



Analysis of Alternatives

Ketron Island Microgrid Study

Ketron Island, WA

July 7, 2026



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Acronyms and Abbreviations

ARL	Agricultural Resource Land
BESS	battery energy storage system
CAPEX	capital expenditure
CUP	Conditional Use Permit
HDR	HDR Engineering, Inc.
HOMER	hybrid optimization of multiple energy resources
IFC	International Fire Code
kW	kilowatt
kWh	kilowatt hour
MW	megawatt
MWh	megawatt hour
NFPA	National Fire Protection Association
NPV	net present value
O&M	operations and maintenance
PCC	Pierce County Code
PV	photovoltaic
SOC	state of charge
RNC	Rural Neighborhood Center
ROM	rough order of magnitude

1.0 Introduction

Ketron Island, a small community in Puget Sound, located in Pierce County, Washington, is currently served by a single underwater power cable that has exceeded its usable life, prompting the need for a long-term, reliable energy supply solution. HDR Engineering, Inc. (HDR), was tasked by Tacoma Power with developing a four-phase study culminating in a 10 percent microgrid design for the island. The first two phases of this effort—Task 1: Real Estate Potential Assessment and Peak Electrical Energy Load Forecast and Task 2: Microgrid Technology Screening Memorandum—established the island’s development constraints, identified likely growth scenarios, and evaluated feasible technologies for a permanently islanded microgrid.

Task 1 determined that daily electric loads range from the current no-growth projection of 1,763 kilowatt hours (kWh) with an 85-kilowatt (kW) peak to a high-growth scenario of 1,811 kWh with a 260-kW peak (HDR 2025). These values define the required performance envelope for potential microgrid configurations. These values can be seen in Figure 1-1 and Figure 1-2. For each case, monthly average and peak loads are shown for severe and normal weather cases.

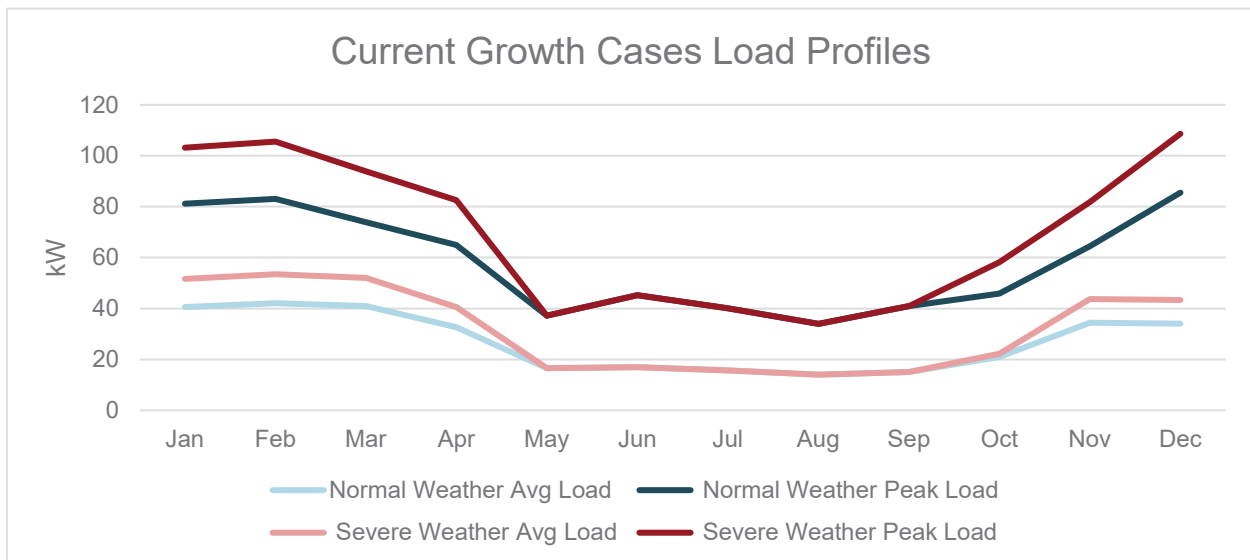


Figure 1-1: Current Growth Monthly Average Load Profiles

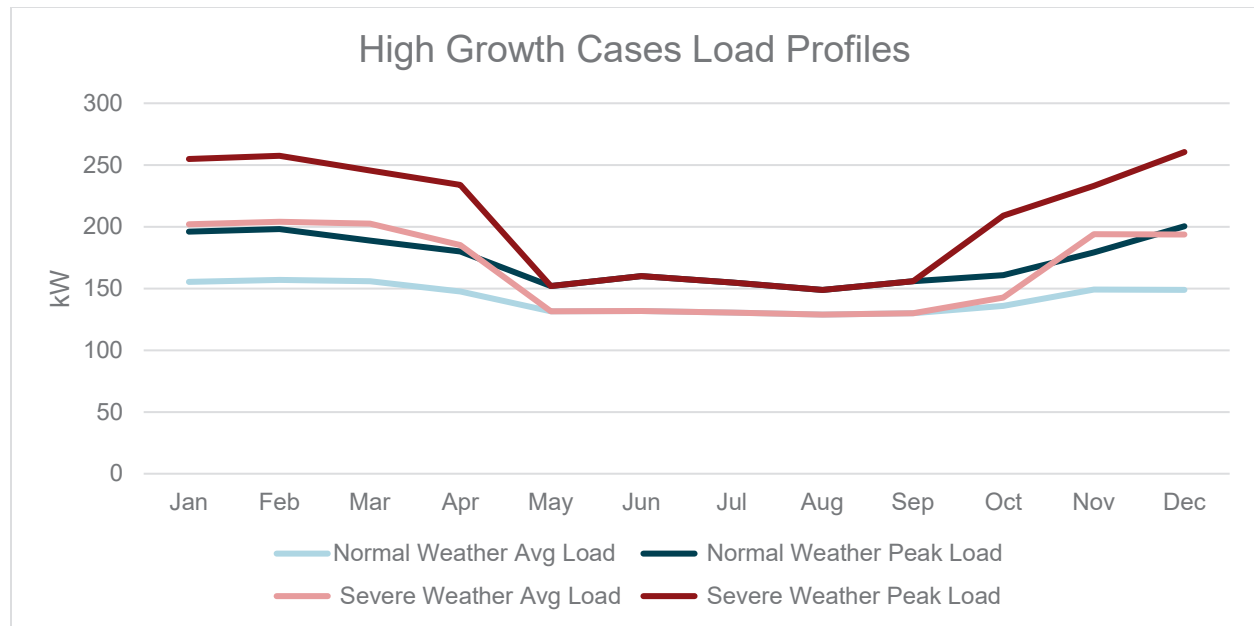


Figure 1-2: Current Growth Monthly Average Load Profiles

During Task 2, all potential generation technologies were researched and evaluated against several criteria to determine if they were technically, economically, and commercially feasible alternatives for producing power independently and at scale for the island. Those technologies that were lacking were discarded from further consideration (HDR 2026). The remaining technologies were deployed in a way that would allow them to function with low cost and reliability as a microgrid alternative. Five alternatives were constructed for further evaluation. They are:

- Alternative 1 – Solar PV + BESS + Diesel Generator
- Alternative 2 – Solar PV + Wind + BESS + Diesel Generator
- Alternative 3 – Expanded Solar PV + BESS + Diesel Generator
- Alternative 4 – Solar PV + BESS + Hydrogen Fuel Cell
- Alternative 5 – Distributed Diesel + Household BESS

Building on this foundation, Task 3: Analysis of Alternatives, compares the shortlisted configurations in terms of performance, cost, reliability, land requirements, and operational feasibility. The results of this analysis will guide Tacoma Power's selection of a preferred microgrid approach and inform the subsequent development of the 10 percent design in Task 4.

1.1 Purpose and Level of Design

The asset sizing presented herein is intended to support planning-level alternatives analysis in HOMER and stress-testing under variable load and weather scenarios. HOMER (Hybrid Optimization of Multiple Energy Resources) is a software package used to model, simulate, and optimize distributed energy systems, including microgrids, by comparing costs, performance, and feasibility of different energy configurations. HOMER evaluates the performance of specific sized equipment under specific load conditions. It provides analysis to support planning rather than discrete point sizes or final engineered designs. These proposed microgrid designs

- only include commercially available equipment;
- are bounded by site feasibility and equipment operating limits; and

- provide sufficient detail to compare cost, resilience, fuel consumption, and emissions outcomes.

Detailed electrical studies, protection coordination, and final equipment selection will be addressed in Stage Four, when a single microgrid is selected for advanced design, not within Phase Three when proposed microgrids are being analyzed and compared.

1.2 Governing Sizing Principles

Operation of a permanently islanded microgrid requires a Battery Energy Storage System (BESS) to form electrical output to specific frequency and voltage characteristics. All proposed microgrids will include BESS and customer device usage will draw from them in all cases. The operating philosophy used throughout this report is to use the BESS to provide constant power and follow the load. To charge the BESS, renewable power sources will be maximized and only curtailed when the load is met and the BESS is fully charged. Dispatchable generation, such as the diesel generators will be dispatched last, to minimize fossil fuel generation. Once they are running, they will continue running at max capacity until the BESS is fully charged to capitalize on higher efficiency. This resilience-oriented strategy restores the BESS to an upper reserve target once the state of charge falls below a lower reserve threshold, maintains the operating margin during permanently islanded service, and allows the dispatchable resource to run at higher loading where it operates more efficiently.

- BESS as Grid-Forming Resource – BESS forms the grid, manages voltage and frequency, and responds instantly to load changes.
- Renewables Complement Firm Generation – Solar and wind resources are sized for operational feasibility and land use requirements to minimize fossil fuel generation and are not relied upon to meet firm capacity or contingency requirements.
- Diesel Generation – The diesel generator acts as a strategic energy-security asset rather than a primary power source. It maintains resiliency during extended low-solar periods, recharges the BESS when storage approaches reserve limits, supports sustained high-load periods, and remains offline during normal sunny or mild-load conditions when the BESS is within its operating band.¹
- Fuel Cell – In the microgrid alternative that includes a hydrogen fuel cell, it is modeled as a load-following dispatchable resource that can rapidly increase output and quickly reduce output to follow the load profile and support BESS charging. The fuel cell can also receive a setpoint within its operating guardrails, with an optimal operating range of approximately 30 to 100 percent of nameplate output.²
- Weather and load scenarios are applied after system configuration and sizing are fixed, to validate robustness rather than redefine the system configuration.

¹ In Phase Two, several fossil fuel alternatives were considered, including natural gas, biodiesel, and propane. These fossil fuels were evaluated and for reasons that included availability, cost, deliverability, storage requirements, safety, and other concerns, it was determined that diesel fuel was superior in all respects. The decision was to proceed in Phase 3 with diesel exclusively.

² This is not to be confused with round trip efficiency of hydrogen electrolysis (power to H₂, and then converted H₂ to power)

1.3 Load Basis for Sizing (Common to All Configurations)

The following four load profiles were modeled and evaluated as part of the microgrid performance analysis.

1. Current development, normal weather
2. Current development, severe weather
3. High growth development, normal weather
4. High growth development, severe weather

Although all four profiles were evaluated as part of the performance modeling, the financial discussion presented below focuses on Load Profile #2 – Current Development, Severe Weather. This is the most relevant planning case for Tacoma Power because the Real Estate Potential Assessment and Peak and Energy Load Forecast concluded that significant new development on Ketron Island is unlikely over the 20-year planning horizon and identifies 0% growth as the primary planning scenario.

Load Profile #2 therefore provides the most appropriate basis for comparative financial evaluation because it reflects the most credible development outlook under the more critical weather conditions. In the case of unexpected real estate development, microgrids can often be scaled up by adding modular components for generation, energy storage, etc. If a microgrid is determined to be the best alternative for power delivery on the island, planners should consider in their designs the potential for growth.

The single microgrid equipment configuration was developed as follows:

- Diesel generation was sized to meet the highest demand observed across the four load profiles.
- Hydrogen Fuel Cell was sized based on the technology minimum loading constraint of 30 percent of rated capacity to avoid underloading fuel cell when BESS is fully charged, and load is too low to absorb the minimum fuel-cell output. Frequent shutdown and restart to manage these conditions is not a practical control strategy, given the unit's long cold-start³ duration and the lifecycle and maintenance impacts associated with excessive cycling.
- Renewable generation and BESS will be sized on annual energy, fuel-consumption, land availability, and commercially available equipment sizes rather than any single load scenario.

The finalized equipment configuration was simulated under all four load profiles to assess system performance across current and high-growth conditions and both normal and severe weather scenarios.

1.4 Asset Sizing by Technology

The asset sizes presented in this section are intentionally bounded to support resilient microgrid planning and reflect commercially available, buildable technology configurations rather than purely theoretical optimization results. The sizing approach allows Tacoma Power to compare alternatives using practical engineering assumptions, including equipment availability, operating limits, site feasibility, reliability requirements, and planning-level cost evaluation.

³ Cold-start means to start the unit from off/zero percent output. This metric is used to quantify how long it takes a unit to come online from completely off.

1.4.1 Diesel Generation

Conceptual sizing includes a 300-kW diesel generator to support a permanently islanded operation is sufficient to serve the projected 260-kW peak island demand even under the worst-case projected loading condition. This size provides adequate capacity to support island operation without relying on renewable generation during periods of unfavorable weather. Diesel generators provide the firm capacity backbone and establish the upper bound of island operating capability under worst-case load and resource conditions.

1.4.2 Solar Photovoltaics

Solar photovoltaics (PV) is sized to provide meaningful fuel offset without creating ramping or curtailment issues in island operation. The size of solar is bounded by the availability of land suitable for fixed ground-mount stands (approximately 0.5 acre per 200 kW). It is assumed that for alternative A there is a single half-acre solar array capable of producing 200 kW. For alternative C it is assumed that there is two separately located half-acre solar arrays on the island capable of producing a total of 400 kW of solar energy. Solar is treated as a fuel and emissions offset resource.

1.4.3 Wind Generation

Wind is sized to provide meaningful fuel offset without creating ramping or curtailment issues in island operation. Wind generation is complimentary to solar in that at dawn and dusk, when solar is inactive or tapering off, wind is generally at its peak production. It is assumed that there are ten 20-kW wind turbines installed for the microgrid configuration that includes wind, giving a total of up to 200 kW of wind generation power production. Sizing is governed by commercially available equipment and area ordinance requirements (about 0.01 acre per turbine including setbacks). Wind is treated as a fuel and emissions offset resource.

1.4.4 Battery Energy Storage System

Energy storage is an enabling technology, not a replacement for an actual power generation source. In general, in microgrid design, a battery energy storage system is sized to 25–50 percent of peak critical load (kW) with an energy duration of 2–4 hours at rated power (kWh). BESS that have a peak discharge of 1,000-kW and a 2–4-hour discharge are the most commercially common. This size of BESS is cost-effective for a microgrid of the size required on Ketron Island that is focused on generator smoothing, renewable firming, and blackstart support. BESS supports operational flexibility rather than total energy independence.

1.4.5 Hydrogen Fuel Cell/Storage

The fuel-cell configuration is sized to replace diesel-based generation as a dispatchable resource that follows load and supports BESS reserve management, rather than as a direct one-for-one replacement for diesel nameplate capacity.

Hydrogen systems provide a strategic non-diesel pathway for permanently islanded operation. In the modeled approach, the fuel cell operates within its minimum and maximum power output bounds and responds to load and BESS reserve conditions. For current-development summer load profiles, solar PV and the BESS can support the load without fuel-cell operation, preserving hydrogen for periods of lower renewable output and higher demand. During periods when dispatchable support is required, the fuel cell follows the net load and BESS charging requirement within an optimal operating range of approximately 30 to 100 percent of nameplate output.

This deployment strategy is agreeable with the technological requirements of fuel cell operation. It is also assumed that the fuel cells are installed in phases, beginning with a 115-kW unit and scaled up to two 300-kW units if the island reaches a high-growth scenario. Under the current-development/severe-weather case, a 300-kW fuel cell exceeds the operational flexibility required by the microgrid. With an effective minimum loading constraint of 30 percent of rated capacity, the unit cannot stably dispatch below approximately 90 kW. This creates a mismatch during periods when the BESS is fully charged, and native load is too low to absorb the minimum fuel-cell output. Frequent shutdown and restart to manage these conditions is not a practical control strategy, given the unit's long cold-start duration and the lifecycle and maintenance impacts associated with excessive cycling. This also means that the capital allocation to support fuel cells has phases, reducing the overall cost/risk of this microgrid alternative against others.

Hydrogen systems are evaluated as a strategic alternative, not a direct one-for-one substitute for diesel generation.

1.4.6 Decentralized Generator plus BESS

Alternative 5 is modeled as 23 independent site-level microgrids rather than as a single island-wide system. Each house or house-equivalent load, such as the loads associated with the ferry dock and water system, is served by a 50-kW diesel generator, a 40-kWh BESS, and a 200-gallon diesel tank. Solar panels were not considered part of this alternative due to the variability and uncertainty of the structural conditions of residences for rooftop solar. The operating logic assumes that the diesel generator charges the battery and serves load locally; once started, the generator runs at full load, allowing for maximum operating efficiency, until the battery is fully charged to reduce start frequency, lower operations and maintenance (O&M) burden, and maintain higher generator efficiency at elevated load factors. The Alternative 5 fleet includes both year-round residences and summer-only residences, so annual operation reflects a combination of continuous and seasonal occupancy patterns.

One potential advantage of Alternative 5 is that Tacoma Power could eliminate the need to continue operating the existing island distribution system. According to Tacoma Power, decommissioning the island distribution system in place is estimated to save approximately \$30,000 per year in operations and maintenance expense. Because this alternative would serve each premise through independent generator-and-BESS systems rather than a shared island-wide microgrid, it may allow Tacoma Power to avoid some future distribution-system maintenance, repair, and replacement obligations. Other advantages to Alternative 5 include reduced permitting complexity and no land acquisition costs.

2.0 Operational Performance by Alternative and Scenario

Across the alternatives, the modeled operational behavior follows the dispatch philosophy defined in this report. In general, the BESS supplies early-morning and overnight load; solar generation serves daytime demand and recharges the BESS when available; and dispatchable generation is held in reserve unless required to maintain reliability, restore battery reserve, or support extended periods of high demand or low renewable availability. This reserve-oriented strategy preserves a straightforward operating philosophy in the permanently islanded system and allows the dispatchable resource to run at higher loading once the BESS falls below its lower reserve threshold.

Alternative 2 introduces wind generation, which complements solar production during periods when PV output is low and can reduce diesel runtime under favorable wind conditions. Alternative 3 increases solar penetration and reduces thermal contribution where the added PV can be absorbed by the BESS and the load without excessive curtailment. Alternative 4 replaces diesel with hydrogen-backed firm capacity and changes both the dispatch profile and the fuel-supply dependency of the system. Alternative 5 is evaluated as a decentralized service case in which each premise is served by a standalone generator-and-storage package rather than by a shared island-wide microgrid.

HOMER Grid was used to simulate annual operation for Alternatives 1, 2, 3, and 5 across the modeled load and weather scenarios. For Alternatives 1 through 3, HOMER was used to evaluate island-wide configurations in which renewable generation, battery storage, and dispatchable resources interact through a shared system to maintain load service while minimizing lifecycle cost. For Alternative 5, HOMER was used to evaluate a decentralized service case in which each premise is served by its own standalone generator-and-storage package rather than by a shared island-wide microgrid.

Alternative 4 was evaluated separately using an Excel-based dispatch model developed from the same load basis, solar production assumptions, BESS operating logic, and reserve philosophy used elsewhere in the study. In that model, dispatch is determined from the interaction of load, solar PV, BESS state of charge, and fuel-cell operating guardrails rather than through a direct HOMER simulation. This approach was used to represent the fuel-cell operating logic more explicitly within the project's defined control philosophy.

Unless stated otherwise, all narratives and figures in Section 2 refer to a single “typical year” case defined as current development, severe weather – existing development under adverse weather that elevates seasonal peaks and increases reliance on firm generation capacity during stressed periods. The main body focuses on this case because it is most diagnostic of reserve strategy and firm-supply needs. Seasonal dispatch excerpts (“summer” and “winter”) and annual energy-flow graphics reflect this same Current/Severe year. For Alternatives 1, 2, 3, and 5, these graphics are based on HOMER outputs. For Alternative 4, the dispatch and annual energy-flow interpretation are based on the Excel dispatch model. The full chart set and supporting tables are provided in the appendices.

2.1 Alternative 1 – Solar PV (200 kW) + BESS (1 MW/4 MWh) + Diesel Generator (300 kW)

Alternative 1 provides simple and conventional architecture, combining solar PV, BESS, and diesel backup in a configuration with relatively low integration complexity and familiar operational characteristics.

This configuration relies on mature, commercially proven technologies. Solar PV and lithium-ion BESS are widely deployed, and diesel generation provides dependable firm capacity during renewable shortfalls. Delivery reliability risk is relatively low because the major equipment categories are standard and available from multiple vendors. The principal reliability concern is fuel dependence: prolonged severe weather, extended cloud cover, or high-growth load conditions will increase diesel runtime and therefore dependence on delivered fuel availability.

- Summer Operating Profile
 - Refer to Figure 2-1. During representative summer days, solar generation carries most daytime demand and charges the BESS toward its upper state of charge (SOC) bound

(15 to 100 percent), leaving the battery to cover evening and overnight load; the diesel generator remains largely offline (unless a late-day deficit risks dip below the minimum SOC reserve). Short, smooth BESS cycling trims solar variability, while any surplus will be curtailed if the BESS is near its SOC cap and demand is already met.

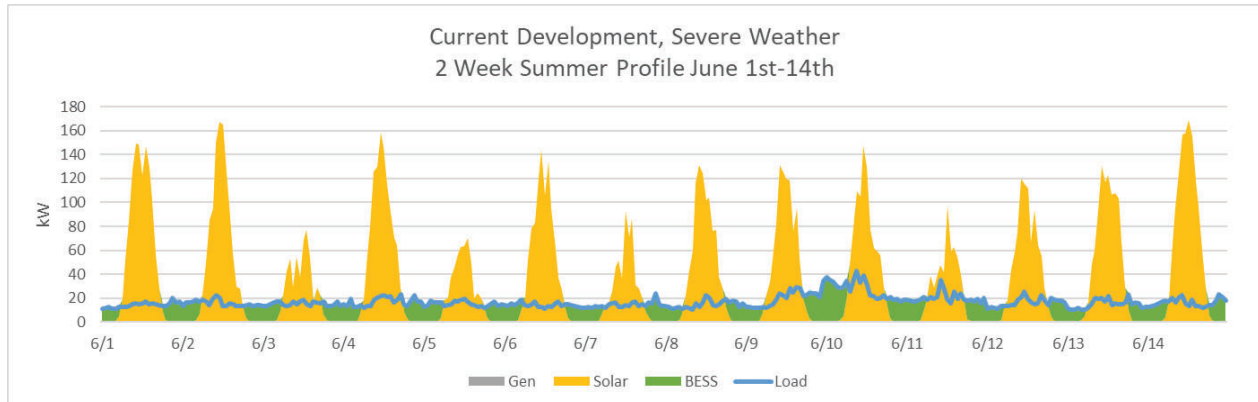


Figure 2-1: Alternative 1 Summer Dispatch Profile

- Winter Operating Profile
 - Refer to Figure 2-2. Winter operation features lower PV output and higher, more sustained demand, so the BESS typically discharges deeply through pre-dawn, then relies on longer or earlier diesel runs in late afternoon/evening to restore SOC and protect reserve. The diesel is held above a healthy minimum load while simultaneously charging the battery to avoid light-load operation, while the BESS continues to smooth intra-hour variability and cover short ramps. Midday PV still contributes, but limited irradiance means curtailment is rare and dispatchable energy supplies a larger share of the daily balance.

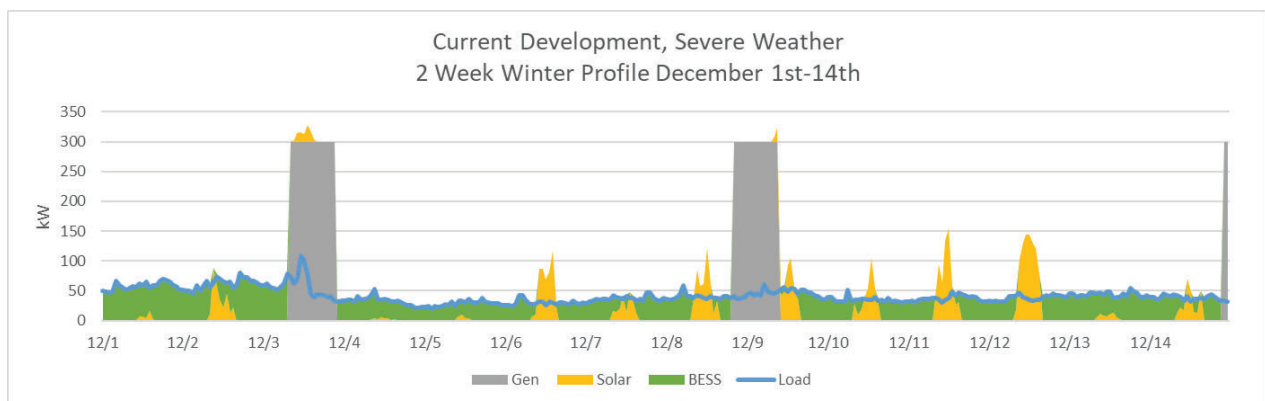


Figure 2-2: Alternative 1 Winter Dispatch Profile

- Operational Summary for Alternative 1
 - In winter, lower solar availability and higher heating-driven demand deepen BESS cycling and trigger more frequent diesel starts to restore reserve or support extended evening peaks; by contrast, summer shows high renewable fraction and minimal diesel runtime. The BESS supplies a greater share of overnight load in summer, while in winter its SOC spends more time near the lower reserve band, prompting more frequent periods of diesel charging. Overall, summer improves renewable utilization and reduces

fuel use; winter shifts the balance toward higher dispatchable contribution to maintain reliability.

2.2 Alternative 2 Results – Solar (200 kW) + Wind (200 kW) + BESS (1 MW/4 MWh) + Diesel (300 kW)

Alternative 2 adds renewable diversity through wind generation, which improves seasonal energy balance and reduces diesel dependence, but it also introduces additional mechanical equipment and site-specific considerations.

This alternative introduces renewable diversity, which can improve energy balance and resilience if wind production complements solar production. However, delivery reliability risk is materially higher because the project depends on 10 individual wind turbine units, creating more failure points, more poured concrete foundations, more electrical connections, and a larger maintenance burden. Small wind turbines also tend to have more variable performance and lower overall efficiency than utility-scale turbines.

- Summer Operating Profile
 - Refer to Figure 2-3. In summer, PV supplies daytime demand and charges the BESS, while wind contributes opportunistically, often during shoulder hours, allowing longer charging windows and later battery discharge into the night. Diesel runtime is minimal; the BESS handles net-load ramps and intra-hour variability, and curtailment is reduced when wind's timing complements PV.

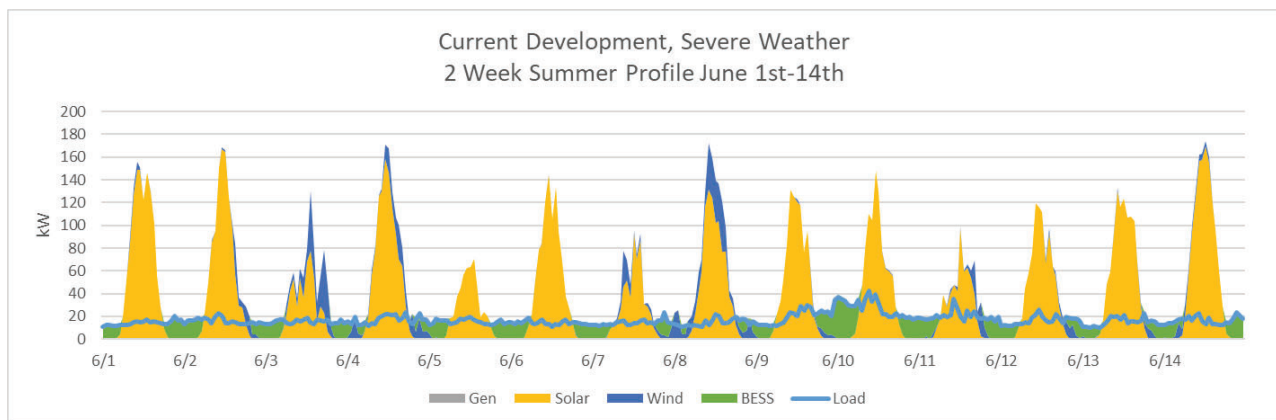


Figure 2-3: Alternative 2 Summer Dispatch Profile

- Winter Operating Profile
 - Refer to Figure 2-4. With PV reduced, wind becomes the swing factor: when available, it offsets diesel operation and rebuilds SOC, but during wind lulls the diesel runs earlier and longer to protect reserves. The BESS buffers fast wind variability and shifts energy between windy hours and evening peaks; winter renewable energy curtailment remains rare because load typically absorbs available output.

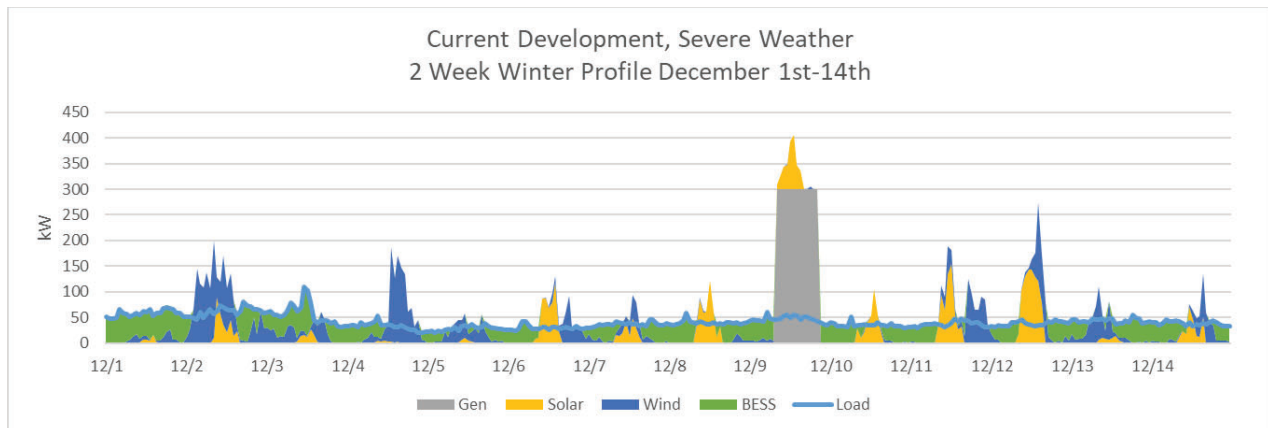


Figure 2-4: Alternative 2 Winter Dispatch Profile

- Operational Summary for Alternative 2
 - In winter, the contribution of wind is a substitute for PV as output declines and reduces diesel runtime relative to a PV-only portfolio. Under this configuration, diesel generator runtime is cut roughly in half from about 2 days in a 2-week period to about 1 day in a 2-week period, although during low-wind spells the diesel still runs more frequently than in summer to protect BESS reserve. The BESS experiences deeper cycling in winter as it shifts energy to higher loads, whereas in summer it cycles shallower with PV carrying daytime energy. Summer maximizes renewable share with minimal diesel, while winter leverages wind to moderate fuel use, yet still sees higher dispatchable support than summer.

2.3 Alternative 3 Results – Expanded Solar (400 kW) + BESS (1 MW/4 MWh) + Diesel (300 kW)

Alternative 3 increases solar penetration and reduces long-term fuel use under favorable conditions, though its incremental benefit depends on the degree to which the larger PV array can be utilized without excessive curtailment.

This alternative retains the same core technology maturity advantages as Alternative 1 while improving renewable contribution through a larger solar array. The technology stack is comparatively simple and operationally familiar. Delivery reliability is therefore expected to be high, with the main residual risk being dependence on solar output for diesel displacement. Because it avoids wind and hydrogen, this alternative likely has the strongest combination of technology maturity, reliability, and maintainability for high development/severe weather scenario. For consistency the results in this section are based on a “typical year” case defined as current development, severe weather.

- Summer Operating Profile
 - Refer to Figure 2-5. The expanded PV advances and lengthens BESS charging and extends diesel-off periods; on many days, the battery reaches the upper SOC band by midday, enabling battery-only evening service. Once load and BESS headroom are reached, significant midday curtailment is observed. Even so, overall fuel use is minimized, and BESS cycling remains relatively shallow. For consistency, the results in this section reflect the “typical year” case (current development, severe weather). This alternative would best serve a high-development/worst-winter scenario.

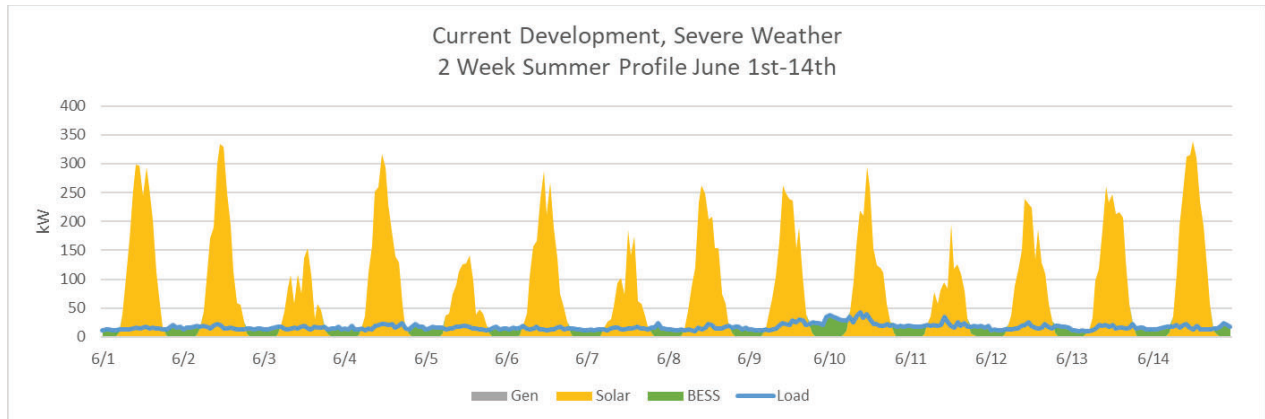


Figure 2-5: Alternative 3 Summer Dispatch Profile

- Winter Operating Profile
 - Refer to Figure 2-6. Even in winter, the larger PV array can restore SOC on clear days, and delay diesel starts, yet lower irradiance and longer evening peaks still drive deeper BESS cycling and more frequent diesel charging runs than in summer. Curtailment is uncommon in winter, and the added PV reduces fuel consumption versus smaller-PV cases whenever sunlight is available.

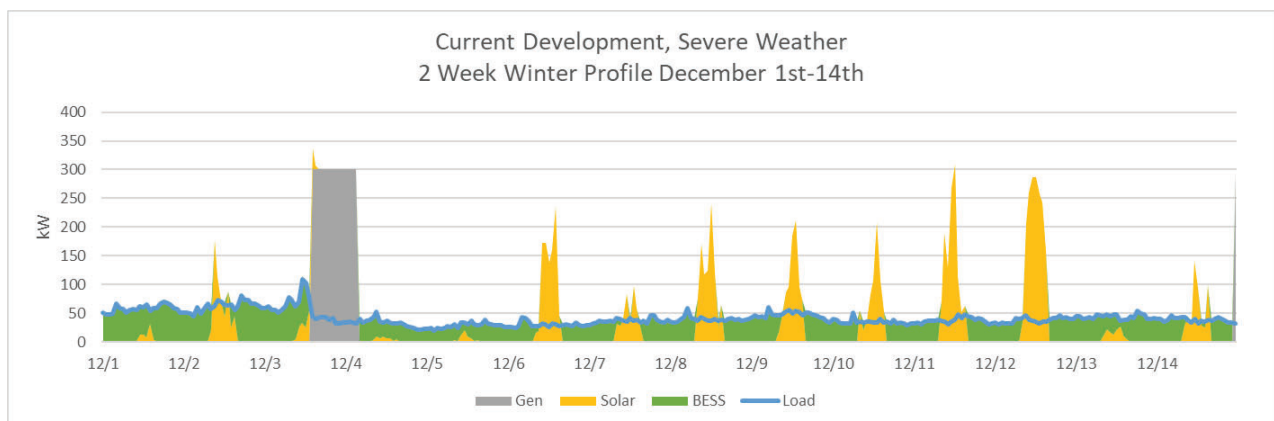


Figure 2-6: Alternative 3 Winter Dispatch Profile

- Operational Summary for Alternative 3
 - In winter, the larger PV array still reduces diesel hours relative to smaller-PV cases, but lower irradiance and higher demand drive deeper BESS discharge and more frequent diesel charging runs than in summer. The renewable fraction remains highest in summer; in winter it is moderated by seasonal resource limits, with the BESS operating nearer to its minimum SOC threshold more often. Compared with Alternatives 1 and 2, the expanded PV reduces winter fuel reliance, cutting diesel generator runtime from 2 days in a 2-week period to about 1 day in a 2-week period – although diesel support still increases materially relative to the summer profile. Over the course of the year Alternative 3 has a 51% reduction in diesel fuel consumption compared to Alternative 1.

2.4 Alternative 4 Results — Hydrogen Fuel Cell (115 kW) + BESS (1 MW/4 MWh) + Solar (200 kW)

Alternative 4 provides a non-diesel zero-carbon dispatchable pathway with zero on-site fossil use, but its practicality depends strongly on hydrogen supply assumptions, storage requirements, commercial support, and cost.

This option has the greatest conceptual appeal from an emissions-reduction standpoint, but it also has the highest reliability risk. The fuel cell package itself may be technically viable; however, the full system depends on a reliable hydrogen supply chain, hydrogen storage, pressure regulation, safety systems, controls integration, and potentially specialized maintenance support.

- Summer Operating Profile
 - Refer to Figure 2-7. During current-development summer conditions, solar PV and the BESS support the load without fuel-cell operation. Solar serves daytime demand and charges the BESS, and the BESS then discharges through evening and overnight periods. Because the fuel cell has a long cold-start process, it is not treated as an instant-start resource and remains offline during normal summer operation unless reserve protection, forecasted extended net-load deficit, or other abnormal operating conditions justify bringing it online in advance. This operating pattern preserves hydrogen fuel while retaining the fuel cell as a dispatchable resource available to follow load and restore reserve when needed.

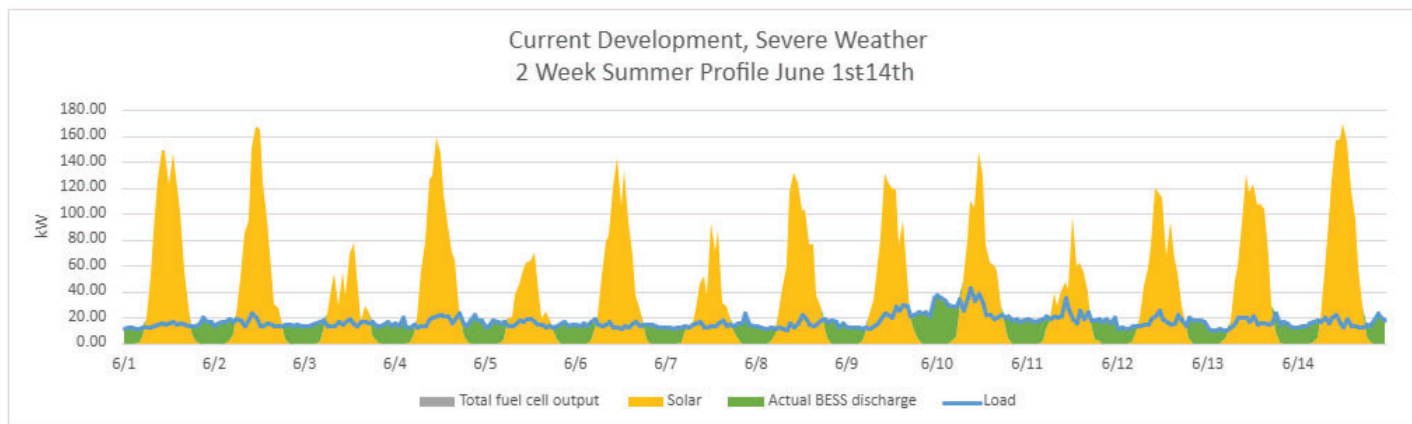


Figure 2-7: Alternative 4 Summer Dispatch Profile

- Winter Operating Profile
 - Refer to Figure 2-8. With lower PV availability and higher seasonal load, the fuel cell is dispatched more frequently and operates within its preferred range to follow net load and support BESS charging. The BESS continues to manage short-duration ramps and power-quality events, while the fuel cell restores reserve margin once the battery approaches its lower reserve threshold. Winter operation therefore increases hydrogen use because dispatchable support is required more often and for longer durations than in summer.

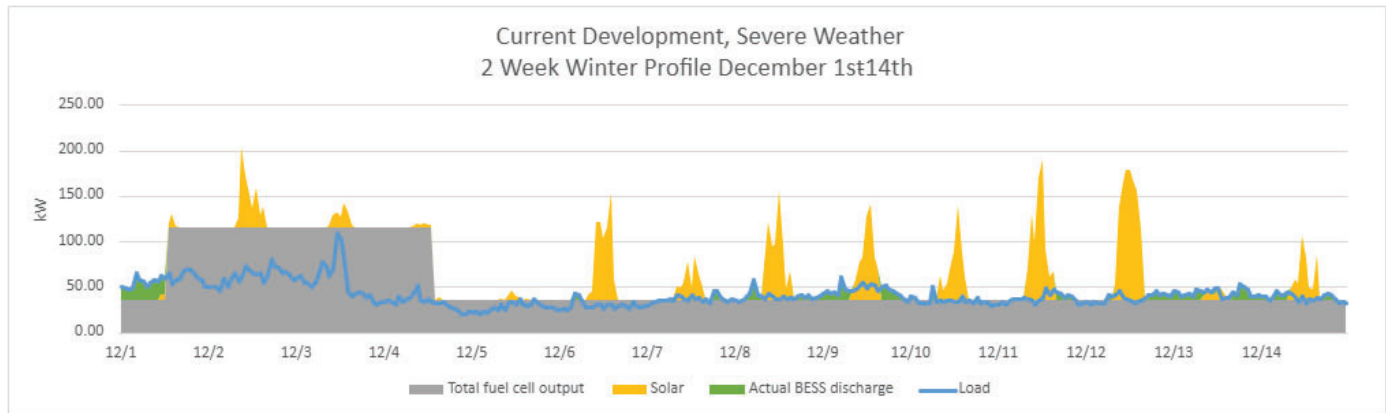


Figure 2-8: Alternative 4 Winter Dispatch Profile

- Operational Summary for Alternative 4
 - Summer operation is characterized by high renewable contribution and low hydrogen use because solar PV and the BESS can carry the current-development load for extended periods without fuel-cell operation. Winter shifts the balance toward more frequent fuel-cell dispatch, deeper BESS cycling, and greater reliance on hydrogen-backed firm support to preserve reliability during prolonged renewable deficits. Across the year, the fuel cell acts as a flexible dispatchable resource that follows load and restores reserve rather than as a continuously operating baseload unit.

2.5 Alternative 5 Results – Distributed Diesel (50 kW) with BESS (40 kWh)

Alternative 5 is modeled as a decentralized fleet of 23 separate systems, rather than as a single island-wide microgrid. Each residence or house-equivalent load is served by its own 50-kW diesel generator, 40-kWh battery energy storage system, and 200-gallon diesel tank. The residential and non-residential (i.e., house-equivalent loads) are not connected to a larger shared grid, do not exchange energy with one another, and are therefore operated as independent site-level systems. Operational performance is determined by the interaction of each individual load, generator dispatch, battery reserve, and fuel availability rather than by centralized resource sharing or island-wide controls. This case also includes both year-round residents and summer-only residents, which creates different seasonal operating patterns across the fleet. The ferry dock and other non-residential loads are modeled as year-round residents.

- Summer Operating Profile
 - Refer to Figure 2-9. During summer conditions, the battery at each house absorbs short-duration load fluctuations and serves local demand between generator runs, while the diesel generator provides the primary charging source for the battery. Once the generator starts, it is operated at full load and continues running until the battery is fully charged. This dispatch approach reduces the number of generator starts, lowers maintenance burden associated with repeated short-cycle operation, and takes advantage of higher generator efficiency at elevated load factors. For summer-only residences, generator runtime is concentrated in the occupied May–October period, while year-round residences continue to operate throughout the full year. As a result, the summer fleet profile includes both intermittently occupied homes with seasonal

generation demand and continuously occupied homes with steady service requirements. The load profiles for year-round and summer-only residents are identical, but the times at which the generator turns on are slightly off set between the two plots. This is because the BESS is assumed to be fully charged on January 1st in the year around case and in the summer only case the BESS is assumed to be fully charged at the start of the summer. This difference is what creates the offset seen in Figure 2-9.

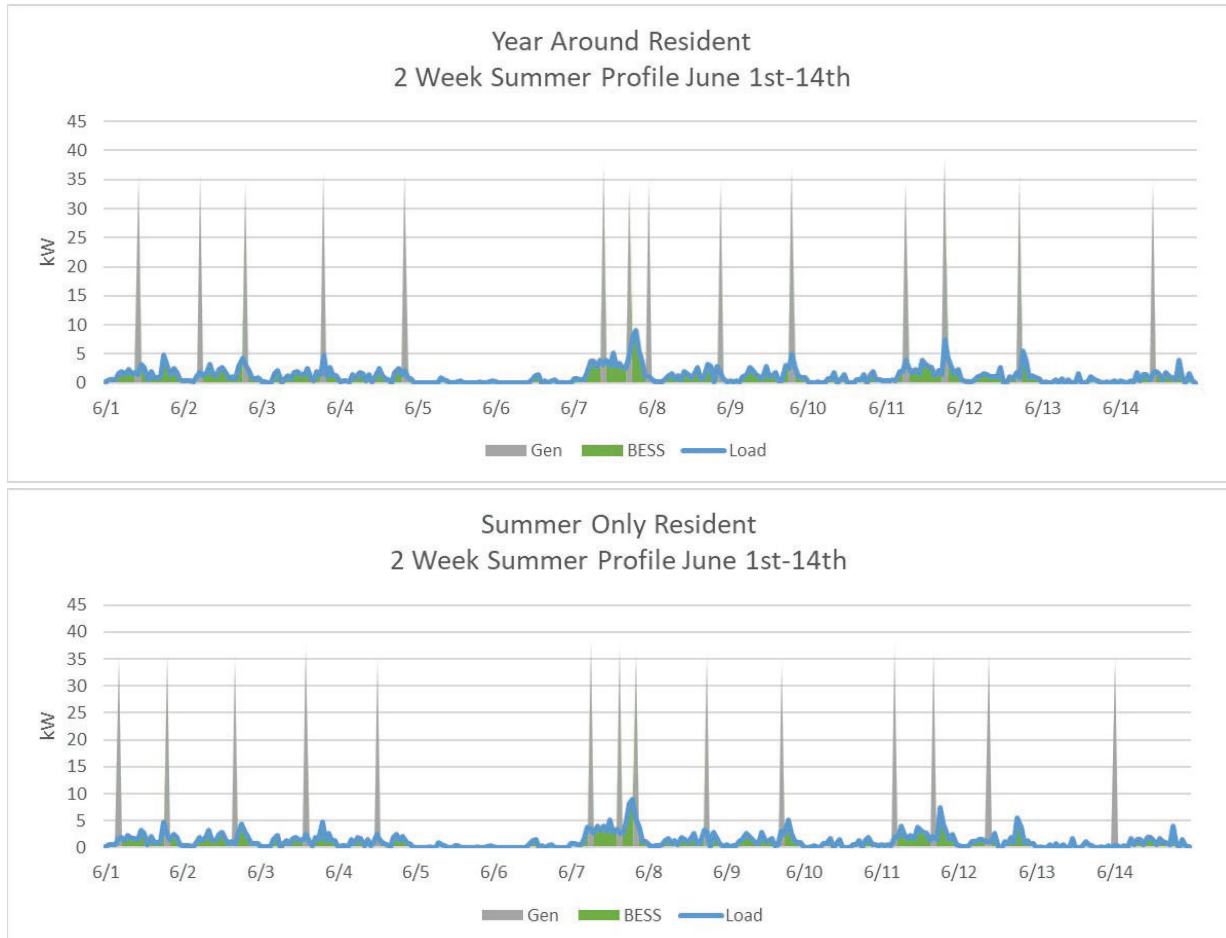


Figure 2-9: Alternative 5 Summer Dispatch Profiles

- Winter Operating Profile
 - Refer to Figure 2-10. During winter conditions, the year-round residences experience higher sustained demand and reduced periods during which the battery alone can carry the load, leading to more frequent generator dispatch and a greater share of diesel-led operation. The operating logic remains the same: once a generator starts, it runs at full load until the battery is recharged, minimizing the number of start-stop cycles and preserving higher operating efficiency. Because there is no shared renewable generation or pooled reserve, each home maintains its own reserve independently, and winter reliability depends on the condition of each generator, each battery, and each on-site fuel supply. The summer-only residences contribute little or no winter demand, so the winter operating profile is dominated by the year-round portion of the fleet.

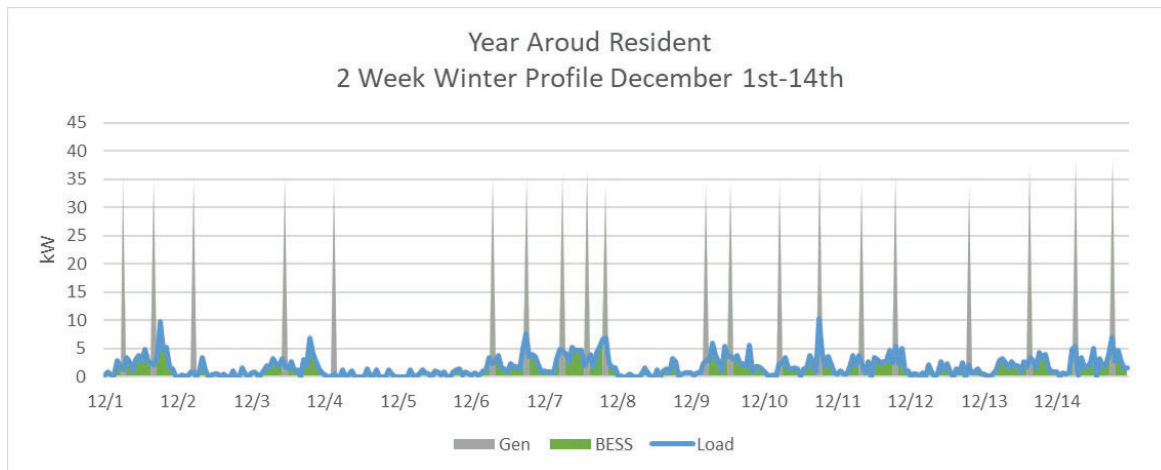


Figure 2-10: Alternative 5 Winter Dispatch Profile

- Operational Summary for Alternative 5
 - Alternative 5 provides a decentralized site-level resiliency model in which each house remains operationally independent, but it also creates the most fuel-intensive and operationally fragmented profile in the alternatives set. The battery functions primarily as a load buffer and generator-charging reserve, not as a long-duration standalone energy source. Generator dispatch is intentionally concentrated into fewer, higher loading runs to reduce O&M cost and capitalize on better efficiency at higher load factors. Summer operation is lighter overall because of lower demand and the presence of seasonal residences, while winter operation is driven primarily by the year-round homes and shows greater diesel runtime and stronger dependence on site-level fuel availability. Relative to the island-wide alternatives, Alternative 5 does not capture the efficiency benefits of shared renewable generation, centralized dispatch optimization, or pooled reserve margin; its operating strength is local independence, and its tradeoff is higher aggregate fuel use and a larger number of independent systems that must each remain maintained, fueled, and serviceable.

3.0 Financial Evaluation and Risk Analysis

3.1 Opinion of Capital Cost

HDR prepared rough order of magnitude (ROM) capital expenditure (CAPEX) estimates for each microgrid asset alternative. The estimate is considered a +100/-50% Class 5 estimate based on the current level of conceptual design. The estimate classification is based upon Association for the Advancement of Cost Engineering International, Recommended Practices 18R-97 – As Applied in Engineering, Procurement, and Construction for the Process Industries. The pricing in this estimate should be considered primarily for screening and evaluation purposes only. Final costs may vary based on detailed engineering stages developed in later project phases. The estimate assumes there is no shortage of qualified labor craftsmen. A labor study has not been conducted at this stage of the project.

The estimate scope is structured around the microgrid alternative scenarios with costs developed by technology and with interconnection infrastructure allowances appropriate to each microgrid

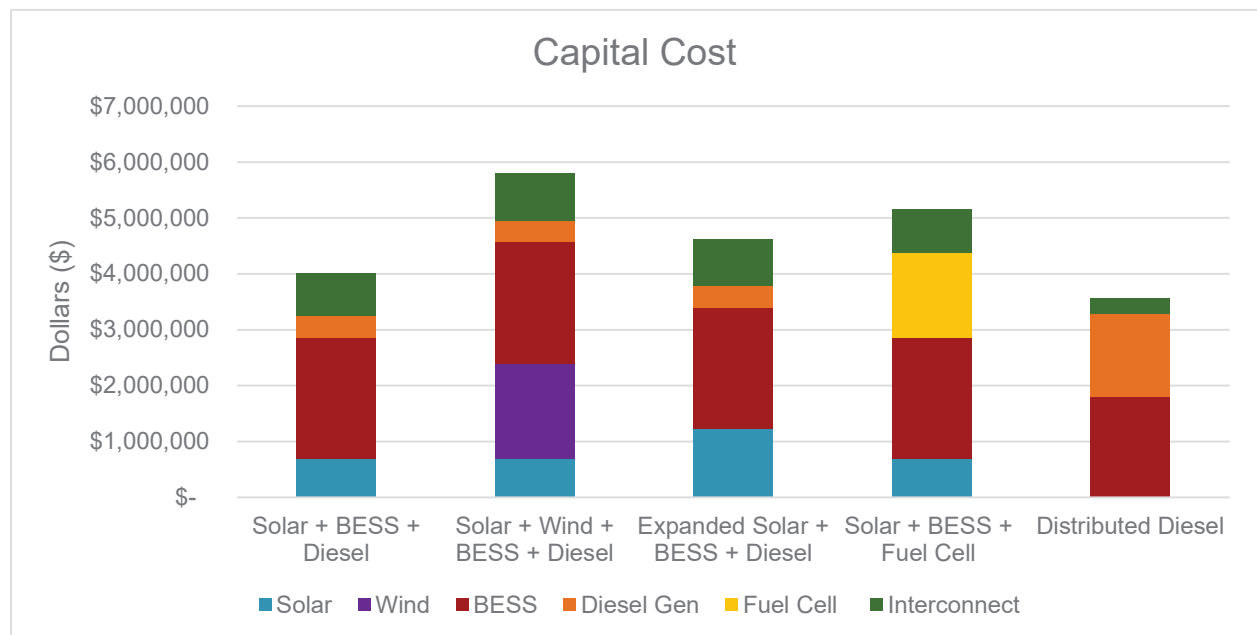
configuration. Each technology scope includes site work, foundation, structural steel, electrical, and mechanical components. The scope allowances and material pricing were based on a combination of preliminary quantity takeoffs, unit cost metrics, historical project data and estimator judgment. Pricing was presented in current 1st Quarter 2026 US Dollars. Labor pricing was based on approximation of local Washington union wages and a straight time work schedule. The pricing includes base wages, fringe benefits, payroll taxes and insurance. Labor productivity was factored in based on the offshore site location and work conditions.

The CAPEX “Addon” column costs include engineering, construction management, construction indirects, project indirects, and overhead/profit fee. An overall project contingency of 25 percent was included to cover scope risk and unknown site conditions, and is included in the Addon costs.

Costs attributed to land acquisition, easements or right-of-way acquisition, escalation, undefined site obstructions, excessive weather, and schedule delays are excluded from the estimate.

Table 3-1: Ketrone Island Microgrid Asset Class 5 Rough Order of Magnitude Estimate

Capital Estimates	Solar + BESS + Diesel	Solar + Wind + BESS + Diesel	Expanded Solar + BESS + Diesel	Solar + BESS + Fuel Cell	Distributed Diesel + BESS
Solar	\$682,771	\$682,771	\$1,230,437	\$682,771	\$0
Wind	\$0	\$1,708,845	\$0	\$0	\$0
BESS	\$2,174,961	\$2,174,961	\$2,174,961	\$2,174,961	\$1,787,006
Distributed BESS					
Diesel Gen	\$390,802	\$390,802	\$390,802	\$0	\$1,502,886
Distributed Gen					
Fuel Cell	\$0	\$0	\$0	\$1,511,223	\$0
Interconnect	\$756,167	\$848,863	\$826,773	\$774,388	\$283,513
Total Plant Capital Costs	\$4,004,701	\$5,806,242	\$4,622,973	\$5,143,343	\$3,573,405
Capital Estimates (Breakdown)	Solar + BESS + Diesel	Solar + Wind + BESS + Diesel	Expanded Solar + BESS + Diesel	Solar + BESS + Fuel Cell	Distributed Diesel + BESS
Solar	17%	12%	27%	13%	0%
Wind	0%	29%	0%	0%	0%
BESS	54%	37%	47%	42%	50%
Diesel Gen	10%	7%	8%	0%	42%
Fuel Cell	0%	0%	0%	29%	0%
Interconnect	19%	15%	18%	15%	8%



A detailed Class 5 OPCC estimate table for each alternative is provided in Appendix D, where individual assets Material, Labor and Sub dollar amounts are provided.

3.2 Financial Analysis with Sensitivities

The financial evaluation compares the alternatives on a common operating basis using the #2 load profile under “current development/severe weather” conditions. The analysis incorporates capital cost, yearly operation and maintenance cost with escalation, hourly load, renewable production, battery operation, dispatchable generation, and curtailment, which allows the financial comparison to reflect the way each alternative performs under the modeled representative year.

The results separate the alternatives clearly in terms of capital cost, fuel-price exposure, renewable contribution, operating complexity, and long-term cost stability. Alternative 1 occupies the lowest-capital position but carries the highest exposure to diesel price volatility among those centralized diesel-backed portfolios. Alternative 2 increases renewable contribution and reduces diesel dependence but introduces greater equipment complexity and resource uncertainty and represents the highest 20-year net present value (NPV) case under the modeled basis. Alternative 3 delivers the strongest overall balance of capital efficiency, operating savings, and implementation predictability. Alternative 4 provides the strongest decarbonization pathway and exposed to hydrogen supply-chain assumptions. Alternative 5 is the most fuel-dependent and operationally fragmented option because it relies on multiple standalone systems rather than a shared island-wide resource portfolio.

Diesel price escalation has the greatest effect on Alternative 5 among all Alternatives because it remains the most fuel-dependent option over the modeled year. Among the centralized diesel-backed alternatives, Alternative 1 is the most sensitive to diesel price escalation because it relies more heavily on diesel generation than Alternatives 2 and 3.

Table 3-2: Ketron Island Microgrid Alternatives Financial Comparison

Alternative	Cost Position	Key Financial Driver	Main Risk/Sensitivity	Summary Interpretation
Alt. 1 – Solar + BESS + Diesel	Lower centralized CAPEX	Diesel fuel exposure	Diesel price and runtime	Simple, low first-cost baseline but higher long-term fuel exposure
Alt. 2 – Solar + Wind + BESS + Diesel	Higher NPV	Added wind equipment and O&M	Wind performance and turbine availability	Renewable diversity, but added complexity and performance uncertainty
Alt. 3 – Expanded Solar + BESS + Diesel	Best cost-risk balance	Diesel reduction through added PV	Solar utilization and curtailment	Strong balance of maturity, fuel reduction, and implementation predictability
Alt. 4 – Solar + BESS + Fuel Cell	High CAPEX/strategic decarbonization	Hydrogen supply and storage	Delivered hydrogen cost and vendor support	Strongest non-diesel pathway but dependent on hydrogen logistics

Alternative	Cost Position	Key Financial Driver	Main Risk/Sensitivity	Summary Interpretation
Alt. 5 – Distributed Diesel + BESS	Low initial system complexity at each premise	Repeated diesel systems and fuel	Distributed O&M and fuel logistics	Summary Interpretation

3.3 Alternative 1 – Solar PV + BESS + Diesel

Alternative 1 is the lowest first-cost centralized option and the most straightforward to deploy from a technology and construction standpoint. Its primary financial tradeoff is long-term operating exposure; diesel remains the dominant firm-energy source during extended low-solar periods and adverse winter conditions, which makes this alternative the most sensitive to diesel fuel escalation among the centralized portfolios. Battery storage improves energy reserve management and shifts generated energy to periods when firm generation would otherwise be required but it does not eliminate reliance on diesel under the modeled severe-weather basis. As a result, Alternative 1 establishes the baseline low-CAPEX position in the comparison, but it provides the weakest protection against future fuel-cost volatility among diesel based centralized options.

3.4 Alternative 2 – Solar PV + Wind + BESS + Diesel

Alternative 2 delivers the highest renewable contribution among the diesel-backed centralized portfolios by combining the generation diversity of wind and solar with the common battery and diesel backbone. This directly reduces diesel runtime and lowers exposure to fuel-price escalation relative to Alternative 1, particularly where wind production complements solar during non-solar hours and stressed weather periods. The tradeoff is that this alternative carries the highest equipment complexity among the renewable-heavy cases, along with greater dependence on actual wind performance and turbine availability. Its financial outcome is therefore stronger than Alternative 1 when wind assumptions are achieved, but less predictable than Alternative 3 because more of its value depends on resource performance and distributed equipment reliability.

3.5 Alternative 3 – Expanded Solar PV + BESS + Diesel

Alternative 3 provides the strongest overall cost-risk balance in the financial comparison. The expanded PV field materially reduces diesel consumption relative to Alternative 1 while maintaining a simpler and more predictable system structure than Alternative 2. The result is a lower and more stable operating-cost profile, improved resilience to fuel-price escalation, and fewer execution variables than the wind-assisted case. This alternative captures most of the economic value associated with higher renewable contribution without introducing the additional O&M complexity and performance uncertainty associated with wind or the supply-chain sensitivity associated with hydrogen. Across the modeled basis, Alternative 3 emerges as the strongest balanced solution in terms of lifecycle savings, implementation clarity, and long-term cost stability.

3.6 Alternative 4 – Solar PV + BESS + Fuel Cell

Alternative 4 provides the strongest non-diesel pathway, and its financial profile is shaped by high initial capital cost, hydrogen storage and safety requirements, replacement considerations, and dependence on hydrogen supply and delivery assumptions. The operating logic for this case was

developed in an Excel-based dispatch model rather than HOMER so that the interaction of solar PV, BESS reserve management, load-following behavior, and fuel-cell operating guardrails could be represented directly. Under that modeled operating philosophy, the fuel cell does not run routinely during current-development summer periods because solar PV and the BESS are able to support the load and preserve hydrogen fuel. The alternative's value therefore appears primarily in periods when Tacoma Power places a premium on decarbonization, reduced local combustion, or a transition away from diesel dependence during higher-stress operating conditions.

3.7 Alternative 5 – Distributed Diesel + Household BESS

Alternative 5 represents a decentralized service model in which individual premises are served by their own generator-and-storage systems rather than through a shared island-wide microgrid. Each standalone system is operated so that, once the generator starts, it runs at full load until the local battery is fully charged. This reduces the number of generator starts, lowers O&M burden associated with repeated cycling, and improves generator efficiency relative to lighter-load operation. The fleet includes both year-round and summer-only residences, which results in a mixed annual load pattern with continuous service at some premises and seasonal operation at others. Even with that operating logic, the alternative remains the most fuel-dependent and operationally fragmented option because it does not benefit from shared renewable generation, centralized dispatch optimization, or pooled reserve. It is the lowest capital cost alternative.

3.8 Financial Modeling Assumptions of Costs

Table 3-3 summarizes the principal financial modeling assumptions used in the financial analysis. The maintenance assumptions were developed using technology specific O&M benchmarks for comparable assets and were applied as annual \$/kW-year allowances for lifecycle cost modeling.

Diesel fuel costs are based on the Department of Energy's Clean Cities and Communities report. Hydrogen fuel costs are based on the Department of Energy's Hydrogen Program Record #24005, "Clean Hydrogen Production Cost Scenarios with PEM Electrolyzer Technology, but escalated to 2026 dollars and island service. Solar and residential BESS O&M estimates are based on National Renewable Energy Laboratory data. Fuel cell O&M estimates are based on Energy Information Agency 2026 Annual Energy Outlook data, but a 2.2 multiplier was implemented to reflect commercial O&M costs in lieu of utility scale costs and island services. Wind cost is based on representative vendor estimate. Commercial scale BESS and diesel generator O&M cost assumptions are based on internal knowledge and engineering judgement. Both centralized and decentralized BESS replacement costs are based on an escalation of original capital cost and expected to occur in year 10. Fuel cell restacking costs are assumed to be 70 percent of capital cost and occur in year 10.

Table 3-3: Financial model basis/assumptions

Financial Parameters	Units	Value	
Discount Rate	WACC	7.00%	
Project Life	Years	20	
Fuel	Units	Value	Escalation
Year 1 Diesel Cost	\$/gal	4.77	3%
Year 1 Hydrogen Cost	\$/kg	9	3%
Maintenance Assumptions	Units	Value	Escalation
Solar	\$/kW-yr	24	3%
Wind	\$/kW-yr	30	3%
BESS	\$/kW-yr	36	3%
Diesel Gen	\$/kW-yr	28	3%
Fuel Cell	\$/kW-yr	84	3%
Residential Scale BESS	\$/kW-yr	97	3%
Residential Scale Diesel Gen	\$/kW-yr	28	3%
Replacement Assumptions	Units	Value	
Centralized BESS	\$	\$ 2,174,961	3%
Distributed BESS	\$	\$ 1,787,006	3%
Fuel Cell Restack	\$	\$ 1,057,856	3%

3.9 Sensitivity Findings

Sensitivity findings reinforce the differences among the alternatives and show that the ranking is driven by a small number of dominant uncertainties. Diesel price escalation has the greatest effect on Alternatives 1 and 5 because both remain heavily dependent on diesel fuel over the modeled year. Renewable resource variability has the greatest effect on Alternative 2 because its lifecycle benefit depends materially on wind production and turbine availability. Load growth and adverse weather increase reliance on firm generation across all alternatives and make the common BESS more operationally constrained, which increases the relative value of alternatives that reduce firm-generation use without introducing additional resource or supply-chain uncertainty. Under those conditions, Alternative 3 remains the most stable performer because it lowers diesel dependence while preserving a simpler operating and maintenance structure than Alternative 2 or Alternative 4. Hydrogen delivered cost and supply reliability dominate the sensitivity profile of Alternative 4 and control whether it functions as a strategic decarbonization pathway.

Figure 3-1 illustrates how changes in capital cost assumptions affect the 20-year life-cycle cost of the five microgrid alternatives. Based on the model outputs provided, the relative ranking remains unchanged across the CAPEX sensitivity range, with alternatives 1 and 5 remaining the lowest-cost options and alternative 4 remaining the highest-cost alternative.

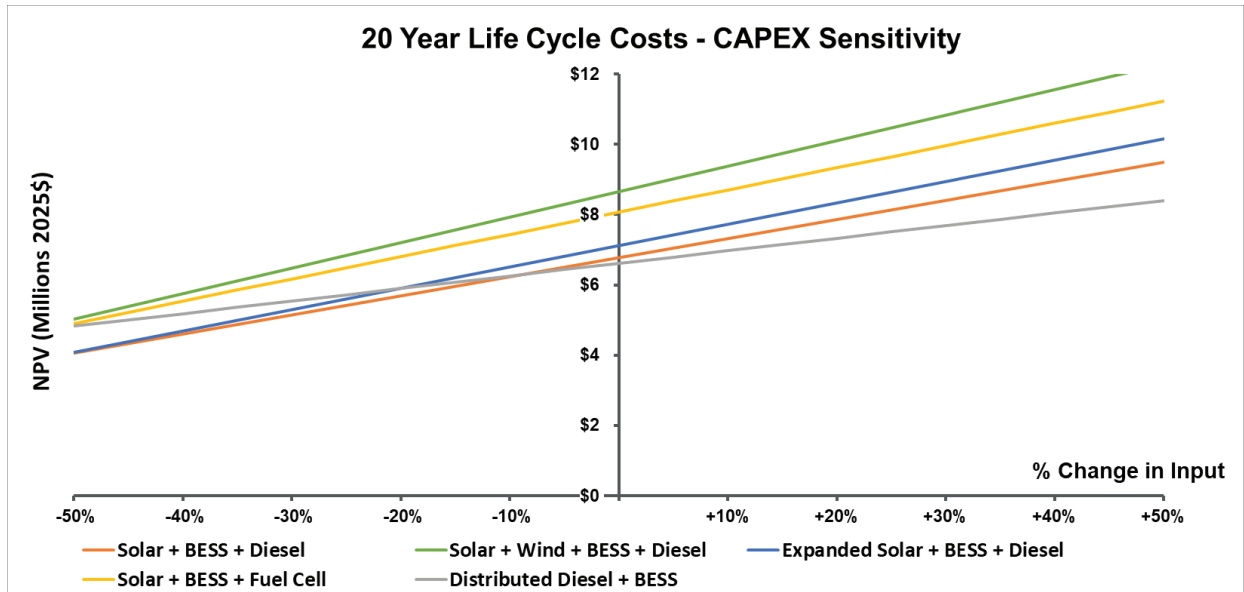


Figure 3-1: 20-year Life Cycle Costs – CAPEX Sensitivity

The Figure 3-2 chart shows the effect of diesel fuel price uncertainty on the long-term economics of alternatives. Alternative 5 (Distributed Diesel + BESS) is the most sensitive to fuel cost changes relying more heavily on diesel consumption.

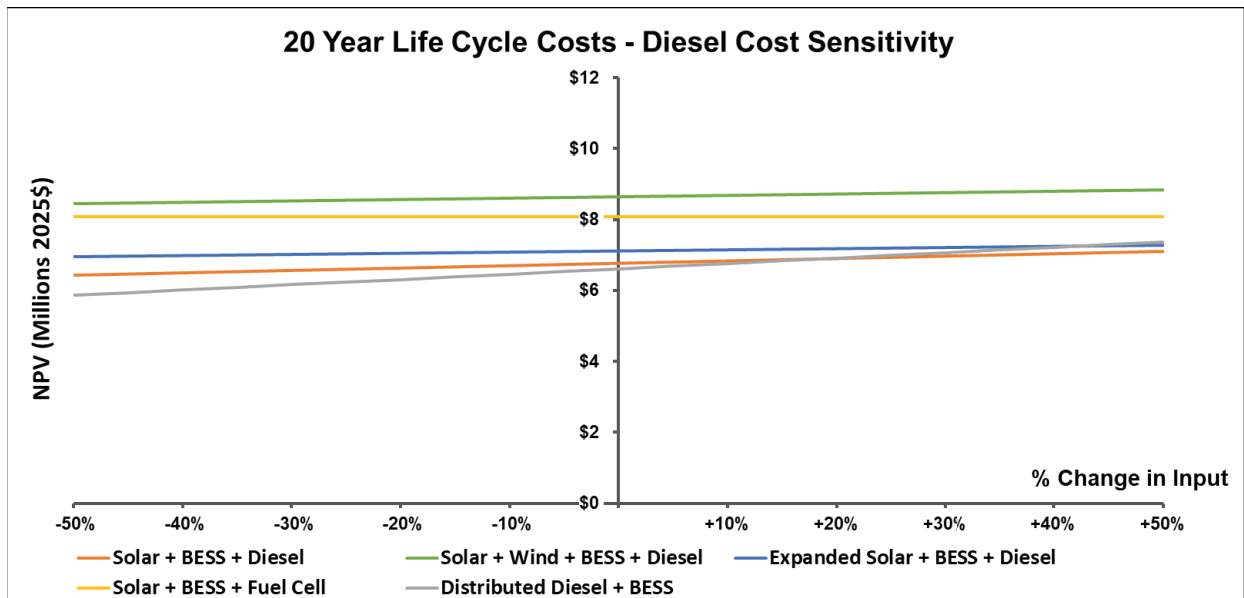


Figure 3-2: 20-year Life Cycle Costs – Diesel Cost Sensitivity

Figure 3-3 evaluates how changes in annual O&M assumptions influence total 20-year life-cycle cost. The results indicate limited movement in relative cost position across the alternatives, except for the Distributed Diesel + BESS due to its heavy reliance on fuel usage.

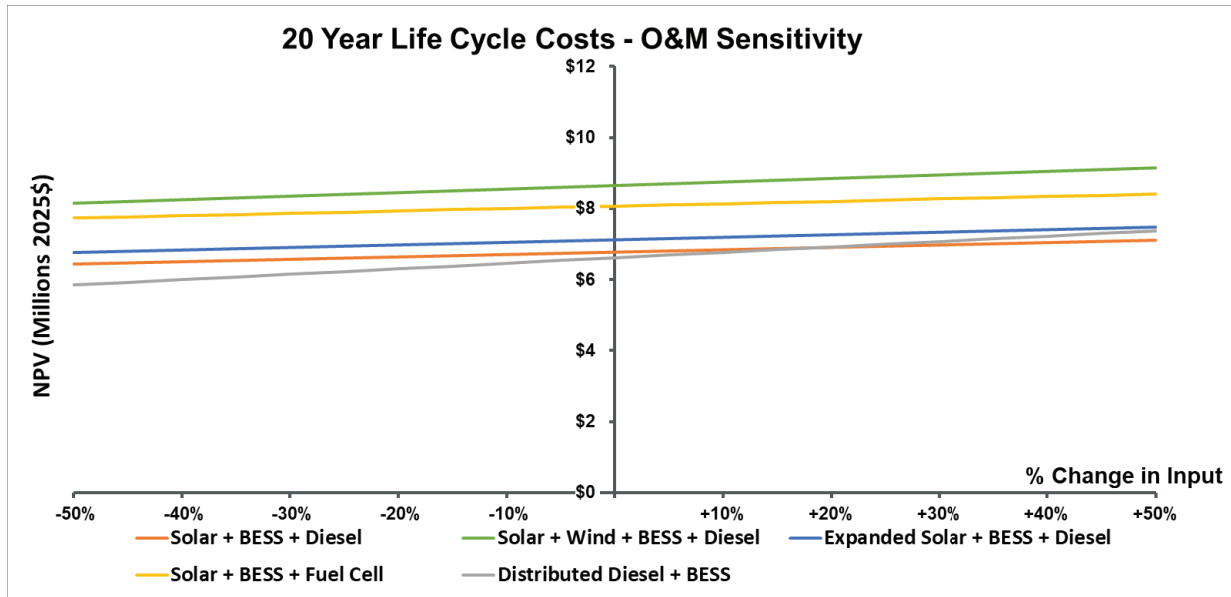


Figure 3-3: 20-year Life Cycle Costs – O&M Sensitivity

Figure 3-4 isolates the impact of hydrogen fuel price assumptions on Alternative 4, with the Solar + BESS + Fuel Cell configuration being the only alternative affected.

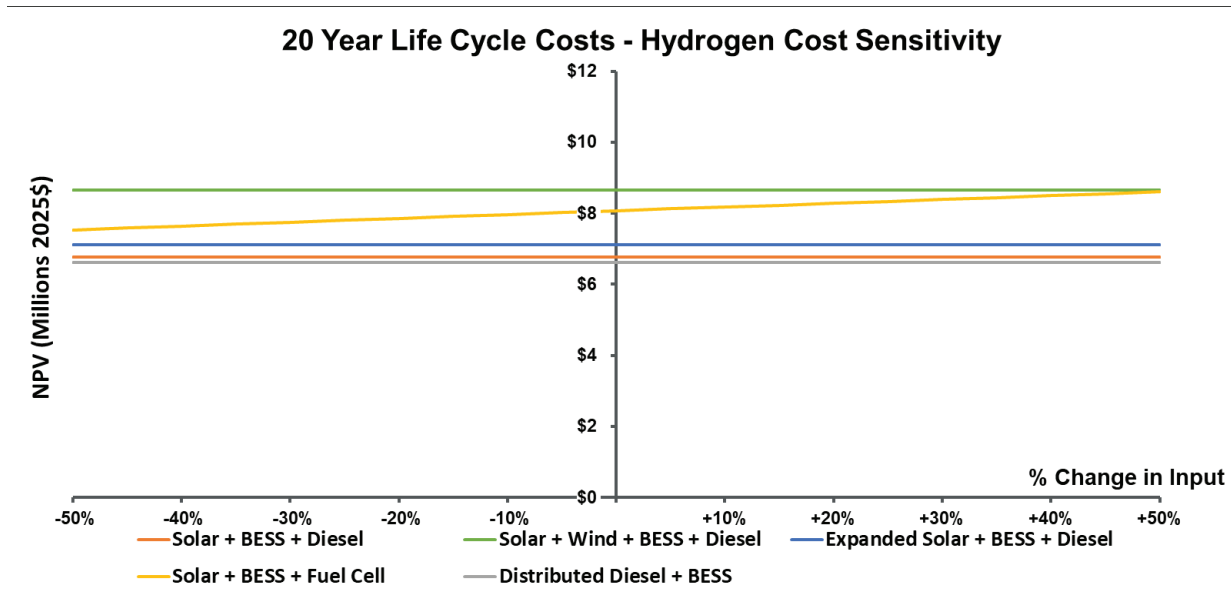


Figure 3-4: 20-year Life Cycle Costs – Hydrogen Cost Sensitivity

Figure 3-5 illustrates how changes in fuel prices affect the 20-year life-cycle cost of each microgrid alternative. Distributed Diesel + BESS is the most sensitive because of its comparatively high diesel consumption, whereas the renewable-forward alternatives show lower fuel-cost exposure; the fuel-cell case is affected by hydrogen price changes and remains the highest fixed system cost.

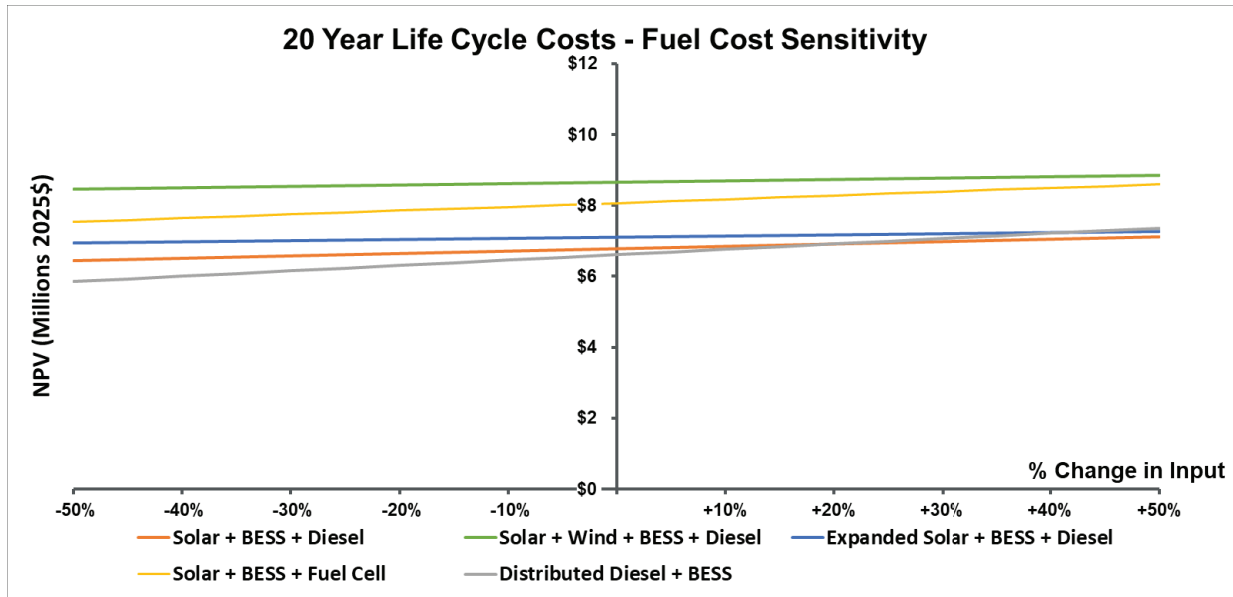


Figure 3-5: 20-year Life Cycle Costs – Fuel Cost Sensitivity

3.10 Comparative Financial Conclusion

3.10.1 Basis of Financial Analysis

The financial conclusions presented below are based on load scenario that the Real Estate Potential Assessment and Peak and Energy Load Forecast report identified as most credible over the 20-year planning horizon. The real estate report concluded that significant new development on Ketron Island is unlikely. On that basis, the analysis presented in this section is based on the Current Development, Severe Cold Weather; HDR did not perform financial analyses for the other load scenarios. Life cycle costs do not include carbon offset purchases or carbon tax.

3.10.2 Financial Comparison Findings

Based on the 20-year financial model, capital cost estimate, O&M and fuel assumptions, and sensitivity results presented above, the financial comparison establishes the following findings:

- Alternative 1 has the lowest capital cost among the centralized options and the highest long-term diesel exposure among those centralized diesel-backed alternatives. It remains financially attractive where low capital cost is the primary decision driver, but it provides weaker protection against long-term fuel-cost volatility than Alternatives 2 and 3.
- Alternative 2 provides a strong renewable contribution among the diesel-backed centralized portfolios and adds resource diversity through wind, but it also introduces greater sensitivity to wind performance and increased system complexity. Under the modeled basis, Alternative 2 represents the highest 20-year NPV case, which reflects the combined effect of added equipment complexity, capital cost, and long-term maintenance uncertainty.
- Alternative 3 provides a highest renewable contribution through its expanded solar configuration, and it offers the best overall cost-risk balance and the strongest combination of operating savings, implementation predictability, and long-term cost stability. It remains the preferred overall solution under the modeled basis.

- Alternative 4 provides the strongest decarbonization pathway, and remains sensitive to hydrogen supply-chain assumptions, but its lifecycle economics improve materially when the fuel-cell capacity is aligned with the island load profile and BESS-supported dispatch strategy.

Alternative 5 is the most fuel-dependent and operationally fragmented option and does not capture the shared-system benefits available to the island-wide alternatives. It remains highly exposed to diesel price volatility and repeated site-level maintenance

Table 3-4: Financial Summary

Alternative	Capital Cost	Fuel Exposure	O&M Complexity	Technology/Delivery Risk	Overall Financial Interpretation
Alt. 1 – Solar + BESS + Diesel	Lower	Higher diesel exposure	Moderate	Low	Low first cost, but higher long-term fuel exposure
Alt. 2 – Solar + Wind + BESS + Diesel	Higher	Lower than Alt. 1	Higher	Higher	Renewable diversity, but more complexity and higher uncertainty
Alt. 3 – Expanded Solar + BESS + Diesel	Moderate	Lower diesel exposure	Moderate	Low to moderate	Best overall cost-risk balance contingent on land availability
Alt. 4 – Solar + BESS + Fuel Cell	Higher	Hydrogen exposure	Higher	Higher	Strategic non-diesel option, but dependent on hydrogen assumptions
Alt. 5 – Distributed Diesel + BESS	Lower/moderate	Highest diesel exposure	Higher distributed O&M	Moderate	Decentralized fallback with higher fuel and maintenance exposure

Taken together, the financial comparison identifies Alternative 3 as the strongest overall balance of cost, operational performance, and resilience to O&M cost escalation under the modeled basis. Alternative 1 remains the lowest-capital baseline among centralized configurations. Alternative 2 is attractive only where wind performance is well validated and its execution complexity is acceptable, but under the current assumptions it produces the highest 20-year NPV. Alternative 4 remains the strategic decarbonization option in comparison. It performs better financially than Alternative 2 under the modeled basis, and Alternative 5 functions primarily as a decentralized resiliency fallback rather than a fully integrated island-wide microgrid solution.

Table 3-5: Comparative Financial Results by Alternative

Results Summary						
Annual Production		Solar + BESS + Diesel	Solar + Wind + BESS + Diesel	Expanded Solar + BESS + Diesel	Solar + BESS + Fuel Cell	Distributed Diesel
	Solar kWh	227,653	227,653	455,305	227,653	-
	Wind kWh	-	78,608	-	-	-
	BESS kWh	183,186	156,942	178,499	87,680	-
	Distributed BESS kWh	-	-	-	-	276,246
	Diesel Gen kWh	154,190	89,578	74,993	-	-
	Distributed Diesel kWh	-	-	-	-	340,206
	Fuel Cell kWh	-	-	-	154,120	-
Year 1 Costs						
	Solar	\$4,800	\$4,800	\$9,600	\$4,800	\$0
	Wind	\$0	\$6,000	\$0	\$0	\$0
	BESS	\$36,000	\$36,000	\$36,000	\$36,000	\$0
	Distributed BESS	\$0	\$0	\$0	\$0	\$89,240
	Diesel Gen	\$58,576	\$37,573	\$32,838	\$0	\$0
	Distributed Gen	\$0	\$0	\$0	\$0	\$32,200
	Fuel Cell	\$0	\$0	\$0	\$89,652	\$0
	Total O&M	\$99,376	\$84,373	\$78,438	\$130,452	\$121,440
20 year PV of Operating Costs						
	Solar	\$63,992	\$63,992	\$127,984	\$63,992	\$0
	Wind	\$0	\$79,990	\$0	\$0	\$0
	BESS	\$1,922,549	\$1,922,549	\$1,922,549	\$1,922,549	\$0
	Distributed BESS	\$0	\$0	\$0	\$0	\$1,189,718
	Diesel Gen	\$780,915	\$757,525	\$437,790	\$0	\$0
	Distributed Gen	\$0	\$0	\$0	\$0	\$341,127
	Fuel Cell	\$0	\$0	\$0	\$2,252,422	\$0
	20 year NPV OP Costs (NPV \$2026)	\$2,767,456	\$2,824,056	\$2,488,323	\$4,238,963	\$1,530,845
Capital Estimates						
	Solar	\$682,771	\$682,771	\$1,230,437	\$682,771	\$0
	Wind	\$0	\$1,708,845	\$0	\$0	\$0
	BESS	\$2,174,961	\$2,174,961	\$2,174,961	\$2,174,961	\$1,787,006
	Diesel Gen	\$390,802	\$390,802	\$390,802	\$0	\$1,502,886
	Fuel Cell	\$0	\$0	\$0	\$1,511,223	\$0
	Interconnect	\$756,167	\$848,863	\$826,773	\$774,388	\$283,513
	Total Plant Capital Costs	\$4,004,701	\$5,806,242	\$4,622,973	\$5,143,343	\$3,573,405
Estimated 20 Yr Life Cycle Costs (NPV \$2026)		\$ 6,772,157	\$ 8,630,298	\$ 7,111,296	\$ 9,511,090	\$ 6,611,276

3.11 Risk Assessment and Management

A detailed planning-level Risk Register is provided in Appendix B. Appendix B captures risks associated with generation technology and delivery reliability, environmental and regulatory permitting, land acquisition and right of way, and schedule risks related to permitting, procurement, and delivery of major equipment components for each alternative.

The risk assessment confirms that the alternatives separate clearly by technology integration risk, fuel and supply-chain dependence, and execution complexity. The permanently islanded nature of the Ketron Island system is an important risk driver in all cases because the alternatives cannot rely on mainland grid support during abnormal operating conditions; each configuration must therefore carry its own operational resilience through local generation, storage, controls, and fuel logistics.

The assessment identifies five distinct risk profiles. Alternative 1 has the lowest integration complexity but remains strongly dependent on diesel deliveries during prolonged low-renewable periods. Alternative 2 improves renewable diversity and reduces diesel dependence, but it introduces a materially higher mechanical and maintenance burden through the addition of multiple wind turbines. Alternative 3 reduces diesel use while preserving a relatively simple and mature architecture, which makes it the strongest overall balance of technology maturity, maintainability, and fuel-risk reduction. Alternative 4 provides the strongest non-diesel pathway but has the most complex supply-chain and operational support requirements because it depends on hydrogen logistics, storage, safety systems, and vendor-supported fuel cell operation. Alternative 5 distributes risk across 23 individual systems rather than one shared microgrid, which reduces dependence on centralized infrastructure but materially increases fleet maintenance burden, distributed fuel handling, and the number of independent failure points. It is possible that arrangements between Tacoma Power and individual property owners could be negotiated that mitigate risks associated with Alternative 5.

3.12 Generation Technology and Delivery Reliability

The principal operational risk across Alternatives 1 through 4 is the ability of the permanently islanded microgrid to coordinate multiple distributed resources under a BESS-first, renewable-priority, dispatchable-backup control strategy. In these cases, the BESS serves as the grid-forming asset and is responsible for stabilizing voltage and frequency, supporting black start, and responding to fast variations in load and renewable production. That makes battery availability, inverter performance, controls integration, and reserve management central reliability considerations for every island-wide alternative.

For Alternative 1, the key generation reliability risk is diesel dependence during extended adverse conditions. The generator technology itself is mature and widely available with generally available maintenance labor, which reduces equipment uncertainty, but long-duration reliability is still tied to delivered fuel availability and healthy generator operation. This risk can be minimized with larger duration of fuel storage on the island, but this would require a larger storage tank. The project operating philosophy intentionally uses the BESS to reduce short-cycle diesel operation and preserve reserve, but firm generation remains essential when solar contribution falls during winter or severe weather. Diesel operation also carries the usual low-load risk, which is commonly managed by keeping the generator above a healthy loading range and using battery charging to absorb surplus output.

For Alternative 2, the main reliability benefit is renewable diversity: wind reduces dependence on a single resource type and can offset diesel use during low-solar periods. The corresponding risk is the introduction of many more mechanical components, more electrical interfaces, and more maintenance exposure. The use of multiple small turbines creates more potential failure points than the other island-wide alternatives and makes annual performance more dependent on turbine availability and actual wind conditions. If wind resources were to be considered further detailed site-specific studies of wind speeds and production rates would be appropriate to confirm the generation potential.

For Alternative 3, reliability improves relative to Alternative 1 because the larger solar field lowers diesel dependence while preserving a comparatively simple system architecture. The residual risk remains seasonal solar limitation rather than equipment novelty: winter and extended low-solar periods still require firm generation support, but the technology mix itself remains relatively mature

and maintainable. As a result, this alternative has the most favorable balance between reduced fuel use and technology reliability.

For Alternative 4, the dominant reliability issue is not the electrochemical generation process itself, but the full hydrogen support chain around it. Reliable operation depends on hydrogen availability, on-site storage, pressure regulation, controls integration, and specialized vendor-supported O&M. Under the modeled operating philosophy, the fuel cell is dispatched to follow load and support BESS reserve recovery within its operating guardrails rather than being kept online continuously in all seasons. For current-development summer load profiles, solar PV and the BESS can support the load without routine fuel-cell operation, while winter and other stressed periods rely more heavily on hydrogen-backed dispatchable support. This creates a more complex reliability envelope than the diesel-backed options even though the fuel cell provides a stable non-diesel firm-power pathway when dispatched.

With Alternative 5, generation reliability becomes a fleet-management issue rather than a central-microgrid issue. Each site-level system, including residential and non-residential customers, is individually resilient to the extent that its generator, battery, and fuel tank remain available, but the island no longer benefits from shared reserve or common dispatch optimization. The operating strategy intentionally runs each generator at full load once started in order to recharge the battery, reduce cycling, and maintain higher efficiency, but this also means reliability depends on repeated site-level generator performance across the full fleet. The year-round residences dominate winter reliability exposure, while the summer-only residences contribute primarily to seasonal fleet maintenance and fuel-management demand.

3.13 Environmental and Regulatory Permitting

Appendix A provides a high-level comparison of permitting and environmental constraints for the five proposed microgrid configurations on Ketron Island in Pierce County, Washington. For each configuration, the table identifies key land use and environmental factors that may affect feasibility under Pierce County regulations. The table is intended as a preliminary guidance tool to help compare relative regulatory requirements and overall feasibility among the proposed options.

The table highlights several key zoning considerations that influence where specific microgrid configurations may be sited. Ketron Island includes three primary zoning designations: Rural 10 (R10), Rural Neighborhood Center (RNC), and Agricultural Resource Land (ARL). R10 is the predominant zoning designation across the island. The Pierce County ferry terminal property is located within the RNC zone, and a large parcel located near the center of the island is designated ARL. These zoning distinctions determine where each configuration may be allowed and under what conditions.

Solar electrical generation facilities up to 5 acres in size are allowed in the R10 and the RNC zones with the approval of a Conditional Use Permit (CUP). All other types electrical generation facilities, including wind turbine installations, are permitted only within the R10 zone and also require a CUP. Electrical generation facilities are not allowed in the ARL zone (Pierce County Code [PCC] 18A.19.020).

Shoreline jurisdiction also may provide constraints on where the projects may be located. Shoreline jurisdiction generally extends landward 200 feet of the ordinary high water mark. There are three shoreline environments on Ketron Island: Natural, Conservancy, and High Intensity. Utilities are permitted with a shoreline substantial development permit in the Natural and Conservancy shoreline environments. New non-water-oriented uses are prohibited in the High Intensity shoreline

environment (the shoreline area around the ferry terminal), except in situations where the use does not conflict with or limit opportunities for water-oriented uses or when there is no direct access to the water's edge (PCC 18S.60.030).

Environmental constraints further affect siting and design feasibility. Ketron Island contains several mapped critical areas, including fish and wildlife habitat conservation areas, erosion hazard areas, landslide hazard areas, and wetlands. Depending on site-specific conditions, these critical areas may impose additional setbacks and/or design limitations that could affect the allowable location and configuration (Title 18E PCC).

All proposed configurations must comply with Pierce County noise standards at the property line, as summarized in Appendix A. Generators and associated fuel storage must comply with all applicable International Fire Code (IFC) and National Fire Protection Association (NFPA) requirements, as well as applicable air quality regulations, as further detailed in Appendix B. These requirements will be evaluated in greater detail once a microgrid option is selected.

3.14 Land Acquisition and Right of Way

Land acquisition and right-of-way requirements differ materially across the alternatives because the project is being evaluated as a permanently islanded system with no ability to import power during abnormal operating conditions. Alternatives 1 through 4 depend on centralized siting for major generation and storage assets, while Alternative 5 distributes those siting requirements across individual premises.

Alternative 1 has a moderate centralized footprint consisting of the solar array, BESS, diesel generation, and associated access, fuel storage, and equipment clearances. Alternative 2 has the highest land and right-of-way complexity because it adds multiple wind turbines, turbine setbacks, foundations, access requirements, and collection wiring to the common PV, BESS, and diesel footprint. Alternative 3 increases the centralized land requirement relative to Alternative 1 because of the larger PV field but remains simpler from a right-of-way and access standpoint than the wind-assisted case. Alternative 4 has a compact generation footprint relative to Alternative 3, but hydrogen storage, safety setbacks, and associated equipment spacing increase siting sensitivity compared to diesel-only centralized options.

Alternative 5 shifts land and access requirements away from a single centralized plant and distributes them across the island. Each premise requires sufficient space for a generator, battery system, and fuel tank, together with code-compliant setbacks, service access, and construction clearance. This reduces dependence on a single centralized parcel but increases the number of sites that must accommodate equipment placement, installation access, and long-term maintenance access. As a result, land risk in Alternative 5 is not concentrated, but it is repeated across the full fleet of separate residential systems.

Overall Ketron Island presents high overall -land acquisition risk. The island's restrictive zoning, ferry dependent access, aging utility infrastructure, environmental constraints, and extremely thin resale market significantly limit development feasibility for any property on the island. Recent sales indicate average pricing of approximately \$17.40 per square foot for residential property and \$1.64 per square foot for vacant land. Residential properties are characterized by the presence of a dwelling or other built structure on the parcel. In contrast, vacant land consists solely of undeveloped property without any buildings or improvements. Land value should be underwritten strictly for long-term, low intensity rural or conservation use, not speculative appreciation or subdivision. All properties on Ketron Island have no municipal sewer system in which owners must rely on individual septic

systems and private water, which increases site-specific failure and extreme risk. Because of these real estate-related risks, property on Ketron Island has very complicated usability, higher construction costs, and diminished buyer appeal.

3.15 Schedule Risks due to Procurement/Delivery of Major Equipment

Schedule risk is shaped by a combination of permitting complexity, vendor lead time, marine logistics, and the number of major equipment packages that must be delivered and installed on the island. Because Ketron Island requires offshore delivery and weather-dependent mobilization, schedule risk is influenced not only by supplier lead times, but also by the timing and sequencing of transportation, staging, and installation activities.

Alternative 1 has the most straightforward procurement and delivery profile among the centralized options. Solar PV, BESS, and diesel generation are mature equipment categories with broad supplier availability, and the principal schedule risks are tied to island delivery windows, permit timing, and coordination of the centralized site works. Alternative 2 carries the greatest schedule risk among the island-wide renewable-assisted options because it requires multiple small wind turbines, more foundations, more electrical interfaces, and more individual equipment deliveries. The number of separate turbine units increases the risk of staggered deliveries, installation bottlenecks, and extended commissioning duration.

Alternative 3 increases procurement scope relative to Alternative 1 because of the larger solar field, but it avoids the multi-unit wind erection risk of Alternative 2 and the specialized hydrogen supply-chain risk of Alternative 4. Alternative 3 has slightly higher marine logistical coordination than Alternative 1. Alternative 4 has the highest schedule uncertainty overall because it depends on specialized fuel-cell equipment, hydrogen storage and safety systems, vendor-supported integration, and permitting coordination for hydrogen handling. In addition to equipment lead time, this alternative is exposed to delays associated with storage-system design, safety review, and the supporting fuel-delivery chain.

Alternative 5 offers phasing flexibility because the distributed installations can be sequenced across multiple premises rather than tied to a single centralized critical path. However, that same distributed structure creates a different schedule burden: multiple generator, battery, and tank deliveries; repeated site mobilizations; repeated inspections; and more site-level coordination. As a result, Alternative 5 reduces dependence on a single centralized equipment yard, but it introduces a larger number of installation events that each carry their own schedule risk.

4.0 References

HDR Engineering, Inc. (HDR)

- 2025 *Real Estate Potential Assessment and Peak Electrical Energy Load Forecast*. Ketron Island Microgrid Study. October 27, 2025.
- 2026 *Microgrid Technology Screening Memorandum*. Ketron Island Microgrid Study. March 5, 2026

Appendix A. Permitting and Environmental Constraints

Permitting and Environmental Constraints

	Solar + BESS + Diesel Generation	Solar + Wind + BESS + Diesel	Expanded Solar + BESS + Diesel generation	Hydrogen Generation + BESS + Solar	Decentralized Diesel Generation
Description	- Solar - 1 acre or less of land - BESS – 1 MW/4 MWh - Diesel Generation - two (115-kW) generators with above ground fuel storage (tanks size TBD)	- Solar - 1 acre or less of land - Wind - BESS – 1 MW/4 MWh - Diesel Generation - Two (115-kW) generators with above ground fuel storage (tanks size TBD)	- Solar - More than 1 acre of land - BESS – 1 MW/4 MWh - Diesel Generation - two (115-kW) generators with above ground fuel storage (tanks size TBD)	- Hydrogen Generation - Solar - 1 acre or less land - BESS – 1 MW/4 MWh	Diesel Generation - Each household provided a diesel generator (tank size TBD)
Pierce County Allowable Zones	R10 RNC	R10		R10	R10 RNC ARL
Pierce County Permitting Zone Limitations	R10 - Electrical Generation Facilities are allowed with a Conditional Use Permit (CUP) RNC - Solar Generation Facilities up to five acres or less are allowed with a CUP ARL – Electrical Generation Facilities of any type not allowed	R10 - Electrical Generation Facilities are allowed with a CUP Freestanding Wind Turbine/Generators are limited as follows: 10 kW (greater kW must be necessary and approved by Pierce County) - Must meet Pierce County noise regulations RNC - Solar Generation Facilities up to five acres or less are allowed with a CUP ARL – Electrical Generation Facilities of any type not allowed	R10 - Electrical Generation Facilities are allowed with a CUP RNC - Solar Generation Facilities up to 5 acres or less are allowed with a CUP ARL – Electrical Generation Facilities of any type not allowed	R10 - Electrical Generation Facilities are allowed with a CUP RNC – Non-Solar Electrical Generation Facilities of are not allowed ARL – Electrical Generation Facilities of any type not allowed	Allowed in all Zones. Must meet building, environmental, and fire setbacks and meet noise requirements

	Solar + BESS + Diesel Generation	Solar + Wind + BESS + Diesel	Expanded Solar + BESS + Diesel generation	Hydrogen Generation + BESS + Solar	Decentralized Diesel Generation
Pierce County Minimum Building Setbacks by Zone – R10	Front – 25’ Interior – 10’ Rear – 30’	Front – 25’ Interior – 10’ Rear – 30’ Wind - 50’ from all property lines (setback increase for every foot over 40’)	Front – 25’ Interior – 10’ Rear – 30’	Front – 25’ Interior – 10’ Rear – 30’	Front – 25’ Interior – 10’ Rear – 30’
Pierce County Minimum Building Setbacks by Zone – RNC	Front – 25’ Interior – 5’ Rear – 5’	N/A - Wind or Diesel Electrical Generation Facilities not allowed	Front – 25’ Interior – 5’ Rear – 5’	N/A - Hydrogen Generation not allowed	Front – 25’ Interior – 5’ Rear – 5’
Pierce County Minimum Building Setbacks by Zone – ARL	N/A - Electrical Generation Facilities not allowed	N/A - Electrical Generation Facilities not allowed	N/A - Electrical Generation Facilities not allowed	N/A - Hydrogen Generation not allowed	Front – 25’ Interior – 30’ Rear – 30’
Pierce County Shorelines	Natural Conservancy High Intensity *	Natural Conservancy High Intensity *	Natural Conservancy High Intensity *	Natural Conservancy High Intensity *	Natural Conservancy High Intensity *
	* Use cannot conflict with or limit opportunities for water-oriented uses	* Use cannot conflict with or limit opportunities for water-oriented uses	* Use cannot conflict with or limit opportunities for water- oriented uses	* Use cannot conflict with or limit opportunities for water- oriented uses	* Use cannot conflict with or limit opportunities for water- oriented uses
Pierce County Critical Areas	Fish and Wildlife Habitat Erosion Hazards Landslide Hazards Wetland Buffer and Setbacks (varies, dependent on the delineated wetland category)	Fish and Wildlife Habitat Erosion Hazards Landslide Hazards Wetland Buffer and Setbacks (varies, dependent on the delineated wetland category)	Fish and Wildlife Habitat Erosion Hazards Landslide Hazards Wetland Buffer and Setbacks (varies, dependent on the delineated wetland category)	Fish and Wildlife Habitat Erosion Hazards Landslide Hazards Wetland Buffer and Setbacks (varies, dependent on the delineated wetland category)	Fish and Wildlife Habitat Erosion Hazards Landslide Hazards Wetland Buffer and Setbacks (varies, dependent on the delineated wetland category)

Pierce County Noise Limitations	Solar + BESS + Diesel Generation	Solar + Wind + BESS + Diesel	Expanded Solar + BESS + Diesel generation	Hydrogen Generation + BESS + Solar	Decentralized Diesel Generation
	60 dBA at the property line * 50 dBA at the property line * (Nighttime limitation Between the hours of 10 p.m. and 7 a.m.) *Assumes EDNA Class C Noise Source and EDNA Class A Receiving Property	60 dBA at the property line * 50 dBA at the property line * (Nighttime limitation Between the hours of 10 p.m. and 7 a.m.) *Assumes EDNA Class C Noise Source and EDNA Class A Receiving Property. Wind generators have additional noise requirements which is 57dBA at the property lines adjacent to residential uses (47dBA at night).	60 dBA at the property line * 50 dBA at the property line * (Nighttime limitation Between the hours of 10 p.m. and 7 a.m.) *Assumes EDNA Class C Noise Source and EDNA Class A Receiving Property	60 dBA at the property line * 50 dBA at the property line * (Nighttime limitation Between the hours of 10 p.m. and 7 a.m.) *Assumes EDNA Class C Noise Source and EDNA Class A Receiving Property	60 dBA at the property line * 50 dBA at the property line * (Nighttime limitation Between the hours of 10 p.m. and 7 a.m.) *Assumes EDNA Class C Noise Source and EDNA Class A Receiving Property
Pierce County Height Limitations	R10 – 40' RNC – 45' Shoreline Jurisdictions – 35'	R10 – 40' Wind (Freestanding) - 100' (additional setbacks required) Shoreline Jurisdiction – 35'	R10 – 40' RNC – 45' Shoreline Jurisdiction – 35'	R10 – 40' RNC – 45' Shoreline Jurisdiction – 35'	R10 – 40' RNC – 45' Shoreline Jurisdiction – 35'

Appendix B. Ketron Island Microgrid Study Risk Register

Risk #	Risk Name/Description	Risk Driver/Cause of Risk	Potential Outcome/Consequence	Mitigation Strategy
1	Air - Need for Construction Permit (NOC)	Construction of fuel burning equipment (Diesel Generators).	Notice of Construction Permit needed from the Puget Sound Clean Air Agency (PSCCA). If the facility is deemed a major source of air pollution, an Air Operating Permit (Title V) is required. These permits must be renewed every five years.	Unlikely to reach major source at current levels. A NOC will be required when constructing either way. Ecology responds to these within 60 days.
2	Air - tBACT (Toxics Best Available Control Technology)	Ecology will require mitigation for tBACT	Notice of Construction (NOC) requires it.	Require Tier 4 Engines or Diesel Particulate Filter
3	Air - Air Modeling	Tier 1 Review - Fuel usage will likely put emissions above Small Quantity Emission Rate (SQER). If not considered emergency.	If model demonstrates impacts above ASIL (Acceptable Source Impact Level), will need to go to Tier 2 Review and do a Health Impact Analysis If approved, will need to notify public	Larger property boundary can reduce areas with high impacts.
4	Air - HIA (Health Impact Analysis)	Tier 2 Review - Low ASIL for Diesel Particulate Matter and proximity to sensitive groups.	Longer permitting process, more indepth analysis if Tier 2 is not approved	
5	Real Estate / Property Acquisition	The non-local nature of many of these property owners could delay obtaining rights of entry to conduct further investigation and studies.	Schedule Delays	Early engagement with subject property owners once potential sites are identified.
6	Real Estate / Property Acquisition	The non-local nature of many of these property owners could delay in identifying and acquiring easements and fee acquisitions	Schedule Delays	Early engagement with subject property owners once a potential site is identified.
7	Permitting - Noise	Noise generation	May limit the size of properties that can be used.	Noise abatement measures may need to be deployed to meet Pierce County noise limitations.
8	Permitting - Fuel Storage	Large amounts of fuel storage must meet International Fire Code (IFC) and the National Fire Protection Association (NFPA) standards.	Fuel storage amount and configuration may be limited.	Larger properties can allow for more varied configurations.
9	Permitting - Permit Acquisition	Permit Acquisition Timelines	There is a risk of permit acquisition delays with state and local jurisdictions.	Selecting configurations with less permits required.
10	Fire and Life Safety issues - Combustible and flammable liquids or gas	Small lots may have difficulty meeting the separation requirements for storing and use of combustible or flammable liquids or gas. Required separation distances increase with tank size increase. Areas within a code-defined distance from the tank(s) will require maintaining the area free of combustible debris or vegetation. Classified electrical equipment and wiring are likewise required on code-based tank size. Extent of the classified area is based on tank size and type.	Smaller tanks with more frequent refills may be required. The side of the structure facing the tank may need to be upgraded to 2-hour fire resistive construction. Existing electrical, and electrical equipment added near the tank, will require explosion-proof (Classified) wiring. Unstable or unlevel ground where the tank is placed will require leveling, compaction, or other upgrades. Access to the tanks will be required to be cleared and maintained.	Easements on adjacent properties for tank location. Shared tank sites if applicable. Multiple smaller tanks may also decrease the required separation.
11	Real Estate / Property Acquisition	Title Encumbrances	There could be various title encumbrances the could trigger delays and additional costs. This includes unclear ownership, easement releases, clearing title actions, indentifying utility conflicts, boundary disputes, ect.	Conduct early title reviews of the property we will be acquiring, conduct early utility coordination, evaluate surveyed plans as soon as possible
13	Real Estate / Property Acquisition	Condemnation	Property acquisitions that go to condemnation could pose a threat to schedule	Engage early with Tacoma Power, include condemnation process in schedule
14	All 1 – Diesel fuel dependence during prolonged low-solar periods	Permanently islanded operation with winter/severe-weather conditions increases reliance on delivered diesel	Higher operating cost, greater exposure to fuel logistics, and risk of service interruption if deliveries are disrupted	Maintain onsite fuel inventory, preserve BESS reserve margin, and confirm emergency fuel-delivery strategy

15	Alt 1 – Centralized diesel/PV/BESS permitting and code compliance	Centralized combustion generation, fuel storage, and battery equipment must satisfy local permitting, fire code, and noise requirements	Permit delay, added design scope, or siting restrictions at the preferred centralized site	Coordinate early with AHJ and permitting staff; include code-compliant setbacks, acoustics, and fire/life-safety requirements in site planning
16	Alt 1 – Centralized site land and access constraints	A single site must accommodate PV, BESS, diesel generation, fuel storage, access, and clearances within applicable zoning and critical-area limits	Constrained layout, increased civil cost, or need to shift the preferred equipment yard location	Perform early site screening and layout optimization
17	Alt 1 – Major equipment procurement and island delivery delays	Island delivery windows, weather-dependent transport, and coordination of diesel/BESS/PV packages can delay the critical path	Delayed installation, delayed commissioning, and potential resequencing of construction work	Lock long-lead procurement early, develop marine logistics plan, and sequence delivery/staging work before site mobilization
18	Alt 2 – Wind turbine fleet reliability and maintenance burden	Multiple small wind turbines create more mechanical components, electrical interfaces, and maintenance exposure than other island-wide options	Higher forced outage risk, reduced renewable contribution, and greater O&M burden over time	Use standardized turbine package, spare parts strategy, preventive maintenance program, and conservative wind-performance assumptions
19	Alt 2 – Wind permitting, setback, and noise constraints	Wind turbines introduce additional zoning, setback, visual, acoustic, and potential wildlife-review requirements	Permit delay, downsizing, or loss of preferred turbine locations	Complete early siting/permitting screening and engage stakeholders and agencies before finalizing turbine layout
20	Alt 2 – Wind site footprint and collection-line access	Turbine pads, setbacks, access routes, and electrical collection increase the site footprint and ROW complexity	Higher civil/electrical scope and reduced siting flexibility compared with PV-only options	Screen candidate parcels early and optimize turbine spacing, access, and collection routing
21	Alt 2 – Wind equipment procurement and erection schedule risk	Multiple turbines, foundations, and erection activities increase procurement coordination and field-installation complexity	Longer installation duration, staggered deliveries, and delayed commissioning	Package turbine procurement through a limited number of vendors, confirm erection logistics early, and phase installation
22	Alt 3 – Residual diesel dependence during winter/resource-limited periods	Expanded PV lowers annual fuel use, but winter and prolonged low-solar periods still require diesel support	Fuel exposure remains during stressed periods, although reduced relative to smaller-PV cases	Maintain reserve-oriented dispatch strategy and confirm fuel storage/logistics for winter operation
23	Alt 3 – Larger centralized solar footprint permitting/siting constraints	The larger PV field increases land demand and may interact with zoning, setbacks, and critical-area limitations	Need for additional land, changed site layout, or increased permitting effort	Confirm centralized parcel availability early and optimize PV layout to preserve clearances and access
24	Alt 3 – Larger PV field right-of-way and access requirements	Expanded array area increases construction access, maintenance access, and civil work needs at the centralized site	Higher site-development cost and schedule sensitivity if usable area is constrained	Advance site screening and allow for phased civil/electrical installation planning
25	Alt 4 – Hydrogen supply-chain and fuel-cell operating reliability	Fuel-cell operation depends on hydrogen availability, storage, pressure regulation, controls integration, and vendor-supported O&M	Service interruption, reduced availability, or inability to dispatch when firm support is needed	Confirm fuel supply and storage strategy, maintain vendor support assumptions, and preserve BESS reserve margin to cover start and dispatch delays
26	Alt 4 – Hydrogen permitting and safety-system requirements	Hydrogen storage and handling introduce additional safety, code, and permitting review beyond the diesel-backed alternatives	Longer permit duration, added design requirements, or restricted siting options	Advance hydrogen safety review early and incorporate storage, ventilation, and separation requirements into conceptual design
27	Alt 4 – Hydrogen equipment siting and setbacks	Storage, safety buffers, and associated balance-of-plant equipment increase siting sensitivity at the centralized location	Reduced parcel flexibility and greater chance of layout revision	Screen candidate sites specifically for hydrogen storage and safety spacing before locking conceptual layout
28	Alt 4 – Specialized procurement and delivery of fuel-cell/hydrogen systems	Fuel-cell equipment, storage systems, and vendor-supported integration carry longer and more specialized lead times	Highest schedule uncertainty of the alternatives and potential delay to commissioning	Identify long-lead packages early, engage vendor on schedule assumptions, and align procurement with permitting sequence
29	Alt 5 – Fleet-level generator reliability and distributed maintenance burden	Twenty-three separate generators and batteries must each remain maintained, serviceable, and fueled	Higher aggregate outage exposure, more maintenance events, and more operational coordination than a centralized plant	Standardize premise-level equipment, implement fleet maintenance program, and use remote monitoring where practical
30	Alt 5 – Premise-level permitting, noise, and fuel-storage compliance	Each residential-scale installation must satisfy site-specific building, fire, environmental, and noise requirements	Repeated review cycles, inconsistent permitting outcomes, or installation delay at individual homes	Develop standard premise package, confirm typical permit path with county/AHJ, and use repeatable installation details

31	Alt 5 – Distributed site constraints at individual premises	Generators, BESS units, and tanks must fit within property setbacks, access constraints, and local site conditions at each home	Some premises may require custom siting, modified layouts, or additional civil work	Complete premise-level screening and maintain standard design with limited approved variations
32	Alt 5 – Repeated procurement, delivery, and installation events	The distributed strategy requires many separate deliveries, inspections, and mobilizations rather than one centralized build	Longer overall execution duration and greater cumulative schedule risk from repeated field activities	Phase installations, bundle equipment procurement, and coordinate deliveries/inspections through a centralized rollout plan
34	Alt 5 – Pierce County Ferry suitability	The distributed strategy must provide generation technology that meets the Pierce County Ferry system requirements to maintain power to the ferry dock	If not suitable, ferry service to Keitron Island could be affected	Coordinate with Pierce County Ferries to understand the requirements needed to maintain power to the ferry dock
35	Ferry Service - Fuel Delivery	Reliance on the Pierce County Ferry system for diesel fuel deliveries to Keitron Island would put limitations on both fuel delivery timing and quantities	These limitations could increase the risk of the system running out of diesel between deliveries	Plan for more frequent fuel deliveries during winter months when there is a higher reliance on diesel

Appendix C. HOMER Modeling Results

1: Solar + BESS + Diesel

Generation Type	Size	Notes
Diesel Generator	300 kW	
Solar	200 kW	1/2 acre land area
BESS	1000 kW/4hr	One standard BESS unit size

Operational Strategy Description:

Solar generation is used for daytime loads and to charge BESS for off-peak deployment. Diesel generation is run when the load cannot be met with available solar and BESS reserve. Once the generator is running it runs at full load until the BESS is fully charged to limit the number of times the diesel generator needs to kick on to limit O&M costs and to capitalize on higher equipment efficiencies at higher load factors.

Results

Fuel Usage

All values are yearly

Current dev., normal weather	26,673	L
Current dev., severe weather	39,819	L
High growth dev., normal weather	295,692	L
High growth dev., severe weather	345,761	L

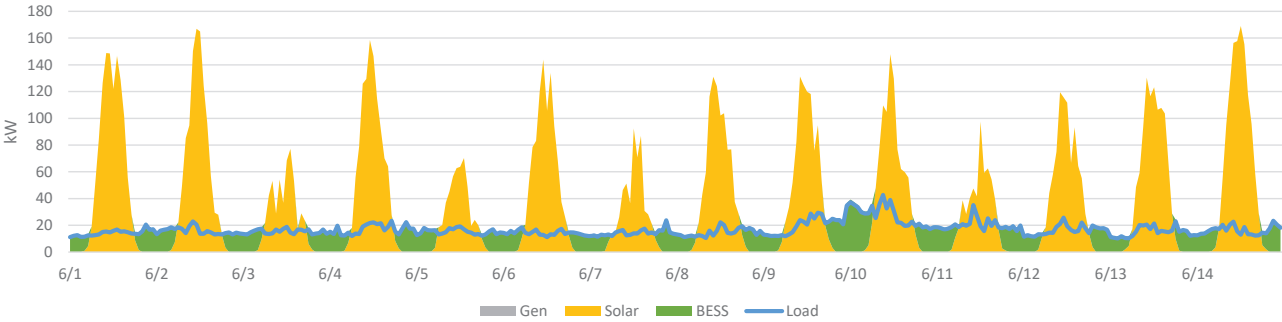
Gen Run Hours

Current dev., normal weather	353	hrs
Current dev., severe weather	523	hrs
High growth dev., normal weather	3,833	hrs
High growth dev., severe weather	4,480	hrs

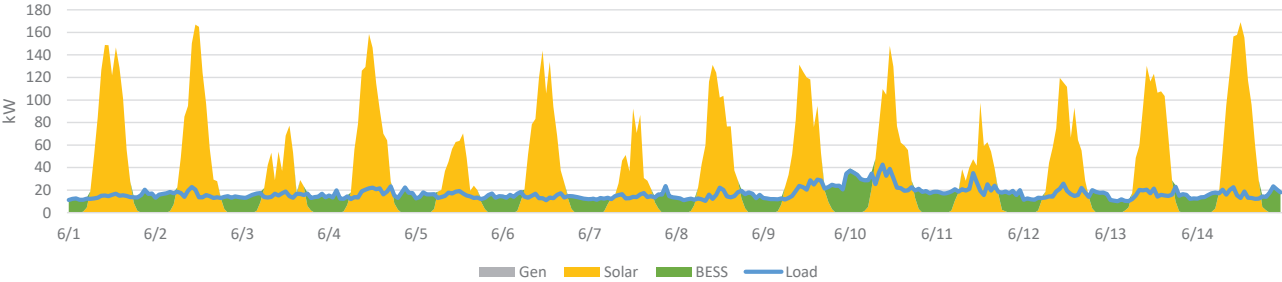
Solar Curtailment

Current dev., normal weather	149,399	kWh
Current dev., severe weather	142,411	kWh
High growth dev., normal weather	6,622	kWh
High growth dev., severe weather	5,246	kWh

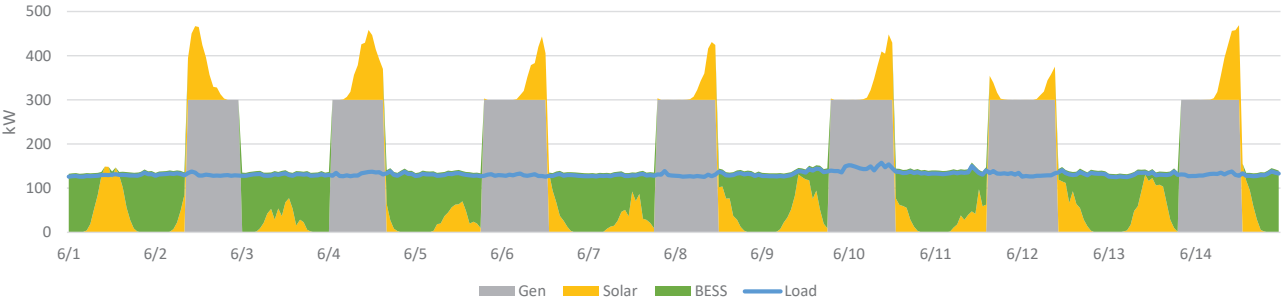
Current Development, Normal Weather
2 Week Summer Profile June 1st-14th



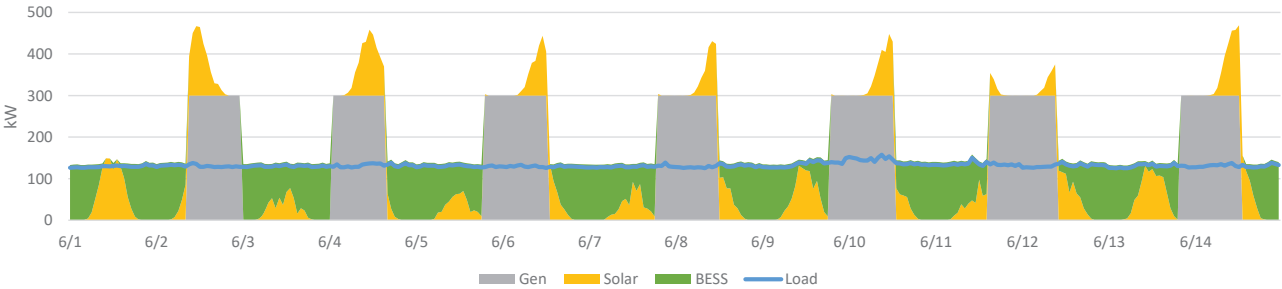
Current Development, Severe Weather
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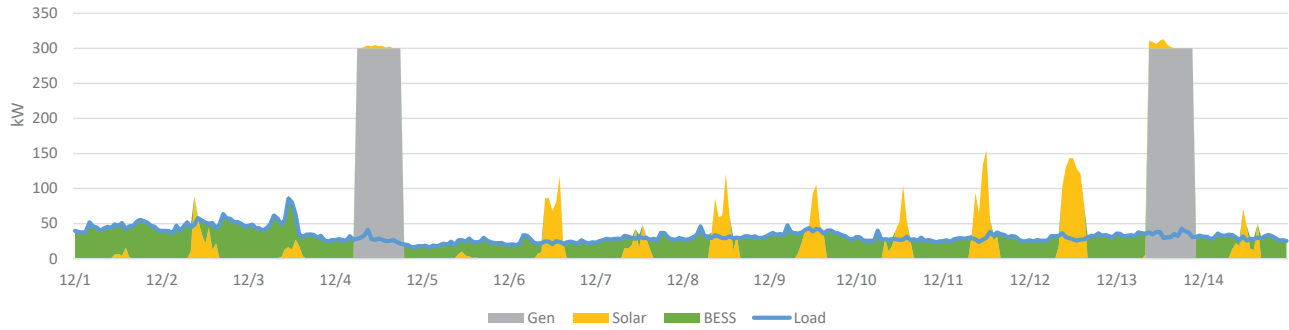
High Growth Development, Normal Weather
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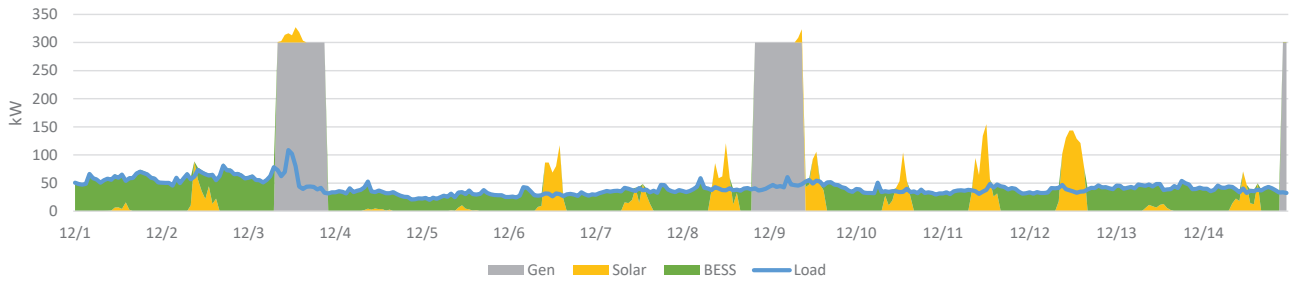
High Growth Development, Severe Weather
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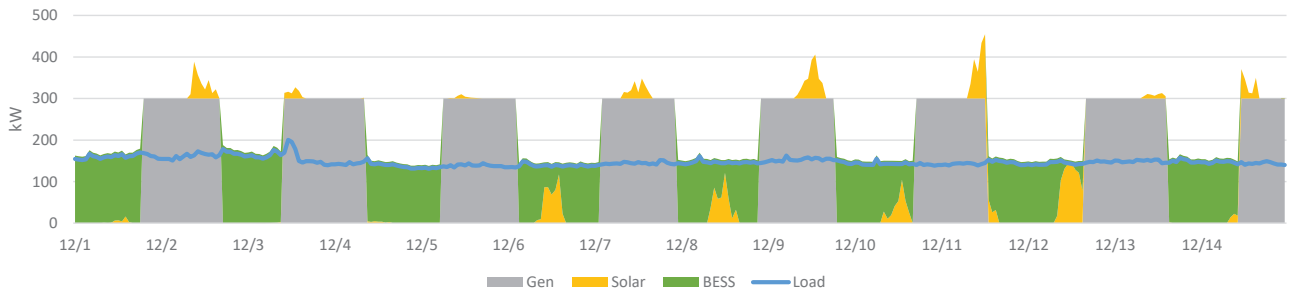
Current Development, Normal Weather
2 Week Winter Profile December 1st-14th



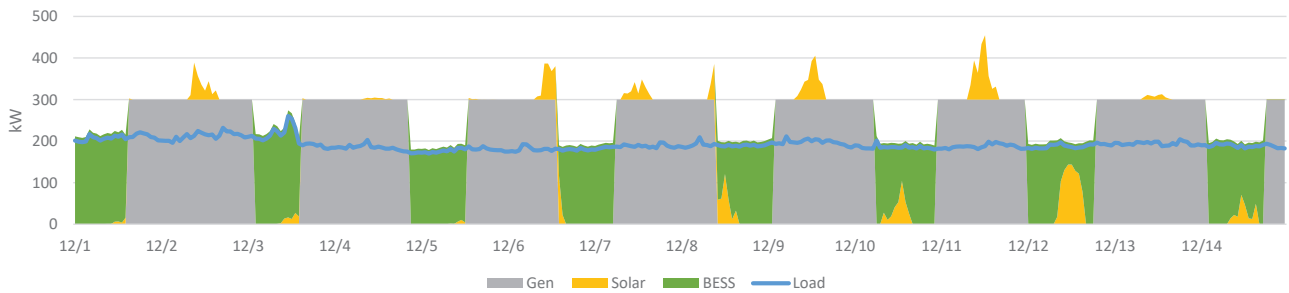
Current Development, Severe Weather
2 Week Winter Profile December 1st-14th



High Growth Development, Normal Weather
2 Week Winter Profile December 1st-14th



High Growth Development, Severe Weather
2 Week Winter Profile, December 1st-14th



2: Solar + Wind + BESS + Diesel

Generation Type	Size	Notes
Diesel Generator	300 kW	
Solar	200 kW	1/2 acre land area
Wind	200 kW	(10) 20kW turbines
BESS	1000 kW/4hr	One standard BESS unit size

Operational Strategy Description:

Solar generation is used for daytime loads and to charge BESS for off-peak deployment. Wind peaks during dawn and dusk supplement solar generation to charge BESS and cover the load. Additionally wind is more available in the winter when solar is less available, allowing for less diesel generation during the winter than with solar alone. Diesel generation is run when the load cannot be met with available solar or wind and BESS reserve. Once the generator is running it runs at full load until the BESS is fully charged to limit the number of times the diesel generator needs to kick on to limit O&M costs and to capitalize on higher equipment efficiencies at higher load factors.

Results

Fuel Usage

All values are yearly

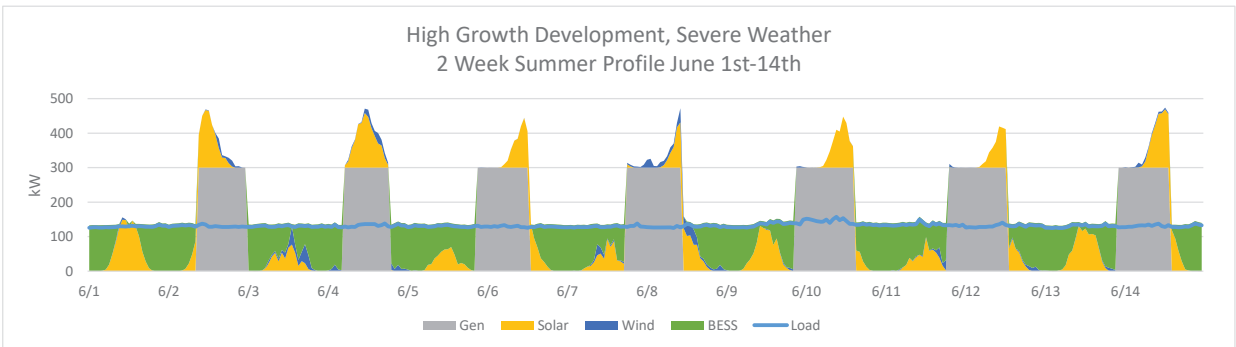
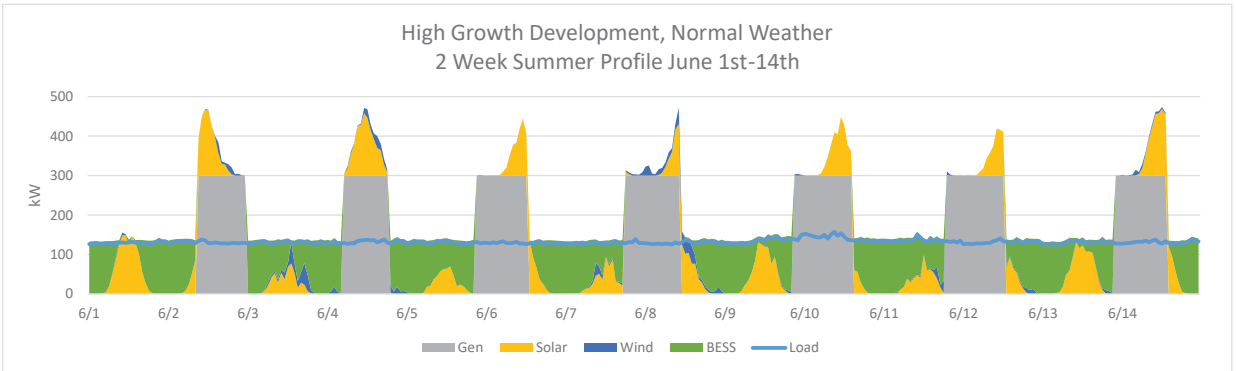
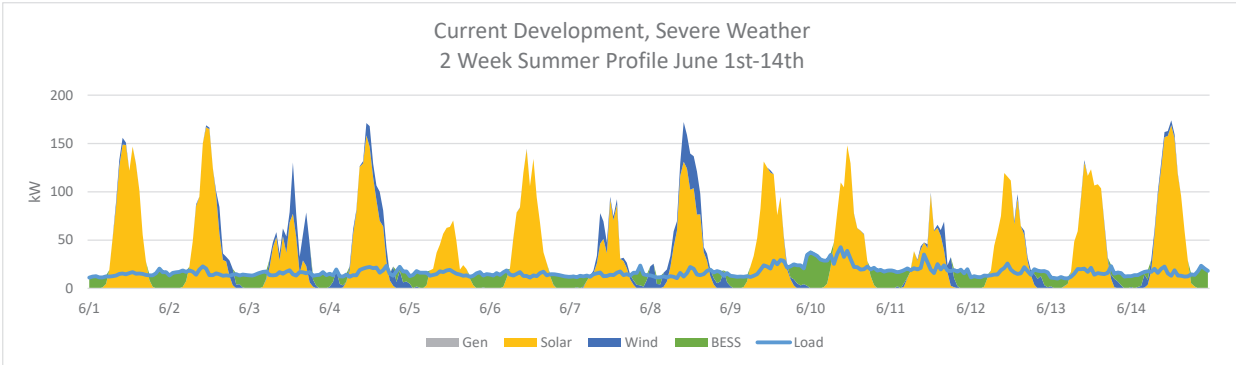
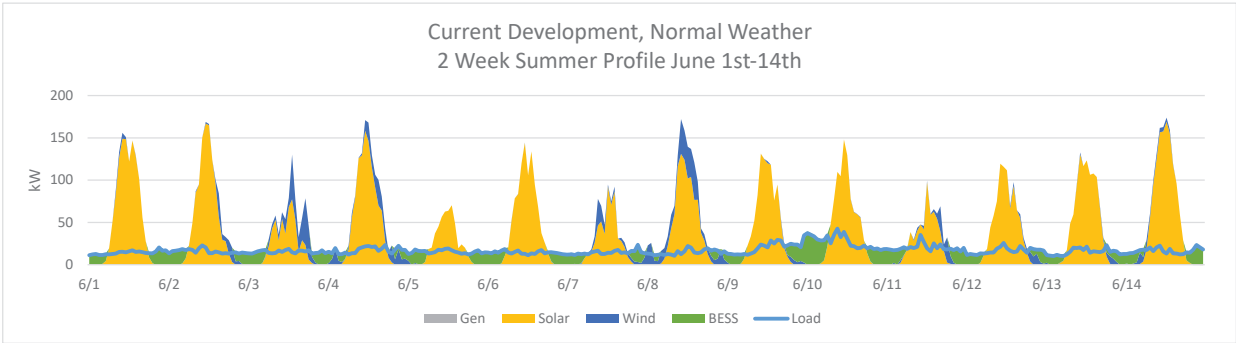
Current dev., normal weather	10844 L
Current dev., severe weather	23151 L
High growth dev., normal weather	275433 L
High growth dev., severe weather	326167 L

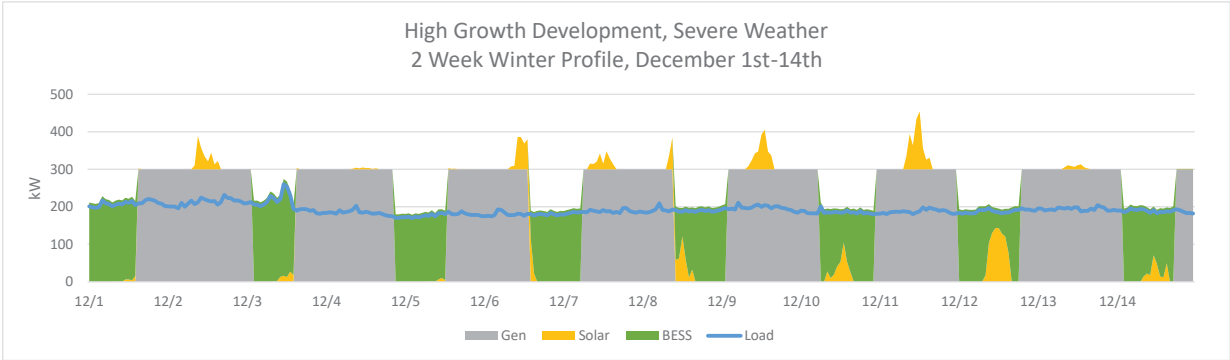
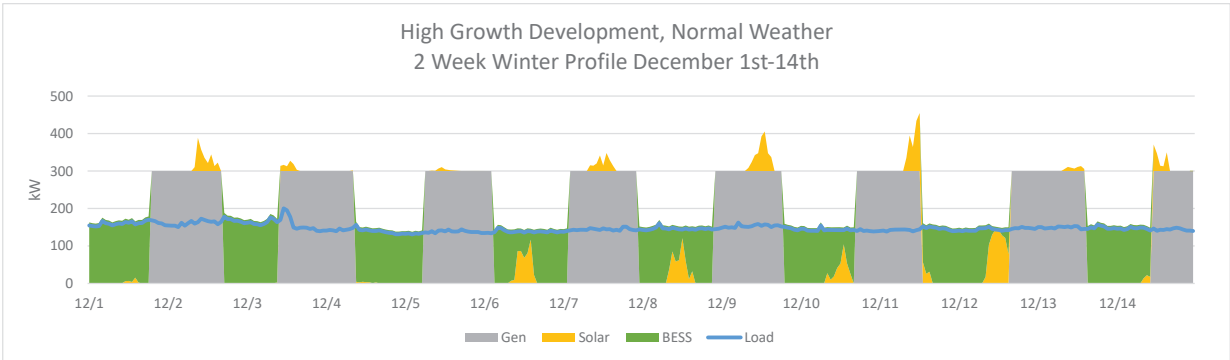
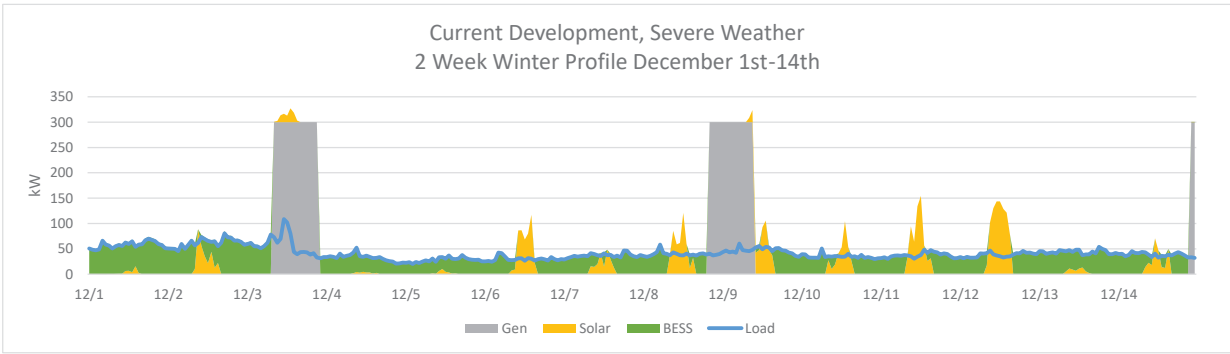
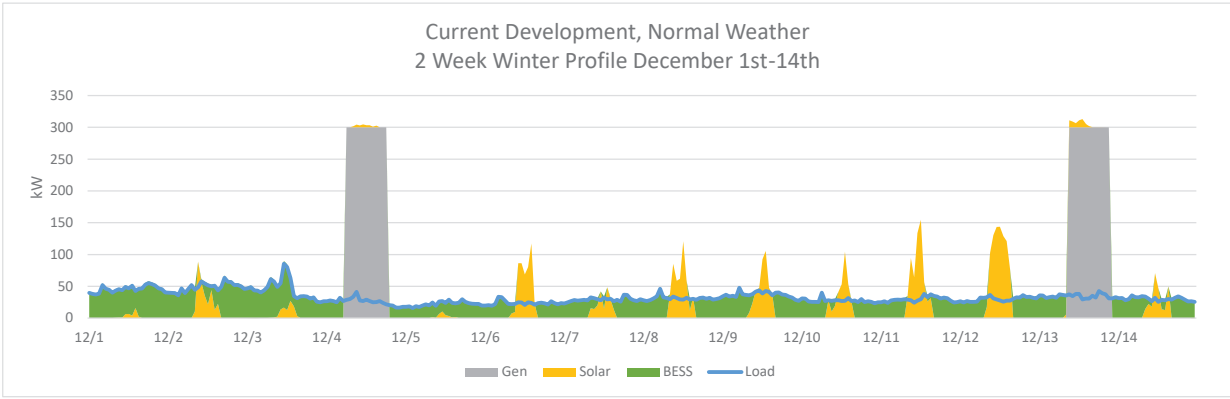
Gen Run Hours

Current dev., normal weather	147 hrs
Current dev., severe weather	308 hrs
High growth dev., normal weather	3572 hrs
High growth dev., severe weather	4226 hrs

Solar Curtailment

Current dev., normal weather	195291 kWh
Current dev., severe weather	184189 kWh
High growth dev., normal weather	15351 kWh
High growth dev., severe weather	10163 kWh





3: Expanded Solar + BESS + Diesel

Generation Type	Size	Notes
Diesel Generator	230 kW	
Solar	400 kW	1 acre land area
BESS	1000 kW/4hr	One standard BESS unit size

Operational Strategy Description:

The expanded solar generation is used for daytime loads and to charge BESS for off-peak deployment. Diesel generation is run when the load cannot be met with available solar and BESS reserve. Once the generator is running it runs at full load until the BESS is fully charged to limit the number of times the diesel generator needs to kick on, limit O&M costs, and capitalize on higher equipment efficiencies at higher load factors. Expanded solar allows for more solar energy to be captured and stored for off-peak solar hours and less diesel generation to be needed during these times.

Results

Fuel Usage

All values are yearly

Current dev., normal weather	10,254 L
Current dev., severe weather	19,394 L
High growth dev., normal weather	237,340 L
High growth dev., severe weather	288,127 L

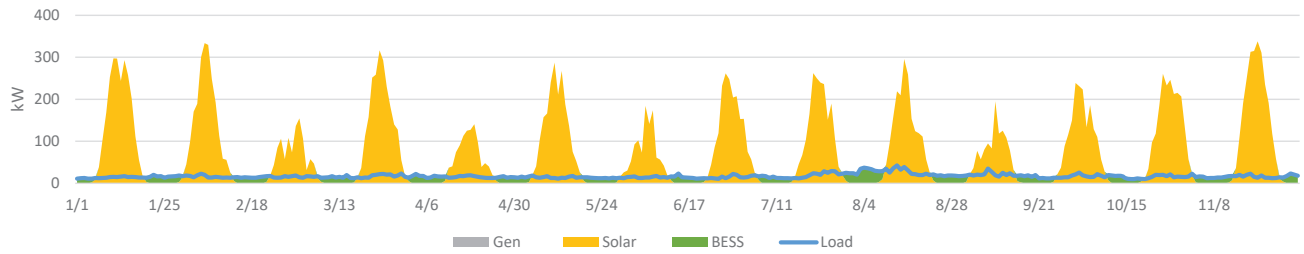
Gen Run Hours

Current dev., normal weather	142 hrs
Current dev., severe weather	261 hrs
High growth dev., normal weather	3090 hrs
High growth dev., severe weather	3743 hrs

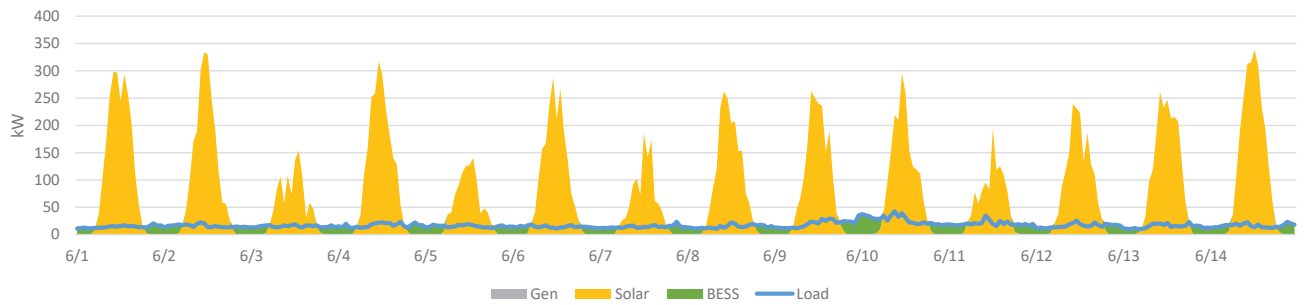
Solar Curtailment

Current dev., normal weather	365,041 kWh
Current dev., severe weather	354,955 kWh
High growth dev., normal weather	121,787 kWh
High growth dev., severe weather	104,264 kWh

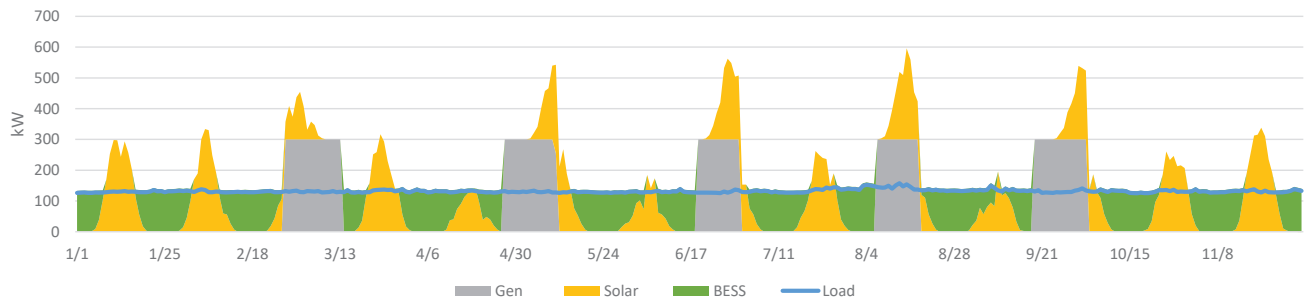
Current Development, Normal Weather
2 Week Summer Profile June 1st-14th



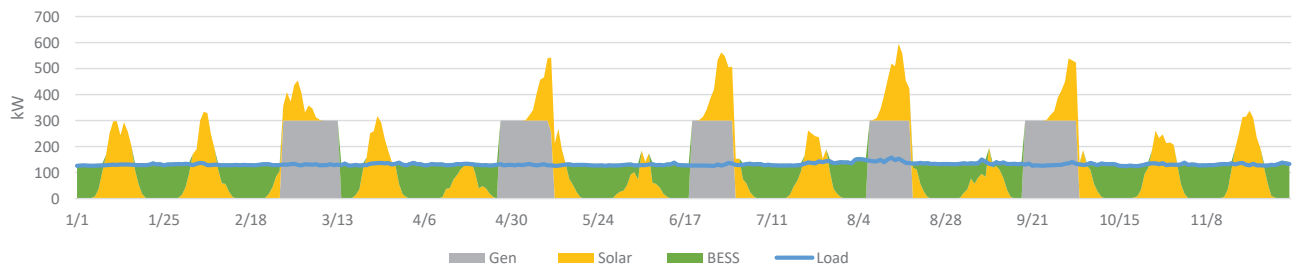
Current Development, Severe Weather
2 Week Summer Profile June 1st-14th



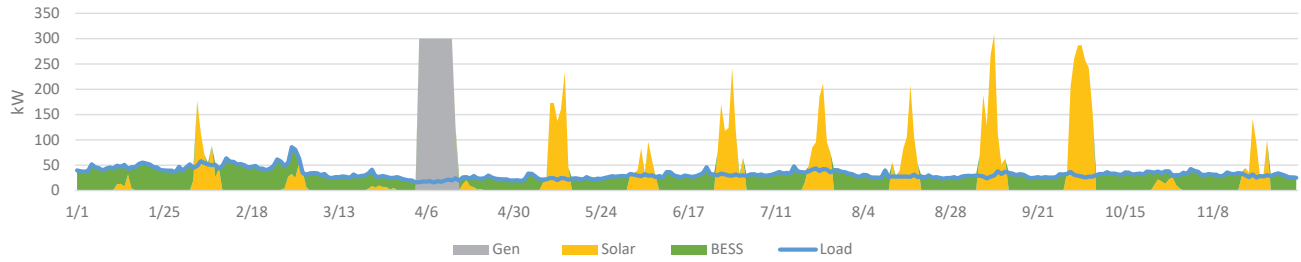
Growth Development, Normal Weather
2 Week Summer Profile June 1st-14th



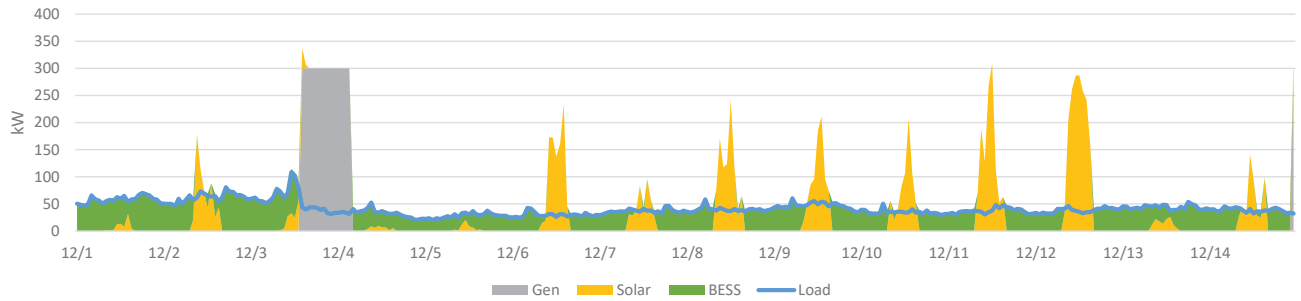
High Growth Development, Severe Weather
2 Week Summer Profile June 1st-14th



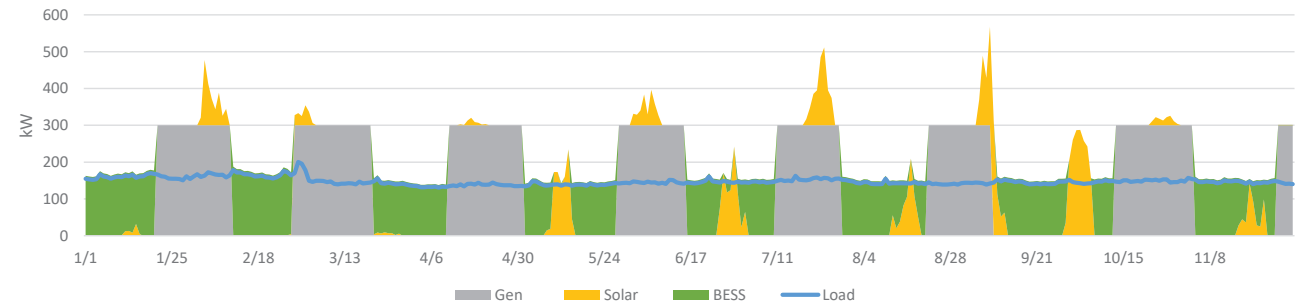
Current Development, Normal Weather
2 Week Winter Profile December 1st-14th



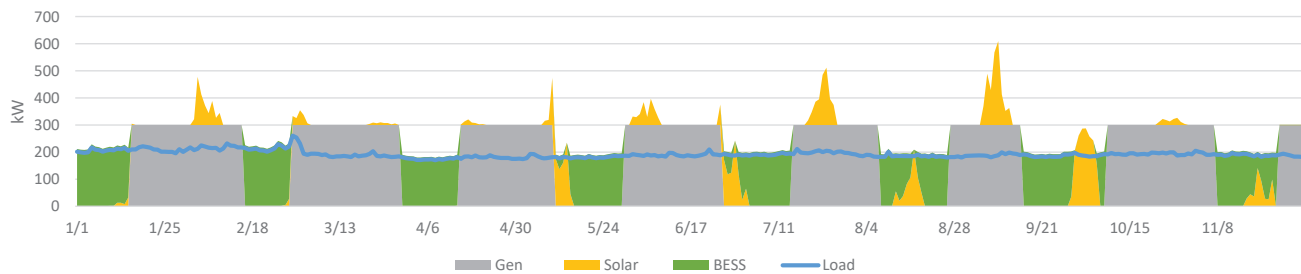
Current Development, Severe Weather
2 Week Winter Profile December 1st-14th



High Growth Development, Normal Weather
2 Week Winter Profile December 1st-14th



High Growth Development, Severe Weather
2 Week Winter Profile December 1st-14th



4: Solar + BESS + Fuel Cell

Generation Type	Size	Notes
Fuel Cell	115/230 kW	
Solar	200 kW	1/2 acre land area
BESS	1000 kW/4hr	One standard BESS unit size

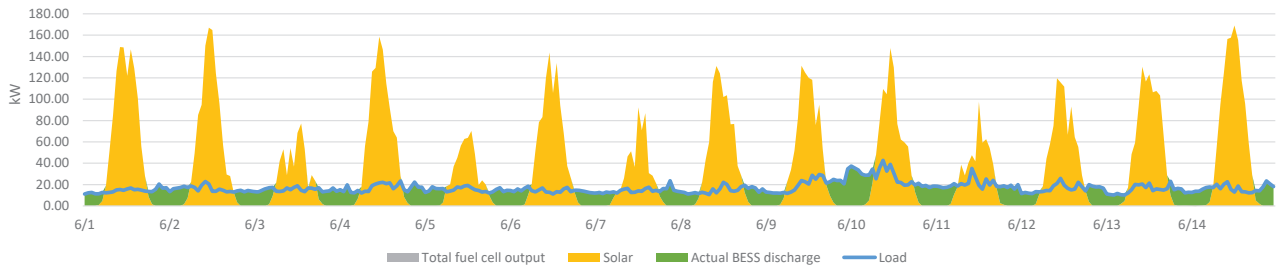
Operational Strategy Description:

The fuel cell is run at 30% base load to maintain temperature and allow the fuel cell to ramp up as needed. Solar generation is used for daytime loads and to charge BESS for off-peak deployment. The fuel cell is ramped up when the load cannot be met with available solar and BESS reserve. Once the fuel cell is ramped up it runs at full load until the BESS is fully charged and then ramps back down to 30% base load.

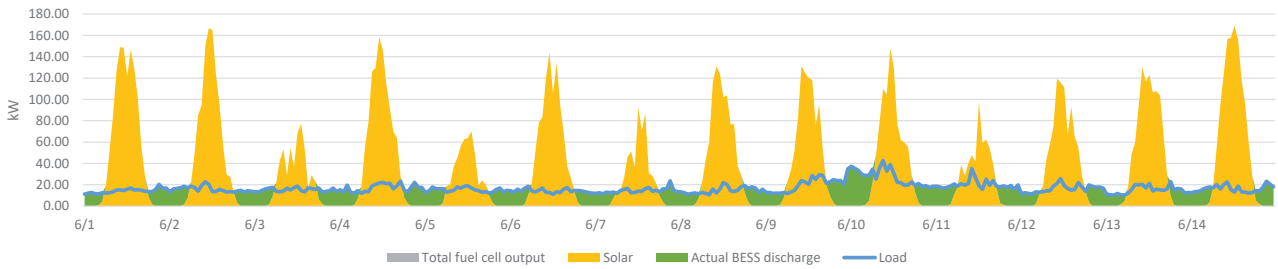
Results

Fuel Usage	All values are yearly	
Current dev., normal weather	7,596	kg
Current dev., severe weather	8,888	kg
High growth dev., normal weather	66,645	kg
High growth dev., severe weather	78,427	kg

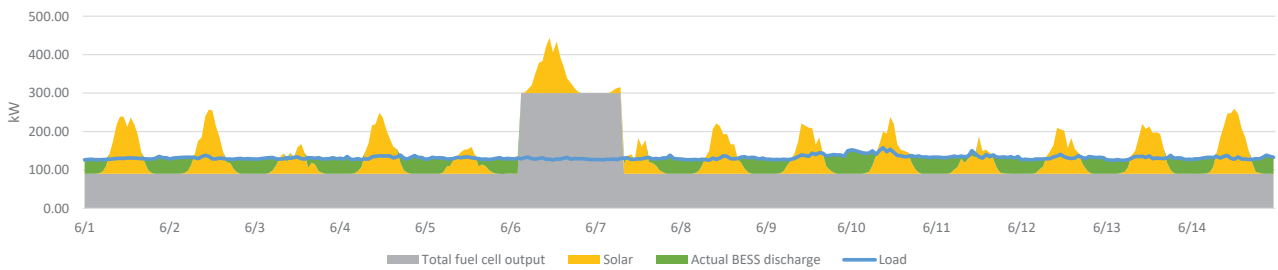
Current Development, Normal Weather
2 Week Summer Profile June 1st-14th



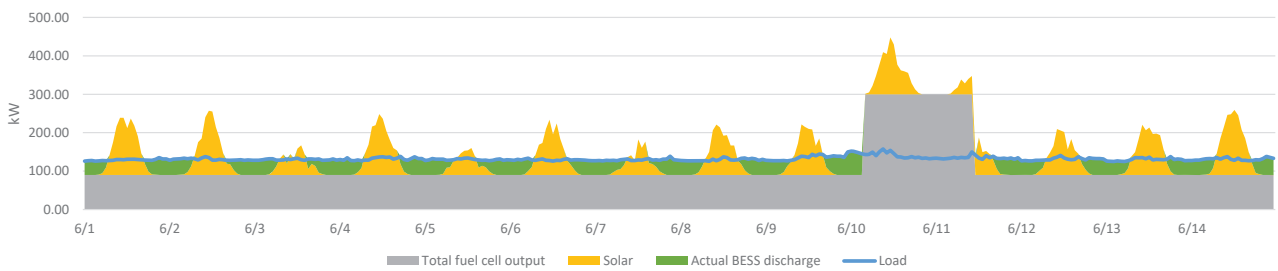
Current Development, Severe Weather
2 Week Summer Profile June 1st-14th



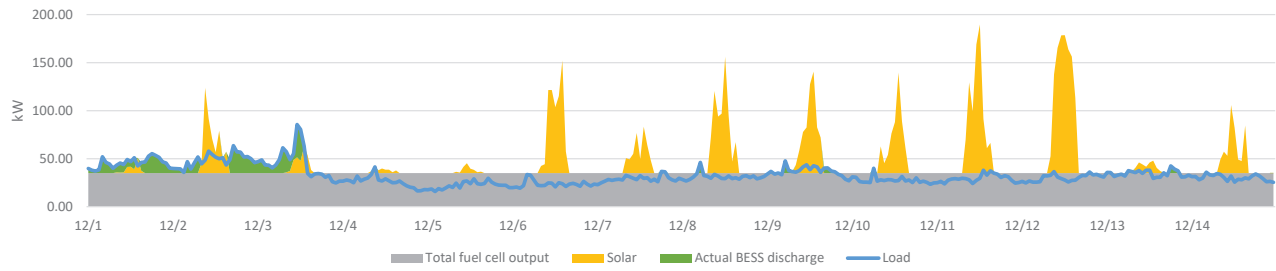
Growth Development, Normal Weather
2 Week Summer Profile June 1st-14th



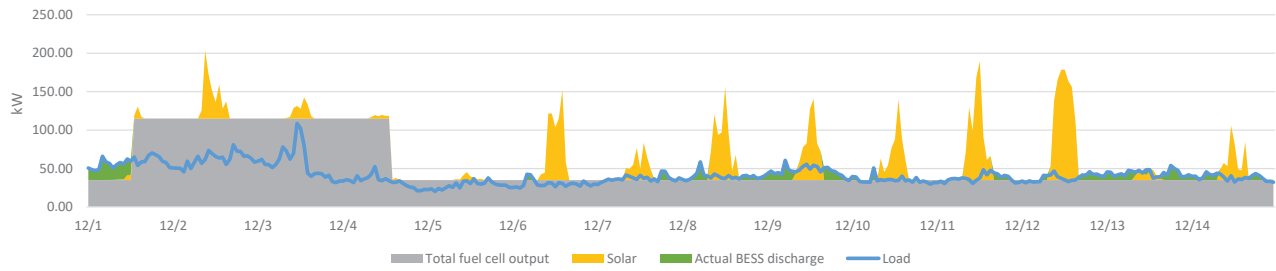
High Growth Development, Severe Weather
2 Week Summer Profile June 1st-14th



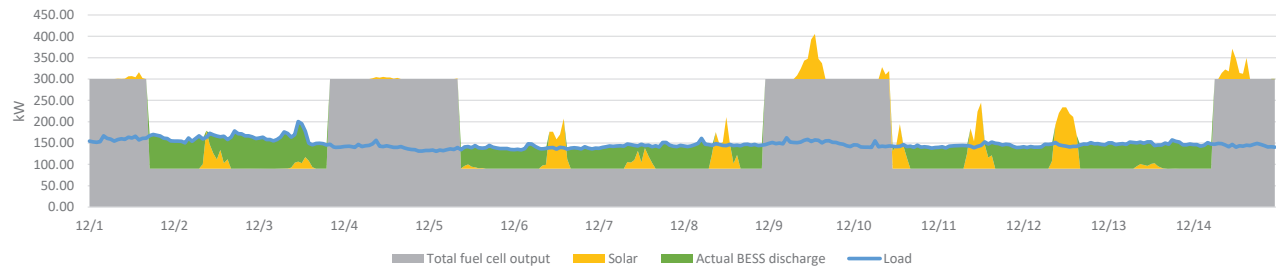
Current Development, Normal Weather
2 Week Winter Profile December 1st-14th



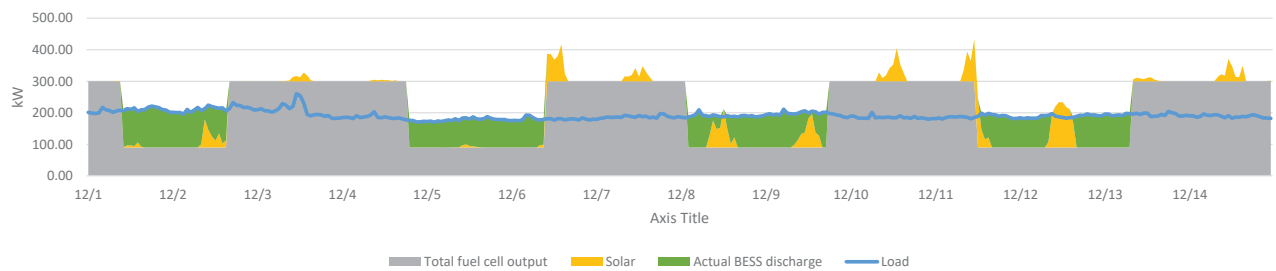
Current Development, Severe Weather
2 Week Winter Profile December 1st-14th



High Growth Development, Normal Weather
2 Week Winter Profile December 1st-14th



High Growth Development, Severe Weather
2 Week Winter Profile December 1st-14th



5: Distributed Diesel + BESS

Generation Type	Size	Notes
Diesel Generator	50 kW	per residence
BESS	40 kWh	per residence

Operational Strategy Description:

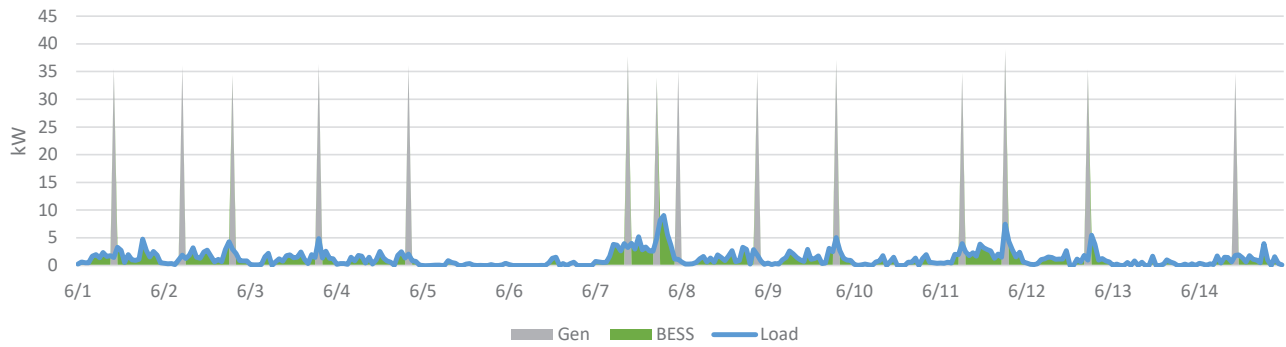
The distributed diesel strategy relies on a diesel generator to charge a BESS to meet each site's load. The sites are not connected to a larger grid and are handled as completely separate microgrids. Once the generator is running it runs at full load until the BESS is fully charged to limit the number of times the diesel generator needs to kick on, limit O&M costs, and capitalize on higher equipment efficiencies at higher load factors.

Results

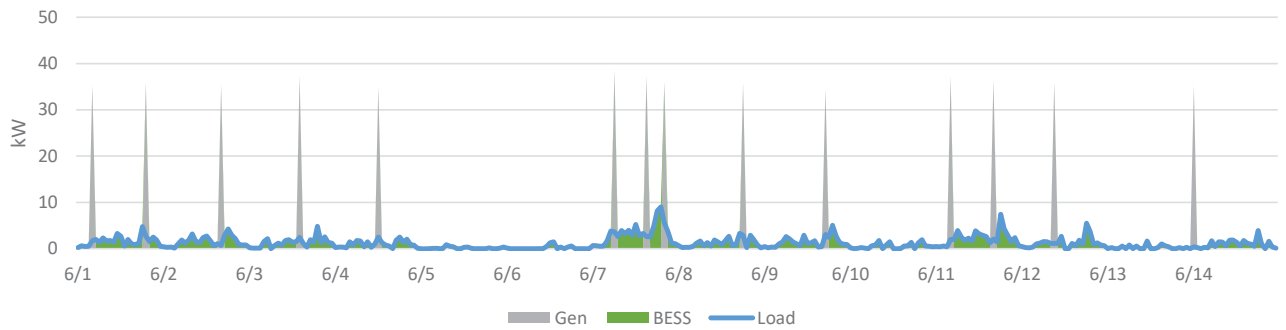
Fuel Usage	All values are yearly
Summer only resident	4,163 L
Year-round resident	1,423 L
Whole Island Current dev., severe weather	89,708 L

*Assuming same load as case B

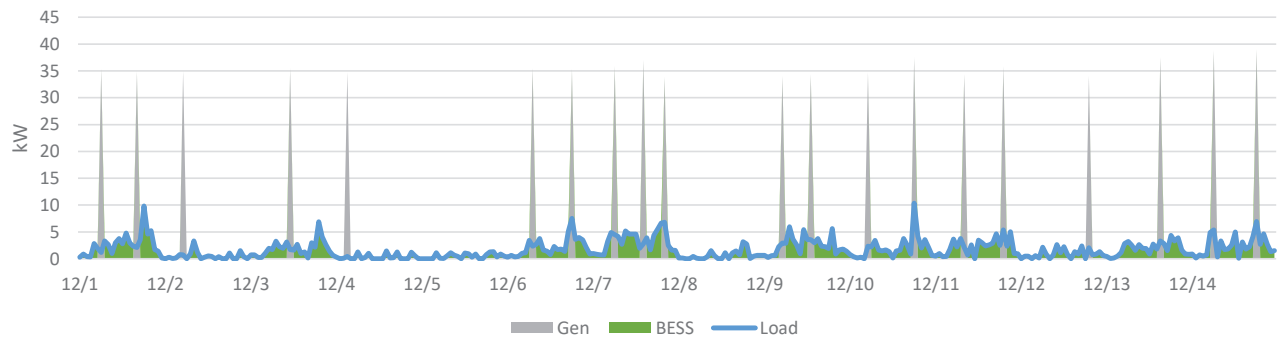
Year Around Resident
2 Week Summer Profile June 1st-14th



Summer Only Resident
2 Week Summer Profile June 1st-14th



Year Aroud Resident
2 Week Winter Profile December 1st-14th



Appendix D. Class 5 OPCC Estimate



Ketron Island
Ketron Island Microgrid Asset
Class 5 Rough Order of Magnitude Estimate

Date: 4/23/2026
Revision: 01
HDR Project: 10435748

Description	Material Amount	Labor Amount	Sub Amount	Total Amount
Alternative 1				
BESS (1 MW, 4 Hr)	2,058,062	116,899		2,174,960
Diesel Generator (300 kW)	292,265	98,537		390,802
Solar (200 kW)	460,262	133,226	89,283	682,771
Interconnection	555,741	200,426		756,167
Alternative 1	3,366,330	549,087	89,283	4,004,700
Alternative 2				
BESS (1 MW, 4 Hr)	2,058,062	116,899		2,174,960
Diesel Generator (300 kW)	292,265	98,537		390,802
Solar (200 kW)	460,262	133,226	89,283	682,771
Wind (200 kW)	446,415	570,032	692,398	1,708,845
Interconnection	640,796	208,066		848,863
Alternative 2	3,897,800	1,126,760	781,681	5,806,241
Alternative 3				
BESS (1 MW, 4 Hr)	2,058,062	116,899		2,174,960
Diesel Generator (300 kW)	292,265	98,537		390,802
Solar (400 kW)	860,942	190,929	178,566	1,230,437
Interconnection	626,347	200,426		826,773
Alternative 3	3,837,616	606,791	178,566	4,622,972
Alternative 4				
BESS (1 MW, 4 Hr)	2,058,062	116,899		2,174,960
Hydrogen Fuel Cell (115 kW)	1,341,066	170,157		1,511,223
Solar (200 kW)	460,262	133,226	89,283	682,771
Interconnection	573,962	200,426		774,388
Alternative 4	4,433,352	620,707	89,283	5,143,342
Alternative 5				
BESS (40 kWh)	1,424,882	362,124		1,787,006
Diesel Generator (50 kW)	1,047,708	455,179		1,502,886
Interconnection	167,633	115,880		283,513
Alternative 5	2,640,223	933,182		3,573,405

Lower Range: -50%

AACE Classification Accuracy Range

Upper Range: +100%