a standard that describes the essential requirements for emergency power supply systems, which typically include the utilization of generators (O'Connor, 2023). The key requirements in NFPA 110 for microgrids are as follows:

Power supply: As per NFPA 110, emergency power systems, including those built into microgrids, are required to have a stable power source that can support the associated loads during power outages. The standard lays forth precise specifications for the power source, such as generators or other DERs, and their ability to supply the facility with the necessary amount of electricity (NFPA, 2022).

Fuel Storage & Delivery: NFPA 110 provides rules for fuel storage capacity, maintenance practices, and processes to assure an uninterrupted fuel supply during emergencies. It also addresses the storage and transportation of fuel for emergency power system generators (NFPA, 2022).

Transfer Switches: During power outages, automated transfer switches (ATS) that enable smooth transfers between utility power and emergency power are required to meet certain standards set out by NFPA 110. In microgrid deployments, these switches are essential for guaranteeing a seamless flow of electricity from the utility grid to the microgrid system (NFPA, 2022).

Testing and Maintenance: NFPA 110 specifies rules for testing frequencies, testing load banks, and recording the associated test results, emphasizing the need of routine testing and maintenance. These steps guarantee the emergency power system's dependability and preparedness in the event of a crisis (NFPA, 2022).

Installation and Commissioning: The commissioning and installation of emergency power systems are covered by NFPA 110. It provides instructions for the system's design, installation, and documentation to guarantee adherence to safety and performance criteria (NFPA, 2022).

NFPA 855. The safety of energy storage devices and their installation in buildings is a concern of this standard. The standard is broken down into chapters that cover installation, protection, and equipment, as well as the maximum energy storage capacity permitted based on location and technology. Additionally, some standards are particular to certain energy storage system types. The measure also specifies decommissioning, emergency response, operation, and maintenance standards (Lamb & Matthew, 2020). As per NFPA 855, the following are the requirements for the BESS in the microgrids:

System Design and Installation: NFPA 855 outlines requirements for the design and installation of energy storage systems in microgrids. It takes into account the system layout, clearances, ventilation, and fire safety precautions. These recommendations guarantee the secure integration of energy storage technologies inside microgrids (NFPA, 2023).

Electrical Safety: The standard discusses requirements for insulation, grounding, and overcurrent prevention in relation to electrical safety precautions for microgrid systems. With the help of these regulations, electrical risks should be reduced and the microgrid should run securely (NFPA, 2023).

Emergency Response: NFPA 855 specifies the standards for emergency shutdown processes, fire suppression systems, and safety precautions to prevent the spread of fire inside energy storage systems (NFPA, 2023).

NFPA 1221. The NFPA 1221 standard covers installation, upkeep, and use of emergency services communication systems such as fire stations, ensuring service delivery, including prompt receipt of calls, dispatching of emergency units, and accurate location identification within the required timeframe. Reliable emergency communications are necessary for the fire department, police enforcement, emergency medical services, and other groups to respond to emergencies effectively (Fire Police EMS, 2016). This standard has been updated by NFPA 1225, which adds requirements about the inspection of the communications systems at the fire station facility (ANRITSU, 2022).

Microgrids Case Studies

There have been several successful microgrid projects at the critical facilities in the United States. Some of them are described below for understanding the technology used and challenges faced for having a clear overview of the lessons learned which could be replicated to the HBFS No.1 microgrid:

Porter Ranch Fire Station 28 Microgrid

As per the NREL report on "Microgrids for Resiliency," the Los Angeles Department of Water and Power (LADWP) Porter Ranch Fire Station 28 Nanogrid serves as a prime example of a community-oriented microgrid project. The facility, combining a rooftop solar system with a 12-kW, 40 kWh battery energy storage system, provides backup power and critical services during grid outages. In addition to reducing demand-based charges, the microgrid as benefits and specifications as shown in Table 1 demonstrates its reliability by successfully supplying over 7 hours of resiliency during a grid outage due to heavy rainfall (NREL, 2020). LADWP plans to replicate this model by identifying 12 near-term candidates for community microgrids, prioritizing disadvantaged areas within its service territory. This initiative aligns with LADWP's goal of achieving 100% clean energy by 2045, enhancing resiliency and reducing reliance on natural gas (NREL, 2020).

Table 1: Description of Los Angeles Department of Water and Power Porte Ranch Fire Station Microgrid (NREL, 2020).

Facility Name	**LADWP's Porter Ranch Fire Station 28 Nanogrid**
Technology Used	Solar PV and BESS
Solar Capacity	12 kW
Battery Capacity	40 kWh
Resiliency Attained	7 Hours or more
Community Services	Cooling, electronic charging, Other critical services
Clean Energy Goals	100% clean energy by 2045

<u>Fremont Fire Station Microgrid</u>

Three fire stations in City of Fremont (Fire Station No. 6, Fire Station No. 7, and Fire Station No. 11), have successfully installed solar emergency microgrid systems with the efforts of Gridscape Solutions and the City of Fremont. The systems were supported by a $1.8 million grant from the California Energy Commission (Gore, 2019).

These microgrid systems, which include an energy management system, solar PV canopy systems, and battery energy storage, are designed to optimize local energy resources in both grid-connected and off-grid scenarios situations as shown in Table 2. The microgrid systems can supply at least 4-6 hours of clean renewable power during utility power outages brought on by natural disasters like wildfires or earthquakes, assuring ongoing operations. The challenges faced by the facility were the interconnection process, city approval process, and soil liquefaction issues (Gore, 2019).

Table 2: Fremont Fire Station microgrid technology and benefit descriptions (Gore, 2019)**.**

Facility Name	**City of Fremont Fire Station No. (6, 7 and 11)**
Technology Used	Solar PV and BESS
Solar Capacity	37.1 kW (Fire Station No. 6) 43.4 kW (Fire Station No. 7) 37.2 kW (Fire Station No. 11)
Battery Capacity	Information Unavailable
Resiliency Attained	4-6 Hours
Community Services	Cooling, electronic charging, other critical services
GHG Emission Reduction	142,000 lbs of CO_2e

Portland Fire Station No.1 Microgrid

Fire Station No. 1 in Old Town is home to Portland's first microgrid installation. The station is around 55,000 square feet in size and can house 13 on duty people. This microgrid consists of an existing 125-kW diesel generator, a 30-kW solar PV panel, and a 30-kW/60-kWh Li-ion BESS as shown in Table 3. The project was led by Portland Fire Rescue and the Bureau of Planning and Sustainability, with funds totaling around $115,000 obtained through several Portland Gas and Electric (PGE) programs (Mango, 2020).

Table 3: Description of Portland Fire Station No. 1 microgrid (Mango, 2020).

Facility Name	**Portland Fire Station No. 1**
Technology used	Solar PV and BESS
PV Capacity	30 kW
Battery Power/Capacity	30 kW/60 kWh
Resiliency Attained	4 hours
Benefits to the Grid	BESS enables participation in Demand Response
Community Services	Utility cost savings will be directed to community welfare programs and fire station upgrades
Replicability	Future plans to build microgrids serving the Red Cross shelters

The solar plus storage microgrid will provide power to computers and communications equipment at the fire station for up to 4 hours during an outage, enhancing the overall resiliency. Furthermore, the microgrid is reducing the energy costs, and these cost savings could be re-invested for community focused endeavors such as public programs or necessary fire station upgrades (Mango, 2020). Portland is also planning to replicate its design for other critical facilities which could serve as prospective Red Cross shelters for the community in emergency situations.

Microgrid Benefits

Adopting microgrids offers numerous benefits to the customer. These benefits include providing resiliency in the time of power outage, cost savings, GHG emission reductions, and many more. The benefits that microgrids provide are described below:

Resilience

The ability of a system to sustain utility disturbances, effectively address them, and quickly recover while maintaining the continuation of crucial functions is known as resilience. Although some utilities have set up microgrids to guarantee a continuous power supply to important clients and sites, the overall electric power system still has lacunae that prevent the delivery of uninterrupted and dependable electricity. Resilience, according to the Federal Energy Regulatory Commission (FERC), is the capacity to withstand and lessen the effects of disruptive events, including the ability to foresee, absorb, adjust for, and quickly recover from such occurrences (IEEE, 2018).

The three separate phases of resilience in the electric power system are shown in Figure 14 by a trapezoid graph: "preparation," "adaptation," and "recovery." The graph below exhibits various modes such as normal operation, operation during disturbances without resiliency measures, and operating during disturbances with resiliency measures. Resilience becomes essential during the overall phase because a conventional system confronts collapse and takes longer to recover, but a resilient system reacts quickly to grid disruptions and recovers quickly. The improvement of resilience is accomplished via a variety of strategies, such as lowering the recovery time, lengthening the system's ability to withstand disturbances, and reducing the size of disruptions (Rickerson, Zitelman, & Jones, 2022).

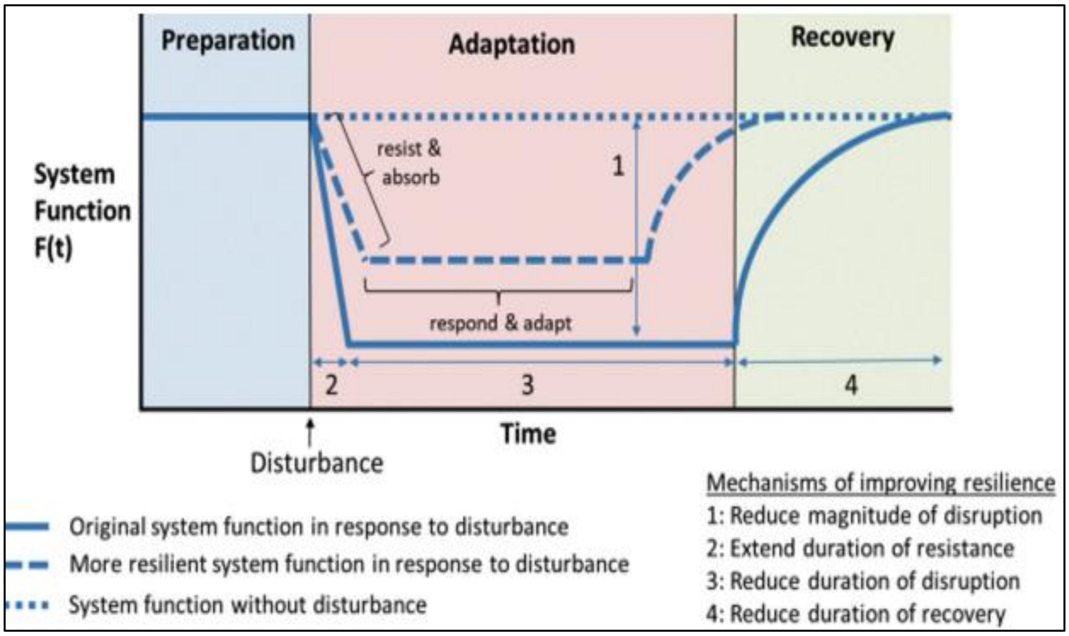


Figure 14: Resilience Trapezoid (Rickerson, Zitelman, & Jones, 2022)

Determining the prioritization of loads within a system is crucial when evaluating the financial implications of resilience. For instance, the communication system at a fire station is of paramount significance since it directly affects the safety and well-being of people and property. Load prioritization plays a crucial role in identifying and prioritizing the essential loads that are critical for a facility during a power outage. At a fire station, important equipment such as medical devices, lighting loads, computers, alarms, and automatic door openers are typically considered high-priority loads. By prioritizing these loads, the facility can integrate them into a microgrid (MG) system to ensure uninterrupted power supply during outages. This approach ensures that vital functions and operations, such as emergency medical equipment, lighting for visibility, data management, security alarms, and efficient gate operations, can continue without interruption, even when the main power grid is down. Load prioritization enables the fire station facility to effectively manage its energy resources and maintain operational continuity, enhancing its overall resilience in emergency situations.

Assigning a value to resilience allows for the potential realization of various benefits, such as reduced insurance rates, lower mortgage rates, increased grid services value, and access to government incentives. Considering the value of resilience as one of the key financial metrics creates potential for cost saving measures and further assistance from pertinent stakeholders (NREL, 2018).

Demand Charge Reduction

The demand charge is an ongoing fee that is included in utility bills based on peak load. It is included in part to recover the expenses of maintaining the infrastructure required by the electric company to supply power to a location. As a result, the demand charges will climb in direct proportion to the peak load (NYSERDA, 2023). Microgrids can be used to reduce demand charges by avoiding charging the BESS during the peak time of use (TOU) and charging the BESS during off-peak or super-off-peak TOU during a time when demand charges and energy prices are higher (NYSERDA, 2023). Peak shaving is one of the benefits of microgrids, and effective reduction of peak demand can substantially reduce demand charges.

Microgrids with solar PV and storage are widely used to lower demand charges. The microgrid controller is set up to either use stored energy from the battery to satisfy load demands during peak demand rate periods (e.g., early evening) when solar power is not operational, or to counterbalance grid energy usage during peak times when sunlight is available. Peak shaving is successfully accomplished using this integrated strategy, which lowers demand charges and related costs.

Demand charges are calculated on a monthly basis. For example, the HBFS No.1 is currently enrolled under PG&E's B-19 TOU rate, which has demand charges based on the maximum peak demand, maximum demand of the whole month, and part-peak demand. However, the demand charge calculation for the summer months (June to September) and winter months (October to May) are different. The demand charge calculation for summer months numerically could be shown as:

Equation 1: Demand charge calculation for summer months for various time of use periods.

Total Demand Charges ($) = peak demand (kW) * peak demand TOU rate ($/kW)) + maximum part peak demand (kW) * maximum part peak rate ($/kW) + Maximum demand (whole month) (kW) * maximum demand rate ($/kW)

Similarly for winter months the demand charges are the same but they do not consider the demand charges for the part peak TOU. The mathematical representation would be:

Equation 2: Demand charge calculation for winter months for various time of use periods.

Total Demand Charges ($) = peak demand (kW) * peak demand TOU rate ($/kW)) + Maximum demand (whole month) (kW) * maximum demand rate ($/kW)

Energy Offset

The energy offset is defined as difference in the amount of energy generated from the solar PV and the energy discharged from the BESS to serve the load leading to optimized grid demand. The energy offset could even be 100% depending on the size of the PV and BESS system. Facilities decide on how much percentage of electricity they want to offset from the proposed system. Increasing the percentage of energy offset requires a larger PV array and energy storage system.

The energy offsets are reflected in the monthly energy bills through the use of a bi-directional meter provided by the utility. Such a bi-directional meter records both the energy imported from the grid and exported to the grid. Under net-metering interconnection arrangements, which are common in California for single-customer microgrids, the utility calculates this net energy exported and deducts it from the subsequent energy bills (CPUC, 2021).

Energy Arbitrage

Energy arbitrage refers to a strategy where electricity is acquired during non-peak hours, when grid prices are most affordable, and subsequently stored for later use during peak hours when grid electricity prices are at their highest (JUSWE, 2021). There are techniques to preserve energy or electricity, but the cheapest energy is the one you don't consume. The most straightforward method to enhance the efficiency of energy round trips is through energy arbitrage, which involves strategically purchasing electricity during periods of low prices and utilizing or selling it when rates are at their peak. The basic idea is to purchase power when rates are low and use (or sell) it during peak times (JUSWE, 2021).

While the cost of installing energy storage systems is falling (PG&E, 2023a), energy bills for PG&E customers have increased around 4.5% for small commercial customers and 3.9% for large commercial customer effective from March 1, 2023 (PG&E, 2023b). As a result, Behind the Meter (BTM) energy storage is becoming more and more accessible to electric utility consumers. BTM energy storage devices are already widely employed for load control and backup power (JUSWE, 2021). In Figure 15 we can understand the sale and purchase of energy from a solar PV system and battery to the conventional utility grid. The surplus energy is fed back to the grid when the solar PV array is generating the energy. During the night time the BESS is discharging to the load. The net exports at the end of the month results in financial benefits and is reflected in the customer's energy bills.

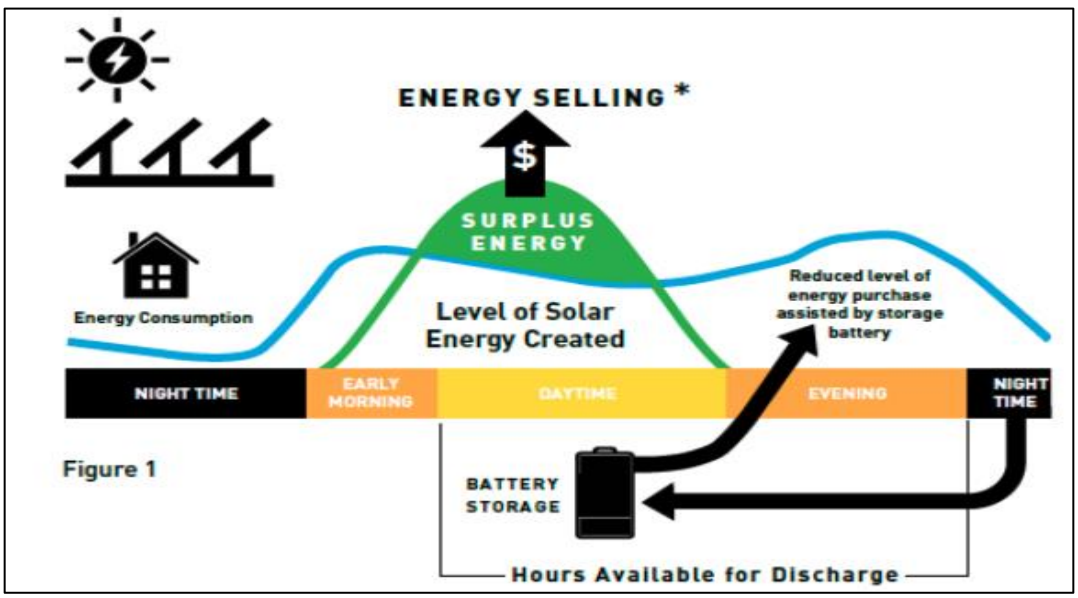


Figure 15: Energy arbitrage schematic diagram (Ingold, 2017)

Demand Response

By adjusting the facility power use at peak times in response to time-based tariffs or other financial incentives, customers have the chance to significantly contribute to the reliable operation of the electric grid through demand response. Some electric system designers and operators employ demand response programs as resource choices for balancing supply and demand.

These initiatives may cut the price of power in wholesale markets, which will reduce retail prices (U.S DOE, 2023). Offering time-based rates including time-of-use pricing, critical peak pricing, variable peak pricing, real-time pricing, and critical peak rebates are some ways to include consumers in demand response initiatives (U.S DOE, 2023). In Figure 16 we can observe peak demand reduction through using more load that is aligned with the renewables during the peak period, by avoiding high energy consuming devices in the peak period, and shifting to off-peak or part peak periods in order to minimize the load on the grid. Demand response is one of the key operations performed by the microgrid. The microgrid manages the site load in response to the grid conditions and price signal forecast. Apart from actively managing the loads, microgrids also participate in grid stabilization by optimizing the peak demand and providing features such as ancillary services which help in frequency regulation and voltage support.

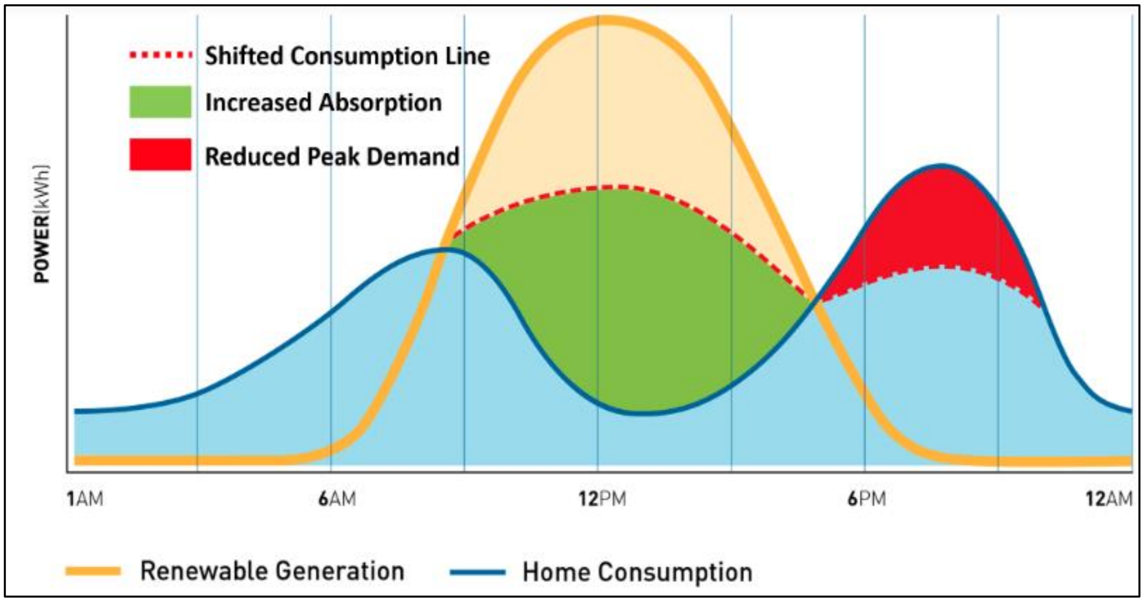


Figure 16: Demand response lowering the peak demand (Cooney, 2019)

As per the U.S. DOE's "Confronting Duck Curve" report, the introduction of the "Duck Curve" shown in Figure 17 by the California Independent System Operator in 2013 has made it a popular subject in conversations about the extensive use of solar photovoltaic (PV) electricity. The duck curve, so named because of its likeness to a duck, shows how the daily variance in power consumption and solar energy supply varies. Solar energy floods the market while it's sunny, but it becomes less prevalent when the evening electricity demand peaks (Jones-Albertus, 2017).

In Figure 17, a graphical representation of the duck curve depicts a 24-hour period in California during the spring, when the impact is most noticeable due to bright skies and comfortable temperatures, resulting in decreased power consumption since less air conditioning and heating is used. The duck curve is significant because it is a turning point for solar energy and highlights the challenges of integrating renewables in the grid.

This is especially important for places like California, where solar adoption is already quite strong. In fact, solar energy generated for the first time over 40% of the state's power in March of the year 2020, highlighting the need for preemptive steps which accommodate higher levels of solar energy (Jones-Albertus, 2017).

Also, an additional challenge that arises due to widespread solar adoption is the possibility of generating excess energy that surpasses the immediate demand. This excess-generation is curtailed by the operators, which further results in diminishing economic and environmental benefits (Jones-Albertus, 2017).

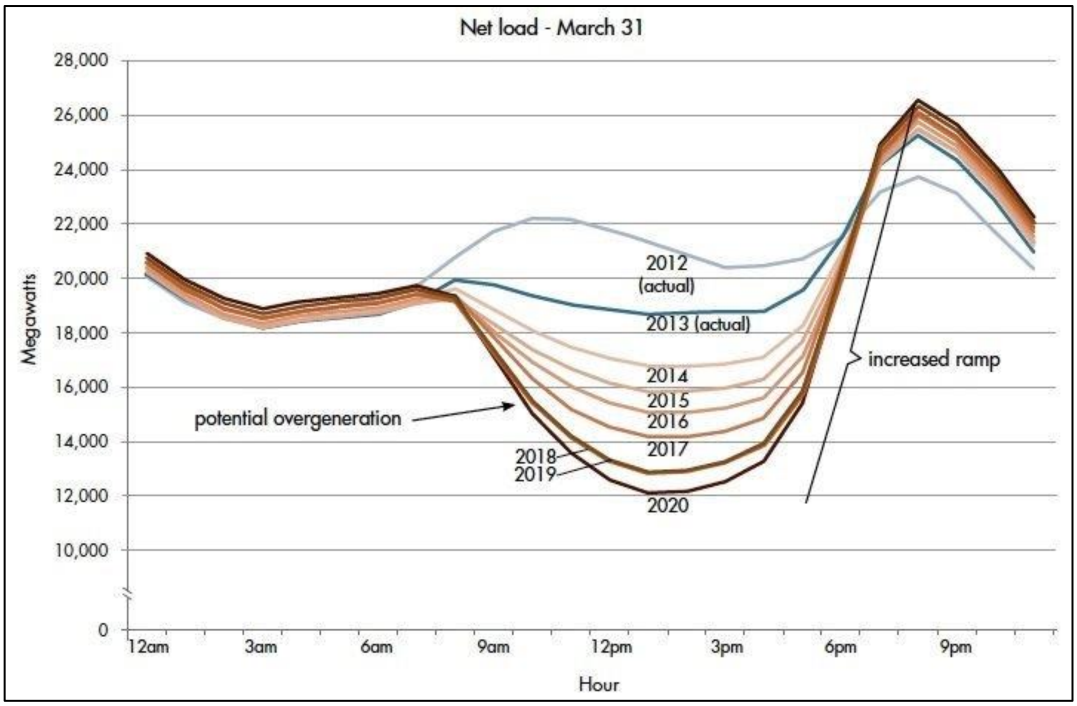


Figure 17: California Duck Curve (Jones-Albertus, 2017).

GHG Emission Reduction

Microgrids can integrate energy from the renewables such as PV with on-site batteries, enabling use of less grid energy and helping lower greenhouse gas emissions. The conventional powerplants that still power much of the grid accounted for almost 65% of the total generation and emitted around 35 million metric tons of CO_2e in the year 2021 (CEC, 2023). These emissions consider both in-state generation and imports.

HBFS No.1 also relies on the grid energy as well as the diesel-based generator. Apart from procuring power from conventional power plants, the HBFS No. 1 facility also has a diesel-based generator which adds to overall GHG emissions. So, inclusion of the clean energy microgrid would not only help the state as well as the Humboldt County to achieve the emission targets, but it would also further reduce dependance on the genset by powering the loads at the time of grid outages with solar power and battery storage.

Apart from all the benefits listed above, a survey was conducted by the Zpryme and IEEE to quantify the top benefits which encourage customers to adopt microgrids. Some of the benefits highlighted by Zpryme and IEEE are shown in Figure 18. They indicate that the top three benefits noted in customer surveys were microgrids meeting local demand, enhancing grid reliability, and ensuring local control of supply. The other three microgrid benefits noted in the survey are enhanced electric supply, energy cost reduction, and grid security (Zpryme Research & Consulting, 2012). However, the survey by Zpryme and IEEE is from the year 2012, and responses may have changed over the course of time.

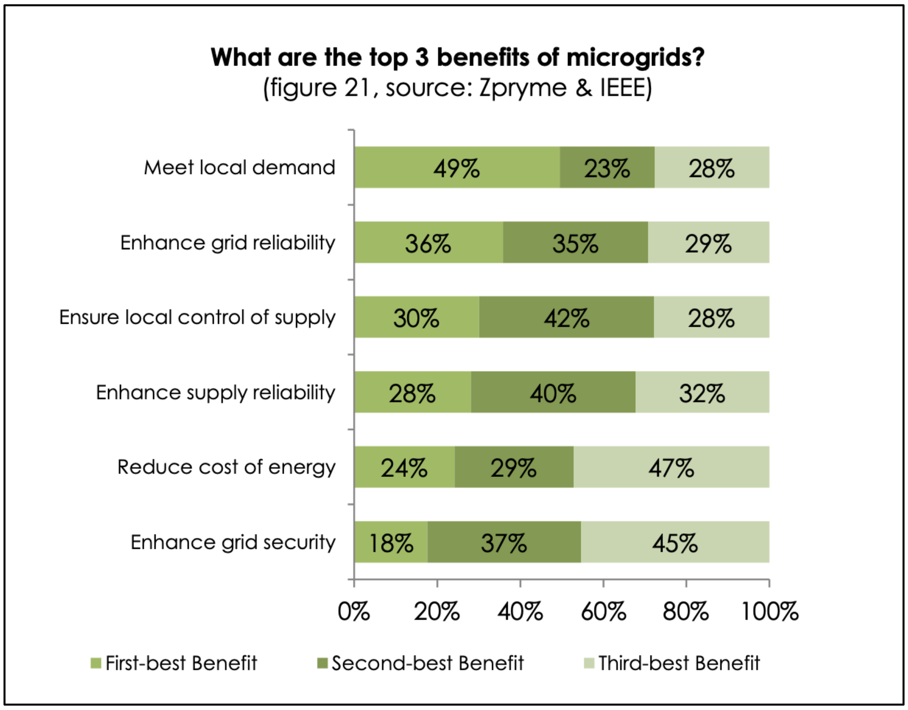


Figure 18: Microgrids benefits as perceived by potential customers response (Zpryme Research & Consulting, 2012)

Microgrid Incentives

To support the clean energy targets using renewables and storage systems, federal and state agencies offer various incentive programs. These incentives are broadly divided into two parts: clean energy tax credits (ITC and PTC) and the state incentives such as the Self Generation Incentive Program (SGIP), which are also applicable to the HBFS No.1 facility.

ITC: The Investment Tax Credit is a federal government incentive offered against the investment by an entity or individual for an alternative source of energy generation and storage. The U.S. has amended the business investment tax credit in the past. For example, the ITC offered in the year 2020 to 2021 was 26%, but due to the Inflation Reduction Act (IRA) of 2022, the ITC was increased to 30% or more depending upon fulfilling specific requirements as mentioned below (U.S DOE, 2023). The new IRA bill extends a 30% credit for projects that begin construction before 2025, and it also includes a direct pay option for tax-exempt entities.

The direct pay or elective pay option offers tax-exempt and local government agencies the opportunity to receive a payment that matches the complete value of tax credits for clean energy infrastructure projects. Unlike competitive grant and loan programs where there is a possibility of not receiving an award, the direct pay option ensures that entities meeting the criteria for both direct pay and the underlying tax credit will receive their payment. This allows these entities to benefit from the full value of the tax credits (White House, 2022). Also, for add-ons there is a provision for 10% bonus for domestic manufacturing requirements if steel, iron, or manufactured components fulfill the criteria for local manufacturing standards. Also, a 10% bonus ITC is awarded to clean energy projects that are located in low income community (U.S DOE, 2022).

PTC: The production tax credit is defined as the incentives offered against the usage of renewable energy technologies such as solar PV and storage system. The incentives are given as a per kilowatt-hour tax credit for 10 years from the beginning of operation of the installed technology including the inflation rates. The PTC amount is 2.75 ¢/kWh (U.S DOE, 2023). However, it's important to note here that a facility must either opt for PTC or ITC credits, not both (Batra, Pande, Reddy, & Madan, 2022).

The Self-Generation Incentive Program (SGIP) in California offers rebates to customers of three major investor-owned utilities (IOUs): Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E), for the installation of eligible BESS. The purpose of this initiative is to offer financial incentives to encourage the use of BESS supporting the customers and the conventional grid. Critical facilities such as fire stations qualify for larger rebates under the SGIP, covering nearly 100% of the BESS cost, and microgrids with significant renewable energy penetration may also be eligible for a bonus. SGIP covers the BESS costs if it is included in the microgrid system (CPUC, 2020b).

The SGIP rebate program, as presented in Table 4 below, provides different refunds to different consumers, including government organizations, vital facilities, non-residential clients including enterprises and retailers, and the general market. The general market rebate type is accessible to all consumers and covers a sizeable percentage of the

BESS cost at about $350/kWh or 35% of the overall cost. The terms equity and equity resilience refer to two additional rebate mechanisms. With an incentive of $850/kWh, or 85% of the cost of the BESS, the equity rebate primarily targets fixed agencies and consumers. The equity resilience budget, which offsets almost 100% cost of the BESS, or around $1000/kWh, is applicable for critical facilities such as fire stations and hospitals (CPUC, 2020b).

Table 4: SGIP Incentive Structure for different rebate types (CPUC, 2021)

SGIP Rebate Type	**Rebate Rate ($/Wh)**	**Type of Customers**
General Market	0.35	All
Equity	0.85	Govt. Agency, non-profit and small businesses, DAC
Equity Resilience	1.00	Fire Stations, Hospitals and other critical facilities

The California Public Utilities Commission (CPUC) provides map links that enable facilities to confirm if they comply with the requirements for the equitable resilience budget. These requirements include being a crucial institution, being sited in a low-income community, and having gone through two or more Public Safety Power Shutoffs (PSPS) circumstances. Figure 19 & Figure 20 shows how the HBFS No. 1 in Eureka complies with all requirements in order to be eligible for the “equity-resilience” budget.

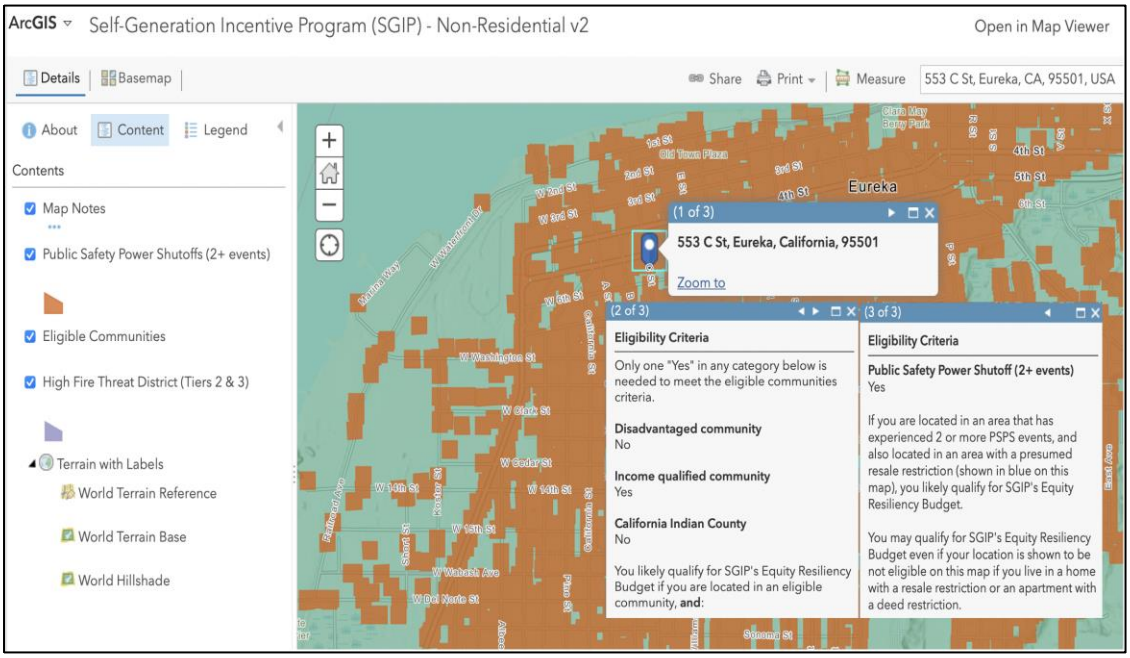


Figure 19: SGIP map for Equity Resilience criteria for HBFS No. 1 facility at Eureka (ESRI, 2022)

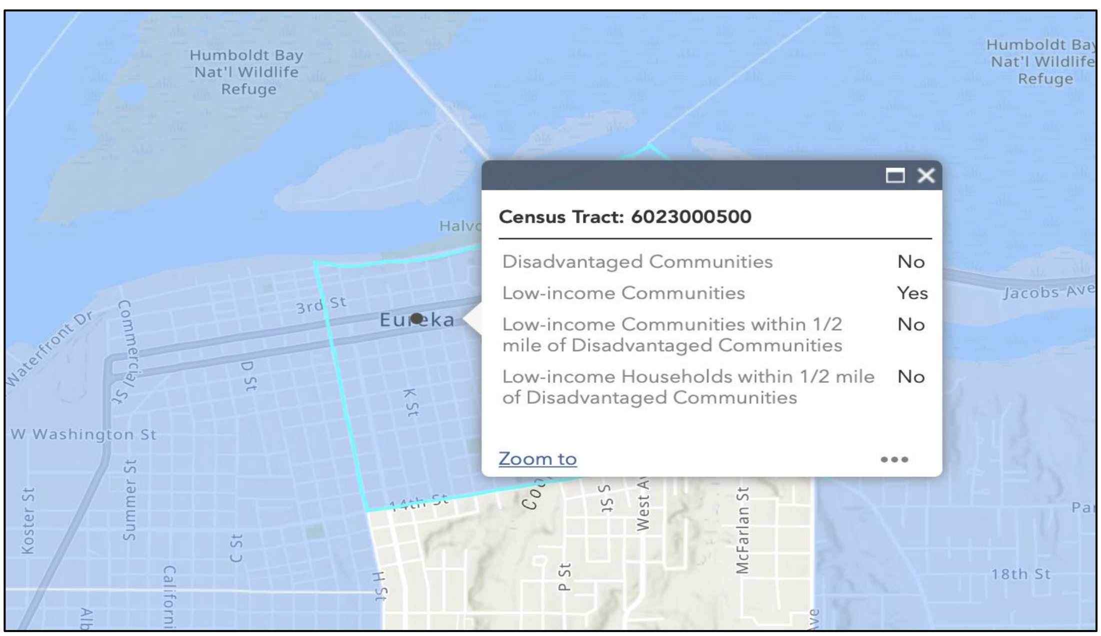


Figure 20: Low Income Community Map for HBFS No. 1 in Eureka (CARB, 2023).

Value of Resiliency and Reliability

The vulnerability of conventional grids due to grid failure with or without major event days (MEDs) often results in a lack of reliable power supply to customers, including critical facilities. Such outages have a cost, which in case of a fire station would be both social and monetary. However, the social costs could be loss of life or property damage, which are difficult to quantify. For business interruptions there are resiliency and reliability metrics which can be used to quantify the value of lost load (VoLL).

Resilience is defined as the capacity to anticipate and adjust to changing circumstances, to resist interruptions, and to recover quickly, whereas reliability is defined as the system's capacity to meet demand while adhering to agreed criteria and in the required amount (Wang, 2021).

Several system level costs of outages, as per the “Grid Modernization Initiative” by U.S. DOE, are the cost of recovery, the lost revenue by the utility, the cost incurred by the utilities due to grid damages, and the interruption cost due to the power outage event (Kintner-Meyer, 2021). These costs can be avoided by more resilient power systems that include microgrids as one tool for improving resilience.

What is the value of resilience? One way to estimate it is by accounting for the avoided loss in load. As per the NREL report “Quantifying and Monetizing Renewable Energy Resilience” report, the value of resiliency (VoR) could be quantified mathematically as, Equation 3. Equation for calculation of VoR:

$$\text{VoR} = \text{VoLL}\int_0^T Lc\,(t)dt \text{ (Anderson, et al., 2018)}$$

Where, VoLL is the value of lost load in $/kWh, L_c is the additional critical load which was served during an outage period of time (T). The value of lost load used in this study was $100/kWh (Anderson, et al., 2018).

There has been a long effort to quantify resilience metrics by government agencies and research organizations. Many of the proposed resilience metrics are based on the direct and indirect impact on customers. The direct impact on customer services is comprised of critical and non-critical customers hours of outage experienced and unserved energy demand, whereas the indirect impacts are the costs when the backup power of critical services fails and business interruption repercussions (Kintner-Meyer, 2021). For critical facilities such as fire stations or hospitals, if the business is interrupted due to a power outage, it could lead to serious repercussions including loss of lives.

Reliability metrics (per IEEE 1366 standards) are typically quantified via SAIDI, SAIFI, CADI and MAIFI (Enis, 2021). The definitions of these metrics are as follows:

System Average Interruption Duration Index (SAIDI)

System Average Interruption Duration Index is defined as the sustained duration of outage or interruption experienced by average customer during a particular time period (Layton, 2004).

Equation 4. Equation for calculating the SAIDI value:

$$SAIDI = \Sigma (r_i * N_i) / N_T$$

Where, r_i: Restoration time (minutes),

N_i: Total number of customers experiencing interruption,

N_T: Total number of customers being served

System Average Interruption Frequency Index (SAIFI)

System Average Interruption Frequency Index is defined as how frequently a system user encounters outages on average in a given year (Layton, 2004).

Equation 5: Equation for calculating the SAIFI value:

$$SAIFI = \Sigma (N_i) / N_T$$

Where, N_i: Total number of customers experiencing interruption,

N_T: Total number of customers being served

Customer Average Interruption Duration Index (CAIDI)

Customer Average Interruption Duration Index is defined as once an interruption or an outage is witnessed then what is the typical amount of time it takes to restore service. CAIDI could be defined as the SAIDI divided by SAIFI (Layton, 2004).

Equation 6: Equation for calculating the CAIDI value:

$$CAIDI = \Sigma (r_i * N_i) / N_i$$

Where, r_i: Restoration time (minutes),

N_i: Total number of customers experiencing interruption, Momentary Average Interruption Frequency Index (MAIFI)

Momentary Average Interruption Frequency Index calculates the typical frequency of brief interruptions a client encounters during a certain period of time. The majority of distribution systems simply keep track of brief disruptions at the substation, failing to take into consideration equipment installed on poles that can briefly disrupt a customer. Because it is challenging to determine whether a temporary interruption has occurred, MAIFI is rarely utilized in reporting distribution indices. By adding together, the number of device operations, MAIFI is determined (opening and reclosing is counted as one event) (Layton, 2004).

Equation 7: Equation for calculating the MAIFI value:

$$MAIFI = \Sigma\ (IDi * N_i)/\ N_T$$

Where, ID_i = Number of interrupting device operations.

N_i = Total number of customers interrupted.

N_T = Total number of customers served.

It is important to understand the significance of major event days (MEDs), which as per CPUC are defined as high impact but low frequency events, and have a substantial impact on conventional grids. Due to such events, reliability metrics such as SAIFI, SAIDI and CAIDI can increase sharply in the context of prolonged outages. This increase shows the vulnerability of the grid in response to such events and could hamper the functioning of critical facilities such as fire stations. However, these impacts don’t account for casualties such as death of people due to lack of available medical services offered by first responders such as fire station and hospital staff.

As observed in Figure 21 below, the year 2019 involved a very high SAIDI (with MED) value of around 1400 minutes, and a high CAIDI value of around 700 minutes. Also, since the recent reliability indices for the year 2022 are still not published by PG&E, the effect of the December 2022 earthquake on SAIFI, SAIDI and CAIDI values is not yet known. However, the earthquake was limited to a focused geographical area in Humboldt County, and the effect was likely small on the overall PG&E circuit even though it had serious repercussions locally in Humboldt County.

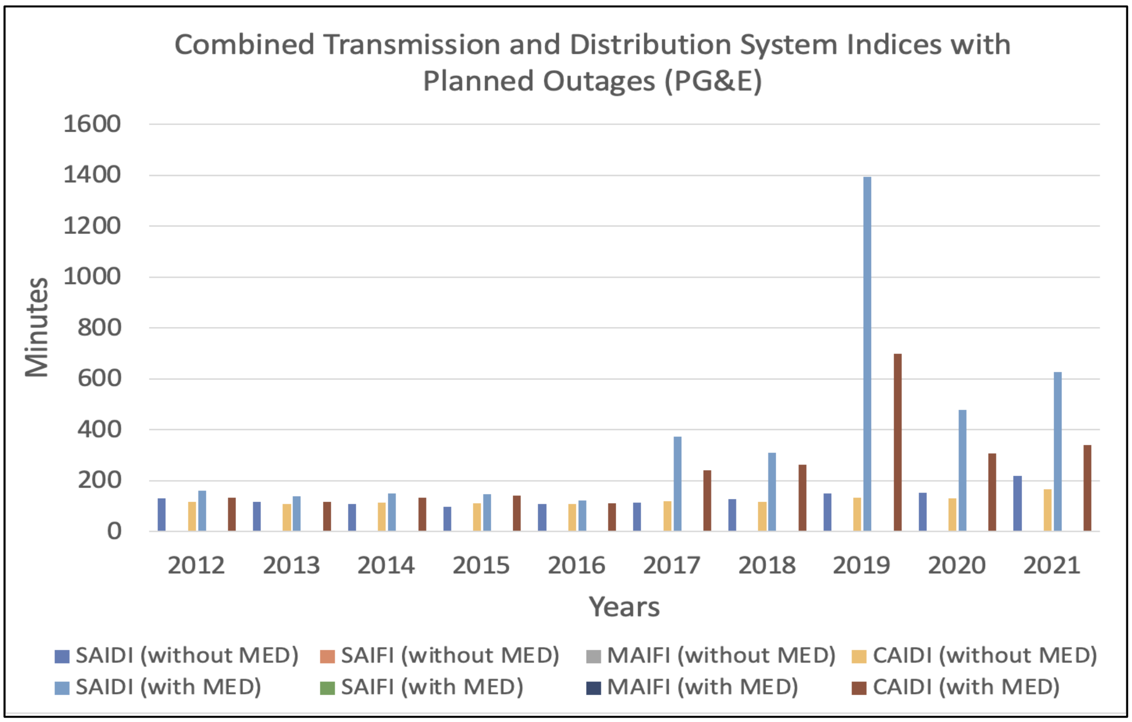


Figure 21: Historical reliability metrices for PG&E (PG&E, 2022)

Interruption Cost Estimation (ICE) Calculator

In pursuit of quantifying the value of lost load (VoLL), various state and research agencies have come up with open-source tools which take the above-mentioned reliability metrics such as SAIFI, SAIDI and CAIDI into account. One such tool that has been used in this study to quantify the VoLL for HBFS No.1 is LBNL's Interruption Cost Estimator Calculator (ICE). As shown in Table 5, the sectors are divided into three parts: residential, small commercial and industrial (C&I), and medium and large C&I. For the small C&I, the model assumes the customer's annual energy consumption is under 50,000 kWh, whereas for the medium and large C&I category the consumption should be over 50,000 kWh (Sullivan, Schellenberg, & Blundell, 2015). So, HBFS No. 1 falls under the category of medium and large C&I as its annual energy consumption is over 50,000 kWh. Table 5 illustrates the variations in interruption costs across different sectors or customer types.

Table 5: Interruption cost estimation calculator for various customer category depicting the value of lost load (Schellenberg & Larsen, 2023)

Sector	**Cost per Event**	**Cost per Average kW**	**Cost per Unserved kWh**
Residential	$7	$9	$3
Small C&I	$1,300	$600	$220
Medium and Large C&I	$14,000	$270	$100

Microgrid Market

The microgrid market in the U.S is witnessing a significant growth due to widespread adoption across various states. As per a report by Wood Mackenzie, the U.S. microgrid market has reached around 10 GW of installed capacity of solar and storage in the third quarter of 2022. This has led to around 47% increase in the solar PV and storage capacity as compared to the year 2017 (Wood Mackenzie, 2023). The C&I sector has secured 48% share in the microgrid adoption in the year 2022, wherein the governments which own and operate the critical facilities have contributed almost 22% of the total C&I share (Nilsson, 2023). In Figure 22 we can observe that over 100,000 cumulative installs of microgrid systems were made across the U.S. in the non-residential sector, whereas in California alone the number of installations was about 40,000 through 2021 (Barbose, Darghouth, O’Shaughnessy, & Forrester, 2022).

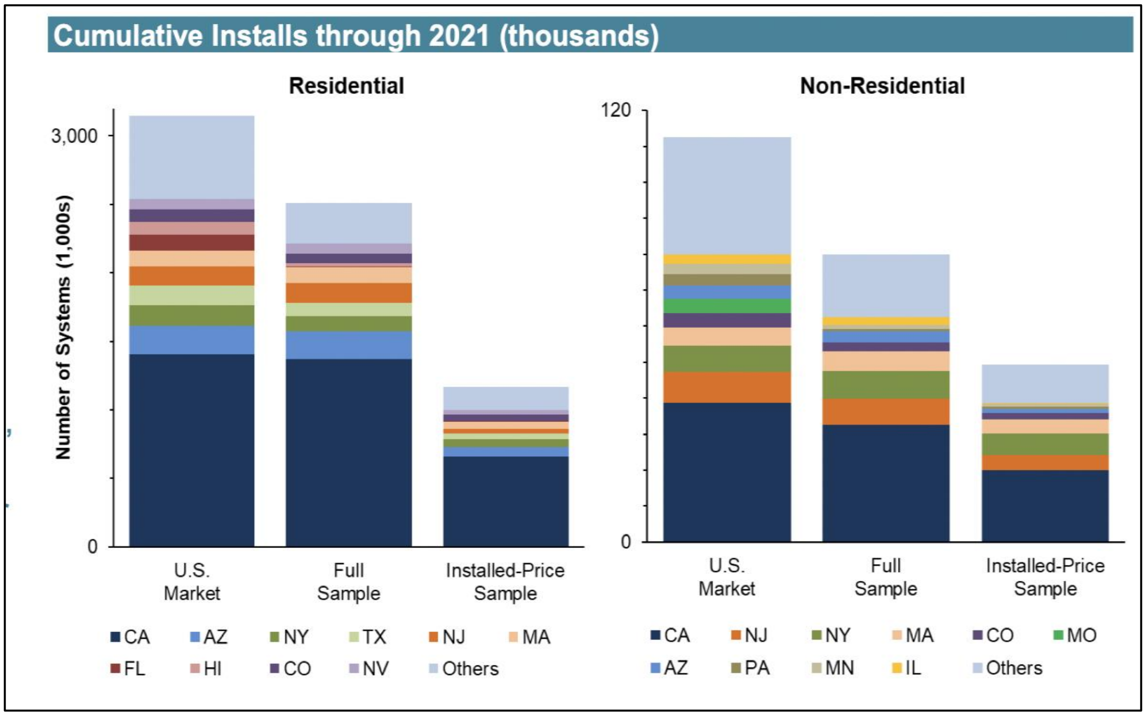


Figure 22: U.S microgrid project cumulative installation through year 2021 (Barbose, Darghouth, O'Shaughnessy, & Forrester, 2022)

Talking specifically about the fire station as per a report by U.S. Fire Administration, there are a total of around 27,000 fire departments in U.S. and its territories, of which around 68% of them have one fire station and around 30% have 2 or more fire stations. California itself has around 850 fire departments (U.S Fire Administration , 2023). As mentioned in the case studies section, microgrids have been installed in fire stations in Fremont and Los Angeles. State authorities have started considering microgrids as an option to serve first responders during emergencies. Hence, microgrids fire stations have good market potential across the U.S. in general and California in particular.

Concept of Operations for the Microgrid

A concept of operations document is a way to describe the intended behavior of a microgrid. As per PG&E's "Community Microgrid Technical Best Practices Guide" report, the routine operation of a grid-connected system can be referred to as "Blue Sky Mode." During this mode, all distributed energy resources (DERs) authorized to run on the grid must abide by the necessary interconnection laws and do business in accordance with their standard interconnection agreements (PG&E, 2020). This includes abiding by any constraints on the flow of resources used to produce or use power, such as those on charging or generation.

Due to power outage when the main interconnection points (MIPs) open and distributed energy resources (DERs) capable of operating in grid-forming mode switch to it, islanded mode is activated (PG&E, 2020). In this mode, grid-forming generators continuously modify the injection or absorption of real and reactive power to exactly meet the electrical loads within the microgrid's established boundaries. The protection relays at the MIPs and points of common coupling (PCCs) operate in islanded mode according to their predetermined settings for islanded operations, continually scanning for any signs of electrical faults occurring within the electrical boundary of the microgrid (PG&E, 2020).

These operational states depend on the microgrid boundary. As per NREL's 2020 report titled "Microgrid Energy Resilience," to ensure the secure separation of a microgrid from other electrical systems in emergency situations, it is necessary to determine the points at which isolation can be achieved. The first stage is locating the point of common coupling (PCC) between the power system of the external utility and the microgrid installation (Booth, Reilly, Butt, Wasco, & Monohan, 2020).

However, there might be more than one PCC in an installation in some circumstances, and some PCC points might be left open under normal circumstances without any power flow. For larger microgrid deployments, the isolation point at the PCC has occasionally been used as an existing switching or protection device, although changes may still be required. Potential isolation sites should be marked on the schematics during the assessment of the current conditions and thoroughly checked during on-site inspections. In situations where the microgrid includes only a specific section of the installation loads, such as a particular feeder, isolation may occur further down the distribution system from the PCC (Booth, Reilly, Butt, Wasco, & Monohan, 2020).

METHODS

With the primary objective of assessing the potential for a solar plus storage microgrid at the Humboldt Bay Fire Station No. 1, a variety of methods were taken into consideration. These approaches have been carefully chosen to guarantee that the study's objectives, including better operational performance, decreased carbon emissions, and greater energy resiliency, are properly addressed and achieved.

As noted in Figure 23, I conducted a site visit and discussion with HBFS No. 1 stakeholders where I gathered information about the existing state of electrical infrastructure. Additionally, I conducted a distributed energy resource assessment to evaluate the feasibility of incorporating renewable energy sources such as solar PV and BESS. Using the 15-minute load data provided by the City of Eureka Building Department, I performed an energy demand analysis to obtain the load shape for sizing the DERs. To get the hourly PV generation data, I used the System Advisory Model (SAM) software package. The load shape, PV generation data and the PV and BESS size was further used in the microgrid simulation model to obtain the technical, economic, and environmental performance of the microgrid. The results of all technical, economic and environmental performance along with the fire station personnel discussions can be utilized for stakeholder engagement and achieving effective regulatory compliance.

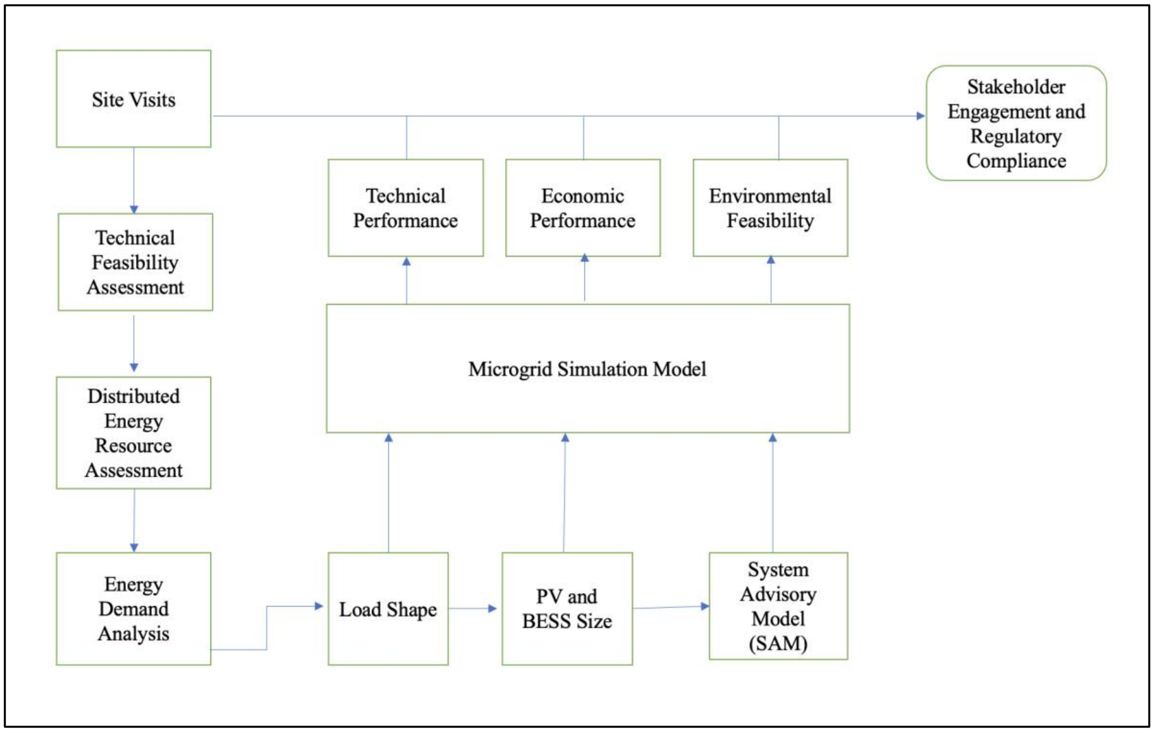


Figure 23: Flowchart showing various methodologies adopted in the HBFS No. 1 microgrid project.

Site Visit

I visited the Humboldt Bay Fire Station No. 1 (see Figure 24) to collect information about the ways in which the microgrid may support the facilities operations, especially during emergencies or MEDs. The site visit and discussion with clients enabled access to historical electric load data, understanding the existing state of the electrical system at the facility, and identifying potential locations for the placement of solar PV panels and BESS.

Figure 24: View of Humboldt Bay Fire Station No.1 in Eureka, CA (Source: Google Maps).

The site visit aimed to gain a comprehensive understanding of the fire station's energy needs, operational requirements, and goals for the microgrid project. Discussions focused on critical loads, resilience during power outages, potential cost savings, and the importance of reducing dependence on conventional energy sources. The insights gathered from the discussions provided valuable input for assessing the site's feasibility and tailoring the microgrid design to meet the specific needs of the fire station.

Site Visit Process: Discussions were conducted with key stakeholders at the fire station to gather valuable insights and understand the specific requirements for the microgrid. The following individuals were involved in the discussions:

Sean Robertson - Fire Station Chief: Discussed the operational needs, critical loads, and priorities of the fire station during power outages. Explored the potential benefits of a microgrid system and any specific challenges or concerns. The Fire Station Chief also informed me about the study done by RCEA for energy efficiency upgrades. However, the reports were not available but could be used in future and clubbed with the microgrid study for load optimization.

Nick Launius – Battalion Chief: Gathered information regarding the existing electrical infrastructure, energy usage patterns, and potential areas for energy optimization at the fire station. Explored the feasibility of incorporating renewable energy sources and energy storage systems.

Talia Flores – Public Information Officer: Being the first point of contact has helped me to get the access to the fire station and also worked closely with the City of Eureka to get the necessary clearances for the study. Helped in accessing the electrical and building designs and also providing information on the total stationed staff at the HBFS No. 1.

Jeff Raimey – Community Services Deputy Director (City of Eureka): Discussed the process for accessing historical 15-minute load data from PG&E. Also, guided me about the sensitivity and ethical use of the concerned documents related to the fire station.

Table 6 below depicts the excerpts of the HBFS No. 1 site visit in which I have observed the key factors which could be necessary for the microgrid feasibility analysis.

Table 6: Key parameters observed and recorded during HBFS No. 1 facility site visit.

Key Factors	**Importance for Microgrid Feasibility Analysis**
Availability of Space	Helps in determining the installations of the proposed DERs.
Site Layout	Important for placement and interconnection of all the proposed microgrid components.
Interconnection with Electrical Infrastructure at HBFS No. 1	Important for assessing the ease of interconnection with the existing electrical infrastructure.
Historical Electric Load Data	Provides insight about the electricity usage pattern and also helps in PV and BESS sizing.
DER Assessment	Evaluates the feasibility and capacity of accommodating distributed energy resources.
Critical Loads	Identifies the crucial loads which needs un-interrupted power.
Resiliency Needs	Duration of backup power needs for the HBFS No. 1facility.
Grid Interconnection	Assess the potential for interaction with grid for energy arbitrage.
Regulatory Requirements	Identifying the key stakeholders necessary for way forward.

Technical Feasibility

Existing Electrical Infrastructure

Documenting the current state of existing electrical infrastructure of the fire station facility will let us know about the upgrade requirements to sustain the microgrid power system. This is done by accessing the electrical drawings, which include information about the main panel and all the sub-panels attached to the existing electrical infrastructure available at the HBFS No. 1 facility. The outcomes of this investigation are documented in single-line diagrams (SLD), which show a power system by symbolizing each part of the system. It offers a clear overview of the connections and configuration of the system's parts, along with relevant information like output ratings and voltages. For HBFS No. 1, the SLD is broadly divided into two parts. First is the main panel where the distribution lines of PG&E connect with the HBFS No. 1 facility, and second are the sub-panels which are connected to the main panels which ultimately serve the various loads of the facility. The rated capacity for the main panel is 600 amps (or a load of 150 KVA). The main panel is rated at 120/208V and has a three-phase connection shown in Figure 25.

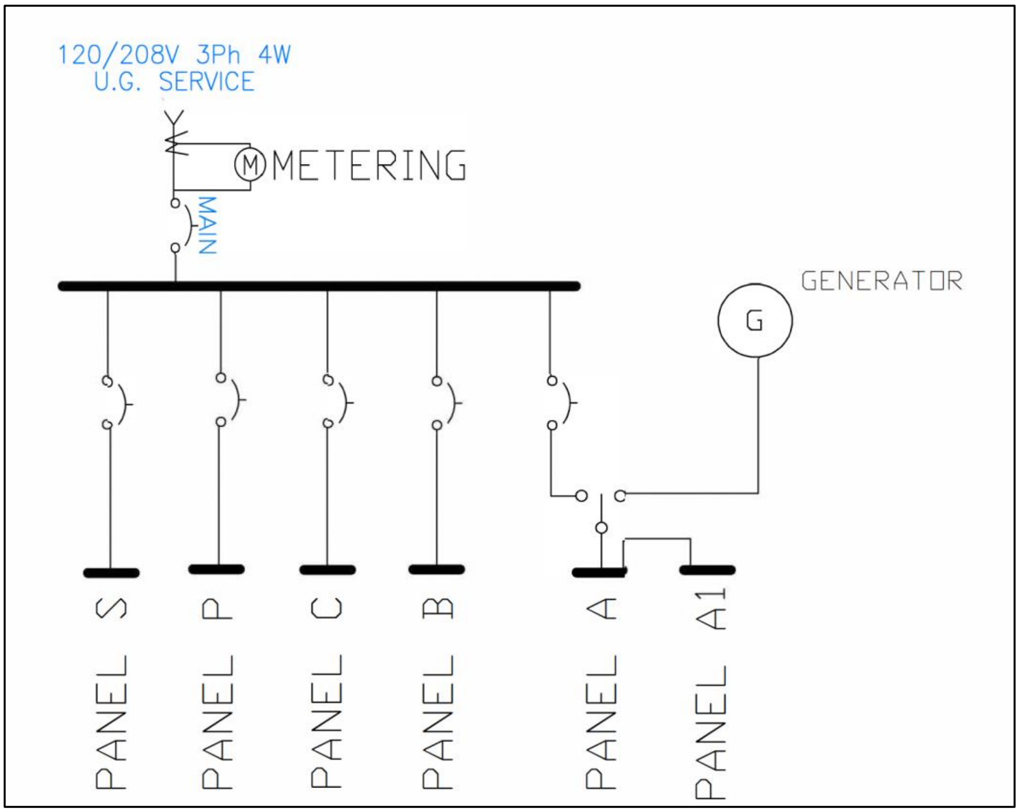


Figure 25: Existing SLD for the HBFS No. 1 facility

There are a total of six sub-panels in the fire station facility, which are distributed among the first and second floor as shown in Figure 25. Panel A & B are on the first floor with a rated capacity 150 amps each while Panel C is located at the second floor and has a rated capacity of 60 amps. Panel P serves the furnace, supply fan and exhaust fans, whereas Panel S serves the welder, compressor and water heater and other loads. Apart from these, Panel A serves the door openers, time clocks, hose pump apparatus room lights and other critical loads. Panel A1 serves the TV terminal, telecommunication terminal, radio and alarm systems.

ICA Map Information

The Integration Capacity Analysis (ICA) map from PG&E is designed to help contractors and developers identify potential project locations for distributed energy resources (DERs). The ICA is a complex modeling study that depends on detailed information about the electric distribution system, taking into account elements including physical infrastructure, load performance, and existing and future generators. It describes a distribution line segment's ability to accommodate more DERs while avoiding issues that can jeopardize customer dependability and power quality. Such problems could call for distribution line upgrades, which might have an impact on the price and timing of DER hookups (PG&E, 2022). As shown in Figure 26, we can observe the ICA maps for the fire station facility circuit no. Eureka E 1105, which could integrate a maximum of 430 kW of PV generic hosting capacity, which is more than sufficient for a microgrid at the location. A detailed interconnection study may be required, however, to confirm availability of hosting capacity.

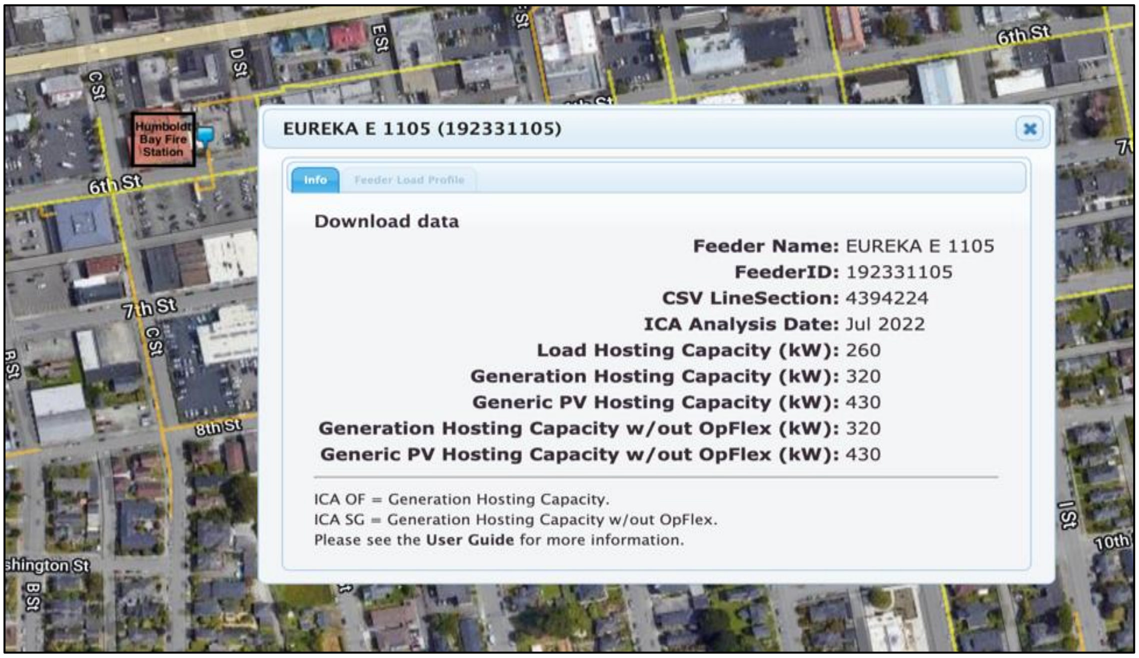


Figure 26: ICA Map Information for the HBFS No. 1 Facility (PG&E, 2023).

Distributed Energy Resource (DER) Assessment

For the assessment of energy resources, I have categorized the DER options into two categories: 1) existing energy resources at the fire station facility and 2) potential renewable energy resources that could be integrated with the microgrid.

Existing DERs

During the site visit I identified a diesel genset as the single existing distributed energy resource currently available at the HBFS No. 1 facility. The fire station procures the energy from PG&E through feeder Eureka E 1105 circuit as shown in Figure 26 (ICA Map) above. The electricity rate schedule for the facility is B-19 time of use (TOU).

The diesel generator available at the site has name plate ratings of 83.3 KVA and 156 KVA for single phase and three phase operations, respectively. As per the kW ratings, the generator could supply up to 83.3 kW in single phase operation and 125 kW loads in three phase operation. The operation of the generator depends upon the situation and power requirement. The generator would run in a three-phase mode when there is a need to operate three phase loads like pumps and air compressors and in single phase mode for supplying power to lighting and communication loads. The facility also has a 1000-gallon diesel storage tank at the site, which may last up to 2-3 days during emergency cases for refueling the fire engines and fire trucks. The picture of the diesel genset and the storage tank is shown in Figure 27.

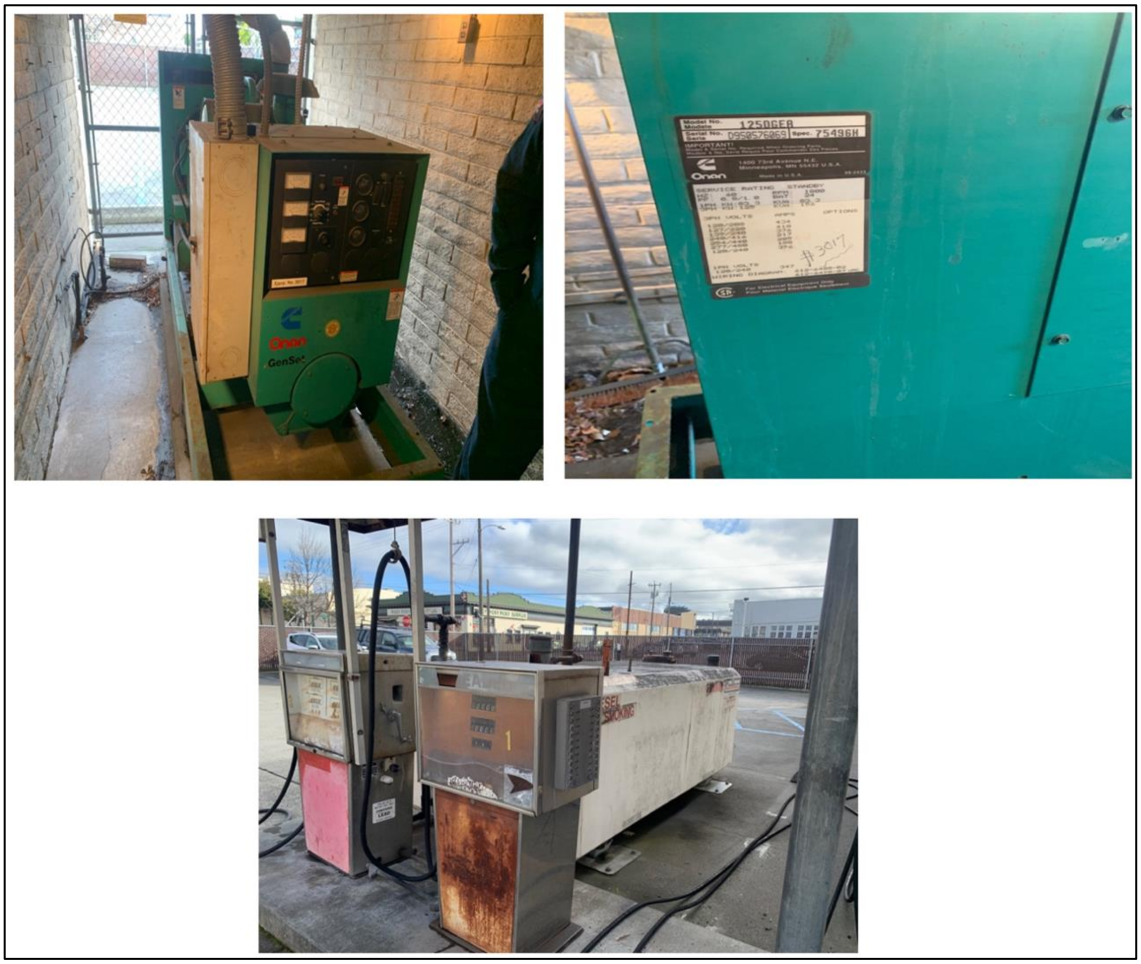


Figure 27: Genset and Diesel Storage Tanks at the HBFS No 1 Facility.

<u>Distributed Energy Resource Assessment</u>

During the site evaluation of potential distributed energy resources suitable for the HBFS No. 1, I have focused on analyzing the viability of solar PV systems and battery energy storage systems (BESS). During my site visit, I carefully assessed the available areas for the placement of PV panels and the BESS. The primary objective was to identify renewable generation technologies that can ensure resiliency during grid outages, allowing for un-interrupted business operations at the fire station. The site offers four potential locations for the installation of solar PV panels as illustrated in Figure 28 below. The total solar PV size that could be installed on the roof is around 75 kW, whereas the two carports have a total potential of 50 kW. Despite the absence of obstructions on the rooftop where the PV panels could be installed, it is important to account for potential shading losses in the study. Although shading effects are minimal due to the unobstructed nature of the installations, I have taken into consideration the possibility of shading and its impacts on the performance of the PV system.

Figure 28: Potential locations for solar PV panel installation at the HBFS No. 1 facility (Helioscope, 2023).

The other proposed DER is the battery energy storage system that could be installed near the genset area. There are various battery technologies available in the market such as Li-ion, lead acid batteries, and flow batteries which are commonly used in behind the meter (BTM) microgrid power systems. The most cost-effective battery chemistry for BTM applications right now is lithium-ion (Bowen & Gokhale-Welch, 2021). The rise of lithium-ion batteries can be ascribed to the technology's huge price drops, which totaled over 89% between 2010 and 2020. Furthermore, it is anticipated that prices will continue to drop in the coming years. The use of BTM battery energy storage systems (BESS) and the potential benefits of integrating them into power system operations are both becoming more and more popular as a result of the cost reductions (Bowen & Gokhale-Welch, 2021). So, the Li-ion BESS system would be appropriate for the HBFS No. 1 facility and also considering the battery cabinet size, the whole system could be installed near the genset area (Symtech Solar, 2022).

Energy Demand Analysis

To understand the energy usage pattern of the HBFS No. 1 facility, the City of Eureka provided historical 15-minute load interval data from PG&E which was analyzed using a spreadsheet model. The HBFS No. 1 load shape is shown in Figure 29, where I have observed that the total annual electricity consumption was estimated to be about 100 MWh with an average load of around 12 kW and a peak load of 32 kW. The maximum energy consumption and peak load were observed in the month of January. The HBFS No. 1 facility has an average monthly energy consumption in the winter months (October through May) of around 9 MWh, whereas in the summer months the average monthly energy consumption was around 8 MWh. The annual electric load shape for the HBFS No. 1 facility as shown in Figure 29 can help size the solar PV system and BESS, which is further explained in the solar PV and battery sizing section, below.

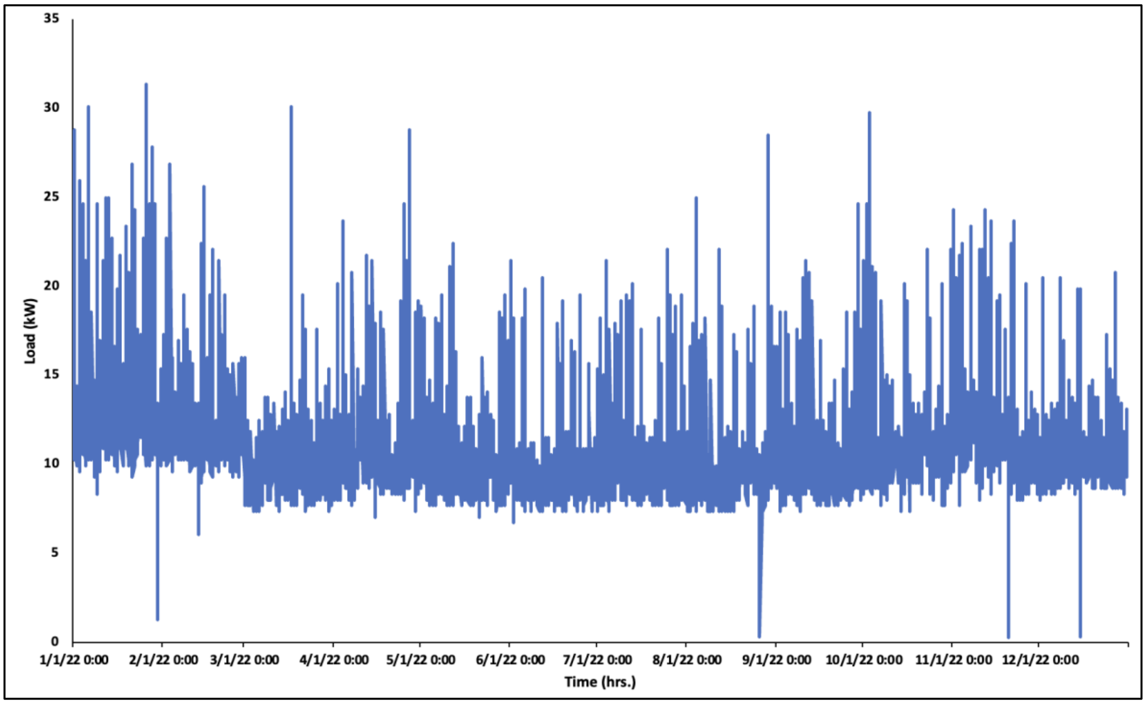


Figure 29: Load shape of the HBFS No. 1.

PV and BESS Sizing

To determine the optimal photovoltaic (PV) system size for achieving a net-zero status for the building, I have used an open-source analysis tool. The needed total capacity of the PV system was determined using the PV Watts calculator, a reputable instrument in the industry (NREL, 2023). The availability of space at the fire station emerged as a critical limitation throughout the assessment process, among other crucial considerations. This restriction led to a thorough evaluation of the property. In the end, it was determined that the roof area was the best place for solar PV installations because it perfectly matched the needed space for achieving net-zero building status. To estimate the output of the solar array, I have used System Advisory Model (SAM) software which uses a combination of factors including the solar panel capacity, efficiency and the available roof area. The constraints based on the roof area are taken into account to determine the size of the solar PV system that is required to make the building net zero.

The battery sizing process considered the peak load of the HBFS No. 1 facility as the reference point, aiming to ensure resilient and reliable power delivery according to guidelines provided by PG&E's "Community Microgrid Enablement Program Guide" (PG&E, 2020). To achieve this, peak load of the facility was multiplied by a factor of three (PG&E, 2020), and a battery with a duration of 4 hours was considered. The 4-hour battery is selected primarily for two reasons. First to achieve higher degree of resilience for the HBFS No. 1 and second, to access the 100% SGIP incentive, which is given for both 2 and 4-hour duration batteries whereas for 6 hour or more duration batteries the SGIP incentives declines to 50% (CPUC, 2022).

Microgrid Simulation Model

A microgrid simulation model was created by the me to analyze the technical performance of all the components of the microgrid in "Blue Sky" and "Islanded" modes. It is implemented with a spreadsheet model which considers technical parameters such as hourly PV generation, hourly demand of the HBFS No. 1, BESS SOC, BESS discharging to the load and PV curtailment when the microgrid is islanded. The goal of the energy model is to assess and analyze the technical performance of all the components within the microgrid system. The model features include the following:

Evaluate system's performance in "Blue Sky" mode: The microgrid's performance when linked to the main power grid is evaluated using the energy model. It examines the behavior of the parts in terms of energy generation, storage, and distribution, including solar PV panels, battery energy storage systems, and other renewable energy sources. The system's effectiveness, dependability, bill savings and overall performance under typical grid circumstances are all determined by this assessment.

Performance evaluation of the system in "Islanded" mode: The energy model also evaluates the microgrid's autonomy in "Islanded" mode, where it works apart from the primary power grid. It evaluates how the parts work together and balance energy supply and demand inside the microgrid, guaranteeing a steady supply of electricity to crucial loads. The system's resilience, stability, and capacity to maintain electricity during grid outages or emergencies are all determined by this study. The selection for the best case and worst case for the microgrid to island was based on analyzing the solar PV generation and load demand profile.

Improve system setup and operation: The energy model helps to determine the best ways to configure and run the microgrid's components. It enables the testing of many scenarios, such as modifying the renewable energy sources' output, determining the size of the battery storage system, or tweaking the way energy resources are distributed. The model assists in determining the most effective and economical design for the microgrid by analyzing various configurations and approaches. Following are the key parameters that I have considered for the microgrid simulation model:

<u>Demand</u>

The MG simulation model begins with the load data of the HBFS No. 1 facility, which is arranged with time intervals representing the duration of the model. The 15-minute load data that was collected from PG&E for the years 2019 to 2023 was used to create the energy demand profile for HBFS No. 1. However, it was discovered that there were gaps in the data, where certain periods had missing data.

To fill these data gaps, a synthetic data set was generated. The process of creating the synthetic dataset involved two key steps. Firstly, for each month of the year, I identified the single occurrence of that month in the four-year data set that had the highest electricity consumption and peak load for HBFS No. 1 (e.g., for the month of January, I reviewed all the available data for that month during the 2019 to 2023 period and identified which January month had the highest energy consumption and peak load). By selecting the months with the highest energy consumption from the available load dataset, I have ensured that the PV and BESS systems were not undersized.

Secondly, the selected load dataset for each year was aggregated, allowing for a comprehensive energy demand analysis. This process provided an indication of the overall energy consumption patterns, enabling assessment of the facility's energy needs and sizing the PV and BESS for the microgrid.

PV Generation

I have used System Advisory Model (SAM), which is an open-source tool developed by NREL, to analyze the technical performance of the solar PV system using the weather file of the desired location. Based on a typical annual weather pattern, and considering all relevant losses, SAM estimates hourly interval generation data for the PV system which could be used for further microgrid simulations (Blair, et al., 2018).

Energy Balance (Blue Sky)

In order to calculate the surplus or deficit energy, the hourly load profile is added to the hourly solar generation data that was obtained from SAM. In the peak time-of-use (TOU) period I wanted to use the BESS for peak shaving in the Blue-Sky mode. For the off-peak, part-peak, and super-off-peak time of use (TOU) periods, I designed the logic in such a way that the microgrid model uses the PV generation (during sun hours) and/or grid to serve the load. In the model I assume the battery will charge at a 95% efficiency and suffer 5% losses during discharge, resulting in a 90% round trip efficiency (RTE) (Ramasamy, et al., 2022). In Table **7**, I have shown the logic used to model the BESS during various time of use periods.

Table 7: Logic used for modelling the battery storage operations in the microgrid simulation model for Blue Sky mode.

TOU Period	**Logic for BESS Operation**
Super-Off Peak	BESS will be charged from surplus PV generation and/or conventional grid
Off-Peak	BESS will be charged from surplus PV generation and/or conventional grid
Peak	BESS will discharge to the load
Part Peak	BESS will either charge from the excess PV generation and/or conventional grid

To ensure the BESS operates effectively, various calculations and constraints are taken into account. One key calculation involves assuming a 90% round-trip efficiency (RTE) for the BESS. This means that during discharge, the BESS will only deliver 90% of the stored energy, accounting for losses incurred during the charging and discharging processes. To determine the BESS discharge required to meet the load, the combined values of PV generation and the load are calculated. This quantifies the load deficit that needs to be fulfilled by the BESS. To ensure this load deficit is met by the BESS, the BESS discharge is then multiplied by a factor of 1.05. By considering these calculations, the BESS can efficiently discharge the required amount of energy to meet the load demand, while accounting for losses and incorporating a margin of safety. The microgrid model utilizes the battery energy storage system (BESS) to effectively manage the demand charges during peak periods, as indicated in the table. In non-peak time-of-use (TOU) periods, the electrical grid and photovoltaic (PV) generation adequately supply the load. Additionally, any excess PV generation beyond the facility's demand and BESS charging requirements is exported back to the grid, enabling energy arbitrage through the utilization of net surplus credits.

Islanded Mode

In the islanded mode the microgrid will isolate from the grid using relays, and the microgrid controller will establish a grid forming mode. In this operational state, the load is either served by the PV or the BESS. The battery will drain during island mode operation if the BESS SOC previous to the outage is higher than the required minimum SOC of 10% (Ramasamy, et al., 2022). If the SOC of the BESS reaches 10% or lower, it will cease discharging power and enter an idle state. During this time, the BESS will solely rely on solar PV generation to recharge and replenish its energy storage. This mechanism ensures that the BESS doesn't deplete its energy reserves beyond the specified threshold limit. Table 8, below, describes the logic used for the BESS in the microgrid model during islanding mode.

Table 8: BESS logics for operating during the islanded mode.

TOU Period	Logic for BESS Operation
Super-Off Peak	BESS will discharge to the load and can charge from PV excess generation
Off-Peak	BESS will discharge to the load and can charge from PV excess generation
Peak	BESS will discharge to the load and can charge from PV excess generation
Part Peak	BESS will discharge to the load and can charge from PV excess generation

The load plus PV generation value at which the BESS SOC exceeds 90% and the load plus PV generation is larger than zero (surplus) is where the model specifies PV curtailment during the islanding operation. It is possible to charge the BESS to 100%, but to ensure the safety and extended life of the BESS, the maximum and minimum SOC of the BESS are selected (Gkavanoudis, Oureilidis, Kryonidis, & Demoulias, 2016).

Islanded Mode (Critical)

In this scenario the BESS SOC reaches 10% and the BESS stops discharging to the load. At this time the MG controller directs the ATS to start the genset and initiate load shedding so that only critical loads are served. In this context the load is served through the genset and PV array, with surplus PV generation being utilized to charge the BESS.

I have considered the "best case" and the "worst case" scenarios in order to evaluate the effectiveness of the microgrid in an island state. The "best case" is based on the month that has the most solar production and while also considering which time period has the highest surplus (June) or lowest deficit (December) of solar PV generation plus demand. On the other hand, the “worst case” scenario is based on the month with the lowest solar output and the particular time period with the maximum deficit of solar PV generation plus demand. The model during the islanded state is able to quantify the resiliency achieved by accounting for the state when the BESS SOC reaches 10% or below, PV curtailment (if any), PV discharging to load, and PV charging the BESS.

Energy Bill Calculation

For the calculation of the energy bill for the HBFS No. 1 facility, the microgrid simulation model estimates based on PG&E B-19 time of use (TOU) rates. The energy consumption, peak load and maximum demand for peak, part-peak, off-peak and super off-peak time of use (TOU). The model provides the demand for scenarios with and without the microgrid in place to enable differentiate between how much the HBFS No. 1 would be paying before and after inclusion of the microgrid. The B-19 TOU rate schedule is shown in Table 9 below, which is applicable to the HBFS No. 1. For the summer season the applicable demand charges are multiplied by the maximum peak, maximum part peak and maximum demand for the month. The energy charges are calculated by using the monthly energy consumption with microgrid multiplied with energy TOU rates.

Table 9: B-19 TOU rate for commercial customer of PG&E (PG&E, 2023)

				Load	**Rate ($/kW)**	**Energy**	**Rate ($/kWh)**
B-19-TOU	**Monthly Customer Charges**	**Rate ($)**	**Summer**	**Max. Peak**	$35.81	**Peak**	$0.21563
	Mandatory B-19 S:	$31.80047		**Max. Part-Peak**	$7.27	**Part-Peak**	$0.17320
	Mandatory B-19 P:	$48.07426		**Maximum**	$27.10	**Off-Peak**	$0.14319
	Mandatory B-19 T:	$66.08368	**Winter**	**Max. Peak**	$2.53	**Peak**	$0.18868
	Voluntary B-19: S, P, T:	$6.44846		**-**	-	**Off-Peak**	$0.14307
				Maximum	$27.10	**Super Off-Peak**	$0.08188

In the calculation of the energy bills, it is important to consider an additional caveat regarding HBFS No. 1's power procurement from Redwood Coast Energy Authority (RCEA). RCEA charges a generation credit to the facility, in addition to PG&E's delivery charges. However, the difference in the energy bills between PG&E's total energy charges (generation plus delivery) and the combination of PG&E's delivery charges plus RCEA's generation charges is minimal (RCEA, 2022) . Therefore, for the sake of simplicity in calculation, the assumption was made to consider PG&E's total energy charges only.

CONOPS for the HBFS No. 1 Microgrid

The literature review section, above, includes information about how the HBFS No. 1 microgrid would behave in response to Blue Sky and Islanded Mode operations. I have developed a basic concept of operations (CONOPS) shown in Table 10 for the microgrid which includes parameters such as PV, Battery, MG controller, relays and the genset.

As depicted in Table 10 in the Blue Sky or the energy balance mode, the microgrid will allow maximum generation by the PV systems whereas the battery will be in grid following mode. The genset will be at the idle position. The relays will be closed for supply of the grid energy. The microgrid controller will operation in grid following mode. Similarly, during the islanding operations, the relays will isolate the microgrid from the grid and the BESS and genset will form the (local) grid within the microgrid.

Table 10: Concept of operations for the microgrid at the HBFS No.1 facility.

Status	**Description**	**PV**	**Battery**	**Genset**	**Relays**	**MG Controller**
Blue Sky (Energy Balance)	Business as usual operations	Maximizing Generation	Grid Following	Standby	Closed	Grid Following
Islanded	Grid outage	Maximizing Generation	Grid Forming	Standby	Open	Grid Forming
Islanded (Critical)	BESS below 10% SOC	Maximizing Generation	Charging from PV	Grid Forming	Open	Grid Forming with Load Shedding

Microgrid Cost

Based on the system design and sizing, I have estimated the upfront cost of installing a microgrid for the HBFS No. 1 facility. These costs include the cost of equipment such as solar PV panels, Li-ion BESS, microgrid controllers, etc. The other costs included were electrical balance of system, structural balance of system, installation labor, engineering, procurement and construction (EPC) overhead, permitting, inspection and interconnection (PII), overhead and contingency.

The cost breakdown for the HBFS No. 1 microgrid is inspired from NREL Q1 2022 cost estimates. Ramasamy and colleagues classify these costs based on two benchmarks, the minimum sustainable price (MSP) and modeled market price (MMP) rates (Ramasamy, et al., 2022) . By taking into account the lowest costs each input provider may charge to maintain their long-term financial sustainability, the MSP benchmark is intended to estimate the minimal prices at which product suppliers can stay financially viable. The MMP benchmark reflects the impact of market movements during Q1 2022 and strives to preserve continuity with earlier benchmark reports (Ramasamy, et al., 2022). MMP is an illustration of the usual national system expenses that American installers incur and pass down to American customers. Within each PV market sector, representative systems are used to create the MMP and MSP standards. While the MMP benchmark reflects the baseline price within the market price distribution, taking into account the market circumstances, the MSP benchmark evaluates the lowest sustainable price based on a long-term perspective of market conditions (Ramasamy, et al., 2022).

However, I have considered the MMP prices for the study and other sources for estimating the cost of installing the microgrid at the HBFS No.1 shown in Table 11.

Table 11: Methodology for estimating the HBFS No. 1 microgrid installation cost.

Items	**Units**	**Cost Estimate**	**Source**
PV Modules (including structural BOS)	$/kW	$2.00	(Barbose, Darghouth, O'Shaughnessy, & Forrester, Tracking the Sun, 2022 Edition, 2022)
Li-ion BESS (including structural BOS)	$/kWh	$580	(Ramasamy, et al., 2022)
Electrical BOS	$	PV Electrical BOS + Storage Electrical BOS + (3% * storage electrical BOS)	(Ramasamy, et al., 2022)
Installation Labor	$	75% * (PV installation labor and equipment + storage installation and equipment)	(Ramasamy, et al., 2022)
EPC Overhead	$	13% * (Structural BOS + Electrical BOS + Installation Labor)	(Ramasamy, et al., 2022)
Sales Tax	$	Sales Tax Rate (Eureka)*(PV Module Cost)	(Sales Tax Handbook, 2023) & (Ramasamy, et al., 2022)
Microgrid Controller	$/kW	$155/kW	(Giraldez, Flores-Espino, MacAlpine, & Asmus, 2018)
Switchgear	$	$70,000	(Quinn, 2019)
PII	$	Storage PII* 1.02	(Ramasamy, et al., 2022)
Contingency	$	3% * (PV Module Cost)	(Ramasamy, et al., 2022)
Developer Overhead	$	6% * (PV Module Cost)	(Ramasamy, et al., 2022)
EPC/Developer Net Profit	$	8% * (PV Module Cost)	(Ramasamy, et al., 2022)

Economic Feasibility

To describe the microgrid project viability for the HBFS No. 1, it is important to utilize standard financial metrics that describe performance. The financial metrics that will be used for this microgrid project will be net present value (NPV), benefit-cost ratio (BCR) and levelized cost of energy (LCOE) and payback period. This section describes how they are used.

Net Present Value (NPV)

Net Present Value (NPV) is the present-day value of all upcoming cash inflows and outflows throughout the whole investment period. A widely used valuation method, NPV analysis may be used to determine the value of a company, investment security, capital project, new business venture, cost-cutting program, or any circumstance involving cash flow. The NPV helps to comprehend the present-day value of all upcoming cash inflows and outflows throughout the whole investment period.

Future cash flows are discounted to their present value. The idea behind discounting the cash flows in a NPV is first to take into consideration the risk associated with a potential investment, and the second is to take into account the time worth of money (CFI, 2018). To determine the applicable discount rate for renewable energy projects undertaken by local government agencies like HBFS No. 1, the I have relied on a comprehensive NIST 2022 report on “Energy Price Indices and Discount Factors for LCC Analysis” (Kneifel & Lavappa, 2022). The discount rate of 3% has been adopted from the report, which ensures a sound basis for estimating the present value of future cash flows and assessing the economic viability of the HBFS No. 1 microgrid project. Mathematically, the NPV could be written as;

Equation 8. Calculation of net present value (NPV) for the HBFS No. 1 microgrid project

$$NPV = A_1/(1+d) + A_2/(1+d)^2 + \ldots\ldots - I_0$$

Where, A_1 is the cash flow in the year 1 and

A_2 is the cash flow in the year 2,

d is the discount rate and

I_0 is the CAPEX cost of the system at the year 0.

Benefit Cost Ratio (BCR)

In a cost-benefit analysis, the benefit-cost ratio (BCR) is a statistic used to summarize the relationship between the relative costs and benefits of a proposed endeavor. It is possible to communicate the BCR using quantitative or qualitative metrics. When a project's BCR exceeds 1.0, it means that a corporation and its stakeholders may expect a favorable net present value from the project (Hayes, 2022).

In context of the fire station, the BCR becomes important because the value of resiliency (VoR) is one of the key parameters to analyze the project viability for the facility. The potential costs of power outages, including productivity losses, equipment damage, and other pertinent aspects, are quantified in order to integrate the VoR. The investments made in the microgrid system, such as those for the PV and battery installations, control systems, and related infrastructure, are then contrasted with these expenses.

The VoR is taken into account in the determination of the BCR by evaluating the economic advantages of the microgrid system in terms of improved resilience. This makes it possible to evaluate the project's economic feasibility more thoroughly by considering both the physical advantages of improved dependability and continuity of operations and the indirect financial returns.

Mathematically, the BCR could be written as;

Equation 9. Equation for calculating the benefit-cost ratio (BCR)

$$BCR = \text{Total Benefits } (\$) / \text{Total Costs } (\$)$$

Where the total benefits are the summation of present value of all the benefits in the cash flow and the total costs is the total initial CAPEX cost of the microgrid system and the present value of replacement and O&M costs.

Levelized Cost of Energy (LCOE)

The levelized cost of energy (LCOE) offers a way to contrast different power-generating processes by considering their scope and duration. Essentially, it is the price of buying power generated by an energy source throughout its operational life. The net present value is used while calculating LCOE. Utility firms and governments use levelized cost of energy analyses for a variety of purposes. It enables them to evaluate whether specific projects need financial support in order to be economically viable and to compare developing technologies with those currently included in the electricity grid. The distribution of cash for subsidies between conventional and renewable energy sources that receive tax incentives is also greatly influenced by LCOE (Stein, 2023) Mathematically, the LCOE could be calculated as:

Equation 10. Equation for calculating the LCOE

$$LCOE = \text{Total Discounted Costs} / \text{Total Discounted Energy}$$

Where, the discounted costs are the summation of the initial CAPEX cost and the associated O&M and replacement costs. The discounted energy is the sum total of all the discounted energy generated from the generating technology.

However, it is imperative to understand that due to the significant increase in value offered by storage, the levelized cost of electricity (LCOE) is not a complete statistic for evaluating solar power (PV) systems with storage. Instead, a different statistic known as the benefit/cost ratio (described above) considers the added value offered through storage (Denholm, Eichman, & Margolis, 2017).

Payback Period

Payback period is a standard method used by businesses, financial professionals, and investors to gauge the return on an investment is the payback time. It helps in estimating how long it will take to recover the initial investment expenditures. This measurement helps in decision-making, especially when quick assessments are required for investment endeavors (Kagan, 2023).

The payback period could also be divided into two broad types. The first type is the simple payback period, and the second type is the discounted payback period. The simple payback period is the amount of time required to match the investment on the project, whereas the discounted payback period is the amount of time required to match the investment considering the present value of the investment and benefits.

Environmental Feasibility

As discussed in the literature review section, the other aspect of this study is to understand how the microgrid is optimizing the energy demand of the fire station and consequently translating the optimized energy consumption to GHG emission reductions. For this, the I have first identified the baseline scenario which typically involves calculating emissions related to the RCEA's power mix in the business-as-usual case. To estimate the reduction in GHG emissions, I have calculated the net energy demand of the facility by taking the difference between the energy procured from the grid and the clean energy (from solar PV) fed back to the grid for a year. This net energy demand is then multiplied by the power content label of the RCEA. The power content label of RCEA takes into account the GHG emission intensity of the power mix. By applying this calculation, I have estimated the GHG emission reduction that could be achieved by the HBFS No. 1 facility.

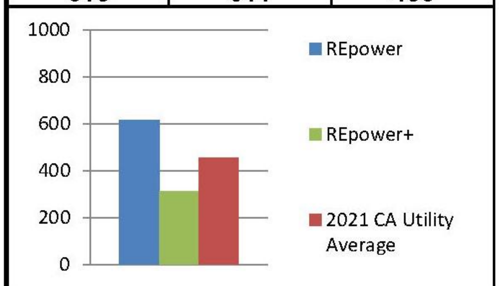
As per RCEA's 2021 power content label shown in Figure 30, the GHG emission intensity is broadly divided into three possibilities, including the base plan (RE power), REpower+ and California utility average emissions, having GHG intensity of 0.615 lbs of CO_2e/ kWh, 0.311 lbs of CO_2e/ kWh and 0.456 lbs of CO_2e/ kWh respectively (RCEA, 2023). For estimating the greenhouse gas emissions (GHG), I have considered the REpower GHG emissions as per the 2021 RCEA power content label. Acknowledging the limitation of assuming a 2021 baseline for GHG emissions, it is important to note that in practice, the GHG emissions intensity of grid electricity in California is expected to decrease over time due to the state's climate and clean energy objectives. However, conducting an analysis that incorporates the projected changes in baseline emissions intensity over time is beyond the scope of this particular study.

2021 POWER CONTENT LABEL

Redwood Coast Energy Authority

https://redwoodenergy.org/power-resources/

Greenhouse Gas Emissions Intensity (lbs CO_2e/MWh)		
REpower	REpower+	2021 CA Utility Average
615	311	456



Energy Resources	REpower	REpower+	2021 CA Power Mix
Eligible Renewable[1]	**33.1%**	**100.0%**	**33.6%**
Biomass & Biowaste	15.5%	0.0%	2.3%
Geothermal	0.0%	0.0%	4.8%
Eligible Hydroelectric	0.1%	33.3%	1.0%
Solar	0.1%	33.3%	14.2%
Wind	17.4%	33.3%	11.4%
Coal	**0.0%**	**0.0%**	**3.0%**
Large Hydroelectric	**10.5%**	**0.0%**	**9.2%**
Natural Gas	**0.0%**	**0.0%**	**37.9%**
Nuclear	**0.0%**	**0.0%**	**9.3%**
Other	**0.0%**	**0.0%**	**0.2%**
Unspecified Power[2]	**56.4%**	**0.0%**	**6.8%**
TOTAL	**100.0%**	**100.0%**	**100.0%**
Percentage of Retail Sales Covered by Retired Unbundled RECs[3]**:**	**0%**	**0%**	

[1]The eligible renewable percentage above does not reflect RPS compliance, which is determined using a different methodology.

[2]Unspecified power is electricity that has been purchased through open market transactions and is not traceable to a specific generation source.

[3]Renewable energy credits (RECs) are tracking instruments issued for renewable generation. Unbundled renewable energy credits (RECs) represent renewable generation that was not delivered to serve retail sales. Unbundled RECs are not reflected in the power mix or GHG emissions intensities above.

For specific information about this electricity portfolio, contact:	**Redwood Coast Energy Authority (707) 269-1700**
For general information about the Power Content Label, visit:	http://www.energy.ca.gov/pcl/
For additional questions, please contact the California Energy Commission at:	Toll-free in California: 844-454-2906 Outside California: 916-653-0237

Figure 30: RCEA’s 2021 power content label for different power mix choices (RCEA, 2023).

Also, to account for how much GHG emissions were reduced by replacing the genset with the use of solar plus storage during power outages, I have calculated the emissions from the genset by multiplying the emission factor of 22.5 lbs of CO_2/gallon

(Center for Sustainable Systems , 2022) by the gallons of diesel consumed by the HBFS No. 1 facility. To calculate the gallons of diesel consumed by the genset I have used the genset specification sheet (Appendix B) and calculated how many gallons of diesel are used by the genset to serve the load.

Stakeholder Engagement and Regulatory Compliance

Stakeholder engagement is one of the most crucial steps in achieving a successful project. The HBFS No. 1 falls under the jurisdiction of City of Eureka. Hence all the finances and expenditures are covered by the City of Eureka. So, for implementing a microgrid project, engagement with officials of the city is of utmost importance. This will not only help them to assess and decide whether to go forward with the project, but it will also help them to get all the mandatory clearances associated with project.

During the site visit, I had the opportunity to engage with the Deputy Director of the City of Eureka's Building Division to discuss the responsibility for paying the energy bills on behalf of the fire station. This engagement with stakeholders is a crucial aspect of the microgrid project. It includes collaboration with HBFS No. 1 to understand their specific needs and requirements, as well as engagement with local government agencies for financing and navigating the local permitting and approval processes.

Furthermore, involvement with federal and state agencies is essential for accessing incentives like the ITC and SGIP respectively. Working closely with the utility company, PG&E, is vital for the interconnection process and receiving technical guidance. Additionally, partnership with the Redwood Coast Energy Authority (RCEA) provides valuable support and expertise in implementing the microgrid project effectively.

For the regulatory compliances as argued above, the microgrid installations has to follow certain rules and standards enforced by CEC, CPUC and PG&E which have been described in the microgrid standards section above. Apart from these standards, the HBFS No.1would require an engineering firm for project development so that the feasibility study is in accordance to receive the incentives, clean energy tax credits and smooth interconnection agreement.

Assumptions

I have established a number of assumptions when conducting the analysis to evaluate the technical and financial performance of the microgrid. As shown in Table 12 and Table 13, pertinent sources support these presumptions.

Technical suppositions were based on NREL Q1 2022 estimations, which offer trustworthy information for a Li-ion Battery Energy Storage System (BESS) in the context of a commercially co-located Photovoltaic (PV) and BESS microgrid. These estimations provide insightful information about the capabilities and traits of the selected technology. Furthermore, the System Advisory Model (SAM) default values were used to determine other inputs, including operation and maintenance (O&M) expenses and other default values. SAM is a well-known piece of software that incorporates several system factors and financial considerations to help in the appraisal of renewable energy projects.

The analysis made sure that the technical and financial components of the microgrid were evaluated on a solid and reliable foundation by relying on these well-known sources and making consistent assumptions. The validity of the study's conclusions is increased overall by this method, which also contributes to maintaining correctness and dependability throughout the research.

Table 12: Technical assumptions for solar PV and battery energy storage system

Parameters	Values	Source
PV system losses	14.1%	(Blair, et al., 2018)
BESS round trip efficiency	90%	(Ramasamy, et al., 2022)
BESS min and max state of charge	10% and 90%	(Ramasamy, et al., 2022)
DC to AC Ratio	1.10	(Blair, et al., 2018)
Li-ion BESS replacement	13 years	(NRECA, 2020)

For the economic performance of the microgrid, the assumptions are made for the financial model which apart from the CAPEX cost considers the following economic parameters to analyze the lifetime costs of the microgrid as shown in Table 13.

Table 13: Economic parameter central assumptions for the HBFS No. 1 microgrid.

Parameters	Values	Source
Annual discount rate	3%	(Kneifel & Lavappa, 2022)
Annual O&M charges	$20/kW for PV and $10/kWh for BESS	(Blair, et al., 2018)
Annual utility escalation rate	4%	(Wood, 2022)
Annual DC degradation	0.5%	(Blair, et al., 2018)
Analysis period	25 years	(Blair, et al., 2018)
Annual net surplus credit (NSC) escalation rate	3%	(PG&E , 2023)

RESULTS AND DISCUSSIONS

This section provides a detailed analysis of the findings obtained from the site visit carried out and the insightful discussions conducted with the HBFS No. 1 personnel. It encompasses a detailed overview of the suggested DERs for the HBFS No. 1, providing an in-depth analysis of the technical feasibility assessment outcomes, microgrid design, and the technical, economic, and environmental performance results.

Site Visit

To physically access the HBFS No. 1 site I have visited the site for once. During the site visit I had the opportunity to understand the priorities of the HBFS No. 1 personnel regarding the implementation of a clean energy based microgrid. It was evident from the conversation with Battalion Chief Nick Launius that they foremost wanted a resilient power system which could ensure uninterrupted power supply during business as usual and emergency scenarios. The other staff at the fire station also echoed the need of reliable power supply to support critical loads, which includes communication systems, medical equipment and other major equipment.

The fire station personnel are also aware of the Humboldt County emission goals and strictly abide by them. Also, during the visit, I was also told by the Fire Chief Sean Peterson about the energy efficiency upgrade study done by RCEA, which is also something good to consider for optimizing loads and moving towards electrification. The genset was one of the main concerns, as they face challenges to switch to it during emergency situations. I have also tried to understand their perspective towards microgrids and how it could serve them most effectively. I got to know their experience during the 2019 PSPS situation, which involved operational challenges. During the discussion with fire station personnel, it was also highlighted that the cost effectiveness and long-term savings are also significant considerations for going forward with the microgrid project. However, in the Portland Station No. 1 microgrid case, the utility cost savings were invested in critical system upgrades at the fire station facility, and this could be replicated at the HBFS No.1 ensuring better operational efficiency.

Overall, the discussion with the fire station personnel highlighted their interest and their commitment towards the ensuring the safety and well-being of the community they serve.

Microgrid Design

The microgrid design for the HBFS No. 1 incorporated specific methods to ensure reliable and sustainable energy supply. The following are the results for microgrid design:

PV and BESS Placement and Sizing

The sizing and placement of PV and BESS components in the microgrid design project is very crucial. As per observations during the site visit, I selected the roof area of the HBFS No.1 facility to place the solar PV panels, while the BESS would be placed near the genset area.

The sizing of the PV, as explained in the methods section, was determined based on two key factors: 1), the goal was to design a PV system that would enable HBFS No. 1 facility to achieve net-zero energy consumption. By utilizing the PVWatts calculator, a desired size of 70 kW for the PV system was obtained. 2): constraints such as the available roof area were taken into consideration to validate the feasibility of installing a 70 kW PV system within the given constraints, Helioscope software (as shown in Figure 28) was utilized. The analysis confirmed that the proposed PV system size could indeed be accommodated effectively. By considering both the net-zero energy objective and the physical limitations of the facility, the sizing of the PV system was carefully determined. This approach ensures that the PV system is appropriately sized to meet the energy requirements of HBFS No. 1 while working within the given constraints.

For BESS sizing, I wanted a to provide the HBFS No. 1 facility at least 1 day of autonomy as per a discussion with the Battalion Chief (HBFS No. 1). As a result, I selected a 90 kW BESS which is almost three times the peak load (31.3 kW) of HBFS No. 1 facility, to enable safe and reliable operation of equipment within the boundaries of the microgrid. The battery capacity was selected for 4-hour duration. This will provide more resiliency than a 2-hour duration BESS (comparison shown in results) while still capturing the SGIP incentive to offset 100% of the BESS cost. For the placement of the 90 kW/360 kWh BESS, the HBFS No. 1 facility would need to provide a space of 70 square feet as per the battery cabinet specification (Symtech Solar, 2022). There is sufficient space near the genset.

The recommended sizes of the PV and the BESS is shown in the Table 14 below.

Table 14: Recommended PV and BESS size for the HBFS No. 1 facility.

Distributed Energy Resource	**Size**
Solar PV	70 kW
Battery Energy Storage System (BESS)	90 kW/360 kWh

Hence all these parameters have been used in the study to analyze what are potential benefits of the proposed microgrid design which is further explained in the following sections.

ICA Map Results

As shown in Figure 26 in the technical feasibility section of the Methods section demonstrates that the PG&E feeder (Eureka E 1105) serving HBFS No. 1 has a PV generic hosting capacity of 430 kW (maximum) without requiring any upgrades. Therefore, the estimated PV system size of around 70 kW can be safely integrated into the PG&E circuit. This indicates that the proposed PV system falls within the feasible capacity limits of the existing infrastructure.

Proposed SLD for HBFS No. 1

As shown in Figure 31, the proposed SLD for the fire station could be observed. In “Blue Sky” mode, the BESS and PV system will synchronize with the grid and follow grid-tied use cases such as time-of-use (TOU) and demand level management.

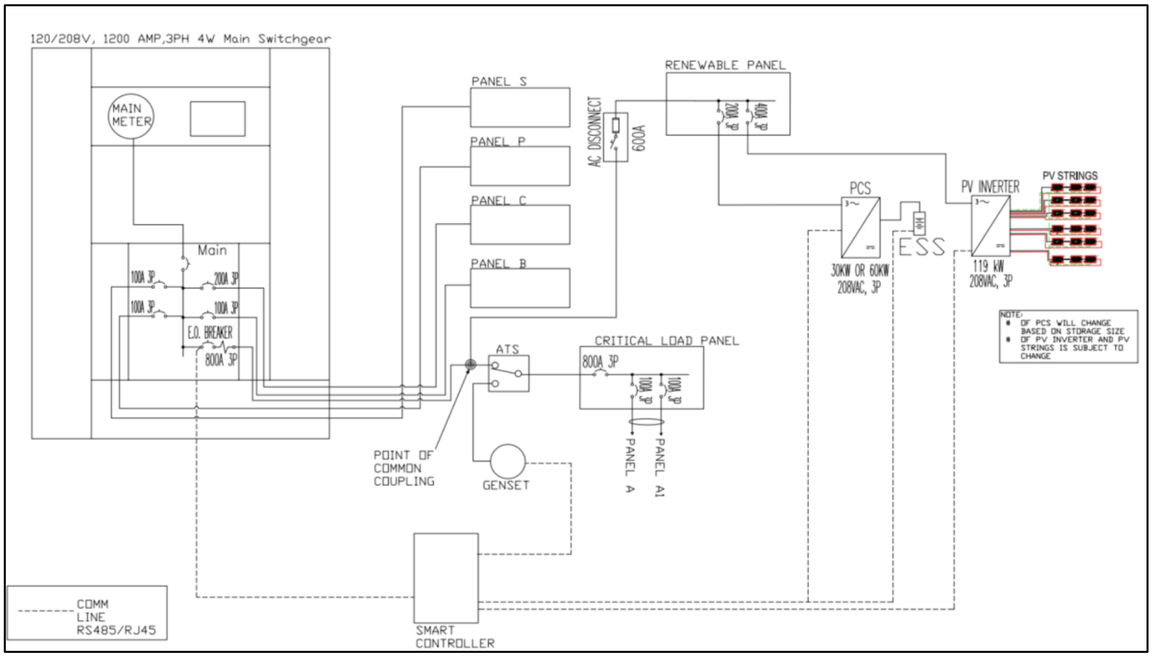


Figure 31: Proposed single line diagram for HBFS No. 1 after installation of microgrid, showing the main and sub-panels, smart controller, automatic transfer switch (ATS), solar PV, BESS, and point of common coupling (POCC).

In islanded mode, the controller will detect a utility power outage and open the electrically operated (EO) breaker. The BESS and PV system will disconnect from the utility, and the BESS inverter will be set to grid-forming mode. The critical load connected to Panel A, and Panel A1 will receive power from the BESS and PV system after a five-minute delay as per Rule-21. When the BESS is depleted, the automatic transfer switch (ATS) will switch to the generator, and the critical load panel will receive power from the generator. When the utility power is restored, the ATS will switch to normal mode, and the critical load panel will receive power from the utility after the EO breaker is closed. If the critical load panel is already receiving power from the BESS and

PV system when utility power is restored, the controller will first idle the BESS power conversion system (PCS) and set it to grid-following mode from grid-forming mode. Once the BESS PCS is set to grid-following, the smart controller will close the EO breaker. The smart controller will also control the auto-start feature of the generator to avoid false starts during each transition between grid-connected and off-grid modes.

Technical Performance Results

The technical performance evaluates microgrid's effectiveness and efficiency in meeting the energy demands of the system for the HBFS No. 1 facility. This section presents an overview of the technical performance results obtained from the analysis of the microgrid. The performance metrics considered include the state of charge (SOC) of the battery energy storage system (BESS), PV generation, load characteristics, and system resiliency.

Blue-Sky Mode Simulation Results

The microgrid simulation model was utilized to evaluate the performance of the 70 kW PV system and 90 kW Battery Energy Storage System (BESS) with a 4-hour duration in the "Blue-Sky Mode". As shown in Figure 32, below, we can observe key parameters such as the peak demand in the off-peak, super-off peak, peak, and part-peak time of use periods the values were around 30 kW, 29 kW, 32 kW and 30 kW, respectively, whereas the average load was estimated to be about 12kW. Furthermore, the average daily PV generation was determined to be around 12 kW for a 24-hour period, with a maximum PV generation of approximately 42 kW. It is worth noting that the peak demand occurred at 7:00 PM in the month of January, and the BESS, with a state of charge of around 79%, effectively managed this demand. Additionally, the average daily PV exports to the grid was estimated approximately around 7 kW.

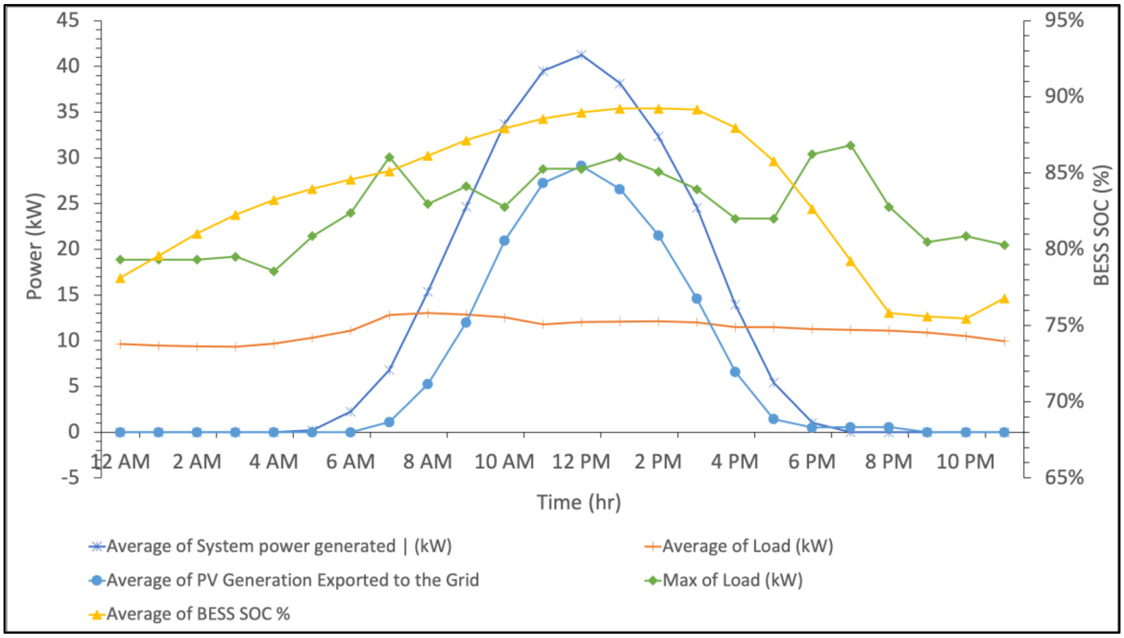


Figure 32: Overall typical performance of the HBFS No. 1 microgrid for a year in "Blue-Sky" mode showing various technical parameters such as peak load, PV generation, excess PV curtailment exports to the grid, average of BESS state of charge and average load.

As shown in Table 15, the microgrid successfully optimizes the grid demand and showcases the reduction in grid dependency. The off-peak period shows an increase of 19% in energy consumption with the microgrid, reaching 50,000 kWh annually. In the part-peak period, where solar generation is limited, the microgrid significantly reduces energy consumption from 12,800 kWh without the microgrid to 4,700 kWh with the microgrid, resulting in around 65% decrease.

Table 15: Energy and peak load optimization with and without microgrid (MG) scenario.

Time of Use	**Maximum Demand without MG (kW)**	**Maximum Demand with MG (kW)**	**Total energy procurement from the grid without MG (kWh)**	**Total energy procurement from the grid with MG (kWh)**
Off-Peak	30	15	42,000	50,000
Super-Off Peak	30	15	22,400	4,200
Peak	32	0	20,600	0
Part Peak	28	10	12,800	4,700

During the peak period, the microgrid efficiently meets the load requirements, resulting in almost zero energy consumption. In the super off-peak period, characterized by cheaper electricity, the microgrid consumes only around 5,000 kWh. This is attributed to the solar generation being sufficient to charge the battery and power the loads, particularly during the summer months, and occasionally in the winter months. In contrast, without the microgrid, the facility consumed around 22,400 kWh in the super-off-peak period under the business-as-usual case whereas with microgrid it is optimized to around 4,200 kWh.

The net electricity exports to the grid were calculated around 18,000 kWh, which is around 18% of the total electric load for the HBFS No. 1 facility. This significant net export of energy is not only beneficial for the grid but also brings financial incentives. PG&E provides net surplus credit rates, allowing the facility to receive credits for the surplus energy exported.

Islanding Mode Simulation Results

The microgrid simulation was employed to investigate the performance of a 70 kW PV system and a 90 kW/360 kWh BESS during islanded or grid-disconnected operation. Two case scenarios were analyzed: the "best case scenario" and “the worst case”. In the "best case scenario," the month with the maximum solar generation across the year was selected, and the specific point where the solar PV generation plus load resulted in the greatest surplus energy was examined. Similarly, the “worst-case scenario” was examined selecting the month when the solar PV generation was minimum across the year and the specific interval when the solar PV generation plus load depicted the maximum deficit.

The graph in Figure 33 presented below depicts the "best case resilience period" observed on June 26th at 12:00 PM. During this event, the Battery Energy Storage System (BESS) state of charge (SOC) at the time of the outage was estimated to be approximately 90%. Additionally, there was an excess of around 54 kW in solar PV generation.

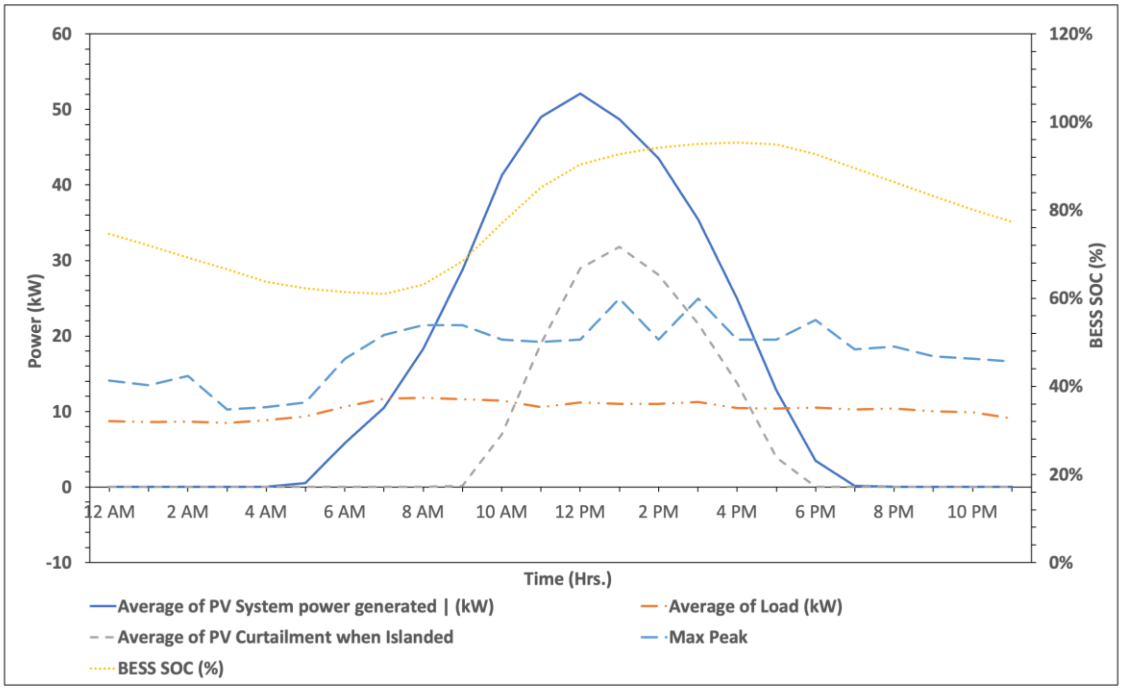


Figure 33: Microgrid performance for the HBFS No. 1 facility for the best-case scenario in islanded mode showing the average trends over the course of a 52-day period of continuous resilience.

With an average load of around 10.2 kW and a peak load of 25 kW, the average BESS SOC was shown to be 79% over a long duration island event. The microgrid exhibited 52 days of resilience during this timeframe, meaning that it would be possible to run continuously without the need for a backup generator during that time. The typical peak load was observed during the day time around 1:00 PM which was easily managed by the solar PV generation. The average load in this time period was observed to be around 10 kW. The average PV curtailment was estimated by calculating the surplus energy from solar PV after serving the load and charging the BESS to maximum SOC was estimated around 6 kW due to excessive PV generation during summer months (June 23rd to August 15th).

For the worst-case resilience scenario as shown in Figure 34, I have selected the time frame with the minimum solar generation and a deficit compared to the load. The interval starts from Dec 27th 7 PM and ends at Dec 28th 11 PM. As shown in Fig 18, the total PV generation was estimated to be only 112 kWh, and the average and peak loads were 11 kW and 21 kW, respectively. The BESS SOC when the hypothetical outage occurred was 73%, and the total energy demand for the specific time frame was around 330 kWh. The battery reaches the minimum allowable SOC of 10% on Dec 28th at10 PM. The whole performance of the microgrid provided a resiliency of 28 hours.

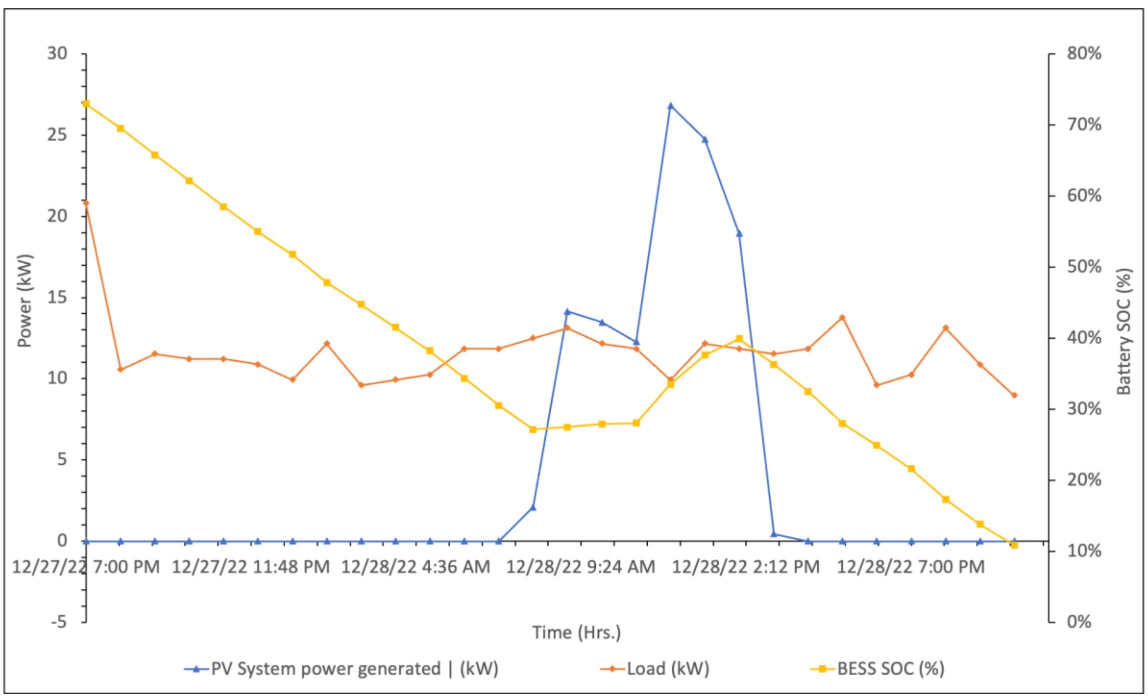


Figure 34: Microgrid performance for the worst-case scenario at HBFS No. 1 facility in islanded mode showing a resiliency for around 28 hours.

The primary drivers of the performance of the microgrid in the best and worst case are the size of the PV solar system, BESS and the solar radiation availability. However, the reason of selecting larger size battery is to have resiliency at the time of outages, especially for a critical facility which cannot afford business interruption due to power outages. However, I have also carried out a sensitivity analysis by reducing the size of the PV system and the BESS to understand the impacts on resiliency of the proposed microgrid system (described in a later section). Based on the results obtained from the previous section, it is evident that the microgrid is effectively meeting the needs of the fire station. The "best case scenario" analysis revealed that during the outage on June 26th at 12:00 PM, the microgrid was able to provide a resiliency of 52 days whereas in the worst-case scenario the microgrid was able to provide a resiliency of 28 hours, which is around 1 day. This indicates that the microgrid was capable of providing a significant amount of energy to power the fire station's critical loads without the need for backup generators, but in a worst-case scenario if the outage is more than 28 hours the generator needs to be used in combination with load shedding.

The availability of stored energy in the BESS, coupled with the continuous solar PV generation, allows the microgrid to operate autonomously for an extended period without relying on the backup generator in most months.

Economic Performance Results

As discussed in the methodology section, the key metrics to identify the economic feasibility of a project used in this study are NPV, LCOE, BCR and payback period. The economic performance results are based on the CAPEX cost of the microgrid system, which includes various components and installation labor charges.

The economic performance of the microgrid system was assessed by considering various cost components. The total capital expenditure (CAPEX) for implementing the microgrid was estimated to be approximately $575,000, excluding the Investment Tax Credit (ITC). This CAPEX includes the costs associated with the solar PV system, battery energy storage system (BESS), control system, and installation expenses. In addition to the initial CAPEX, the replacement cost of the BESS was taken into account, amounting to approximately $68,000. This cost reflects the need to replace the BESS after its expected lifespan. A fixed operation and maintenance (O&M) cost of around $5,000 per year was calculated using the fixed O&M costs for PV and BESS as shown in Table 13 to cover routine maintenance and monitoring of the microgrid components (Blair, et al., 2018).

To incentivize the adoption of the microgrid, the project could receive approximately $200,000 in incentives through the Self-Generation Incentive Program (SGIP) over a five-year period. These incentives provided financial support to offset around 100% of the upfront costs of the battery storage system and improved the economic viability of the microgrid project. Furthermore, the implementation of the microgrid system could also the HBFS No.1 facility in utility cost savings. These savings are estimated to be around $12,000 per year, reflecting the reduced reliance on grid electricity and the ability of the microgrid to generate and store renewable energy. The net surplus credits by exporting excess PV generation to the grid was estimated to be around $1,600 annually. By considering the CAPEX, BESS replacement cost, O&M expenses, SGIP incentives, utility cost savings and net surplus credits, a comprehensive assessment of the economic performance of the microgrid was conducted. These factors collectively contribute to the overall financial viability and attractiveness of the microgrid system for the fire station.

The economic evaluation results of the microgrid system without considering the investment tax credit (ITC) credits are as follows:

The estimated levelized cost of energy (LCOE) for the microgrid was estimated approximately around $0.434/kWh as shown in Table 16. However, it is important to note that relying solely on LCOE may not fully capture the value that energy storage brings to the microgrid (Denholm, Eichman, & Margolis, 2017). Therefore, the benefit/cost ratio (BCR) was also analyzed as a substitute metric that takes the added value of storage into account.

Table 16: Financial metrics results for the HBFS No. 1 microgrid project without income tax credit (ITC).

Financial Metrics	**Value**
LCOE	$0.434
BCR	0.77
NPV	-$163,000
Simple payback period	Not applicable
Discounted payback period	Not applicable

The BCR for the project, without ITC credits, was estimated to be 0.77 which shows the costs are more than the benefits of the project. Additionally, the NPV for the microgrid system over a 25-year lifetime period was estimated to be around -$163,000. which shows that the project is not paying back within the analysis period. This was primarily due to the higher capital expenditure (CAPEX) cost of the microgrid system and the phased nature of the incentives received through the SGIP program.

The cash flow chart for no ITC credit as shown in Figure 35 shows the annual cash flow for the HBFS No. 1 microgrid project. The average discounted benefits were estimated to be around $22,000 annually whereas the average discounted SGIP incentives received from the year 1 to year 5 was estimated around $40,000 annually. I have also considered BESS replacement at the year 13. However, the project without the support by federal clean energy tax credit (ITC) is not feasible for the fire station as the CAPEX cost is high. For this I have also considered the various ITC rebates under the Inflation Reduction Act (IRA) available for the HBFS No. 1 to analyze the project economic feasibility.

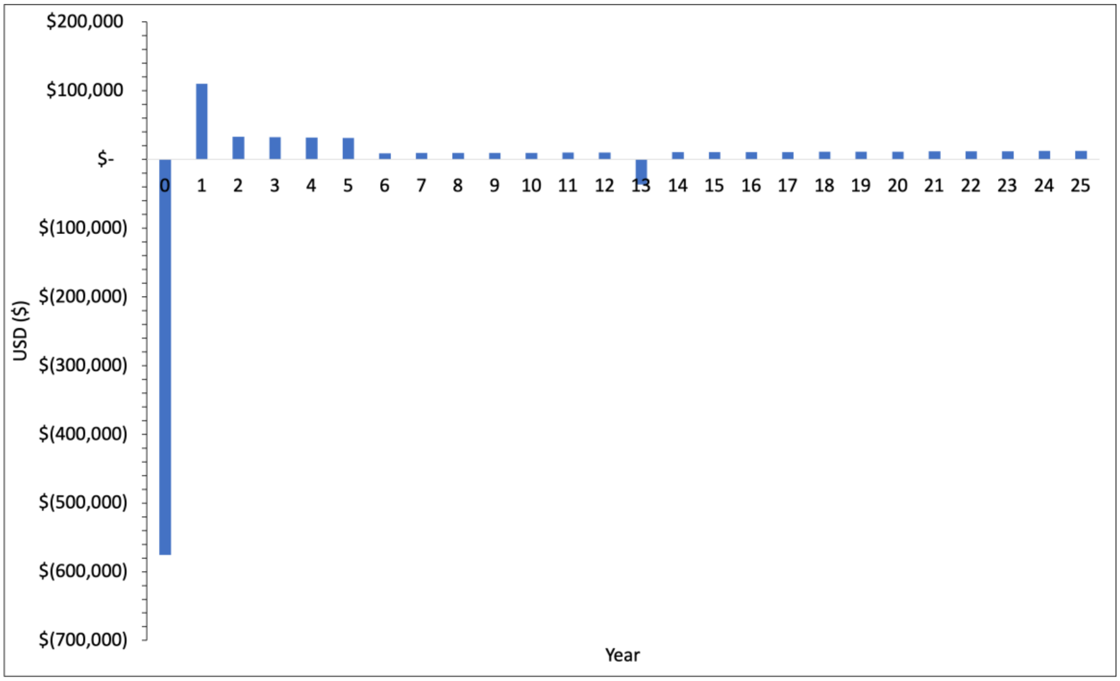


Figure 35: Discounted cash flow for the HBFS No. 1 microgrid project with a discount rate of 3% for an analysis period of 25 years including SGIP incentives and the BESS replacement at year 13.

GHG Emission Reduction

The HBFS No. 1 relies on PG&E's and RCEA's conventional power system to fulfill its electrical energy needs, consuming approximately 98 MWh annually. However, once after implementing the microgrid system, based on the assumptions of the spreadsheet model, consumption of grid electricity by the HBFS No. 1 facility would be significantly reduced to approximately 59 MWh, representing a substantial 40% decrease in grid energy usage. This demonstrates the effective reduction in the grid demand achieved through microgrid deployment. optimization and energy management achieved through the microgrid deployment which uses the combination of solar PV generation and peak shaving through the BESS.

I determined the overall net demand for the HBFS No. 1 facility over the course of a year to be approximately 2000 kWh, taking into account both exports and imports to/from the grid. By multiplying this overall net demand by the GHG emission intensity of 0.615 lbs. CO_2e/kWh, I estimated that the facility's GHG emissions could be reduced to 1200 lbs. This reduction in emissions represents a significant improvement, especially when compared to the baseline case scenario, which is estimated to produce around 60,000 lbs of GHG emissions. Therefore, the HBFS No. 1 facility has the potential to decrease its carbon footprint related to electricity by more than 98%, showcasing a remarkable achievement in terms of GHG emission reduction.

Similarly, to survive an outage of 28 hours which is the resiliency identified in the worst-case scenario, using the generator specification sheet (shown in Appendix B) the genset would have consumed around 90 gallons of diesel fuel, emitting around 2,000 lbs. of GHG emissions. So, an additional 2000 lbs. of GHG emission could be avoided annually if there are yearly outages totaling 28-hour in length.

Sensitivity Analysis

Since the analysis depends on several assumptions, I have performed some sensitivity analysis on the project to understand and show how the technical as well as the economic performance of the microgrid changes with changes in the size of the PV array, the size of the BESS, and economic assumptions, respectively. The performed sensitivity analyses are as follows:

Variation in PV and BESS size

As I have sized the system of 70 kW PV and 90 kW/360 kWh BESS (base case), it was imperative to resize the PV array and BESS to understand how much resiliency and other parameters are impacted by increasing or decreasing the size of the PV and the BESS while in islanded state.

As shown in Table 17, in the 70 kW PV and 45 kW 180 kWh BESS system, the average state of charge (SOC) of the battery energy storage system (BESS) throughout the year was approximately 75%, with a minimum SOC of 10% observed in January. In the "best-case" scenario, as shown in the Figure 36, the system exhibited an average SOC of around 65%, with an average load of 10 kW. The PV generation averaged around 20 kW, and the peak load also reached approximately 20 kW. Additionally, reducing the BESS size by half resulted in a reduction of system resiliency to 138 hours or around 6 days.

Table 17: Sensitivity results of changing the PV and BESS size.

Sensitivity No.	**PV Size (kW)**	**BESS Size (kW/kWh)**	**Resiliency (Best Case) (Hrs.)**	**Resiliency (Worst Case) (Hrs.)**	**CAPEX Cost ($)**	**Utility Bill Savings/Year ($)**
(Base Case)	70	90/360	1263	28	575,000	12,000
1.	70	45/180	138	6	464,000	11,000
2.	35	90/360	260	22	493,000	10,000
3.	35	45/180	42	5	380,000	10,000

Whereas, in the "worst case" scenario depicted in Figure 37, the average state of charge (SOC) of the battery energy storage system (BESS) dropped to approximately 28%, while the average load was estimated at around 13 kW. PV generation was minimal at almost 0 kW, and the peak load reached around 21 kW. In this scenario, the system could only survive an outage for 5 hours, representing a significant reduction in resiliency compared to the base case of the 70 kW PV and 90 kW/360 kWh BESS system, where the system's resiliency decreased by over 80% to just 4 hours. The microgrid manages the utility bills and lowers it by almost by 50%.

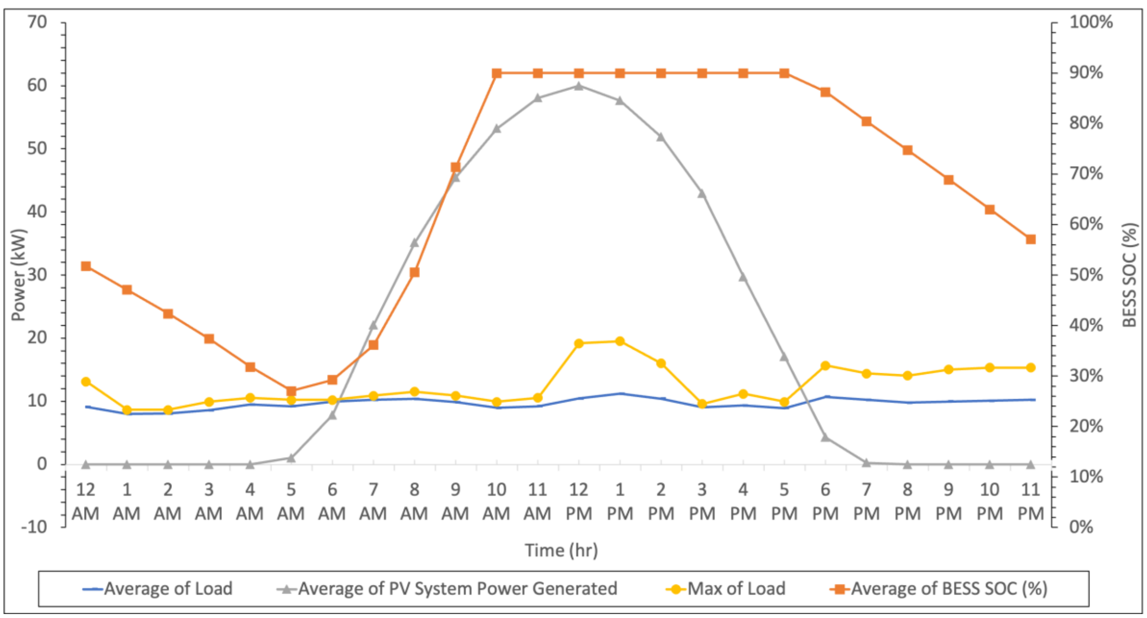


Figure 36: HBFS No. 1 microgrid performance for 70 kW PV and 45 kW and 180 kWh BESS for islanding operation in best case scenario for around 6 days.

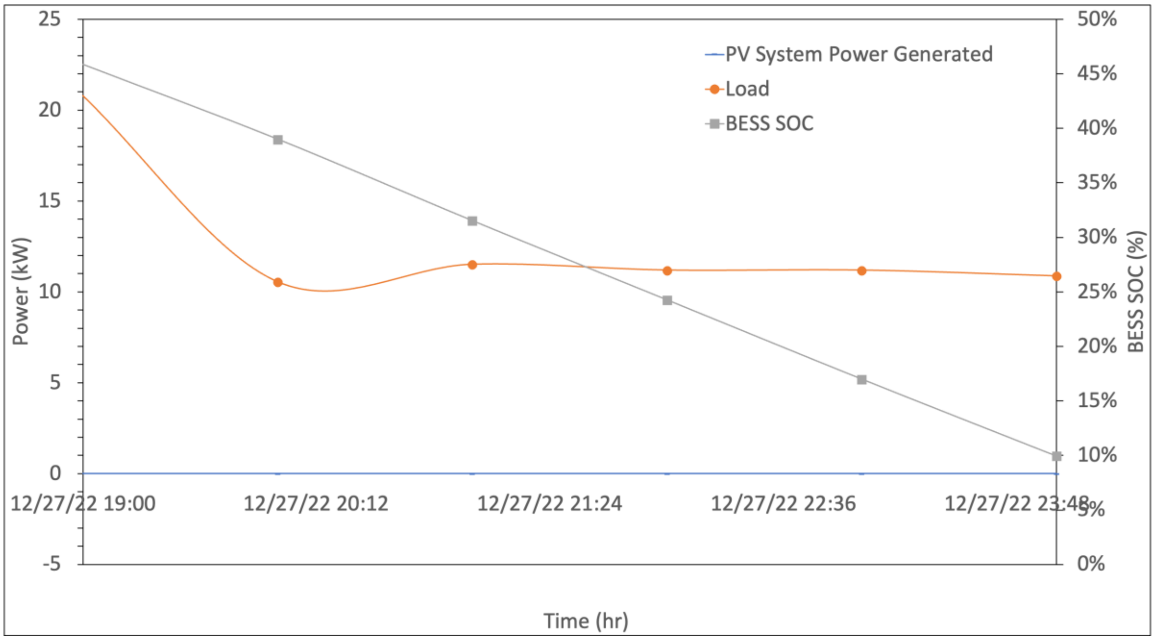


Figure 37: HBFS No. 1 microgrid performance for 70 kW PV and 45 kW and 180 kWh BESS for islanding operation in worst case scenario for 6 hours.

The 35 kW PV system combined with the 90 kW/360 kWh BESS resulted in an average battery state of charge (SOC) of 85%. In the best-case scenario (Figure 38), the BESS SOC averaged around 68% with an average load of 10 kW and a peak load of 20 kW. The system provided a resiliency of 10 days, approximately 20% of the base case. In the worst-case scenario (Figure 39), the average BESS SOC was 65%, with an average load of 12 kW and a peak load of 21 kW. The microgrid's resiliency in this scenario was 23 hours (around 1 day), and the total PV generation was 58 kWh. The larger BESS size helped maintain better performance, as the resiliency decreased by only 15% compared to the base case. The energy bill savings with this system is around $10,000 per year.

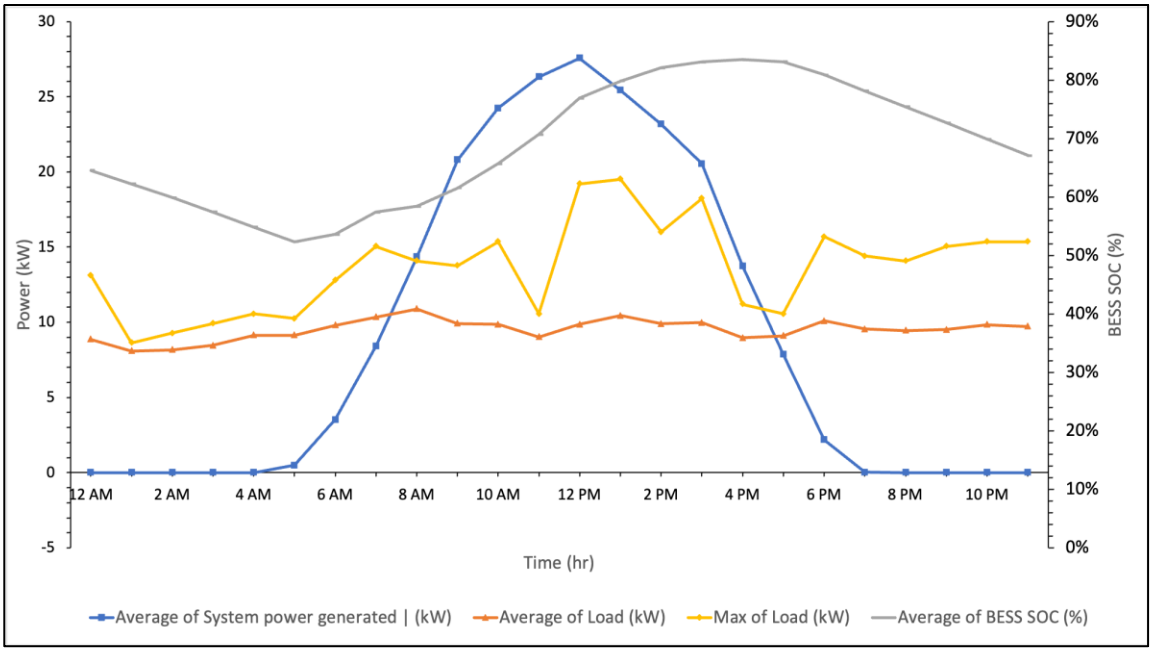


Figure 38: HBFS No. 1 microgrid performance for 35 kW PV and 90 kW and 360 kWh BESS for islanding operation in best case scenario for a period of 11 days.

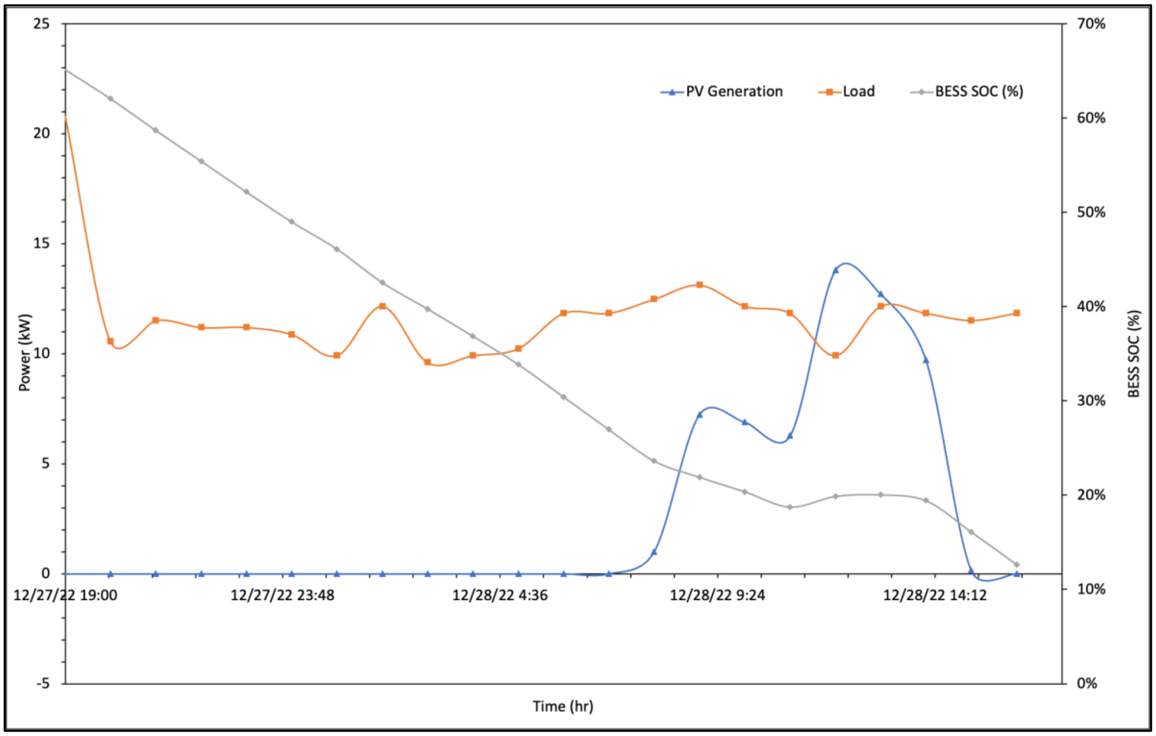


Figure 39: HBFS No. 1 microgrid performance for 35 kW PV and 90 kW and 360 kWh BESS for islanding operation in worst case scenario for 22 hours.

With the 35 kW PV and 45 kW/180 kWh BESS system, the average BESS state of charge (SOC) was approximately 75%, with a minimum SOC of 10%. In the best-case scenario (Figure 40), the average BESS SOC was 58%, with a peak load of 20 kW and an average load of 10 kW. The average PV generation was 10 kWh, and the system's resiliency was reduced to 138 hours (around 6 days). In the worst-case scenario (Figure 41), the average BESS SOC was 25% of the original capacity, with an initial SOC of 40% at the time of outage. However, the resiliency was reduced by approximately 80%, around 4 hours, compared to the base case. There was no PV generation at this time frame. The energy bill saving with the 35 kW PV and 45 kW/180 kWh system is also same as that of 35 kW PV and 90 kW/ 360 kWh system this is because the peak demand charge savings are done by even smaller size of PV and battery also.

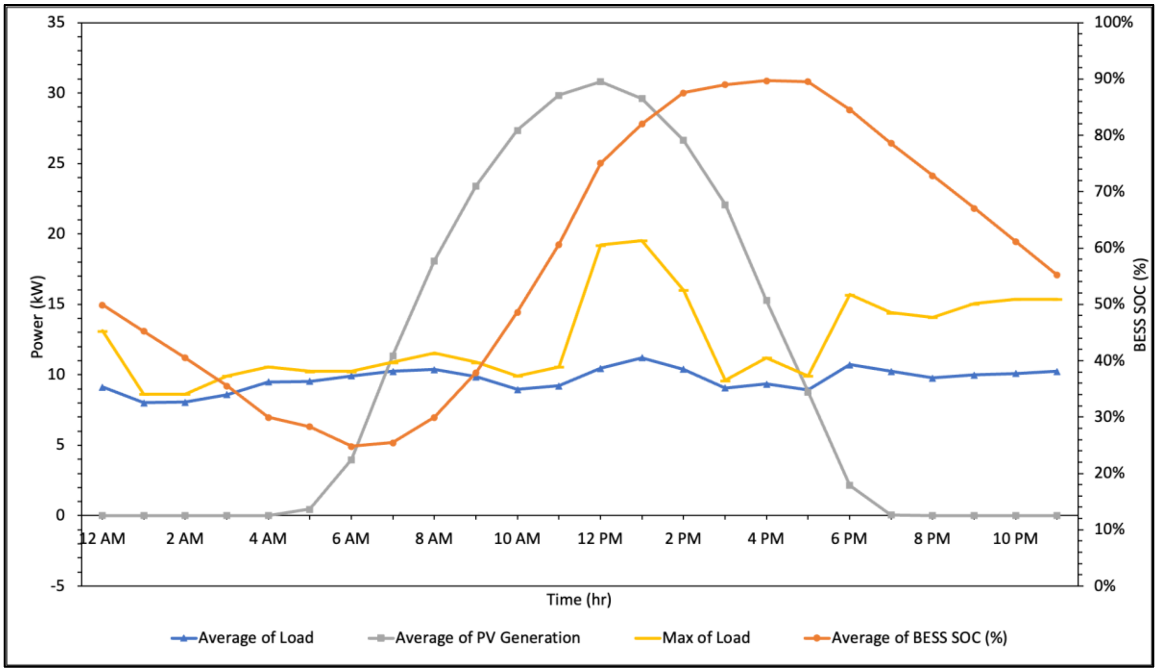


Figure 40: HBFS No. 1 microgrid performance for 35 kW PV and 45 kW and 180 kWh BESS for islanding operation in best case scenario for 42 hours.

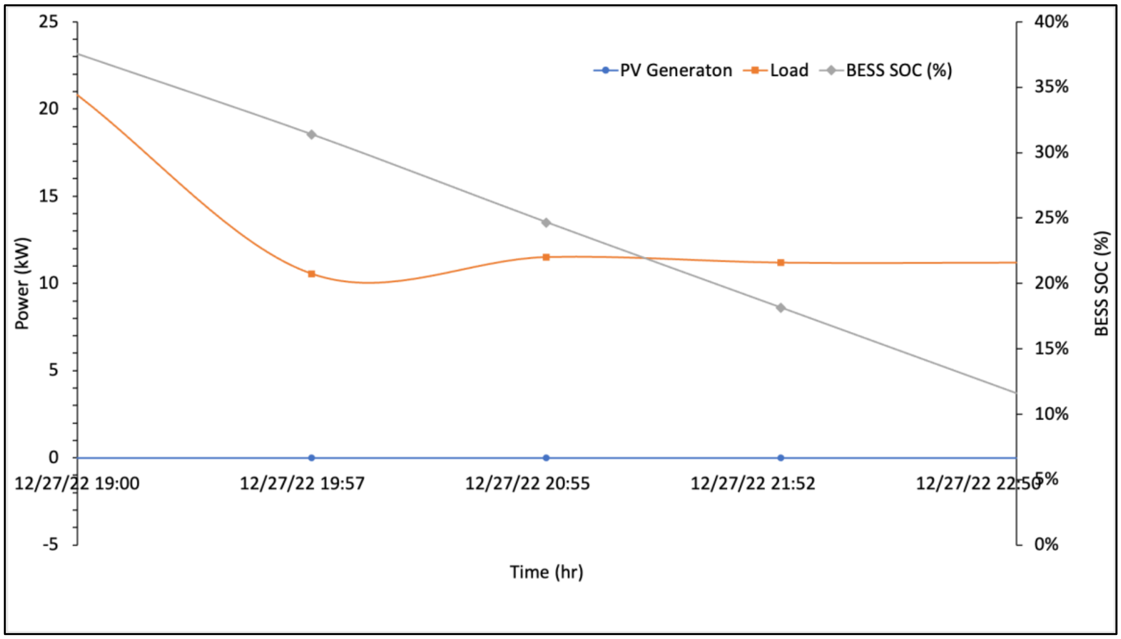


Figure 41: HBFS No. 1 microgrid No. 1 performance for 35 kW PV and 45 kW and 180 kWh BESS for islanding operation in worst case scenario for 5 hours.

Change in Tariff Structure

The electricity bill savings were one of the most important parameters in the project economics, and they could contribute substantially to the lifetime savings. I have considered B-19 TOU for the energy bill calculation, which has shown around 50% reduction in the utility costs. At the same time, it was also imperative to understand that once the fire station facility becomes a qualified solar customer whether the B-19 option R tariff structure is an optimal rate or not. So, I have performed a sensitivity analysis which suggests that the HBFS No. 1 can save around $200 in demand charges annually, but the energy charges increase by $1000 per year, resulting in a reduction of around 43% in utility costs as compared to the business-as-usual case. So, while the B-19 TOU is the best option as of now, once the total load of the facility increases, considering B-19 R would be a good option for HBFS No. 1 to consider. The comparison of monthly energy bills for the fire station with and without microgrid (MG) and MG with B-19 and B-19 option R are shown in Figure 42.

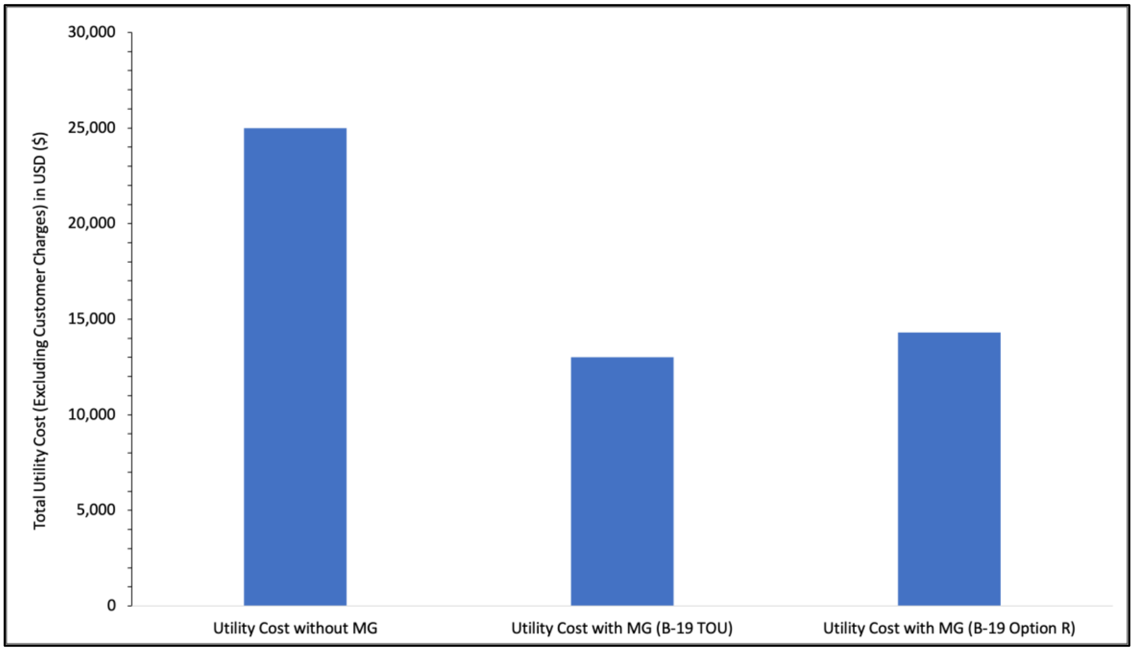


Figure 42: Results of the utility cost savings with and without microgrid with electricity rate B-19 TOU and B-19 option R of PG&E.

Considering different ITC rebates

The sensitivity analysis of the fire station's microgrid project includes varying ITC rebates from 30% to 50% based on the low-income community bonus (10%) and domestic content bonus (10%) (U.S DOE, 2022). The CAPEX costs for different ITC rates were approximately $575,000 (base case), $400,000 (30% ITC), $327,000 (40% ITC) and $267,000 (50% ITC).

In the Table 18 we can observe that the ITC rates has a substantial impact on the levelized cost of energy (LCOE) and NPV. For every 10% increment in the ITC the LCOE reduction is around 10% and approximately 30% increase in NPV. The ITC is a critically important factor for improving overall project economics, and switching from negative NPV and unfavorable BCR into positive investments.

Table 18: Results of the various financial metric for base case and different investment tax credit (ITC) rates.

ITC Rate (%)	**CAPEX Cost ($)**	**LCOE ($/kWh)**	**NPV ($)**	**BCR**	**Simple Payback Period (Years)**
Base Case	575,000	0.43	-163,000	0.77	Not applicable
30%	400,000	0.33	-52,000	0.90	Not applicable
40%	327,000	0.29	-8,000	0.98	Not applicable
50%	267,000	0.25	31,000	1.08	19

It is important to acknowledge that if the customer receives ITC on the BESS cost, the Self-Generation Incentive Program (SGIP) incentive will be calculated based on the final BESS capital expenditure (CAPEX) cost after deducting the ITC (CPUC, 2021). However, in the financial analysis conducted, it was observed that excluding the ITC from BESS capital cost had minimal impact on project economics assessing the full benefits derived from the SGIP.

Variation in Discount Rates

In order to consider potential changes in the local economy, such as inflation or deflation, I have included a range of -25% (from 3% to 2.25%) and +25% (from 3% to 3.75%) from the initial discount rate of 3% for the base case scenario (Hau, et al., 2018). Additionally, a discount rate of 6.1% was employed in the sensitivity study, based on

NREL Q1 2022 assumptions, as noted by Ramasamy et al. (2022). The variation in discount rates reflects the sensitivity analysis, allowing for a comprehensive assessment of the project under different economic conditions.

In the base case scenario as shown in Table 19, by decreasing the discount rate by 25%, the NPV increases by $25,000, whereas increasing the discount rate by 25% decreases the NPV by $21,000 as compared to the base discount rate of 3%. A discount rate of 6.1% decreases the NPV by almost $71,000 compared to the base case. Wherein by decreasing the discount rate by 25% the BCR value increase by 5% and increasing the discount rate by 25% decreases the BCR by 5% as compared to the base discount rate of 3%, but with a 6.1% discount rate the BCR is decreased by 18% as compared to the base case. In all case scenarios the project has a discounted payback period of more than 25 years and hence not applicable for the financial viability of the project.

Table 19: Results of impact of discount rate variations on various financial parameters for base case scenario.

Discount Rate (%)	**NPV ($)**	**BCR**	**LCOE ($/kWh)**	**Discounted Payback Period (Years)**
Base Case (3%)	-163,000	0.77	0.434	Not applicable
2.25%	-138,000	0.81	0.408	Not applicable
3.25%	-184,000	0.73	0.462	Not applicable
6.1%	-234,000	0.63	0.555	Not applicable

For the 30% ITC case shown in Table 20, applying similar methodology of decreasing and increasing the discount rate by 25% the BCR values are 0.95 and 0.86 which is a mere 4% change as compared to the base case. The NPV even with 30% ITC is negative and the payback period is also not a feasible option.

Table 20: Results of impact of discount rate variations on various financial parameters for 30% ITC scenario.

Discount Rate (%)	**NPV ($)**	**BCR**	**LCOE ($/kWh)**	**Discounted Payback Period (Years)**
Base Case (3%)	-52,000	0.90	0.333	Not applicable
2.25%	-28,000	0.95	0.316	Not applicable
3.75%	-73,000	0.86	0.353	Not applicable
6.1%	-123,000	0.74	0.417	Not applicable

As shown in Table 21, the project economics by decreasing the discount rate substantially improves which is the BCR values with 2.25% discount rate is greater than 1 and yields a positive NPV of $15,000. Also, the payback is still high but within the lifetime period.

Table 21: Results of impact of discount rate variations on various financial parameters for 40% ITC scenario.

Discount Rate (%)	**NPV ($)**	**BCR**	**LCOE ($/kWh)**	**Discounted Payback Period (Years)**
Base Case (3%)	-8,000	0.98	0.289	Not applicable
2.25%	15,000	1.03	0.269	24
3.75%	-28,000	0.94	0.297	Not applicable
6.1%	-75,000	0.81	0.356	Not applicable

In 50% ITC rate the project yields positive results in all the case scenarios except with the discount rate of 6.1% is shown in Table 22. The BCR values increases to 1.13 by reducing the base discount rate by 25%, whereas, by increasing the base discount rate by 25% the BCR decreases to 1.03. In both cases mentioned, the NPV is positive and shows promising results for project financial viability. The discount rate of 6.1% with 50% ITC doesn't show positive results for project economics as the BCR is less than 1, the NPV is negative and the payback period is more than the project lifetime of 25 year.

Table 22: Results of impact of discount rate variations on various financial parameters for 50% ITC scenario.

Discount Rate (%)	**NPV ($)**	**BCR**	**LCOE ($/kWh)**	**Discounted Payback Period (Years)**
Base Case (3%)	31,000	1.07	0.253	23
2.25%	54,000	1.13	0.239	22
3.75%	11,000	1.03	0.269	24
6.1%	-36,000	0.90	0.307	Not applicable

Furthermore, the overall BCR for all the case scenarios with 50% ITC is expected to be above 1except with a discount rate of 6.1%, indicating that the benefits will outweigh the costs. This will further support the decision to pursue the project. Taken together, the financial analysis will demonstrate positive outcomes and underscore the potential viability and desirability of moving forward with the project.

Impact of Value of Resiliency (VoR) on NPV and BCR

Two trustworthy sources were used to evaluate the value of lost load: the ICE calculator from LBNL and the NREL study, which both found the value to be about $100/kWh (Anderson, et al., 2018). I have used Equation 1 from the literature review part to determine the Value of Resiliency (VoR). The critical load in this computation was established as 30% of the average total load during the worst-case scenario outage. I have calculated the outage length to be 24 hours broadly because of two reasons: first, as argued in the NREL report, it would not be appropriate to calculate the VoR for more than 24 hours (Anderson, et al., 2018), and, second, considering the most recent seismic outage in December 2022 which led to an outage of around 20 hours or more for many customers in the Humboldt County.

The VoR was projected to be around $11,000 annually using those methods and assumptions (similar in scale to utility cost savings). It is important to note here that the existing backup generator is also able to provide this value in most cases. However, incorporating the value of resiliency (VoR) into the study and taking into account the change in investment tax credit (ITC) rates as shown in Table 23 resulted in a significant increase in net present value (NPV) for various scenarios as compared to not taking the value of resilience into account. In the base case scenario, incorporating the value of resilience (VoR) in the analysis resulted in a significant increase in the Net Present Value (NPV).

Table 23: Results of the impact of value of resiliency (VoR) on net present value (NPV) and benefit cost ratio (BCR).

ITC Rate (%)	**NPV with VoR ($)**	**NPV without VoR ($)**	**BCR with VoR**	**BCR without VoR**	**SPB Period with VoR (years)**	**SPB Period without VoR (years)**
Base Case	$20,000	-163,000	1.02	0.77	19	Not applicable
30%	$130,000	-53,000	1.24	0.90	14	Not applicable
40%	$180,000	-8,000	1.37	0.98	14	Not applicable
50%	$220,000	31,500	1.52	1.08	13	19

When considering a 30% Investment Tax Credit (ITC), the NPV with VoR showed an increase of 34% compared to the NPV without VoR. Furthermore, when comparing the NPV with VoR and a 30% ITC to the NPV without VoR, the increase was even more substantial, reaching 120%. The BCR on the other hand, witnesses an increase of 32% in the base case with a VoR as compared to BCR without the VoR. Similarly for 30%, 40% and 50% ITC values with the VoR, there are increase of 37%, 39% and 40% respectively.

Since the Value of Resiliency (VoR) is a theoretical value that estimates the cost of energy unserved and societal impacts, it is highly encouraged for critical facilities such as HBFS No. 1 to conduct a comprehensive analysis that incorporates VoR into their decision-making process. This would provide a more accurate assessment of the benefits which are more than just project economics.

Variation in CAPEX cost

In this study, it is important to acknowledge that the CAPEX cost estimates are subject to uncertainties and assumptions. There is a possibility of a potential increase (+25%) in the CAPEX cost beyond the estimated value due to unexpected cost escalation factors. Conversely, there is also the potential for a significant decrease of up to 25% in the CAPEX cost, driven by future advancements in technology that could lead to cost reductions. These variations in CAPEX cost highlight the need to consider a range of potential scenarios and factor in the inherent uncertainties when assessing the financial viability and feasibility of the microgrid project.

As shown in Table 24 below, by decreasing the cost by 25%, the NPV increases by around 88% which is -$23,000 from base case, whereas increasing the cost by 25% decreases the NPV by 85% reaching around -$300,000. The BCR on the other hand observes an increase of 24% with a CAPEX reduction of 25%, whereas an increase in CAPEX cost by 25% decreases the BCR by 16%.

Table 24: Results of variation in CAPEX cost and its impact on the various financial metrics for base case scenario (No ITC).

Variation in CAPEX (%)	**CAPEX Cost ($)**	**NPV ($)**	**BCR**
-25%	431,000	-23,000	0.96
Base Case	575,000	-163,000	0.77
+25%	719,000	-303,000	0.64

Table 25 below highlights the sensitivity of key financial parameters to changes in project costs. A 25% reduction in costs leads to a significant increase in NPV of about $97,000, while a 25% increase in costs results in a decrease of $100,000 in NPV. The BCR shows a 22% increase with cost reductions and a 14% decrease with cost increases. Additionally, the payback period is higher for base case and with increasing the CAPEX cost by 25%.

Table 25: Results of variation in CAPEX cost and its impact on the various financial metrics for 30% ITC case.

Variation in CAPEX (%)	**CAPEX Cost ($)**	**NPV ($)**	**BCR**
-25%	302,000	45,000	1.10
30% ITC Base Case	400,000	-52,000	0.90
+25%	503,000	-150,000	0.77

As shown in Table 26 below, when the cost is decreased by 25%, the net present value (NPV) experiences a significant increase of approximately around $71,000.

Conversely, increasing the cost by 25% results in a substantial decrease in NPV, around -$87,000. In terms of the benefit-cost ratio (BCR), a reduction in cost by 25% leads to a notable increase of 20%. However, when the cost is increased by 25%, the BCR decreases by 14.2%. The simple payback period demonstrates a similar trend. By reducing the cost, the payback period decreases by nearly 3 years. These findings highlight the sensitivity of the project's financial performance to changes in cost, emphasizing the importance of cost management and optimization in achieving favorable outcomes. Hence the project is feasible only in the case of decreasing the CAPEX cost by 25%.

Table 26: Results of variation in CAPEX cost and its impact on the various financial metrics for 40% ITC case.

Variation in CAPEX (%)	**CAPEX Cost ($)**	**NPV ($)**	**BCR**
-25%	245,000	71,000	1.18
Base Case	327,000	-8,000	0.98
+25%	409,000	-87,000	0.84

In Table 27 below, it is interesting to note that with 50% ITC the economic parameters such as NPV and BCR substantially increases by reducing the CAPEX cost by 25% whereas increasing the CAPEX cost by 25% doesn’t give positive outcomes. The project is indeed feasible in base case and reducing the CAPEX cost. The BCR increases by 18% with a 25% cost reduction and decreases by 14% with a 25% cost increase.

Table 27: Results of variation in CAPEX cost and its impact on the various financial metrics for 50% ITC case.

Variation in CAPEX (%)	**CAPEX Cost ($)**	**NPV ($)**	**BCR**
-25%	200,000	96,000	1.28
Base Case	267,000	31,000	1.08
+25%	334,000	-33,000	0.93

The overall sensitivity analysis of CAPEX costs indicates that the 50% investment tax credit (ITC) value presents the most economically feasible option for the project which was obvious except in the case when the CAPEX cost was increased by 25%. However, it is essential to carefully consider the eligibility and realistic value of the ITC for the specific case of HBFS No. 1. As explained in the incentive section the HBFS No. 1 is eligible for up to 50% ITC and could be a realistic value of ITC to consider here.

Stakeholder Engagement and Way Forward

To effectively gauge the HBFS No. 1 project development, the fire station personnel along with the concerned authorities of the City of Eureka have to create a roadmap of how to proceed with the project. They should engage the concerned members such as City of Eureka, CPUC, RCEA and PG&E for financing, incentives and interconnection processes.

Considering the technical, economic and environmental feasibility of the project, the staff of the HBFS No. 1 could engage an engineering firm which could help them to conduct the analysis needed to proceed with the microgrid project and to complete all the necessary requirements such as interconnection process, necessary environmental clearances, and grant proposal submission.

The involvement of RCEA would be valuable for the HBFS No. 1 as they could bring a lot of insights about the renewable energy projects they have achieved or executed in the past. The way forward for the fire station would be sharing the project timeline with concerned authorities and the hired engineering firm, actively participating in meetings and focusing on becoming a prospective Red Cross shelter in the time of emergency. In a nutshell for the way forward it is always better to follow a timeline which ensures efficiency and proper engagement.

AREAS OF UNCERTAINTY

Discussing the areas of uncertainty, it is important to acknowledge the limitations and potential challenges in the study. Some of the key areas which one needs to focus on before implementing the HBFS No. 1 microgrid project are as follows:

Energy Balance

Especially in the grid connected scenario, the study offers a useful framework for assessing the performance of microgrid. However, it is crucial to recognize that the model does not fully capture all potential savings that may be expected from the microgrid with specific control sequences and optimization algorithms that are available from the vendor (to be selected in procurement phase). Since I have designed the microgrid in energy balance mode for peak shaving, hence the potential savings were a bit less than a case that captures additional savings opportunities. REopt is one such open-source tool available which could be a good reality check to understand this uncertainty as it uses advanced algorithm to discharge the battery and serve the load to optimize the grid demand up to maximum. A check of the spreadsheet model against REOpt indicated there could be more savings available with a more robust optimization approach if it is possible to implement.

Controls and Electrical Design

The electrical design details and controls algorithms described above are preliminary and subject to updates and revisions if this project enters detailed design and construction. There could be unforeseen issues with the costs of the overall microgrid system, system integration, compatibility with existing infrastructure, or compliance with regulatory requirements that may require adjustments or modifications to the design. It is important to note that the actual implementation of the microgrid system will involve thorough engineering analysis and consultation with experts to ensure optimal performance, safety, and compliance with industry standards.

Capital Expenditure (CAPEX)

The CAPEX cost assumed in the study relies on various components in which some of the costs of components are the national average cost and not Eureka specific. So, there are chances of unexpected increases in the cost which could further impact different economic feasibility parameters of the project. Hence these costs need to be verified by the local microgrid developers. However, in the sensitivity analysis I have considered a buffer of 25% in the CAPEX cost.

Future Regulatory Policies

Considering the uncertainty of policies related to clean energy, we are not sure of how policies could be modified in the future. These policies may be good for a customer or may be discouraging. For example, if the IRA benefits or SGIP incentives are reduced or unavailable during construction it will affect the HBFS No. 1 project feasibility.

Discount Rates

In this project I have assumed a discount rate of 3%, which is applicable to the local government agencies such as fire stations. However, we are not sure what is the exact discount rate the local government agencies consider in Humboldt County for clean energy projects. As we have seen in the sensitivity analysis, discount rate has huge impact on the project financial feasibility. So, definitely the assumption of the discount rate is a key area of uncertainty.

CONCLUSIONS AND NEXT STEPS

This technical, economic and environmental feasibility study envisaged the potential costs, benefits and processes of implementing a microgrid project at HBFS No. 1. The assessment for the technical performance of the microgrid suggests that it could be a possible reliable and resilient source which can help the fire station to function autonomously without being interrupted due to grid outages including routine outages and major event days.

The recommended size of the microgrid system that was considered for detailed analysis integrated 70 kW solar PV with a 90 kW / 360 kWh battery system, along with other components to complete the microgrid. For this system, the best- and worst-case scenario for resilience in particular suggests that the microgrid has a capability to achieve from about 1 day (28 hours) to about 50 days of autonomous operation, respectively (depending on the best case vs. worst case weather and load). Integrating a renewable generation source with a BESS and advanced control technologies helps the microgrid to optimize the demand from the conventional grid and enhance the efficiency of the station.

Supporting economic viability of the project, the microgrid is estimated to help the fire station offset the electric energy bills by more than 50% (about $12,000 per year). The estimated upfront cost for the system is $300,000 to $600,000 (depending on the federal tax credits (ITC) received by HBFS No. 1. Without any incentives, the system would take 25 years or more to pay back (assuming 3% discount rate). SGIP incentives from the State of California (CPUC) and federal clean energy tax credits (ITC) under the

IRA (30% to 50%) are important for the project economics, and together could offset up to more than 50% of the overall CAPEX cost. A direct pay option for the tax-exempt entities has been recently included under IRA which directly covers the upfront cost of the system. With the likely available incentives included, the payback period ranges from more than 25 years to 13 years. Further value of resilience (VoR) benefits, which theoretically would improve project economics, are difficult to quantify but could make the project an even more attractive investment. Using a value of resilience of $100/kWh, and 24 avoided outage hours per year (assumed considering December 20th, 2022 earthquake as an approximate benchmark for annual outages), the overall additional value could be around $11,000/year, which is similar in scale to the utility bill savings from the project.

In terms of environmental feasibility, by including solar as the generation source and battery for peak shaving, the microgrid helps the HBFS No. 1 to achieve a net-zero status, which consequently helps the facility to curb their carbon footprint by around 98% as compared to the business-as-usual case. This represents a contribution to the climate goals of Humboldt County. The system also will reduce the reliance on diesel fuel for backup power. The HBFS No. 1 microgrid project will not only help the fire department to serve their people better, but it will also provide benefits for the community, environment through deployment of renewable energy and the economy through enhanced resilience of critical community services.

The next steps for the fire station would start with understanding in more detail the capabilities of microgrids and how the technology could be helpful for them for seamless operation especially during blackout or MEDs. This can support operations and help the fire station could serve as a prospective Red Cross shelter for the nearby citizens during emergency. Building a microgrid would require engaging with local government officials, contracting for engineering, procurement, and construction services. The work to be completed would also involve engagement with the IOU (PG&E) and other technical agencies and developers for accomplishing the project successfully and ensuring a collective responsibility of all the stakeholders.

Throughout the process of development, it is important to reduce risks to the project success. Some of the risks associated with the project are the availability of financial incentives (especially SGIP which has to be ensured form the CPUC), which are important for supporting the overall financial case for the project. CAPEX cost is also one of the key risks. If there is an unexpected cost rise of 25% compared to typical pricing (due to inflation or local conditions), it substantially impacts the economic parameters. Thus, all such dimensions of the project have to be ensured before one should go forward with the project.

Overall, a microgrid for the HBFS No. 1 would be a good and potentially economically favorable step towards meeting clean energy goals and ensuring resiliency.

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APPENDICES

Appendix A: HBFS No. 1 Diesel Genset specification sheet (CSDI, 2001)

Engine

Cummins heavy duty diesel engines use advanced combustion technology for reliable and stable power, low emissions, and fast response to sudden load changes. This generator set engine is certified to U.S. EPA Mobile Off Highway Tier I emissions standards. Mechanical governing is standard. Electronic governing is available for applications requiring constant (isochronous) frequency regulation such as Uninterruptible Power Supply systems, non-linear loads, or sensitive electronic loads. Optional coolant heaters are recommended for all emergency standby installations or for any application requiring fast load acceptance after start-up.

Specifications – Engine

Base Engine	Cummins Model 6CT8.3-G2, Turbocharged, diesel-fueled
Displacement in^3 (L)	504.0 (8.3)
Overspeed Limit, rpm	2100 ±50
Regenerative Power, kW	22.00
Cylinder Block Configuration	Cast iron with replacable wet cylinder liners, In-line 6 cylinder
Cranking Current	550 amps at ambient temperature of 32°F (0°C)
Battery Charging Alternator	37 amps
Starting Voltage	12-volt, negative ground
Lube Oil Filter Types	Single spin-on canister-combination full flow with bypass
Standard Cooling System	104°F (40°C) ambient radiator

Power Output	**Standby**	**Prime**
Gross Engine Power Output, bhp (kWm)	207.0 (154.4)	188.0 (140.2)
BMEP at Rated Load, psi (kPa)	168.0 (1158.3)	152.0 (1048.0)
Bore, in. (mm)	4.49 (114.0)	4.49 (114.0)
Stroke, in. (mm)	5.32 (135.1)	5.32 (135.1)
Piston Speed, ft/min (m/s)	1596.0 (8.1)	1596.0 (8.1)
Compression Ratio	16.8:1	16.8:1
Lube Oil Capacity, qt. (L)	25.2 (23.8)	25.2 (23.8)
Fuel Flow		
Fuel Flow at Rated Load, US Gal/hr (L/hr)	54.0 (204.4)	54.0 (204.4)
Maximum Inlet Restriction, in. Hg (mm Hg)	4 (102)	4 (102)
Maximum Return Restriction, in. Hg (mm Hg)	10 (254)	10 (254)
Air Cleaner		
Maximum Air Cleaner Restriction, in. H_2O (kPa)	25.0 (6.2)	25.0 (6.2)
Exhaust		
Exhaust Flow at Rated Load, cfm (m^3/min)	1221.0 (34.6)	980.0 (27.7)
Exhaust Temperature, °F (°C)	1065 (574)	951 (511)
Max Back Pressure, in. H_2O (kPa)	41.0 (10.2)	41.0 (10.2)

Fuel System	Direct injection, number 2 diesel fuel, fuel filters; water separator; automatic electric fuel shutoff

Fuel Consumption		**Standby**				**Prime**			
60 Hz Ratings, kW (kVA)		**125 (156)**				**113 (141)**			
	Load	1/4	1/2	3/4	Full	1/4	1/2	3/4	Full
	US Gal/hr	3.3	5.4	7.5	9.9	3.1	4.9	6.9	8.9
	L/hr	12	20	28	37	12	19	26	34

Figure A1: Genset specification sheet currently installed at HBFS No. 1.

Appendix B: Electricity Bill saving with MG for B-19 and B-19 R (Excluding Customer charges)

Table B1: Monthly energy bill calculation for HBFS No. 1 for business as usual (B-19 TOU), with microgrid (B-19 TOU) and microgrid with B-19 option R.

Month	**Utility cost before MG (B-19 TOU) ($)**	**Utility cost after MG (B-19 TOU) ($)**	**Utility cost after MG (B-19-R TOU) ($)**
Jan	2229	1269	1438
Feb	1840	1118	1234
Mar	1799	1039	1127
Apr	1821	998	1075
May	1434	911	975
Jun	2286	1020	1107
Jul	2504	1056	1152
Aug	2832	1105	1214
Sep	2536	1121	1236
Oct	1914	1103	1201
Nov	1787	1153	1273
Dec	1617	1170	1288
Total	**24,600**	**13,100**	**14,300**