SANTA CATALINA ISLAND REPOWER FEASIBILITY STUDY

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Santa Catalina Island
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1.0 OVERVIEW

This Feasibility Study evaluates various options to repower Santa Catalina Island with an alternative generation supply that is compliant with new emissions regulations and conforms to the State of California's and Southern California Edison's (SCE's) stated goals towards greenhouse gas reduction and renewable energy deployment. The air emissions regulations from the South Coast Air Quality Management District (SCAQMD) were recently revised to require a reduction in NOx emissions. This regulatory change will impact the existing diesel generation fleet at the SCE Pebbly Beach Generating Station (PBGS), which are nearing their end-of-life. Retrofitting the existing fleet for life extension and improved emissions to come into compliance is not an option due to age and technical restrictions. New generation assets, therefore, are needed to replace the lost capacity once they are retired. SCE initiated this feasibility study to investigate the technical and economic implications of several generation options to repower the island with emissions compliant sources.

NV5 and the National Renewable Energy Laboratory (NREL) conducted this feasibility study in support of SCE and the US Environmental Protection Agency (EPA), evaluating opportunities and constraints to repower the island. Three categories of emissions compliant generation options were evaluated, both separately and in combination, and they are:

- Emissions Compliant Fossil Fuel Generation
- Renewable Energy and Battery Storage Hybrid
- Submarine Power Cable for Interconnection to the Mainland Grid

The emissions compliant fossil fuel generation analysis evaluated generators of varying capacity ratings and fuel types to replace the existing diesel fleet. Fossil Fuel Generation Option 1 evaluated the replacement of all diesel generators in time for the SCAQMD emissions deadline of Jan. 1, 2024.Fossil Fuel Generation Option 2 looked at replacing just two existing generators with new diesel or propane generators to be in service by Jan 1, 2023, with the remaining generator replacements to be in service by Jan 1, 2027. Supplemental reviews to Option 1 and Option 2 included the assessment of propane and LNG as a viable alternative fuel source.

Renewable energy and energy storage systems were assessed as alternatives to complement the existing diesel generation capacity. These systems were reviewed based on the resource availability of various technologies, environmental site due diligence, and infrastructure upgrades. The results of this assessment indicate that solar PV and battery storage offer the best combination of variable renewables and energy storage for the needs of the island. This study includes an in-depth analysis of a 60% renewable microgrid configured to use solar plus storage and new diesel generation. A multi-phase implementation plan is presented that allows for sequencing with distribution upgrades and a new communications system.

The third category focused on interconnecting Catalina Island with the mainland via a submarine power cable. Based on constructability and permitting considerations, NV5 chose a 35.5 mile undersea route extending from Catalina's Pebbly Beach Generating Station to the mainland's Huntington Beach Generating Station. By powering Catalina Island from the mainland, the impetus for emissions requirements is shifted to the mainland power supply, which is already or will become emissions-compliant. This option carries a high degree of complexity and uncertainty that will need to be mitigated to ensure project success.

NREL performed a techno-economic modeling and optimization analysis of the various generation options. Their study, which is based on the Renewable Energy Optimization and Integration (REopt) software tool, produced a detailed cost and generation analysis across a broad spectrum of repowering models. The outputs of NV5's repower solution studies were used as inputs to NREL's techno-economic simulations, and the outputs of those simulations were used as inputs to NV5's broader island analysis.

Lastly, NV5 conducted a preliminary demand-side analysis of opportunities to reduce the overall electric load on the island. This analysis included a comprehensive review of SCE's large load customers and SCE's annual load profile that resulted in an actionable list of recommendations for load reduction. Early results suggest total electricity consumption could be reduced by an estimated 21% via an estimated $7.8 million investment in energy efficiency improvements and a 6 year simple payback.

The feasibility study offers valuable insight into the engineering and financial considerations to implement the generation and supply-side alternatives to repower Catalina Island. Ultimately, this study should serve as a guide to the various repowering options and as an outline for next steps. Recommendations for future study include a more detailed review of load reduction, potential implications of vehicle and building electrification, a distribution control system upgrade plan, further distribution system impact studies, potential cost efficiencies due to SCE's ownership of both water and electric utilities, and a finalized techno-economic analysis to iterate the selected repowering solution.

2.0 EXISTING LAND, ENVIRONMENTAL, AND ELECTRICAL CONDITIONS

The purpose of this section is to provide a brief overview of the existing land, environmental conditions, existing electrical load and electric distribution infrastructure of Catalina Island. This includes a background on island ownership, biological and cultural resources, existing load profile, and an electrical load-flow analysis. By determining and documenting existing conditions on the island, the team can consider different types of generation at various locations across the island.

2.1 ISLAND OVERVIEW

Santa Catalina Island sits 26 miles off the coast of Southern California. Known familiarly as Catalina, it has a population of approximately 4,100 with 3,800 residents living in the City of Avalon. There is significant tourism on the island, and it receives approximately 900,000 visitors each year. The island has an area of 48,000 acres, 88 percent of which is owned by the Catalina Island Conservancy. SCE is responsible for providing electricity, water, and gas to the entire island.

Peak load on the island is approximately 5.5MW and minimum demand is 0.9 MW. Based on Pebbly Beach generation data provided by SCE, annual energy consumption was approximately 29 gigawatt hours (GWh) in 2017. Current electrical infrastructure on the island includes three 12kV distribution circuits, Wrigley Line, Interior Line, and Hi-Line, one substation, located at Pebbly Beach, near the City of Avalon, and one switchyard, located at Two Harbors.

The Pebbly Beach Generating Station (PBGS) has six diesel generators that provide a combined nameplate capacity[1] of 9.4 MW, 23 propane microturbines that provide 1.5MW and a sodium-sulfur (NaS) battery 1MW / 7.2MWh. The diesel generators were built between the 1950s and 1990s and several have exceeded the 30-year design life (See Table 3-2 for specific installation year information). The microturbines are expected to be operational until 2022 and the NaS battery is expected to be operational until 2031.

At Two Harbors, there is a switchyard where the Interior and Hi-Line intersect. Near Two Harbors, there is a marine lab owned by the University of Southern California (USC) with 23kW of rooftop solar. For a more in-depth discussion regarding the island's existing power infrastructure, refer to Section 2.5.

2.2 LAND OWNERSHIP

The Santa Catalina Island Conservancy owns the controlling interest in Catalina Island. In 1974 it entered into a 50-year Open Space Easement Agreement with the County of Los Angeles that set aside 88 percent of the island for preservation of the natural character of the Island and improvement of the Island's access and recreational opportunities (Santa Catalina Island Local Coastal Plan, 1983). The Santa Catalina Island Company owns 11% of Catalina Island and its ownership includes much of Catalina Island's resort properties, commercial properties and infrastructure facilities. The last 1% of Catalina includes all other property owners.

The Santa Catalina Island Conservancy was established shortly after the agreement with the County of Los Angeles to manage, in perpetuity, Catalina Island's biotic resources. The Santa Catalina Island Local Coastal Plan (C LCP) guides coastal development on Catalina Island and recognizes and

[1] Technical documents provided by SCE indicate the nameplate capacity of Unit 12 is 1,575 kW. The Facility Permit to Operate assigns a capacity of 1,500 kW to Unit 12. The BACT Analysis will reflect the permitted operating capacity for Unit 12: 1,500 kW. The Feasibility Study uses the nameplate capacity of Unit 12: 1,575 kW, yielding a capacity of 9.4 MW.

responds to the goals and requirements of the Open Space Easement Agreement, the Santa Catalina Island Conservancy and the California Coastal Act. It ensures that the vast majority of Catalina Island will remain in its present natural state.

2.3 EXISTING ENVIRONMENTAL CONDITIONS

The purpose of this section is to provide the reader with an overview of high priority sensitive resources located on Catalina Island and its surrounding waters. This discussion below focuses on biological and cultural resources and island stakeholders. All sensitive resources, including those not listed, are protected by local, state, and federal laws and/or regulations. Potential renewable energy development, including a possible electric submarine cable to the mainland, would need to consider strategies to protect biological and cultural resources, including engagement of Island and mainland stakeholders to gain input.

2.3.1 Biological Conditions

Catalina Island is considered an Ecologically Sensitive Area and supports many sensitive biological resources that are unique to Catalina Island. The dominant plant communities on Catalina Island in terms of cover by area are; Coastal sage scrub (38.1%), Island chaparral (29.4%), Grassland (19.5%) and bare land (9.4%), making up greater than 96% of Catalina Island's terrestrial habitat[2]. Several unique and important plant communities (Island woodland, Southern riparian woodland, etc.) are represented in the remaining lands and are considered sensitive habitat garnering special protection.

Avian species of Catalina Island are a mix of mainland species differing in density and habitat use in multiple cases. A total of 263 species have been documented on Catalina Island with 11 species considered globally threatened[3] Sixteen land mammal species have been documented on Catalina Island and all the species are either introduced or Catalina Island endemics. Of the five Catalina Island endemic land mammal species only the Santa Catalina Island fox (*Urocyon littoralis catalinae*) and the Santa Catalina Island shrew (*Sorex ornatus willetti*) are currently afforded special protection under state and/or federal statutes. Three marine mammal species utilize various offshore rocks and shorelines as habitat and are protected under the Marine Mammal Protection Act (MMPA). Eight species of bats and fourteen amphibians or reptiles are documented to occur on Catalina Island, with three of the species considered rare.

Marine resources inhabiting the intertidal and subtidal waters around Catalina Island are abundant and represent an exceptional diversity of marine habitats and species. The waters surrounding Catalina Island are home to two federally endangered abalone species and a host of habitats and species that are protected from take or project related impacts. Catalina Island has nine marine protected areas distributed around the Island that range from State Marine Reserves restricting all take of living marine resources to State Marine Conservation Areas that provide for limited take of specific species. Intertidal sand beach and rocky reef habitat and subtidal habitat are considered Environmentally Sensitive Habitat Area (ESHA) by the California Coastal Commission (CCC) and the CLCP and are provided protection from coastal development impacts.

2.3.2 Cultural Resources

The Channel Islands are considered highly sensitive for cultural resources. Large burial sites have been found and recently recovered on Catalina Island, further adding to the island's sensitivity. Although many of the energy generation and supply alternative sites may be located within previously

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[2] (Knapp, 2010)

[3] (Avibase, 2020)

disturbed areas, this does not preclude the presence of archaeological resources. The local and federal lead agencies are likely to require cultural resources investigations to ensure that adequate consideration was given to cultural resources under the federal and state regulatory systems. Archaeological surveys should be anticipated to be required as part of the United States Army Corp of Engineers (USACE) or CSLC/CCC/County permitting process unless previously completed within the last two years. Typically, archaeological surveys are required to satisfy the lead federal agencies compliance needs for Section 106 of the National Historic Preservation Act. The lead agency may also require standalone cultural resources studies which would be used to open consultation with the State Historic Preservation Office, as required by federal regulation.

Local agencies will also be required to analyze the potential impacts to cultural resources under California Environmental Quality Act (CEQA). In addition to the standard archaeological survey, the lead CEQA agency will also be required to consult with local tribes under Assembly Bill 52. These efforts typically result in a requirement for cultural resources (e.g., archaeological and/or Native American) monitoring during ground disturbing activities.

2.4 EXISTING AND FORECASTED ELECTRICAL LOAD PROFILE

The purpose of this section is to describe the existing load conditions of the island. SCE provided NV5 with three years of annual hourly generation data (2015, 2016, & 2017). Descriptions of this generation data and a summary of the island's expected load growth are presented in the following section.

2.4.1 System Demand

SCE selected calendar year 2017 as the base year for evaluation of service and operating characteristics. Hourly generation data from 2017 were evaluated to identify service demand and generation requirements.

Power generation at Pebbly Beach Generating Station consists of six engine generator sets (9,400 kW), and twenty-three microturbines (1,490 kW) (Figure 2-1). Capacity is supplemented by one NaS battery, capable of delivering up to one MW for seven hours (7 MWh).

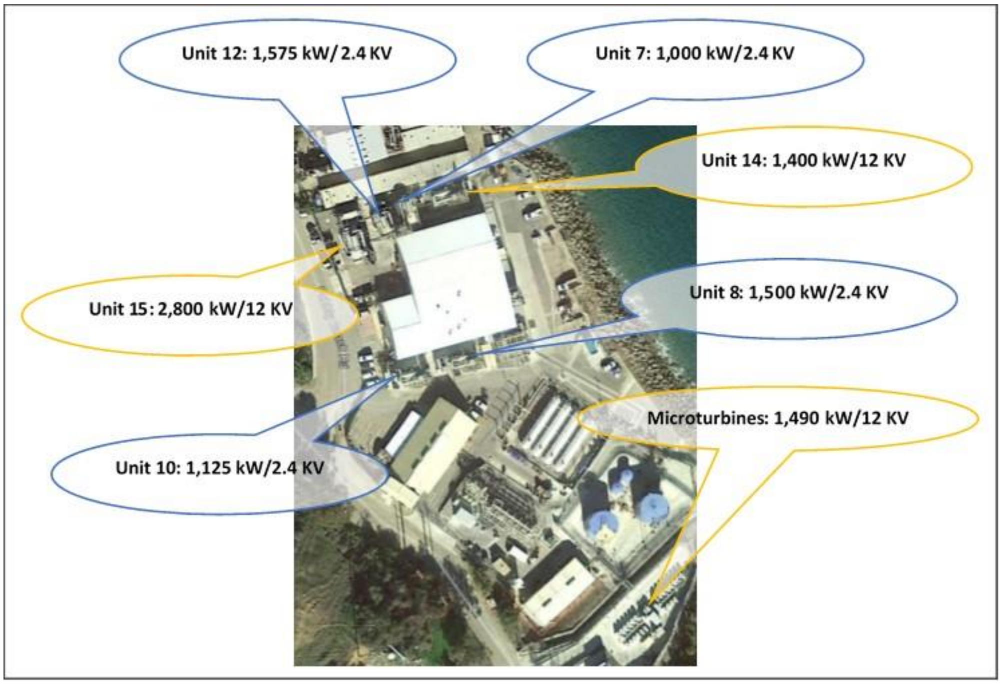

Figure 2-1 - Existing Generators: Location, Capacity and Voltage

The plant generates at two distribution voltages: 2.4 kV and 12 kV. The microturbines and two engine generators, Unit 14 and Unit 15, (5,659 kW) directly serve the 12 kV system. The remaining generator capacity, units 7 through 12, (5,236 kW) serve the 2.4 kV system. Both systems can serve the electric utility load and operate either in combination or independently at various times.

Table 2-1 - Operating Hours: Generation with Single Service Voltage

Distribution Voltage	2017
12 kV Only	1,062
2.4 kV Only	789

Duration curves were developed to indicate maximum demand and the relative, concurrent contribution of generators by distribution service voltage. This review indicates a concurrent historic peak demand of about 5,350 kW occurred on August 3, 2017.

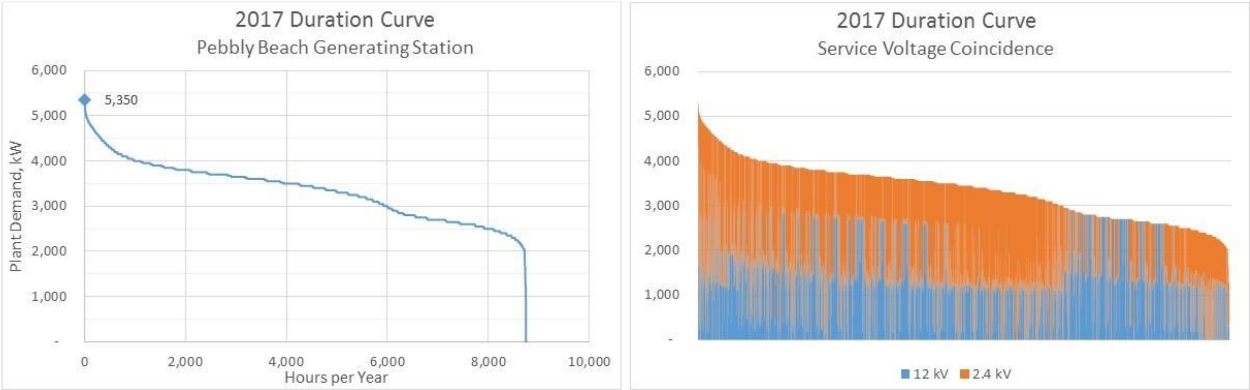

Figure 2-2 - 2017 Generation Profile

The highest maximum demand (non-coincidental) on the capacity operating at 12 kV was 4,750 kW. The corresponding non-coincidental maximum demand on the 2.4 kV system was 4,950 kW.

2.4.2 Incremental Demand Growth Forecast

A twenty-year forecast horizon provides a basis for illustrating future utility demand. Several general factors contribute to the future service demand on the plant: new development (residential, commercial, industrial, government/institutional); refurbishment of existing facilities; economic expansion; climate, etc. Five development efforts have been identified for Santa Catalina Island: water utility improvements, residential development, hospital expansion, trail head visitor center and expansion of Hamilton Cove.

Table 2-2 - Utility Service Demand Growth Forecast with Contingency

Local Development Projects	Demand, kW
Water Utility Improvements	740
Residential Development	420
Hospital Expansion	90
Trailhead Visitor Center	70
Hamilton Cove Expansion	20
Total	**1,340**

These projects have the potential of adding about 1,340 kW to the demand for electric service on the island over the next 5 years, yielding an anticipated maximum demand of about 6,700 kW (5,350 kW + 1,340 kW). The assigned development period for these projects is five years, or about through 2024.

Property development on the island beyond the identified projects is strictly regulated. Development is also limited by the availability of fresh water. Planned expansion of the desalination plant could support additional development and consequently an increase in utility load.

A general load growth rate of 0.5% and 1.0% per year has been applied to year 6 through year 20 to provide a range of electric service demand. This forecast range is inclusive of the historic demand, identified projects, and general load growth as shown in Figure 2-3, Figure 2-4, and Figure 2-5.

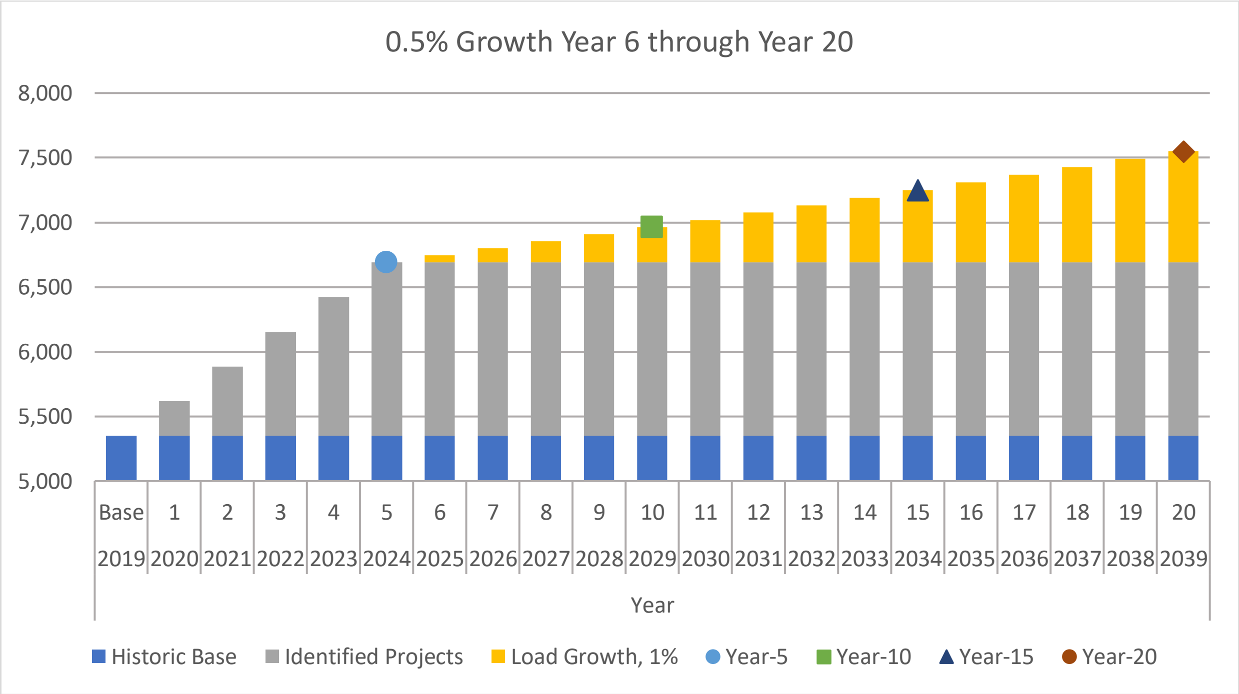

Figure 2-3 - Catalina Island 20 Year Load Growth, 0.5%

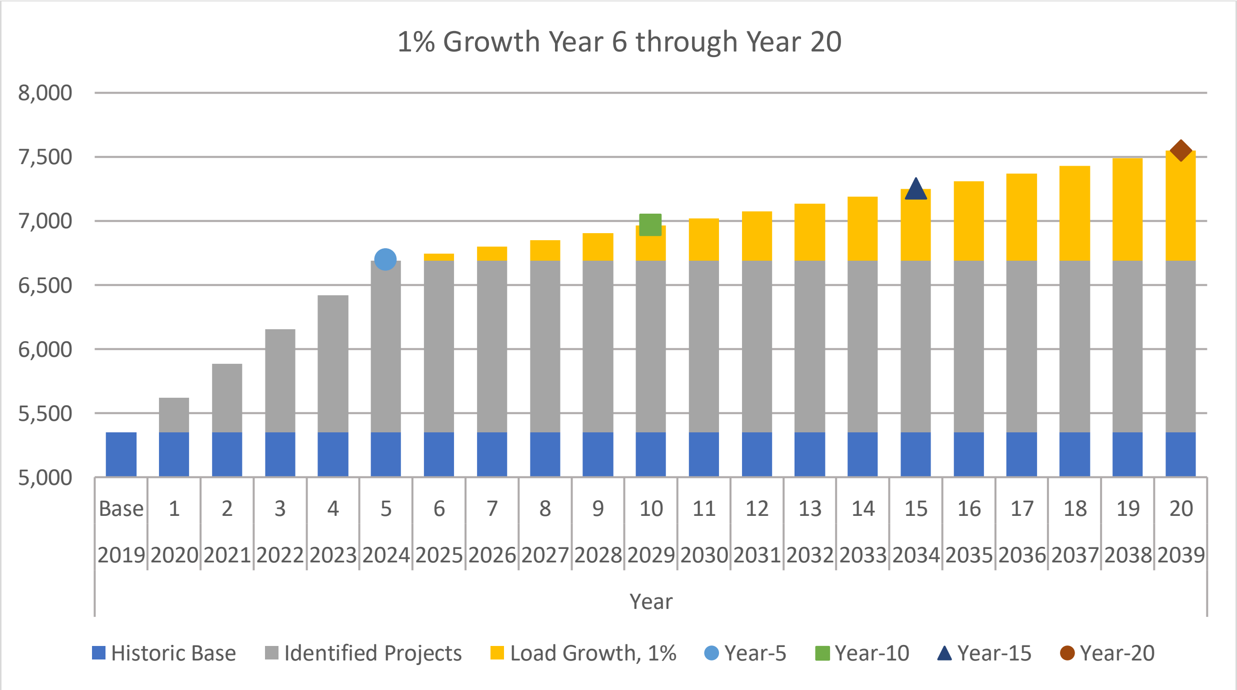

Figure 2-4 - Catalina Island 20 Year Load Growth, 1%

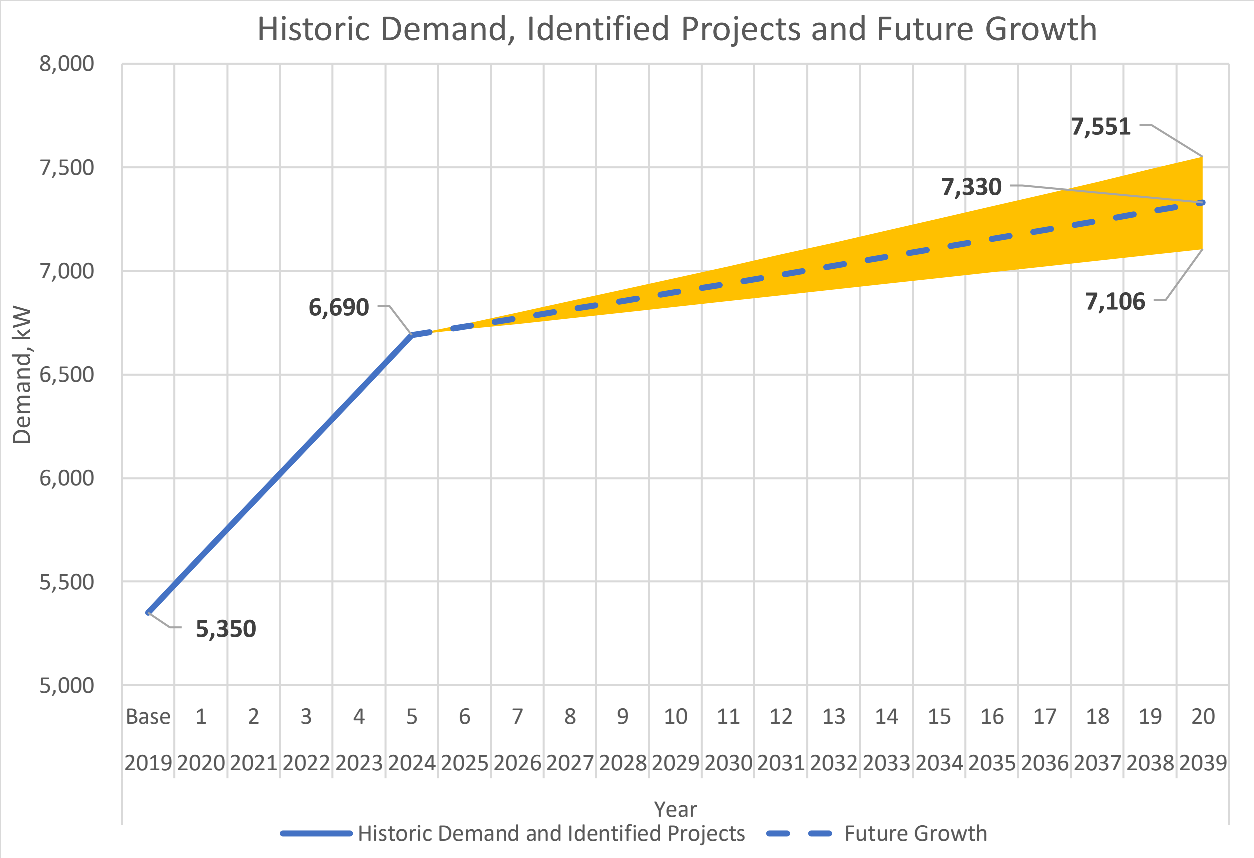

Figure 2-5 - Catalina Island Future Growth

2.5 EXISTING ELECTRICAL INFRASTRUCTURE AND DISTRIBUTION

2.5.1 Introduction

NV5's approach in designing an island microgrid included conducting an electrical load flow analysis on the 12kV distribution system on Catalina Island. This section describes the background and methodology in building a working electrical grid model that provides accurate load flow results based on current grid conditions. During the renewables and battery storage analysis portion of this feasibility study, the working model is used as a tool to test various scenarios of interconnecting increasing amounts of renewable energy at various points across the island. See Section 4.3 for further details on the system impact studies conducted with this model to study impacts and mitigation strategies to integrate distributed energy resources throughout the island.

Some of the existing major equipment included in this model are transformers, voltage regulators, sectionalizing/protection devices, switches, and conductors. The load flow analysis enables simulation of an electrical grid's behavior under various generation and load conditions, such as during summertime peak load versus wintertime off-peak load times. It also is used to identify the power quality impacts under worst case scenarios and to find mitigation strategies to solve for those issues. In order to study some of these impacts and understand what sorts of mitigation will work under varying degrees of renewables integration, the NV5 team first needed to establish a baseline grid model that could achieve trustworthy load flow results under present conditions.

It's important, first, to review some basic properties of an electrical distribution system and how Distributed Energy Resources (DER) might cause impacts to the grid. An electrical system's voltage generally will decrease as the load gets farther away from the source, namely the Pebbly Beach Generating Station, and as demand increases. When power is injected at different points that the grid is not set up to regulate around, there can be unforeseen consequences. Additionally, when variable generation resources like solar quickly ramp up or down, such as with a passing cloud, there can be a transient impact to power.

The following section discusses some of the high-level steps involved with building and validating a working model in Synergi Electric.

2.5.2 Methodology

SCE provided NV5 with a CYME model of the Catalina Island 12kV distribution system that was approved for conducting load flow studies (Figure 2-6). CYME is an electrical distribution system analysis software used to conduct studies on electrical infrastructure. Included with this model were several load flow simulation printouts for both heavy and light loading conditions.[4] The CYME model provided could not be used to conduct a short circuit analysis on the island due to not having source Thevenin impedances at the substation.

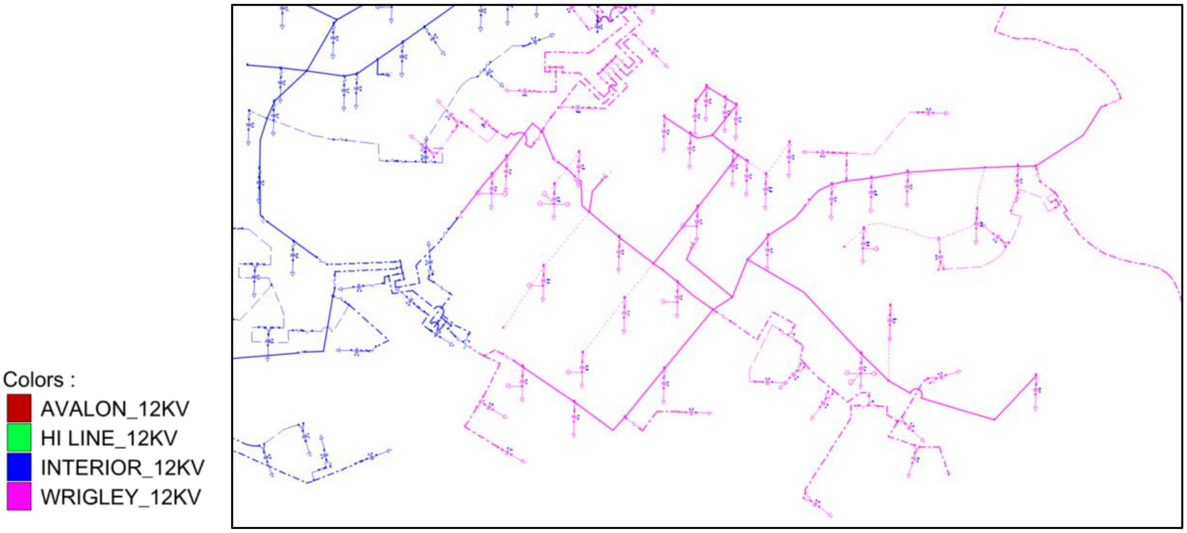

Figure 2-6 – CYME Model, City of Avalon Distribution Network

In addition to the electronic copies of the CYME model, SCE provided the following:

1. Existing Net Energy Metering (NEM) devices on the island (54kW installed as of 5/21/19)
2. Conductor sizes and lengths
3. Unbalanced loads on the island and associated power factor
4. Existing low voltage transformers and associated number of customers (mostly 12kV to 120/240V)

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[4] (Southern California Edison, 2019)

5. Customer meter information across the Hi-Line, Interior, and Wrigley distribution lines
6. Protective and isolation devices including in-line switches, fuses, relays, and reclosers
7. High loading and low loading values (see screenshot below)
8. Catalina Island Pebbly Beach Generating Station single-line diagram
9. Catalina Island distribution feeder map drawings in AutoCAD

NV5 used these inputs to reconstruct the grid model in Synergi Electric, an industry standard GIS based electrical analysis tool. NV5 underwent a series of validation exercises to ensure the same load flow results were achieved under the same load conditions provided in the SCE example loading cases. NV5 also underwent a robust audit of equipment ratings as compared to a spreadsheet database that was provided by SCE, to ensure the equipment ratings were mapped over correctly.

To start, NV5 rebuilt the three main distribution feeders within its Synergi model: Hi-Line, Interior, and Wrigley. Below is a list of the modeling assumptions used to rebuild the Catalina Island grid model:

1. Every conductor was included/modelled per the Excel spreadsheets. All conductor sizing was pulled from the equipment spreadsheets. Lengths were based on scaled AutoCAD feeder maps provided by SCE.
2. Customer loads were lumped at residential step-down transformers or small taps along the feeder.
3. The Avalon distribution feeder was modelled, however the information provided showed this feeder to be disconnected with no load assigned to it. (NV5 assumes that this feeder is for redundancy to use when one of the other feeder breakers need maintenance).
4. System nominal ph-ph voltage is 12 kV – assumption was made based on email traffic and values found in CYME model.
5. System send out voltage is 12,200V – From the CYME model. This send out is 1.0167pu without assuming any sort of bandwidth. Typically, the send out would be toward the higher end of the ANSI A limit due to the voltage drop properties of long lines (i.e. 1.04pu with +/- 0.01pu bandwidth). The lowest voltage seen on the Catalina model was 0.975pu during heavy loading which is still within ANSI A range.
6. All capacitors on the system are automatic switching capacitors. Sensitivity to capacitor operation was minimal.
7. Only feeder tie switches were modeled. In-line switches do not impact load flow results. Tie switches were useful in modeling alternate grid configurations.
8. The Pebbly Beach Generation substation was modeled as an infinite bus[5].

[5] This allows power to back-feed through the transformers if the island load is not high enough. This allowed NV5 to test the constraints of the grid and review maximum possible PV power production. In practice, a central control system will modulate the power output of the DERs in order to match generation to the instantaneous demand. See Section 4.4.2 and 4.4.3 for further details on the Microgrid controllers and DERMs solutions.

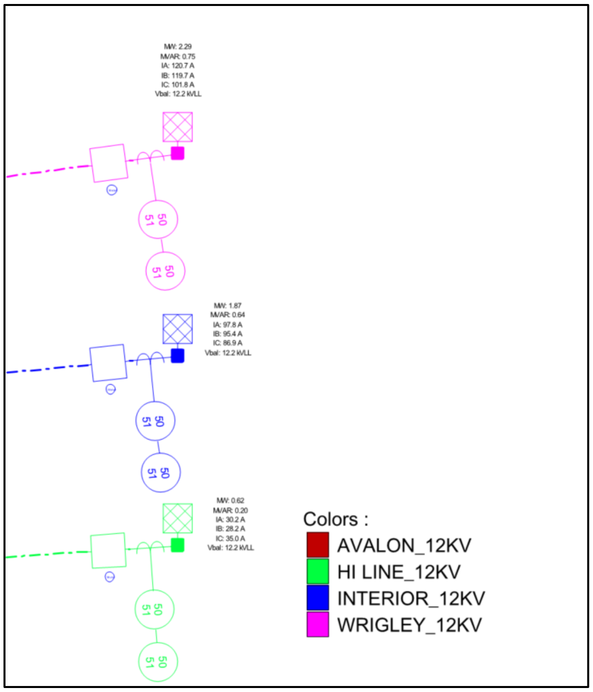

Figure 2-7 – Screenshot from SCE CYME Model Showing High Loading Values

A more in-depth discussion of NV5's Synergi results and Catalina's existing electrical distribution network can be found in Section 4.3.

3.0 EMISSIONS COMPLIANT FOSSIL FUEL GENERATION

Rule 1135 as promulgated by South Coast Air Quality Management District offers two alternative paths for compliance with new emission limits: mass based compliance and performance based compliance. The mass-based compliance path establishes a fixed limit of total annual emissions of NOx. The deadline of the mass-based compliance path is January 1, 2026. Total annual NOx emissions must not exceed 13 tons after the compliance deadline. The performance based compliance path has specific limits for regulated pollutants expressed in terms of parts per million of exhaust volume (ppmv) or pounds per one million British thermal units (MMBTU) of fuel consumption. Performance based compliance does not limit total annual emissions in terms of tons per year. The deadline of the performance based compliance path is January 1, 2024.

As will be discussed subsequently, Rule 1135 offers some flexibility for compliance through a 3-year extension of the respective deadlines. The deadline extension stipulates interim conditions of compliance for either path (Table 3-1).

Table 3-1 - Rule 1135 Compliance Options

Compliance Path	Original Deadline	Extended Deadline	Interim Thresholds
Performance-Based	1/1/2024	1/1/2027	At least two Rule 1135 conforming engines operational by 1/1/2023
Mass-Based	1/1/2026	1/1/2029	2022 NOx emissions ≤ 50 tons 2023 NOx emissions ≤ 40 tons

The extended deadline whether performance based, or mass based does require an annual mitigation fee of $100,000 until fully compliant with Rule 1135.

The diesel engine generator capacity providing electric service to the island is aging, with the weighted average service life of the engine generator sets exceeding 40 years. The existing diesel engine generators will not comply with the new air quality emission limits. The age of capacity and changing emission requirements are prompting an initiative to consider options for new generation capacity.

This technical section of the feasibility study seeks to determine the best path forward to accomplish replacement of the diesel fleet with units that will meet or exceed the performance based emissions standards. Performance based standards offer greater flexibility for compliance rather than the fixed annual limits of the mass-based standard.

3.1 GENERATOR REPLACEMENT

3.1.1 Capacity of Pebbly Beach Generating Station

New, replacement capacity must be sufficient to reliably serve future demand requirements. Plant capacity must also have provision for an operating reserve to ensure reliability and continuity of service. Operating reserve is typically defined as the greatest of; 5% of maximum demand, or the single largest contingency (loss of largest unit capacity). However, given the singular dependence of electric service to Catalina on PBGS, the historic practice for operating reserve is sufficient capacity to fulfill demand with two units out of service.

Table 3-2 - Existing Generator Capacity

Unit	kW	kV	Engine Speed (RPM)	Service Year
7	1,000	2.4	720	1958
8	1,500	2.4	900	1963
10	1,125	2.4	720	1966
12	1,575	2.4	900	1976
14	1,400	12	900	1986
15	2,800	12	900	1995
Sub-total	9,400			
Microturbines	1,490	12		2011
Total	**10,890**			

The effective operating capacity of the existing plant configuration (sans microturbines and battery storage) is 5,025 kW (with two largest units out of service: 9,400 kW – 2,800 kW – 1,575 kW). The existing operating capacity might be generally sufficient to meet present service demand requirements, but this is conditional on which units are out of service during peak load conditions.

> New capacity is premised on direct replacement of existing capacity with new diesel engine generators:
> - Limited space for additional units
> - Additional emission points (more engines) will complicate the permit process

The demand forecast of 7,330 kW ± 220 kW is greater than the existing effective operating capacity. The capacity of the individual replacement units will need to be larger than that of the existing units to provide capacity sufficient to serve the demand forecast.

Replacement capacity should also preserve the respective service voltages: 12 kV and 2.4 kV. Service distribution from plant is at 12 kV. The 2.4 kV system serves internal plant loads, and distribution loads (12 kV) after transformation.

The emissions of the replacement generators must also comply with the performance-based limits of Rule 1135[6] for regulated pollutants: nitrous oxide, ammonia, carbon monoxide, volatile organic compounds and particulate matter.

Table 3-3 - Emission Limits for Diesel Internal Combustion Engines

NO_x (ppmv)[1,4]	NH_3 (ppmv)[1]	CO (ppmv)[2,4]	VOC (ppmv)[3,4]	PM (lbs/MM BTU)
45	5	250	30	0.0076

1 Corrected to 15% oxygen on a dry basis and averaged over a 60-minute rolling average

2 Corrected to 15% oxygen on a dry basis and averaged over 15 minutes

3 Measured carbon, corrected to 15% oxygen on a dry basis, and averaged over sampling time required by the test method

4 The NO_x, carbon monoxide, volatile organic compounds emissions limits in Table 3-3 shall not apply during start-up and shutdown

[6] Issued and administered by the local governing jurisdiction: South Coast Air Quality Management Division

The engines must also comply with National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Engines (NESHAP). Existing, stationary compression ignition engines greater than 500 horsepower must limit CO concentration to less than 23 ppmv at 15% O2 or reduce CO emission be 70% or more[7].

Two manufacturers have affirmed availability of diesel engine generators conforming to Rule 1135 under full, continuous load operation: Cummins and EMD. Simultaneous compliance with Rule 1135 and RICE NESHAP has yet to be confirmed. Potential modifications to the engines or operating protocols of the engines and associated incremental capital costs for possible compliance to Rule 1135 and CO limits under partial load conditions are yet to be identified, or simply determined if such modifications could be effective. A third manufacturer, Caterpillar, offers engines that are Tier 4 compliant but do not conform to the limits of Rule 1135.

The capacity of the engine-generators available from Cummins and EMD are generally comparable to the existing plant capacity, ranging from 1,233 kW to 2,983 kW:

Table 3-4 - Tier 4 Capacity: Cummins and EMD

Manufacturer	Model	Capacity (kW)	Engine Speed (RPM)
Cummins	QSK50-G8	1,233	1,800
	GSK60-G17	1,633	1,800
	CA542	2,127	1,800
EMD	8 E 23	1,491	900
	12 E 23	2,237	900
	16 E 23	2,983	900

3.1.2 Generator Replacement Options

Rule 1135 outlines two general options/timelines for replacement of engine generators conforming to emissions performance limits of Table 3-3:

1. Replace all existing engine generator sets with Rule 1135 conforming engines by January 1, 2024.
2. Replace at least two existing engine generator sets with Rule 1135 conforming engines by January 1, 2023. The remaining engine generator sets must be replaced with Rule 1135 compliant capacity by January 1, 2027.

The second option is premised on a three-year extension of the conformance deadline, available through Rule 1135. One condition of the deadline extension is that at least two engines are replaced and operational by January 1, 2023. A second condition of the extension is a mitigation fee of $100,000 payable for every year or portion of year after January 1, 2024 unitl all engines conform to Rule 1135. The remaining engines may continue to operate but must be replaced or taken out of service within the deadline extension. A request for extension of the deadline must be submitted to SCAQMD at least 365 days prior to January 1, 2024.

NOTE: Unit 15 of the six existing engine generators is exempt from Rule 1135 and may remain in service.

[7] Issued and administered by the local governing jurisdiction: South Coast Air Quality Management Division.

3.1.2.1 Option 1 – Replace All Existing Engines by January 1, 2024

As noted previously engine generator sets 7 through 12 are connected to the 2.4 kV system, while Unit 14 and Unit 15 are connected to the 12 kV system. The transformer of the 2.4 kV system has a rated capacity of 7,500 kVA, or about 6,000 kW with a 0.8 power factor. The engines now connected to the 2.4 kV system have a nameplate capacity of 5,200 kW. Absent replacement and upgrade of the 2.4 kV transformer, the capacity and operation of replacement engines on the 2.4 kV system must account for this transformer limitation by:

1. Shifting one of the engines from the 2.4 kV system to the 12 kV system; and/or
2. Managing the operation of the engines on the 2.4 kV system so the kVA rating of the transformer is not exceeded (generators on the 12 kV system may need to increase generation during such periods)

Space is available within the 12 kV panels for a third engine generator set (Unit 15 plus two replacement units) with the removal of the microturbines[8], allowing a three + three configuration on the respective voltages.

Replacement capacity with engine generator sets from Cummins could potentially feature five units at 2,127 kW plus 2,800 kW from Unit 15, yielding a total capacity of 13,435 kW and operating capacity of 8,508 kW. Operating capacity is defined as capacity with the two largest units out of service: 13,435 kW – 2,800 kW – 2,127 kW = 8,508 kW.

The operating service voltage of the respective replacement engines is not changed: units 7, 8, 10, and 12 are on the 2.4 kV system and Unit 14 is on the 12 kV system. As noted previously, the simultaneous operation of the 2.4 kV engine generators will need to be managed to stay within the capacity of the 2.4 kV transformers.

Table 3-5 - Five Engine Generator Replacement Scenario

Unit Designator	Existing Capacity		Replacement Capacity, kW		
	kW	kV	kV	Cummins	EMD
7	1,000	2.4	2.4	2,127	1,491
8	1,500	2.4	2.4	2,127	2,237
10	1,125	2.4	2.4	2,127	2,237
12	1,575	2.4	2.4	2,127	1,491
14	1,400	12	12	2,127	2,983
15	2,800	12	12	2,800	2,800
Microturbines	1,490	12			
Total Capacity	10,890			13,435	13,239
Operating Capacity	6,515			8,508	7,456
Reserve Capacity	4,375			4,927	5,783

The corresponding replacement scenario with engine generator sets from EMD might feature two units at 1,491 kW, two units with 2,237 kW, a fifth unit at 2,983 kW plus 2,800 kW from Unit 15, yielding a total capacity of 13,239 kW and operating capacity of 7,456 kW (13,239 kW – 2,800 kW – 2,983 kW). With Unit 8 shifted to the 12 kV system, the total replacement capacity on the 2.4 kV system is within the limitation of the 2.4 kV transformer: 5,219 kW (1,491 kW + 1,491 kW + 2,237 kW).

[8] Operation of the microturbines are a condition of the air emissions permit presently in effect. Removal of the microturbines will require permit amendment in conjunction with the permit changes necessitated by the imposition of Rule 1135.

The demand forecast of the plant, 7,330 kW ± 220 kW, is generally within the operating capacity of either replacement configuration (Cummins or EMD).

Figure 3-1 - Service Capacity and Future Demand

3.1.2.2 Option 2 – Replace at Least Two Existing Engines by January 1, 2023

Option 2 affords an attractive replacement scenario that has the potential to leverage results of the feasibility study yet conform to regulatory requirements. Under Option 2, at least two existing engines must be replaced with Rule 1135 conforming engines. The replacement engines must be operational by January 1, 2023. The timing of future replacement engine generators can then be planned to:

- Mitigate the risk of service disruption of multiple, simultaneous engine replacements necessary for compliance under Option 1, and
- Better accommodate the scope of renewable energy systems and storage systems identified by this feasibility study.

As noted previously Unit 15 is exempt from Rule 1135 and may remain in operation. Of the remaining engine generators, Unit 8 and Unit 10 appear to be the most likely candidates for the replacement engines.

With the two-engine replacement scenario it may be preferable to maintain continuity of engine manufacturer (in contrast to the full replacement of all engines by 2024 under Option 1). The incumbent engine manufacturer is EMD. On this basis the two-engine replacement scenario using EMD 2,237 kW units[9] may be:

[9] The smaller 1,491 kW units could replace Units 8 and 10 as noted in the text. Yet all engines must be replaced per Rule 1135. The smaller engines may be better suited as replacements for Unit 7 and Unit 12 given the space limitations of the respective sites.

Table 3-6 - Two Engine Replacement Scenario with EMD

Unit			Replacement: 8 & 10	
	kW	kV	kW	kV
7	1,000	2.4	1,000	2.4
8	1,500	2.4	2,237	2.4
10	1,125	2.4	2,237	2.4
12	1,575	2.4	1,575	2.4
14	1,400	12	1,400	12
15	2,800	12	2,800	12
Microturbines	1,490	12		
Total Capacity	10,890		11,249	
Operating Capacity	6,515		6,212	
Reserve Capacity	4,375		5,037	

Reserve Capacity: Unit 15 plus the next largest capacity unit

Both replacement engines will retain connection with the 2.4 kV system. Total capacity on the 2.4 kV system will be 7,049 kW, potentially 17.5% over the associated transformer capacity: 6,000 kW or 7,500 KVA at 0.8PF.

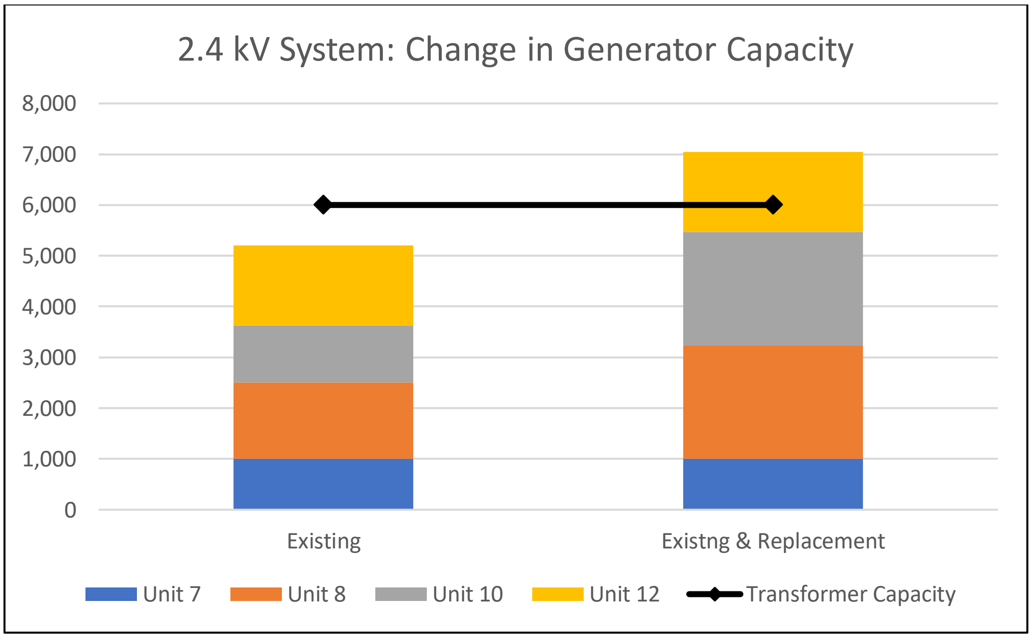

Figure 3-2 - 2.4 kV System Capacity–Generators and Transformer

Operating capacity of the plant with the two replacement engines is just over 6,200 kW. The service demand on the plant could approach 6,400 kW if identified projects are developed as anticipated. Unless mitigated through the use of battery storage, engine maintenance may need to be planned to ensure availability of the larger capacity units during periods of peak seasonal demand.

The remaining replacement units would likely follow the configuration of Option 1 engine replacement:

Unit 7	1,491 kW/2.4 kV
Unit 12	1,491 kW/2.4 kV
Unit 14	2,983 kW/12 kV

Total installed capacity with Unit 15 remaining in service is 13,239 kW. Operating capacity, with two largest units out of service, is 7,456 kW and is sufficient to serve the forecast of utility demand.

3.1.2.3 Alternate Fuel for Engine Generator Replacement: Propane

Propane engine generator sets are smaller in capacity relative to the diesel engine generator sets. Unit capacity is generally smaller because of the combustion characteristics of propane. Two manufacturers offer propane engine generators suitable for Pebbly Beach Generating Station: Caterpillar and Jenbacher. Propane units available through Caterpillar have a capacity of 1,382 kW. The Jenbacher propane engine generator sets are rated at 1,025 kW.

3.1.2.4 Two Engine Propane Replacement

Table 3-7 shows a probable configuration with Caterpillar and Jenbacher propane engine generators replacing Unit 8 and Unit 10.

Table 3-7 - Two Engine Replacement Scenario with Propane Engine Generator Sets: Units 8 & 10

Unit			Caterpillar		Jenbacher	
	kW	kV	kW	kV	kW	kV
7	1,000	2.4	1,000	2.4	1,000	2.4
8	1,500	2.4	1,382	2.4	1,025	2.4
10	1,125	2.4	1,382	2.4	1,025	2.4
12	1,575	2.4	1,575	2.4	1,575	2.4
14	1,400	12	1,400	12	1,400	12
15	2,800	12	2,800	12	2,800	12
Microturbines	1,490	12				
Total Capacity	10,890		9,539		8,825	
Operating Capacity	6,515		5,164		4,450	
Reserve Capacity	4,375		4,375		4,375	

In either replacement option, the capacity on the 2.4 kV system remains below the transformer limit of 6,000 kW.

The propane units would occupy two of the five available engine sites, with Unit 15 remaining in service. Potential capacity contribution from renewable energy systems notwithstanding, the replacement capacity of the remaining units must be sufficient to provide operating and reserve capacity for the anticipated service demand of about 7,330 kW. With the caterpillar propane engine generator sets, the three replacement units would likely consist of two 2,237 kW diesel engine generator sets and one 2,983 kW diesel engine generator set (presuming EMD). Similarly, selection of Jenbacher propane engine generator sets will drive three replacement units consisting of two 2,983 kW diesel engine generator sets and one 2,237 kW diesel engine generator set (again presuming EMD). The sites of Unit 10 and Unit 12 and adjacent infrastructure will require substantial modifications to accommodate placement of these large capacity engines.

3.1.2.5 All Engine Propane Replacement

Propane could be used as the exclusive fuel for generation. A 100% propane fleet will require significant changes to layout and configuration relative to the existing engines. Seven engines rather than six will be needed to provide a general equivalence of capacity for more equitable comparison with diesel engine generator scenarios. It is likely that an eighth engine will be necessary within five to ten years to ensure sufficient operating capacity to serve future utility demand.

Table 3-8 contains a probable configuration featuring Caterpillar 3520 propane engine generators.

Table 3-8 - Probable Propane Generator Configuration

Unit	Existing		Caterpillar	
	kW	kV	kW	kV
7	1,000	2.4	1,382	2.4
8	1,500	2.4	1,382	2.4
10	1,125	2.4	1,382	2.4
12	1,575	2.4	1,382	2.4
14	1,400	12	1,382	12
15	2,800	12	1,382	12
Microturbines	1,490	12		
New Capacity			1,382	12
Total Capacity	10,890		9,674	
Operating Capacity	6,515		6,910	
Reserve Capacity	4,375		2,764	

The seven engine configuration, placed around the perimeter of the Main Building, is an expansion of the two propane engine placement described previously. Five engines would be placed in the space now occupied by Units 7, 12, 14, and 15. However the foot print of the propane engine generator sets (48' x 12') and associated external radiators (10' x 22') will essentially require the demolition of all structural steel and concrete pad/foundations used by the existing engines. Some of the external radiators may need to be elevated to ensure access to existing infrastructure (monitoring wells and sewer sumps) and to engines for maintenance. The all propane option will also require new fuel storage and delivery infrastructure. As noted previously, the existing propane storage supports the operation of the microturbines and service requirements of a propane customer base.

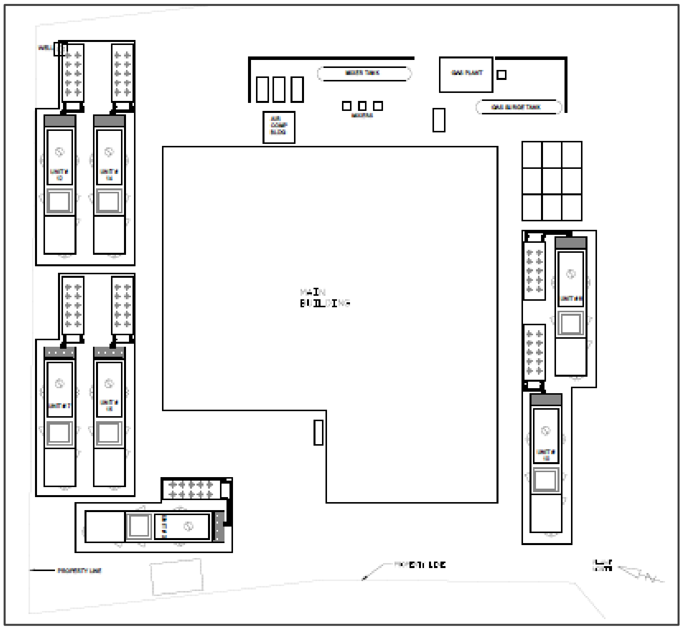

Figure 3-3 – General Arrangement of 100% Propane Generator Fleet

The available storage capacity, three 30,000-gallon tanks, is insufficient to also support the operation of the proposed engine generator sets and provide fuel reserve. Total tank capacity on the site in 120,000 gallons, or four 30,000-gallon tanks. One tank was taken out of service because the site does not have adequate water supply for fire deluge for all four tanks. Historically, a fuel reserve of 135,000 gallons is maintained by the plant to ensure continuity of operations if fuel deliveries are interrupted. This magnitude of fuel provides approximately a 30-day reserve. A propane tank array consisting of eight 30,000-gallon tanks will provide about a 28 day reserve for propane engine generator sets. Supplemental use of the existing propane storage at the plant can provide the remaining two days of fuel reserve.

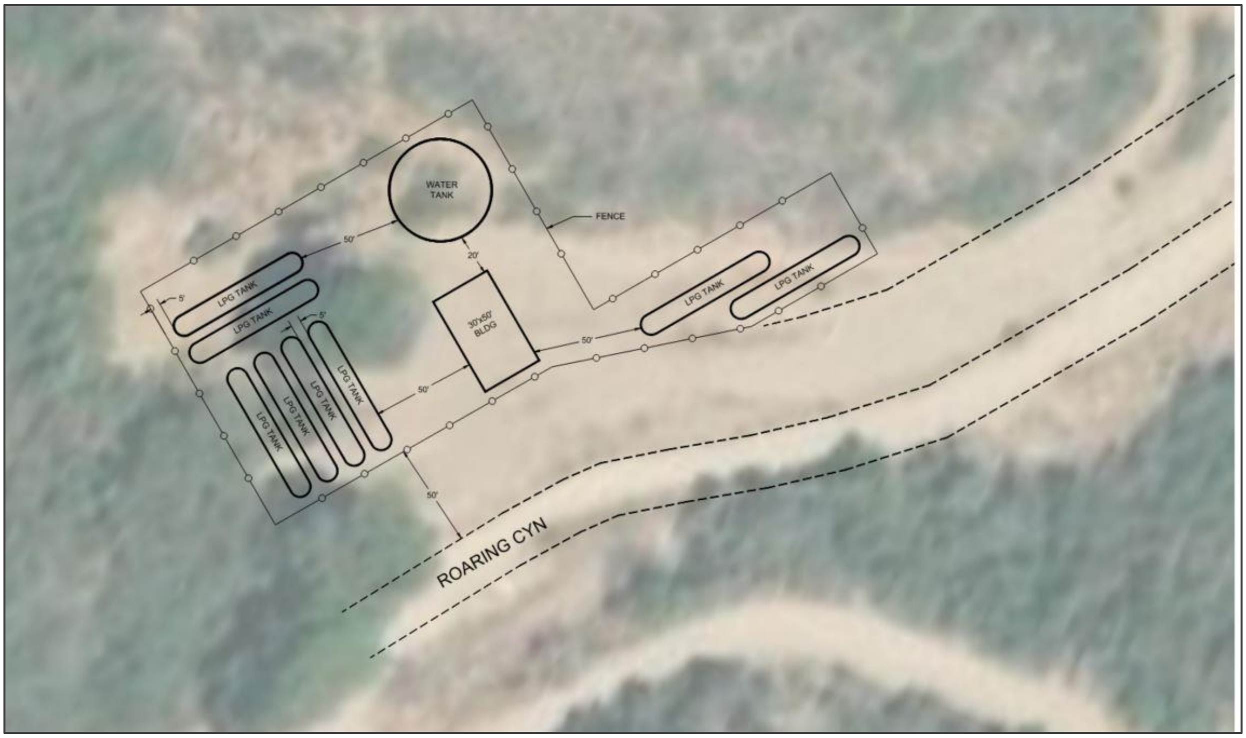

Figure 3-4 - Propane Storage for 100% Propane Generator Fleet

The plant site does not have the space for placement of this storage capacity, and also does not have adequate water for fire deluge as already noted. The nearest potential location offering sufficient space is the area presently used as a track for off-road vehicles, approximately one-half mile southwest from the plant by road (Wrigley Road and Dump Road). The site will also include a 2 million gallon water tank for fire deluge, and a small building with space for office and local control interface, stand-by generator and pumps for fire deluge. Water to fill the deluge tank would be delivered by truck. A utility corridor between the storage site and the plant will provide the propane fuel connection, electric service and communications path data/security/alarm. The site will be fenced with controlled access for fuel deliveries and utility personnel. The estimated construction cost of developing the propane storage necessary to support the operation of an all propane engine generator plant is $14.38 million with a corresponding project cost of $16.10 million. This cost will be included in the consolidated cost of the all propane alternate. Note: This estimated cost does not include acquisition of the site for the propane storage.

The ability to obtain land and to complete permitting and construction in time to meet the deadlines of Rule 1135 depends on a number of factors outside of SCE's ability to control. Therefore, completion of this option within the regulatory timeline should be considered a low probability.

3.2 ELECTRICAL POWER SYSTEM

3.2.1 General Description of System

The Pebbly Beach Generating Station electrical power system is configured into three major voltage levels:

- 240V Auxiliary Power System
- 2.4 kV Power System
- 12 kV Power System

<u>Reference Drawings:</u>
SCE Drawings
5478606-1, PBGS One Line Diagram auxiliary power
5478060-1, PBGS One-Line Diagram
5220447-1, PBGS 12 kV Positions 2X through 5 Three-Line Diagram
5478069-1, PBGS 12 kV Positions 6 through 10 Three-Line Diagram
442813-10, PBGS No. 1 Transformer Bank, 2.4 to 12 kV Three-Line Diagram

NV5 Drawings
E001, Electrical Symbols and Abbreviations (Appendix B)

3.2.1.1 240V Auxiliary Power System

With reference to SCE Drawing 5478606-1 the following has been determined. The 240-volt power system serves power plant auxiliary systems, e.g. lighting and 120-volt convenience power, heating and ventilating systems, compressed air system, fuel oil systems and motor control centers for other auxiliary loads. The system is served from the 500 kVA, 2400-240-volt, 3-phase Station Light & Power (SLP) transformer. This transformer is configured in a delta- delta winding configuration but has a delta – open corner delta grounding transformer connected on its load side to detect and alarm a ground fault on the 240-volt system. In this manner, a ground fault anywhere on the system will not trip a circuit breaker. The 240-volt system and the plant can continue in operation until the ground fault is found and repaired.

Coincidental peak load data on the 240-volt was not available. NV5 is assuming is no spare capacity on the existing 240-volt system, and additional loads, e.g. a fourth air compressor or a backup tie to a propane engine-generator auxiliary system, will require replacing the existing SLP transformer and 240-volt Switchgear BA with larger capacity equipment.

3.2.1.2 2.4 kV Power System

With reference to SCE Drawing 5478060-1 the following has been determined. The drawing suggests that the existing 2.4 kV power system is operated as an ungrounded system. Transformer Bank 1 is wired in a delta configuration on its secondary side. Each of the four 2.4 kV engine-generators are delta wound. NV5 anticipated that the Generating Station Repowering project will continue with configuration but recommends that this item be discussed with SCE technical staff.

The 2.4 kV system includes a new lineup of 2.4 kV metal clad switchgear in an outdoor enclosure located on the on the southeast corner of the power plant. Each 2.4 kV diesel engine generator is connected to the switchgear by 2.4 kV power circuits as listed below:

1. Engine-Generator 7, 1000 kW, power cable 3-350 kcmil
2. Engine-Generator 8, 1500 kW, power cable 2-250 kcmil/phase

3. Engine-Generator 10, 1125 kW, power cable 3-500 kcmil
4. Engine-Generator 12, 1075 kW, 3-750 kcmil

The new switchgear has rating of 2,000 amperes of continuous current. As of April, 2019, the new switchgear had not yet been fully commissioned and the existing 2.4 kV switchgear was still in operation.

The new switchgear includes:

- 1,200-ampere power circuit breakers for each of the four 2.4 kV engine-generators
- SL&P transformer
- 2.4-12 kV Transformer Bank 1
- Tie between the operating bus and transfer bus
- Spare circuit breaker.

The 2000-ampere continuous current rating of the new switchgear is sufficient for the proposed three 2,237 kW diesel engine-generators that will replace existing units 8, 10, and 12. However, circuit breakers for Units 8 and 10 have current transformers rated 500-5 amperes, which must be replaced if 2,237 kW engine-generators are installed.

The temporary 2.4 KV power circuit between the 2.4 kV Switchgear and Transformer Bank 1 was observed during a site visit on April 25, 2019. The temporary circuit consists of 2-750 kcmil cables per phase, with an approximate ampacity of only 990 amperes, or 4,115 kVA capacity. It was not known at the time of this Report what the permanent circuit will be. This should be confirmed during the design phase of this project.

The 2.4 kV switchgear also includes a set of three 2.4 kV – 120V potential transformers, wired in grounded wye-open corner delta configuration, to sense and alarm a ground fault on any one phase. It is anticipated that this system need not be modified and will continue in operation with the ungrounded 2.4 kV system.

3.2.1.3 12 kV – 2.4 kV, 7,500 kVA Transformer Bank 1

Transformer Bank 1 consists of six single-phase 1,250 kVA liquid filled (total 7,500 kVA), outdoor substation-type transformers that are connected to overhead 2.4 KV and 12 kV busses within a fenced area south of the plant. The transformers have no cooling fans. SCE keeps a matching spare, single-phase, 1,250 kVA transformer in the transformer yard. SCE has not reported any issues with Transformer Bank 1.

NV5 could not examine the transformer nameplates for additional information, so NV5 conservatively assumes that the 1,250 kVA rating is the self-cooled, 65C rise rating of the transformers. This assumption dictates a 7,500 kVA constraint on the largest amount of proposed 2.4 kV electrical generation if the existing Transformer Bank is not replaced. The proposed replacement Cummins engine-generators for Units 8, 10, and 12 are each rated 2,200 kW at 0.8 PF, which coordinates nicely with the rating of existing Transformer Bank 1. The proposed replacement EMD engine-generators for Units 8 and 10 are each rated 2,237 kW at 0.8 PF, which also coordinates nicely with the rating of Transformer Bank 1. On this basis, NV5 does not anticipate that Transformer Bank 1 is replaced within the Power Plant Repowering Project and has not included replacement costs in the Opinions of Probable Cost included in this report.

The Transformer Bank 1 fenced area is approximately 30 FT x 30 FT, which is large enough to install two 3,750 kVA, 65C rise, and 12 kV-2.4 kV pad mount transformers if SCE desires. This work could be scheduled during a spring or autumn period of low load when two of the proposed three 12 kV engine-generators can adequately serve the entire island, and the 2.4 kV engine-generators are not needed.

3.2.1.4 12 kV Power System

The 12 kV power system consists of an outdoor lineup of 12 kV switchgear located between the Transformer Bank 1 area and the road. The circuit breakers in the switchgear rated 12 kV, 1200-amperes, with an interrupting rating of 25,000 amperes. The switchgear is adequately rated for connections of the proposed replacement engine-generators. Each circuit breaker is adequately rated to safely interrupt the maximum fault current if all the proposed generators were in operation and contributing to a bolted three-phase fault on the immediate load side of the circuit breaker.

The 12 kV switchgear includes 1,200-ampere circuit breakers for these existing generators and associated 12 kV power circuits:

1. Microturbines system, all 480V generators with a 2000/2576 kVA, OA/FA, 55/65˚C rise step-up transformer, power cable 3-250 kcmil
2. Engine-Generator 15, 2,800 kW, power cable 3-2/0 AWG
3. Engine-Generator 14, 1,400 kW, 3-2/0 AWG

The circuit breakers for these generators have 300-5A current transformers which do not have to be replaced. Therefore, no modifications to the 12 kV switchgear are anticipated to accommodate connection of new units to replace Engine-Generators 14 and 15 (2,933 with EMD; 2,127 kW with Cummins; or 2,500 kW with Caterpillar), and/or a possibly similar-sized propane fired unit to replace the microturbines system.

3.2.1.5 System Controls

The Generating Station presently operates through an Emerson Ovation distributed control system. Most controls are analog and alarms hardwired from mechanical switches.

3.2.1.6 Grounding System

The Station's 2.4 kV power system is operated as an ungrounded system. Existing Generators 7, 8, 10, and 12 are shown as delta-connected units on one-line diagram 5126943-10. No neutral grounding impedances are shown on the drawing, and no grounding impedances outside the engine-gen enclosures were observed during our April, 2019. A three-phase potential transformer bank is connected to the 2.4 kV operating bus and configured grounded wye primary – open corner delta secondary, with a ground detection relay, IEEE device 64, monitoring the voltage across the open corner delta secondary.

The temporary (2-750 kcmil per phase) 2.4 kV power circuit between the 2.4 kV switchgear and the 12 kV-2.4 kV-volt substation transformers, which is installed in a trench in the driveway and laid on the ground up the small grade to the transformer yard, are 5 kV EPR/PVC shielded conductors. The circuits did not appear to have a separate grounding conductor(s) installed with the insulated power conductors.

The 2.4 kV engine-generators do not produce line-ground fault current on the 2.4 kV system since they are delta connected. The 12 kV-2.4 kV Transformer Bank 1 is connected delta on the 2.4 kV secondary side, so there is no contribution from the 12 kV to a ground fault on the 2.4 kV system. As noted above, there is a ground fault sensing relay, IEEE Device 64, which alarms if one phase goes to ground, but does not trip any circuit breakers. In this manner, the system can stay in operation while the plant operators make arrangements to have the ground fault fixed.

Generator 15 is a 2.4 kV generator and is connected to the 12 kV bus through a delta-delta step-up transformer. Generator 15 does not contribute line-ground fault current for a ground fault on the 12 kV distribution system. The Microturbines system are also connected to the 12 kV distribution system through a delta primary transformer, and also do not contribute line-ground fault current to a ground fault on the 12 kV distribution system.

It appears from review of the referenced drawing that Generator 14 is operated ungrounded.

Drawing 5220447-11 shows a grounded wye – closed delta grounding transformer connected to the 12 kV Operating Bus. This transformer serves as the return path for line-ground fault current on the 12 kV distribution system. A protective relay monitors the ground fault return current back through the transformer’s primary grounded neutral.

NV5 does not anticipate any changes or modifications to the ungrounded configuration of the existing 2.4 kV power system or the grounding transformer configuration of the 12 kV distribution system. Relay settings should be confirmed during the 30 percent design phase of the Generating Station Repowering Project.

The station “light & power” auxiliary power system is served by Station Light & Power Transformer SLP, which is delta-delta connected. A grounding transformer is connected on the 480V side of the SL&P transformer, so the system is effectively a grounded system for personnel and equipment safety.

On the basis of the above discussion, plant power systems grounding is not an issue for the feasibility study phase of this project. However, NV5 recommends that the design engineer for subsequent phases of the project discuss the existing power systems’ grounding configurations with SCE.

3.2.2 Description of Recommended Power System Upgrades

3.2.2.1 240V Auxiliary Power System

Refer to NV5 drawing E100, Ultimate 12 kV/2.4 kV/240V One-Line Diagram (Appendix B). The existing 240V auxiliary power system, served by 500 kVA Station Light & Power Transformer through 1600-ampere Switchgear BA, may not be large enough to serve the ultimate Generating Station coincidental load plus these additional auxiliary loads:

1. Fuel Gas Compressor for an alternate propane fueled engine-generators.
2. Enclosure shore power requirements for the proposed natural gas engine-generator.
3. Air compressor 4, to address greater starting air requirements for the larger diesel engine-generators. NV5 anticipates that another 150-160 PSIG, 170 cubic feet per minute (CFM) air compressor may be needed at the suggestion of Marine Services, Inc. (a vendor/integrator of EMD engine-generators familiar with the Generating Station).
4. Larger radiator fan motors on the radiators furnished with the replacement diesel engine-generators (no horsepower data available at the time of this Report).

NV5 anticipates that a 1000 kVA Station Light and Power Transformer may be needed, and larger main Switchgear BA with a main bus rating of 3200-ampere. We have included estimated costs of replacing the existing Station Light and Power transformer and the existing main Switchgear BA in the Opinion of Probable Cost.

The concept system design shown on NV5 drawing E100 is only to determine feasibility of repowering the plant and developing a first opinion of probable cost. Blackstart procedures and loads, as well as auxiliary loads for the ultimate plant, should be determined during the design phases of this project to design the ultimate auxiliary power system.

Propane Fueled Engine Generator

NV5 anticipates that the potential propane engine-generator(s) will have substantial auxiliary power requirements, including a fuel gas compressor, propane air mixing station to deliver suitable fuel gas to the new unit, enclosure "shore power" requirements for lighting, heating (engine block and enclosure) and ventilation, and electric motor-driven remote radiator fans. A separate 240V auxiliary power system is proposed for a propane engine-generator unit, with a backup cross-tie circuit to the new Switchgear BA. In this manner, both the propane engine-generator 240V auxiliary power system and the Generating Station 240V power system can be fully operation if one station power transformer or main feeder cable is not available. The existing 250 kW emergency engine-generator can stay in operation to provide emergency power for controls, life safety, and blackstart operations. The 250 kW emergency engine-generator may be replaced with a 450 kW unit if the unit must also serve the fourth air compressor.

3.2.2.2 2.4 kV Power System

NV5 anticipates that existing 2.4 kV diesel engine-generators 8 (1,500 kW) and 10 (1,125 kW) will be replaced by new diesel engine-generators 8R (2,237 kW EMD unit) and 10R (2,237 kW EMD unit), respectively. If other engine-generator manufacturers' products are furnished, e.g. three Cummins 2,100 kW units, then the third unit may be installed in the location of either existing Unit 7 or Unit 12. In either scenario, four 2.4 kV generator circuit breakers are available (currently serving existing generators 7, 8, 10, and 12) and are suitably rated for even the 2,237 kW EMD generators. Larger current transformers may need to be installed at each circuit breaker for controls and protective relaying.

The entire 2.4 kV switchgear is suitably rated for continuous current, fault interruption and fault withstand for the anticipated new engine-generators. No major modifications to the 2.4 kV Switchgear are anticipated.

The capacity of the main 2.4 kV power circuits and raceway from the existing generators' locations to the 2.4 kV Switchgear will need to be increased if larger generators are provided. Substantial work may be necessary to install additional underground raceway. At the time of this Report, is it not known if spare underground raceway was stubbed out from the new 2.4 kV Switchgear installation to accommodate the future installation of additional raceway and larger power circuits. If not, then the installation will be more complicated and costly, but is still feasible.

3.2.2.3 12 kV Power System

NV5 anticipates that existing 12 kV diesel engine-generators 14 (1,400 kW) and 15 (2,800 kW) will be replaced by new 2,983 kW diesel engine-generators. In addition, NV5 anticipates that the microturbines could potentially be taken out of service as the existing diesel engine generators are replaced. A replacement engine generator could then be connected to the existing 12 kV circuit breaker positions in the 12 kV Switchgear presently used by the microturbines.

The existing 12 kV Switchgear has a rated interrupting capacity of 25,000 rms symmetrical amperes as noted on the switchgear nameplates. The interrupting capacity rating is substantially greater than the total three-phase bolted fault short circuit capability of anticipated three 12 kV generators plus 7,500 kVA of 2.4 kV generation on the low voltage side of Transformer Bank 1. Therefore, the ratings of the existing 12 kV Switchgear are adequate for the anticipated generation installed within the Generating Station Repowering Project. No major modifications to the 12 kV Switchgear are anticipated.

3.2.2.4 System Controls

Marine Services, Inc. advises that controls furnished on the proposed EMD engine-generators can be easily configured into the existing Emerson Ovation distributed control system using Modbus or Profibus communications.

3.3 ESTIMATE OF PROBABLE CONSTRUCTION COST

3.3.1 Electrical

Estimated capital costs are presented for the 2.4 kV system and 12 kV system. The upgrade of the 240V plant auxiliary system are presented only in the context of the potential use of propane engine generators.

Changes to the 2.4 kV and 12 kV systems are segregated for each engine bay or site: replacement engines for Bays 7, 8, 10 and 12 are presently assigned to the 2.4 kV system, and Bays 14 and 15.

Figure 3-5 - Engine Bays and Engines

3.3.1.1 2.4 kV Power System

The cost of changes to the 2.4kV system to accommodate installation of new replacement engine generators, is inclusive of: demolition and restoration for new ductbank; new ductbank, cables and terminations; low-voltage power, control, metering and relaying circuits; relays, relays settings and equipment testing, raceways to plant; grounding; and communication circuits and integration with the Ovation system.

The variation of capital cost estimate for each engine bay is a primarily function of the relative distance to 2.4 kV switchgear See estimated capital costs in Table 3-9.

Table 3-9 - Estimate of Capital Cost: 2.4 kV System

Bay	7	8	10	12
Capital Cost	$ 733,800	$ 474,100	$ 563,500	$ 705,100

Note: Capital cost if all units (7-12) remain on 2.4 kV system.

3.3.1.2 12 kV System

The cost of changes to the 12kV system to accommodate installation of new replacement engine generators, inclusive of: demolition and restoration for new ductbank; new ductbank, cables and terminations; low-voltage power, control, metering and relaying circuits; relays, relays settings and equipment testing, raceways to plant; grounding; and communication circuits and integration with the Ovation system. Total capital cost of changes for replacing Unit 14 on the 12 kV system was found to be $641,800.

3.3.1.3 2.4 kV Auxiliary Power System

The cost of upgrades to the 240 V plant auxiliary system is estimated at just over $1.1 million. The cost estimate accounts for demolition of existing electric equipment and work, a new 450 kW diesel engine-generator, fourth air compressor with VFD, a new switchboard and transformer, and associated electrical work. These upgrades are necessary to support operation of propane or LNG engine generator options, and do not apply to diesel engine replacement.

3.3.2 Engine Generator Sets

The estimated cost of generator sets are presented by vendor (Cummins and EMD), engine capacity and service voltage (12 kV or 2.4 kV). The estimated cost includes engine generator sets plus allowances for spare parts and tools; freight and delivery; and site work. Site work consists of foundations and concrete work; supports for auxiliary systems and access platforms; mechanical connections; controls and controls integration; start-up, crane rental; placement and installation. A contingency of 15% is applied to site work.

The cost estimates are based on vendor quotes for major equipment, construction costs of recently completed engine generator projects of similar unit capacity. The cost of site work for engine replacements is considered to be essentially equivalent given the relatively small variation of engine generator capacity.

Table 3-10 presents the estimated cost for diesel engine generator replacement. The base capacity of Cummins engine generator set is 2,127 kW. The estimated installed cost of the Cummins 2,127 kW unit is $3.36 million and $3.32 million for 12 kV generator or 2.4 kV generator, respectively.

The replacement capital costs with EMD is based upon two units: one with a capacity of 2,983 kW (used in for engine replacement scenario) and the other with a capacity of 2,327 kW (five engine and four engine replacement). The estimated cost of the 2,983 kW unit with a 12 kV generator is approximately $3.70 million. The estimated cost of the 2,327 kW unit with a 2.4 kV generator is approximately $3.48 million, or $3.53 million with a 12 kV generator.

Table 3-10 - Estimated Cost of Replace Engine Generator Sets: Diesel

Manufacturer	Capacity: kW/kV	Unit Cost, Installed	$/kW
Cummins	2,127/12	$3,521,500	$1,656
	2,127/2.4	$3,471,500	$1,632
EMD	2,983/12	$3,910,400	$1,311
	2,237/12	$3,686,500	$1,648
	2,237/2.4	$3,636,500	$1,626
	1,491/2.4	$3,507,500	$2,352

The estimated cost of using propane generator sets as presented in Table 3-11 is about $3.11 million and $3.16 million with Caterpillar, 2.4 kV and 12 kV, respectively, or $2.11 million with Jenbacher (2.4 kV).

Table 3-11 - Estimated Cost of Replacement Engine Generator Sets: Propane

Manufacturer	Capacity: kW/kV	Unit Cost, Installed	$/kW
Caterpillar	1,382/2.4	$3,111,500	$2,251
	1,382/12	$3,161,500	$2,288
Jenbacher	1.025/2.4	$2,107,000	$2,056

3.3.3 Fuel Delivery and Urea Systems

New diesel fuel delivery and urea systems may be necessary to support the transition to new, generally larger engine generator sets. A single trench, nearly 700 lineal feet, is anticipated for the new fuel system and the urea system. The systems are based on containment (double-wall) piping with an estimated construction cost of about $555,000. The cost estimate includes demolition of the existing systems, waste disposal, trench and back fill, concrete paving and a 25% allowance for unknown detail.

This capital cost is included in Option 1 replacement (other than Unit 15 all engines replaced by January 1, 2024), but not carried in the consolidated capital cost of Option 2 replacement (two engines by January 2, 2023).

Figure 3-6 - Fuel Delivery Distribution

3.4 CONSOLIDATED COST ESTIMATES

The cost for diesel engine generator replacement has been consolidated for Option 1 replacement and Option 2 replacement scenarios. The consolidated construction cost is inclusive of the replacement engine generator sets, engine removal/demolition, and electrical connection and cabling (2.4 kV and 12 kV system improvements). Option 1 replacement scenario also includes the capital allowance for new fuel delivery/urea systems. Project cost includes fees and expenses associated with engineering, bid support and commissioning. For a more in-depth cost analysis, refer to Appendix A.

3.4.1 Option 1 – All Engine Replacement

The estimated construction cost and project cost of all engine replacement is presented in Table 3-12. The total estimated construction cost of Option 1 engine replacement cost ranges from $25.91 million for the EMD five engine replacement to $25.03 million for the five engine replacement with Cummins.

Cummins: 5 x 2,217 kW *EMD: 5 x 2,237 kW*

Figure 3-7 - Option 1 All Engine Replacement

The corresponding project cost of the all engine replacement scenarios is $28.03 million with Cummins or $29.02 million with EMD (Table 3-12).

Table 3-12 - Estimated Consolidated Cost of Replacement Engine Generators–Option 1

Vendor	Cummins	EMD
Configuration	One 2,127 kW/12 kV Four 2,127 kW/2.4 kV	Two 2,237 kW/2.4 kV Two 1,491 kW/2.4 kV One 2,983 kW/12 kV
Replacement Capacity	10,635 kW	10,439 kW
Construction Cost	$ 25,030,700	$ 25,914,300
Project Cost	$ 28,034,400	$ 29,024,000
$/kW, Project Cost	$ 2,636	$ 2,780

The all propane option will consist of three 12kV engine generator sets and four 2.4 kV engine generator sets. The total project cost of the all propane option is $49.25 million (Table 3-13).

Table 3-13 - Estimated Consolidated Cost of Replacement Engine Generators–Option 1 (Propane)

Configuration	7-Engine, Propane Four 1,382 kW/2.4 kV Three 1,382 kW/12 kV
Replacement Capacity	9,764 kW
Construction Cost	$ 43,973,400
Project Cost	$ 49,251,300
$/kW, Project Cost	$ 5,091

3.4.2 Option 2 – Two Engine Replacement

Table 3-14 presents the estimated construction and project costs of Option 2 engine replacement: two emission compliant engines by January 1, 2023.

Unit 8 and unit 10 are replaced. Both replacement engines are connected to the 2.4 kV system in all instances, diesel or propane.

Table 3-14 - Consolidated Cost of Option 2: Two Diesel Engine Replacement

Vendor	EMD	Caterpillar	Jenbacher
Configuration	2-Engine, Diesel Two 2,237 kW/2.4 kV	2-Engine, Propane Two 1,382 kW/ 2.4 kV	2-Engine, Propane Two 1,025 kW/ 2.4 kV
Replacement Capacity	4,474 kW	2,784 kW	2,050 kW
Construction Cost	$ 9,872,300	$ 9,921,600	$ 7,646,900
Project Cost	$ 11,056,900	$ 11,112,400	$ 8,564,500
$/kW, Project Cost	$ 2,471	$ 4,020	$ 4,178

Construction cost and project cost of two engine replacement with EMD is approximately $9.87 million and $11.06 million, respectively.

The construction cost of two propane replacement engine generators is $9.92 million with a project cost of $11.11 million for Caterpillar, or $7.65 million and $8.56 million for Jenbacher. The cost estimate of these scenarios includes the upgrade to the 240V electric system for plant auxiliaries. As noted elsewhere the system upgrades will provide capacity to serve the incremental electric load associated with the propane engine generator sets. The cost of control/controls integration is also increased slightly to account for the diversity of engine/fuel types.

The total project cost of the propane option with Caterpillar is comparable with that of the two engine diesel replacement (EMD) yet the project cost per kW is significantly higher: over $4,000/kW versus about $2,471/kW. The project cost of the Jenbacher propane engines is about 25% less than the project cost of the EMD engines however, the project cost per kW of the Jenbacher propane offering is nearly $4,200/kW.

EMD: 2 x 2,237 kW

Caterpillar: 2 x 1,382 kW

Jenbacher: 2 x 1,025 kW

Figure 3-8 - Option 2 Two Engine Replacement

3.4.3 LNG Option

The use of LNG fueled engine generators was also investigated as an alternate to propane or diesel engine generators sets. A configuration consistent with the capacity and service profiles of Pebbly Beach Generator Station would feature two 2,500 kW natural gas engine generator sets, one 12 kV and one 2.4 kV, and LNG fuel system infrastructure. The LNG fuel system would have a capacity of 120,000 gallons (four x 30,000 gallons), and feature a chemical suppression system, which may eliminate the need of a water deluge system (that presently restricts the use of existing propane storage tanks). The transition to LNG may also precipitate changes to the equipment of customers that have subscribed deliveries of the propane-air distributed from the plant.

The estimated project cost of using LNG replacement engine generator sets, featuring engines from MTU Onsite Energy and LNG fuel system from Chart Industries, is $19.39 million.

Table 3-15 - LNG Option Pricing

Configuration	Two Engine Two 2,500 kW/2.4 kV
Replacement Capacity	5,000 kW
Engine Generator Sets	$ 4,568,800
Spare Parts/Tools	$ 10,000
Freight/Delivery	$ 657,000
Crane Rental	$ 20,000
Placement/Installation	$ 1,030,000
Plant Renovations	
Engine Removal/Demolition	$ 500,000
Structural	
Foundations/Concrete Work	$ 300,000
Supports/Access Platforms	$ 50,000
Mechanical Connections	$ 30,000
Electrical	
2.4 kV Modifications	$ 1,037,600
240 V Plant Auxiliaries Upgrade	$ 1,102,900
Controls/Controls Integration	$ 20,000
LNG Infrastructure	$ 5,628,000
Start-up	$ 60,000
Contingencies: 15%	$ 2,280,000
Construction Cost	$ 17,266,400
Engineering	$ 1,467,600
Bid Support	$ 259,000
Commissioning	$ 345,300
Project Cost	**$ 19,388,300**
$/kW, Project Cost	**$ 3,868**

3.5 COST ADJUSTMENT FOR SANTA CATALINA ISLAND

All project costs are affected by location, especially so for projects in remote or isolated locations such as Catalina. The logistics of project delivery and development on a remote site such as an island will escalate costs: mobilization, transportation and probable lodging of work crews, delivery of construction materials and construction equipment to site, storage and lay-down areas for construction materials and project equipment, removal and disposal of demolition materials, etc.

A range of potential cost has been forecast on the basis of the nominal consolidated project costs presented in Table 3-16 and Table 3-17. A location adjustment factor is applied to the individual cost components of the respective scenarios: a multiple of 3 for high location adjustment and 2 for low location adjustment. The factor is not applied to components that generally are not location dependent, such as engine generator sets, spare parts/tools, fees for engineering services and bid support. The factor will apply to location dependent components such as mobilization, labor, transportation and shipping.

The location adjusted project cost for Option 1 all engine replacement with Cummins engines (five 2,217 kW units) ranges from $38.29 million to $48.68 million, compared to a nominal cost of $28.03 million. The corresponding costs of the five engine replacement scenario with EMD range from $39.56 million to $50.09 million compared to a nominal project cost of $29.02 million.

Table 3-16 - Location Adjusted Project Cost: Option 1 All Engine Replacement

	Cummins Five 2,127 kW (Diesel)	EMD Two 2,237 kW Two 1,491 kW One 2,237 kW (Diesel)	Caterpillar Seven 1,382 kW (Propane)
Nominal Project Cost	$ 28,034,400	$ 29,024,000	$ 49,251,300
Location Adjustment			
High	$ 48,675,900	$ 50,087,800	$ 104,739,600
Low	$ 38,292,600	$ 39,556,000	$ 76,995,900

The nominal project cost of the all propane option with Caterpillar engine generator sets is $49.25 million with location adjusted cost ranging from $77.00 million to $104.74 million.

The nominal project cost of two diesel engine replacement (Option 2) is $11.06 million with two 2,237 kW units from EMD, with a location adjusted project cost ranging from $15.00 million to $18.94 million. The alternate fuel propane replacement engine generators from Caterpillar have an estimated project cost of $11.11 million with a location adjusted cost of $16.33 million to $21.55 million. Jenbacher replacement propane engines have an estimated project cost of $8.56 million. The location adjusted project cost with Jenbacher engines ranges from$13.04 million to $17.52 million.

Table 3-17 - Location Adjusted Project Cost: Option 2 Two Engine Replacement: Diesel or Propane

	EMD Two 2,237 kW Diesel	Caterpillar Two 1,382 kW Propane	Jenbacher Two 1,025 kW Propane
Nominal Project Cost	$ 11,056,900	$ 11,112,100	$ 8,564,500
Location Adjustment			
High	$ 18,935,000	$ 21,551,900	$ 17,519,200
Low	$ 14,995,900	$ 16,332,000	$ 13,042,000

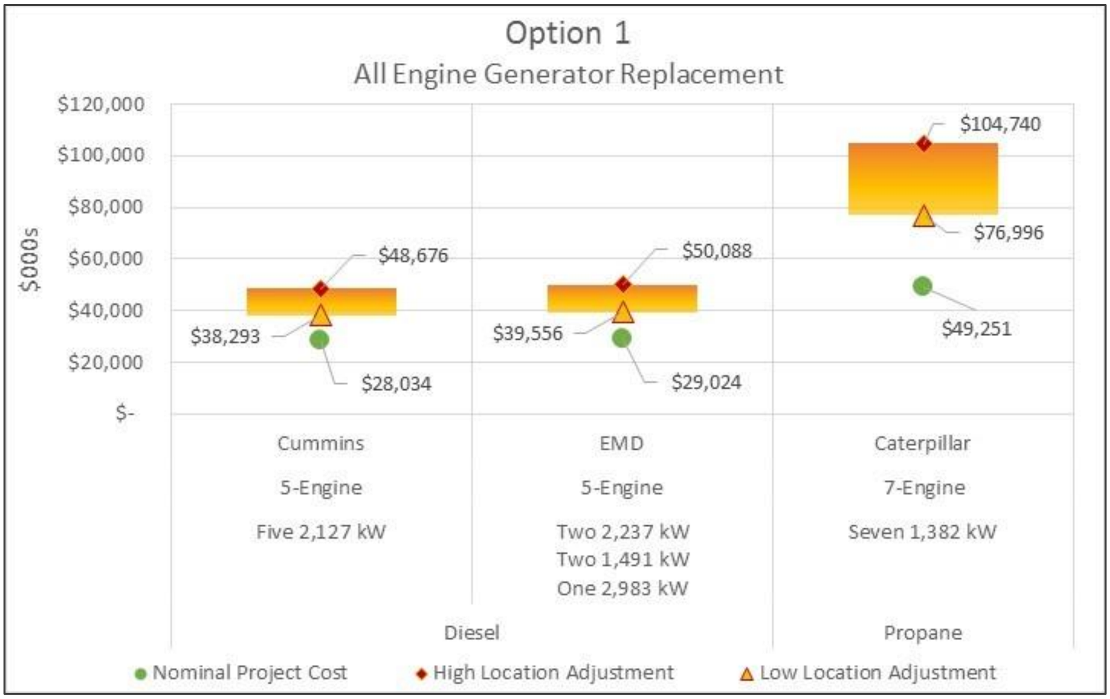

Figure 3-9 - Location Adjusted Project Costs: All Engines

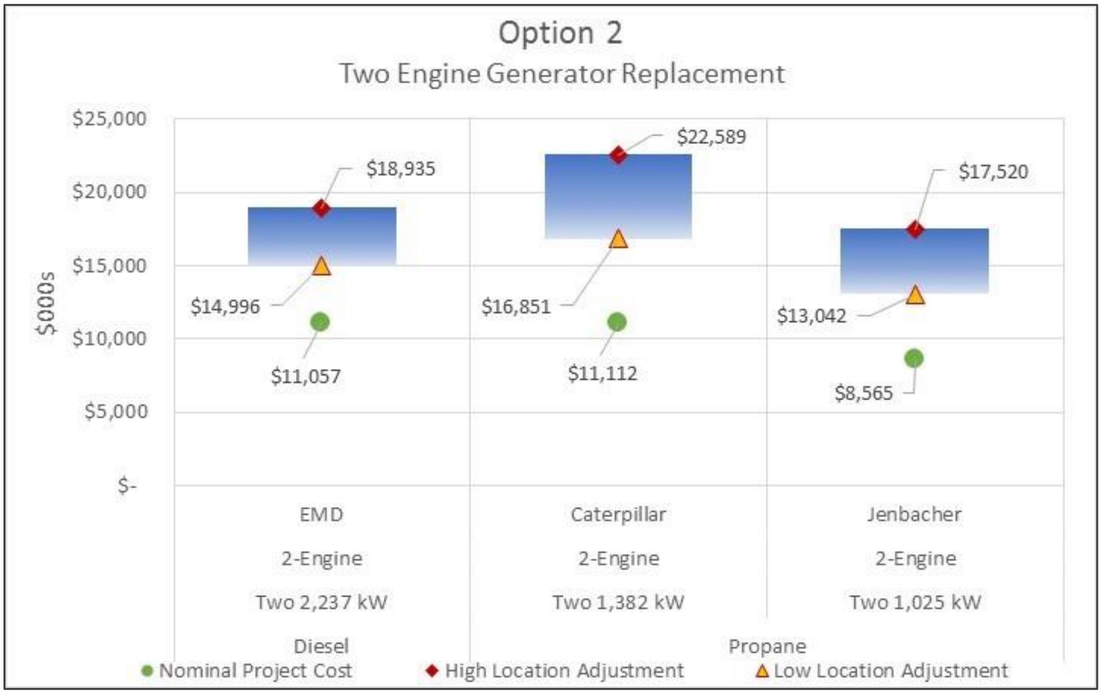

Figure 3-10 - Location adjusted Project Cost: Two Engines

3.6 PERMITTING AND SCHEDULE ESTIMATES FOR POWER PLANT GENERATION

This air permit summary provides an overview of discretionary permitting to remove and replace the existing five generators so as to meet compliance with SCAQMD Rules, including but not limited to, Rule 1135. Two options are offered; Option 1 would permit the replacement of five generators; Option 2 would replace two generators.

Option 1 would begin with Title V Permit Modification for the facility and Permit to Construct (PTC) applications (for each generator) being filed with SCAQMD in the first half of 2020. The permit process is expected to take 12-18 months. All replacement engines must be operational by January 1, 2024.

Option 2 is based on the deadline extension available under Rule 1135 and would follow the same permitting schedule as outlined for Option 1, but two replacement engines must be operational by January 1, 2023. The remaining engines (aside from Unit 15) would need to be replaced within the extended deadline: January 1, 2027.

In addition to SCAQMD permitting, a Coastal Development Permit (CDP) and Conditional Use Permit (CUP) Amendment will be required for engine replacement. These three discretionary permits will require environmental review per the California Environmental Quality Act (CEQA). The project may trigger some form of mitigation to accommodate sea level rise. In addition, due to past historical site use, it's likely that archaeological monitoring would be required to protect resources potentially impacted during generator foundation and underground construction. It is expected that the lead agency (SCAQMD) will determine that the project qualifies for a CEQA Mitigated Negative Declaration. Table 3-18 identifies a cost range and time frame to implement either Option 1 or Option 2. Table 3-19 identifies permits required, months to obtain, and cost.

Table 3-18 - Environmental Document and Permitting Components with Associated Tasks, Time Frames and Costs

Agency	Document/Permits	Task	Timeframe for Completion	Costs
South Coast Air Quality Management District (SCAQMD)	Title V Permit Modification and Permit to Construct Applications	▪ Facility Permit Modification Fee ▪ Permit to Construct Fee (per new generator) ▪ Equipment Modification Fee (per modified piece of existing equipment) ▪ Application Preparation ▪ Modeling and Risk Assessment	12-18 months	#1 – Facility Mod: $3,000 #2 – PTC: $6,000 - $12,000 per new generator/SCR combination #3 – Equipment Mod: $4,000 per modified existing permitted unit #4 – Permit App: $50,000 #5 – Modeling/HRA: $20,000 total
SCAQMD	Continuous Emissions Monitoring System Permit	▪ CEMS Certification Application ▪ Quality Assurance Plan ▪ Diagrams ▪ Source Test (per test) ▪ RATA Testing (per CEMS)	6-9 months	#1 – Certification: $50,000 per unit #2 – QAP: $10,000 per unit #3 – Figs: $5,000 per unit #4 – Source Test: $20,000 per test #5 – RATA Testing: $20,000 per unit
Los Angeles Regional Water Quality Control Board	Storm Water Pollution Prevention Plans (SWPPs)	▪ Construction SWPPP ▪ Post-Construction Water Quality Management Plan (WQMP) ▪ SWPPP under the IGP	3 months	#1 – CGP SWPPP: $7,500 per site #2 – WQMP: $5,000 - $!5,000 per site #3 – IGP SWPPP: $5,000 per site
Environmental Protection Agency (EPA) / Certified Unified Program Agency (CUPA	Spill Prevention, Control, and Countermeasure (SPCC) Plan	▪ Minor Plan Updates ▪ Plan Modification and Recertification	1-3 months	#1 – Minor: $5,000 #2 – Major: $15,000
CUPA	Hazardous Materials Business Plan	▪ HMBP Modifications	1 month	#1 - $5,000
Conditional Use Permit Amendment (CUP)	Amend Existing Permit to allow multiple Unit replacement with Greater Capacity	▪ Provide full project description and process discretionary approval of CUP	18 months	#1 - $45,000 -$75,000
CEQA Compliance	Mitigated Negative Declaration	▪ Assess 21 environmental categories. ▪ Provide mitigation to Achieve "less than significant" threshold	18 months	#1 - $75,000-$140,000
Coastal Development Permit Amendment	Amend Existing permit to allow multiple Unit Replacement with Greater Capacity	▪ Demonstrate consistency with Local Coastal Plan and comply with Approved Mitigation Measures	18 months	#1 - $50,000 -$100,000

Table 3-19 - Estimated Cost for Permit Options

Permit Option	SCAQMD Title V	SCAQMD CEQA	SCAQMD Continuous Emissions Monitoring System	Los Angeles Regional Water Quality Control Board SWPPP	Los Angeles County Hazardous Materials Business Plan	SCAQMD CEQA MND	City of Avalon Amend Conditional Use Permit	State of California LCP-CDP	Estimated Costs	Estimated Months
1	X	X	X	X	X	X	X	X	$2,012,000	18
2	X	X	X	X	X	X	X	X	$1,012,500	18

4.0 RENEWABLE ENERGY

The renewable energy and energy storage analysis considers the feasibility of powering the island with various renewable penetration thresholds. To start, a wide sweep of renewable energy technologies was conducted to determine if a resource exists on the island with sufficient capacity and an economic business case to justify pursuing a given technology. Next, a detailed siting analysis identified more than 40 unique sites across the island. These sites were evaluated based on a number of factors including environmental concerns, land ownership, permitting, constructability and renewable resource availability. Resource assessment was supplemented by NREL via a techno-economic analysis performed in REopt. Their analysis validated various renewable energy technologies and provided capex and lifecycle costs for multiple renewable penetration scenarios. After site selection, an electrical load flow analysis was performed to study the potential impacts to grid operations from DER interconnection and recommended mitigation strategies. Lastly, a detailed project description is provided for an example 60% renewable microgrid.

4.1 RENEWABLE RESOURCE ASSESSMENT

NV5 evaluated the potential generation from various renewable technologies, taking into account the environmental, permitting, land-use, resource availability, and electric distribution system constraints. A summary of NV5’s resource assessment is listed in the next section.

In conjunction with the renewable resource assessment of the island, NV5 reviewed over 40 unique candidate site locations. This review included the creation of a renewable site matrix with details on each site and an interactive GIS model. This GIS model of Catalina became the most important tool in determining which sites were viable for development. The methodology and individual site analysis that went into this filtering process is discussed after the renewable resource assessment.

4.1.1 On-Shore Solar Feasibility

4.1.1.1 Irradiance

The amount of solar energy produced in a specific geographical area depends on the average daily solar irradiance. Solar irradiance is defined as the power per unit area (typically in Watts per square meter) received from the sun. More generally, it is a measurement of how much solar energy is received over a pre-defined area. PV projects that receive a higher amount of annual irradiance produce a higher amount of energy.

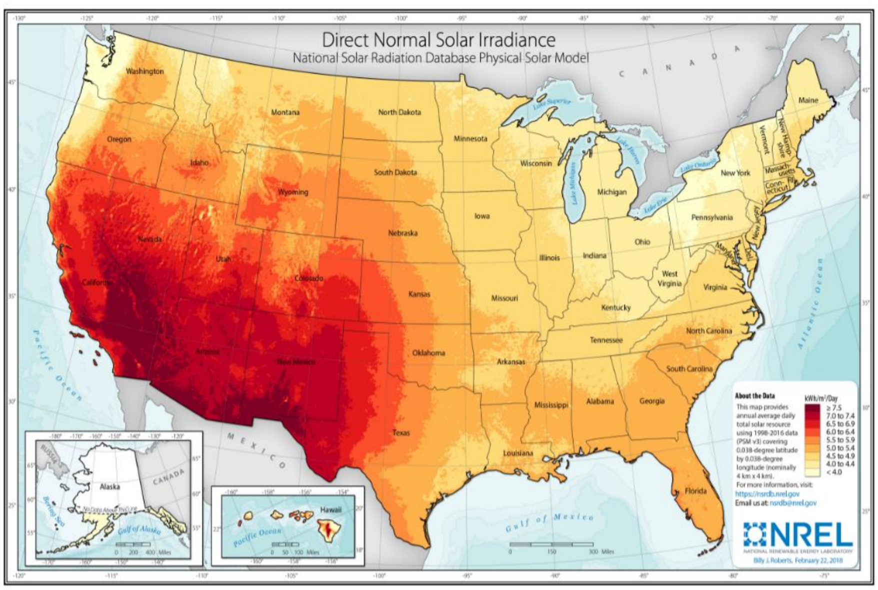

Figure 4-1 - NREL Solar Irradiance Map

Catalina is well-positioned to take advantage of a high average solar irradiance.

According to NREL's geospatial data map (Figure 4-1), Catalina Island's average daily irradiation averages around 6.0 to 7.0 kWh/m^2. Additional validation for these high daily irradiation levels comes from the NREL Solar Prospector website which calculates a daily average solar irradiance value of 6.02 kWh/m^2. In terms of energy, these figures indicate that every day for every square meter, between 6 and 7 kWh of energy in the form of sunlight hits the earth.

To validate these results, solar generation on Catalina Island has been modeled using Helioscope by Folsom Labs. Helioscope simulates the solar array's production for every hour of a typical meteorological year (TMY). It also accounts for the operating characteristics of each of the major equipment in the system such as modules and inverters and the configuration with how the equipment is installed. Based on these parameters and system size, the production model will generate the annual amount of solar energy production. These models are discussed further in Section 4.2.3.

4.1.1.2 Topography

Topography is another important factor when it comes to ground-mount solar design. For large utility-scale projects, it is most cost-effective to find a footprint where the land is generally flat.

Fixed-tilt racking systems typically have east-west slope tolerances of between 12% and 15%. Tracker systems typically have slope tolerances between of 7% and 10% degrees north-south and between 10% and 15% east-west. These values should be considered maximum slope tolerances and not ideal for real-world site development. Mitigating these higher slopes can require substantial civil grading, including soil removal and compaction. Civil grading can add substantial costs to the project, both in the form of construction work and also in the erosion and drainage problems that may occur in the long term.

Most of Catalina Island's topography is made up of undulating mountains with significant slopes. There are limited locations with flat area. Many of the reviewed sites would require significant grading work and, in the worst cases, may simply not be feasible due to excessive slopes. The topography of individual sites is discussed further in Section (4.2.3).

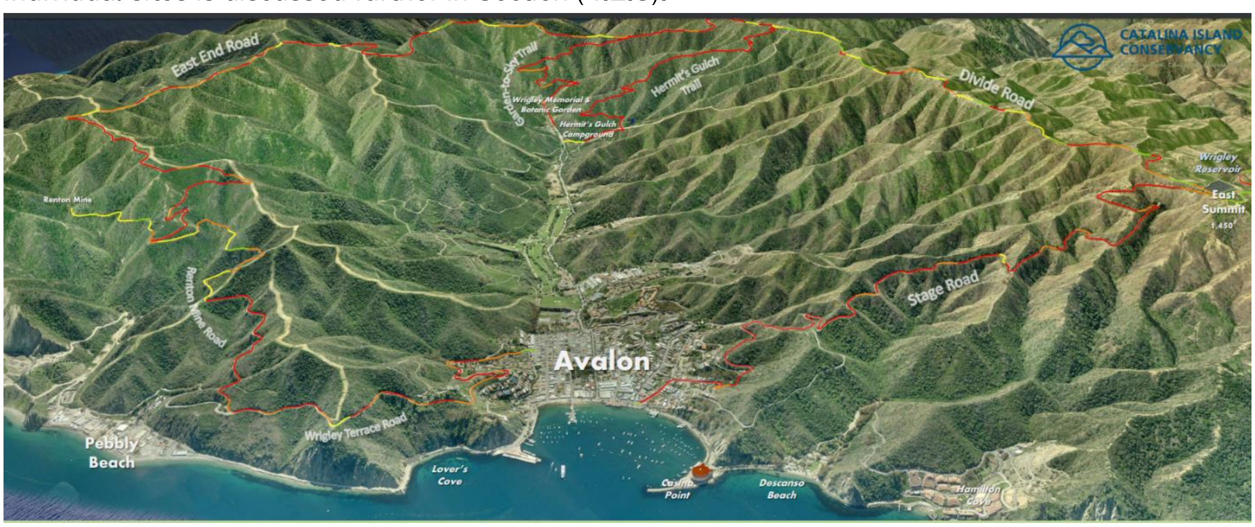

Figure 4-2 - Catalina Island Topography Map[10]

[10] Catalina Island Conservancy

4.1.1.3 Soils

Another construction consideration is the quality of the soils. Stiff clays can require thicker I-beams for racking foundations to properly drive into the soil without deflecting or refusal. Shallow bedrock can require earth anchors, rock screws or other expensive foundation types that add costs. Loose sandy soils may not provide sufficient “gripping” strength to keep the table arrays anchored and resist the wind uplift force, so deeper and sometimes more frequent foundations are required for those soil types.

Based on the historical soils report conducted by the Natural Resources Conservation Service (NRCS)[11], a variety of soil types of varying slopes exist across the island. The soil types are location dependent and vary between the interior and the coast. Soils located in the interior region of the island include Beaches-Abaft complex, Dewpoint-Masthead-Coastwise complex, Masthead-Coastwise-Typic Haploxeralfs complex, Purser-Luff complex, Dewpoint-Luff association, Purser-Rock outcrop complex. The common characteristic between these different soil types is shallow bedrock. According to the soils report, the majority of these soils experience “abrupt textural change” at depths of less than six inches and “lithic” and “paralithic bedrock” at depths between 11 and 57 inches[12].

Soils found near the shore include Typic Haploxerepts-Xerofluvents-Argixerolls complex, Beaches-Abaft complex, and Typic Argixerolls-Urban land. These soils types are generally silt loam or loamy sand at shallower depths that remain loamy sand or transition into clay at deeper depths. These soil types do not experience a restrictive feature at depths shallower than 80 inches, making these locations more ideal to use driven piers.

Figure 4-3 - Catalina Island - NRSC Soils Report Snapshot

It is NV5’s recommendation that a geotechnical analysis be undertaken prior to further developmental activities at a particular site and include frequent test pits for cursory soil classification and bedrock identification beyond the usual soil borings. Once this is done, a civil engineer will be able to recommend the most cost-effective racking installation system.

Ultimately, ground-mount solar is favorable for Catalina Island. The high irradiance and generally sunny weather at this location will lead to high annual production. Drawbacks including soil conditions and topography can be mitigated through site due diligence and engineering measures.

[11] (United States Department of Agriculture - National Resources Conservation Service, 2019)

[12] (United States Department of Agriculture - National Resources Conservation Service, 2019)

4.1.2 Floating Solar

Floating solar is a new power generation technology in which traditional PV solar panels are mounted to flotation devices and installed on bodies of water. Historically, floating solar has been installed on reservoirs, lakes, and ponds. Few examples exist worldwide of installations in an ocean or coastal setting. Floating solar is becoming more mainstream throughout the world, though it should still be viewed as a relatively new technology with a limited track record. According to Wood Mackenzie[13], 2.4 gigawatts of floating solar was planned to be installed by the end of 2019.

Floating solar typically has higher costs than traditional ground-mount applications of similar size and location. This is due to the specialized nature of the procurement and installation work, a lengthier and more complex permitting process, and a more costly O&M burden. One challenge comes from the floating, mooring, and anchoring systems, which tend to vary across the industry and many sites require customized solutions. Local conditions such as dynamic water-level variation, exposure to extreme weather, and local environmental and permitting regulations have made standardization difficult across this nascent industry. Operations and maintenance is a more costly and logistical burden whereby the frequency and scope of inspections will increase due to the environmental exposure, but also the technicians may require specialized training and certifications for underwater verifications and repairs.

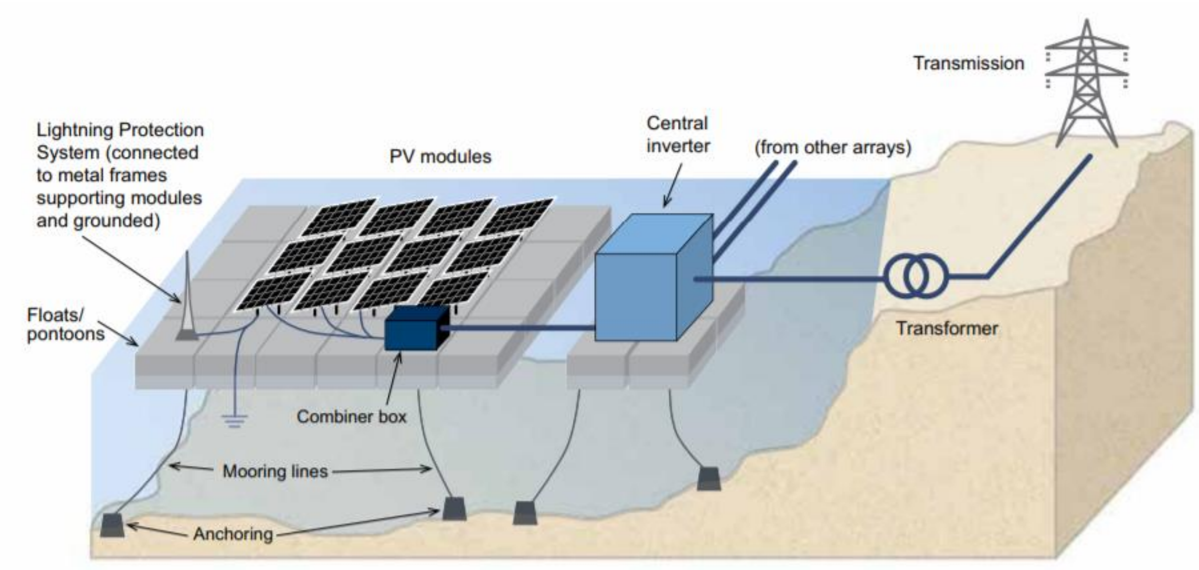

Figure 4-4 - Schematic Representation of Large-Scale Floating PV System[14]

Catalina Island has several lakes and reservoirs where floating solar could theoretically be installed. Most prominent among those are Middle Ranch Reservoir, Haypress Reservoir, and Wrigley Reservoir. Middle Ranch Reservoir has had the most study and analysis completed among the three sites listed above. In addition to the power production, a floating solar project may reduce evaporation which will preserve potable water supply and lower the electric load by SCE on further desalination and pumping.

[13] (Cox, 2019)

[14] (Solar Energy Research Institute of Singapore, 2019)

There are, however, several risks in committing to floating solar at Catalina. The most apparent risk is the lack of a robust track record. While floating solar is becoming more mainstream throughout the world, large-scale projects have only just started to come online within the past several years. It is difficult to draw conclusions from these recently installed projects and to determine what the long-term challenges may be.

Other risks include the environmental and permitting challenges. Bald Eagles are known to roost near the lake and use its waters for foraging habitat. Any reduction of foraging habitat or interference caused by floating solar panels and associated equipment will require regulatory review and permitting. Bald Eagles are listed under the California Endangered Species Act as endangered and would require California Department of Fish and Wildlife consultation and permitting under Section 2081 of the California Endangered Species Act (CESA)[15]. In addition, federal consultation with the United States Fish and Wildlife may be required under the federal Bald and Golden Eagle Protection Act and Migratory Bird Treaty Act.

Other improvements required as part of floating solar installations, such as underground cabling, would cause impacts to the lakebed and bank. As such, these impacts would require agency review and permitting by the USACE, California Department of Fish and Wildlife, and Los Angeles Regional Water Quality Control Board (LARWQCB).

However, there are certain benefits that make Catalina Island more appealing for floating solar than other locations. While SCE does not outright own the property on which the reservoir sits, they do own the property where the dam exists and have 100% of the water rights. Both the World Bank Group and Wood Mackenzie provide discussion on the challenges of developing floating solar on reservoirs or lakes in the context of 3rd party ownership. Both studies point out that there are major challenges in developing floating solar on bodies of water that are not owned by the solar developer. SCE's access to the water rights of the Island's reservoirs may streamline the negotiation and coordination process in the development of floating solar.

Figure 4-5 - Middle Ranch Reservoir

Overall, NV5 views floating solar as a low to medium probability option for Catalina Island. The technology is new without a robust track record, costly to install and maintain, and the environmental permitting process is likely to be complex and time-consuming.

15 (Kern, 2019)

4.1.3 On-Shore Wind Feasibility

Wind power production is directly related to the average wind speed at the location of installation. Standard wind turbines typically reach nameplate power production at a wind speed of 10m/s to 12m/s (22mph to 27mph). Because power production scales exponentially with wind speed, higher wind speeds produce power orders of magnitude greater than that produced at lower wind speed (see Figure 4-6 below).

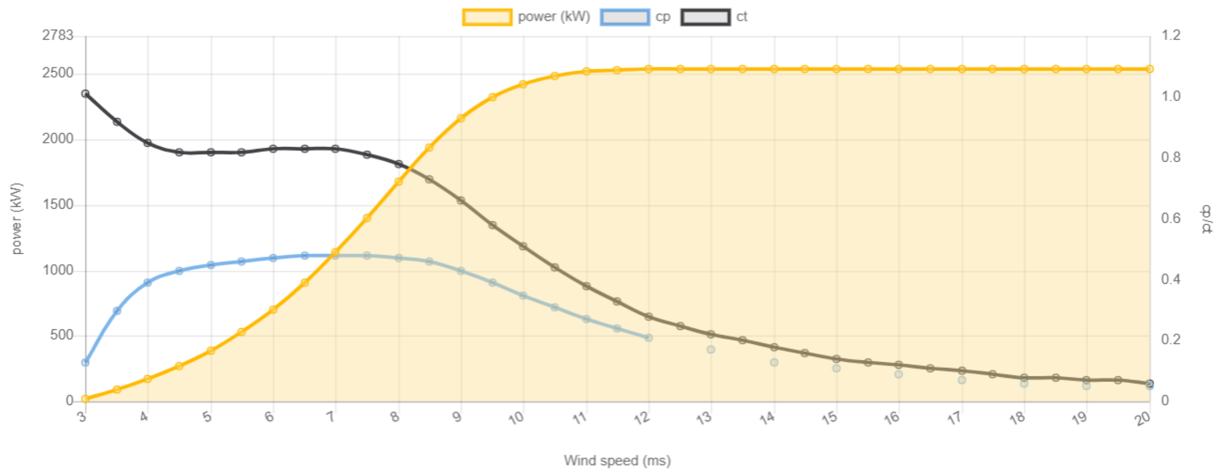

Figure 4-6 - General Electric (GE) 2.5MW, 110m Wind Turbine Power Curve

Determining this average annual wind speed is essential when creating the annual production system model. Without accurate wind speed data, it is impossible to accurately forecast the yearly production. For this reason, it is common for utility-scale wind projects to collect one to three years' worth of hourly wind speed data at the site location. This is achieved by installing a meteorological "met" station on a pole at the rotor height of the proposed wind turbine. The met station will record wind speeds throughout the day and upload this information to a server for use in modelling wind production.

Absent this level of analysis and data collection, alternative methods exist to collect hourly wind speed data. NV5 has utilized a variety of sources in determining the average wind speed at both ground level and a typical 90m rotor height. The following section describes NV5's methods for wind data collection.

4.1.3.1 Global Wind Atlas

The Global Wind Atlas is an online mapping tool developed by the World Bank in conjunction with the Department of Wind Energy at the Technical University of Denmark. It was created to help policymakers and investors identify potential high-wind areas for wind power generation anywhere in the world. NV5 chose the Global Wind Atlas as a data source based on its validation by real-world measurements, other wind atlases, and mathematical calculations[16].

Based on the Global Wind Atlas model, the average wind speed for the 10% windiest areas has been calculated at 4.89 m/s at a rotor height of 100m.

[16] (Global Wind Atlas, n.d.)

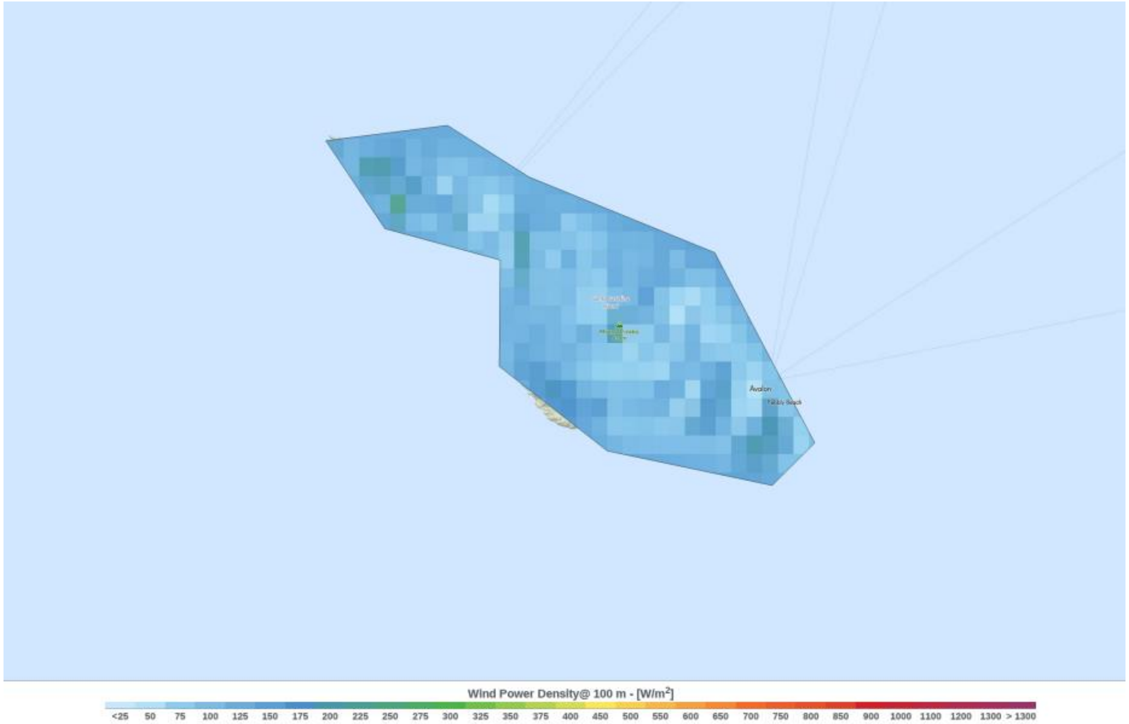

Figure 4-7 - Wind Power Density Map of Catalina Island (Global Wind Atlas)

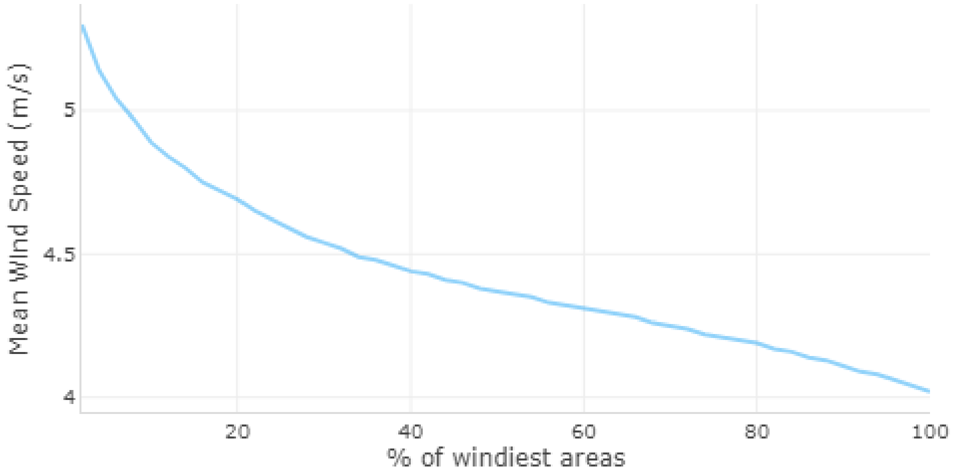

Figure 4-8 - Average Wind Speed (m/s) of Catalina Island (Global Wind Atlas)

4.1.3.2 NREL Wind Prospector

The NREL Wind Prospector is an online mapping application built on the OpenCarto framework, a web GIS framework developed by the NREL Geospatial Data Science team[17]. The NREL Wind Prospector is known as one the industry benchmarks for preliminary wind speed analysis. NV5 chose to use the NREL Wind Prospector based on its reputation in the wind industry and due to NREL's explicit involvement with the renewable resource assessment.

Wind Prospector offers a variety of data outputs depending upon the conditions chosen by the user. The most pertinent data for the purpose of modelling wind production are the wind speeds at a variety of heights and the wind class of the island. The Wind Prospector data indicates that the average wind speed on the island varies between 4 to 5.5 m/s at a height of 100m. In addition, the wind power class of the island ranges from Class 1 to Class 4 with the majority of the island falling in the Class 1 and 2 ranges. The wind power class is a rating system used to rank the quality of location of a wind turbine and the average speed at that location. The higher the class, the higher the acceptability of the location for wind power production.

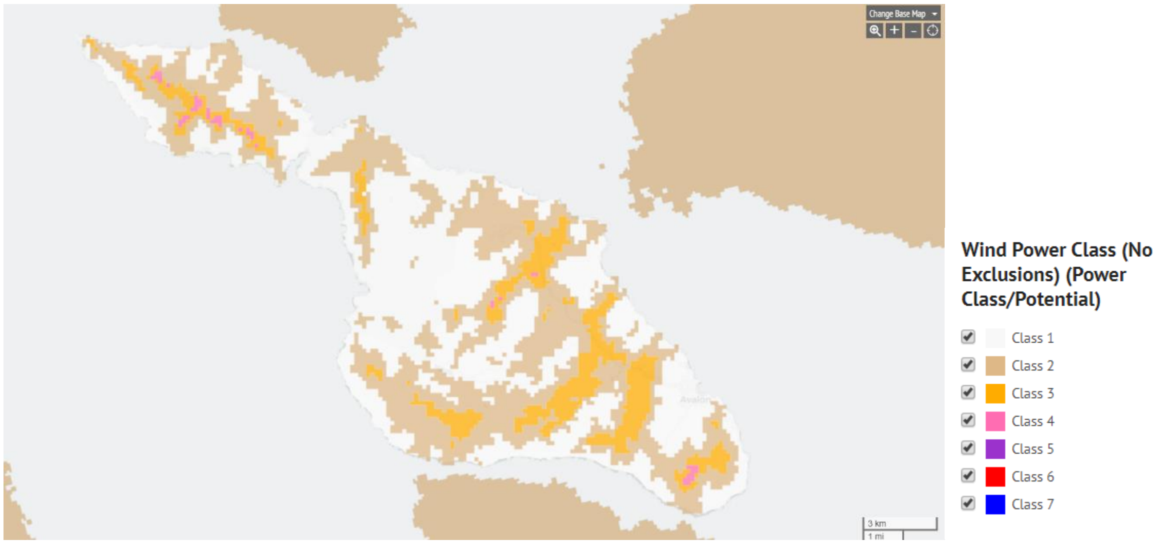

Figure 4-9 - Catalina Island Wind Power Class Zones (NREL Wind Prospector)

[17] (National Renewable Energy Laboratory, n.d.)

4.1.3.3 Santa Catalina Island Climate Stations

The last data source was derived from existing meteorological stations located throughout Catalina Island. At the time of this analysis, NV5 had access to daily weather data from twelve climate stations (Figure 4-10). The longest continuously operating met station is located at the Avalon/Catalina Airport with data ranging back to 1943. Each station produces hourly readings of precipitation, wet bulb temperature, dew point, humidity, air temperature, solar radiation, and, average, maximum, and directional wind speed[18].

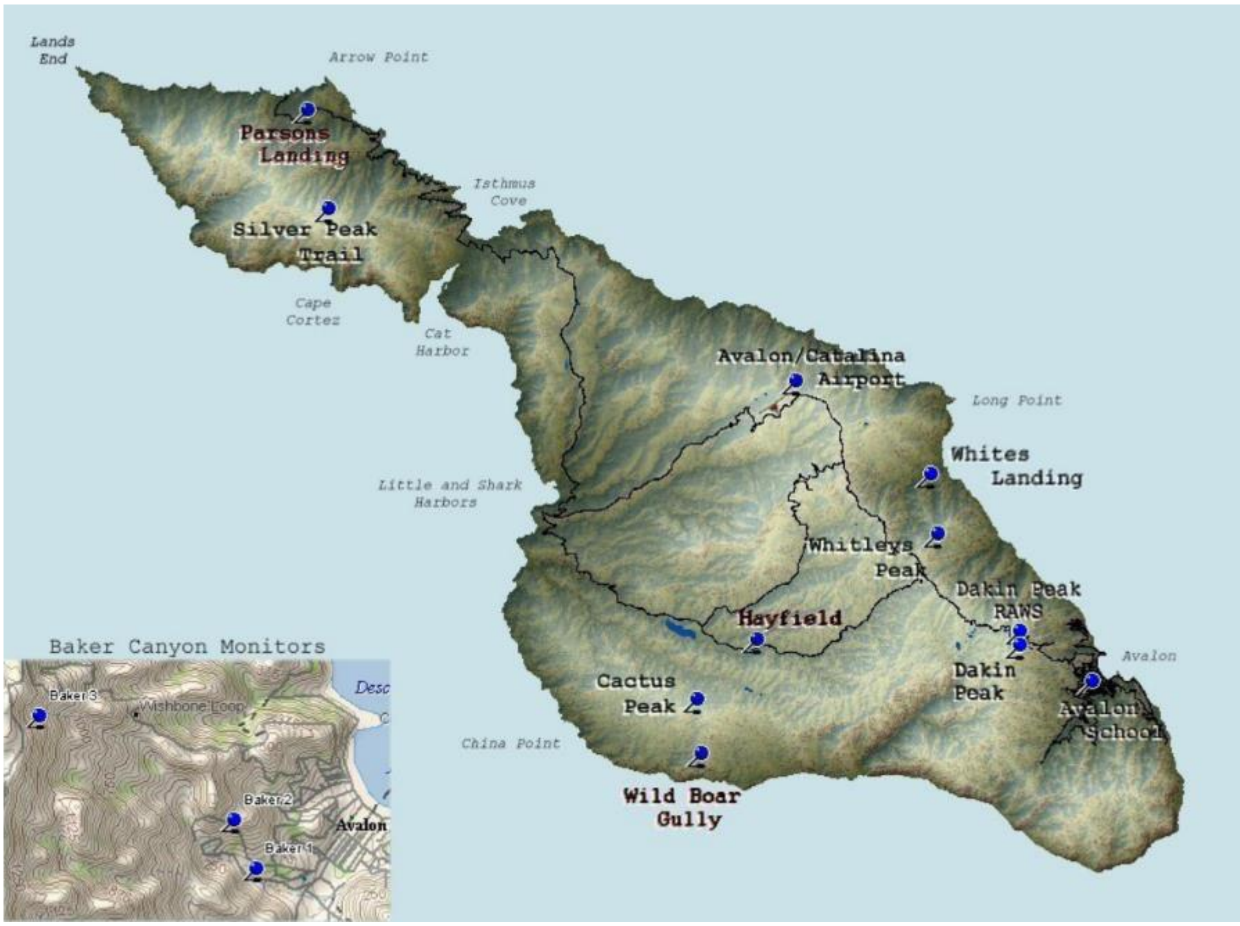

Figure 4-10 – Location of Weather Stations on Catalina (wrcc.dri.edu/Catalina)

NV5 took samples from four met stations located across the island. The met stations included: Whitley Peak, Dakin Peak, Airport-in-the-Sky, and Cactus Peak. These met stations were chosen both for their locations (at the highest peak within their respective mountain ranges) and the completeness of the wind speed data. NV5 calculated monthly wind speed data over a period of two years, January, 2015 to December 2016 (Table 4-1).

[18] (Western Regional Climate Center, n.d.)

Table 4-1 - Mean Wind Speed at Various Locations

Mean Wind Speed				
	Cactus Peak	Airport-in-the-Sky	Dakin Peak	Whitley Peak
Date	**m/s**	**m/s**	**m/s**	**m/s**
Jan-15	2.94	2.69	2.75	2.80
Feb-15	3.27	3.09	3.28	3.38
Mar-15	3.34	2.99	3.16	3.33
Apr-15	3.71	3.72	4.09	4.22
May-15	3.32	3.53	3.44	3.62
Jun-15	2.78	2.57	2.41	2.50
Jul-15	3.00	2.87	2.63	2.71
Aug-15	3.20	2.81	2.66	2.76
Sep-15	2.90	2.72	2.86	3.07
Oct-15	3.45	3.30	3.49	3.57
Nov-15	4.05	4.09	4.55	4.86
Dec-15	4.94	4.47	4.91	5.56
Jan-16	3.99	4.05	4.23	4.52
Feb-16	3.71	3.50	3.52	3.68
Mar-16	4.29	4.37	4.59	4.87
Apr-16	4.17	3.82	4.27	4.36
May-16	2.90	3.22	2.88	3.18
Jun-16	2.93	2.79	2.85	2.86
Jul-16	2.62	2.60	2.46	2.57
Aug-16	2.63	2.77	2.49	2.46
Sep-16	2.95	2.90	3.02	3.06
Oct-16	3.31	3.20	3.36	3.35
Nov-16	3.59	3.12	3.79	3.78
Dec-16	4.08	6.04	2.88	4.11
Average	**3.42**	**3.39**	**3.36**	**3.55**

Average wind speed across the four sites was found to range between 3.36m/s and 3.55m/s.

4.1.3.4 NREL Findings and Analysis

In addition to the NV5 resource assessment, NREL completed its own analysis as part of its REopt data gathering process. They found that the strongest sites at Catalina at 55m above ground will have an average wind speed of less than 6m/s (Figure 4-11).

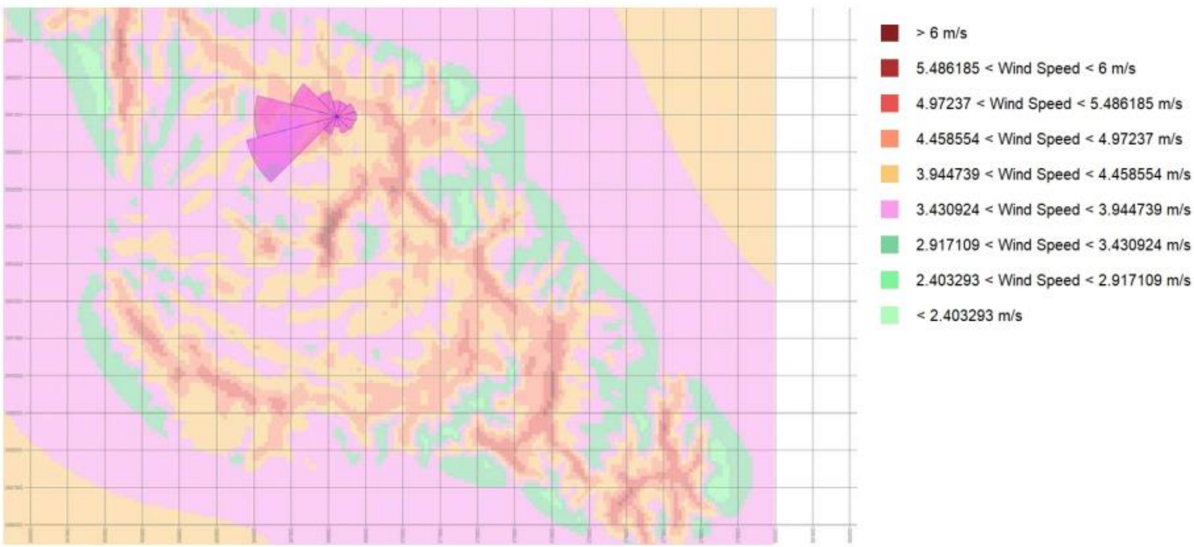

Figure 4-11 – Airport 55m Annual Average Wind Speed

NREL conducted a sensitivity analysis to evaluate a range of wind speeds averaging between 3.52 and 7.82m/s for different hub heights. The rationale for running a sensitivity study analyzing different wind speeds and costs is based on the uncertainty in wind speed at near hub heights. In addition to a lack of wind speed measurements at hub heights, the extremely complex terrain also increases the uncertainty of the feasibility of wind power. The steep slopes decrease the accuracy of wind speed calculations as slope angles increase and may also cause reduced energy production from the turbines due to extreme inflow angles.

Per NREL's sensitivity analysis, it was found that for wind power to be cost-effective, the wind resource would need to be double what was found on Catalina and the capital costs to be half of NREL's estimate. Based on these results, NV5 and NREL consider it highly unlikely that wind power can be an effective source of renewable energy on Catalina Island. For more information regarding this sensitivity analysis, refer to Section 6.2.2.7.

4.1.4 Wave Power

During the course of the feasibility study, SCE contacted a wave power generator vendor, to gather information on the feasibility of wave power at Catalina Island. The vendor attaches “floaters” to an existing pier or structure in the water. Waves cause the floaters to rise and fall, compressing and decompressing hydraulic pistons to build up pressure. This pressure rotates a hydraulic motor, which rotates the generator, creating electricity.

Figure 4-12 - Wave Generation Technology

The vendor provided SCE with a report in which they calculated the average wave heights along Catalina’s shores and potential locations for these projects. Portions of that report are included below:

> *The wave heights along Santa Catalina Island’s coasts range from an average wave height of 0.75-1.5 meters. The wave heights along the southern and western sides of the island are more robust as they are exposed to the open ocean. According to the wave height map shown below (*Figure 4-13*), we can see that the wave heights on the Southern and Western side of the island range from between 1-1.5 meters whereas the wave heights on the northern and eastern sides of the Island range from .75-1 meter. The minimum required wave height for the wave energy system are 50cm and as such all sides of the island offer suitable wave heights for an installation. However, the southern and western side of the island offer higher waves which in turn offer a higher potential for electricity production.*
>
> *The southern and western sides of the island enjoy a higher average wave height, however, there is a lack of existing structures on which to install a power station. However, a special structure using pylons could be installed…in order to benefit from the higher waves. Most of the southern and western sides of the island are solid cliff faces and as such are not suitable for an installation with pylons with the exception of the northern and southern tips.*

While this type of technology shows promise in using existing, unutilized docks and ocean structures (specifically on the northern side of Catalina), the product itself is relatively untested. At the time of this analysis, this vendor had only two projects in operation worldwide. If SCE were to proceed with the development of a project using wave power technology, that project should be seen as a pilot project rather than a "tried-and-true" repower solution for Catalina.

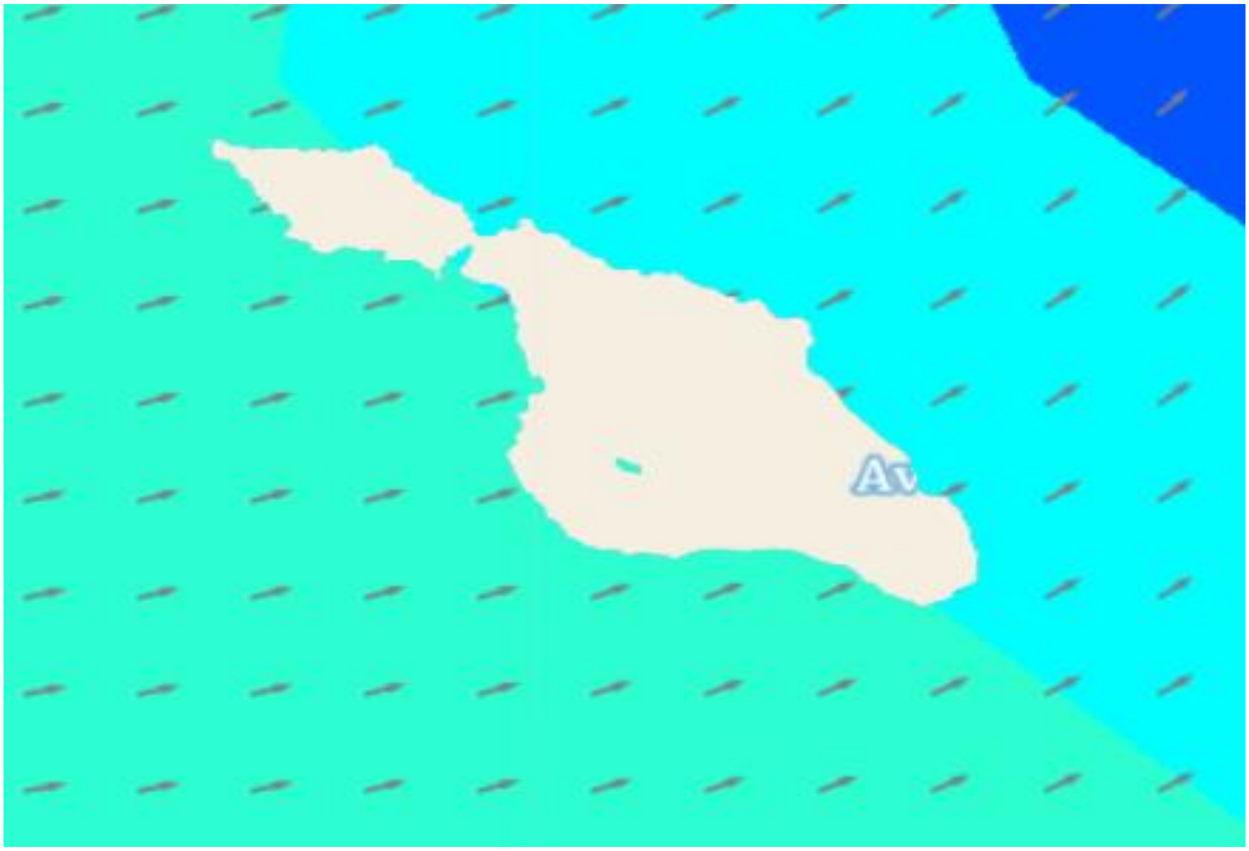

Figure 4-13 – Catalina Island Wave Height and Direction

4.1.5 Energy Storage

NV5 evaluated energy storage as a supplemental technology used to stabilize a high renewable energy penetration portfolio. Energy storage also offers opportunities for resiliency by providing a grid-forming resource that would allow load pockets to form microgrids in the event of a grid outage. This section presents a summary of some of the readily available energy storage technologies, and how each unique technology might perform given the use cases identified on Catalina. Table 4-2 lists and compares the various energy storage technologies that were evaluate for this feasibility study.

Table 4-2 - Data and ratings extracted from World Energy Council 2020[19]

Technology	Efficiency	Lifetime	Fire Risk (Low, Med, High)	Advantages	Disadvantages
Sodium Sulfur (NaS)	80-90%	15 yrs; 4500 cycles	Med	Very high energy density and small physical footprint High charging and discharging efficiency Long cycle life	High temp - thermal management Thermal self-discharge limits idle time Safety concerns due to reaction of sodium with sulfur
Lithium-ion (Li-ion)	85-95%	15 yrs;	High	Very high energy density and small physical footprint Low maintenance No requirement for priming Relatively low self-discharge High rated voltage	Highly reactive and flammable Requires recycling programs and safety measure Natural Degradation Suffers from aging effect
Flow Battery	60-90%	10 yrs; 10,000+ cycles	Low	Independent energy and power sizing Scalable for large applications Longer lifetime in deep discharge Long cycle life (10,000+ full cycles)	More complex than conventional batteries Significantly less deployment than Li-ion High cost of vanadium (if using) and current membrane designs
Flywheel	90-95%	>15 yrs	Low	High power density (swift charging and discharging) High performance in terms of cycle efficiency Low environmental impact Low cost maintenance Long cycle life without degradation	Low energy density with high rate of self-discharging over time Replacement parts can be expensive with long lead times Prone to external shocks and high-energy failures
Pumped Hydro Storage (PHS)	75-85%	60 yrs	Low	Established technology deployed at scale Rapid ramping potential Very low self-discharge	Environmental concerns due to relatively low energy density High initial investment costs result in longer return on investment Limited by available geography and environmental impacts

[19] (Pauline Blanc, 2020)

4.1.5.1 Sodium Sulfur (NaS)

This energy storage system is a chemical energy storage system based on a cathode (positive electrode) made of molten sulfur and an anode (negative electrode) made of molten sodium (Na). The electrolyte is an aluminum-based ceramic, which also provides physical separation between the two electrodes. Common operating temperatures can be 300-360^{o}C. These systems benefit from a long useful life of 15 years or 4500 cycles. There is currently a 1MW/7.2MWh NaS BESS operating at Pebbly Beach. Further deployments of a NaS BESS system would leverage institutional knowledge, training, and could expand an existing O&M program for the current system. High operating temperatures and potential risks with the sodium and sulfur interactions may make remote deployment less desirable and difficult to permit, but perhaps still worthwhile at existing SCE facilities such as PBGS and Two Harbors.

Figure 4-14 - NGK Locke NaS BESS

4.1.5.2 Lithium Ion (Li-ion)

Lithium-ion battery systems are among the most widely-used grid-scale energy storage technologies deployed today. Li-ion boasts the greatest power and energy density of any close competitor in the market, and there has been a dramatic decrease in installed prices over the last ten years. This has led to Li-ion becoming the most popular and economic BESS technology installed for grid support and renewable energy production augmentation. Li-ion installations benefit from a wide selection of vendors with robust supply chains, as well as experienced contractors and service professionals to build and operate the systems. They are also a known quantity in terms of long-term performance, degradation, and system benefits.

This battery chemistry does pose enough of a flammability and combustion risk, especially considering the high profile failures in Arizona Public Service territory in 2019, that significant fire risk mitigation measures would be needed for Li-ion deployments that may not be required for some of the other technologies. The LA County Fire Department and California Fire Codes stipulate redundant water deluge systems in addition to a chemical-based or other fire suppression system. A condition to the operating permit is likely to include a new water hookup at each Li-Ion BESS project site. Some of the sites proposed may be in urban and developed areas where this is not a major hurdle. But remote project sites without an existing water supply may need to consider alternate battery chemistries to avoid this additional infrastructure cost.

Other newer Li-ion chemistries may be worth exploring, such as lithium ferro phosphate, that are non-toxic and do not require active HVAC temperature management systems due to the stable nature of those chemistries.

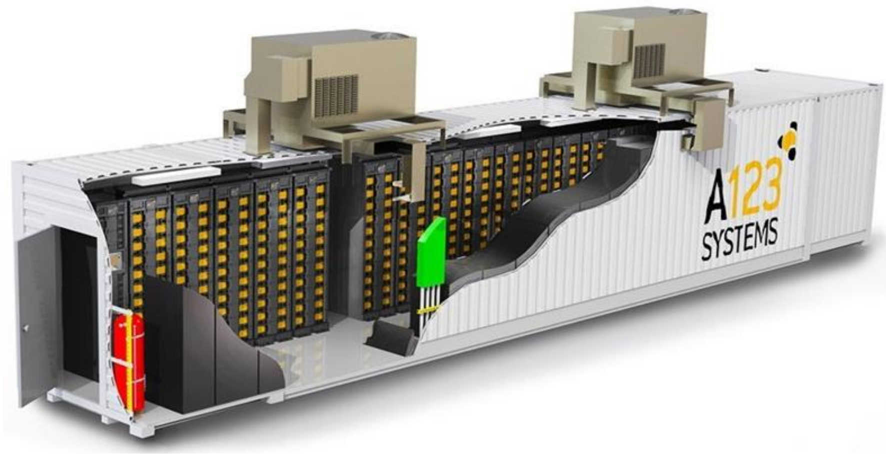

Figure 4-15 - A123 Systems, Inc. Lithium-ion Containerized BESS

4.1.5.3 Flow Batteries

Flow batteries use liquid electrolytes with fixed cells to store and regenerate power. Various flow battery chemistries exist such as vanadium redox, zinc-bromine, iron-chromium, etc. Flow battery benefits include low temperature operations and non-flammable/hazardous materials. They also decouple the power capacity from the duration of energy storage. One can add more hours of storage through the addition of larger electrolyte tanks but leaving the battery and power conversion systems largely intact. Flow batteries have low energy density and often require a larger footprint of 2.5:1 as compared to the land area needed for a Li-ion based energy storage system. On Catalina, flow batteries would be good storage solutions in remote areas where a water supply is not feasible to meet the fire suppression requirements of a deluge system in the case of deploying Li-ion or other chemistries deemed as potential fire risks.

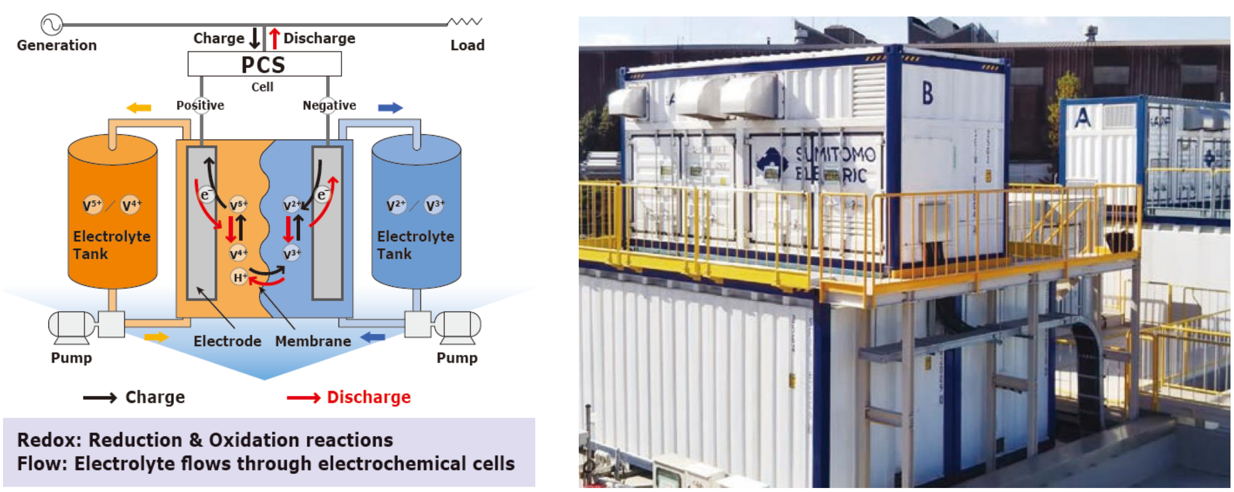

Figure 4-16 - Sumitomo Electric Industries, Inc. Vanadium Redox Flow Battery

4.1.5.4 Flywheel

A flywheel is an energy storage device that stores kinetic energy in a rotating mass. The system charges when power from the grid supplies a motor that accelerates the flywheel to high speeds. The system discharges by having the motor act as a generator which is powered by the kinetic energy of the rotating mass. Flywheels are ideal for short bursts of high-power injection and offer voltage and frequency regulation through active and reactive power addition and absorption. The near-instantaneous response of a flywheel is beneficial to mitigate frequency excursions commonly resulting from cranes and hoists at shipping ports and industrial facilities. SCE has noted the Catalina system experiences frequency excursions when the quarry is operating some of its heavy machinery, and a flywheel could help correct for that issue.

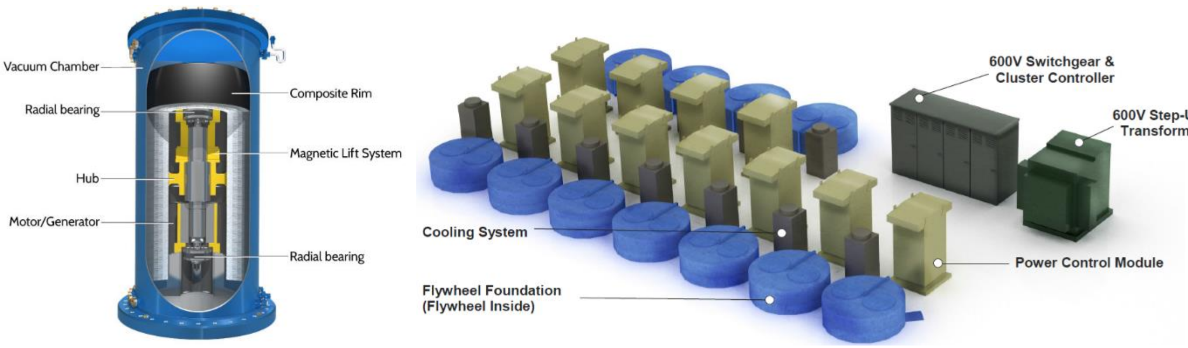

Figure 4-17 - Beacon Power Diagram

4.1.5.5 Pumped Hydro Storage (PHS)

This energy storage technology is among the oldest grid-scale energy storage systems with nearly 95% of the world's energy storage market being met by PHS[20]. This storage system "charges" by pumping water to a higher elevation reservoir, and discharges by allowing the water to flow downhill through turbines to generate electricity. These projects are often limited by geography – there needs to be an uninhabited valley or feature for flooding a reservoir, and the environmental impact – flooding a large area would impact the habitats of many plants and animals. However, there are potential opportunities to utilize existing reservoirs on the island, such as Middle Ranch, as a form of long-term diurnal or seasonal storage. There have also been studies in utilizing existing conduits such

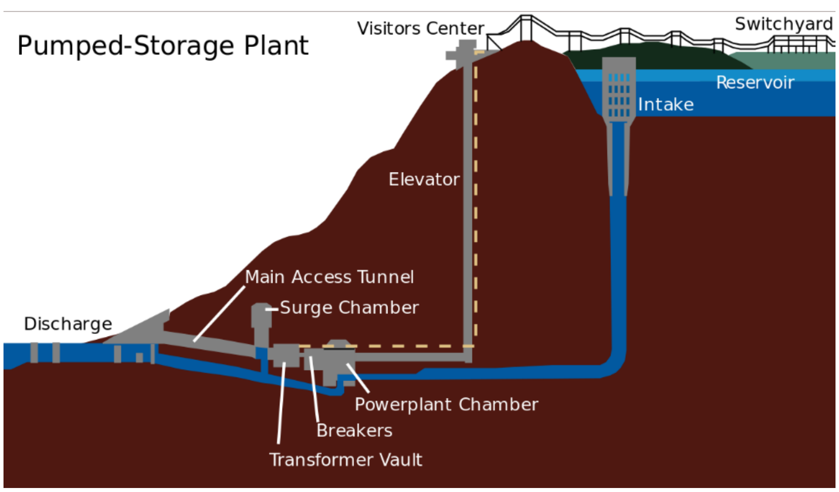

Figure 4-18 - Diagram of TVA Raccoon Mountain Pumped-Storage Plant

[20] (Pauline Blanc, 2020)

as irrigation canals and water supply lines as reservoirs for PHS[21].Given SCE's role as the water distribution utility on Catalina, there may be an opportunity that warrants further exploration.

4.1.5.6 Summary

This technology comparison is meant to serve as an evaluation tool but does not offer a final recommendation. Because of the wide assortment of commercially available energy storage technologies, it is recommended that any future procurement by SCE for energy storage projects on Catalina be technology-agnostic at the RFP stage. The bid documents should prescribe in the scope of work the intended use cases and constraints for the project but should allow bidders the opportunity to recommend and submit various storage solutions. This will allow for a wider bidding audience and diversity in technology solutions offered, but still ensure the intent of the project is met.

4.1.6 Ocean Thermal Energy Conversion (OTEC)

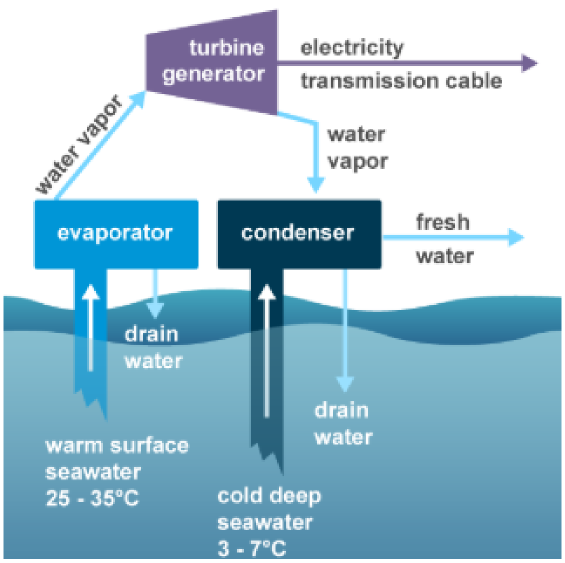

Figure 4-19 – Ocean Thermal Energy Conversion System (US Energy Information Administration)

OTEC is a process for producing energy by harnessing temperature difference between the warmer ocean surface waters and the cooler deep ocean waters. The process works by pumping warm water through an evaporator, producing water vapor that drives a turbine/generator. The vaporized fluid is then turned back to a liquid in a condenser cooled with cold ocean water pumped from the deeper depths.

Ultimately, OTEC technology was not pursued due both to lack of resources for the study of ocean temperatures in the area and the lack of a historical track record of successful projects using this technology. It is NV5's recommendation that if there is desire to pursue this type of technology, it should be viewed as a pilot project rather than a true solution to repower Catalina Island.

4.2 SITE SELECTION

The second step in the development of renewable energy projects on Catalina Island was the selection of feasible locations for development. Renewable resource assessments and site selection were performed in tandem; the resource assessment was used to provide a focus on technologies, and therefore, site locations, that were more suitable for Catalina. Geography and existing site conditions, in turn, fed into the feasibility of various renewable resources. The methodology and results of this circular process is described in the following section.

4.2.1 Site Selection Methodology

Site selection began with the creation of a preliminary list of potential site locations. These locations were technology dependent and were chosen based on a number factors, varying by technology type.

[21] (Moniz, 2015)

Land-based solar technology, for example, required a different set of standards to determine desirable locations than wind or wave-based technologies. In essence, this required a different filtering process for each technology type to determine which locations, and technologies, would be most suitable for development. Prior to this technology specific filter, however, several general requirements were applied to create a preliminary site list and map. These requirements are listed below:

- Preferred sites should not contain sensitive flora and fauna, wetlands, streams, endangered species, or lie within mapped biological conservation areas. The desire was to avoid or limit potential environmental impact, regulatory permitting, and possible mitigation.
- Sites needed to be of sufficient size or closely located to nearby sites so that a cumulative total was near 1 acre. Cost effectiveness for energy production was deemed improved with sufficient scale.
- Sites should be located near one of the island's 12kV lines. A key desire was to avoid or limit environmental impacts caused by new access roads, individual pole maintenance areas, and temporary impacts caused by construction.
- Ocean sites must avoid marine conservation areas, sensitive fish rock outcroppings, and conflict with recreational or boating navigation.

Using the criteria listed in above, NV5 developed an electronic map incorporating a variety of GIS layers. . GIS data was gathered from numerous sources including NREL, SCE, and Rincon, a mapping research company. Layers from these sources were used as constraints or opportunities for renewable development. Constraint layers included environmentally sensitive areas, marine conservation areas, wetlands, riparian areas, hazardous waste zones, native habitats, oak tree forests, and recreational zones. Opportunity layers included previously developed sites, area of previous disturbance with limited native vegetation, moderate slope areas, road access, and proximity to SCE's existing distribution lines.

Ultimately, this desktop analysis and the screening process described above resulted in preliminary selection of 46 possible sites including solar, floating solar, wind, tidal, and battery storage technologies. Table 4-3, Table 4-4 and Figure 4-20, Figure 4-21, and Figure 4-22 outline the sites that were reviewed and discussed throughout the lifetime of this project.

Table 4-3 - Preliminary Renewable Site List, Sites 1-23

Site Number	Technology Type	Location
1	PV	North of Patrick Reservoir
2	PV	Northwest of Haypress Reservoir
3	PV	Southeast of Middle Ranch Reservoir
4	PV	Northwest of Middle Ranch Reservoir
5	PV	Southeast of Two Harbors
6	PV	South of Two Harbors
7	PV	Wrigley-Rusack Property
8	Wind	South of Shark Harbor
9	Wind	South of Shark Harbor
10	Ocean Thermal Energy	South of Catalina, in ocean
11	Wave Energy	Southeast of Catalina, in ocean
12	Ocean Thermal Energy	South of Catalina, in ocean
13	Floating Solar	Middle Ranch Reservoir
14	Floating Solar	Haypress Reservoir
15	PV	Wrigley Reservoir
16	Rooftop PV	Pebbly Beach Generating Station Office R
17	Rooftop PV	Pebbly Beach Generating Station Connex Roof
18	Wind	South of the airport, toward Mount Orizaba
19	Wind	Along Divide Road, south of Wrigley Reservoir
20	Floating solar	White’s Landing
21	Floating solar	Offshore, east of Catalina Beverage
22	Rooftop PV	Catalina Beverage Roof
23	Floating solar	Mount Ada Reservoir

Table 4-4 - Preliminary Renewable Site List, Sites 24-46

Site Number	Technology Type	Location
24	Rooftop PV	Near Avalon Fire Department
25	Rooftop PV	Hotel Atwater
26	Rooftop PV	Whitley Reservoir
27	Floating Solar	City of Avalon Reservoir, west of Holiday Inn
28	PV	Empire Quarry East of Two Harbors
29	PV	USC Wrigley
30	Wave power	East side of Catalina Landing
31	Wave power	East of Casino
32	Wave power	Gallagher Canyon Cove
33	Wave power	Shark Harbor
34	PV	Two Harbors Substation
35	PV	Northwest of Two Harbors Substation
36	PV	Southeast Two Harbors Substation
37	PV	South of Wrigley-Rusack Property
38	PV	South of Wrigley-Rusack Property
39	PV	Northeast of Middle Ranch Reservoir
40	PV	Northeast of Middle Ranch Reservoir
41	PV	Northeast of Middle Ranch Reservoir
42	PV	East of Middle Ranch Reservoir
43	PV	Middle Ranch Wells
44	PV	Two Harbors
45	PV	Airport-in-the-Sky
46	PV	Connolly Pacific South Quarry

Figure 4-20 – Catalina Island Renewable Energy Site Location

Figure 4-21 - Southern Catalina Island Renewable Energy Site Locations

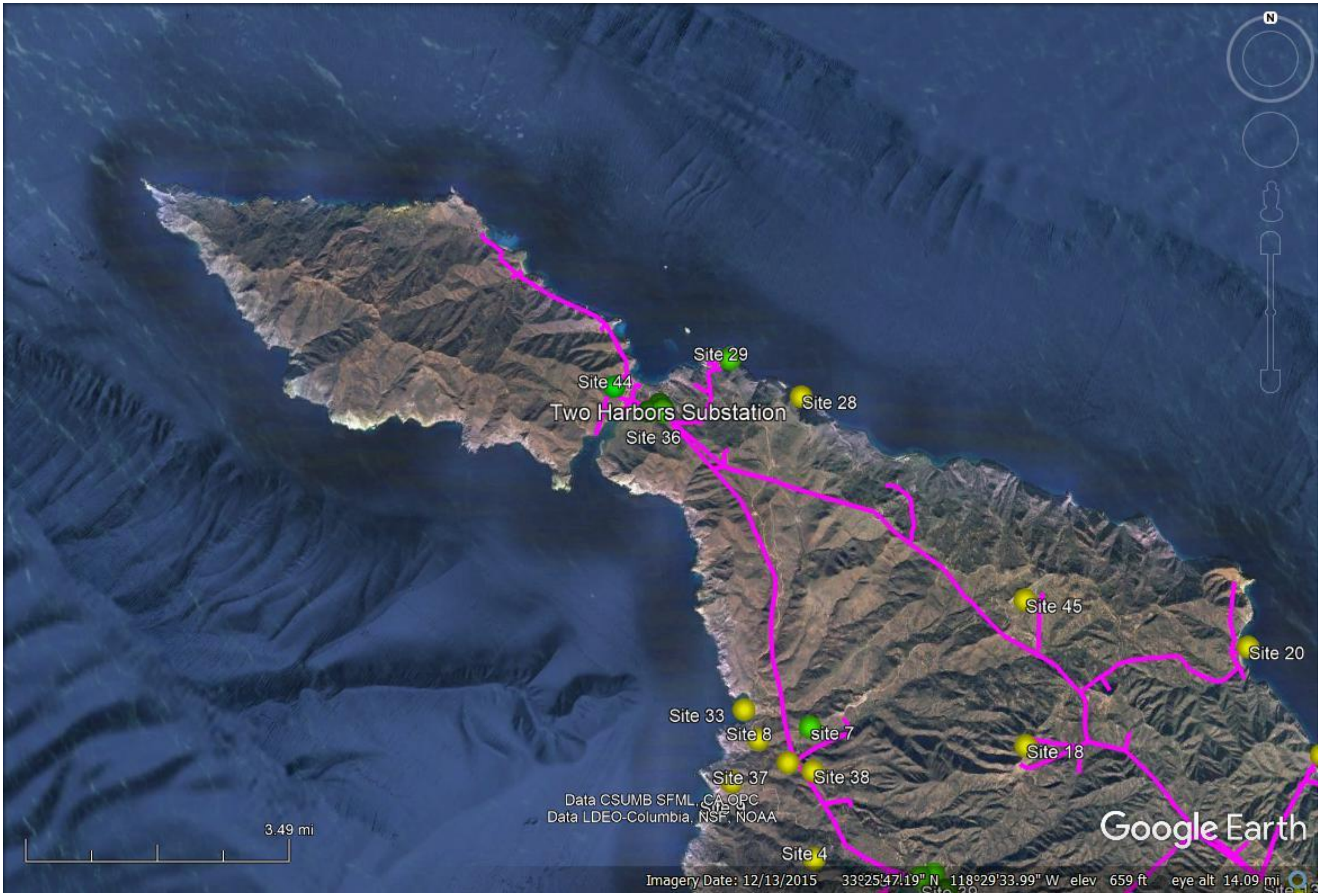

Figure 4-22 - Northern Catalina Renewable Energy Site Locations

Over the course of the project and through additional research, it became clear that particular technologies were better suited for Catalina. Highly feasible technologies filtered to the top while less feasible technologies filtered to the bottom. This filtering process was based on both the resource analysis outlined in Section 4.1 and the results of NREL's REopt analysis. The resource analysis resulted in low feasibility assessments for wind, wave, and ocean thermal technologies, and high feasibility assessments for solar (particularly land-based solar).

NREL's analysis showed similar findings. NREL provided an input to the filtering process using their modelling software, REopt. REopt was used to consider various renewable generation combinations by comparing and contrasting life-cycle cost and power output. NREL used REopt to simulate solar, wind, wave, and battery storage projects to determine which renewable technologies provided optimal life-cycle costs and consistent power generation. They considered both wind and wave technology in their model, but these technologies were found not to be as cost effective as alternatives given the assumptions used for the analysis (for further discussion of NREL's REopt results, see Section 6.0).

Each site received a ranking among different categories. These categories included regulatory complexity, biological sensitivity, wetland sensitivity, and approximate power generation. Each site was ranked according to its potential within the context of these categories. Each site was also reviewed on a more holistic level. NV5's ultimate site rankings were functions of the categorical rankings described earlier and a lengthy review and discussion process with SCE, NREL, and the EPA.

Sites were ranked low, medium, or high and during the ranking process, some general trends emerged. Sites with the following attributes tended to filter to the top:

- Renewable technologies with a demonstrated track record of success
- Locations with previously disturbed land, leading to fewer regulatory hurdles
- Locations close to existing distribution lines, especially the Interior Line
- Sites with larger nameplate capacities (kW/MW)
- Renewable technologies with favorable resources

Sites with the following attributes tended to filter to the bottom:

- Untested/unproven renewable technologies
- Sites near coastal areas, leading to a more challenging permitting and regulatory process
- Sites with smaller nameplate capacities (kW/MW)
- Sites located far from existing distribution lines
- Sites located on land unlikely to be available for development

In essence, this filtering process removed wind, wave, and ocean thermal technologies as viable renewable resources. What remained was a mix of land-based solar ranked as "high" and floating solar ranked as "medium." While wind, wave, and ocean thermal technologies were filtered out, it should be noted that there may be a place for these technologies in the future. Wave and ocean thermal technologies in particular are still in very early stages of development. As these technologies become more mainstream, it may be worth revisiting the implementation of pilot projects on Catalina.

For more detail on individual site rankings, descriptions, and commentary, refer to Appendix C (Renewable Site Matrix).

4.2.2 Site Selection Results

Ultimately, a total of 13 sites were given a high ranking (sites given a high ranking are marked in green on Figure 4-20, Figure 4-21, and Figure 4-22. All of the high-ranking sites were ground-mount solar; site numbers are shown in Table 4-5.

Table 4-5 - 13 High Ranking Renewable Sites

Site Number	Technology Type	Location
3	PV	Southeast of Middle Ranch Reservoir
5	PV	Southeast of Two Harbors
7	PV	Wrigley-Rusack Property
29	PV	USC Wrigley
34	PV	Two Harbors Substation
35	PV	Northwest of Two Harbors Substation
36	PV	Southeast Two Harbors Substation
39	PV	Northeast of Middle Ranch Reservoir
40	PV	Northeast of Middle Ranch Reservoir
41	PV	Northeast of Middle Ranch Reservoir
42	PV	East of Middle Ranch Reservoir
43	PV	Middle Ranch Wells
44	PV	Two Harbors

After the selection of the 13 high ranking sites, NV5 chose sites for a more thorough and in-depth analysis. Four unique locations emerged as the most viable candidate sites. These sites were selected as a result of mutual collaboration between SCE, NREL, and NV5. The criteria that led to the selection of these four sites included:

1. Permitting availability
2. Environmental availability
3. Ease of constructability
4. Proximity to electrical infrastructure
5. Favorable expectations regarding land acquisition
6. High nameplate capacity (kW/MW)

Sites 3, 5, 7, and 29 were selected for in-depth analysis, and they are shown in Figure 4-23 below.

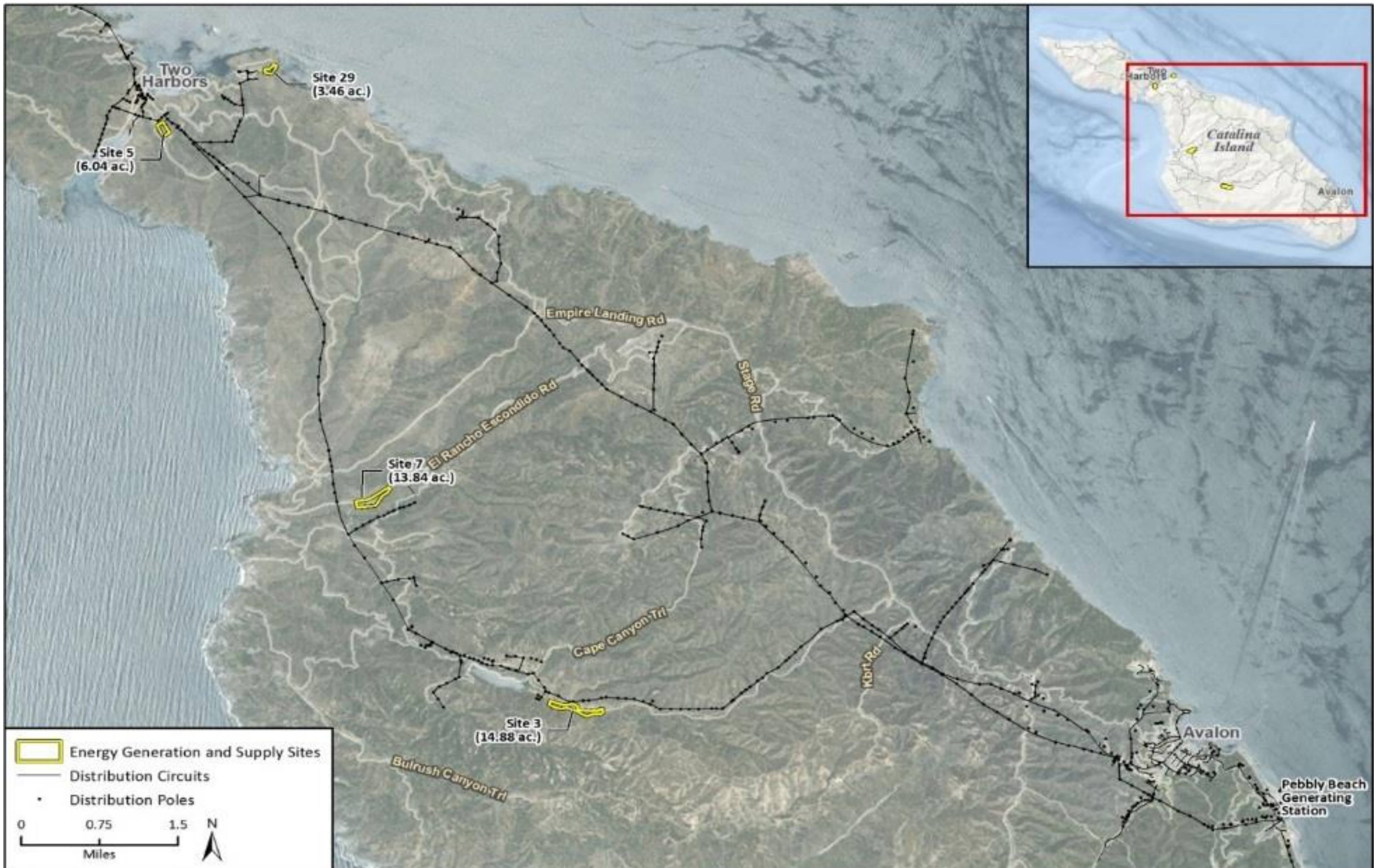

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Figure 4-23 - Site Locations 3, 5, 7, and 29 Selected for In-Depth Analysis

4.2.2.1 Basis of Design, Production, and Cost

For evaluation purposes, NV5 prepared conceptual designs for the top four candidate sites. The projects are modeled as south-facing fixed tilt ground-mounted solar arrays. The power and control cables will route from the panels to the equipment pads through wire harnesses and conduit mounted behind the racking structures and within direct buried conduit. Underground conduit crossing drive aisles will be reinforced either by being concrete encased or by other approved means.

Equipment pads will be installed on the larger sites to house medium-voltage (MV) step-up transformers, auxiliary power, and the data acquisition / SCADA module. The inverters were modeled as string inverters, though this is subject to change based on the final design. The inverters will convert the power output of the solar panels from DC to AC, at which point a step-up transformer will be used to increase the voltage to the MV distribution level of 12kV. The step-up transformers are to be loop-fed to minimize wiring, trenching, and MV switchgear costs. An underground, MV cable will be installed to "collect" the solar output from each MV transformer and route to the main equipment pad containing the main disconnect, site controller, and utility telemetry. From there, the interconnection circuit or "gen-tie" is routed to the final Point of Common Coupling (PCC) located at the existing utility distribution line.

The weather station used for this analysis is the Long Beach Daugherty Field, which is a TMY3, Class I weather station. The dataset used from this weather station is called an 8760 file for the 8,760 hourly weather data points to account for each hour in a calendar year. Each data point includes parameters such as solar irradiance, ambient temperature, wind speed and direction, liquid precipitation, among others. It is constructed by stitching together 12 monthly data records for the median weather over the/ time span of 1991-2005. The result is a 12-month, hourly data set representing a realistic modeling scenario.

The reason that Long Beach Daugherty Field was chosen is that it is the closest location to Catalina with an existing TMY3 8760 file. While Long Beach and Catalina Island share similar climates, Long Beach tends to have warmer annual temperatures and slightly more sunny days per year. These differences in climate are unlikely to drastically affect the annual production; however, NV5 recommends that prior to development of a solar array, the solar developer or EPC collect more granular weather data from Catalina Island and rerun the production model.

Based on collaboration between NREL and SCE, a generic capital cost was determined for the installation of ground-mount solar across Catalina Island. The generic capital cost used for this analysis was found to be $2.646/W-DC. It should be noted that this price does not include additional land acquisition costs or utility interconnection upgrade requirements. Excessive civil grading or other advanced site work were also not included in this cost calculation. Final pricing is site dependent, with larger sites likely to experience $/Watt price decreases due to economies of scale.

Table 4-6 - Site Selection Summary

Site Selection Summary					
Site Number	Size (Acres)	DC Capacity (MW)	AC Capacity (MW)	Estimated Capital Costs	First Year Annual Production (MWh)
Site 3	15	5.60	4.50	$ 14,820,000	9,219
Site 5	6	2.13	1.75	$ 5,640,000	2,890
Site 7	14	3.80	3.13	$ 10,050,000	6,622
Site 29	3.5	1.00	1.00	$ 2,650,000	1,782
Total	**38.5**	**12.53**	**10.38**	**$ 33,160,000**	**20,513**

4.2.3 Site Specific Analysis

4.2.3.1 Site 3

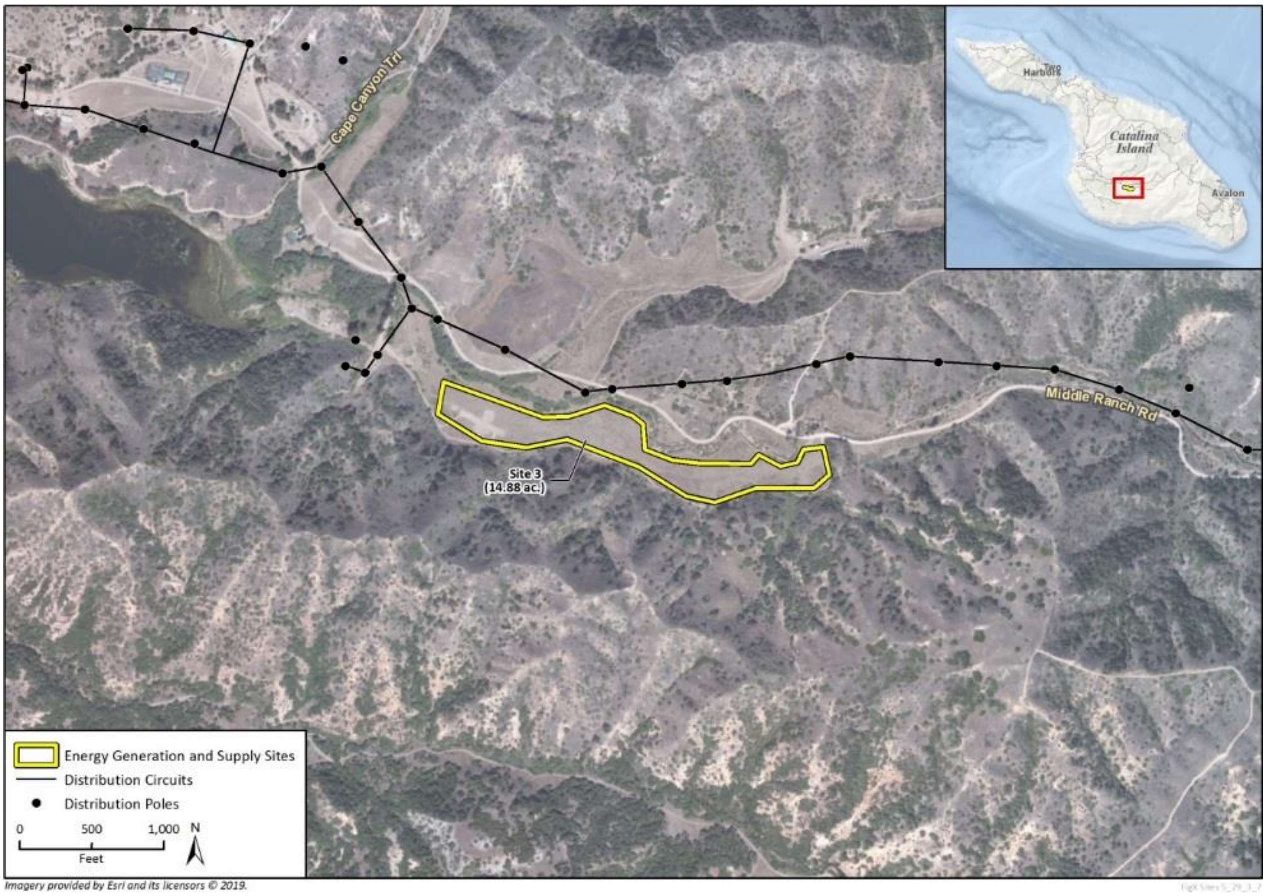


Figure 4-24 - Site 3

Site 3 is the largest of the four sites at approximately 15 acres. The site lies in the Middle Ranch area, located in the highlands toward the southern-central part of the island. The site is in a previously developed agricultural area within a valley on the southern side of the site and Middle Canyon Road on the northern boundary of the site. Site 3 is in disturbed land and is relatively free of native vegetation over most of the site; sparse vegetation consisting of shrubs and small tree occur toward the east end of the site. The site is outside of jurisdictional waters and is separated from the canyon to the south by a graded dirt access road. A potentially jurisdictional vegetated channel feature runs along the length of the north boundary, between the site boundary and Middle Canyon Road, but appears to be outside the site boundary. The vegetated channel appears to flow toward Middle Ranch Reservoir to the west of the site.

Solar Analysis

Site 3 has a long, thin footprint and is generally flat without significant changes in elevation. NV5 designed the array to optimize the amount of solar energy produced each day by setting the azimuth of the racking system at a south-facing 180 degrees. Inter-row spacing was set at 8' to maximize the total amount of solar at the site. 20' exterior and interior roads were designed utilizing best-practice standards.

The equipment selected to run this model included 16,240 345W Canadian Solar Polycrystalline solar panels and thirty-six Chint CPS125KTL (125kW) string inverters. Both equipment choices are subject to change based on recommendations by the engineer of record and the solar developer, as well as global market prices. For the purposes of modelling annual power production, however, both the inverter and solar module act as a fair representation of a generic product.

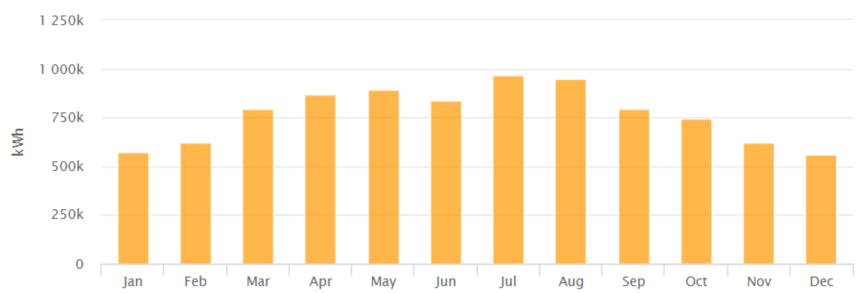
By designing the site to utilize as much of the available area as possible (while also including interior and exterior roads), the overall nameplate capacity of the site was found to be 5.6 MW DC and 4.5 MW AC with a DC/AC ratio of 1.25. Annual production was calculated to be 9.219 GWh, for a kWh/kWp/yr ratio of 1645.5.

The array was designed to interconnect at the SCE owned Hi-Line distribution line located 100 feet north of the array.

One of the drawbacks of this site location is the elevated ridge located 1,000 feet south of the array. This ridge rapidly slopes up from the same elevation as the array to a height of approximately 400 feet. Because of the height and location of this mountainous region, it is likely that it will cause shading that will reduce the total amount of annual solar production. This mountain was modeled in Helioscope and caused a loss in production of approximately 4.6%.

While this is a significant loss in production, the advantages of the site outweigh the shading issues caused by the southern ridge. The topography, size, proximity to utility distribution lines, and the fact that the site lays in previously disturbed land all contribute to making this site a top choice for solar development. It is recommended, however, that a more thorough shading analysis be done prior to the development of the site. This shading analysis is part of the due diligence of any solar developer in determining the annual impact to energy production.

Monthly Production



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Month	GHI (kWh/m^2)	POA (kWh/m^2)	Shaded (kWh/m^2)	Nameplate (kWh)	Grid (kWh)
January	95.3	131.2	125.3	668,906.1	575,080.4
February	111.0	139.1	134.9	720,746.7	619,503.5
March	158.9	182.6	178.0	953,107.8	796,284.7
April	189.4	200.8	196.0	1,049,182.2	865,878.9
May	208.3	208.7	203.1	1,088,678.5	894,923.8
June	199.8	194.2	188.6	1,008,594.6	838,985.7
July	227.0	224.1	218.5	1,170,432.0	963,746.8
August	212.1	221.4	216.2	1,160,185.7	946,698.1
September	165.4	184.6	180.0	964,156.0	794,341.6
October	138.4	170.8	166.4	890,137.6	746,237.0
November	104.8	141.2	135.8	725,277.8	619,649.8
December	90.4	128.6	121.6	648,171.2	558,054.3

Figure 4-25 - Site 3 Monthly Production

4.2.3.2 Site 5

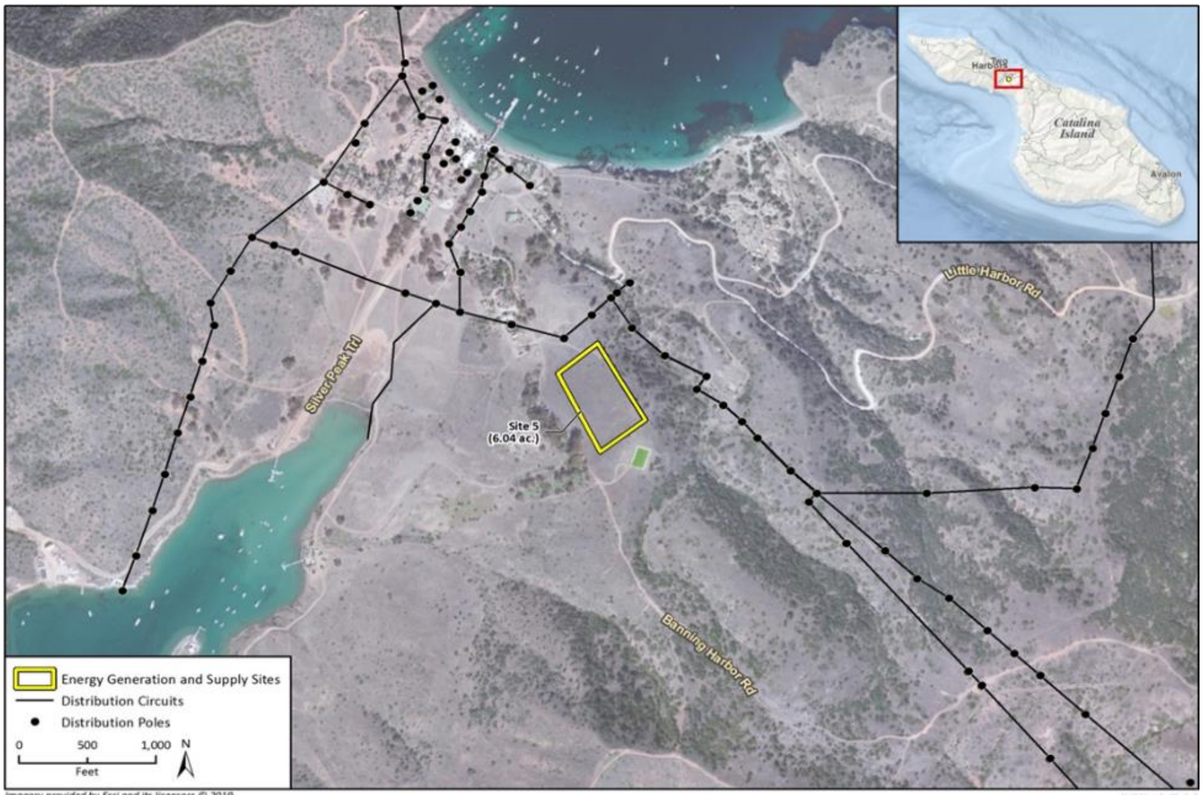
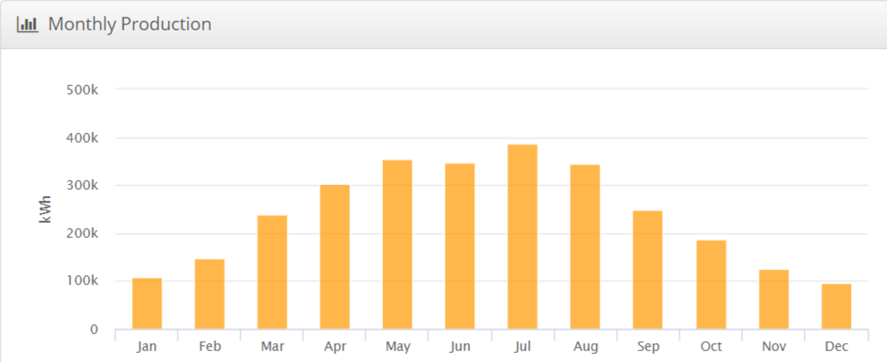


Figure 4-26 - Site 5

The Two Harbors area is the second largest community on Catalina Island. The unique area provides access via a narrow isthmus to both the western and eastern sides of the island in very close proximity to each other. The Two Harbors area serves as access to the University of Southern California (USC) research facility as well as a center for recreational boating and island access. Site 5 lies near Two Harbors in a previously developed agricultural area in a low coastal plain on the southwestern portion of the island. The site is approximately six acres and lies 1,300 feet from Isthmus Cover to the north and 1,400 feet from Catalina Harbor bay to the southwest. Based on aerial imagery and the in-person site visit, Site 5 appears to be located entirely in disturbed land free of native vegetation. A potentially jurisdictional channel lies approximately 350 feet to the east and appears to be completely outside boundary of the site. Graded dirt access roads are in the northeast corner of the site and to the west.

Solar Analysis

Site 5 has a rectangular footprint encompassing approximately six acres. The site slopes upward from north to south, increasing in elevation from 250 feet to 500 feet. NV5 designed the array to utilize the natural topography of the site by setting the azimuth of the racking system at a north-facing 318 degrees. A more traditional south-facing array is possible but would require extensive civil grading and earthwork. NV5 recommends that a detailed cost-benefit analysis be undertaken to determine whether the costs associated with a south-facing array are outweighed by the additional production over the lifetime of the system.



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Month	GHI (kWh/m²)	POA (kWh/m²)	Shaded (kWh/m²)	Nameplate (kWh)	Grid (kWh)
January	95.3	63.4	61.5	117,238.0	109,112.3
February	111.0	83.4	81.0	158,717.0	147,889.7
March	158.9	132.7	129.2	257,867.5	238,069.7
April	189.4	168.8	164.5	331,578.3	304,118.1
May	208.3	199.0	193.5	393,559.2	355,108.9
June	199.8	196.2	190.1	386,839.5	346,842.0
July	227.0	219.9	213.6	434,809.2	386,743.6
August	212.1	195.6	190.8	386,885.3	343,891.7
September	165.4	141.2	137.6	275,927.7	248,707.7
October	138.4	106.9	104.1	205,026.0	187,636.5
November	104.8	72.4	70.3	135,322.0	125,122.5
December	90.4	57.2	55.4	104,480.8	96,878.4

Figure 4-27 - Site 5 Monthly Production

The equipment selected to run this model included 6,188 345W Canadian Solar Polycrystalline solar panels and fourteen Chint CPS125KTL (125kW) string inverters. Both equipment choices are subject to change based on recommendations by the engineer of record and the solar developer, as well as global market prices. For the purposes of modelling annual power production, however, both the inverter and solar module act as a fair representation of a generic product.

By designing the site to utilize as much of the available area as possible (while also including interior and exterior roads), the overall nameplate capacity of the site was found to be 2.13 MW DC and 1.75MW AC with a DC/AC ratio of 1.22. Annual production was found to be 2.890 GWh, for a kWh/kWp/yr ratio of 1,353. This ratio is lower than what would normally be found on Catalina because of the north-facing tilt azimuth of the array.

The array was designed to interconnect at the SCE owned Interior distribution line located 80’ northwest of the array.

4.2.3.3 Site 7

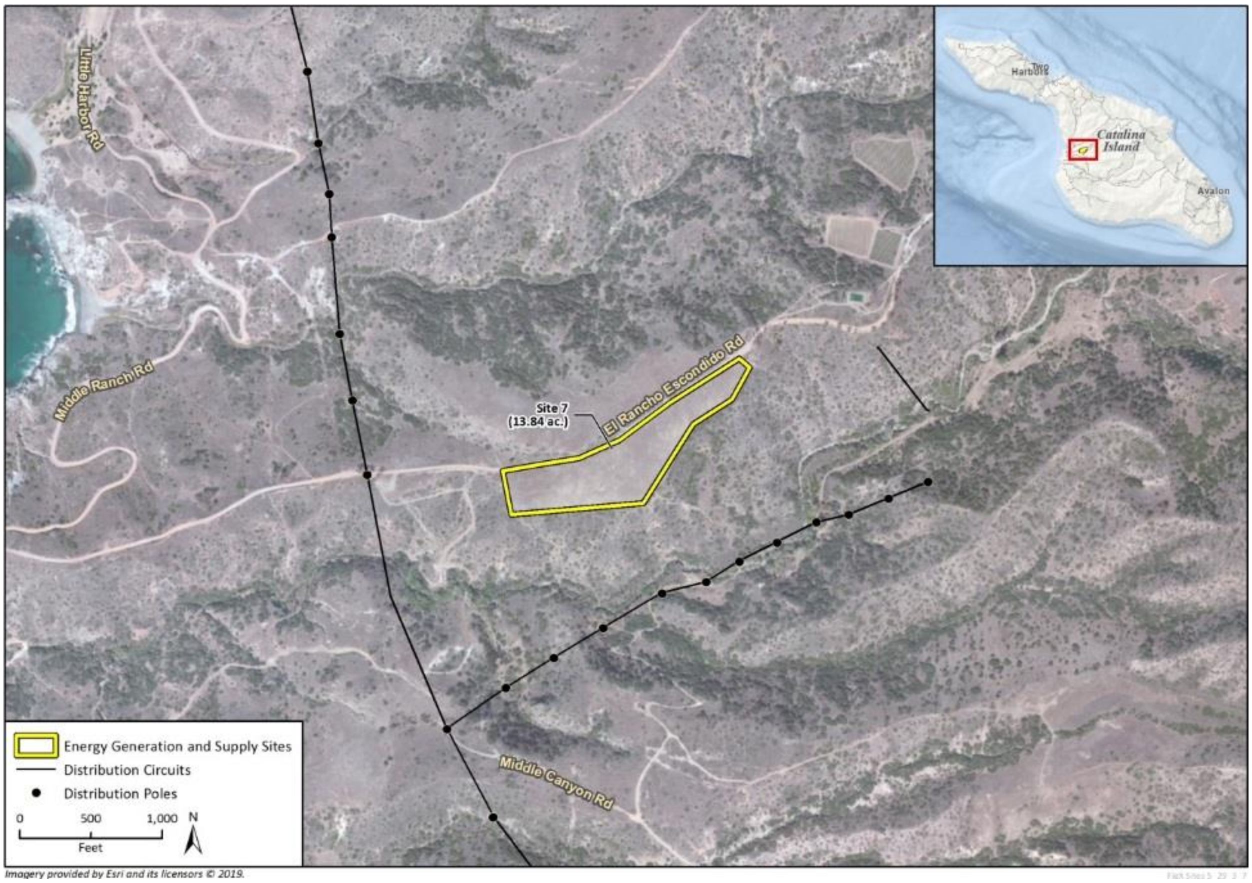


Figure 4-28 - Site 7

Site 7 is the second largest of the four sites at approximately 14 acres. The site is in the central portion of the Island toward the western edge of the island approximately 3,200 feet from Shark Harbor. Rancho Escondido Road runs along the northwestern boundary of the site and leads to a nearby active winery approximately 1,000 feet to the northeast of the site. The site is in a previously developed agricultural area and is relatively free of natural vegetation. The site sits on a small rise with valleys on the northwestern and southeastern sides. The site appears to be well outside any potentially jurisdictional channels.

Solar Analysis

Site 7 has a dogleg footprint and slopes gently downward from north to south without significant changes in elevation. NV5 designed the array to optimize the amount of solar energy produced each day by setting the azimuth of the racking system at a south-facing 180 degrees. Inter-row spacing was set at 8 feet to maximize the total amount of solar at the site. 20 foot exterior and interior roads were designed utilizing best-practice standards.

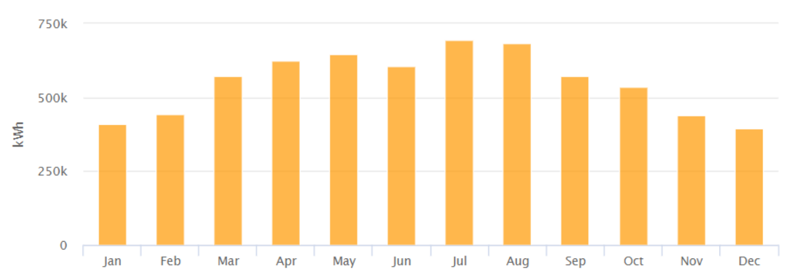
The equipment selected to run this model included 11,012 345W Canadian Solar Polycrystalline solar panels and twenty-five Chint CPS125KTL (125kW) string inverters. Both equipment choices are subject to change based on recommendations by the engineer of record and the solar developer, as well as global market prices. For the purposes of modelling annual power production, however, both the inverter and solar module act as a fair representation of a generic product.

By designing the site to utilize as much of the available area as possible (while also including interior and exterior roads), the overall nameplate capacity of the site was found to be 3.80 MW DC and 3.13 MW AC with a DC/AC ratio of 1.27. Annual production was calculated to be 6.622 GWh, for a kWh/kWp/yr ratio of 1,743.

The array was designed to interconnect at the SCE owned Hi-Line distribution line located a quarter mile west of the array.

One of the benefits of this site is that there is additional previously disturbed land north of the El Rancho Escondido Road. If other locations are deemed non-viable because of land ownership or other constructability reasons, or if more solar power is desired, the area north of Site 7 should be explored as an alternative area for development.

Monthly Production



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Month	GHI (kWh/m²)	POA (kWh/m²)	Shaded (kWh/m²)	Nameplate (kWh)	Grid (kWh)
January	95.3	131.2	126.8	458,675.3	409,366.1
February	111.0	139.1	136.1	492,578.7	442,892.7
March	158.9	182.6	179.4	650,738.3	574,337.8
April	189.4	200.8	197.3	715,902.0	625,844.3
May	208.3	208.7	204.7	743,475.8	646,893.4
June	199.8	194.2	190.1	689,271.3	604,093.3
July	227.0	224.1	220.0	798,821.9	694,726.2
August	212.1	221.4	217.6	791,444.0	682,198.5
September	165.4	184.6	181.3	658,051.9	571,339.3
October	138.4	170.8	167.7	608,022.6	535,036.3
November	104.8	141.2	137.2	496,341.7	441,375.7
December	90.4	128.6	122.8	443,487.2	394,204.7

Figure 4-29 - Site 7 Monthly Production

4.2.3.4 Site 29

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Figure 4-30 - Site 29

Site 29 lies near Two Harbors on the peninsula on the southeast end of Isthmus Cove. The site is approximately 3.5 acres and lies approximately 175 to 200 feet from the Pacific Ocean. Site 29 is flat and consists of approximately 40 percent vegetated area and 60 percent developed and disturbed area. Along the south boarder of the side, a potential wash is apparent on aerial imagery running to the northwest; however, vegetation appears to be scrub and not riparian in nature. The wash terminates at a graded, dirt access road that runs along the northwest boarder of the site and serves the development directly to the west of the site.

Solar Analysis

Site 29 has a dogleg footprint that has a gentle downward slope from east to west. NV5 designed the array to optimize the amount of solar energy produced each day by setting the azimuth of the racking system at a south-facing 180 degrees. Inter-row spacing was set at 8 feet to maximize the total amount of solar at the site. 20-foot exterior and interior roads were designed utilizing best-practice standards.

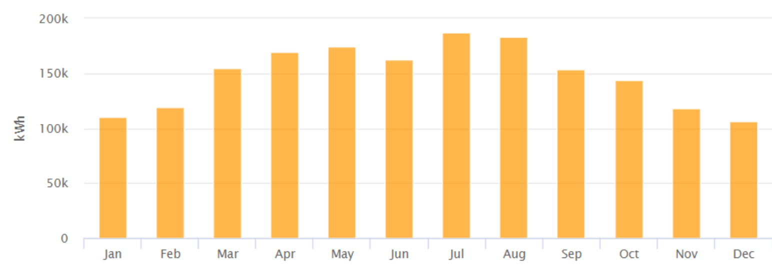
The equipment selected to run this model included 2,900 345W Canadian Solar Polycrystalline solar panels and eight Chint CPS125KTL (125kW) string inverters. Both equipment choices are subject to change based on recommendations by the engineer of record and the solar developer, as well as global market prices. For the purposes of modelling annual power production, however, both the inverter and solar module act as a fair representation of a generic product.

By designing the site to utilize as much of the available area as possible (while also including interior and exterior roads), the overall nameplate capacity of the site was found to be 1.0 MW DC and 1.84 MW AC with a DC/AC ratio of 1.00. Annual production was calculated to be 1.782 GWh, for a kWh/kWp ratio of 1,781.

The array was designed to interconnect at the SCE owned Interior distribution line, either in front of the meter or behind the meter at the USC Marine Lab located 500 feet west of the array.

This proposed site is unique in that it is located on land owned by the USC Marine Lab. Based on conversations with the Marine Lab's head supervisor, USC would be a willing participant in allowing solar or battery storage to be developed on their property. The site manager expressed interest in an interconnection model that would offset power used by the Marine Lab with any additional power being exported directly to the grid. What he describes is similar to a Net Energy Metering application in which customer owned solar energy is used to offset electricity bills. The Marine Lab is currently awaiting confirmation of a power purchase agreement (PPA) for the campus which includes a small PV facility to be installed on the western side of the site.

Monthly Production



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Month	GHI (kWh/m^2)	POA (kWh/m^2)	Shaded (kWh/m^2)	Nameplate (kWh)	Grid (kWh)
January	95.3	131.2	126.7	120,657.4	110,101.2
February	111.0	139.1	135.9	129,550.1	118,937.0
March	158.9	182.6	179.1	171,166.8	154,702.8
April	189.4	200.8	197.1	188,323.5	168,983.6
May	208.3	208.7	204.4	195,547.2	174,478.0
June	199.8	194.2	189.9	181,267.1	162,512.9
July	227.0	224.1	219.7	210,128.1	186,858.1
August	212.1	221.4	217.4	208,205.4	183,414.0
September	165.4	184.6	181.1	173,097.3	153,572.8
October	138.4	170.8	167.5	159,941.9	143,572.5
November	104.8	141.2	137.0	130,565.9	118,602.7
December	90.4	128.6	122.7	116,679.8	106,257.4

Figure 4-31 - Site 29 Monthly Production

4.3 SYNERGI ANALYSIS

4.3.1 Introduction

NV5 utilized the Synergi electric distribution model to validate current grid conditions and test the electrical system impacts of interconnecting DER at various points across the island. The purpose of this analysis is to understand electrical thresholds arising from DER interconnection and to study opportunities to increase renewable penetration with distribution upgrades. The results on electrical limitations are based on worst case scenarios where PV assets are not managed by an integrated island-wide microgrid control system. The results of these studies are universal across technology and final design may vary from what is analyzed in this section. Though the analysis produces quantitative results that are reported in the respective scenario descriptions, the numbers arrived for each scenario are to be used as a comparative evaluation criteria for site selection and/or for planning purposes towards distribution upgrades. They do not satisfy the need for a dedicated system impact study for any proposed DER.

4.3.2 Methodology

To begin the electrical distribution studies, it was necessary to select the top candidate sites from the overall renewable site matrix. See Section 4.2.1 for information on how these sites were selected. The top candidate sites selected through this process were PV Sites 3 (Section 4.2.3.1), 5 (Section 4.2.3.2), 7 (Section 4.2.3.3), and 29 (Section 4.2.3.4). NV5 understands that these sites are subject to change based on new information from SCE, environmental permitting, and island stakeholders; however, the modelling of these sites still provides useful information in how PV and energy storage generally affect Catalina Island's existing infrastructure.

After selecting the top candidate sites, a methodology was established during the modelling process. The national standard for utility voltage tolerance in North America is ANSI C84.1. This standard establishes nominal voltage ratings and operating tolerances for 60Hz electric power systems above 100V. Depending on the loading of the line, the reactive power demand of the load, in-line field equipment settings and other factors, nominal distribution voltage will fluctuate throughout the day. It is therefore critical that utilities regulate the nominal voltage and maintain it within strict tolerance levels. ANSI C84.1 provides a voltage tolerance graph with two ranges, Range A and Range B.

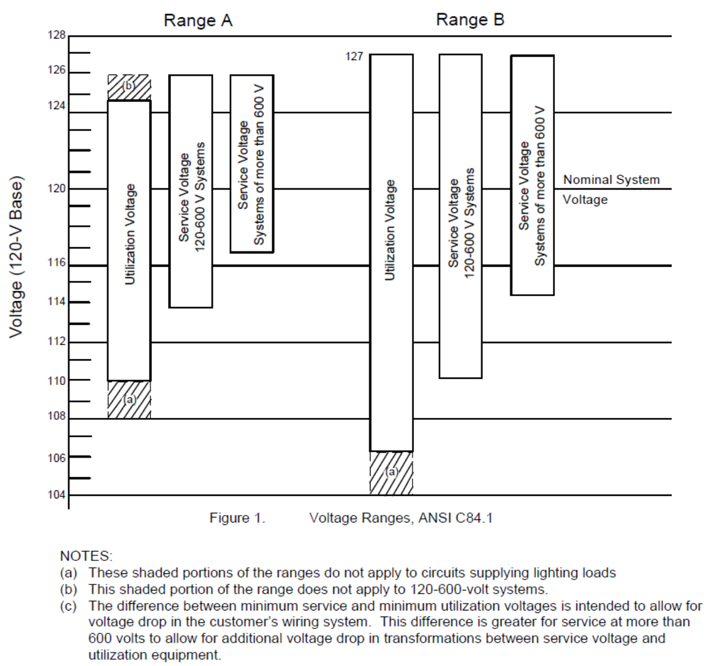


Figure 4-32 – ANSI C84.1 Voltage Tolerances

According to ANSI C84.1, Range A provides the normally expected voltage tolerance on the utility supply for a given voltage class. Variations outside the range should be infrequent. When looking at Catalina Island's 12kV system, the third bar is used and allows for a voltage tolerance of +5% to -2.5% above and below the nominal send out voltage (12.2kV).

When large-scale PV or battery storage is connected to the grid, large swings in voltage and changes in system frequency can occur during times of variable renewable production. The Synergi model can be used to test worst-case scenarios such as when the PV array is injecting full nameplate power to the grid or when PV instantaneously drops from its nameplate capacity to zero. These worst-case scenarios were reviewed to determine whether, and at which power production output, steady state voltage violations or power quality violations, in the form of voltage flicker, occur. Many of these worst-case scenarios pose potential issues to the existing infrastructure. NV5 was able to mitigate these issues with a combination of PV inverter power factor adjustments, system upgrades, and curtailment. These mitigation strategies are discussed in further detail throughout this section.

NV5 performed the Synergi analysis under both heavy and light loading conditions. Heavy loading occurs when the grid is operating at maximum capacity when the load is greatest and the most electricity is required. Light loading occurs when the grid is operating at minimum capacity or when the grid has the least amount of load throughout the year. Total light loading demand was set at 1.1MW based on observed values for 2017. NV5 based load allocation of the model from the CYME model provided by SCE which included a demand of 5.5MW for the island. Heavy loading demand was increased to 7.0MW as a request by SCE engineering to include future projected demand.

It is important to note that electrical impact studies are not site neutral. Power generation interconnecting to the grid at different locations will cause different impacts to the system. A simple example is a 1MW PV array interconnecting onto smaller conductors at one location vs. the same 1MW PV array interconnecting onto larger conductors at a different location. The same 1MW PV array that could export power at the larger conductor interconnection point without issue may cause overloading or voltage problems at the smaller conductor interconnection point. This simple example is meant to illustrate the concept that specific interconnection points must be chosen to run system impact studies. It is not possible to run a "site neutral" study because every point of interconnection has different tolerances and characteristics. In practice, this means that while the results of this analysis can provide broader trends, if alternative locations are chosen for interconnection, additional electrical impact studies will be necessary.

To provide the most valuable range of information, NV5 established five scenarios to be run in Synergi. Each scenario utilizes a combination of the highest ranked sites selected in Section 4.2.2. The five scenarios under study are listed as follows:

Table 4-7 - Renewable Energy Scenarios

Scenario	Max PV Capacity (AC)	Battery Storage Capacity	Reconductoring	Annual Renewables Penetration %
Scenario 1 – No Existing Distribution Line Upgrades	3.2 MW	0 MW	0 miles	16%
Scenario 2 – Infrastructure Upgrades	5.2 MW	0 MW	4.7 miles	25%
Scenario 3 – Infrastructure Upgrades	7.9 MW	0 MW	8.4 miles	32%
Scenario 4 – 60% Renewable Penetration Case	15.7 MW	12 MW / 90MWh	9.2 miles	60%
Scenario 5 – 100% Renewable Penetration Case	44 MW	36MW / 340 MWh	-	100%

4.3.2.1 Existing Distribution Line Discussion

Three main distribution circuits provide power to the bulk of Catalina Island: Wrigley, Interior, and Hi-Line. Wrigley is a shorter distribution line that primarily powers the City of Avalon. Interior is the longest line on the island, stretching northwest past Two Harbors to the overnight camp facilities at the northernmost point of Catalina. The Hi-Line is the second longest line, routing south through Middle Ranch before turning north to Two Harbors Switchyard. The proposed DERs are located adjacent to either the Interior Line or the Hi-Line.

The Interior Line is composed of one set of three 336Al conductors. The circuit starts at the Pebbly Beach Substation before downsizing to 1/0 Al conductors at the Two Harbors Switchyard. The Hi-Line circuit is also composed of one set of three 336 Al conductors at the Pebbly Beach Substation. The wires convert to 1/0 Al conductors at the Falls Canyon Dam near the load break switch connection between the Hi-Line and Interior Line. The conductors remain 1/0 Al for the remaining length of the circuit. Each scenario resulted in various infrastructure upgrades needed to interconnect the DERs onto the grid. These infrastructure upgrades are discussed in the following sections.

4.3.3 Scenario 1 – No Existing Distribution Line Upgrades

This scenario was chosen as the control case to highlight the maximum amount of solar power that could be exported to the grid within the constraints of available "top tier" candidate sites without causing any major issues to the grid. It was assumed that only the top candidate sites from the Renewable Energy Matrix could be utilized and that battery storage would not be utilized for power quality mitigation in order to simulate a worst-case scenario.

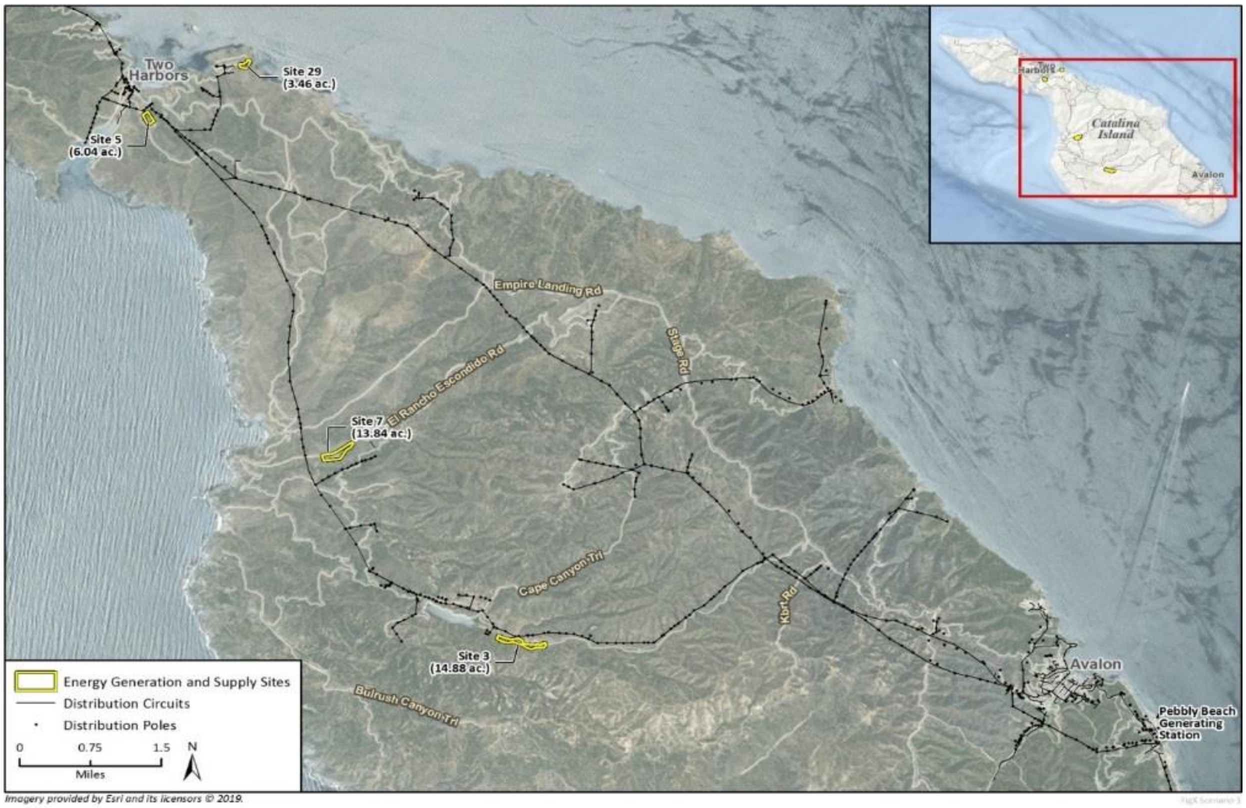


Figure 4-33 - Scenario 1 Distribution Map

Interior Line Interconnections – 2.2MW AC

- Sites 5 and 29
- Site 5 max output: 1.2MW AC @0.98 leading PF
- Site 29 max output: 1.0MW AC @0.97 leading PF

Hi-Line Interconnections – 1.0MW AC

- Sites 3 or 7, but not both
- Site 3 max output: 1.0MW AC @0.95 leading PF
- Site 7 max output: 750kW AC @0.95 leading PF

During the simulation, it was found that the maximum PV allowed across both the Hi-Line and the Interior Line was a total of 3.2MW AC. This 3.2MW includes a total of 2.2MW on the Interior Line and 1.0MW on the Hi-Line. At higher power outputs, both lines began to experience steady state overvoltages outside of the allowable ANSI A range. In particular, the Interior Line experienced overvoltages on utility lines near the USC Marine Lab. The Interior Line also experienced a large 4.5% voltage fluctuation when the PV swung from 100% to 0% operation during heavy loading. Typical industry standards allow for a voltage fluctuation of up to 2% for a single PV site to go from full on to full off instantaneously. This ratio can be used linearly as say a passing cloud that drops PV output from 100% to 25% should not cause a voltage fluctuation greater than 1.5%.

It is important to note that the available capacity of the Interior Line (northern distribution line) is higher than that of the Hi-Line (southern distribution line). Generally, this is due to the larger conductor size of the Interior Line (336 Al) vs. that of the Hi-Line (1/0 Al). Larger conductors have a lower impedance which produces less voltage rise than smaller conductors connected to a similar site, additionally the lower impedance means less power is lost as heat allowing for more ampacity before overloading the conductor. It was found that the Hi-Line can only handle 1.0MW of solar generation at the Middle Ranch location before the utility lines experienced overloading. The Interior Line, on the other hand, was able to handle up to 2.2MW of power at the USC and Two Harbors locations. In order to interconnect higher levels of PV, as shown in the Scenarios 2 through 5 (Section 4.3.4 - 4.3.7), it became necessary to increase the conductor size of the lines.

Based on NREL's follow-up REopt analysis, it was found that this level of PV penetration provides a renewable energy ratio of 16% annually. Specifically, under this scenario, 16% of the total annual energy consumed on Catalina Island is derived from a renewable energy resource.

4.3.4 Scenario 2 – Infrastructure Upgrades – 4.7 Miles Reconductoring

Scenario 2 was specified to showcase a higher PV penetration than Scenario 1 while also minimizing the amount of necessary reconductoring. The modelled sites were again selected from the list of "top-tier" candidates and battery storage was not used for power quality mitigation.

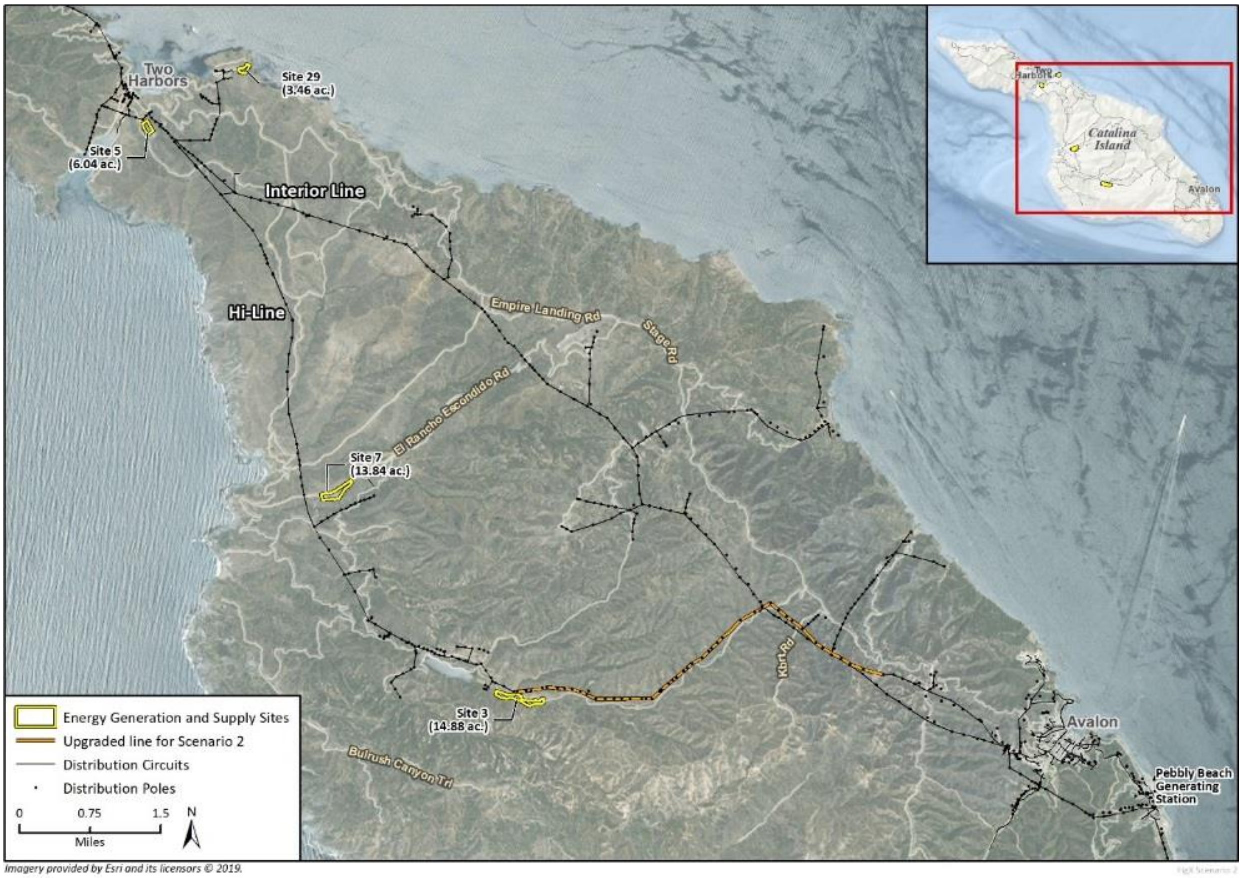


Figure 4-34 - Scenario 2 Distribution Map

Interior Line Interconnections – 2.2MW AC

- Sites 5 and 29 (Two Harbors and USC sites)
- Site 5 max output: 1.2MW AC @0.98 leading PF
- Site 29 max output: 1.0MW AC @0.97 leading PF

Hi-Line Interconnections – 3.0MW AC

- Site 3 (Middle Ranch site)
- Site 3 max power: 3.0MW AC @ leading 0.95PF

During the simulation, it was found that PV sites 5 and 29 were still able to export up to 2.2MW AC to the grid without triggering any violations on the Interior Line. On the Hi-Line, it was found that when PV Site 3 operated at a maximum output of 1.0MW AC, overvoltages began to occur. In order to mitigate the overvoltages, it was necessary to upgrade the existing distribution lines from 1/0 Al to 336 Al along a 4.7-mile span (shown in the image above, highlighted in orange). By upgrading the distribution lines to 336 Al covered conductor, PV Site 3 was able to produce its maximum nameplate output of 3.0MW AC without causing line violations. Combined, the total nameplate capacity of PV across the island totaled 5.2MW AC.

Based on NREL's follow-up REopt analysis, it was found that this level of PV penetration provides a renewable energy ratio of 25% annually. Specifically, under this scenario, 25% of the total annual energy consumed on Catalina Island is derived from a renewable energy resource.

4.3.5 Scenario 3 – Infrastructure Upgrades – 8.4 Miles

Scenario 3 was an additional "upgrades" case performed to highlight the maximum amount of solar production possible when all four top-tier candidate sites were developed. Because of the more abundant amount of PV interconnected to the grid, this scenario included the greatest amount of utility reconductoring. As in Scenarios 1 and 2 (Section 4.3.3 & 4.3.4), it was assumed that only top candidate sites from the Renewable Energy Matrix could be utilized and that battery storage would not be exporting power to the grid at the same time as the PV arrays.

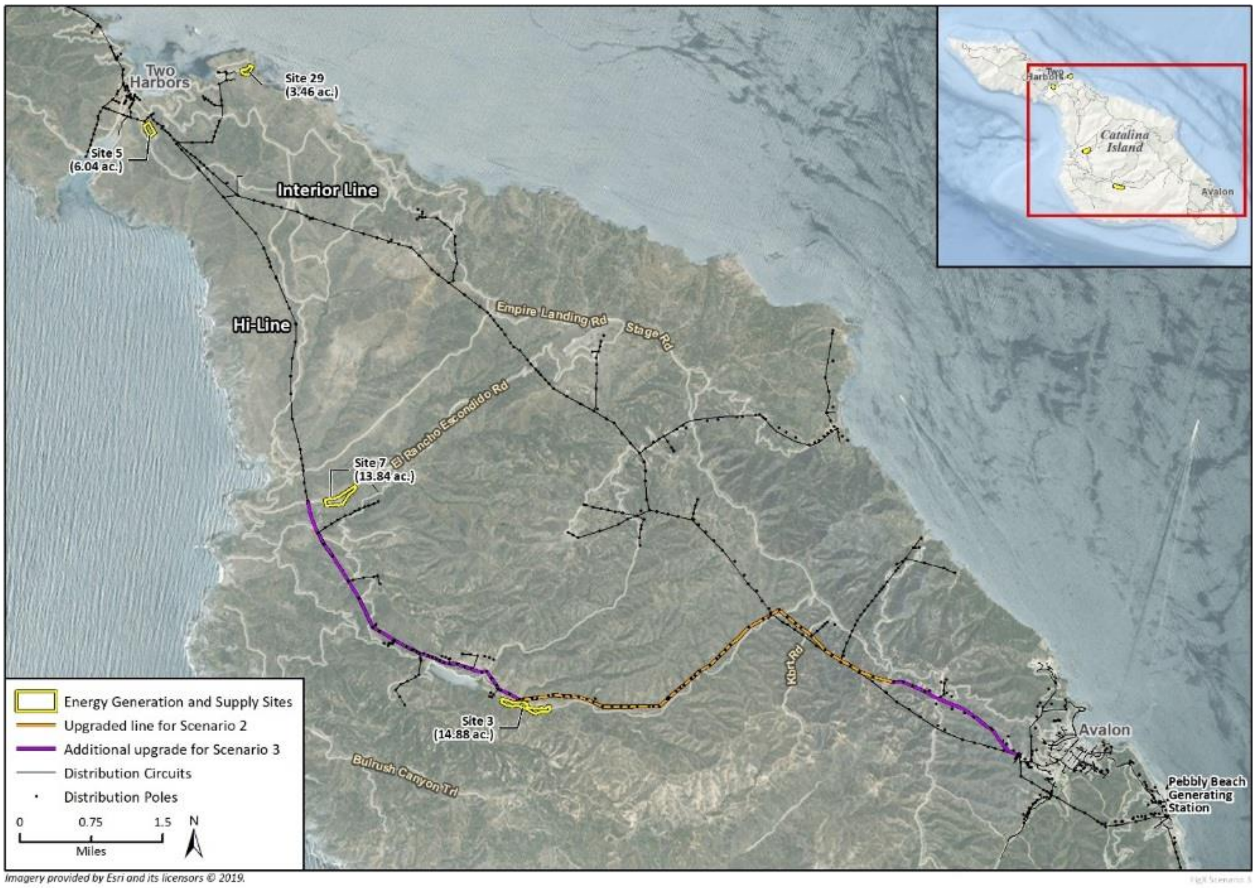


Figure 4-35 - Scenario 3 Distribution Map

Interior Line Interconnections – 2.2MW AC

- Sites 5 and 29 (Two Harbors and USC sites)
- Site 5 max output: 1.2MW AC @0.98PF
- Site 29 max output: 1.0MW AC @0.97PF

Hi-Line Interconnections – 5.7MW AC

- Site 3 and 7 (Middle Ranch and Wrigley Winery site)
- Site 3 max output: 3.0MW AC @0.95PF
- Site 7 max output: 2.7MW AC @0.95PF

Scenario 3 utilized the same base model as Scenario 2 with an assumed PV penetration of 5.2 MW and upgrades to the Hi-Line 1/0 Al conductor along a 4.7 mile stretch of the grid. In addition to the Scenario 2 specifications, analysis was performed to determine the maximum amount of allowable power at PV Site 7. It was found that all of the available real estate at PV Site 7 could be developed for solar if an additional 3.7 miles of distribution line were upgraded from 1/0 Al to 336 Al. Across all the sites, this led to a maximum PV interconnection value of 7.9MW AC with a required reconductoring length of 8.4 miles. The areas where additional reconductoring was necessary is shown on the map above, highlighted in purple.

Based on NREL's follow-up REopt analysis, it was found that this level of PV penetration provides a renewable energy ratio of 32% annually. Specifically, under this scenario, 32% of the total annual energy consumed on Catalina Island is derived from a renewable energy resource.

4.3.6 Scenario 4 – 60% Renewables Case – Infrastructure Upgrades

California has instituted one of the most progressive Renewable Portfolio Standards (RPS) in the nation. California law requires that 60 percent of electricity retail sales come from renewable resources by 2030. Based on this RPS and feedback from SCE, the 60% renewables penetration case, Scenario 4, was developed.

Before a Synergi model could be run, it was necessary to determine the makeup of a 60% renewables microgrid at Catalina Island. To complete this task, NREL ran a simulation within REopt setting the renewables penetration ratio factor to 60%. This factor forces the simulation to only consider cases where renewable resources provide at least 60% of the annual power requirements of the island. This does not mean that renewable energy must provide 60% of the generation at all times, only that it provides 60% of the total load used over the course of a year.

The REopt model assumes that fossil fuel generation will be available It also assumes that the existing 1MW / 7MWh battery storage will continue to be available.

NREL found that in order to provide 60% renewable penetration, a total of 15.6MW DC of new PV and 12MW of new battery storage would be needed. It should be noted that this simulation is location independent. REopt does not factor the locations of new or existing generation on the island; it simply provides the lowest life-cycle cost portfolio mix based on the system parameters. There may be many alternative 60% renewable penetration cases higher or lower values of PV or battery storage. REopt's goal was to find the lowest-cost version and provide the generation mix.

REopt is only meant as a techno-economic analysis tool, and therefore does not factor in the physical constraints of the grid in the way that Synergi Electric does. To match the solar capacity that was sized during the 60% renewable REopt simulation, it was necessary to include additional locations for solar modelling to reach the 15.6MW DC value. Using the nameplate capacities calculated during the individual site analysis section, the maximum amount of solar across the top four sites was 12.53MW DC. This creates a shortfall of 3.07MW DC between the available capacity of the studied locations and the calculated PV value from the REopt analysis. To make up for this shortfall, NV5 included some of the sites that were originally deemed "top-tier," but did not previously undergo individual site analysis within its Synergi model. The original top-tier sites and the new sites are shown in Table 4-8.

Table 4-8 - Scenario 4 – Original and New Site Nameplate Capacities

Original Sites	MW DC
Site 3	5.6
Site 5	2.13
Site 7	3.8
Site 29	1
Subtotal	**12.53**

New Sites	MW DC
Site 35	0.152
Site 36	0.11
Site 39	0.604
Site 40	0.42
Site 41	0.434
Site 42	0.246
Site 7[22]	1.2
Subtotal	**3.166**
Total	**15.696**

The nameplate capacity of the additional sites was found by applying a formula of five acres per MW DC. A more in-depth analysis of these individual sites was outside the scope of this report; however, five acres per MW DC is a typical industry standard that is widely used during the development stage. The addition of sites 35, 36, 39, 40, 41, 42, and the augmentation of PV Site 7 provided enough additional PV capacity to reach the 15.6MW target.

Several different cases were identified and run in Synergi Electric as a result of the additional nameplate power needed to meet the 60% renewable penetration. One of the main additions was that of battery storage that is not co-located with a PV array. This addition means power will need to flow from the PV arrays to another remote area of the grid to charge the batteries. The ideal location for this additional battery capacity is at the Pebbly Beach substation to make optimal use of PV generation from both Hi-line and Interior circuits. The underlying study cases were classified as follows:

1. Light loading with remote BESS charging.
2. Heavy loading with remote BESS charging.
3. Light loading 100% renewable without charging remote BESS.
4. Heavy loading 100% renewable without charging remote BESS.
5. Maximum allowed output of hi-line circuit solar & BESS interconnection limited by voltage rise in conductor (not to exceed total island heavy demand).
6. Maximum allowed output of interior circuit solar & BESS interconnection limited by voltage rise in conductor (not to exceed total island heavy demand).

[22] The additional capacity at PV Site 7 is derived from the expansion of the site boundaries to north of El Rancho Escondido Road.

Additionally, a few new assumptions were made with regards to battery storage, due to the amount of storage required by NREL's 60% renewable penetration:

1. Co-located PV & storage:
    a. Co-located storage will only be charged by the co-located PV array and not by the grid.
    b. These sites will never inject power to the grid greater than the nameplate AC rating of the PV site.
2. No modifications of existing normally open or normally closed tie switches were made.
3. No Flicker cases are considered due to the stabilizing nature of the battery storage systems.
4. Solar sites and batteries will always operate between 0.9 leading and 0.9 lagging power factor.
5. Maximum remote BESS charge rate is the same as the nameplate discharge rate.

4.3.6.1 Light Loading with Remote BESS Charging

When looking at light loading on Catalina Island the Interior circuit had no issues with full nameplate generation of PV at both site clusters along the line, Two Harbors Substation and USC Wrigley Marine Science Center. Minor power factor adjustments were made to 0.98 leading in order to keep voltage within the ANSI A range.

With existing infrastructure, the Hi-line can only support a curtailed output of 1.2MW of PV generation at 0.9 leading power factor at the Middle Ranch location before voltage violations start to appear along the circuit. These voltage violations can be mitigated by upgrading 3.8 miles of 1/0 AL conductor to 336 AL. These upgrades allow for an increased output of Middle Ranch to 4.3MW at 0.9 PF. At this point, the site output starts to overload the existing 1/0 conductor. By upgrading all 1/0 conductor to 336 AL between the substation and Middle Ranch the power factor can be increased to 0.97 leading which is a much more comfortable operating power factor and leaves room for adjustment if issues arise. With this arrangement the MW demand of the island is sufficiently met and there is no need to operate the El Rancho Escondido Rd site at any capacity as this site requires more upgrades with no additional output.

With maximum solar generation on Interior and upgrades on Hi-line, the proposed PV arrays can support 100% of the MW load of the island. Due to power factor adjustments there is still a need for the diesel generators to support 1.5 Mvar of load. This would most likely involve curtailing the solar output to find a good balance of MW and Mvar support from the diesel generators.

4.3.6.2 Heavy Loading with Remote BESS Charging

During heavy loading on Catalina Island the Interior circuit had no issues with full nameplate generation of the Two Harbors Substation and USC Wrigley Marine Science Center PV Sites at unity power factor. With the increased loading at the Two Harbors area, the addition of these PV sites helps to keep the voltage up without the need to utilize the nearby capacitor banks.

Utilizing the existing infrastructure, the Middle Ranch site on the Hi-line circuit must be curtailed to a maximum output of 1.55MW at 0.9 leading power factor before causing steady state voltage violations. By upgrading 3.5 miles of 1/0 conductor to 336 AL conductor, Middle Ranch operates at a maximum of 4.3MW at 0.9 leading power factor. Any additional generation will overload the existing 1/0 conductor requiring all 1/0 conductor between the substation and the Middle Ranch site to be upgraded.

By upgrading all 1/0 conductor between the substation and the El Rancho Escondido Rd site (approx. 9.2 miles) it is possible to allow the Middle Ranch site at full 6.404MW capacity with a 0.97 leading power factor and also bring the El Rancho Escondido Rd site online at a curtailed output of 1MW with a 0.93 leading power factor. This would require an additional 6.3MVA of generation from the diesel generators to support the heavy loaded island, assuming PV is solely dedicated to charging the BESS at Pebbly Beach.

4.3.6.3 Light Loading 100% Renewable without Charging Remote BESS

During light loading there are many different scenarios where PV could support the entire island demand if not charging BESS at the same time. This would most likely require reactive power balancing from the BESS at Pebbly Beach due to the leading power factor nature of PV arrays to maintain ANSI A voltages. For example, the 1.46MW Two Harbors Substation solar site can support the entirety of the island during light loading conditions when reactive power support is provided. Further study is needed to determine the most effective way to provide var support to the PV arrays.

4.3.6.4 Heavy Loading 100% Renewable without Charging Remote BESS

In this case, the Two Harbors PV cluster would output 1.46MW at unity power factor and the USC Marine Science Center PV array would output 1MW at 0.99 leading power factor. Both sites would export power onto the Interior line. The Middle Ranch Site would be curtailed to 0.7MW at unity PF and El Rancho Escondido Rd. Site would be turned offline. Middle Ranch would export power onto the Hi-Line. The assumption in this case is that there would be 4MW of BESS at Pebbly Beach (0.92 lagging PF) that was charged via PV and could export power continuously. This case also assumes that the Pebbly Beach BESS would be responsible for both var balance and frequency control.

While this case may not be the preferred method of operation, it illustrates that it is possible to power the island during heavy loading solely through renewable energy in a very specific instance.

4.3.6.5 Maximum Allowed Renewable Output of the Hi-line Circuit

It is possible to support the island heavy loading with only renewables on the Hi-line circuit, but only after upgrading the 1/0 conductor from the substation to the Middle Ranch site. Without these upgrades the Hi-line circuit can only support a curtailed value of the Middle Ranch site of 1.5MW with 0.9 power factor (or 1.2MW with 0.9 power factor during light loading). With upgrades the heavy loading scenario can be supported by curtailing the Middle Ranch site to 3.4MW at 0.97 leading power factor and using the 4 MW BESS at 0.9 lagging power factor from Pebbly Beach. In this scenario all existing capacitor banks on the island must be closed in to help support the reactive power demand of the PV site and the island.

4.3.6.6 Maximum Allowed Renewable Output of the Interior Circuit

The PV interconnections on the Interior circuit pose no issues with the existing infrastructure. A 0.96 leading power factor on all sites is sufficient to eliminate steady state overvoltage for all cases with full proposed MW output. Electrically speaking, the Interior has more capacity for additional PV power export. However, the lack of available area for solar development near the Interior circuit has placed constraints on the total amount of PV available.

4.3.6.7 Summary of Results

Proposed PV interconnection on the Interior line is achievable without changes to the existing infrastructure. The Hi-line interconnections prove more challenging. Even though there is land to build a large amount of PV, a significant amount of distribution upgrades – approximately 9.2 miles of reconductoring - will be needed to interconnect the full capacity of those sites. Even with upgrading the line to 336 AL there is no case where both the Middle Ranch and El Rancho Escondido Rd sites could both output maximum generation at the same time. Both locations could fully charge co-located BESS and slowly output that energy at no more than 1.5MW combined at any point with the existing

1/0 conductor in place or at 4.3MW with conductor upgrades from the El Rancho Escondido Rd site to the substation. Additional consideration could be given to dynamically rearranging normally open and normally closed-circuit tie switches that would increase the output capacity of the Hi-line.

4.3.7 Scenario 5 – 100% Renewable Case

Based on NREL's REopt model, a 100% renewable energy scenario on Catalina Island would require 44MW DC of solar PV and a 36MW / 340MWh battery energy storage system. The large quantity of both PV and battery storage is due to the 100% constraint imposed within the REopt analysis. Guaranteeing 100% renewable power means that the island must be powered by solar plus storage even during long stretches of time where solar energy is not produced (or produced at a very low level) due to inclement weather. In this scenario, there must be enough backup powered stored within the battery storage system to "ride out" long periods of time with little to no solar production. This requires a large solar and battery storage system with excess capacity to ensure these "sun drought" stretches will be covered.

On an island with approximately 5.5 MW of peak demand in 2019, it is difficult to simulate 44 MW DC of power injected at any moment in time. Even if this could be modeled electrically, the siting analysis did not produce enough physical sites to meet the solar and storage capacities that were dispatched in the REopt simulation. For these reasons, the 100% renewable case was not run as a standalone scenario in Synergi Electric.

Using the findings from the Scenario 4 Synergi analysis, NV5 believes the 100% renewable scenario could be built with much larger system capacities behind the meter at sites selected for the 60% renewable scenario, and that the apparent power injected to the grid would continue to be limited at the same thresholds, but the total energy harvested and stored with local battery storage could be used to maintain a steady power output at each PCC.

4.3.8 Grid Upgrades Discussion

Based on the Synergi studies in the previous sections, it was found that the 1/0 Al Hi-Line conductors were inadequate to allow for the full injection of the proposed high-capacity solar and battery storage resources. In order to inject the full power capacities studied, it was necessary to reconductor the circuit using larger conductors with higher ampacity limits and lower impedances.

Numerous factors influence the methodology in upgrading conductors on Catalina. Both the CPUC Fire Threat Map and the SCE DDS-10 documents outline the technical requirements (See Appendix D). Because Catalina Island is in a "Tier 3- Extreme" fire zone, there are additional benchmarks that must be met. One of these benchmarks includes the required use of "covered conductors." Covered conductor has thick insulation surrounding the interior metal core of the cable. Overall, covered conductor can improve reliability by preventing faults due to contact from objects such as tree branches, palm fronds, metallic balloons, or other conductors.

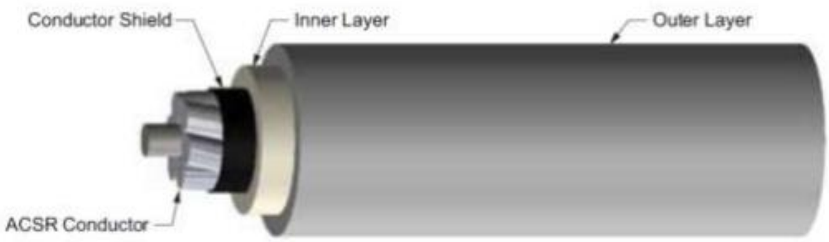


Figure 4-36 - Covered Conductor[23]

SCE's Cables and Conductors standard DDS-9 provides Table 4-9 for overhead covered conductor ampacity ratings.

Table 4-9 - Overhead 90°C Rated ACSR Covered Conductor Economic Loading Standard - 4kV, 12kV, and 16kV

Conductor Size (AWG or kcmil)	Covering Type	Conductor Economic Loading Range Based on Annual Peak Demand within Five Years (Amp)	Normal Operating Rating (Amp)	8-Hour Emergency Loading (Amp)
1/0	HDPE	0-125	271	336
1/0	XLPE	0-125	271	353
336.4	XLPE	126-210	550	685
653.9	XLPE	Above 210	838	1,042

Based on the increased ampacity exported by the proposed solar and battery storage installations, the new conductors shall be rated either 336 ACSR or 654 ACSR.

The other technical requirement is the use of "composite poles." According to SCE's Distribution Overhead Construction Standards, PO 100 – 1.0:

> The use of composite poles is preferred in lieu of wood poles under the following conditions:
>
> - Rear property lines
> - Areas subject to pole shrinkage and constant winds
> - Areas of restricted vehicle access (such as areas with environmental and/or archaeological concerns)
> - When helicopter installation is necessary
> - To reduce or avoid the need for a crane
> - In areas where severe or accelerated pole degradation has occurred in 15 years or less due to factors such as animals (e.g. woodpeckers and bears), insects, fungus, moisture, and other severe environmental conditions

[23] (California Public Utilities Commission, 2019)

The last four bullet points apply to the installation of poles at Catalina Island.

4.3.9 Grid Upgrades Cost Estimate

NV5, in conjunction with SCE's internal estimating group, prepared a cost estimate for the installation of new conductors and poles on Catalina Island. To determine an average cost per mile, NV5 utilized the span highlighted in Scenario 2 as its test case. This section is approximately 4.7 miles in length and contains 45 existing wood poles. To upgrade this section to 336 ACSR covered conductor and install 45 composite poles, the overall cost was found to be $5.16M, or $1.1M per mile (see Appendix E for the cost estimate spreadsheet).

4.4 MICROGRID ANALYSIS

A renewable energy microgrid system as complex as the ones explored on Catalina Island requires sophisticated controls in order to balance the supply and demand on a continual basis given the variable renewable generation sources and changing demand from the customer base. A high-level discussion of the various considerations and major drivers from a cost, implementation, and operations standpoint is presented to help evaluate the options. A recommended implementation is provided for local controllers and system wide management systems to coordinate the various assets on the system.

In addition to sophisticated controls, NV5 will recommend setpoints for behind-the-meter distributed renewable generation systems using smart inverters. These autonomous grid support functions (GSF) such as frequency and voltage Ride Thru, volt/var, and freq/watt among other beneficial services do not require a sophisticated SCADA network connected to each system and provide substantial benefits to a small island distribution system with high variable renewable penetration and low system inertia. Lessons learned from HECO and other unique distribution systems will be leveraged to recommend a best approach for maintaining optimal power quality while managing the costs and logistics of integrating every rooftop solar generator to the SCE SCADA system.

4.4.1 Microgrid Background

The US Department of Energy defines a microgrid as

> *A group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode.*[24]

For the purposes of this analysis, the island's grid is referred to as a "microgrid" as there is a local coordination of loads and generation within a clearly defined electrical boundary.

The effort to repower the island from the existing diesel generation fleet to lower emissions is recommended to be developed in multiple phases. The general phasing plan should be communicated to and understood by all contractors and vendors involved with each phase to ensure no solution for a given phase is restrictive to future phases of the renewable microgrid implementation. This need for flexibility should be at the forefront of any discussion with software and hardware controls vendors on how to manage distributed assets over time with a changing and growing fleet of renewables and storage to control.

[24] (Smith, 2012).

4.4.2 Microgrid Controller

An initial use case includes a microgrid controller to oversee any assets that can be communicated with directly at the local facility. A microgrid controller may reside in a standalone cabinet or integrated in an existing control building. It should interface with any existing site controllers to properly coordinate the dispatch and operation of various assets. For example, if a microgrid controller is deployed at PBGS, it should be capable of integrating with the existing Emerson Ovation DCS and Allen Bradley controllers to control the diesel generators and NaS battery, if desired. Some of the primary functions of the microgrid controller are:

- A singular interface for all assets
- Regulation of real and reactive power flow at the POI

Capabilities to address local power quality issues behind the POICommon hardware components for a microgrid controller in this application are as follows:

- SEL 3355 hardened PC
- SEL 2241 RTAC
- SEL 2401 GPS clock and antenna
- SEL 351 PMU Relay
- Cisco IE 2000 network switch
- NEMA Type 3R cabinet
- Power supply
- UPS
- Rackmount KVM

Figure 4-37 – SEL 2241 Real Time Automation Controller (Schweitzer Engineering Laboratories, n.d.)

4.4.3 Centrally Controlled - DERMS

The renewable microgrid analysis is proposing a significant amount of DER to be interconnected at the distribution level, and for the integration of potential another behind-the-meter DER as well. The increasing levels of distributed generation on the system will pose challenges to the SCE distribution operators. A more active coordination and management of these new distributed assets could be provided by a Distributed Energy Resource Management Systems or a DERMS.

The US Department of Energy has defined a Distributed Energy Resource Management System (DERMS) as, "a software solution that incorporates a range of operations to adjust the production and/or consumption levels of disparate DERs directly or through an aggregator."[25] It offers enterprise-level DER management for real-time control applications. A typical DERMS platform can integrate various generation resources (renewable and thermal), load control, energy storage, voltage support equipment, switches, and isolation devices. Many DERMS platforms are scalable, enabling the addition for future assets as they come on line and with an evolving grid topology.

[25] (U.S. Department of Energy, 2018)

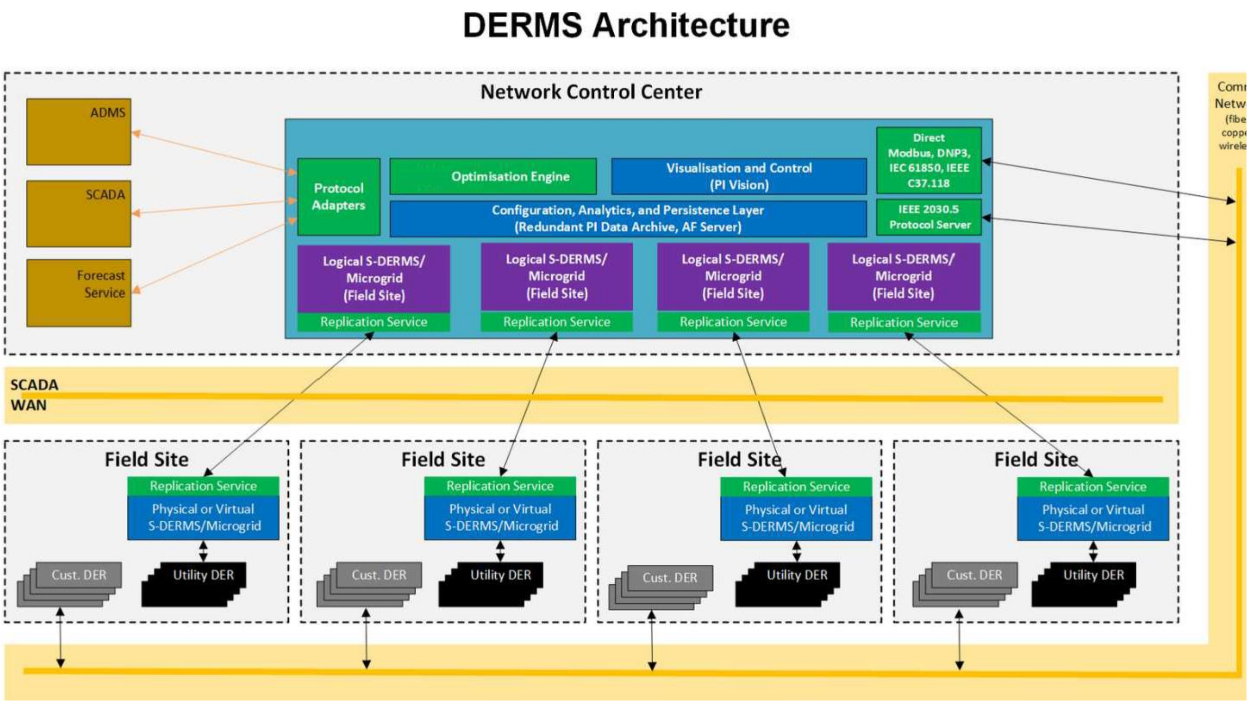


Figure 4-38 - Example DERMS Architecture

A robust DERMS offering can provide multiple value-add functions automatically to grid operators and consumers, using forecasts and real-time data for weather/solar irradiance, load fluctuations, and market pricing conditions. These functions and benefits include:

- Be predominantly cloud-based
- Computes optimal diesel generation set points to minimize island fuel consumption
- Inertial frequency control for the entire island system (modulates controllable DERs to keep generators inside their droop dead-band and regulate island frequency with BESS)
- Control of the normally open switches based on real-time selection of optimal circuit topology
- Use of a network model to compute and control voltage profiles along the feeders, and capable of providing “virtual measurements” where none are available
- Site Resiliency / Critical Load Support
- Frequency Response
- Volt/VAR Compensation
- Optimization of DER generation
- Load Management / Demand Response
- Seamless transition (disconnection and re-connection) to two or more networked microgrids
- Equipment monitoring and analytics

The DERMS software should interface with external principal systems such as SCADA, ADMS, and weather forecasting services to provide real-time network topology, configuration status, load, DER status, and real time system operations data, and control. All relevant data is consumed to produce an optimized solution, detect disturbances, and perform electrical characteristic monitoring in real time. This will ensure that the solution delivers on its potential to provide a scalable solution to support reliability, integrate an increasing number of DERs, and reduce operations and maintenance costs.

4.4.4 Distributed Control – "Peer-to-Peer"

Another approach is a distributed, peer-to-peer automation system. Each DER has a local gateway that broadcasts certain statuses and alarms and can autonomously optimize its local assets' operations based on the local conditions and the status or alarm inputs from the rest of the assets along the communication network. Some of the benefits to this framework are:

- Distributed logic enhances reliability and scalability for future system expansions
- All control is distributed, no centralized control entity, which allows for multiple points of failure
- Redundant grid forming capability

Each asset controller broadcasts certain output signals into the network regarding its current status (out of service, in service, islanded, not islanded, real/reactive power output, etc.) and capability (max/min load, real/reactive power capability, BESS SOC, etc.). In turn, each asset controller "listens" for certain broadcasted information from the other controllers, relays and power meters that informs how it should act based on internal rules-based decision making. These rules are the algorithms built into the control system.

4.4.5 Hierarchical and Networked Microgrids

During this feasibility study many sites were studied for generation and energy storage opportunities. Additionally, NV5 gathered information about various nearby electric customers and loads that might benefit from some added level of resiliency. This presents the opportunity to establish a system of *networked microgrids* or *hierarchical microgrids*, whereby certain subsets of the island's electric grid could disconnect or reconnect to the broader macrogrid with its own generation, load, and storage resources behind the PCC. These can be portions of the 12kV distribution system, like at the substation and/or feeder level, or even behind the customer meter.

It is beneficial at this stage to review the multiple tiers of control solutions with increasing complexity at each level.

- **Tier 1 – Microgrid Controller.** The lowest tier use case assumes a microgrid controller to oversee any assets that can be communicated with directly and locally within the electrical boundaries of a given system.
- **Tier 2 – DERMS.** This is a significantly more complex control solution than a standalone microgrid controller, but offers the future proof flexibility to add more assets over time with simple software patches, although requires robust communication infrastructure to control all of the island DER.
- **Tier 3 – DERMS + Microgrid Controllers = Hierarchical or Networked Microgrids.** This involves the DERMS system managing multiple distributed microgrids as blocks of assets.

Networked microgrids are understood to mean a patchwork of co-equal microgrids that operate with a single, self-healing control scheme such that a loss of any one block does not impact the ability to control and optimize the remainder of the system. There is no "physical" central controller, rather the optimization occurs in the cloud and each physical asset follows the commands of the algorithm based on the total DER and instantaneous load connected at any given time.

Hierarchical microgrids are defined as “a microgrid within a microgrid”. This is closer to a “hive-drone” control scheme that includes a central controller to operate the island DER and other assets, but if any distributed microgrids disconnect from the island macrogrid, then it will operate on its own based on the control scheme of its local controller. A typical assumption is if the microgrid is grid connected, then the central controller can provide higher order optimization and control. If it is islanded, then the control is handled locally. This is a valid assumption if the communication technology relies on shared infrastructure that would suffer an outage from the same events that disrupt power supply, such as fiber optic cables running with the overhead lines or pole-mounted radio repeaters that get damaged and break the line of sight signal. It is also feasible to achieve certain control and optimization through 3G and 4G cell modem communication that could mitigate against loss of communication in the event of an outage. Although, the speed and therefore control functions are limited by the speed of the available communication technology.

A small-scale example of hierarchical microgrids are traditional solar + storage project sites. Traditional DC-coupled solar + storage configurations utilize a solar PV inverter and separate external DC charge controller for the battery DC bus. This requires the solar inverter act as the “hive” and the battery charge controller as the “drone”. Alternatively, utilizing a BESS inverter and solar PV charge controller (aka “reverse” DC-coupled) offers the benefit that it can operate in voltage source mode (grid-forming) and supply a microgrid in the event of an outage. This clarification is provided for awareness since not all solar + storage configurations will offer added resiliency, and this will need to be evaluated to make sure it meets the goals of the individual project.

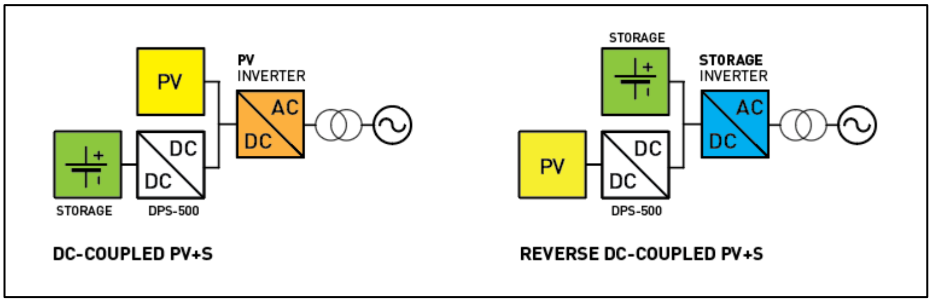


Figure 4-39 - Reverse DC Coupled PV Plus Storage[26]

Whether the approach pursued is a network, hierarchical, or a hybrid of the two, the general outcome is that it will offer a multitude of benefits to the SCE distribution operators, as well as local communities that are made resilient by the ability to remain energized for some amount of time in the event of an outage. SCE has discussed the increasing occurrences of wildfires through the middle of the island as a potential risk factor, and adding an element of resiliency to the various communities across the island while also achieving its renewable energy deployment goals is a win-win situation for SCE and the other island stakeholders.

Below and on the following pages are a site plan and one-line diagram of a proposed microgrid anchored at the Two Harbors switching substation. This microgrid includes 3.392 MW DC of solar PV and 7 MW AC/28 MWh of energy storage. Backup fossil generation could also be included in this

[26] (Davis, 2019)

model, as well as behind the meter DER and DR customers. Under normal “grid-connected” conditions, this microgrid would follow commands from a central control system, namely a DERMS, that would optimize all assets across the island. If a major weather event damages the distribution lines along the island and causes an unplanned outage for the load downstream of Two Harbors, the local microgrid controller would be able to isolate the microgrid and manage its generation and loads locally based on a default control scheme within its electrical boundary.

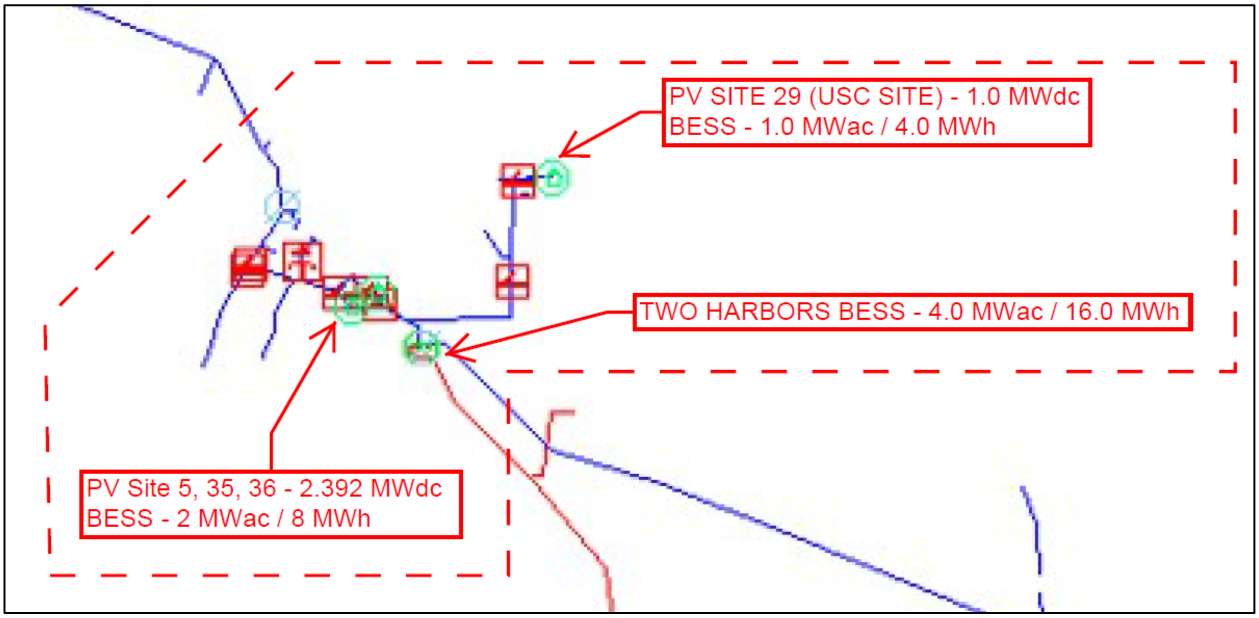


Figure 4-40 - Enlarged Site Plan of Two Harbors

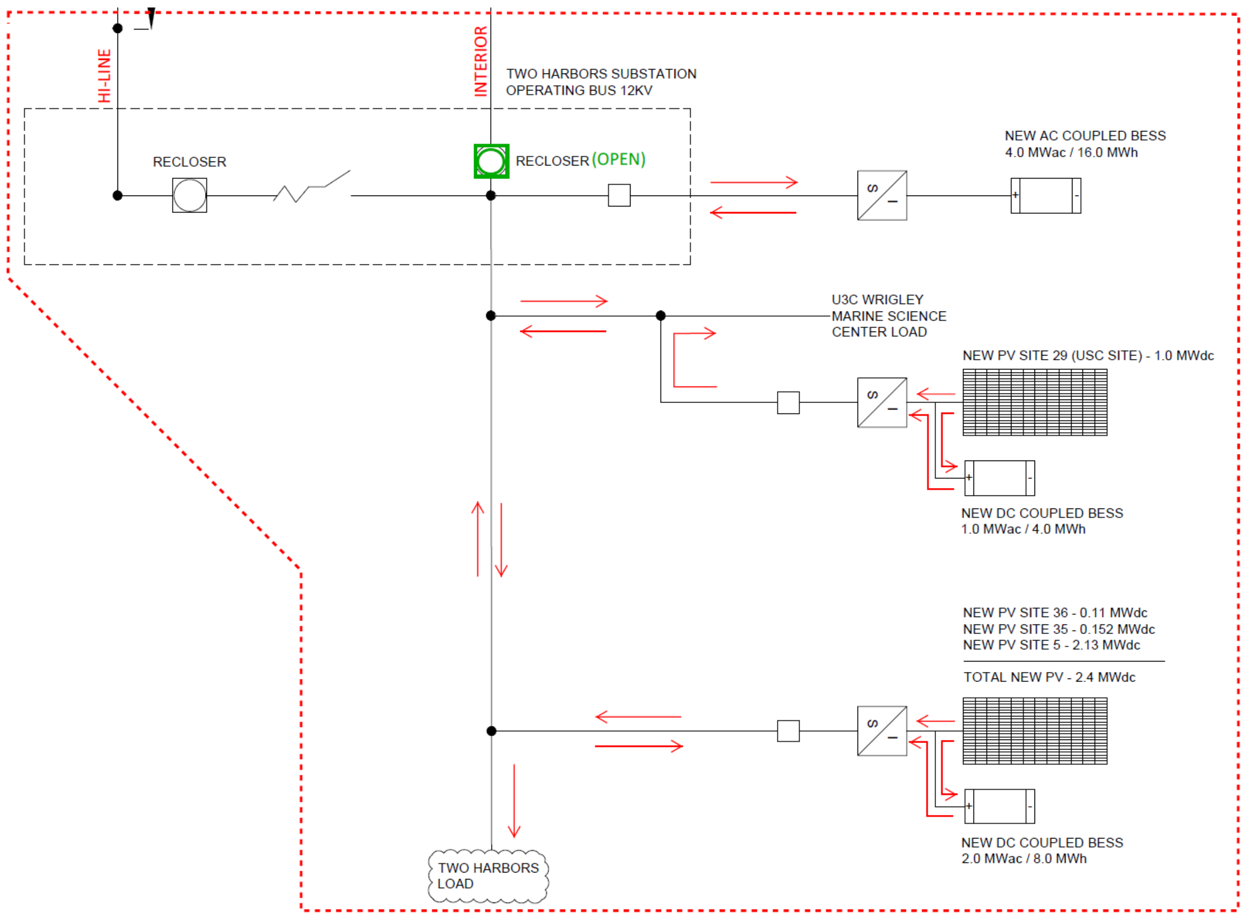


Figure 4-41 - Two Harbors Microgrid One-Line

4.4.6 Grid Operations

Specifying grid interactive smart inverters that are IEEE 1547-2018 compliant will allow for the same equipment that is needed to interconnect the distributed renewable assets to also provide grid support functions under blue-sky conditions. An AC-coupled energy storage project sited at the Two Harbors substation or some other DER with grid interactive smart inverters would have the added benefit of offering voltage support with a volt/VAR scheme and frequency support with a freq/watts scheme. For example, SCE has noted that Two Harbors routinely experiences low voltage, and a local DER with an ability to provide reactive support similar to a capacitor bank would benefit the overall voltage profile for that load pocket. These smart grid functions would be available under blue-sky conditions when the microgrid is still parallel to the island grid. Under black sky conditions such as an unplanned outage, they could supply a local microgrid to keep the load downstream of two harbors energized for a period of time.

4.4.7 SCE Distribution Operator Impacts

Part of NV5's due diligence in the development of a 60% renewable microgrid included the review and forecast of the impacts to current SCE personnel. The installation of new PV and battery storage systems, diesel generators, electrical switchgear and infrastructure, and controls systems will require additional man-hours for O&M, upkeep, and testing. Presently, SCE personnel on Catalina Island includes the following job classifications:

- Instrument, Control, and Electrical (ICE) ICE Foreman
- ICE Tech
- Plant Foreman
- Control Operator
- Plant Equipment Operator
- Admin Clerk
- Utilityman

These key SCE personnel perform a variety of tasks with the overall responsibility of running and maintaining Catalina Island's electrical distribution system. A number of these employees already have responsibilities similar to what would be required in the operations and maintenance of the 60% renewable microgrid. For example, ICE techs currently manage and maintain the existing battery storage located at Pebbly Beach substation. It is likely that, after additional training, future battery storage maintenance would fall under their purview as well.

The ownership model for future PV deployment has not been decided upon. However, if SCE were to own the large solar arrays as part of the 60% renewable microgrid, conversations with SCE have indicated that current personnel would take on solar O&M work. This might include troubleshooting solar inverters, electrical testing of smart devices, and general maintenance of the plant. The number of new technicians will depend on the amount of PV installed. Of course, it is difficult to estimate the resource demand for maintaining these plants at the conceptual stage, however SCE believes that its current staff may be able to take on additional PV maintenance responsibilities.

NV5 has been informed that only one vehicle is currently available for field maintenance. Because the PV arrays are located at a significant distance from Pebbly Beach, new vehicles are likely to be necessary.

The 60% renewable microgrid will require investment in additional training, a new vehicle for maintenance, and additional technicians and specialists. The total number of required new personnel is not yet known.

4.4.8 NREL Techno-Economic Analysis of the Energy Generation Options

NREL performed a techno-economic analysis of various energy generation scenarios using a software tool they developed called REopt. REopt provides concurrent, multiple technology integration and optimization capabilities to help organizations meet their cost savings and energy performance goals. This software platform can optimize a generation portfolio for a given yearly load profile based on a number of constraints such as lowest capital or lifetime cost, minimum emissions, and renewable energy penetration percentage, among others. Results from the earlier phases of the analysis, such as the system sizes for the highest ranked sites and the associated project costs like distribution upgrades, were provided as inputs for the various REopt simulations. Results from the other Repower solutions including the undersea cable and the lower emitting fossil generator replacements were also provided as inputs for this analysis.

The results of the REopt simulations calculated capital cost expenditures and lifecycle energy costs over a 30 year time period for the various renewable energy penetration scenarios and helped provide a comparison to the other generation configurations. The REopt simulations also provided NV5 with the renewable and energy storage aggregate capacities under various renewable penetration scenarios. An example of the multi-step hand-off between the environmental and electrical analyses to the REopt simulation, and back to the final analysis is shown in the following section on a representative 60% renewable microgrid for the island's generation. See Section 6.0 - NREL Phases I & II Summary Report for further details of the REopt study, its methodologies, various simulations that were run, and the results of that analysis.

4.5 60% RENEWABLE MICROGRID

The Feasibility Study team evaluated numerous configurations of renewable microgrids at various penetration levels with myriad considerations pertaining to cost, complexity, schedule to commercial operation, and long-term operations and maintenance. Throughout the duration of the feasibility study, the team maintained focus on the key drivers that initiated this analysis in the first place, and that is to bring the island's power supply into emissions compliance with the South Coast Air Quality Management District for NOx emissions and to pursue a renewable energy based generation mix.

Though there were a myriad of renewable microgrid configurations evaluated, the team focused its final renewable microgrid analysis on one that aligns with the recent California state legislation S.B. 100, which requires the three large investor owned utilities (IOU's) to supply 60% of their energy from renewable sources by 2030. It is important to note that the 60% renewable requirement is to be taken as an average value across the entirety of SCE's service area. It has not yet been determined whether Catalina Island will require a dedicated 60% renewable penetration; however, for the purposes of this study, 60% renewable represents a quantifiable target metric.

To assess the feasibility of constructing and operating a 60% renewable microgrid on Catalina Island, NV5 performed a series of iterative studies in REopt and Synergi Electric. These studies helped determine the amount of renewable power capacity, energy storage power capacity and duration, remaining generation assets, and distribution upgrades that would be needed under this scenario. See Section 6.0 for a detailed description of the REopt scenarios including a detailed explanation of the capital and lifecycle cost estimates.

4.5.1 Project Description

This section provides project specifics on a representative 60% renewable microgrid including example solar PV + BESS sites, standalone BESS sites, and the overall operations considerations for the grid. These sites were selected based on NV5's analysis through siting, environmental, permitting, constructability, and institutional knowledge about the island from SCE. Despite the team's best efforts to develop the model around well-suited sites, the viability for project development at any given location is subject to further analysis and due diligence, and actual energy production may vary in a given year to the benefit or detriment of the overall renewable energy contribution to the generation portfolio. However, the general project overview offers a universal understanding of what it would mean to build and operate a 60% renewable microgrid, regardless of precisely where and how much certain renewable and energy storage systems are built.

Below is a summary of the project sites, technologies, capacity, and energy production. They are grouped as microgrids within the overall island microgrid for simplicity and organizational purposes. This is also an example of hierarchical microgrids as part of the overall island microgrid, or they could also be viewed as co-equal networked microgrids.

Table 4-10 - Overall 60% Renewable Microgrid Summary

Sites	MW DC	MW AC	MWh
Microgrid 1 - Two Harbors Substation	2.392	4	16
Microgrid 2 - USC Wrigley Marine Science Center	1	1	4
Microgrid 3 - El Rancho Escondido Rd	5	3	12
Microgrid 5 - Middle Ranch	7.304	6	24
Microgrid 8 - Pebbly Beach Generating Station	0	7	28

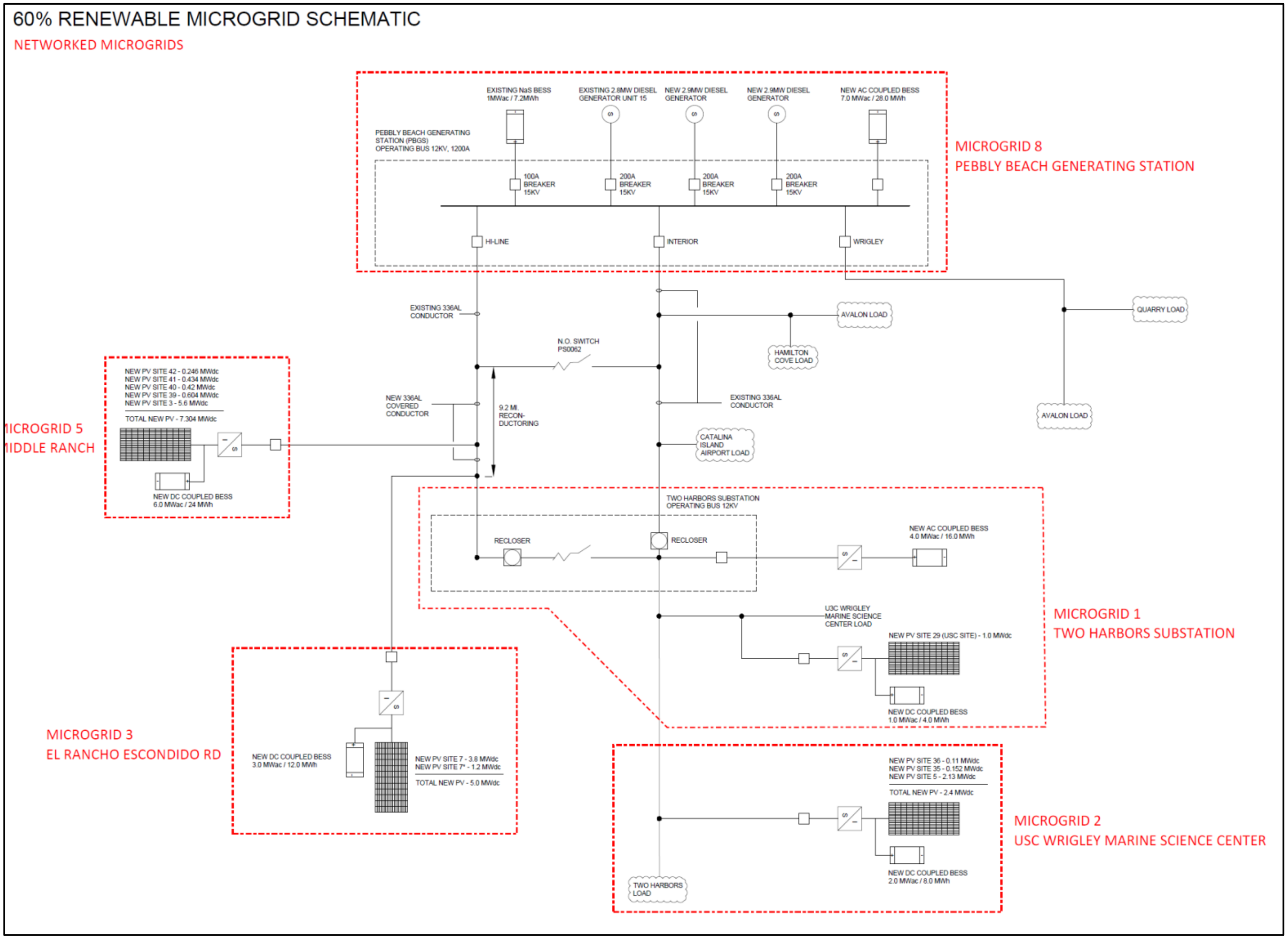


Figure 4-42 - Single Line Diagram for 60% Renewable Networked Microgrids

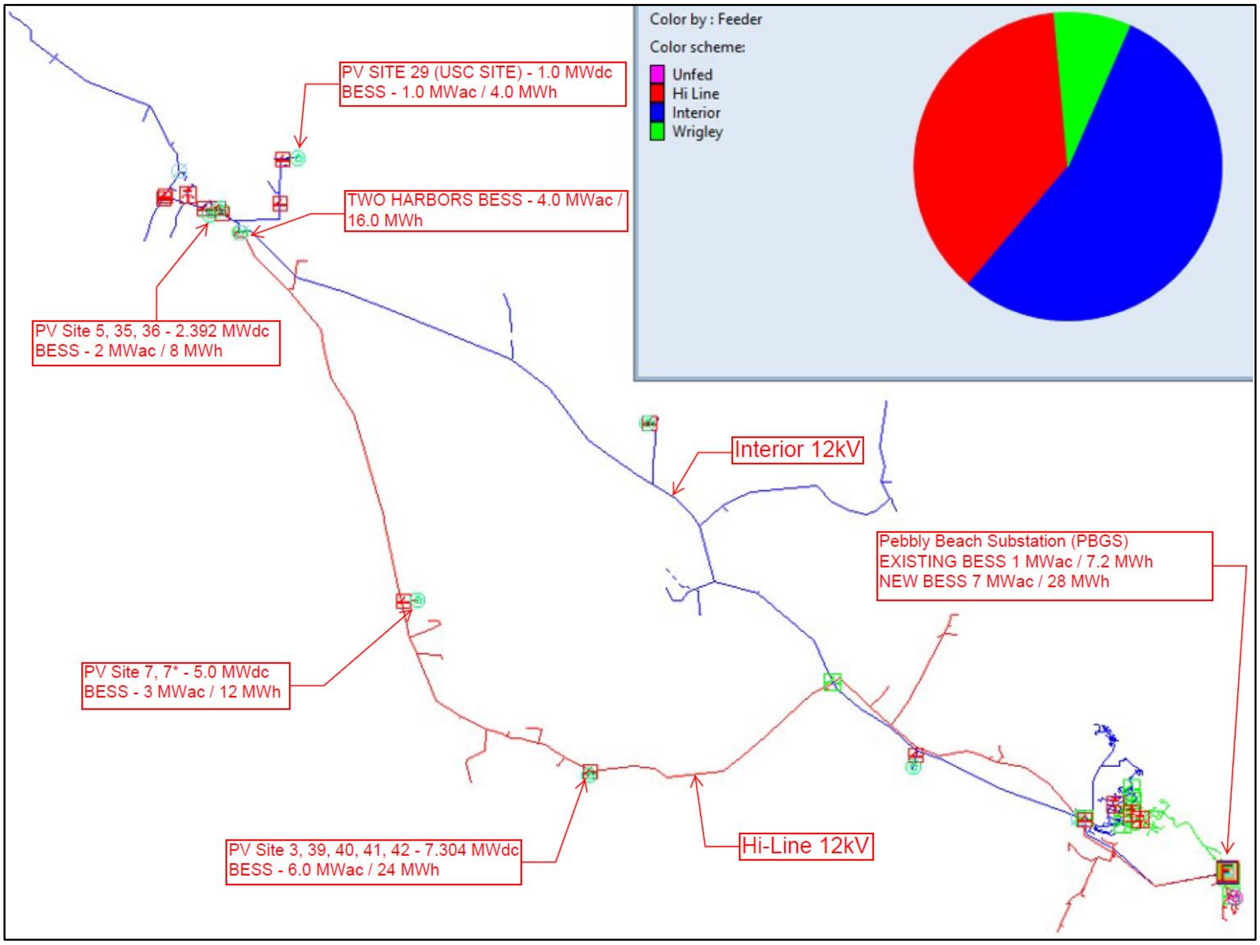


Figure 4-43 - Site Plan for 60% Renewable Microgrid

4.5.2 Microgrid Controller and DERMS

A microgrid controller and DERMS solution for a 60% renewable microgrid would need to manage the operation of many distributed assets and offer the distribution operators a centralized HMI for ease of use. Perhaps the most critical feature is flexibility both in the local microgrid controller, but also with the overall DERMS. It is expected these projects will be built and commissioned in phases, and whichever control solution selected must be nimble enough to accommodate new DER being added down the line.

Asset classes to manage or interface in some fashion:

1. New distributed generation - PV + BESS, standalone BESS, networked microgrids (“hierarchical microgrids”)
2. Existing Emerson Ovation DCS and Allen Bradley controllers to manage existing substation assets PBGS diesel gensets. SCE has indicated that there is a preference to continue using Emerson’s Ovation Distributed Control System. Future renewable generation must be integrated with this existing control system.
3. Large load customers as potential deferrable or Demand Response (DR) customers

4. Existing substation breakers and reclosers (intellirupters) for remote switching/network reconfiguring during changing load/generation or contingency events.

An RTU and HMI would be provided inside the Pebbly Beach Generating Station control room and the software to manage the DERMS system as stated above. A remote HMI should be provided at each DER controller, or the gateway should have sufficient connection ports for technicians to connect a laptop to troubleshoot and upload firmware updates. Many equipment and software vendors will offer firmware updates over the internet, but many electric utilities will typically require an in-person update to mitigate the security risk of an internet connection.

See Section 4.4 for a more in depth review of the key features of a microgrid controller and DERMS, all of which are applicable to the representative 60% renewable microgrid.

4.5.3 Permitting

The example described in this section focuses on a hypothetical 13-acre renewable energy project site on Catalina Island with no specific location. The permitting process for any land based renewable site is expected to follow a consistent approach regardless of whether the Project's components are permitted as one package or segregated into two or more actions. In general, the process begins with Pre-application. Informal consultation with each of the involved permitting agencies is recommended and may involve two or more separate calls or in-person meetings with each agency. The initial agency outreach communication can be a simple email requesting an informal phone call or in-person discussion to present:

1. General description of the project and site
2. Proposed construction methods
3. Anticipated permit needs
4. Existing information and planned focused studies
5. Expected or desired timelines. Following initial informal consultation, the Project would complete the required or suggested focused studies to support the required permit applications and associated environmental review

Once the draft environmental document(s) is in preparation by the lead agency, a second round of consultation with the remaining regulatory agencies should be conducted during preparation of permit application submittals. The second meeting will address previous discussions regarding the Project's development plan, existing conditions information, required application components, and potential mitigation requirements. Once the draft environmental document(s) has been completed and submitted for public review, the permit application packages can be finalized and submitted for formal consideration, although the process can vary from project to project. Permit applications, depending on the agency, can take from four to 12 months to process based on the completeness of the application and information requests by the agency. Additional time may be needed if public comment or participating agencies raise significant issues or challenges. When applications are formally accepted as complete, the local agency prepares a staff report and submits the report for public review or for a hearing. Finally, the permit is issued with specific special conditions or mitigation measures stipulated in the final permit language.

The permit requirements for PV renewable sites are referenced in Table 4-11 below. In addition, a summary of permits and related tasks, timing, duration, and cost is described in Appendix N.

Table 4-11 - Anticipated Planning and Permitting needs for Catalina Island Renewable Energy and Storage Sites

NEPA						PERMITS									
Site	IS-MND	EIR	Cat Excl	EA	EIS	404	401	1600	CESA 2081 (b)	Land-Conditional Use Permit	General Plan/Zoning Amendment	LCP-CDP	NHPA Sec. 106	ESA Sec. 7	Estimated Costs
3	X					X	X	X		X	X	X	X		$233,000 - $333,000*
5	X						X	X		X	X	X			$212,000- $303,000
7	X									X	X	X			$196,000 - $280.000
29	X					X	X	X		X	X	X	X		$201,000 - $288,000
34	X						X	X	X	X	X	X	X	X	$264,000 - $378,000**
35	**X**						**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**$264,000 - $378,000****
36	X											X			$94,000 - $135,000
39	X						X	X		X	X	X			$212,000 - $303,000***
40	X						X	X		X	X	X			$212,000 - $303,000***
41	X						X	X		X	X	X			$212,000 - $303,000***
42	X						X	X		X	X	X			$212,000 - $303,000***
43	X						X	X		X	X	X			$212,000 - $303,000***
44	X					X	X	X		X	X	X	X		$233,000-$333,000

*Low end cost assumes maximum avoidance of resources. High end cost assumes sensitive resources cannot be avoided and more complicated environmental review and permitting required.

** Combining sites outside of Avalon Substation into one application recommended. Combined application is approximately 25 % more than single application.

*** Combining Middle Ranch sites into one application recommended. Combined application is approximately 50 % more than single application.

4.5.4 Recommended Phasing and Implementation Plan

In order to achieve commercial operation of the proposed or similar 60% renewable microgrid, a phasing plan should be implemented that breaks the overall project deployment into manageable procurement and commissioning processes, and allows for lessons learned to be applied towards subsequent phases to enable continuous process improvement and lower costs. This section presents an example phasing plan to achieve the proposed 60% renewable microgrid and offers key considerations on "make-ready" programs for grid upgrades to enable higher renewables penetrations over time. A summary of the phasing plan is provided in Table 4-12 with a detailed description of each phase thereafter.

Table 4-12 - Phasing Plan Summary

Phase	Description	Start	End	Duration
1	• Microgrid 1 – Two Harbors Substation BESS • Microgrid 2 – USC Wrigley Marine Center • Microgrid 8 – PBGS Energy Storage	2020 Q4	2023 Q4	3.25 yrs
2	• Infrastructure Upgrades (reconductor, telecom) • GIS/network model refinement • DERMS	2020 Q4	2025 Q4	5.25 yrs
3	• Microgrid 5 – Middle Ranch	2023 Q1	2025 Q4	3 yrs
4	• Microgrid 3 – El Rancho Escondido Rd	2026 Q1	2028 Q4	3 yrs

Within each phase, the development of a microgrid project or multiple microgrid projects could be broken into separate procurement processes. There is a tradeoff between pricing efficiencies by contractors and vendors for bulk pricing during an "all-at-once" procurement strategy, and the lower prices that SCE can achieve as the installed costs for solar and battery storage continue to fall year after year. Each solar and battery storage development cycle is estimated as follows:

1. Scoping and Procurement – 3 months
2. Engineering Design – 9 months
3. Permitting – 12 months
4. Construction – 9 months
5. Commissioning – 1 month

4.5.4.1 Phase 1

The first phase is an opportunity to take advantage of the smaller renewable project sites with little to no site control issues that do not require any major infrastructure upgrades to reach commercial operation. SCE has conveyed that USC is already pursuing the development of some onsite solar, so that customer could be a willing partner on developing this project in a mutually beneficial manner, and perhaps with SCE's ultimate ownership and control of the system. The Two Harbors switching station is SCE controlled land, and there is a near-term need for voltage support in that vicinity. Pebbly Beach likewise is already controlled by SCE and deploying a second BESS at this site would offer immediate improvements to the fuel consumption and emissions profile of all the diesel gensets. Lastly, there would invaluable learnings from the deployment and operation of these relatively smaller renewable project sites in the case of Microgrids 1 and 2 that would provide benefits to Microgrids 3 and 5 after the fact.

Microgrids 1, 2, and 8 do not need to be procured all at once. By staggering the procurements, small lessons learned can be applied to each milestone along the way including improved scope of work during procurement, better engineering during design, and more seamless permitting, among others. Due to the environmental sensitivity of the entire island, as well as the fire risk concerns of largescale battery storage, there is a significant benefit to SCE figuring out the permitting process and familiarizing permitting authorities with the projects in a staggered manner. There might still be an opportunity to achieve construction and equipment procurement cost efficiencies if the engineering packages can be bid out simultaneously.

4.5.4.2 Phase 2

Activities in Phase 2 include the interconnection “make-ready” tasks needed to support a high renewable penetration island microgrid. This is recommended to start when Phase 1 begins, because this phase must be complete in order to interconnect the larger renewable projects along the Hi-Line circuit in Microgrid 3 and 5. Further study is needed to validate the proposed sites comprising the 60% renewable scenario, but this can be accomplished relatively quickly. Negotiating for site control may be a lengthy process. When site control is established, SCE should begin detailed system impact studies followed by facilities studies to determine the detailed scope of any reconductoring and pole replacements that the larger projects may require. After that is completed, the engineering, procurement, and construction for the distribution upgrades should commence and should include for telecom upgrades. While this is happening, a dedicated team of GIS analysts and designers should be working on updating the GIS. The SCE distribution group should begin the evaluation and procurement process of multiple control vendors, including consideration of a DERMS or mesh control system for the growing distributed renewable microgrid.

4.5.4.3 Phase 3

The Middle Ranch Microgrid as currently sized will need to be curtailed until the Hi-Line circuit is reconductored following a series of detailed impact and facilities studies. This is also the largest solar project site and will require a higher level of control for SCE to manage these assets from a remote location. It has the most to benefit from waiting to gain lessons learned from earlier and smaller renewable and battery projects on the island. For these reasons, it is recommended to hold off on initiating Phase 3 until Phase 1 is complete and Phase 2’s infrastructure upgrades are underway with a clear schedule to its completion prior to Phase 3’s completion.

4.5.4.4 Phase 4

The last phase comprises the build-out of Microgrid 5. It is reserved for last because of the scope of the reconductoring needed to interconnect these assets. Phase 4 could be bid out for engineering and issued for permits simultaneous with Phase 3, however the span of additional reconductoring is great enough that it may not be able to reach commercial operation for at least a year after Microgrid 3. It is a significantly large project that would benefit from lessons learned in Phase 3, and there may continue to be cost declines in solar and battery storage that could reduce the overall project costs. Therefore Microgrid 5 is placed last in the overall phasing plan.

5.0 SUBMARINE POWER CABLE

This segment of the feasibility study examines the potential for installing and operating a 33kV submarine electrical power cable in order to provide energy to Catalina Island. The review has taken into consideration the preferred and previously surveyed 35.5-mile undersea cable routing as well as the potential land conversion locations and terminal upgrades required at each generating station. The preferred route is based upon the previous alternative routing study and draft Project Execution Plan (PEP) conducted by Padre Associates, Inc. in 2004 and 2005, as well as the comprehensive land and seafloor surveys conducted by Fugro Pelagos circa 2004 (formerly Thales GeoSolutions Pacific). The 35.5-mile survey distance is inclusive of the end sections at either landing from the seafloor termination points to the onshore connection vaults. No additional routing options are included in this feasibility review, as they have been deemed non-viable, or geo-physically and biologically constrained, at this time.

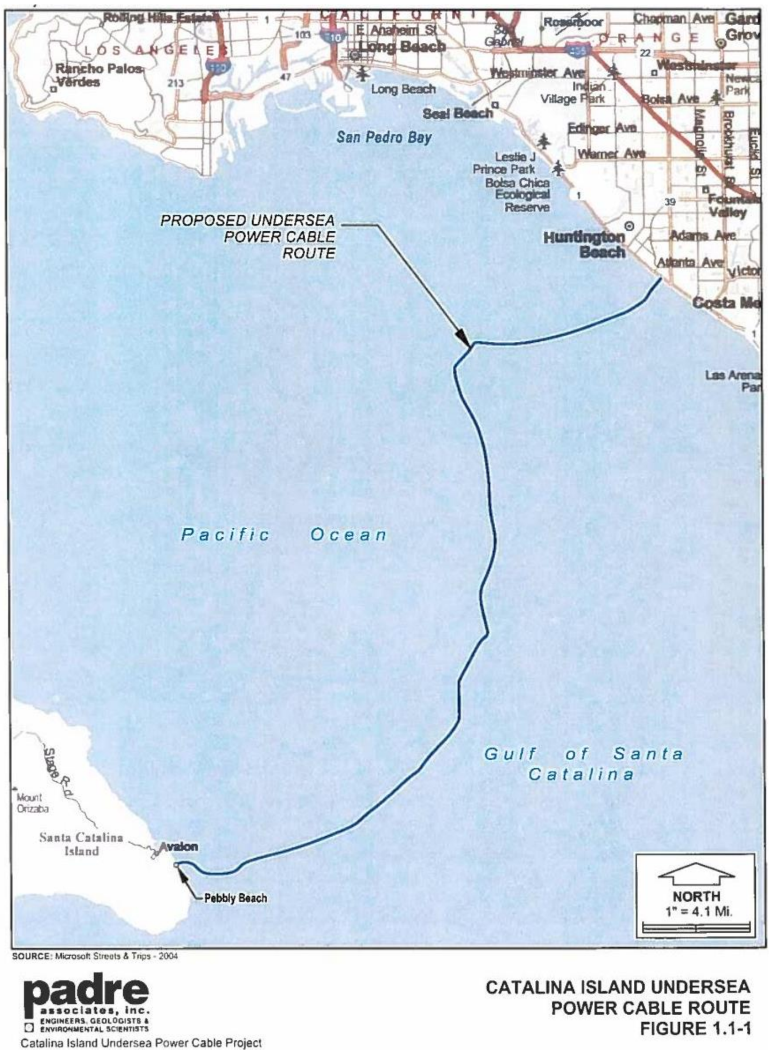


Figure 5-1 - Submarine Cable Route (Source: Padre Draft PEP Report 2005)

5.1 UNDERSEA CABLE INTRODUCTION

Originally in 2003, nine (9) potential medium voltage submarine cable routes were identified by Fugro Pelagos between SCE's Pebbly Beach Generating Station (PBGS) on Santa Catalina Island and the mainland, with five associated existing mainland transmission infrastructure landings. After a detailed review and background check of the available mainland substations and switchyards (Lafayette, Hamilton, Wave, Pico, and Broadway), it was determined that Huntington Beach Generating Station (HBGS) was the most viable alternative, even though no available positions currently exist within its 66kV switchyard. The primary availability of HBGS as the only mainland interface thus limited the submarine cable routing to two alternatives, respectively Fugro Pelagos report options 1A and 1B. The ultimate undersea cable route chosen, option 1B (based on Fugro Pelagos seafloor survey circa 2004), was definitively chosen to avoid crossing steep submarine canyons with fault scarps and high turbidity, to mitigate against hard bottom interfacing, and to minimize onshore construction impacts and costs through use of an existing abandoned 24-inch diameter, 7,400 foot long Cenco pipeline. Cost, constructability, access, long-term maintenance, environmental constraints, permitting, oceanographic considerations, and available terminal landings to existing transmission infrastructure were all contributing factors to the final route selection (route 1B). This 35.5-mile alignment (route 1B) avoids major undersea canyons and has a longer shallow shelf transition, but also has a narrowly constrained alignment due to existing offshore oil developments and steep upper submarine canyon contours.

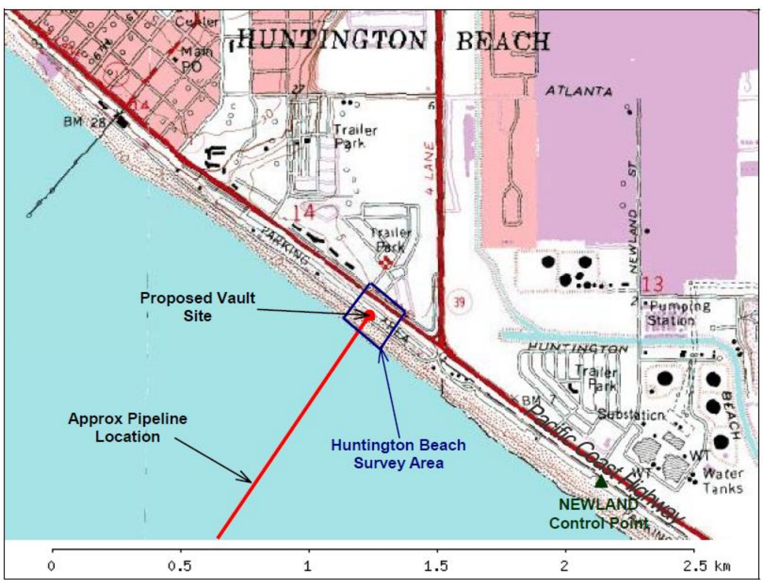


Figure 5-2 - Huntington Beach 24-Inch Pipeline Location (Source: Fugro Pelagos Report 2004a)

The preferred route starts from the California mainland at HBGS and traverses through the Pacific Ocean floor to Santa Catalina Island's PBGS. On the mainland side, the cable at Huntington Beach is proposed to be pulled through the existing abandoned 24-inch Cenco concrete pipeline to a future conversion vault and then travel through underground (UG) trench and overhead (OH) cable pole alignments until reaching HBGS. The abandoned 24-inch pipe extends roughly 7,400 feet off the coast into the Pacific Ocean up to a depth of approximately 50 feet in the water. In the event that the 24-inch Cenco pipeline is determined to be non-usable, an alternative method and route using a Horizontal Directional Drill (HDD) boring would need to be considered from HBGS to a location roughly 5,000 feet offshore and to a depth of approximately 25 to 30 feet in the Pacific Ocean. Use of a new

HDD from HBGS to the Pacific Ocean alignment would eliminate the need for using the existing abandoned 24-inch Cenco concrete pipeline or any vaults and UG trenching outside of the switchyard and substation. Undersea cabling located in the areas of sedimentary habitat to an isobath of approximately 400 feet (i.e. close to the mainland) shall be direct buried to a minimum depth of 3 feet with a target depth of 6 feet; hard bottom conditions will be avoided wherever possible.

The existing switchyard at HBGS currently has no available switch positions in which to land the interconnection. An expansion to the east of the HBGS facility will be required in order to install the additional switches, step down transformer, and associated equipment necessary to connect to the existing transmission system.

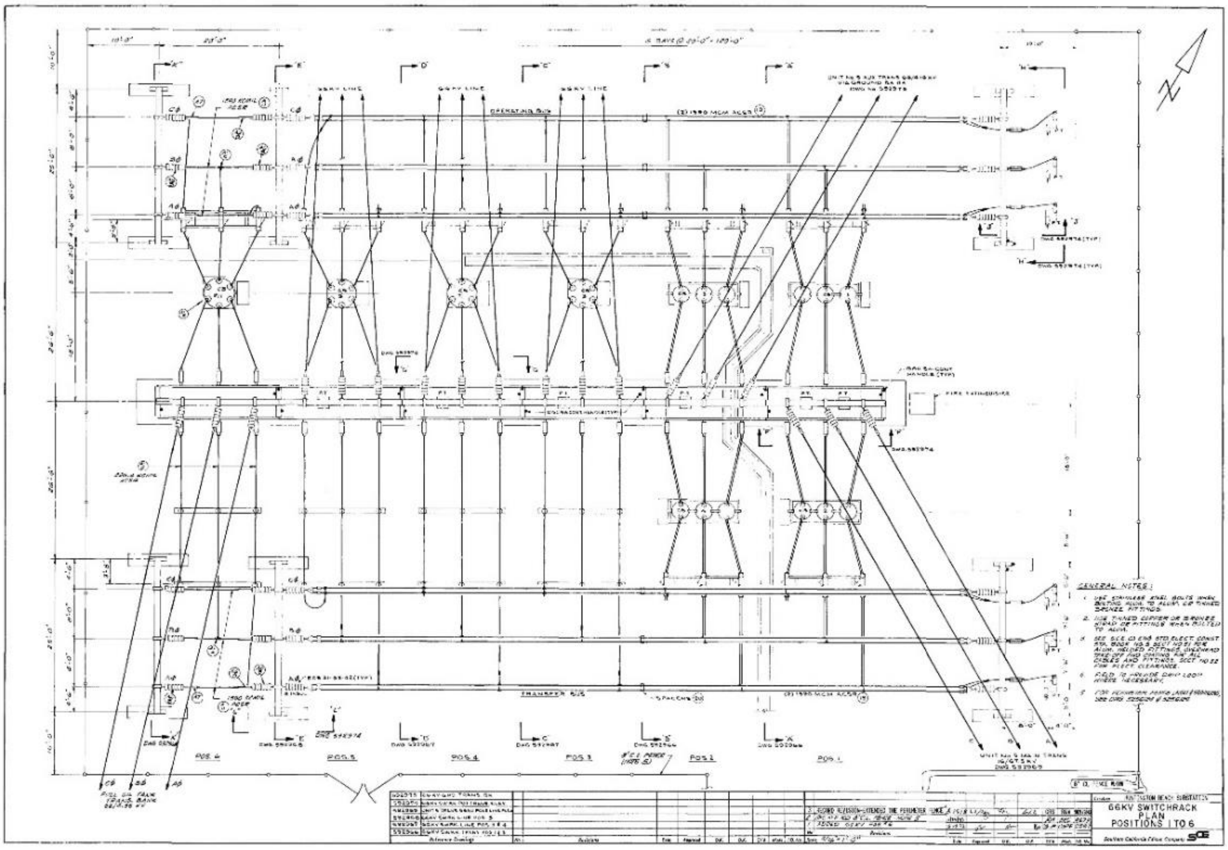


Figure 5-3 - Huntington Beach 66kV Switchyard – Existing Layout / No Available Switch Positions

To landfall the undersea electrical power cable from Huntington Beach's existing abandoned 24-inch Cenco concrete pipeline to the HBGS will require the following additions and upgrades:

- Modifications to the HBGS's existing 66kV switchyard.
- Remediation work and residual material flushing of the abandoned subsurface pipeline.
- Installation of two (2) new subsurface vaults on either side of Pacific Coast Highway (PCH) to intersect the pipeline.
- Installation of UG trenching for the electrical interconnection from the easterly vault at PCH to Beach Street, and then OH to HBGS via the existing power pole alignment.

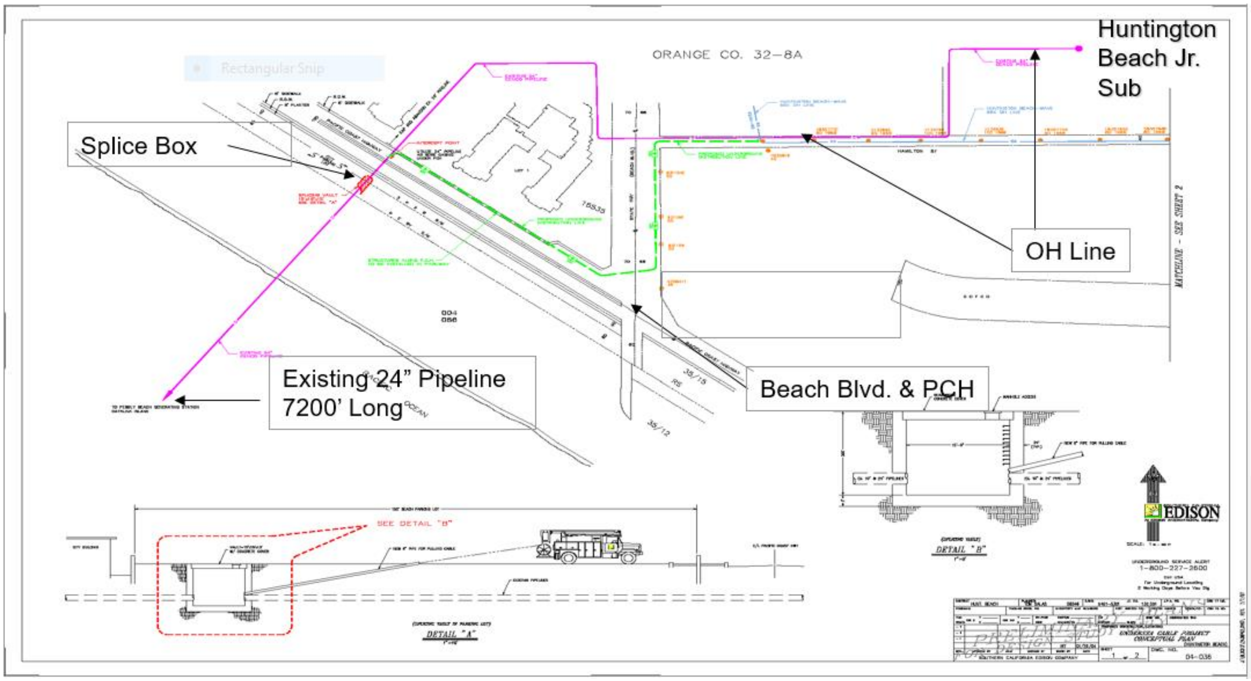


Figure 5-4 - Huntington Beach to HBGS UG and OH Routing

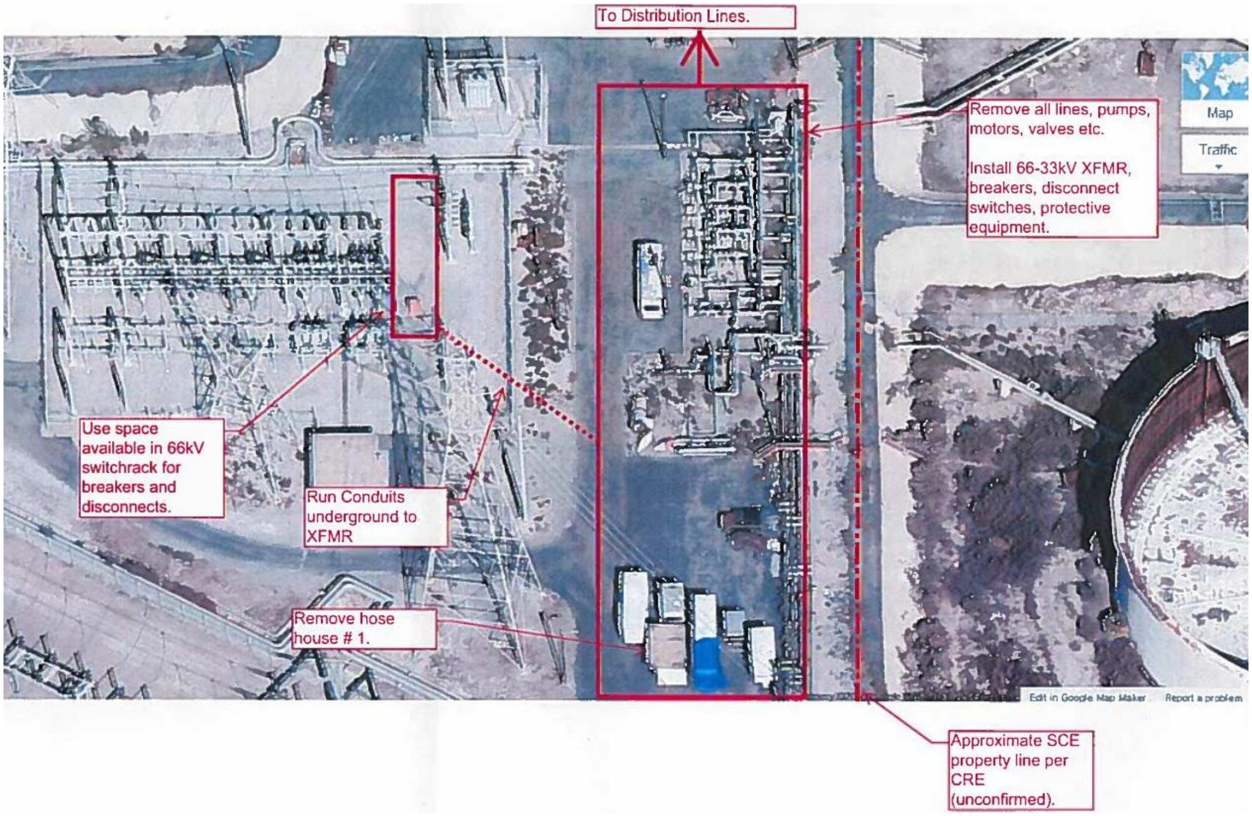


Figure 5-5 - Huntington Beach 66-33kV Substation Conceptual Layout

On the island side at PBGS, it is proposed to pull the undersea cable approximately 800 feet through a new 10-inch diameter HDD borehole from the seafloor bed at a depth of approximately 75 to 80 feet to the area of the station currently occupied by the micro turbines. An expansion of the Pebbly Beach Generating Station will also be required to connect the new submarine cable line into the existing system.

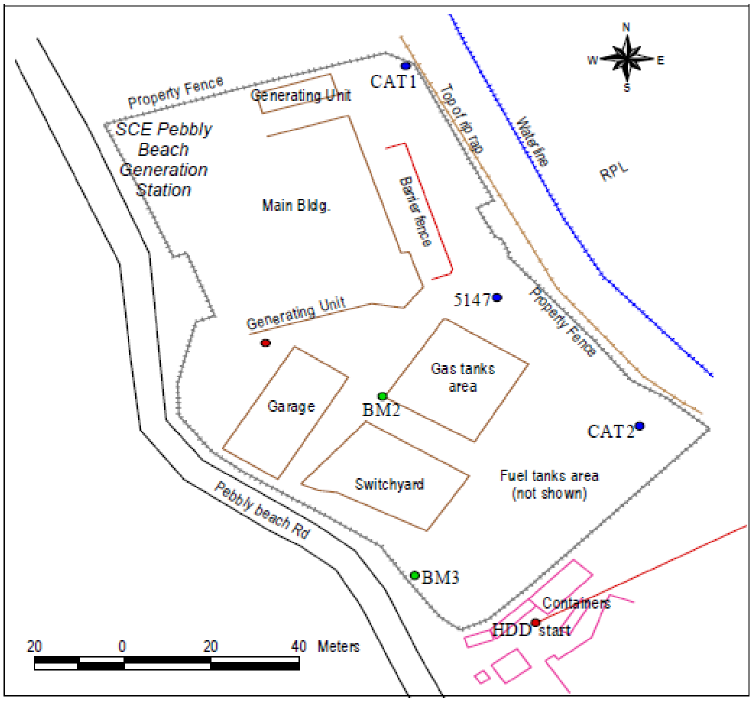


Figure 5-6 - Pebbly Beach Generating Station HDD (Source: Fugro Pelagos Report 2004a)

To accommodate the undersea electrical power cable interconnection on the Catalina Island side, upgrades shall include an HDD from the current micro turbine area into the submarine alignment, construction of an UG vault in the general vicinity of the HDD sending pit, and modifications to the PBGS to allow for the intertie of the power cable.

The undersea power cable installation shall contemplate a direct burial of not less than 3 feet (with a target depth of 6 feet) to the shelf break through the use of a Jet Plow or equivalent burial equipment and shall take into consideration all relevant risk assessments and engineering feasibility studies necessary to safely and properly execute the work. In deeper waters, the cable will most likely have to be installed directed onto ocean floor and protected with conductor shielding casings or layers of steel armoring. The actual physical determination of direct cable burial versus laying the undersea cable on the ocean floor will fall under the means and methods of the General Contractor awarded this scope of work. Exact methods will be a functional result of the Contractor’s required risk assessment in conjunction with the type of ocean floor conditions, along with all associated considerations for cost and installation technique.

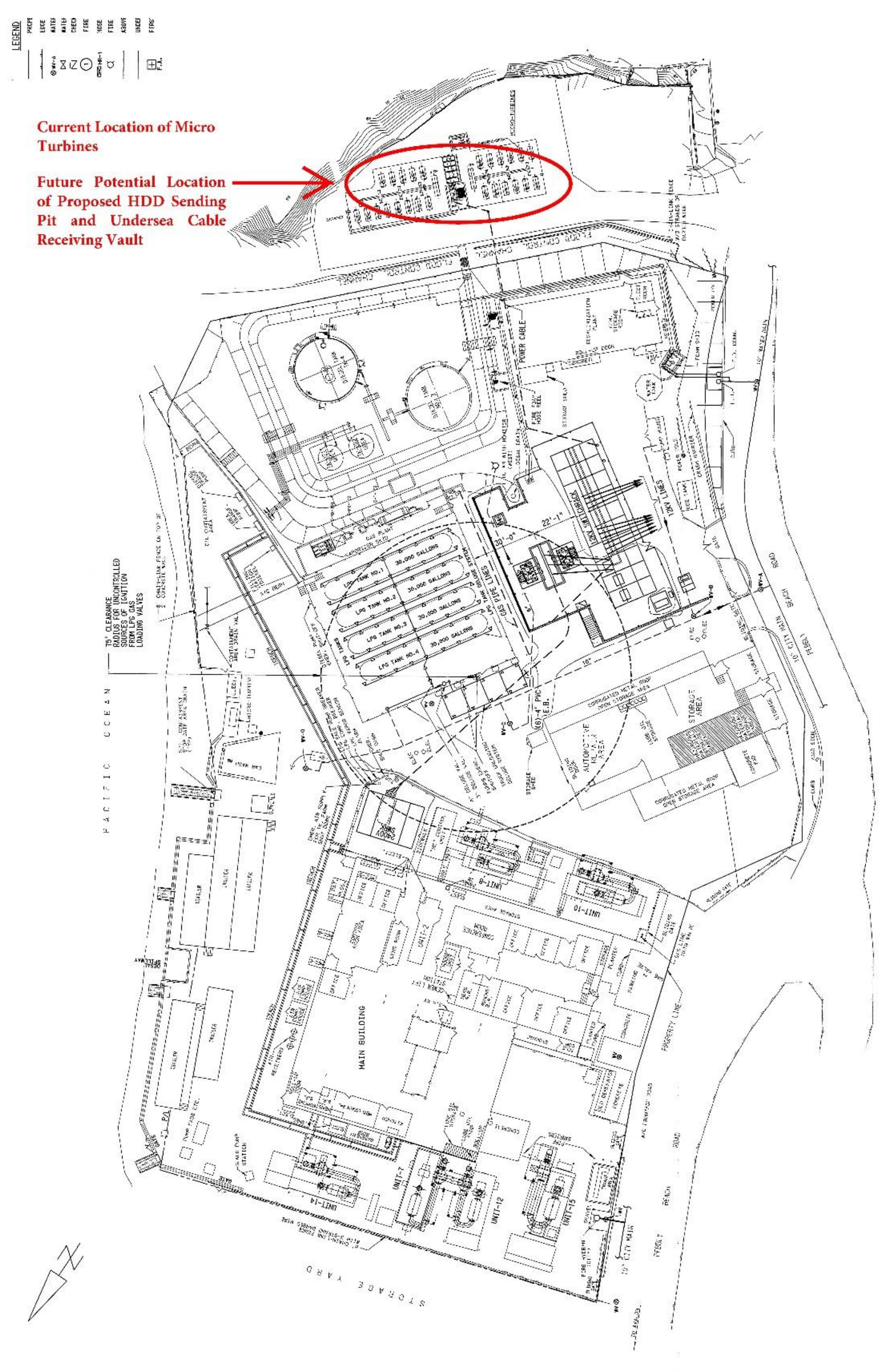
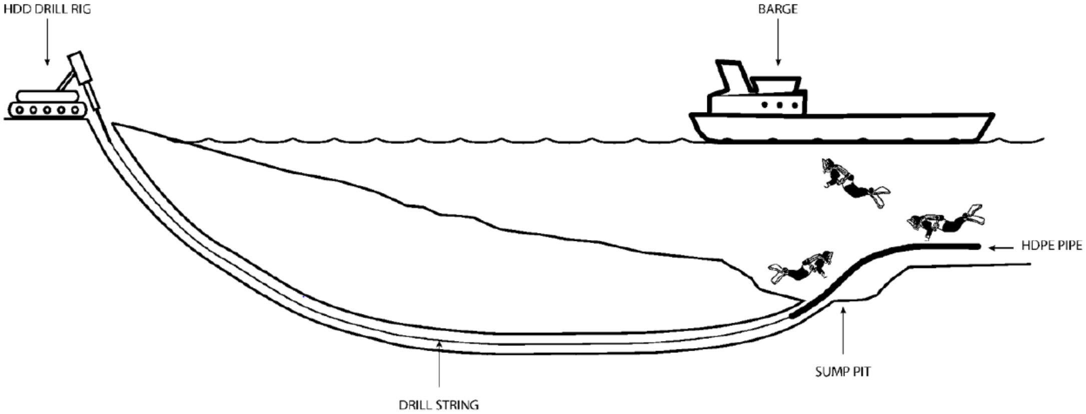


Figure 5-7 - Pebbly Beach Generating Station Layout

5.2 SUBMARINE CABLE OPTION

The undersea power link itself will be a single circuit three core (triplex), 33kV armored submarine cable, 400kcmil per phase. The cable will be lain across the seabed using conventional Jet Plow equipment and installation methods. At the PBGS end of the cable route, an HDD boring will be required from the current micro-turbine yard location, whereby the shore crossing will be in an easterly direction to a depth of approximately 75 feet.



Source: Pacific Gas and Electric Company, 2012

Figure 5-8 - Pebbly Beach Generating Station HDD Seabed Shore Crossing to Coastal Landing

On the HBGS mainland end of the cable route, an abandoned Cenco 24-inch diameter concrete oil pipeline located at Huntington Beach, which extends approximately 7,400 feet offshore to a depth of roughly 50 feet, will be utilized, unless deemed unavailable. If the 24-inch pipeline becomes unavailable, an additional HDD will have to be considered.

Figure 5-9 - Alternative HDD Routing from HBGS

Cables will transition from the triplex submarine cable to traditional single core land cable after they have transitioned on land at each end of the route. The cables will transition within a splicing vault where the armor will be anchored solidly to the vault floor. This will prevent any movement of the cable that could be severe enough to damage the transition splice. The transition splices will be installed after the anchor in order to extend the cable inland to its final termination point. Once the cable exits the splicing vault, the land cable will continue to the generating stations using concrete encased conduit banks (duct bank) to the terminal points in each station. The duct banks will include a package of 5-inch PVC conduits for the land cable along with any additional 4-inch and 2-inch general use conduits. Concrete encased bends (sweeps) will be utilized to connect the conduit system to the termination structures or racks at each end.

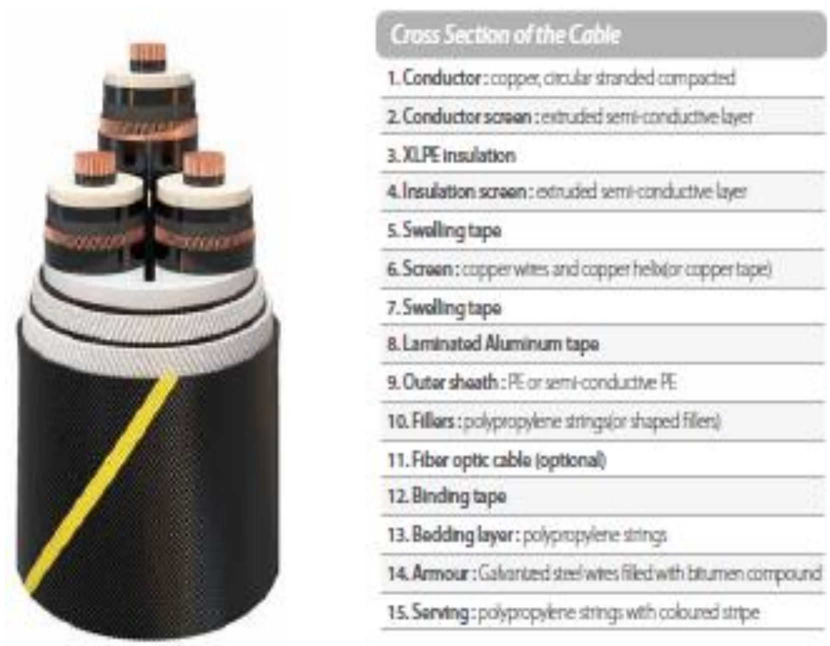


Figure 5-10 - Three-Core Medium Voltage Submarine Cable Example (LS)

To accommodate the new termination equipment, expansions at each generating station will be required. The HBGS has an accessible 66kV switchyard, but there are no available switch positions to support the required tie-in, so the switchyard would need to be expanded to the east in order to allow for the new system and equipment upgrades (which would then reclassify the switchyard as a substation). New switch positions will be installed on the east side of the existing switch position and then conduit will be run to a new 66-33kV substation. The new substation will include the power cable, 250A fuse bypass switches, 66kv to 33kv 10MVA OTC step down transformers, gang operated 1,200A 38kV rated disconnects, and medium voltage breakers.

Expansion at PBGS will also require system and equipment upgrades to accommodate the new connection. A new 33-12kV step-down interface installation will be required to accommodate the new cable termination, along with additional station equipment. The additional equipment within the PBGS substation would include the power cable, 33kv to 12kv 10MVA OTC step down transformers, 15.5kV rated disconnects, and medium voltage breakers. It is also envisioned that an automatic transfer switch (ATS) will be installed so that, in case of an undersea cable power outage or failure, back-up power will be initiated via one of the existing or future PBGS generators.

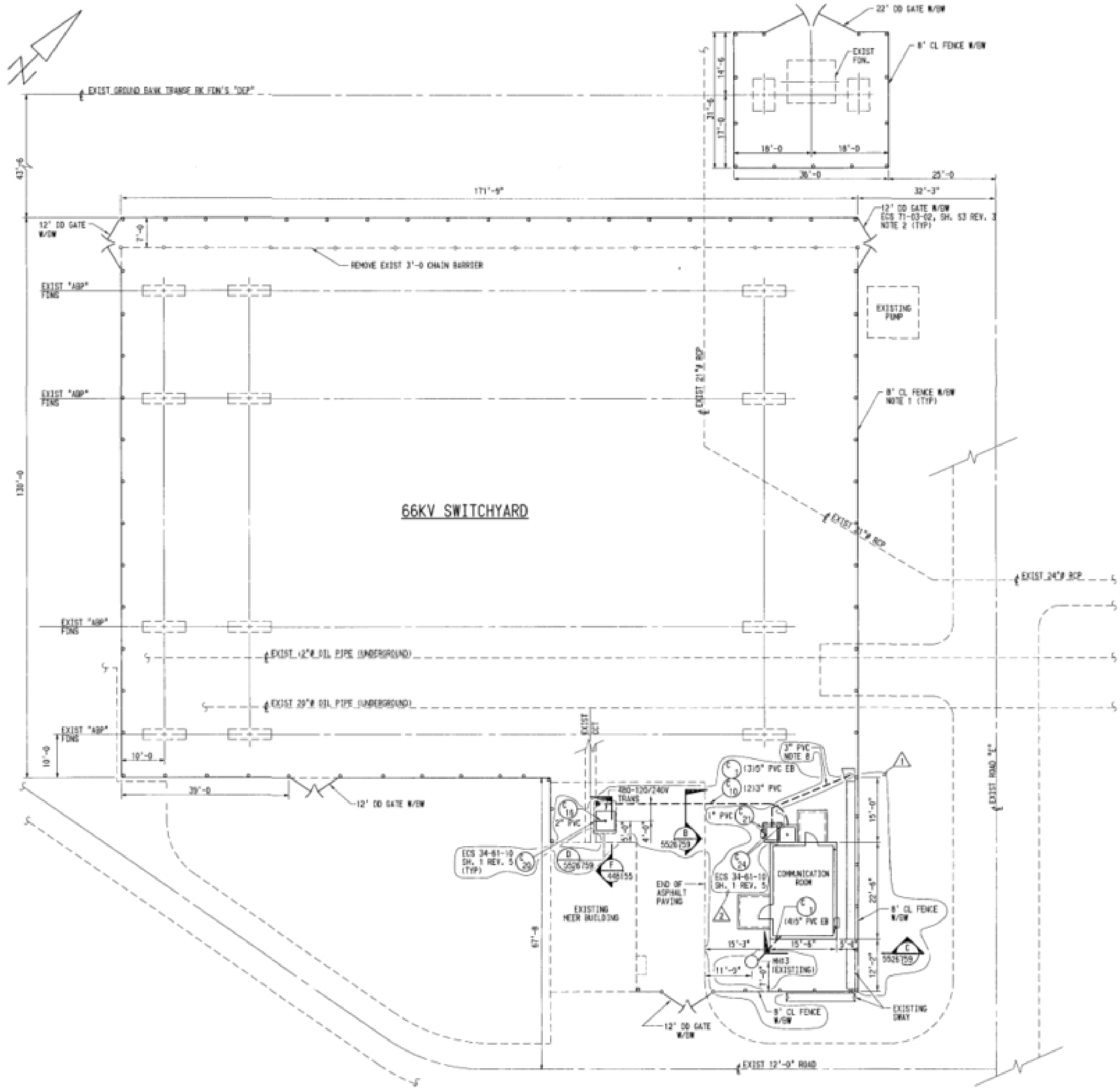


Figure 5-11 - Huntington Beach Switchyard General Layout

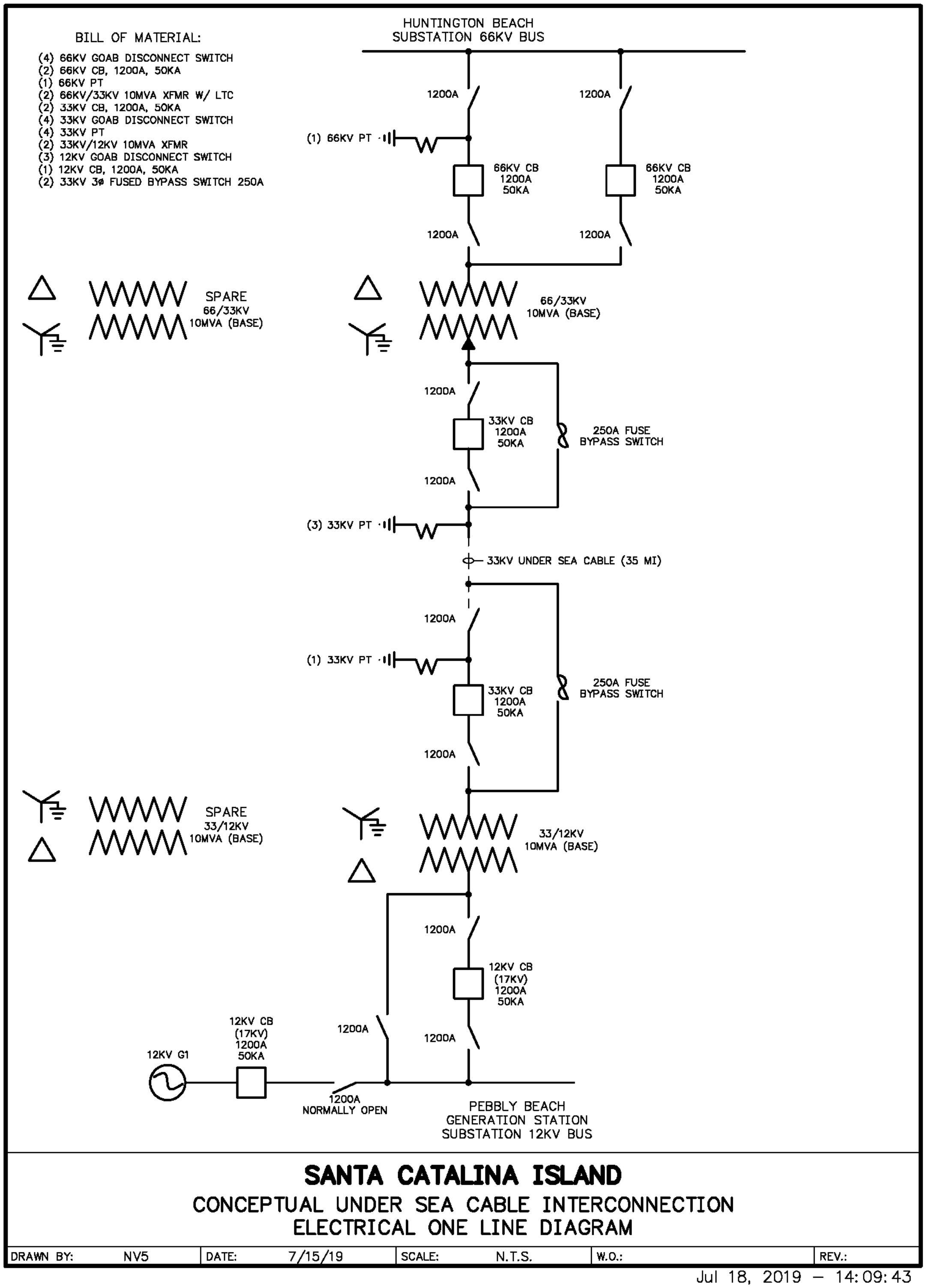


Figure 5-12 – Proposed Undersea Cable Electrical Single Line Diagram (SLD)

5.3 EXECUTION PLAN

The most extensive portion of work for this project will be the engineering, procurement, and construction (EPC) of the submarine power cable. This execution plan looks primarily at the submarine power cable scope of work and does not dive deeply into the substation equipment. It is considered that the survey, geotechnical, permitting, and engineering activities for the substation equipment will all be done simultaneously and by the same party. The equipment and construction portion of the substation equipment will be able to be performed during the long lead-time period that the cable procurement, manufacturing, supply, installation, and commissioning will have on an aggregate level. In general, the overall description of the project will need to contain comprehensive narrative for all work plans and installation method statements, equipment specifications, manpower / resource loaded scheduling, and integrated work plans with all associated safe work procedures and risk assessments. The final Project Execution Plan (PEP) work description should be broken out into the following categories:

- Huntington Beach Generating Station, Overhead, and Underground Improvements.
- Existing Marine Terminal Pipeline Retrofit, Material Flush, and Undersea Cable Installation.
- Pacific Ocean / Gulf of Santa Catalina Undersea Electrical Power Cable Installation.
- Pebbly Beach Generating Station HDD and Undersea Cable Installation.
- Pebbly Beach Generating Station and Underground Improvements.

5.3.1 Preliminary Permit Application

The longest duration task for this work is obtaining the permits necessary for construction. Some permits can take over a year to obtain and as such, preliminary applications should be submitted as soon as possible. In order to submit these applications, a preliminary description of the project and preliminary construction means and methods will need to be drafted and reviewed. The description of work and construction means and methods will need to be thorough enough that the permitting agency understands what and how the project is planned to be executed, but not so detailed that any construction methods may be eliminated from being used.

An environmental impact avoidance and mitigation plan should also be setup as part of the preliminary permit application. The plan should include general concepts and methods that may be used to avoid any impacts that construction activities may cause, along with any mitigation requirements that are needed due to contamination of soils. Preliminary survey and geotechnical investigation will be required to create these plans and draft the preliminary permit applications. The geotechnical investigation will be crucial in identifying if any existing contaminants may be present that could be disturbed by construction activities. Permitting agencies will have a list of required sampling that will need to be completed prior to permit acceptance. Additional information regarding the regulatory strategy, permit requirements and key tasks are contained in Appendix N.

5.3.2 Preliminary Survey and Geotechnical Sampling

The preliminary survey will consist of a current bathymetric survey and a land topographic survey for the entire route. The updated marine survey will be vital to confirming the construction means and methods for the submarine cable installation as well as determining and confirming the feasibility of the cable installation. Water depth and recent / real-time seabed topography can drastically affect the vessel and installation equipment required to install the submarine cable and will need to be known prior to selection of a contractor in order to provide sufficient information to be bid upon. The land survey will consist of traditional surveying methods. The site will be staked and then surveyed by licensed surveyors to create survey grade base maps. The base maps will be used to confirm expansion locations at each substation site along with vault locations, HDD entry and exit points, as well as the duct bank routing.

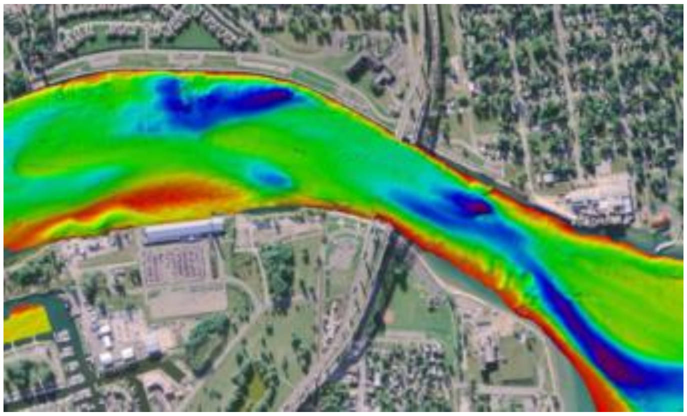


Figure 5-13 - Bathymetric Survey from USGS

The geotechnical sampling will be required for environmental permits and to determine how well the cable will “silt-in”, or how well the submarine cable will settle down into the seabed. This silt-in will be crucial for external protection of the cable from anchor strikes and other foreign objects. If the soil is too hard to allow silt-in, other methods will be required to protect the cable during its 40-year life. The sampling will consist of vibratory sampling with thin walled hollow tube samplers at around one sample every few thousand feet along the route. Samples will also be taken to either side of the cable route periodically to confirm continuity of tested conditions and help mitigate any veins of soil misleading contractors during the proposal process. Samples for all land equipment and thermal resistivity measurements will be collected along the route.

Figure 5-14 - Subsea Soil Sampling (EGS Survey)

Once the sampling and survey are complete, both pieces of information will be compiled into a sub-bottom profile along the cable route (route 1B) and be used to finalize the cable design and preferred alignment. A geotechnical report will also be required to provide detailed review of the sampled findings and make conclusions / recommendations for permits and classification of soils for the installation contractors. This document will be vital with submission of permits for the project. Classification of soils and identification of key pollutants or minerals during this process will help determine if the cable will be permitted to be installed or not by the regulatory committees. The thermal resistivity measurements will be important during the engineering and procurement portions of the project to confirm cable design and capacity.

5.3.3 Pre-Engineering

Pre-Engineering will be completed to finalize the permitting documents needed along with any procurement documents for equipment and construction contractors. Typically, the design will be taken to an Issue for Bid (IFB), or 90% design, level of completeness and then passed off to the construction contractor to be finalized based on their equipment and construction crews. The design will need to be completed by the contractor due to the variability of each contractor's equipment, construction means and methods, and manufacturing methodology. If the engineering is completed prior to a bidder being selected, changes in the design may occur and cause delays once the contractor is selected and bid is awarded.

The preliminary design will include a plan and profile view of the cable route based on the sub-bottom survey and land survey showing an approximate cable route. The plan and profile drawings on land should be to industry standard scale and detail for land cable installation projects while the submarine cable scale will be increased to reduce the number of sheets required for the subsea portion of the route. Transition locations and preliminary anchoring, splicing, and terminating locations will be identified. The equipment at each location will be included to denote anticipated work areas for the contractor as well as allow the contractor to request changes early on in the engineering process.

The drawings will also include a limit of disturbance (LoD) drawing and typical construction sections and details to be used for permit applications and to denote the expected construction methods that the contractors should attempt to meet during the bid process. The LoD drawing will be based on the plan view drawings and will include demarcation of different types of disturbance caused by direct and indirect impacts to the surround area. These impacts will need to be addressed in the environment impact mitigation plan as part of the permitting process.

5.3.4 Permitting

Some permits can take over a year to receive from their respective agencies, and as such, are recommended to be applied for as early in the process as possible. Once the preliminary design for the submarine cable route has been completed, these permit applications can be submitted for preliminary approval. This preliminary approval will allow the cable installation contractor to reduce the amount of time necessary to receive the permits for the work and allow all bidders to know, prior to permit final approval, if there are any installation methods or construction areas that may not be allowed, or be deemed off limits, by the permit agency.

In order to file for pre-approval with the permitting agencies, a set of preliminary drawings identifying anticipated construction methods and the construction route with limits of disturbance anticipated by the construction methods, an anticipated work plan, and an anticipated environmental mitigation plan will need to be developed. These documents will be based on the preliminary survey and geotechnical sampling performed earlier in the project and will require some advanced engineering to be done on the project. The permit applications will then be prepared for each respective permit and information will be submitted based on the preliminary work performed.

Once the application is complete, permitting documentation can be submitted to the respective permitting agencies for review. This review will look for application completeness, as well as any concerns the agencies might have with the preliminary design and impacts. The design can then be adjusted accordingly based on these preliminary comments and a final application can be submitted for pre-approval. These pre-approved permits will then be provided to the construction contractors to be completed during detailed engineering.

Per the previously performed SCE desktop study, Regulatory Agency meetings, and the Padre and Associates draft PEP documentation, the following agencies and permits are anticipated for this project as detailed in Table 5-1.

Table 5-1 - Agency Review and Permitting (Source: Padre Draft PEP Report 2005)

Agency	Project Role / Permit	Regulated Activity
FEDERAL AGENCIES		
U.S. Army Corps of Engineers	Lead NEPA agency – Sections 404 and 10 permits	Discharge of dredge or fill material into the U.S during construction. Structures or work within the waters of the U.S.
U.S. Fish and Wildlife Services	Resource consulting agency/ Section 7 Endangered Species Act	Impacts to listed species or species proposed for listing (onshore plants and animals, marine birds).
NOAA Fisheries (National Marine Fisheries Service)	Interagency Consultation under ESA, MMPA and Essential	Impacts to listed species or species proposed for listing (marine mammals [except otters], white abalone, and fish). Caulerpa survey and reporting. Essential Fish Habitat assessment.
U.S. Coast Guard	Navigational consulting agency, Notice to Mariners.	Activities that might affect navigable waters.
STATE AGENCIES		
State Lands Commission	Lead CEQA agency/pipeline, conduit, and cable corridor lease (submerged lands).	Assessment of impacts and issuance of lease for submerged lands.
Coastal Commission	Coastal Development Permit (offshore areas within the coastal zone and onshore areas within the coastal zone at Pebbly Beach) and onshore appeal of Local CDP.	Consistency determination and CDSP issuance for offshore activities within the coastal zone.
Regional Water Quality Control Board (RWQCB)	Section 401 certification (associated with Corps permit) and discharge permit for drill cuttings / fluids.	Discharge of project-related effluents and approval of drilling fluids.
State Historic Preservation Officer	Section 106 review and compliance.	Consultation associated with shipwrecks or artifacts.
Department of Fish & Game	Consulting resource agency for State listed species and Caulerpa taxifolia regulations.	Impacts to listed species or species proposed for listing. Caulerpa survey and reporting (coordinated with NMFS).
LOCAL AGENCIES		
City of Huntington Beach	Coastal Development Permit (onshore mainland).	Onshore improvements.

South Coast Air Quality Management District	Consulting resource agency for air emissions.	Emission assessments.

Other potential environmental issues that have been identified:

- Marine geological hazards (marine landslides)
- Marine water quality/oceanography (impacts associated with installation)
- Marine biology resources (hard bottom resources, marine mammals, bird colonies)
- Marine cultural resources (shipwrecks)
- Marine transportation (commercial vessel traffic, moorings)
- Commercial and recreational fishing (preclusion areas)
- Air quality (installation impacts, long term beneficial impacts)

5.3.5 Procurement

The procurement process for large EPC style projects of this nature can take a considerable amount of time and effort requiring extensive preparation by the Owner. Bidder selection, Request for Proposal (RFP) documents, including bidder meetings and interviews, will need to be planned ahead of the formal bid process in order to ensure that all portions of the work are accounted for. The benefits of this preparation will be seen significantly during the construction portion of the project. Reduced change orders, delays due to unknown conditions, and overall better preparedness by the contractor are all key advantages to a thorough procurement process.

Pre-selecting bidders can be difficult but will allow for a reduction in “frivolous” bids being received by the Owner. This selection process requires bidders to be vetted through a series of questionnaires being sent out in order to remove bidders who cannot complete the project as requested by the Owner. The questionnaire will include questions about the bidder, their financial wellness, manufacturing capabilities, construction capabilities, safety practices, and experience with similar types of work within this specific market sector. Through these pre-qualification questionnaires, the bidder list can be reduced to a manageable volume of three to six bidders for the final RFP.

The next step will be to create and assemble the RFP documents. The RFP will include separate sections for each scope of work along with requirements for the project as a whole. After the terms and conditions are set in the contract, the overall scope and performance requirements should be set for the project, along with expectations of the Contractor by the Owner. These performance requirements will then be followed by technical and performance requirements for each piece of equipment. Finally, this will be followed by the expectations for construction including best practices, mitigation plan requirements, and permits necessary to complete the work. Once all requirements are set, the Owner should include anticipated schedules for the construction activities and milestone dates for the contract. This will then be followed by a quotation fill-in document that bidders will populate with their pricing for each activity and any breakouts necessary to explain the reason for costs. Attached to the front of the RFP documents should be all milestone dates for the bidding process as well as requirements for bids to be accepted by the Owner.

5.3.6 Construction

Proposed construction methods and existing subsea conditions along the subject submarine electrical power cable alignment are not anticipated to have considerably changed since the favored route (route 1B) was identified in the Padre Associates Inc. PEP circa 2005. Note that significant time has passed and it is expected that authorities and regulatory agencies having jurisdiction will require new geophysical, biological, site specific cultural resource surveys to be prepared prior to any permitting or environmental impact review (EIR) processing.

Once a bidder has been selected, all documents and drawings should be handed over by the Owner to the Contractor to be completed prior to construction. The Contractor will need to complete all design drawings, permits, and other supporting documents based on their equipment and processes. This will also prevent any miscommunication between the Contractor and Owner's provided drawings during construction. The Contractor will also need to confirm the provided site survey and collect any additional soil samples needed for engineering or permitting at this time. The site survey could be a few years old at this point or the route may be required to be adjusted by permitting agencies or the Contractor's equipment. This survey should be a reduced level of effort survey whereby the purpose is to confirm previously recorded conditions rather than create base maps.

The final engineering package will then be submitted to the Owner for review and acceptance prior to construction crews arriving on site. Once the drawings are complete, construction of the cable system can begin. Site development for the substations and installation of the submarine cable are disjointed activities that can run parallel to each other. The anchoring vault located on each shore can be used as a landing area for the land and subsea equipment prior to connection. It is recommended that the site work at each generating station begin first in order to achieve the shortest construction schedule.

The submarine cable installation will be completed from a specialty cable-laying vessel designed to hold and install the long length of cable needed for this project. The vessel will, more likely than not, be the same vessel that was used to transport the cable from the cable manufacturing facility to the project site. This is due to the extreme weight of the continuous cable once manufacturing is complete.

Figure 5-15 - Cable Carrousel

A large carrousel (Figure 5-15) will unwind the cable as it is fed up and through a long tube known as an elephant trunk and off the back of the vessel. The first section of cable, approximately 8,000 feet, will then be attached to buoys and floated to the landing point on land. For the Huntington Beach landing, an abandoned Cenco 24-inch pipe has been identified to be used while an HDD will need to be installed on the Catalina Island landing. Once the cable has been floated out, divers will sink a portion of cable down the pipe opening and connect it to a pull line installed within the pipe. The cable will then be pulled through the pipe and into the anchoring vault, where it will be anchored to allow the rest of the cable to be installed.

Figure 5-16 - HDD Rig and Sending Pit

With the cable pulled through to the landside, the rest of the cable will be sunk and fed into a jet plow, where applicable and feasible, for installation between Huntington Beach and Catalina Island. The jet plow operates by fluidizing the soil underneath its large plow to allow the cable to be buried down into hard soil. The cable feeds down the back of the plow and lays directly behind the tip of the plow where soil then settles back over the top. This process is then repeated continuously across to Catalina Island where the last half mile of cable or so is floated out. From there, the same process as used on the Huntington Beach side is repeated to land the cable into the PBGS anchoring vault.

Figure 5-17 - Jet Plow

The working principle for the jet plow is to fluidize the seabed materials in a narrow path and to a predetermined depth without displacing most of the material or turbidizing the surrounding waters beyond 16.5 feet. The method has been positively proven to place power cables at a consistent required depth of embedment in all jettable bottom conditions. The jet plow is towed by a support vessel propelled with dynamic positioning, or kedging, on anchors. The fluidizing effect provides relatively low and controlled towing forces. Standard model jet plow embedment depth can range from 3 to 6 feet (models available to 15 feet of embedment depth). Available accessory options also include deep-water skid base frames.

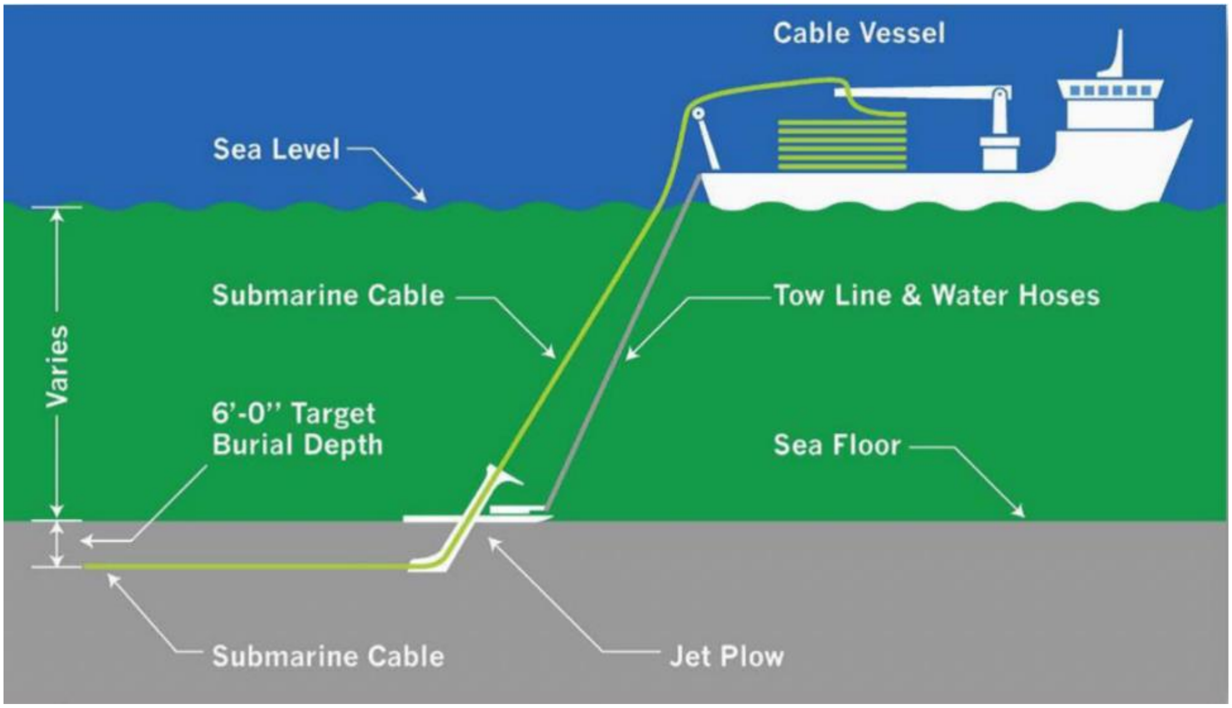


Figure 5-18 - Undersea Cable Installation via Jet Plow

Once physical construction of the sites is complete and all cable has been pulled, the cable can be spliced together and terminated within the substations. When the cable system is complete, jacket integrity testing and a 24-hour soak test can be performed. Traditional cable testing can be extremely difficult to perform on long length submarine cable, so AC Hi-Pot testing and partial discharge testing is not typically recommended. With testing complete, the cable system can be placed into service.

5.3.7 Post Lay Survey

After the cable is placed in service, a post lay burial survey should be performed in order to identify any issues with the cable. Data should be pulled from the position sensor on the jet plow and then "trouble" areas can be identified and surveyed. Typically, this can be achieved using a side scan survey along with a single beam bathymetric survey. This information is then checked against the jet plow position sensor and areas are identified as being not adequately buried.

These areas identified as being inadequately buried can be remediated in two different ways: concrete mattresses and post-lay rock burial. Concrete mattresses (Figure 5-19) are large flat concrete box system that forms a protective layer for equipment underwater. They can be precisely laid over trouble areas but are also quite expensive to install. Post-lay rock burial is a series of rock layers of varying size placed over the top of the cable in order to increase the burial depth. This method is significantly less precise than concrete mattresses but is more cost effective. Precision of post-lay cable burial will typically depend on permitting requirement for the project along with project budget. If concrete mattresses and post-lay rock burial methods prove to be ineffective, other means such as protective encased or split pipe applications will need to be considered.

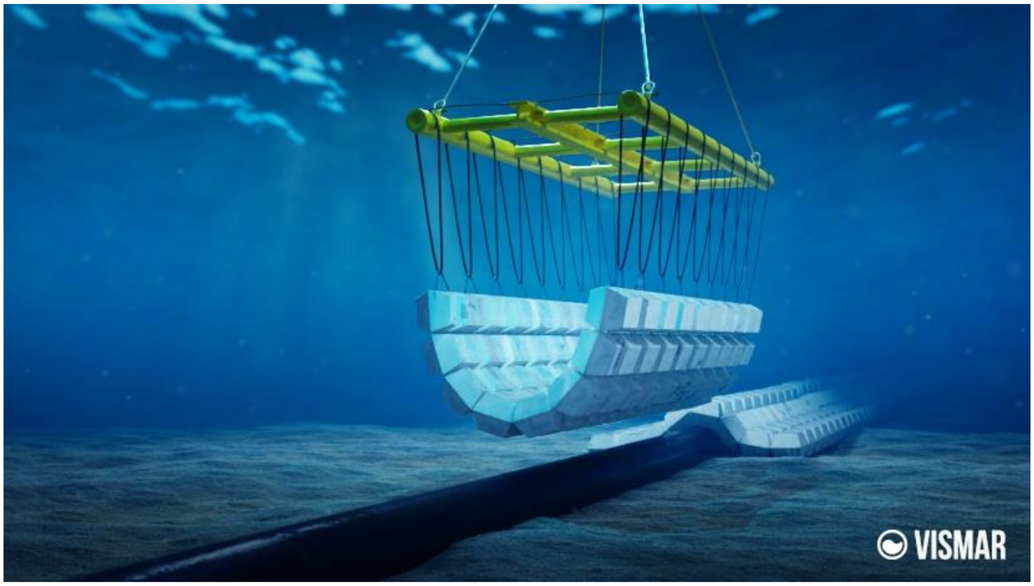


Figure 5-19 - Concrete Mattress System from VISMAR

5.3.8 Operations and Maintenance

Submarine cables are required to operate within extreme conditions over their 40-year life. Due to these conditions, proper maintenance is critical to ensuring the longevity of the system. Typically, submarine cable transition joints and anchors will need to be visually inspected yearly to ensure that no corrosion has occurred to the armor wires and joint supports. Depending on the material selected, cathodic protection may also be required to prevent corrosion and will require yearly inspections. Visual inspections are inexpensive and can be performed by operations personnel within SCE.

Bi-yearly, bathymetric surveys should be performed, especially within the first 5 years of operation, to ensure that the cables are not shifting and that long unsupported spans that could cause the conductor to fatigue are not developing along the route. The bathymetric survey should also be able to identify areas of unprotected cables when compared to the as-built survey that may require additional protection. Bathymetric surveys can be relatively inexpensive but require specialty sonar equipment, vessels to hold the equipment and crews during the survey, and specialized software to interpret the data. In deeper sections, over 300 feet, higher powered equipment may have to be used which can increase these costs.

Approximately every 5 years a side scan sonar survey should be performed to corroborate any findings in the bathymetric survey and provide a clearer picture as to the location of the submarine asset. The side scan sonar survey will provide a clearer picture as to the precise location of the cables and clearly identify long unsupported spans or unprotected cables that could cause failure during operation. Side scan sonar survey is also relatively inexpensive and requires a similar contractor as to the bathymetric survey. Depth is also a concern due to the equipment having to be run relatively close to the seafloor.

On average, O&M costs will run around $500k/ year depending on repairs that need to be performed. This cost does not include any repairs that may need to be made to the submarine cable itself, which could cost well into the millions depending on the location of the damage.

5.4 COST AND SCHEDULE

5.4.1 Cost

The submarine cable project will cost an estimated $226,000,000 with a bulk of the cost coming from the submarine cable itself. This cost is a high-level estimate that includes a 20% contingency, 10 years of operations and maintenance (O&M), and is based on industry knowledge and publicly available information. This cost is not to be construed as a final cost based on bids or estimates from potential bidders. The section herein describes some of the cost basis. Appendix G has detailed breakout of the cost and any assumptions used to determine those costs.

The Rough Order of Magnitude (ROM) Opinion of Probable Costing (OPC) on the equipment required at each substation is in the range $2,500,000 to $3,500,000 and will need to be confirmed during actual project costing and schedule preparation. For the mainland tie-in from the abandoned 24-inch diameter pipeline at Huntington Beach to the nearest overhead transmission pole tying into HBGS, an underground costing of $1,300 per lineal foot has been considered for alignment to the OH riser pole located on Beach Boulevard (Huntington Beach-Wave 66kV). An automatic transfer switch (ATS) will be installed so that, in case of an undersea cable power outage or failure, back-up power will be initiated via one of the existing or future PBGS generators. At this phase, ROM costing for the ATS and back-up generator fall under the miscellaneous category of the OPC.

For the underwater sea cable, the route and shore crossing locations have been confirmed and the following preliminary pricing has been established. For the HDD, a ROM costing of $15,000,000 has been included for the shore crossing from PBGS into the Pacific Ocean. This has taken into consideration the constrained footprint within the current PBGS micro-turbine area. Due to this constraint, the PBGS side of the HDD will need to be designated as the sending pit location; the receiving and pull back location with all associated equipment and materials will have to be performed from barges anchored in the ocean.

With respect to the power cable itself, the conductor shall be designated as a three core, 33kV armored submarine cable with 400kcmil per phase. ROM costing on manufacture and supply for the cable is roughly $60,000,000 with an approximate lead-time of at least 1 year. Installation ROM cost of the undersea cable is roughly $100,000,000 and envisioned to take about 6 to 9 months (including HDD and anchoring vault installation), but is a function of multiple variables, agency approvals, and vessel scheduling.

5.4.2 Schedule

To engineer, procure, and construct the submarine cable project in its entirety (i.e. to ISD = In Service Date) will take approximately three years with most of the time falling under the procurement and construction activities and phases of the project. Production of the cable will take an extensive amount of time due to the length of production and the requirement that the cable shall be manufactured in one continuous length. The total production time, including shipping, is forecasted to take up to one year, and is dependent upon location and production load of the facility.

The construction phase of the project will also take quite some time, but many activities can be achieved concurrently while the cable is being manufactured and tested. The substation expansions and conduit duct bank system for the land cable will need to be complete prior to the cable arriving which will help reduce some schedule. The duration of the cable installation itself should last one half year depending upon what equipment is used for cable laying, terrain, and protection requirements on the ocean floor.

Table 5-2 is a high-level milestone schedule for the project. A detailed breakout of the schedule is included in Appendix H.

Table 5-2 - Submarine Cable Schedule

Milestone No.	Milestone Name	Start Date	End Date
1	Project Kickoff	01/04/2021	-
2	Preliminary Permit Applications	01/04/2021	08/03/2021
3	Preliminary Survey Geotechnical Investigation	01/04/2021	07/23/2021
4	Permitting	04/21/2021	02/16/2024
5	Engineering	08/04/2021	11/01/2022
6	Procurement and Manufacturing	07/26/2021	08/29/2024
7	Construction	03/23/2023	08/26/2025
8	Commissioning and Post Lay Survey	07/21/2025	09/25/2025
9	Project Substantial Completion	-	09/25/2025

5.5 RISK CONSIDERATIONS

There are many potential risks for installation and maintenance of a 33kV submarine electrical power cable project of this magnitude. The following is a list of these potential risks in no particular order:

- Huntington Beach: The existing abandoned 24-inch Cenco concrete pipeline may become unavailable or may be determined to be unusable due to environmental constraints and over contamination.
- Huntington Beach Generating Station: There may be no available area or space in the future for expansion of the substation to accommodate the new interconnection equipment; the project cannot tie into the existing 66kV switchyard as-is.
- Pebbly Beach Generating Station: During the HDD operations, a frac-out could occur during the boring and casing installation.
- On-shore crossings. Potential impacts to near shore environmental and biological resources related to the activities of HDD installation as well as jetting the undersea power cable to a position below the seabed floor.
- Submarine Electrical Power Cable:
    - Being able to achieve proper burial depths or install appropriate protective coverings at deep-sea depths. Hard bottom conditions could result in significant discontinuities that could lead to the cable being suspended above the sea bottom or topography may exist that necessitates the cable to rest upon sharp or jagged points. This could induce excessive and cyclical bending stresses. Cable suspension in strong water currents could induce vibrations that eventually lead to cable damage and failure.
    - Maximum depth (2,500 feet) of the undersea cable installation, the subsea topography and bottom materials, and external threats to the cable integrity. The overall integrity of submarine cable could be compromised by natural phenomenon or human activity. Allowable depth is dictated primarily by the strength of the submarine cable itself in terms of its ability to withstand the tensile stresses from the length of cable suspended between the laying ship and the seafloor.

- Undersea topography, steep slope concerns, and seismic considerations. Steep slope areas or undersea seismic activity could induce gravitational or laterally induced forces that pull the cable downslope, which may cause cable movement, resulting in excessive longitudinal or torsional stresses after placement.
    - Catastrophic failure of the cable within the Pacific Ocean / Gulf of Santa Catalina alignment. Repair and splicing operations could take many months and may not even be possible at maximum depths (2,500 feet or more).
    - There are very few similar and proven power cable installations currently in operation at this depth. A review of installations to date indicates it is feasible to place power cables in water depths of 3,000 feet.
- Environmental Risks (which may necessitate detailed mitigation measures): Dredging areas vs. cable alignment, sandy beach resources, coastal access and recreation, rocky substrate / hard seafloor bottom, deep offshore cable burial, cable crossings, commercial fishing zones, generation of excessive turbidity during undersea cable installation, archeological and biologically sensitive areas, marine habitat and sensitive species, marine geology, water resources, cultural resources.

5.6 CONCLUSION

After preforming a comprehensive feasibility study and due diligence review, installation and operation of a 33kV submarine electrical cable to provide power from the mainland to Catalina Island is a possible and viable option. The endeavor would cost approximately $226,000,000, including a 20% contingency, and take roughly 57 months to execute from start to finish. As indicated in the Risk Considerations section of this review, there are several high probability risks associated with this project, which would have to be specified and accounted for within a project risk register but have not been commercially evaluated in this report.

6.0 NREL PHASES I & II SUMMARY

NREL's role in the first two phases of this project was to perform techno-economic modeling and optimization analysis of the above supply-side generation options (emissions compliant fossil fuel generation, renewable energy and battery storage, and submarine power cable). NREL is using the Renewable Energy Optimization and Integration (REopt)[27] tool to evaluate the potential of these various energy technology options to power Catalina over a 30-year analysis period. This section describes NREL's techno-economic analysis and discusses the lifecycle cost-effectiveness and other factors of various energy system configurations evaluated. Given the collaborative nature of this effort, the techno-economic analysis both utilizes results of NV5 analysis as techno-economic inputs and feeds techno-economic results into NV5's analysis.

6.1 METHODOLOGY

This section provides an overview of NREL's REopt tool and of the phased approach taken for this iterative techno-economic analysis.

6.1.1 REopt Overview

REopt is a techno-economic time series optimization model to support distributed energy systems planning decisions. Formulated as a mixed integer linear program, REopt identifies the cost-optimal mix of candidate technologies, their respective sizes, and dispatch strategy.

Typically, the model's objective function is to minimize the present value of lifecycle costs (LCC) of energy over the analysis period by adjusting modeled system sizes and dispatch. The model can optionally incorporate specific RE targets to identify cost-effective pathways to achieve such targets. The LCC modeled includes capital costs (CAPEX) of new energy generation and storage capacity, the present value of all operating expenses such as fuel costs and operations and maintenance (O&M) costs, and the present value of any financial incentives and depreciation.

The model achieves an energy balance between energy demand and generation in every time step of the year (hourly time steps were used for this analysis) by sizing and dispatching a cost-optimal combination of power purchases (via a potential sub-sea cable in this case), renewable generation, fossil fuel generation and energy storage. The model also includes specific constraints for each of the identified technology options that define how they can operate.

6.1.2 Analysis Phases

Due to the interdependencies of NREL and NV5 sub-tasks, the techno-economic analysis was performed iteratively, with results informing the next phase of analysis to facilitate comprehensive understanding of options and convergence on recommendations for a path forward.

- **Phase I: Preliminary Analysis.** The preliminary analysis considered initial technical and cost assumptions based on inputs from SCE, EPA, NV5, and NREL. Results were presented in October 2019.
- **Phase II: Refined Analysis.** Scenarios and technologies considered in Phase II were informed by the results of Phase I and discussion between SCE, EPA, NV5, and NREL. Some technical and cost assumptions were also updated based on Phase I findings, especially where Phase I

[27] (NREL, 2017)

findings could inform assumptions provided by NV5. Initial results were presented in March 2020.

- **Phase III: Refined Analysis including Demand-Side Factors.** A future phase of this analysis could fully assess the impact of demand-side considerations on generation-side planning. A Phase III techno-economic analysis could be informed by findings from this Phase II REopt analysis and NV5's initial analysis of potential load increases, load reductions, and controllable loads, summarized in Table 6-1 and discussed in more depth in Section 6.3.

Table 6-1 - Potential Future Load Changes

Load Increases	Load Decreases	Deferrable Loads
• Building electrification • Electrification of vehicles • Cruise ships charging	• Energy efficiency measures	• Demand response • Load shifting • Water desalination plant • Island-wide water pumping • Electric crane and rock crusher

This section summarizes the considerations and findings of Phases I and II, focusing on high-level takeaways from Phase I and more detailed results from Phase II, and discusses a potential path forward for Phase III.

6.2 RESULTS

6.2.1 Phase I High-Level Summary

A goal of Phase I was to evaluate a range of options at a high level to facilitate team discussions, improve inputs and assumption for Phase II, and inform selection of scenarios to be assessed in Phase II. Phase I scenarios were collaboratively identified with input from SCE, EPA, NREL, and NV5.

Phase I results yielded the following takeaways:

- Solar PV appears to be cost effective on Catalina.
- Wind turbines do not appear cost effective on Catalina, due to the relatively low estimated capacity factor of 9.9% predicted from the geospatial wind data and the high capital costs associated with distributed wind on an island with complex terrain. Site-specific wind resource measurements for possible wind turbines locations were not available; therefore, NREL wind experts used measure-correlate-predict analysis to identify areas of the island with the strongest resource.
- Additional BESS could stabilize high penetrations of renewables on the island's electric grid.
- Per SCE, Microturbines will be decommissioned once they reach end of life in the next several years.
- An undersea cable interconnecting with the mainland appears more expensive on a lifecycle basis than when compared with on-island generation. This is in part driven by its high

estimated capital cost of $219.9M for a single undersea cable, per NV5. A second cable or on-island generation would also be required to provide redundancy, further increasing costs.

6.2.2 Phase II Detailed Results

Based on the findings and feedback on Phase I, the Phase II analysis incorporated refined techno-economic assumptions, additional technologies and scenarios, and pertinent sensitivity analyses. This section describes the scenarios, considerations, and sensitivities included in the Phase II analysis; for additional details about techno-economic assumptions, see Appendix J.

The load profile used for these analyses is based on the 2017 load profile, which peaks at 5.5 MW, scaled to a peak load of 7 MW per SCE's estimates of load growth. To model this estimated load increase, the electric demand in each hourly timestep was increased by 27% (since 7 MW is a 27% increase over 5.5 MW peak demand). In future work, additional demand-side analysis could be performed to more accurately capture temporal variations in load impacted by future load increases, load reductions, and controllable loads.

To ensure system reliability, spinning reserve requirements and N+2 redundancy requirements were specified as constraints. Spinning reserve requirements are detailed in Appendix J. N+2 redundancy requires that if the two largest generators are offline during the peak load that the remaining generators could still cover the peak load. Renewables and BESS were not assumed to contribute to the N+2 requirement but could support redundancy albeit at higher risk of unavailability.

Table 6-2 summarizes the scenarios evaluated and the high-level results for Phase II, organized into five categories:

- Undersea Cable (UC)
- Fossil Fuel Only (FF)
- Minimize LCC (LC)
- 60% RE Annually (RE60)
- 100% RE Annually (RE100)

The FF and RE100 options serve as analysis bookends. RE60 is predicated on California's S.B.100 target of 60% RE by 2030; however, off-island options could also support this goal. In order to reduce lifecycle costs in LC scenarios, REopt identified the cost-optimal mix of energy technologies to serve Catalina Island's electricity requirements, without considering any renewable energy targets.

Within each of these five categories in Table 6-2 the various scenarios listed (in order of increasing LCC) consider different generator configurations and sensitivity analyses:

- Enumerated (1, 2, 3, etc.) scenarios vary by generator type, number, and size but otherwise use the same load and technology assumptions, as described in Appendix J.
- "Lower PV/BESS CAPEX" (CAP) scenarios assume PV and BESS cost are equal to mainland U.S. price points, rather than in the enumerated scenarios where PV and BESS costs are assumed to be higher on Catalina.
- The energy efficiency (EE) scenarios assume that energy conservation measures (ECMs) are implemented to bring the electrical load profile back to 2017 values, essentially a 21% decrease in demand applied to all hours of the year. This EE case is intended as one simple example to demonstrate the impact demand-side considerations could have on SCE's

generation strategy on Catalina. An additional analysis to include potential load changes and their impact on electricity requirements and generation strategy is recommended and is planned as a Phase III of techno-economic analysis as discussed in Section 6.3.

Unless otherwise noted, all scenarios assume that the existing 2.8 MW diesel generator (Unit 15) and 1 MW, 7.2 MWh NaS BESS are available for use, with the NaS BESS being replaced at end of life, estimated ~2032.

Table 6-2 – Phase II Scenarios and Results Summary

Scenario		Generator / Fuel Type	Sensitivity Analysis	New Generators[28] [MW]	PV Capacity	New BESS Capacity	Estimated PV Footprint	Annual % RE	Estimated Annual NOx Emissions[29]	Estimated CAPEX[30]	Present Value of Estimated LCC
Undersea Cable[31]	UC	Diesel (larger)	---	4 x 2.98	N/A	N/A	N/A	N/A	N/A	$263M	$334M
Fossil Fuel Only	FF-EE	Diesel (larger)	EE	3 x 2.98	N/A	N/A	N/A	N/A	20 tons	$32M	$128M
	FF-1	Diesel (smaller)	---	6 x 1.49					25 tons	$32M	$152M
	FF-2	Diesel (larger) + Propane	---	3 x 2.98 + 1 x 1.38					19 tons	$44M	$165M
	FF-3	Diesel (larger)	---	4 x 2.98					25 tons	$43M	$168M
	FF-4	Diesel (mixed), no unit #15 (2.8 MW)	---	2 x 1.49 + 2 x 2.23 + 2 x 2.98					25 tons	$48M	$169M
	FF-5	Propane	---	7 x 1.38					6 tons	$108M	$230M
	FF-6	LNG[32]	---	4 x 2.5					3 tons	$132M+	$247M+
Minimize LCC	LC-CAP	Diesel (larger)	Lower PV/BESS CAPEX	4 x 2.98	3.8 MW-DC	2.2 MW, 1.1 MWh	24 acres	16%	21 tons	$50M	$165M
	LC-1	Diesel (larger)	---	4 x 2.98	1.2 MW-DC	0	8 acres	5%	24 tons	$46M	$168M
60% RE Annually	RE60-EE	Diesel (larger)	EE	3 x 2.98	12.3 MW-DC	9 MW, 71 MWh	78 acres	60%	8 tons	$127M	$194M
	RE60-CAP	Diesel (larger)	Lower PV/BESS CAPEX	4 x 2.98	15.6 MW-DC	12 MW, 90 MWh	99 acres		10 tons	$126M	$211M
	RE60-1	Diesel (smaller)	---	6 x 1.49					10 tons	$149M	$223M
	RE60-2	Diesel (larger)	---	4 x 2.98					10 tons	$159M	$243M
	RE60-3	Propane	---	7 x 1.38					2 tons	$224M	$302M
100% RE[33] Annually	RE100-CAP	Diesel (larger)	Lower PV/BESS CAPEX	4 x 2.98	44 MW-DC	36 MW, 340 MWh	279 acres	100%	0 tons	$291M+	$354M+
	RE100-1	Diesel (larger)	---	4 x 2.98					0 tons	$395M+	$458M+

[28] Unless otherwise noted, all scenarios assume the existing exempt 2.8 MW diesel generator (Unit 15) and 1 MW, 7.2 MWh NaS BESS are available for use.
[29] Annual NOx emissions listed only account for those emitted during generator operations; they do not include NOx emissions associated with fuel shipments
[30] CAPEX listed includes upfront capital costs of generation and storage technologies, capital costs for distribution system upgrade costs as estimated by NV5, and capital costs of BESS replacement
[31] Undersea cable and 100% RE scenarios list diesel generators; these generators are included to satisfy N+2 redundancy requirements but only operate as backup.
[32] Additional fuel shipping costs and infrastructure upgrades may be required for LNG; additional feasibility analysis is recommended to refine cost assumptions.
[33] Additional integration costs are likely for 100% RE scenario.

6.2.2.1 Undersea Cable

The capital ($221M) and O&M ($5M) costs of the undersea cable were evaluated by NV5. California Independent System Operator (CAISO) day-ahead (DA) electricity costs from the Huntington Beach substation were used to estimate the cost of mainland generation that would supply Catalina Island through the cable. The undersea cable is presumed to be backed up by on-island diesel generators in this scenario (see UC) which adds additional capital and O&M costs to this scenario. The LCC of electricity with an undersea cable is nearly 200% of the LCC of electricity in an all-diesel scenario (see FF-3).

6.2.2.2 Generator and Fuel Options

In order to satisfy N+2 redundancy requirements, all scenarios evaluated have on-island fossil fuel generation to cover the full peak load even if the two largest generators go offline. Three fuel types (diesel, propane, and LNG) and several generator sizes and configurations were evaluated. Note that additional factors beyond those included in the techno-economic analysis, including generator footprint, renewables integration, part load operations, ramp rates, implementation schedule, and spare parts requirements, may also influence generator selection and are not included in this results table.

6.2.2.3 Diesel Generators

Results suggest diesel generation as a lower life-cycle cost option than the other fossil fuel generator options, with a small difference in LCC between smaller (1.49 MW; see FF-1), larger (2.98 MW; see FF-3), or mixed-capacity (see FF-4) generators.

The higher LCCs shown in Table 6-2 can be attributed to the difference in total generator capacity between the scenarios because diesel generator capital and O&M costs were estimated on a constant $/kW basis, as well as the fact that Unit 15 was excluded from the mixed-capacity scenario (see FF-4) per request from SCE which therefore required additional new generation capacity to be purchased. However, the larger generators operate at a slightly higher efficiency than the smaller generators. Note that the full range of diesel generators evaluated appear flexible enough in their partial load and minimum loading requirements to be able to facilitate at least 60% RE according to input provided by NV5.

6.2.2.4 Propane Generators

An all-propane scenario (see FF-5) has a ~40% higher LCC than all-diesel generators but reduces NOx emissions by over 75%. A combined diesel and propane option (see FF-2) could serve as a cost-effective system that reduces NOx emissions by nearly 25% over an all-diesel scenario and provides fuel flexibility for price hedging.

Potential generator fuel-switching or dual fuel options could be considered to facilitate this option; it could be possible to convert the diesel generators to 95% propane. Having multiple fuel options and generators could also provide a hedge against cost increases for either propane or diesel fuel.

Even once emissions associated with additional barge shipments of fuel to the island are considered, propane options are still likely to have total lower NOx emissions. Propane has a higher energy intensity by weight and although it has a lower energy intensity by volume. Thus, Catalina's weight-based fuel shipping rates give propane a shipping cost advantage over diesel. See Appendix J for more details on fuel shipments and emissions implications.

One challenge is that propane fuel storage on the island may be limited by fire suppression requirements and other factors. Nevertheless, it seems plausible that at least one propane generator could be used to replace the propane microturbines with the existing fuel storage and fire suppression system. Additionally, if the buildings on Catalina are eventually converted from a propane supply to electricity, there may be increased flexibility to add or convert to more propane generators.

6.2.2.5 LNG Generators

LNG (see FF-6) appears to be the most expensive generator option evaluated, with an LCC nearly 63% higher than an all-diesel option. This higher LCC is largely driven by higher capital costs for generators and infrastructure upgrades. Additional feasibility studies for this option would be required to more accurately estimate the costs of fuel shipping and infrastructure upgrades.

6.2.2.6 Solar PV + BESS

Solar PV and BESS appear to be cost effective technologies on Catalina. This section discusses the recommended PV and BESS systems recommended and their economics for scenarios seeking to minimize LCC, achieve 60% or 100% RE annually, and considering capital cost and land lease cost sensitivities.

NV5 conducted an analysis to estimate the costs to accommodate increased variable RE generation and potential locations and configurations (e.g. AC-connected vs DC-connected, distributed vs centralized) on Catalina's electric system. These distribution system upgrade cost estimates are included in the capital costs and LCCs listed in Table 6-2; additional details are provided in Appendix J.

6.2.2.6.1 Minimizing LCC

PV is cost-effective on Catalina. Initial analysis suggests that 1.2 MW-DC could be supported by the existing NaS BESS (see LC-1) without changing the LCC of electricity relative to an all-diesel scenario (see FF-3) and assuming 76.5% higher PV capital costs and 31.5% higher BESS capital costs on Catalina vs. the mainland. Such a system could achieve a 5% annual RE penetration and reduce annual NOx emissions by 4-5% relative to the all-diesel scenario (see FF-3). The actual most cost-effective size of a PV system will depend on actual PV pricing and project costs.

6.2.2.6.2 60% Annual RE Target

A 60% annual RE target on Catalina Island could be achieved with approximately 15.6 MW-DC of PV and 12 MW / 90 MWh (~7.5-hr) of additional BESS (see RE60-1). This PV system could require ~100 acres of land. Compared to an all-diesel scenario (see FF-3), NOx emissions would decrease by 15 tons/yr to 10 tons/yr, but the lifecycle cost could increase by $71M (47%). This system presents a high contribution of RE, nearly 200% of the 7 MW peak load on a capacity basis and would require controls and communications systems to integrate with the power system. Rough cost estimates for integration are included but could be higher than those estimated.

If mainland PV and BESS capital costs could be achieved on Catalina, capital costs could be reduced by $33M leading to a 13% reduction in system LCC (see RE60-CAP).

6.2.2.6.3 100% Annual RE Target

A 100% annual RE target was assessed for this analysis. To meet 100% of the electrical load on Catalina with RE, approximately 44 MW-DC of PV and 36 MW, 340 MWh of BESS could be required. This PV system would require ~280 acres of land but could reduce NOx emissions to 0. Relative to an all-diesel scenario (see FF-3), overall LCC increase by $290M+ to over $458M, which is $215M+ more than the 60% annual RE scenario (see RE60-1). These estimates only include NV5's distribution system upgrade cost estimate to facilitate 60% RE; additional distribution system upgrades are likely required to achieve 100% RE but these costs were not calculated or included.

If mainland-based PV and BESS capital costs can be achieved, capital costs could be reduced by $104M leading to a 23% reduction in system LCC (see RE100-CAP). Note that REopt was given the option of identifying a combination of solar PV, wind turbines, wave energy devices, and BESS capital costs are likely to decrease and could become more achievable to reach this 100% RE target, but only selected PV and BESS to achieve the target at lowest lifecycle cost effective as projects are phased over the next decade.

6.2.2.6.4 PV + BESS Capital Cost Sensitivity

A PV and BESS capital cost sensitivity study was performed to evaluate the impact of capital costs on recommended systems and estimated lifecycle costs. Because the base case PV and BESS capital cost assumptions include an area cost factor (ACF) to account for the costs of transportation to and labor on Catalina Island, this sensitivity analysis assessed the implications of achieving mainland costs. PV and BESS capital costs are likely to continue to decrease over the coming years, making projects more cost effective as they are developed in phases.

Removing the ACF from PV and BESS cost assumptions has the following impacts:

- When minimizing LCC without considering any RE target (see LC-CAP), the cost-effective RE annual contribution increases from 5% to 16%. The system size is constrained by NV5-estimated distribution system upgrade costs rather than the cost of the PV/BESS systems themselves. Without considering the distribution system upgrade cost estimates provide by NV5, the estimated PV system size increases to up to 7.6 MW-DC, which could achieve an annual RE contribution of 30%.
- Overall system LCC for the 60% RE scenario (see RE60-CAP) could decrease by 19%.
- Overall system LCC for the 100% RE scenario (see RE100-CAP) could decrease by 23%.

6.2.2.7 Wind Turbines and Wave Energy Devices

Wind turbines and wave energy devices were considered in all the scenarios listed in Table 6-2; but were not found to be as lifecycle cost effective when compared to other options. These technologies and their challenges for Catalina Island are discussed below.

6.2.2.7.1 Wind Turbines

Wind turbines did not appear cost effective on Catalina given the assumptions used for this analysis. This is due to the relatively low capacity factor of 9.9% observed from the geospatial wind data and the high capital costs associated with distributed wind on an island with complex terrain. Wind resource data for specific possible wind turbines locations was not available but was estimated using “measure-correlate-predict” analysis.

A sensitivity on wind resource and turbine capital costs was performed to consider uncertainty in these values. The wind resource was varied across a range of profiles with average wind speeds up to 2.2x those in available data. Capital costs were reduced up to 50%. As shown in Table 6-3, wind may become cost-effective on Catalina with a 2.2x increase in average wind speed for the sites identified with the highest wind resource on Catalina supplemented by a 50% reduction in capital costs.

Table 6-3 - Sensitivity to Higher Wind Resource and Lower Wind Turbine CAPEX

		Average Wind Speed [m/s]				
		3.52	4.05	5.32	6.59	7.82
Capital Cost Reduction	0%	x	x	x	x	x
	10%	x	x	x	x	x
	20%	x	x	x	x	x
	30%	x	x	x	x	x
	40%	x	x	x	x	x
	50%	x	x	x	x	✓

6.2.2.7.2 Wave Energy Devices

Wave energy does not appear to be lifecycle cost effective on Catalina compared to the other options evaluated and given the assumptions used for this analysis. However, wave energy is an emerging technology with less MW deployed vs. the other options considered, which has several implications for this analysis and future planning.

Cost and technical assumptions used in this analysis are based on numbers provided by a wave energy vendor. These costs and performance assumptions were not able to be verified by NREL; the costs appear lower and performance appears higher than other wave energy devices NREL has assessed. Even using the vendor's assumptions, wave power was not found to be lifecycle cost effective compared to the other options at Catalina. Moreover, concerns have been expressed with siting the wave energy infrastructure at Catalina.

However, given its early stage of technology readiness, wave energy could potentially become feasible or even cost effective in the future, pending developments in technology and reductions in costs.

Additional due diligence and evaluation of pilot projects could reduce the risks and confirm costs and generation assumptions. Wave energy device performance is highly device-specific (the industry has not converged to a particular technology) and site-specific. If wave energy is of interest for Catalina Island, a smaller pilot demonstration could be considered to de-risk the reliability concerns associated with a technology that is considerably less mature than PV.

6.2.2.8 Energy Efficiency (EE): Initial Example

Phase III of the techno-economic analysis can focus on the impact of demand-side factors, including load increases, load reductions, and controllable loads. However, leading into Phase III, NREL conducted an initial scenario analysis to demonstrate how demand-side considerations could impact SCE's generation strategy on Catalina. For this example of EE impacts, the electric load in each timestep was decreased by 21% to reduce it to 2017 values.

The assumed load reduction could yield $25-40M (15-25%) reductions in LCC, achieved by reducing the number of generators required to support the load and by reducing annual fuel consumption (see:

FF-EE). Additionally, it could reduce the PV capacity required to meet the 60% annual RE goal by 3.3 MW-DC, reducing LCC by $49M (20%) and PV footprint by 21 acres (see: RE60-EE).

This high-level analysis assumes a constant percent reduction in energy consumption throughout all hours of the year and does not consider the costs of the ECMs. Actual energy efficiency measures are likely to impact the load profile in different ways, as are other demand-side factors, to be assessed in Phase III.

6.3 DISCUSSION: POTENTIAL NEXT STEPS INCORPORATING LOAD INCREASES, DECREASES, AND DEFERABLE LOADS

Additional follow on analysis phases could include more detailed analysis of demand-side energy systems such as increased energy efficiency, demand-side management, water systems, electric vehicles, and building electrification among others.

Especially for an island energy system like Catalina, effectively managing energy loads and consumption can have a significant impact on energy generation strategies and assets, provide an opportunity to lower overall lifecycle cost, and facilitate meeting environmental protections. For example, implementation of energy conservation measures (ECMs) could reduce the amount of generation capacity needed and the amount distribution infrastructure required as illustrated in the initial energy efficiency scenario described above and many other actual examples from the energy efficiency and demand response industry. Additionally, controls to manage deferrable loads on the island could be resources for the island electricity system. Integration of these controllable deferrable loads could result in more optimal cost-effective generation strategies and selection of capital infrastructure. On the other hand, the potential for increasing loads from cruise ships, building and transportation electrification, can also have a significant impact on future generation scenarios.

The techno-economic analysis described in this document is primarily focused on supply-side generation options, with the exception of the one energy efficiency example listed above. A potential future phase III could incorporate additional techno-economic analysis to evaluate how the energy system could be optimized with consideration of both demand and supply-side considerations.

NV5 has conducted a high-level analysis on the energy efficiency (EE) and demand reduction (DR) potential on Catalina Island to assess opportunities to cost-effectively reduce load and emissions and positively influence the island's load profile. The results of this assessment completed by NV5 could be used as technical inputs for a techno-economic EE and DR model to determine the impact to the generation options. Additional utility systems data inputs from SCE and others could also be used to evaluate other load increases and deferrable loads as outlined in Table 6-1.

Moreover, future analyses could evaluate the impacts to the generation strategies resulting from the ability to control deferrable loads (e.g. such as grid interactive hot water heaters, air conditioning, ice storage for air conditioning, water pumps, and water desalination) to determine their impact on energy generation strategies. The impact of the deferrable loads on the load profile may be stacked in addition to the EE and DR impact described above.

Because SCE is also the potable water utility for Catalina Island managing a system of groundwater wells and an existing and expanding desalination plant, they are in a good position to invest in operational and infrastructure improvements to enhance the efficiency of the energy and water systems. This water energy nexus scenario warrants attention and analysis to provide additional insights for SCE consideration to improve the scheduling, operation and construction of desalination, water treatment, and water distribution assets. (Another entity manages the wastewater system).

A key to improving energy generation strategies associated with water treatment and conveyance is to separate the operation of the treatment plant from the water demand that it is serving. This could be achieved by expanding the size of the treatment plant and adding storage in the form of water tanks. Storing water in tanks is very similar in concept to storing energy in batteries, except it is lossless and can be accomplished at much lower cost. Moreover, the variable nature of renewable energy can be synergistic with such dispatchable loads – water could also be treated during periods of high renewable energy production and stored for later use.

A techno-economic analysis could evaluate this water energy nexus scenario. Modeling could help identify cost-effective technologies, sizes, and operational strategies for reducing overall system ownership costs.

Future Phase III analyses could also consider the impact of generation strategies resulting from increases to the load profile. One significant impact to the load profile could be resulting from cruise ships using shore power. A second potential impact could be the development of an electric transportation (ET) (vehicle / boat) charging program. This analysis could also evaluate how an ET charging program could impact and be complimentary to the generation strategy. A third potential load increase could be from the complete removal of propane from buildings and replacing this with electricity. Similarly, the impact of the increases to loads on the load profile may be stacked in addition to the other load impacts described above.

In summary, a phase III techno-economic analysis and modeling of load increases, decreases, and deferrable loads could provide useful information to facilitate decisions on programs, policies, operational practices, and infrastructure investments on Catalina Island to improve to overall effectiveness and efficiency of the energy, water, buildings, and transportation systems.

7.0 ENERGY EFFICIENCY AND DEMAND RESPONSE

NV5's high-level analysis and conservative assumptions indicate that there is the potential to reduce Catalina Island's total electricity consumption by an estimated 21% via an estimated $7.8 million investment in energy efficiency improvements. At SCE's estimated actual gross cost of generation of $0.396/kWh, the approximately 3,560,000 kWh of annual savings would save SCE $1,409,760 per year. This equates to a simple payback of less than 6 years, which is within the assumed 10-year Expected Useful Life of the installed portfolio of Energy Conservation Measures. This very simplified and high-level estimate ignores many factors including inflation, revenue from ratepayers, and the value of peak load reduction. NV5 was not able to develop load reduction estimates nor the first-year gross cost of $/kW for demand reduction due to insufficient information. Catalina Island-specific emissions factors for NO_X of 0.005 lbs/kWh equate to annual reductions of 17,800 lbs/year or 8.9 tons, a 12% reduction from the 75.4 tons emitted annually (as per NREL calculations).[34]

Our EE potential reductions by customer segment are summarized below in Table 7-1.

Table 7-1 - Summary of SCI EE Potential by Customer Segment

Sector	Baseline Annual Use (kWh)	Potential Annual EE Savings (kWh)	EE % Reduction from Baseline	ECMs Total Cost ($)	EE First Year Gross Cost ($/kWh)	EE Lifecycle Gross Cost ($/kWh)
Domestic Tariff Customers						
Single family residences	6,646,618	871,460	13%	1,048,584.95	1.20	0.12
Multi-unit dwellings	100,000	20,000	20%	24,000.00	1.20	0.12
Non-Domestic Tariff Customers						
Top 20 users excluding water systems usage	10,665,742	1,599,861	15%	4,287,628	2.68	0.27
Potable water system	341,745	58,490	17%	65,100	1.11	0.11
Saltwater system	81,020	29,532	36%	43,000	1.46	0.15
Wastewater system	566,109	230,079	41%	339,503	1.48	0.15
Desalination Plant	730,922	73,092	10%	181,269	2.48	0.25
Non-domestic customers excluding Top 20 users	4,516,530	677,480	15%	1,815,645	2.68	0.27
TOTAL	**23,648,686**	**3,559,994**	**21%**	**7,804,730**	**2.14**	**0.21**
					↑ Weighted averages ↑	

[34] See Section 7.9 for qualifying language.

NV5's KPI estimates, assumptions and considerations are detailed in the following Table 7-2.

Table 7-2 - EE KPI Estimates, Assumptions and Considerations

KPI	Value	Notes
SCE annual average cost of generation ($/kWh) in its entire service territory	$0.063/kWh	[SCE source notes this # is:] For a recent year, average cost of the overall supply portfolio (total energy resource recovery account costs/total customer sales).[35]
SCE estimated 2018 average actual generation cost ($/kWh) on Catalina	$0.396/kWh	SCE analyst estimate[36]; other SCE personnel estimate 3–5X mainland average cost; NV5 uses 4X as "Catalina Island factor"
SCE EE program annual average first-year gross cost per saved kWh ($/kWh) in its service territory	$0.14/kWh	SCE 2018 all EE programs first-year gross cost, as per CEDARS data[37]
Estimated SCE EE program annual average first-year gross cost per saved kWh ($/kWh) on Catalina	$0.56/kWh	NV5 uses 4X mainland average as "Catalina Island factor"
Estimated SCE EE program annual average lifecycle gross cost per saved kWh ($/kWh) on Catalina	$0.056/kWh	NV5 assumes 10-year EUL for ECMs and uses estimated first year gross cost $/kWh
SCE EE (not DR) all-programs annual average first-year gross cost per saved kW ($/kW) in service territory	$667/kW	SCE 2018 all EE programs first-year gross cost, as per CEDARS data[38]
SCE DR program annual average first-year gross cost per saved kW ($/kW) in its service territory or on Catalina	N/A	No Catalina Island DR program history
Estimated SCE DR program annual average first year gross cost per saved kW ($/kW) in service territory	$80/kW-yr	DR industry vet: estimated range between $40/kW-yr and $120/kW-yr as a typical cost of capacity at the CAISO level[39]; NV5 uses median value of that range
Estimated SCE DR program annual average first year gross cost per saved kW ($/kW) on Catalina	$320/kW-yr	NV5 uses 4X estimated mainland average value as "Catalina Island factor"
Estimated NO_x emissions per kWh of generation on Catalina	0.005 lbs/kWh	NREL calculation[40]

7.1 INTRODUCTION

This section of the feasibility study complements NV5's Santa Catalina Island feasibility analysis by identifying opportunities and providing recommendations to cost-effectively reduce energy usage (kWh) via energy efficiency (EE); peak demand (kW) via Demand Response (DR) and equivalent load management measures; and associated emissions.

[35] SCE estimate reported by Matt Zents, pers. comm., 10 April 2020.

[36] (Southern California Edison, 2018)

[37] (California Energy Data and Reporting System, 2018)

[38] (California Energy Data and Reporting System, 2018)

[39] Former EnerNOC (DR service provider) executive, pers. comm., 2 April 2020.

[40] NREL calculation, forwarded by NV5's Jack Gardner, pers. comm., 16 April 2020.

EE/DR opportunities were identified through (3) primary sources:

1. Desktop utility metered data analysis for all Catalina customers
2. Reports and other documents provided by SCE or Catalina customers
3. SCE RFI responses and interviews with SCE personnel

The original Scope of Work (SOW) included site visits and ASHRAE Level 1–2 energy audits at up to 10 of the largest energy users, but that effort was interrupted by the COVID-19 pandemic. SCE assisted NV5 with customer outreach by sending out NV5's site energy questionnaire to augment the existing data. In addition, NV5 conducted follow-up customer telephone interviews. However, this outreach yielded only limited information from a couple of customers before site visit planning was halted by the pandemic travel bans, shelter-in-place directives and customers' low response rate due to higher-priority pandemic mitigation work. The following NV5 analysis and recommendations relies heavily on utilizing the best available data and assumptions in lieu of site visits.

7.2 EXISTING CONDITIONS AND ENERGY USE OVERVIEW

Existing conditions at Catalina Island are summarized in the following sections.

7.2.1 Electricity Usage (kWh)

The NV5 EE/DR study team analyzed metered electrical data for 1,749 customers distributed across 2,513 utility meters. Continuous monthly data was provided by SCE for most accounts from January 2017–August 2019. Interval data was only available for 35 meters across 24 customer accounts. The most recent twelve months of metered data indicates a total annual electricity consumption of approximately 26 million kWh.

Please note that there is a discrepancy between the metered consumption-based customer usage data provided by SCE for this EE/DR study, and the generation-based supply data used by the NV5/NREL repower team. SCE provided the repower team with generation data for 2015–2017 collected from the diesel generators, battery storage, and microturbines on Catalina, with a grand total of 29 million kWh supplied across 2017. SCE's metered consumption data for most customers totaled 23.9 million kWh during 2017. The discrepancy between the "supply-side" and the "demand-side" data may result from incomplete customer usage data, and the difference between what is sent out by generating stations into the distribution system and what is consumed by the customers due to line losses, power factor issues, and other factors. The annual load values used in the EE/DR report provide a conservative estimate of what savings might be achieved. If the load is actually higher than the demand-side data suggests, there could be room for further reduction in kWh, and therefore, more savings.

7.2.2 Electrical Load Data (kW)

NV5 did not have sufficient data to develop a detailed load profile for Catalina Island as a whole. The NV5 repower team developed estimates for Catalina's load profile based upon Pebbly Beach generation station output data that is load-following. Estimated peak load is around 5.5 MW. However, this generation data does not provide much insight into the load profiles of individual customers or aggregate customer segments (*e.g.*, residential or commercial users).

The 15-minute interval data for the previously mentioned 35 meters was analyzed against time and other parameters to determine patterns and extrapolate information from.

7.2.3 Customer Segmentation

According to a 2019 SCE study, Santa Catalina Island is home to 1,382 SCE customers across 2,528 service accounts. The breakdown of customer accounts is approximately 90% (1,245) /10% (137) residential and commercial respectively. The service accounts breakdown shifts to 76% (1,931) residential and 24% (597) commercial due to many more commercial customers having multiple service accounts.[41] Some accounts (mostly residential) are all-electric buildings; many are mixed-fuel electricity and natural gas consumers. This EE DR study focuses solely on electricity usage.

The SCE Building Electrification (BE) team developed Figure 7-1 to depict the relative mix of electricity and natural gas service accounts (some customers have multiple service accounts), and fuel use by type for both Domestic (residential) and Non-Domestic (all other) service accounts.

ACCOUNT TYPE	GAS SERV ACCT	ELEC SERV ACCT	KWH	THERMS
Residential	1,245	1,931	7,186,698	184,884
Non-Residential	137	597	18,191,584	286,118

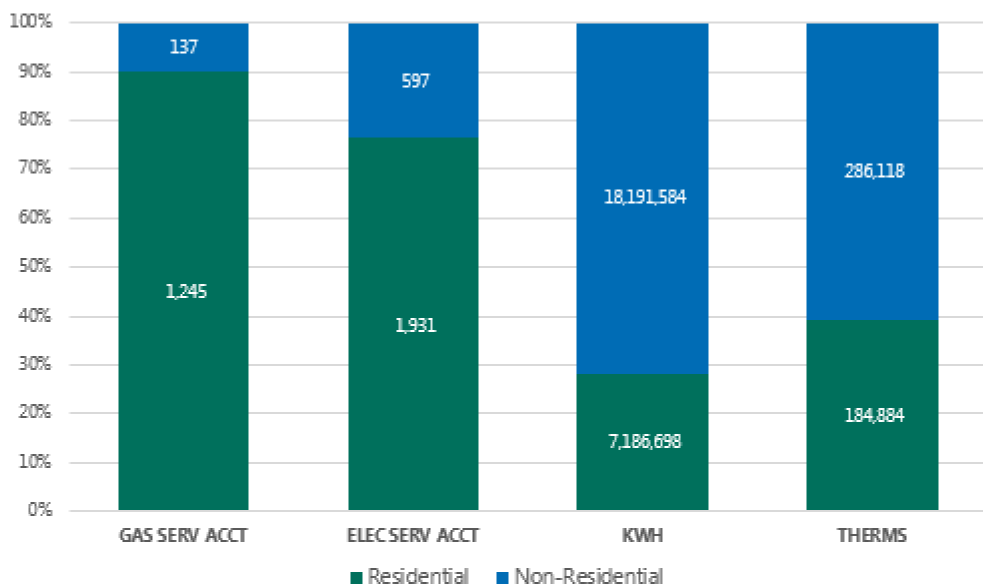


Figure 7-1 - Catalina Island Energy Use Overview

NV5 analyzed the provided utility information to better understand energy consumption by customer segmentation. The analysis of the most recent twelve months or trailing-twelve-months (TTM), revealed that only 27% of electricity is consumed by residential accounts while the remaining 73% are consumed by those on non-domestic tariffs. This corresponds to electrical consumption of 7 million kWh and 19 million kWh respectively. This information is depicted in Figure 7-2 below with residential being referred to as “domestic” and commercial referred to as “non-domestic”. The following sections further analyze the customer based by domestic, non-domestic, and the top 20 consumers.

[41] (Southern California Edison, 2019), Slide 1.

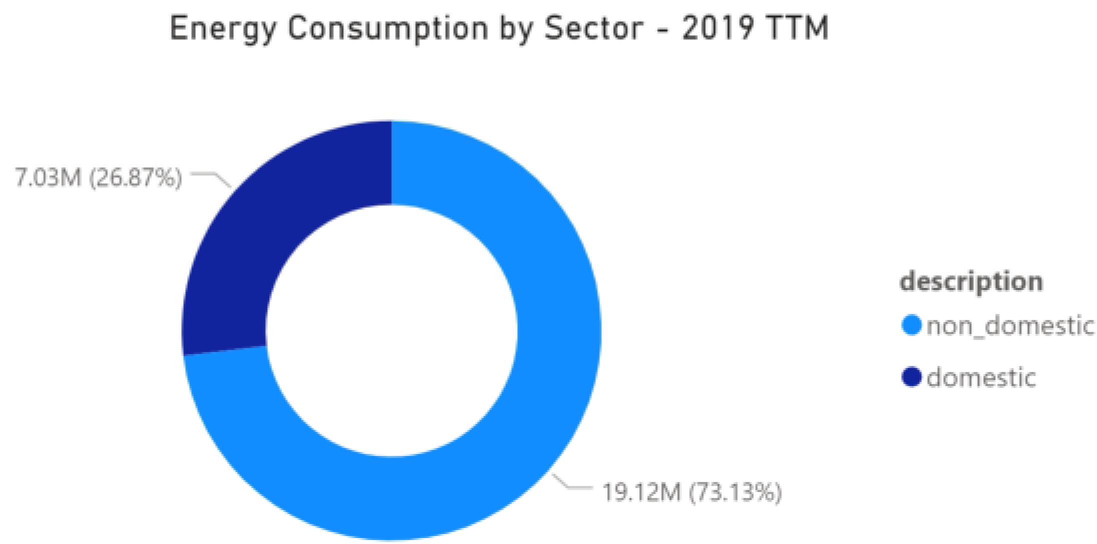


Figure 7-2 – 2019 Energy Consumption by Sector

7.2.4 Domestic Rate Customers

Domestic rate residential customers are 90% of customers and 27% of total electricity usage at 7 million kWh. SCE analysis indicates that 519 or 69% of residential customers are mixed-fuel dwellings (natural gas and electricity) while 31% are electric-only.[42] Much of the housing stock dates from the 1930s–1950s and is relatively poorly insulated. Many lack air conditioning (A/C) and have electric resistance heating systems. SCE analysis indicates that only 364 homes or 21% are larger than 1,500 ft^2,[43] while the national median size for single-family homes was 2,355 ft^2 in 2019.

Analysis of the provided utility data revealed that 20% (257 of 1,245) of domestic customers are on the D-Care, "income-qualified customers", LMI tariff. NV5 utility data analysis indicates these LMI customers account for 2.3 million kWh or 14% of residential electricity consumption. A description of the residential tariffs is provided below.

Table 7-3 - Residential Tariff Rates

Tariff	Definition
Domestic	Single-family dwellings; tiered structure based on consumption
D-Care	"Income-qualified customers" (*i.e.*, income less than 2x Federal Poverty Level), ~20% less than domestic
DM	Domestic multi-family (*e.g.*, apartment buildings and duplexes constructed prior to 1978, residential hotels, and qualifying RV parks).

[42] (Southern California Edison, 2019), Slide 3.
[43] *ibid.*

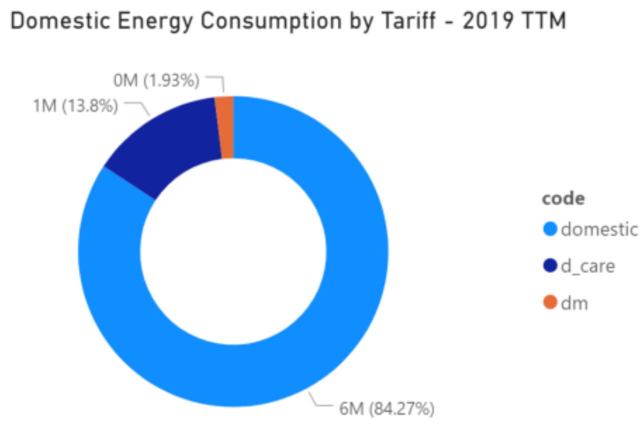


Figure 7-3 - 2019 Domestic Energy Consumption by Tariff

617 homes are all-electric, while 1,182 use mixed fuels (natural gas and electricity). SCE data in Figure 7-4 depicts the mix of these two fuel types in four size classes (NV5 applied an average square footage value to homes of "unknown" size in the SCE data).

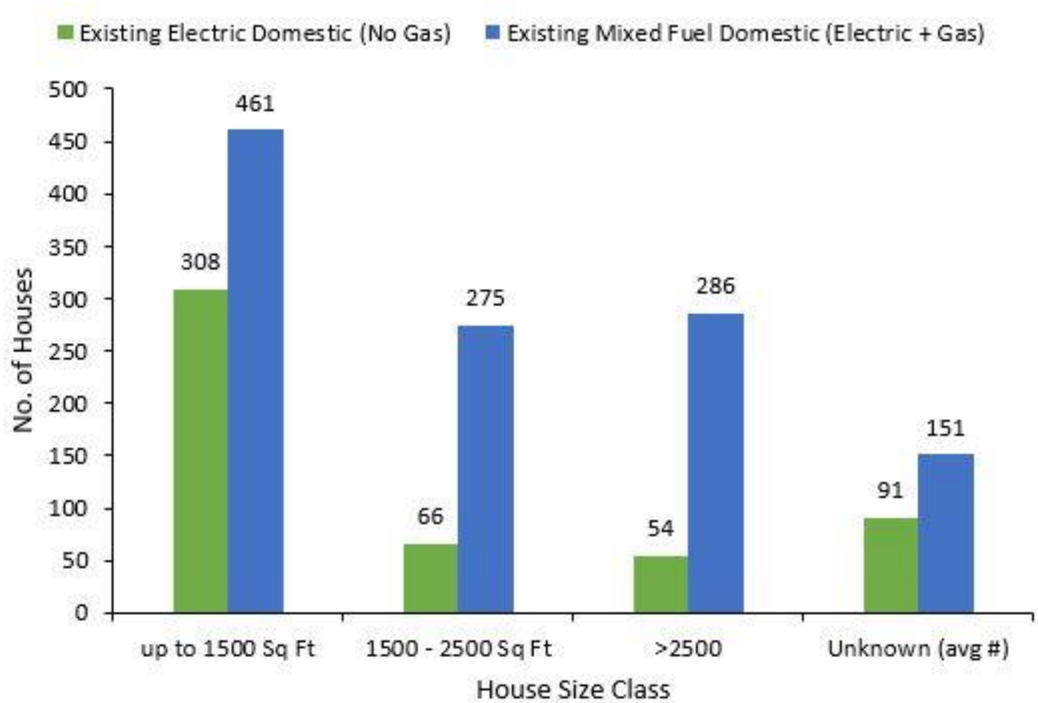


Figure 7-4 - Residential Energy Use by Size Class

Building electrification (BE) is being considered for Catalina (see Section 7.8.2.1). NV5 utilized detailed residential energy use projections developed by SCE's BE team. SCE is developing plans to implement a suite of ECMs for all single-family residences, to reduce their electric load in conjunction with developing plans for a BE campaign.

7.2.5 Non-Domestic Rate Customers

Non-Domestic rate customers—commercial and industrial (C&I), institutional and municipal—comprise only 10% of all customers but account for 77% (19 million kWh) of Catalina Island's electrical usage. The analyzed utility data included 23 unique non-domestic tariffs inclusive of six SCE specific tariffs. The top 10 tariffs account for 96% of the energy consumption and are described below in Table 7-4 and Figure 7-5.

Table 7-4 - Non-Domestic Tariffs

Tariff	Definition
GS-2	General Services, Demand (<200kW)
GS-1	General Services, Non-Demand (<20kW)
SCE-M	SCE Installation Rate
TOU-GS2D	Time-Of-Use, Demand, General Services (<200kW)
PA-2	Time-Of-Use, Demand, Agriculture and Pumping
TOU-GS3-D-SCE	Time-Of-Use, Demand, General Services (<500kW, SCE)
PA-2-SCE	Time-Of-Use, Demand, Agriculture and Pumping (SCE)
TOU-GS-1-D	Time-Of-Use, Demand, General Services (<200kW)
DE	Domestic Service to Utility Employees
GS-2-SCE	General Services, Demand (<200kW, SCE)

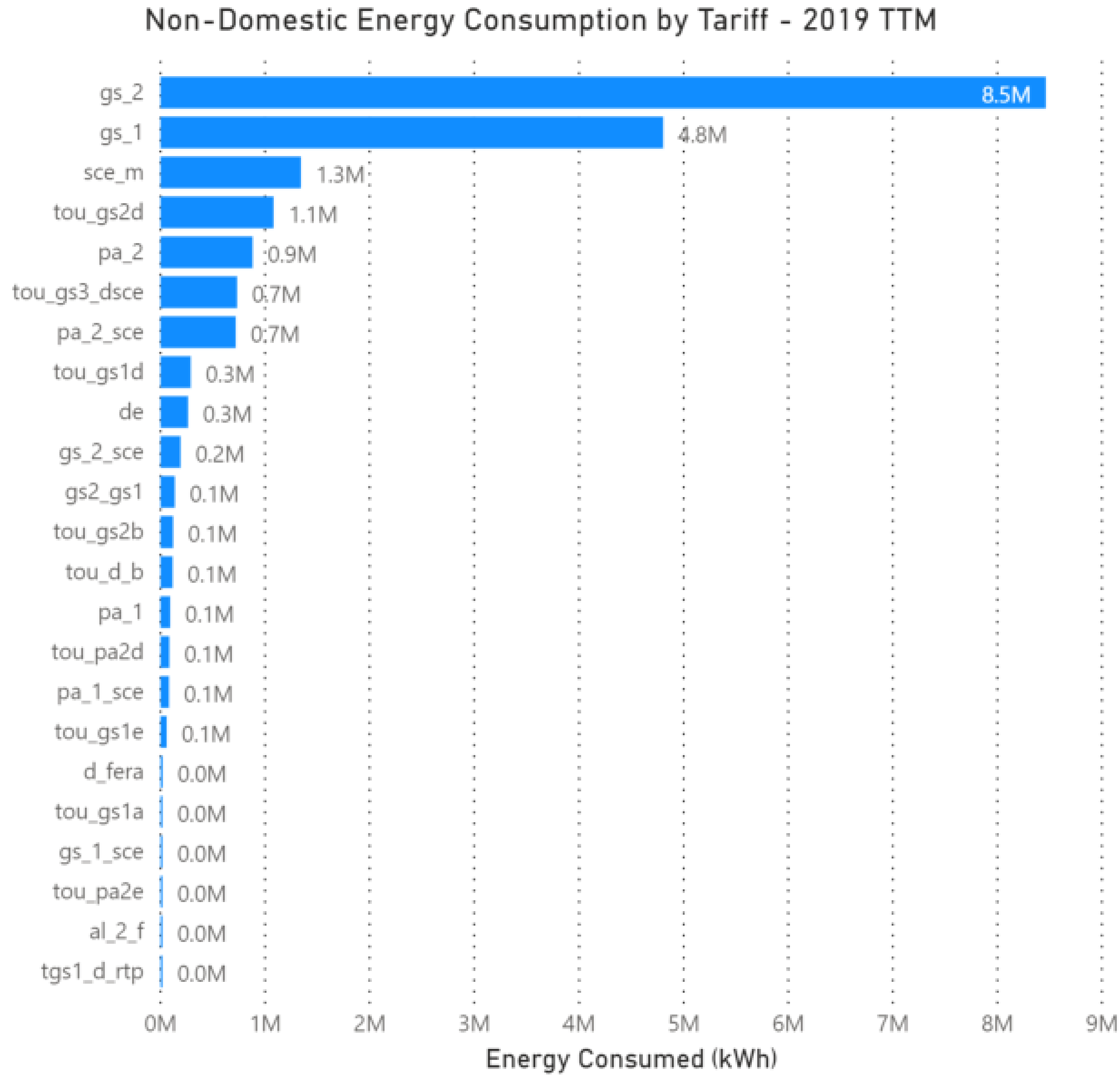


Figure 7-5 - 2019 Non-Domestic Electricity Use by Tariff

7.2.6 Largest Electricity Users

The 2,528 service accounts were grouped by customer and sorted by annual energy consumption. The intention is to produce a list of customers who should receive the focus of energy efficiency and demand response efforts. This is the list NV5 would have used to perform on-site energy audits.

The 20 largest accounts are depicted in Table 7-5. With a combined total annual consumption of 12,385,538 kWh, they represent roughly 48% of the total electricity use of 26,100,000 kWh during the measurement period. Clearly a focus on reducing energy use at these top 20 customers could significantly shape the island's load.

Table 7-5 - Top 20 Customer List[44]

Rank	Customer Name[45]	Facility Type	Annual Usage (kWh)
1	XXXXXXXXXXXXX	Potable and saltwater pumping, desalination, natural gas and electricity production & distribution	2,605,210
2	XXXXXXXXXXXXX	Hotel and Hospitality	1,510,266
3	XXXXXXXXXXXXX	Municipal buildings, wastewater treatment	1,261,363
4	XXXXXXXXXXXXX	Supermarket	744,240
5	XXXXXXXXXXXXX	Resorts and Hotels	638,356
6	XXXXXXXXXXXXX	Marine Institute	614,420
7	XXXXXXXXXXXXX	Multi-purpose/ Variety of Buildings	506,662
8	XXXXXXXXXXXXX	Non-profit outdoor education	495,495
9	XXXXXXXXXXXXX	Supermarket	438,880
10	XXXXXXXXXXXXX	Restaurants and General Store	388,656
11	XXXXXXXXXXXXX	School Buildings	379,742
12	XXXXXXXXXXXXX	Non-profit	377,054
13	XXXXXXXXXXXXX	Transportation Services	374,773
14	XXXXXXXXXXXXX	Condo HOA	371,957
15	XXXXXXXXXXXXX	Resorts and Hotels	361,230
16	XXXXXXXXXXXXX	Health Services	310,680
17	XXXXXXXXXXXXX	Internal Services Facilities	293,775
18	XXXXXXXXXXXXX	Telecommunication	259,619
19	XXXXXXXXXXXXX	Non-profit outdoor education	229,320
20	XXXXXXXXXXXXX	Restaurant	223,840
		Total	**12,385,538**

7.2.7 Catalina Island Water Systems

SCE is its own largest electricity customer on Catalina. The largest portion of SCEs electricity usage is for potable water production (including desalination) and distribution. The water system can be broadly divided into three major sub-systems comprising the potable water system including the desalination facilities, the saltwater system, and the wastewater system including the Wastewater Treatment Facility (WWTF). The potable and saltwater systems are not contiguous, in that not all parts of those

[44] During the measurement period September 2018 through August 2019.
[45] Customer names have been removed to protect sensitive information.

systems are interconnected, as depicted in Figure 7-6. Due to the island's primary industry being tourism, the number of occupants fluctuates daily and seasonally. This variability affects the load profiles of potable water usage, saltwater usage and both desalination and WWTF operations.

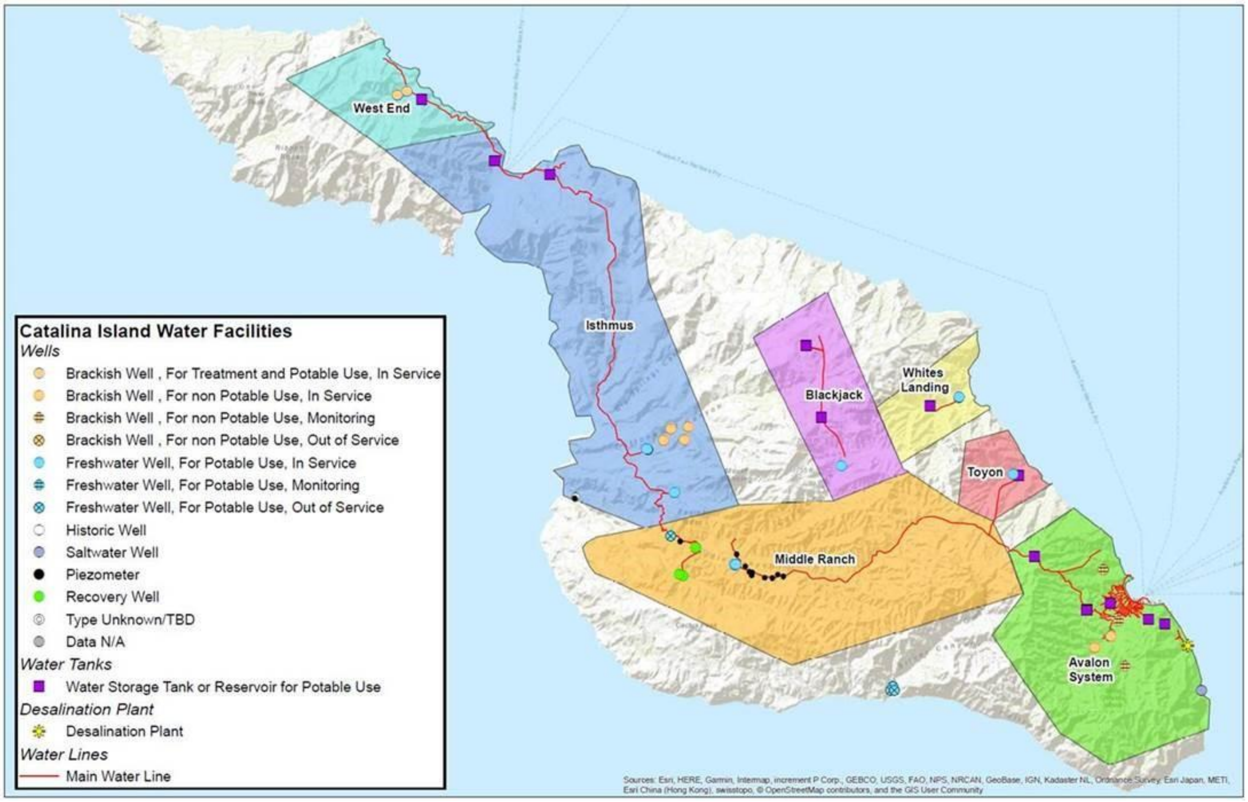


Figure 7-6 - Map of Catalina Island Water Systems

7.2.7.1 Potable Water System

The island's potable water system is owned and operated by SCE. The island utilizes both groundwater and seawater desalination as sources for potable water. The potable water system is not contiguous, in that not all parts of the system are interconnected. Potable water systems serving the island, excluding the City of Avalon, includes Toyon Well and Whites Landing. The water facilities serving specifically to the City of Avalon includes the following:

- 1 Open raw water storage reservoir (Middle Ranch Reservoir)
- 3 Ground water wells (Middle Ranch Wells)
- 1 Covered treated water reservoir (Wrigley Reservoir)
- 6 Storage tanks
- 2 Seawater desalination units

Middle Ranch Reservoir is the main inland reservoir, used to recharge the aquifer. Thompson Dam impounds the ground and surface water runoff into Middle Ranch Reservoir. The reservoir and surrounding aquifer are hydraulically linked. The Middle Ranch wells pump groundwater from the shallow aquifer to Pump House No. 2 for treatment, and then convey the potable water to Wrigley

Reservoir for storage and distribution to the City of Avalon. Seawater (feedwater) for the desalination plant is obtained from the two Quarry Seawater Wells on the South-East side of Catalina Island and conveyed to the Pebbly Beach Generation Station where the seawater desalination units are located. Pump 1 pumps the desalinated water from desalination plant 1 into the Avalon distribution system, and Pump 2 the desalinated water from desalination plant 2 into the Avalon distribution system. A variety of other pumps in the system are also included in this analysis.

The desalination facility is evidently the largest single electricity user on Catalina. The process employs reverse osmosis (R/O) membrane filtration units, thermal energy and pumping. Desalination capacity is being expanded by 50%. Specific information on equipment employed was not available.

Table 7-6 below provides a brief description of the potable water system major pumping installations and corresponding SCE account references.

Table 7-6 - Potable Water System Equipment

Facility	Equipment	Pump Motor HP
Middle Ranch Wells (Groundwater)	Thomson Dam Well: Well 1A Pump	50
	Thomson Dam Well: Well 6A Pump	50
Pebbly Beach Generation Station (Desalination)	Potable Water Pump 1	20
	Potable Water Pump 2	20
SweetWater Well	SweetWater Well Pump	5
Cottonwood Well 2A	Cottonwood Well 2A Pump	3
Howlands Landing	Howlands Well Pump	15
Whites Landing	Whites Landing Well Pump	7.5
Toyon Well	Toyon Well Pump	5
Two Pump Station	Pump Station 2 Pump #3	50
Two Pump Station	Pump Station 2 Pump #4	50
Two Pump Station	Pump Station 2 Pump #5	50
Desalination plant	Reverse osmosis, pumps	Undetermined

Table 7-7 below provides a brief description of the potable water system major pumping installations' baseline annual energy usage (mostly based on 2016 data). The equipment tariff rates and annual usage were taken from Hydraulic Tests Reports.[46] We multiplied SCE's estimated "actual generation cost" on Catalina Island of $0.396/kWh (see Section 7.4.2) by the 2016 annual usage to derive the estimated "actual annual generation cost for pump use" for SCE as both producer and customer in this case.

Table 7-7 - Potable Water System Equipment Electricity Use

Equipment	Tariff ($/kWh)	SCE Actual Generation Cost ($/kWh)	Annual Usage (kWh)	SCE Actual Annual Generation Cost for Equipment Use ($)
Thomson Dam Well 1A Pump	0.37	0.396	33,870	13,413
Thomson Dam Well 6A Pump	0.37	0.396	33,870	13,413
Potable Water Pump 1	0.22	0.396	43,056	17,050
Potable Water Pump 2	0.22	0.396	42,504	16,832
SweetWater Well Pump	0.16	0.396	32,448	12,849
Cottonwood Well 2A Pump	0.20	0.396	23,352	9,247
Howlands Well Pump	0.01	0.396	21,144	8,373
Whites Landing Well Pump	0.26	0.396	10,044	3,977
Toyon Well Pump	0.22	0.396	12,332	4,885
Pump Station 2 Pump #3	0.23	0.396	29,436	11,657
Pump Station 2 Pump #4	0.23	0.396	29,844	11,818
Pump Station 2 Pump #5	0.23	0.396	29,845	11,818
Desalination facilities	0.22	0.396	730,922	289,445

7.2.7.2 Saltwater System - Potable

The saltwater system for Santa Catalina Island is owned by the City of Avalon and operated by Environ Strategy Consultants (ES). The saltwater is used to extend the limited potable water resource in the island. This system provides water to residential and commercial buildings for toilet and urinal flushing and fire suppression. The seawater intake consists of an ocean intake, located in Avalon Bay. Water from the intake is conveyed to the Catherine Booster Station (CBS). CBS pressurizes the saltwater distribution system throughout Avalon, while also filling both Mount Ada and Falls Canyon saltwater reservoirs. The saltwater distribution system also includes two small booster stations to provide saltwater to the higher elevations within Avalon, known as Hill Street Booster Station and Whittley Booster Station.

[46] (Southern California Edison, 2016)

The system includes the following:

- Catherine Booster Station with 2 Pumps
- Distribution Pipe Network
- 2 Reservoirs: Mount Ada Reservoir and Falls Canyon Reservoir
- 2 Additional Booster Stations: Hill Street Booster Station and Whittley Booster Station

Table 7-8 below provides a brief description of the saltwater system major pumping installations and corresponding SCE account references.

Table 7-8 - Salt Water System Equipment

Facility	Equipment	Pump Motor HP
Catherine Booster Station	Main Saltwater Pump #1	100
	Main Saltwater Pump #2	100
Hill Street Booster Station	7.5 HP Centrifugal Pump	7.5
Whittley Booster Station	7.5 HP Centrifugal Pump	7.5

Table 7-9 below provides a brief description of the saltwater system major pumping installations' baseline annual energy usage (based on 2016 data). The equipment tariff rates and annual usage were taken from Hydraulic Tests Reports.[47] NV5 multiplied SCE's estimate for the "actual generation cost" of $0.396/kWh (see Section 7.4.2) by the 2016 annual usage to derive the estimated "actual annual generation cost for pump use" for SCE.

Table 7-9 - Salt Water System Equipment Electricity Use

Equipment	Tariff ($/kWh)	SCE Actual Generation Cost ($/kWh)	Annual Usage (kWh)	SCE Actual Annual Generation Cost for Pump Use ($)
Main Salt Water Pump #1	0.17	0.396	33,696.00	13,344
Main Salt Water Pump #2	0.17	0.396	33,324.00	13,196
7.5 HP Centrifugal Pump	0.20	0.396	7,000.00	2,772

7.2.7.3 Wastewater System

The wastewater system for Santa Catalina Island is owned by the City of Avalon and operated by Environ Strategy Consultants (ES). The Catherine Lift Station (CLS) serves as the initial lift to convey wastewater collected from Avalon to the WWTF. The wet well collects the raw wastewater from Avalon's gravity sewer collector system and the dry well houses the pumps and controls. Pebbly Beach Lift Station (PBLS) serves as the final lift to the WWTF. The PBLS collects raw wastewater from the industrial complex in Pebbly Beach, in addition to wastewater pumped from the CLS.

The system mainly consists of the following:

- Catherine Lift Station (CLS) with 2 centrifugal pumps
- Pebbly Beach Lift Station (PBLS) with 3 centrifugal pumps
- Wastewater Treatment Facility (WWTF)

[47] (Southern California Edison, 2016)

Table 7-10 below provides a brief description of the wastewater system major installations and corresponding SCE account references. Please note that we include only one of the PBLS pumps, Pump #2, because the available information indicated no operational data for Pumps #1 and #3. We inferred that only Pump #2 is operating; if that is mistaken, then the estimated usage would apply to the other operating pump(s) as well.

Table 7-10 - Waste Water System Equipment

Facility	Equipment	Pump Motor HP
Catherine Lift Station (CLS)	Flygt centrifugal pump (model 3153) - Catherine Lift 1	18
	Flygt centrifugal pump (model 3153) - Catherine Lift 2	18
Pebbly Beach Lift Station (PBLS)	Flygt centrifugal pump (model 3171) - PBLS BST 2	25
Waste Water Treatment Facility (WWTF)	Rotary drum screen, aeration tank, clarifier, chlorination, centrifuge dryer, pumps	Undetermined

Table 7-11 below provides a brief description of the Wastewater System major pumping installations' baseline annual energy usage (mostly based on 2016 data). The equipment tariff rates were taken from Hydraulic Tests Reports[48] and from SCE Multiple Point Test Summary file[49]. The annual usage for the pumps was taken from the SCE Multiple Point Test Summary file,[50] and for the WWTF was estimated based on daily usage data in a recycled water system proposal to the City of Avalon.[51] We multiplied SCE's estimate for the "actual generation cost" of $0.396/kWh (see Section 7.4.2) by the annual usage to derive the estimated "actual annual generation cost for waste water system use" for SCE.

Table 7-11 - Waste Water System Equipment Electricity Use

Equipment	Tariff ($/kWh)	SCE Actual Generation Cost ($/kWh)	Annual Usage (kWh)	SCE Actual Annual Generation Cost for Waste Water System Use ($)
Flygt centrifugal pump (model 3153) - Catherine Lift 1	0.17	0.396	18,168	7,195
Flygt centrifugal pump (model 3153) - Catherine Lift 2	0.17	0.396	13,776	5,455
Flygt centrifugal pump (model 3171) - PBLS BST 2	0.17	0.396	54,300	21,503
Waste Water Treatment Facility (WWTF)	0.17	0.396	479,865	190,027

7.3 CATALINA ISLAND LOAD DATA

NV5 analyzed utility data for 2,528 service accounts across 1,382 unique customers. The analysis included over 68 million kWh of electrical consumption from January 2017 to September 2019.

Monthly utility data was provided for all commercial and residential sites from January 2017 through September 2019. Interval data was only available for the larger commercial sites from January 2019

[48] Catalina well pump efficiency report April 2016.pdf
[49] (Southern California Edison - Hydraulic/Industrial Services, 2018)
[50] (Southern California Edison - Hydraulic/Industrial Services, 2018)
[51] (Michael Baker International, 2016), p.55 Table 8-1.

through September 2019. In total, trend data for 2,578 data points was imported into NV5's Analytics software for analysis and visualization.

The monthly utility data was disaggregated across two categories: 1) domestic vs. non-domestic, and 2) utility tariff. This analysis provides insights into the breakdown of power consumption by end-user as well as trending shifts in power consumption over time. This information has been used to generate benchmark KPIs (key performance indicators) for the site.

The interval data is only available for select meters that are participating in time-of-use tariffs. This data was analyzed to provide a deeper understanding of the facilities power consumption with respect to weather and time. The outcome of this analysis are high level energy and demand recommendations. These recommendations are to be further developed from the on-site energy audits.

7.3.1 Electricity Consumption Over Time and by Tariff

Analysis of the monthly utility data has shown a significant increase in annual energy consumption from 2017 to 2019. An analysis of trailing 12 months (TTM) energy consumption shows an increase from 23.9 million kWh in December 2017 to 26.1 million kWh as of October 2019. This is a 9.3% increase over a 21 months period and equates to an average annual increase of 3,488 kWh per day. This information is presented in Figure 7-7.

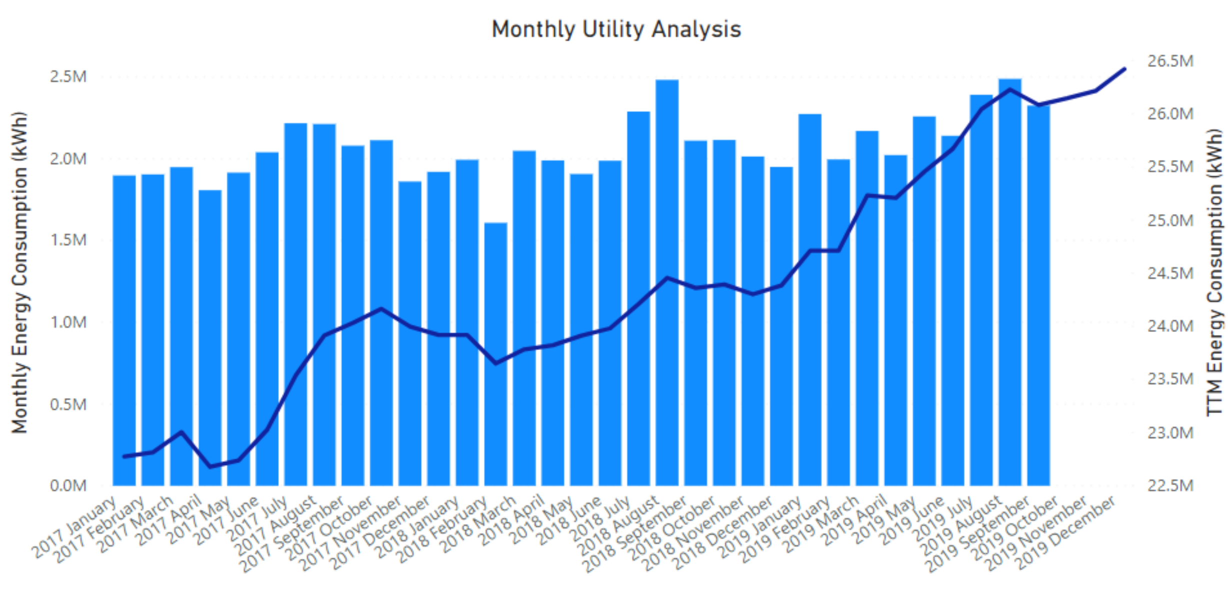


Figure 7-7 - Monthly Utility Analysis

A disaggregation of the utility data by consumer category and tariff structure was performed to understand the primary energy consumers and consumption trends. Energy is primarily consumed by "non-domestic" users at 74% over the entire trend period. However, the primary source of growth is in the "domestic" load which has grown from 24.2% to 26.9% of the island's consumption over this period.

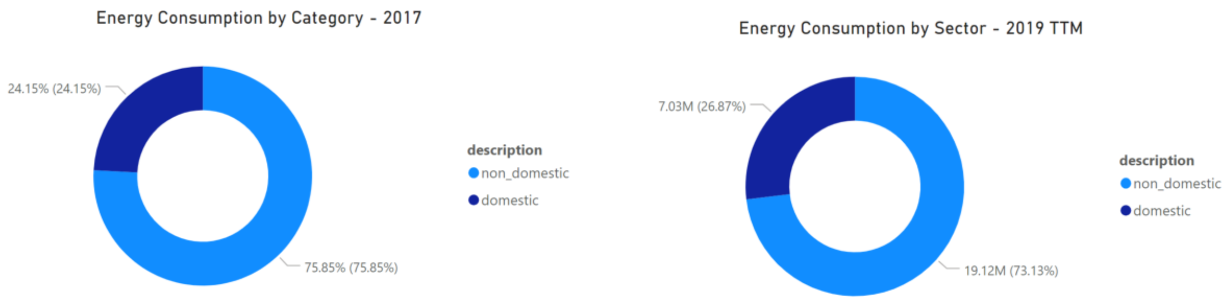


Figure 7-8 - Energy Consumption by Consumer Category

This data can be further broken down by tariff structure. Most "domestic" energy consumption is consumed by those on the "domestic" utility tariff at over 84%. This has remained relatively constant between 2017 and 2019 with a minor expansion of those on the Low-to-Medium-Income, "D-Care" tariff.

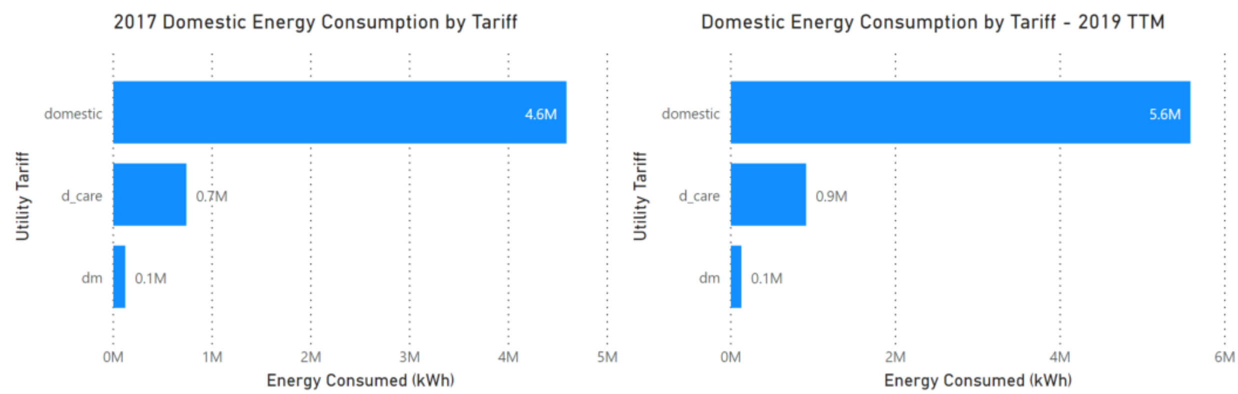


Figure 7-9 - Domestic Energy Consumption by Tariff

The "non-domestic" tariff structure is much more complicated with 23 different tariffs, six of which are SCE specific, and many of which are optional variations of each other. The top two energy consuming tariffs, GS-2 and GS-1 combined, account for over two-thirds of the non-domestic energy consumption.

The GS-2 tariff is aimed at medium-sized business with an expected peak demand between 20 and 200kW. Service accounts on this tariff consume the most energy at 43%. GS-1 (General Services Non-Demand) is comprised of small businesses who are not expected to have a peak demand exceeding 20kW. These service accounts contribute to 25% of the non-domestic energy consumption. TOU-GS3-D-SCE is an SCE specific tariff for peak demands between 200 and 500kW. This tariff is a distant third at 6% of non-residential consumption.

Grouping of similar tariffs provides additional insights into the load profile of the Island.

In total there are 11 variations of the General Service (e.g. GS-1, GS-2 and GS-3) utility tariffs. These accounts in total comprise 16.9 million kWh. This represents 84% of the non-domestic energy consumption and 61% of the Island's total energy consumption.

There are five different pumping and agriculture (PA) tariffs which combined account for 1.87 million kWh. This represents 10% of the non-domestic energy consumption and 7% of the Island's total energy consumption.

There are 11 time-of-use tariffs. This includes four PA tariffs and seven GS tariffs. In total, these tariffs account for 4.1 million kWh. This represents 22% of the non-domestic energy consumption and 16% of the Island's total energy consumption.

There are several small consumer tariffs (<20kW). This includes two PA tariffs and five GS tariffs. In total, these tariffs account for 5.4 million kWh. This represents 26% of the non-domestic energy consumption and 19% of the Island's total energy consumption.

There are nine medium consumer tariffs (20kW - 200kW). This includes four PA tariffs and five GS tariffs. In total, these tariffs account for 11.7 million kWh. This represents 62% of the non-domestic energy consumption and 45% of the Island's total energy consumption.

The complete non-domestic energy consumption breakout is provided in Figure 7-10 below. This chart further breaks the data out by year to show trends over time. The breakout shows that a strong expansion of the GS-2 energy consumers is responsible for the bulk of energy consumption growth from 2017 to 2019.

Chart 6: Non-Domestic Energy Consumption by Tariff

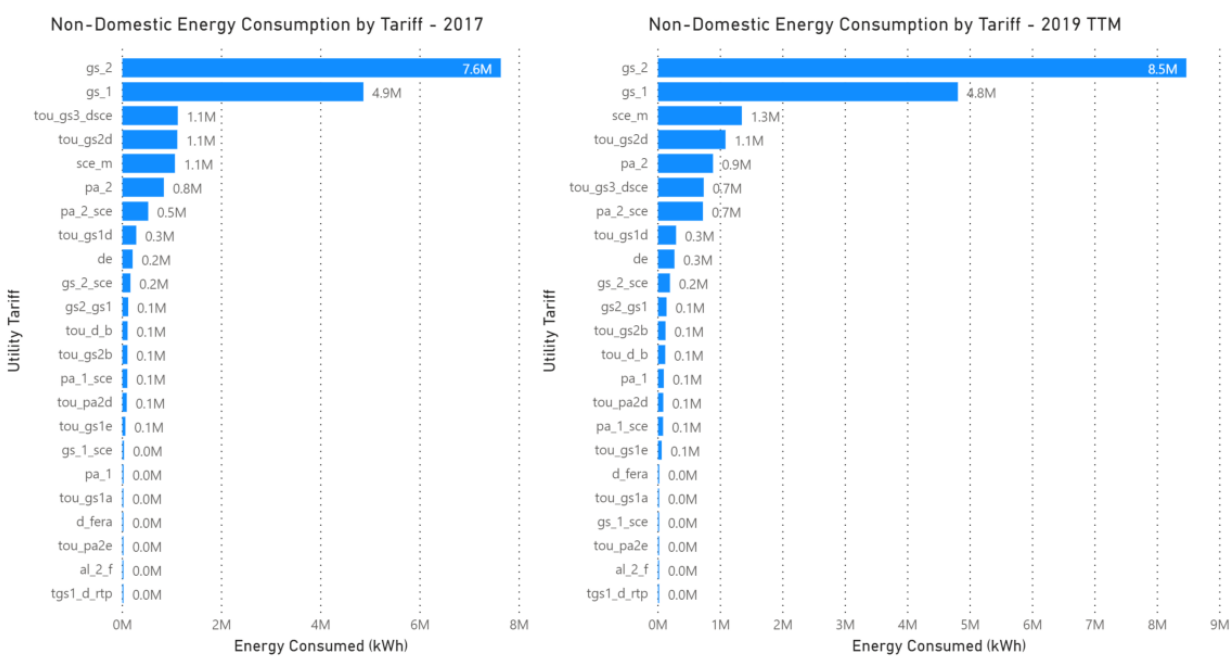


Figure 7-10 - Non-Domestic Energy Consumption by Tariff

7.3.2 Weather dependency analysis

Per the Catalina chamber of Commerce & Visitor's Bureau, Catalina Island is "…described as a mild subtropical climate…" with average summer highs of 75°F and winter lows of 59°F. Weather data for Avalon from the analyzed period confirms this description. The average temperature over the analyzed period was 61.4°F with a standard deviation of 5.7°F. This puts 95% of weather between 50°F and 73°F and makes the area a prime location to leverage airside economizers for free cooling.

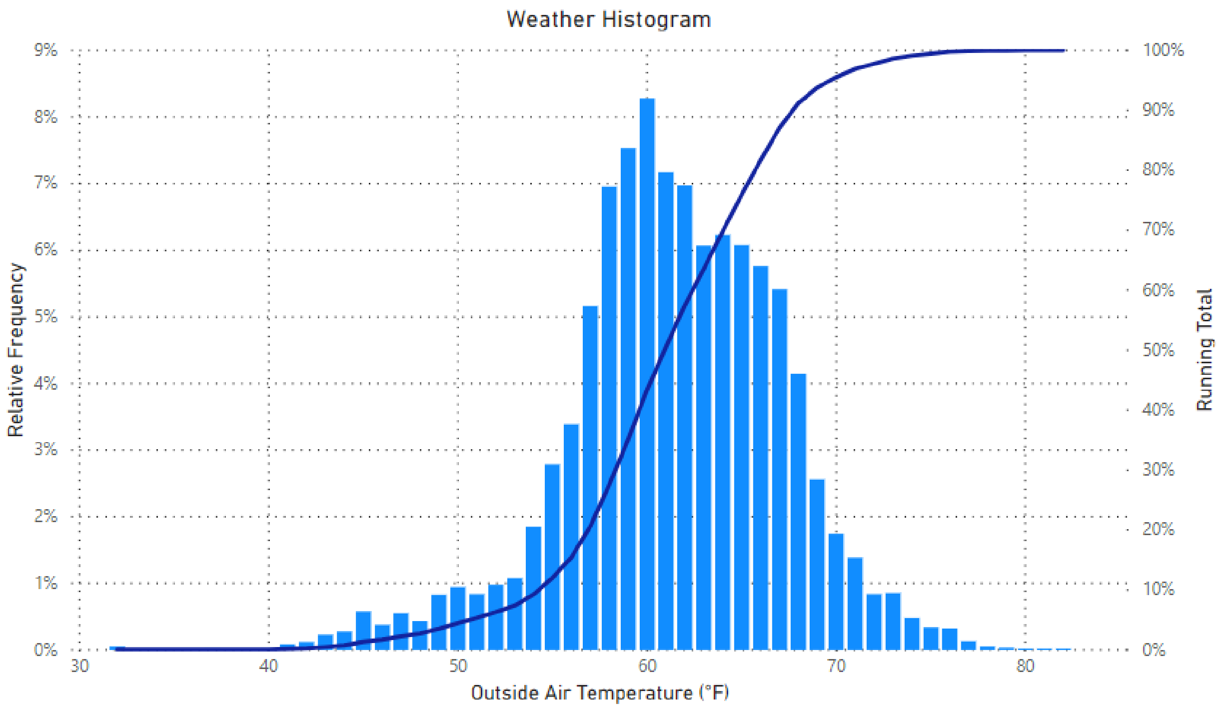


Figure 7-11 - Weather Histogram

Monthly weather data was also compared to cooling and heating degree days (CDD and HDD) with a reference of 65 °F to look for correlations between power consumption and weather data. This analysis revealed little correlation between aggregated power and either CDD or HDD.

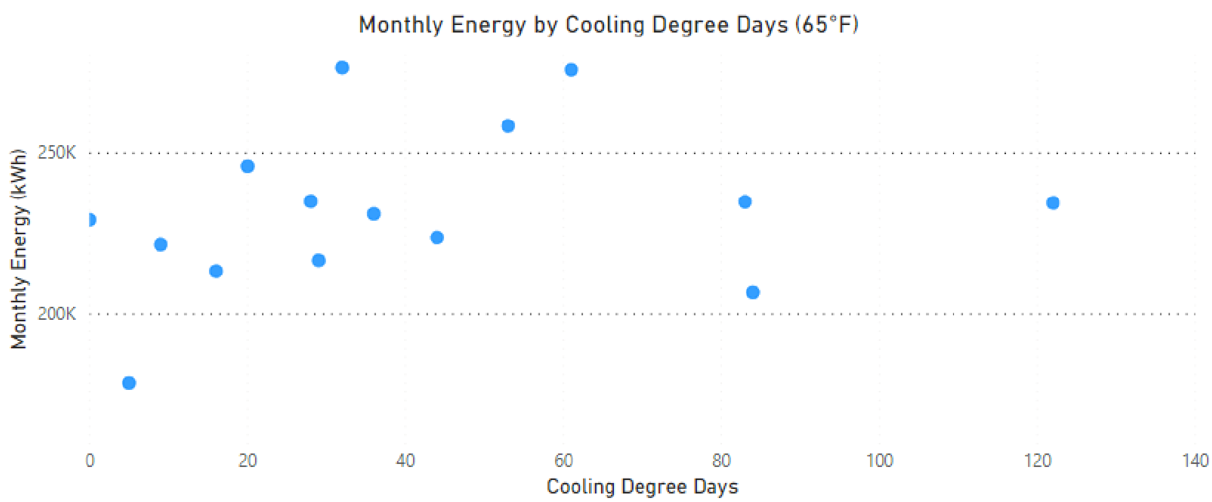


Figure 7-12 - Monthly Energy by CDD

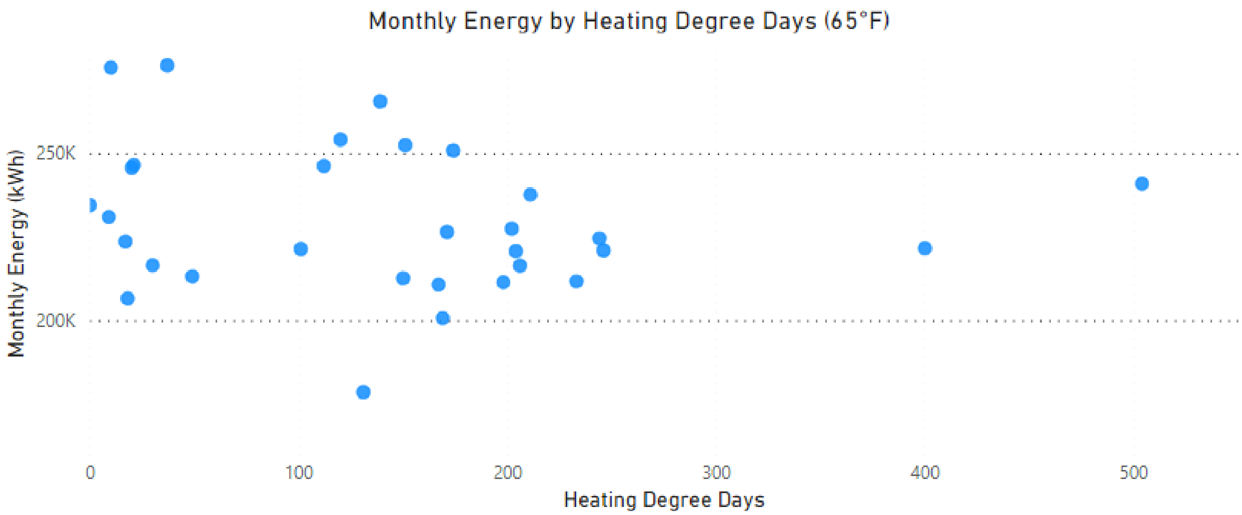


Figure 7-13 - Monthly Energy by HDD

7.3.3 Interval Data Analysis

Interval data was provided for 35 meters from January 2019 through September 2019. This information was aggregated and analyzed to provide a more granular analysis of time and weather for commercial end-users.

The initial study was a sensitivity analysis of electrical demand versus key parameters. The major findings are as follow:

1) There is a non-monotonic relationship between power and outside air temperature. Average power is shown to increase above 40°F but decrease above 65°F. We can conclude from this that weather and cooling loads are not the primary contributor of building energy consumption.
2) There is a clear pattern between power and time of day. Power begins to increase at 5am and rapidly peaks at 8am in the morning. There is a gradual decline throughout the day with a small drop and bump between noon and 1pm as people leave to lunch and return to work. Power flattens from 3pm-5pm and rapidly drops between 5pm and midnight.
3) Power varies significantly with the month. Power consumption decreases during winter and increases through the spring and summer. April is shown to consume significantly more power than the rest of the months. It is unsure if this is an outlier or a common pattern.
4) Power consumption during the weekdays is relatively constant. There is approximately a 12% reduction over the weekend.

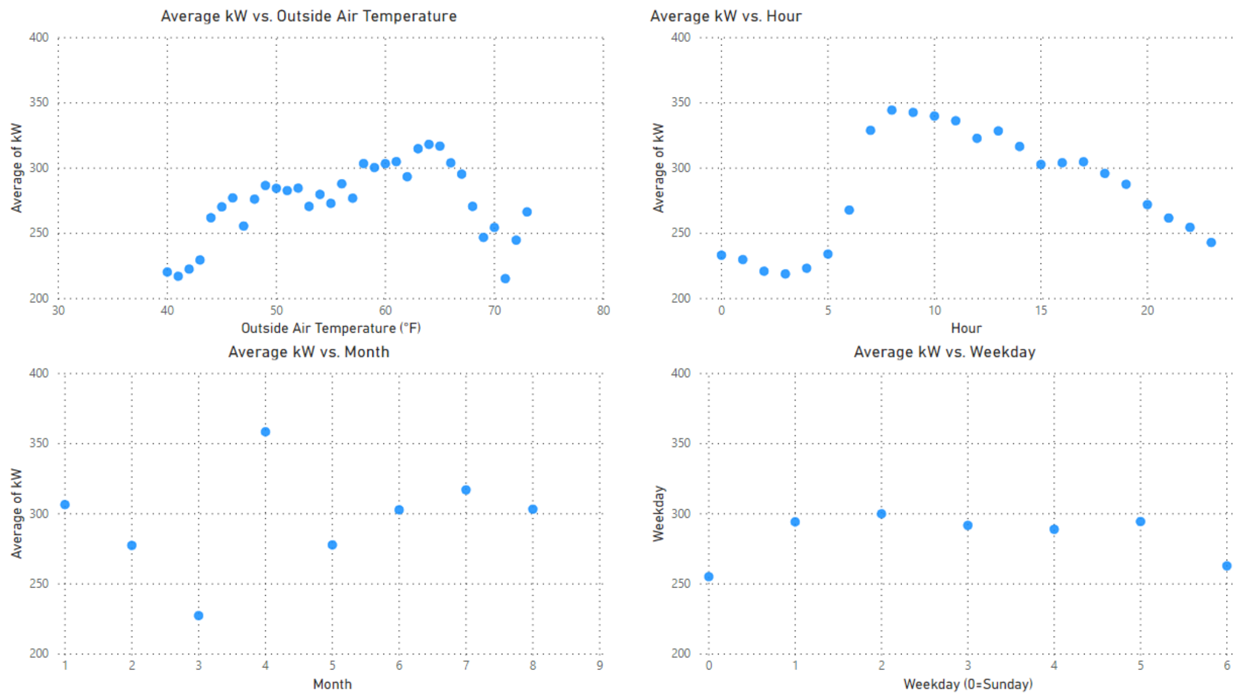


Figure 7-14 - Power Sensitivity Analysis

7.3.4 Opportunities Identified Through Utility Analysis

Interval data for Individual energy meters was analyzed against NV5 analytic algorithms to identify high level opportunities and areas of focus for the on-site energy audits. The findings are as follow:

1) There are four energy meters that consistently demonstrate demand spikes. Spikes are defined as a demand increase of at least 5kW followed immediately by a demand decrease of at least 5kW. This signature is indicative of the simultaneous enabling of large energy consuming equipment such as constant speed, non-soft started motors. The four service accounts are described below with snippets of the spikes in action.

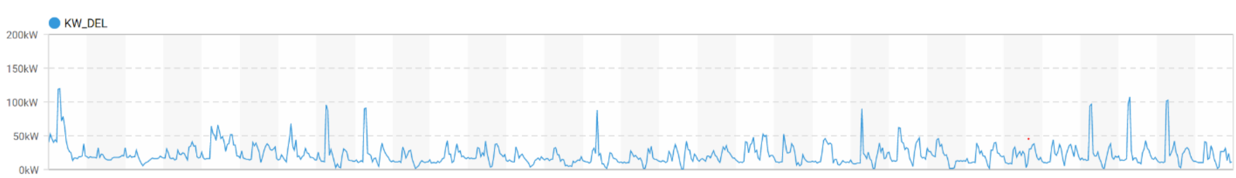


Figure 7-15 - Account ####### - March 2019 Demand Spikes

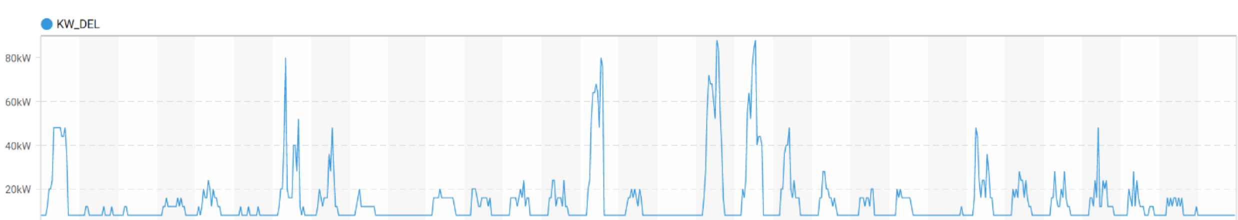


Figure 7-16 - Account ####### - March 2019 Demand Spikes

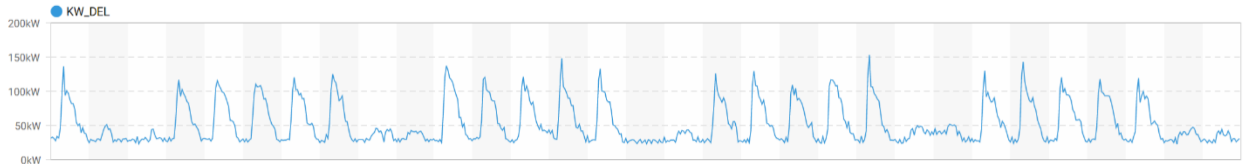


Figure 7-17 - Account ####### - March 2019 Demand Spikes

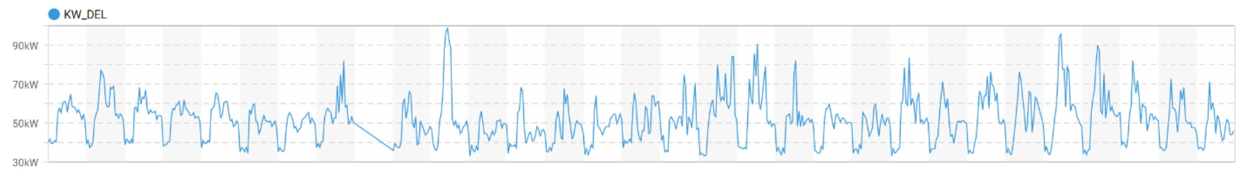


Figure 7-18 - Account ####### - March 2019 Demand Spikes

2) Each meter's nightly power consumption was compared to its daily power consumption to identify potential opportunities for night scheduling. Most sites were shown to have this as an opportunity due to a less than 40% reduction in load during unoccupied hours. An example of this behavior is shown below in Figure 7-19.

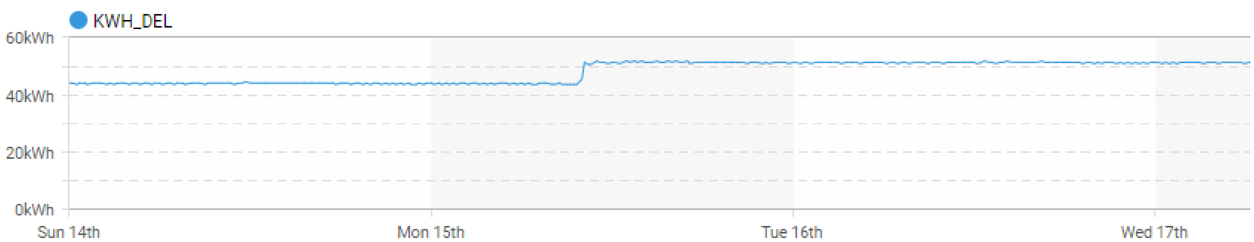


Figure 7-19 - Example of Customer Load Similarity between Day and Night

7.3.5 Utility Data Findings Summary and Next Steps

The multi-level analysis of monthly and interval utility data has provided several insights regarding the demand characteristics of Catalina Island as well as potential energy efficiency and demand reduction opportunities. The findings of this section are summarized as follows:

1) Catalina Island's trailing-twelve-month power consumption has increased by 9.3% over the 21-month analyzed period. The majority of power is consumed by non-domestic customers, but recent growth is attributed to the domestic consumers.

2) The power consumption of Catalina Island is largely weather independent. This is supported in both the monthly macro analysis as well as the hourly detailed analysis. Due to the mild weather conditions, most cooling should be accomplished with airside economizing.

3) Power consumption is driven largely driven by time-of-day and monthly patterns (presumably tourism over spring and summer).

4) Demand events for commercial end-users tend to be either at 8 in the morning when multiple large equipment is simultaneously enabled or at 1pm when employees return from lunch. It is important that soft-starts and VFDs are installed

5) Four meters were found to have several large swings in power consumption within a day.

6) Many sites were found to have minimal reduction in load during the evenings and nights and should be explored for scheduling opportunities.

These observations and findings will be used to guide the analysis of completed questionnaires and focus of the on-site investigation.

7.4 CURRENT LOAD REDUCTION POTENTIAL

7.4.1 Introduction

This section discusses opportunities for energy efficiency (*i.e.*, reduced kWh) and load profile management such as demand response (*i.e.*, reduced kW), and estimated values for the quantity and cost Key Performance Indicators (KPIs) of those reductions.

NV5's goal in developing these KPIs is to answer the following questions: what is the average cost to SCE of reducing the energy use of its customers by one kWh, and of reducing its customers' load demand profile by one kW? Energy analyst Amory Lovins at Rocky Mountain Institute coined the term "negawatt" for a conserved Watt of load reduction, and by extension a "negawatt-hour" for a conserved watt-hour of energy consumption. This concept is applicable to our inquiry, as essentially NV5 is estimating the average cost to SCE of saving or "delivering" a negawatt and a negawatt-hour on SCI. These KPIs would enable a common-basis comparison of both supply-side and demand-side investment options on SCI. In cases where saving a kW is less expensive than investing in an equivalent amount of generating capacity, or conserving a kWh is cheaper than generating it, then demand-side measures would be the more economical choice.

7.4.2 KPI Data and Assumptions

NV5 developed several EE KPI estimations and assumptions due to the lack of data and other information. The most important KPIs for the purposes of this analysis are both the cost of a "negawatt-hour" of reduced customer electricity usage expressed as $/kWh, and the cost per "negawatt" of reduced customer power demand expressed as $/kW, that would be borne by SCE in implementing EE and DR programs on Catalina.

7.4.3 First Year and Lifecycle Gross Cost per kWh

The California Energy Data and Reporting System (*CEDARS*) provides public access to information about utility EE performance and cost-effectiveness. Utility reporting and third-party DSM program impact assessments utilize both first year gross cost and lifecycle gross cost $/kWh metrics. The California Public utility Commission (CPUC) provides the following definitions: "First-year savings are the savings that a measure accrues in the first year after installation, as opposed to lifecycle savings that accrue over the entire lifetime of the equipment or measure that was installed. Lifecycle savings are used in cost effectiveness calculations."[52]

NV5 follows this approach and estimates both first year gross cost and lifecycle gross cost $/kWh metrics. To derive first year gross cost we divide the initial installed cost of the ECMs by the kWh saved in the first year. To derive life cycle gross cost we assume a ten year blended average Expected Useful Life (EUL) for all the equipment collectively installed in EE programs, and divide the initial installed cost of ECMs by ten years of savings (without adjusting for inflation or annual utility cost escalation).

Our estimates do not include any incentives and rebates that the customers might receive. NV5's focus is on the potential cost to SCE of implementing load reduction on Catalina Island, described in terms

[52] CPUC 2018, p.15.

that enable a common-basis comparison between supply and demand options. Our simplified approach ignores potential programmatic accounting and financing differences that might exist between how supply- and demand-side investments are made or where the funds originate. If such significant differences exist, we leave it to SCE to adapt our analysis.

CEDARS provides the following data for SCE EE programs in 2018[53], depicted in Table 7-12.

Table 7-12 - CEDARS Data for SCE EE Programs 2018

Primary Sector	Total Expenditures ($)	First Year Gross (kWh)	First Year Gross kW	Lifecycle Gross (kWh)	First Year Gross Cost ($/kWh)	First Year Gross Cost ($/kW)	Lifecycle Gross Cost ($/kWh)
Agricultural	2,688,429	3,342,367	801	29,780,706	$ 0.80	3,356	$ 0.09
Commercial	56,498,857	84,472,039	17,191	756,836,411	$ 0.67	3,287	$ 0.07
Cross-Cutting	28,260,946	818,119,016	182,444	11,448,184,322	$ 0.03	155	$ 0.00
Industrial	8,341,369	13,400,290	1,385	94,292,089	$ 0.62	6,023	$ 0.09
Public	21,577,994	33,334,065	1,263	169,619,505	$ 0.65	17,085	$ 0.13
Residential	80,039,410	453,557,444	92,730	4,775,072,192	$ 0.18	863	$ 0.02
Portfolio (all Sectors)	197,407,004	1,406,225,221	295,815	17,273,785,224	$ 0.14	667	$ 0.01

7.4.4 First Year and Lifecycle Gross Cost per kW

An important goal for this study was to estimate the cost of a "negawatt" of reduced customer load in the form of a $/kW KPI. However insufficient information was available to develop a refined estimate. Most of the meters on Catalina do not provide interval data, so customer load profile information is unavailable other than monthly peak kW demand and kWh consumption. Generation station data provides an approximation of the entire island's load curve, but this provides minimal insight into customer-specific demand.

Historical data is lacking. Reportedly SCE does not offer direct DR programs. On the mainland, DR programs implemented by third-party aggregators participate in the CAISO capacity market by the coordinated control of equipment at customer locations to reduce demand during peak demand and pricing periods. DR participation is most valuable for customers on Time of Use (TOU) rates. But Catalina is not connected to the mainland grid and therefore does not participate in the DR marketplace.

In the CEDARS data in Table 7-12 above, please note that the first year gross cost per kW of load reduction is orders of magnitude larger than the related $/kWh. NV5 infers that this is because the reductions in customer power demand were collateral byproducts of EE program reductions in customers' energy consumption, rather than resulting from targeted demand reduction measures implemented by a DR program that intends to defer or shift load as the primary objective.

Insufficient information was available to estimate an average kW demand reduction per kWh of consumption reduction, or even to determine whether there is such a generalizable correlation for given types of customers. DR opportunity is a highly customer-specific condition, dependent upon onsite equipment type, energy intensity, and customer daily operating patterns and requirements.

Lifecycle gross cost per kW is difficult to evaluate because DR often relies on installation of new controls and communications to modulate existing customer equipment operations during peak

[53] (California Energy Data and Reporting System, 2018)

demand periods, rather than installing new mechanical or electrical devices with consistent EUL information.

Under these circumstances NV5 made very high-level assumptions and estimates informed by the limited generic information available to us. NV5 estimates $/kW values for a hypothetical SCE DR program in Table 7-13 below. For further discussion see Section 7.7.4.

7.4.5 The Catalina Factor

Another KPI is SCE's actual costs of generation capacity ($/kW) and of electricity generated ($/kWh) on Catalina, which is higher than the equivalent average costs on the mainland service territory. Transporting cargo and personnel by marine vessel or aircraft from the mainland to the island results in higher installed equipment costs. Catalina Island generation costs are spread over a small number of customers, who pay the same average tariffs as mainland customers—yielding revenue well below the level required to cover the utility's expenditures on SCI. This cost adder effect is referred to by some observers as "the Catalina factor."

SCE estimated that the 2018 actual cost of generation on Catalina was $0.396/kWh, incorporating cost factors including fixed operations and maintenance (O&M), variable O&M, fuel and emissions.[54] One SCE analyst estimated that the average cost of the overall supply portfolio in its mainland service territory for a recent year was $0.063/kWh.[55] That suggests that the Catalina factor is roughly a six fold multiplier for generation. The seeming consensus among utility personnel was that the actual generation cost is estimated to 3–5 times the mainland average cost.[56] NV5 chose the middle of that range to make a conservative estimate that the "Catalina factor" for all electricity system-related costs was four times that of the mainland. We apply that "Catalina factor" 4X multiplier to the mainland's average EE costs to develop a specific KPI where specific data was not available or other estimates do not apply.

NV5's KPI estimates, assumptions and considerations are detailed in the following Table 7-13.

Table 7-13 - EE KPI Estimates, Assumptions and Considerations

KPI	Value	Notes
SCE annual average cost of generation ($/kWh) in its entire service territory	$0.063/kWh	[SCE source notes this # is:] For a recent year, average cost of the overall supply portfolio (total energy resource recovery account costs/total customer sales).[57]
SCE estimated 2018 average actual generation cost ($/kWh) on Catalina	$0.396/kWh	SCE analyst estimate[58]; other SCE personnel estimate 3–5X mainland average cost; NV5 uses 4X as "Catalina factor"
SCE EE program annual average first-year gross cost per saved kWh ($/kWh) in its service territory	$0.14/kWh	SCE 2018 all EE programs first-year gross cost, as per CEDARS data[59]

[54] (Southern California Edison, 2018)
[55] SCE estimate reported by Matt Zents, pers. comm., 10 April 2020.
[56] For example, see the quote in Section 4.5.1.
[57] SCE estimate reported by Matt Zents, pers. comm., 10 April 2020.
[58] (Southern California Edison, 2018)
[59] (California Energy Data and Reporting System, 2018)

KPI	Value	Notes
Estimated SCE EE program annual average first-year gross cost per saved kWh ($/kWh) on Catalina	$0.56/kWh	NV5 uses 4X mainland average as "Catalina factor"
Estimated SCE EE program annual average lifecycle gross cost per saved kWh ($/kWh) on Catalina	$0.056/kWh	NV5 assumes 10 year EUL for ECMs and uses estimated first year gross cost $/kWh
SCE EE (not DR) all-programs annual average first-year gross cost per saved kW ($/kW) in service territory	$667/kW	SCE 2018 all EE programs first-year gross cost, as per CEDARS data[60]
SCE DR program annual average first-year gross cost per saved kW ($/kW) in its service territory or on Catalina	N/A	No Catalina Island DR program history
Estimated SCE DR program annual average first year gross cost per saved kW ($/kW) in service territory	$80/kW-yr	DR industry vet: estimated range between $40/kW-yr and $120/kW-yr as a typical cost of capacity at the CAISO level[61]; NV5 uses median value of that range
Estimated SCE DR program annual average first year gross cost per saved kW ($/kW) on Catalina	$320/kW-yr	NV5 uses 4X estimated mainland average value as "Catalina factor"
Estimated NO_X emissions per kWh of generation on Catalina	0.005 lbs/kWh	NREL calculation[62]

7.4.6 NO_x Emissions Reductions

This analysis was initiated due to emissions reductions requirements, particularly for NO_X. The DOE National Renewable Energy Laboratory (NREL) repower team calculated that the NO_X emissions factor for each kWh of generation on Catalina Island is 0.005 lbs/kWh. NREL derived this value from their calculated total of 75.4 tons of NO_X emissions per year, divided by 29,000 MWh of supply (based on generation data) = 5.2 lbs/MWh, or 0.005 lbs/kWh[63].

7.4.7 SCE EE Programs on Catalina Island

SCE reports that 11 different EE program types have been implemented in Avalon since 2012 covering commercial, residential and agricultural sectors. Commercial sector programs accounted for 65% of energy savings and MUD (Multi-Unit Dwelling) sector programs 23% of savings.[64] SCE provided the table below[65] that provides indicative data on the first year gross costs per kWh of these programs. Please note that the table uses a $/kWh KPI calculation that differs from NV5's approach: In this table SCE divides the dollar amount of *incentives distributed* by the kWh reductions annually, rather than

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60 (California Energy Data and Reporting System, 2018)

61 Former EnerNOC (DR service provider) executive, pers. comm., 2 April 2020.

62 NREL calculation, forwarded by NV5's Jack Gardner, pers. comm., 16 April 2020.

63 *Ibid.*

64 SCE analysis by Maurice Ahyow, reported by Molham Kayali, pers. comm., 11 March 2020.

65 *ibid*.

the methodology used by CEDARS that divides the *installed cost of ECMs* by the conserved kWh to derive $/kWh. SCE's methodology is sound for internal program evaluation purposes. NV5 uses the CEDARS methodology to estimate $/kWh KPIs on Catalina (see Section 7.4.3).

The SCE incentives-based data in the table below shows that between 2012–2017 a total of 756 MWh were saved at an average cost of $0.41/kWh conserved, or a weighted average cost of $0.50/kWh conserved when each year's relative share of total savings is factored in. The cost per kWh conserved varied considerably over that period, concomitant to the variety of programs implemented. Since 2017 EE programs have included provision of LED luminaires to Catalina businesses, institutions and residents.

Table 7-14 - Annual Summary of Catalina EE Programs 2012-2017

	2012	2013	2014	2015	2016	2017	All Years
MWh Saved	1	13	58	171	231	282	756
Incentives Distributed	$66	$1,745	$56,735	$60,407	$35,717	$219,781	$374,451
Average Cost per kWh	$0.06	$0.14	$0.98	$0.35	$0.15	$0.78	$0.41

SCE reports that it has not implemented DR programs on Catalina Island. Evidently no third-party DR providers have operated on the island, as it is not connected to the mainland grid and therefore is not a participant in CAISO DR markets.

7.5 DOMESTIC CUSTOMERS RECOMMENDATIONS

7.5.1 Overview

NV5 utilized detailed EE projections developed by SCE's Building Electrification (BE) team. SCE is developing plans to implement a suite of ECMs for all single-family residences, to reduce their electric load in conjunction with developing plans for a BE campaign. NV5 applied the same set of assumptions, estimations and ECMs to the Multi-Unit Dwelling (MUD) sector, SCE's term for multi-family housing (MFH). See Appendix K for more detailed analysis.

The developing SCE program's ECMs and associated financial incentives might vary somewhat depending on whether the customer is on the Market rate tariff or the Income-Qualified rate. NV5 used the equipment cost estimates from SCE's implementation cost projections, without including incentives and rebates that the customers might receive. We estimated both year one gross first cost and lifecycle gross cost using an assumed ten year Expected Useful Life (EUL) of the installed EE equipment. ECMs under consideration include the following packages of improvements that are assumed to be implemented in the SCE analysis:

Conventional and New EE Measures assumed for Catalina

ENERY STAR® LED Lighting
ENERY STAR® Refrigerators
ENERY STAR® HE Clothes Washers
Variable Speed Pool Pumps
Weatherization
Low-Flow Showerheads & Aerators
Smart Thermostats
Commercial and Industrial Customized technologies[1]

Energy Savings Assistance (Income Qualified) Program EE Measures being considered

ENERY STAR® LED Lighting
ENERY STAR® Refrigerators
Variable Speed Pool Pump
Weatherization
Low-Flow Showerheads & Aerators

Figure 7-20 - SCE BE Team Proposed ECMs for Catalina Residences

SCE's BE team worked from workbook assumptions and historical reference data to estimate the EE potential and cost of each ECM. They made a conservative assumption that 35% of the maximum potential EE savings that could theoretically result from comprehensive implementation of the full suite of ECMs in the full portfolio of residences would be achieved. In part they reasoned that some ECMs would already have been implemented by owners, particularly in all-electric homes, and that 100% implementation, customer penetration and participation are unlikely. NV5 adopts this conservative estimation and applied this reasoning to the cost of implementation as well, reducing the total by 65% to 35% of the projected cost of full implementation of every ECM in every home.

7.5.2 Single-Family Homes

The SCE BE team's conservative EE projections indicate that the single-family residential sector would reduce electricity consumption by 13% or 871,460 kWh/year from the baseline usage. This projected reduction would be the result of achieving 35% of the theoretical maximum savings from full implementation of all proposed ECMs in all homes. The gross value of this avoided cost to SCE at their 2018 estimated actual generation cost of $0.396/kWh would be $345,098 annually (this gross figure is not net of revenue from ratepayers). Table 7-15 below summarizes the projected results under the above assumptions.

Table 7-15 - Summary of SCE BE Team Proposed EE Measures for Catalina Residential Customers

Summary for all Catalina Residential Customers	
Total # homes	1,799[66]
Baseline kWh use	6,646,618
Total kWh savings	871,460
kWh % reduction	13%
ECMs total capital cost ($)	1,048,585
EE program $/kWh	1.20

[66] The total number of customer houses is smaller than the actual amount due to the exclusion of outlier high-consumption buildings and customers for which data was lacking

Figure 7-21 below is based on SCE BE team projections and depicts residential customer electrical energy consumption before and after implementation of the proposed suite of ECMs, categorized by house size and all-electric or mixed fuel types. All-electric customers would reduce electricity use by 23% or 556,950 kWh annually, while mixed-fuel customers would see an 8% reduction or 314,510 kWh/year.

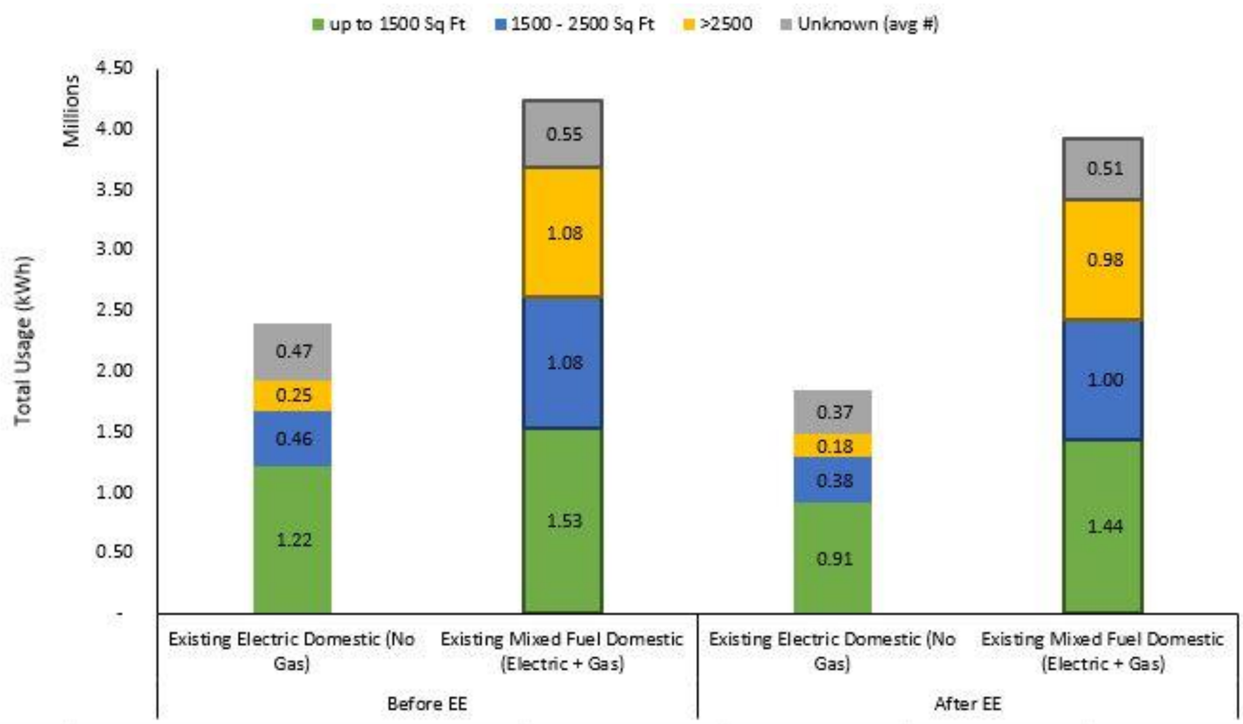

Figure 7-21 - SCE BE Team EE Impacts on Catalina Island Houses by Size and Fuel Type

7.5.3 Multi-Unit Dwellings

Catalina Island's relatively small MUD sector uses roughly 100,000 kWh annually. NV5 assumes the same suite of ECMs would be implemented to achieve the same 35% proportion of maximum savings. Compared to single-family residences, NV5 estimates that a modestly greater 20% savings or 20,000 kWh/year would be achieved in MUD sector buildings. This higher estimate is due to the relatively greater potential for more integrative retrofits achieving deeper reductions, a higher percentage of dwellings' participation in retrofits per building, lower transaction effort due to fewer owners per unit, and the probable higher percentage of centralized HVAC and other systems.

7.6 NON-DOMESTIC CUSTOMER RECOMMENDATIONS

7.6.1 Overview

NV5 assumes that Non-Domestic commercial, industrial and institutional customers' potential EE savings are only slightly higher than Domestic residential customers, at a 15% reduction for the sector. Arguments for a relatively higher savings estimate for Non-Domestic customers include:

A. Greater potential for more integrative retrofits that can achieve deeper reductions.
B. Higher percentage of centralized and energy-intensive mechanical and electrical systems.
C. Reduced transaction effort due to single points of contact and managerial decision-making.

D. Greater access to capital for energy improvements.
E. Stronger economic rationale for cost reductions.

In practice these factors are not always significant or decisive, and in many cases the opposite effect may prevail (*e.g.*, as with factors C–D). Organizational decision-making processes often involve multiple stakeholders with veto power, turnover of key personnel, lack of specialized knowledge, and competing priorities. For these and other reasons, NV5 assumes a 15% level of savings sector-wide that is conservative relative to best practices where facility energy savings from 20%–25% are common (*e.g.*, in Energy Savings Performance Contracts or ESPCs) and deep energy retrofits can yield energy use reductions of 30%–50% or more.

7.6.2 General Recommendations

In addition to the ECMs proposed by the SCE BE team, further customer-specific measures could include:

Table 7-16 - Generic ECMs for Residential and Commercial Buildings

System	ECMs
Envelope	Interior and exterior insulation
	Low U-value / high R-value windows
	Brise soleil shading features
	White roofs: High-albedo coatings
	Green roofs: Vegetative cover
	Passive solar: trombe wall
	Natural ventilation, solar thermal chimneys
HVAC	Airside economizers for free cooling
	Night flush with cool air
	Thermal integration of heating/cooling sources/sinks
	Occupancy sensors, Demand-Controlled Ventilation
DHW	Thermal integration of heating/cooling sources/sinks
	Solar thermal water heating
	High-efficiency fixtures
Controls	Occupancy sensors
	Night/weekend setbacks
	Retro-commissioning
Drivepower	Premium-efficiency motors
	Soft starters, VFDs for variable loads

The applicability and cost-effectiveness of these ECMs would need to be evaluated on a case-by-case basis.

7.6.3 Top 20 Largest Customer Recommendations

NV5 applies a conservative estimate of 15% load reduction projections for each of the largest customers, based upon the assumption (and recommendation) that SCE would focus on the largest customers and provide a comprehensive DSM effort with an integrated suite of ECMs, programmatic attention and incentives. SCE's BE team made the high-level indicative estimates of EE potential for the following business types on Catalina, depicted in Table 7-17 below. These opportunities identified may be applications of either natural gas or electricity, depending upon the customer. Three checks indicate greater opportunity than one check.

Table 7-17 - SCE BE Team EE Potential Indicators by Business Type

Business Type	Water Heating	Space Heating	Cooking Equipment	Clothes Dryers
Hotel/Resort	√ √ √	√ √	√	√
Restaurant	√ √		√ √ √	
Laundry Facility	√ √ √			√ √ √
MF Property	√ √ √	√ √	√	√
Supermarket *	√		√ √	

* Local supermarket has a in-house bakery.

7.6.4 Water systems

NV5 water system EE calculations, estimates and assumptions are detailed in Appendix L.

In 2016 SCE well pump testing specialists conducted a series of water system pump tests on Catalina and made EE recommendations that were not implemented. NV5 used these results to develop our water system EE estimates, including using them as a basis for estimation where EE recommendations were not available for specific equipment. For the purposes of this high-level analysis, NV5 did not adjust the 2016 calculations with an annual cost escalation factor to estimate 2019 values.

NV5 also utilized 2018 EE proposals for wastewater system equipment by the Southern California Regional Energy Network (SoCalREN) to develop EE estimates, utilizing the calculations without adjusting the values with an annual escalation factor to estimate 2019 values.

In most larger and constant duty electric motors generally on Catalina, NV5 recommends installing VFDs or at least "soft starters" to limit motor inrush current, a significant (if brief) contributor to peaking loads. VFDs might also provide kWh savings by modulating electric drive power output to match pumping (or other motor-driven device) requirements in real time. NV5 cannot estimate VFD potential savings without detailed analysis of specific pump or other equipment operations.

7.6.4.1 Potable Water System

Proposed ECMs are pump overhauls for Wells 1A and 6A in Thomson Dam, including retrofitting the pump bowl assembly or impeller with a design that operates at or near the Best Efficiency Point (BEP) for the pump. The proposed ECMs for Potable water Pumps 1 and 2 also are overhauls to the existing centrifugal booster pumps, which may include repairing or replacing/retrofitting pump, bowls and impellers, shafts and bushings, re-aligning impellers, *etc*.

For Thomson Dam Well pumps, the projected savings and EE implementation cost were taken from SCE reports based on pump tests reports[67]. The first-year gross cost ($/kWh) was derived by dividing the implementation cost by the annual kWh savings. EE measures were assumed to have an EUL or life cycle duration of 10 years, from which the life cycle gross cost ($/kWh) was calculated. For Pebbly Beach Potable water pumps, the EE implementation cost was assumed at a motor replacement cost of $200 per HP[68] with an EUL of 10 years, and savings were assumed at 15% of the baseline annual usage. These notional ECMs and EUL metrics were applied to other pumps as well, with a conservative assumption of 15% reduction in usage where site-specific information was unavailable.

The desalination facility is evidently the largest single electricity user on Catalina Island. The process employs reverse osmosis (R/O) membrane filtration units, thermal energy and pumping. Desalination capacity is being expanded. Specific information on existing and planned processes and equipment was not available in sufficient detail to inform notional ECM development. NV5 made a conservative estimate that 10% of facility kWh could be conserved; larger savings potential is probable and worthy of deeper investigation by SCE. NV5 estimated the first year gross cost per kWh based on the $0.62/kWh first year gross cost value for SCE industrial EE programs in 2018 CEDARS data, which we quadrupled according to our “Catalina factor” multiplier to derive the $2.48/kWh value. Our 10% savings estimate and the first-year gross cost $/kWh KPI enabled an estimation of the installed cost for unspecified ECMs.

Table 7-18 below provides a brief description of the potable water system major pumping equipment baseline annual energy usage; the EE recommendations’ estimated implementation cost, energy savings, first year and lifecycle gross cost of saved energy; and the annual value to SCE of avoided generation of the saved kWh at their estimated actual cost of generation.

Table 7-18 - Potable Water System Equipment EE Potential

Equipment	Tariff ($/kWh)	SCE Actual Generation Cost ($/kWh)	Annual avg. kWh	Annual EE POT'L kWh	EE Implementation Cost ($)	First Year Gross Cost ($/kWh)	Lifecycle Gross Cost ($/kWh)	% Reduction in Annual kWh Use	Annual Value Of Avoided Generation ($)
Thomson Dam Well: Well 1A (50 HP motor)	0.37	0.396	33,870	5,457	10,000	1.83	0.18	16%	2,161
Thomson Dam Well: Well 6A (50 HP motor)	0.37	0.396	33,870	5,939	10,000	1.68	0.17	18%	2,352
Potable Water Pump 1 (20 HP motor)	0.22	0.396	43,056	6,458	4,000	0.62	0.06	15%	2,558
Potable Water Pump 2 (20 HP motor)	0.22	0.396	42,504	6,375	4,000	0.63	0.06	15%	2,525
SweetWater Well Pump (5 HP motor)	0.16	0.396	32,448	9,213	1,000	0.11	0.01	28%	3,648
Cottonwood Well 2A	0.20	0.396	23,352	3,503	600	0.17	0.02	15%	1,387

[67] 2016-Pump Test Report Summary.pdf
[68] 2016-Pump Test Report Summary.pdf

Equipment	Tariff ($/kWh)	SCE Actual Generation Cost ($/kWh)	Annual avg. kWh	Annual EE POT'L kWh	EE Implementation Cost ($)	First Year Gross Cost ($/kWh)	Lifecycle Gross Cost ($/kWh)	% Reduction in Annual kWh Use	Annual Value Of Avoided Generation ($)
Pump (3 HP motor)									
Howlands Well (15 HP motor)	0.01	0.396	21,144	3,172	3,000	0.95	0.09	15%	1,256
Whites Landing Well (7.5 HP motor)	0.26	0.396	10,044	1,715	1,500	0.87	0.09	17%	679
Toyon Well (5 HP motor)	0.22	0.396	12,332	3,289	1,000	0.30	0.03	27%	1,302
Pump Station 2 Pump#3 (50 HP motor)	0.23	0.396	29,436	4,415	10,000	2.26	0.23	15%	1,748
Pump Station 2 Pump#4 (50 HP motor)	0.23	0.396	29,844	4,477	10,000	2.23	0.22	15%	1,773
Pump Station 2 Pump#5 (50 HP motor)	0.23	0.396	29,845	4,477	10,000	2.23	0.22	15%	1,773
Desalination Facilities	0.22	0.396	730,922	73,092	181,269	2.68	0.27	10%	28,945

7.6.4.2 Saltwater System

The proposed ECMs for main salt water pumps 1 and 2 are overhauls of the existing centrifugal booster pumps, which may include repairing or replacing/retrofitting pump, bowls and impellers, shafts and bushings, re-aligning impellers, *etc*. No ECMs were proposed for Hill Street Booster Station and Whittley Booster Station pumps in the SCE data.[69] NV5 assumed an overhaul of those two pumps would cost $200/HP and would save 15% of annual kWh.

[69] Environ-Strategy.xlsb

Table 7-19 below provides a brief description of the salt water system major pumping equipment baseline annual energy usage; the EE recommendations' estimated implementation cost, energy savings, first year and lifecycle gross cost of saved energy; and the annual value to SCE of avoided generation of the saved kWh at their estimated actual cost of generation.

Table 7-19 - Salt-Water System Equipment EE Potential

Equipment	Tariff ($/kwh)	SCE Actual Generation Cost ($/kWh)	Annual avg. kWh	Annual EE POT'L kWh	EE Implementation Cost $	First Year Gross Cost ($/kWh)	Lifecycle Gross Cost ($/kWh)	% Reduction in Annual kWh Use	Annual Value of Avoided Generation ($)
Main Salt Water Pump #1 (100 HP motor)	0.17	0.396	33,696	13,960	20,000	1.43	0.14	41%	5,528
Main Salt Water Pump #2 (100 HP motor)	0.17	0.396	33,324	13,472	20,000	1.48	0.15	40%	5,335
Hill Street Booster Station (7.5 HP Centrifugal Pump)	0.20	0.396	7,000	1,050	1,500	1.43	0.14	15%	416
Whittley Booster Station (7.5 HP Centrifugal Pump)	0.20	0.396	7,000	1,050	1,500	1.43	0.14	15%	416

7.6.4.3 Wastewater System

The proposed ECMs for waste water Catherine Lift Station pumps and Pebbly Beach Lift Station pumps are pump overhauls, which may include repairing or replacing/retrofitting pump, bowls and impellers, shafts and bushings, re-aligning impellers, *etc*.[70] [71] The ECMs proposed for WWTF include Aeration Blower replacement and centrifuge replacement.[72] WWTF annual usage was calculated based on the daily average usage data provided in a 2016 proposal to the City of Avalon.[73]

The projected savings for waste water system pumps were taken from SCE reports based on pump tests.[74] The EE implementation cost for Catherine Lift Station pumps were assumed at $200 per HP of the motor[75] with payback period of 10 years from which the first year gross rate ($/kWh) and life cycle gross rate ($/kWh) were calculated. The EE implementation cost for Pebbly Beach Lift station pumps and WWTF were taken from data provided in 2016 proposals to the City of Avalon;[76] no cost escalation factors were applied to adjust this data to 2019 values.

[70] Environ-Strategy.xlsb
[71] Avalon Pump Project Proposal.pdf
[72] Avalon Process Optimization Project Proposal.pdf
[73] Michael Baker International, (2016), *Recycled Water/Energy Sustainability Sub-plan Study*, p.55 Table 8-1.
[74] Environ-Strategy.xlsb
[75] 2016-Pump Test Report Summary.pdf
[76] Avalon Process Optimization Project Proposal.pdf and Avalon Pump Project Proposal.pdf

Please note that we include only one of the PBLS pumps, Pump #2, because the available information indicated no operational data for Pumps #1 and #3. We inferred that only Pump #2 is operating; if that is mistaken, then the estimated savings would apply to the other operating pump(s) as well.

Table 7-20 below provides a brief description of the waste water system major equipment baseline annual energy usage; the EE recommendations' estimated implementation cost, energy savings, first year and lifecycle gross cost of saved energy; and the annual value to SCE of avoided generation of the saved kWh at their estimated actual cost of generation.

Table 7-20 - Waste-Water System EE Potential

Equipment	Tariff ($/kwh)	SCE Actual Generation Cost ($/kWh)	Annual avg. kWh	Annual EE POT'L kWh	EE Implementation Cost $	First Year Gross Cost ($/kWh)	Lifecycle Gross Cost ($/kWh)	% Reduction in Annual kWh Use	Annual Value of Avoided Generation ($)
Catherine Lift 1 (18 HP centrifugal pump)	0.17	0.396	18,168	4,142	3,600	0.87	0.09	23%	1,640
Catherine Lift 2 (18 HP centrifugal pump)	0.17	0.396	13,776	8,789	3,600	0.41	0.04	64%	3,480
PBLS BST 2 (25 HP centrifugal pump)	0.17	0.396	54,300	30,842	17,500	0.57	0.06	57%	12,213
Waste Water Treatment Facility (WWTF)	0.17	0.396	479,865	186,306	314,803	1.69	0.17	39%	73,777

7.6.5 Quarry

A quarry is operated on Catalina, perhaps the only truly industrial customer on the island. Although they are not one of the Top 20 largest electricity users, they are among the 4 "peakiest" customers identified through metered data analysis (see Figure 7-22 below).

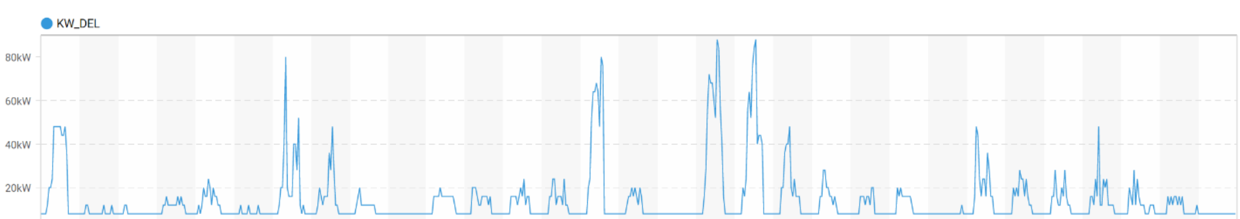

Figure 7-22 - Account #######- March 2019 Demand Spikes

NV5 infers that this load profile is due to inrush current and start-stop usage of large electric drives in equipment such as conveyor belts and a rock crusher. Although NV5 can't offer ECMs or savings estimates without detailed analysis of equipment types and operating profiles, NV5 recommend installing VFDs or at least "soft starters" on larger and constant-duty electric drives to limit motor inrush current, a significant (if brief) contributor to peaking loads in general. VFDs might also provide kWh savings by modulating drive power output to closely follow loads in real time.

7.7 EE IMPLEMENTATION CONSIDERATIONS

7.7.1 Catalina Island Actual Cost of Energy *vs.* System Average EE Program Valuation

A potentially significant constraint is the difference between SCE's actual costs of generation capacity and output and SCE's EE program methodology that applies system-wide average costs. The standard programmatic approach undervalues each potential conserved "negawatt-hour". As an SCE analysis put it:

"Catalina's energy costs are significantly higher than the mainland's (est. 3-4x), yet EE is currently set to system-wide average energy costs, limiting the cost-effective EE programs that can be offered. With Catalina-specific energy costs applied to the wide range of EE measures, SCE could offer a much more comprehensive and deep set of EE offerings to lower Catalina Repower costs for the island."[77]

The same analysis notes potential challenges with the standard Avoided Cost Calculator: "CPUC prescribed system-wide avoided cost values would need to be modified for Catalina-specific values (and benefits allowed under EE portfolio TRC, or risk of opportunity cannibalization)."[78]

7.7.2 ECM EUL Varies According to Equipment Installed

NV5 used an assumed 10-year EUL for all installed EE equipment in estimating lifecycle gross cost KPIs. This is not an unreasonable assumption and is informed by experience with portfolios of ECMs installed in ESPCs, but it is not possible to assess whether or not it is a conservative assumption. Actual equipment EULs will vary and should be evaluated on a case-specific basis, with consideration to factors such as operating and maintenance schemes.

7.7.3 Integrative Comprehensive EE Implementation

In general, a comprehensive approach bundling a portfolio of ECMs for implementation at a given customer provides the most economical approach to attaining maximum energy savings. SCE may wish to employ a similar integrative approach on Catalina, perhaps as a custom measure. On-Bill Financing (OBF) could be employed to help finance portfolios of ECMs; SCE's OBF program features a ten-year repayment period that aligns with NV5's estimated average ECM EUL of one decade.

An SCE analysis noted: "Applicable [EE] Programs (current and potential new)" for Catalina include "Commercial Direct Install; Residential Direct Install; Multi-family EE Rebate Program; Core Calculated; Energy Savings Assistance (ESA)."[79]

From a life-cycle cost of ownership perspective, in most cases it would be more economical and feasible to design and construct a building to be highly energy efficient as-built than it would be to build an equivalent average- or substandard-performance facility and then attempt to finance and implement a retrofit to achieve that superior level of energy efficiency. Given the significant value to SCE of customer load reduction, SCE could consider a custom incentive program for new construction to foster best-practice energy performance for new buildings. Compelling incentives could be offered to owners to employ charrette integrative design workshops, continuous commissioning, compliance with Passivhaus or net-zero building standards, and other methods to minimize new loads. The levels of the incentives could be tied to modeled or proven load reductions, targeted Energy Use Intensity

[77] *Catalina Enhanced EE Feasibility 1-Pager_May 2019*.docx
[78] *Ibid.*
[79] *Ibid.*

(EUI) in kWh/SF, or participation in DR programs (see Section 7.7.4 for further discussion). OBF could be considered to help finance EE and DR measures in initial construction.

7.7.4 Custom DR Program Considerations

As discussed in Section 7.4.4, SCE may wish to implement a pilot or custom DR program where the value of avoided generation capacity is high in the context of the island microgrid. Catalina Island could become a living laboratory for microgrid load management. SCE could contract with DR equipment or service providers or develop the capability themselves.

Another way to approach the $/kW KPI valuation challenge would be to determine what would be SCE's willingness to pay to get DR participation from customers. In that case, consider starting with the costs of peaking loads on their system. Develop a production cost duration curve ($/kWh for each of the 8760 annual hours) to determine the top (*e.g.*,) 50 hours of that annual curve cost. The purpose of the DR programs would be to shave/shift those kWs and their respective costs to SCE. Then the DR program design team could use those cost reductions as the starting point for determining the incentive level for customers or aggregators. The DR aggregator EnerNOC's original business model was to pay their customers about half of the value of peak capacity that they received from the ISOs or utilities. A comparable set of incentives or bill credits could be provided on Catalina, informed by experience with mainland CAISO capacity marketplace DR programs.

Customers on TOU rates would be priority candidates for DR activity. VFDs and soft starters can reduce inrush current in electric motors and other devices to minimize demand spikes (VFDs offer kWh savings as well while serving dynamic loads), and staggered-start Sequences Of Operation (SOO) for equipment can help smooth out peaky customer demand profiles.

The BE program will increase electric load, but also provides an opportunity to install DR infrastructure. See Section 7.8.2.1 for further discussion.

7.8 PROJECTED LOAD INCREASES

7.8.1 Overview

SCE analysis provided the following categories of load growth over the coming decade:[80]

- Building Electrification [undetermined kW]
- SCE Water Upgrades [774 kW]
- Home Development (Santa Catalina Island Company) [254 kW]
- Home Development (Avalon) [169 kW]
- Hospital Expansion [92 kW]
- Trailhead Visitor Center [70 kW]
- Hamilton Cove Expansion [17 kW]
- Cruise Ship Berth Electrification [11 MW]

[80] Information in Sections 5.1 and 5.2 developed by SCE's Maurice Ahyow, contained in *Catalina Feasibility Studies Presentation 2019*.pptx, slide 6 and *Load Calcs v4*.xlsx

7.8.2 Recommendations

As discussed in Section 7.7.3, the biggest bang for the buck in EE and DR efforts is in new design and construction. Given the significant value to SCE of customer load reduction on Catalina, SCE could consider a custom incentive program for new construction to foster best-practice energy performance for new buildings. The incentives would have to be compelling to induce deviations from business-as-usual design, engineering and construction processes that typically result in average-to-poor building energy performance. Best practice results in superior performance; Passivhaus standard buildings have energy use 50–75% lower than standard construction. Net zero energy buildings have little or no load on average, although many examples export electricity to the grid at certain times of day from onsite Distributed Energy Resources (DERs) such a solar photovoltaics (PV), and import electricity at night.

7.8.2.1 Building Electrification

SCE's BE team provided NV5 with excellent data on Catalina Island's residential energy use, EE opportunities and projected kWh savings and increases, but no indication of projected kW load increases. (See Section 7.4.4 for further discussion on the challenges of estimating kW reductions in relation to kWh savings.) The BE team is considering to first retrofit housing with a suite of ECMs and thereby reduce residential sector energy use by 13% or 871,460 kWh from annual usage of 6,646,618 kWh to 5,775,158 kWh per year. Then comprehensive BE improvements would be projected to increase that new lower level of consumption by 33% to 7,680,960 kWh/year—even though the assumed EE and BE measures are assumed to achieve 35% of the theoretical maximum potential decrease or increase in consumption.

As this would be a mass retrofit of mostly single-family residences with the goal of beneficial electrification, economical opportunities for deep energy reductions would be limited. Additional ECMs could be considered. Yet a BE program could provide an opportunity to integrate equipment including Advanced Metering Infrastructure (AMI) and device controls that could establish a load management architecture to help manage increased demand. The potential extent or cost of potential kW reduction can't be estimated with available information. But successful examples should be studied. Elsewhere in the U.S. aggregated controllable electric Domestic Hot Water (DHW) heaters are being used as dispatchable resistive loads and as virtual electro-thermal storage. Other potential BE equipment might be suitable for centralized load management. EE measures such as weatherization, super-insulation and other passive features help maintain comfort when heat pumps are modulated.

7.8.2.2 SCE Water Upgrades

SCE analysis projects that planned potable water system upgrades will add a potential 774 kW of peak load. SCE analysis indicated that the upgrades include a 50% capacity expansion of the desalination facilities (435 kW peak); Wrigley Pipeline/Storage (166 kW peak); and Well System Upgrades including four pumps with 40 HP motors each (173 kW peak). NV5 was not provided with details about the planned upgrades. Neither the extent nor cost of potential kW reduction can be estimated with available information.

Water system EE estimates described in Section 7.6.1 and detailed in Appendix L indicate that 17% reductions in the potable water system (excluding desalination) can be retrofitted at a lifecycle gross cost of $0.11/kWh, less than one-third of SCE's estimated actual cost of generation on Catalina Island. Our conservative estimate of 10% potential savings in desalination electricity use are probably low, and the estimated lifecycle gross cost of $0.25/kWh conserved is less than SCE's estimated actual generation costs. Extensive renovations and new design offer significantly more economical load and usage reductions, particularly in pumping where best practices have reduced pumping system energy use by up to 90% (or more in some cases) at no additional capital cost. VFDs could reduce both energy use and inrush current demand spikes in pump motors.

7.8.2.3 Home Development (Santa Catalina Island Co.)

SCE analysis projects that Santa Catalina Island Co. development of up to 180 units of MUD housing could add 254 kW of peak load and consume 1,023,267 kWh annually. NV5 was not provided with details about the planned development. Neither the extent nor cost of potential kW reduction can be estimated with available information. The potential for SCE to incentivize best practices in residential design and construction for superior energy performance at the least cost is discussed in Sections 7.7.3 and 7.8.2.1.

7.8.2.4 Home Development (Avalon)

SCE analysis projects that proposed MUD development in the City of Avalon of 50 units of public employee housing, 70 units of LMI housing, and a public recreational pool could add up to 254 kW of peak load and consume 682,178 kWh annually. NV5 was not provided with details about the planned development. Neither the extent nor cost of potential kW reduction can be estimated with available information. The potential for SCE to incentivize best practices in residential design and construction for superior energy performance at the least cost is discussed in Sections 7.7.3 and 7.8.2.1. Solar thermal heating of the pool might be considered.

7.8.2.5 Hospital Expansion

SCE analysis projects that proposed hospital expansion of 10 units totaling 7,500 SF could in the City of Avalon could add up to 92 kW of peak load and consume an additional 445,364 kWh/year. NV5 was not provided with details about the planned development. Neither the extent nor cost of potential kW reduction can be estimated with available information. The potential for SCE to incentivize best practices in building design and construction for superior energy performance at the least cost is discussed in Sections 7.7.3 and 7.8.2.1. As a critical facility, hospital energy assurance is vital. DERs such as PV plus a Battery Energy Storage Systems (BESS) could enhance resilience. Passive energy features that help maintain safe interior temperatures and livable conditions without electricity could enhance occupant survivability, such as high R-value / low U-value insulation envelope and windows; natural ventilation; daylighting; and shading features.

7.8.2.6 Trailhead Visitor Center

SCE analysis projects that a proposed Santa Catalina Island Co. 9,000 SF Trailhead Visitor Center with PV could add up to 70 kW of peak load and consume an additional 209,781 kWh/year. NV5 was not provided with details about the planned development. Neither the extent nor cost of potential kW reduction can be estimated with available information. The potential for SCE to incentivize best practices in building design and construction for superior energy performance at the least cost is discussed in Sections 7.7.3 and 7.8.2.1. As a visitor-oriented facility with an environmental education aspect to be built in replacement for the Catherine Hotel, this building might be a good candidate to showcase advanced sustainable building practices and exemplary energy performance.

7.8.2.7 Hamilton Cove Expansion

SCE analysis projects that proposed development of 12 units of housing in the Hamilton Cove area could add up to 17 kW of peak load and consume 68,218 kWh annually. NV5 was not provided with details about the planned development. Neither the extent nor cost of potential kW reduction can be estimated with available information. The potential for SCE to incentivize best practices in residential design and construction for superior energy performance at the least cost is discussed in Sections 7.7.3 and 7.8.2.1.

7.8.2.8 Cruise Ship Berth Electrification

SCE analysis projects that there is consideration of developing a cruise ship berthing facility that could add up to 11 MW of peak load and consume 6,589,440 kWh annually. The entire island's peak load is approximately 5.5 MW now. The concept would be to provide a dock where cruise ships bringing tourists to the island could berth, avoiding the necessity of bringing passengers ashore by small boat as is done now. This berthing facility would have to provide shore power to the ships in order to avoid the vessels running their highly polluting generators while stationary.

NV5 was not provided with details about the planned development nor the potential sources of shore power. Neither the extent nor cost of potential kW reduction can be estimated with available information, but probably no influence on load reduction is possible.

The best case scenarios include radical EE and/or emissions improvements in cruise ship design; development of substantial clean energy generation on or around Catalina Island to serve that massive intermittent peak load, possibly involving significant ocean-based DER capacity; or a cable connection from the mainland of at least 2.5 times the capacity to serve current loads. SCE analysis suggests that shore power would have a load factor of 0.64, indicating that substantial DER or subsea cable capacity equivalent to almost 1.5 times the current peak load would not be utilized during a significant portion of the year when no cruise ship is berthed. As a high-level first impression, the economics of this prospect are unlikely to pose a compelling business case.

7.9 CONCLUSION

In summary, NV5's high-level analysis and conservative assumptions indicate that there is the potential to reduce Catalina's total electricity consumption by an estimated 21% via an estimated $7.8 million investment in energy efficiency improvements. At SCE's estimated actual gross cost of generation of $0.396/kWh (not reflecting the net cost after tariff revenue), the approximately 3,560,000 kWh of annual savings would save SCE $1,409,760 per year. This equates to a simple payback of less than 6 years, which is within the assumed 10-year Expected Useful Life of the installed Energy Conservation Measures. This very simplified and high-level estimate ignores many factors including inflation, revenue from ratepayers, and the value of peak load reduction. Catalina Island-specific emissions factors for NO_X of 0.005 lbs/kWh equate to annual reductions of 17,800 lbs/year or 8.9 tons, a 12% reduction from the 75.4 tons emitted annually (as per NREL calculations)[81].

NV5 was not able to develop load reduction estimates nor the first-year gross cost of $/kW for demand reduction due to insufficient information.

[81] The projected costs and savings are only estimates at this time and a comprehensive in-person energy audit will be required to both develop an accurate baseline and identify EE/DSM opportunities on the Island. In addition, the identified measures will have to be assessed for eligibility for incentives and/or rebates through the available DSM programs as well as from code compliance standpoint. The intent of this exercise is to provide an order of magnitude scope for EE/DSM opportunities only, i.e. several steps will need to be taken prior to confirming the implementation and applicability of the identified measures.

Our EE potential reductions by customer segment are summarized below in Table 7-21.

Table 7-21 - Summary of SCI EE Potential by Customer Segment

Sector	Baseline Annual Use (kWh)	Potential Annual EE Savings (kWh)	EE % Reduction from Baseline	ECMs Total Cost ($)	EE First Year Gross Cost ($/kWh)	EE Lifecycle Gross Cost ($/kWh)
Domestic tariff customers						
Single family residences	6,646,618	871,460	13%	1,048,584.95	1.20	0.12
Multi-unit dwellings	100,000	20,000	20%	24,000.00	1.20	0.12
Non-Domestic tariff customers						
Top 20 users excluding water systems usage	10,665,742	1,599,861	15%	4,287,628	2.68	0.27
Potable water system	341,745	58,490	17%	65,100	1.11	0.11
Saltwater system	81,020	29,532	36%	43,000	1.46	0.15
Wastewater system	566,109	230,079	41%	339,503	1.48	0.15
Desalination Plant	730,922	73,092	10%	181,269	2.48	0.25
Non-domestic customers excluding Top 20 users	4,516,530	677,480	15%	1,815,645	2.68	0.27
TOTAL	**23,648,686**	**3,559,994**	**21%**	**7,804,730**	**2.14**	**0.21**
					↑ Weighted averages ↑	

8.0 RECOMMENDED FURTHER STUDY

The Santa Catalina Island feasibility study set out to analyze various ways to repower the island with a cleaner, more sustainable generation mix that is compliant to recent SCAQMD emissions regulations and provides the best value to SCE and its ratepayers. The three solutions explored in this feasibility study are emissions compliant fossil fuel generation, renewable energy and storage hybrid, and a submarine power cable to tie the island to the mainland's cleaner grid with increasing amounts of renewable energy. This report is intended to provide SCE's decision makers with sufficient information on the available options and a roadmap to undergo each solution. Several aspects of this analysis are recommended for further investigation to provide SCE with actionable information to begin implementing the projects identified in this report or others not yet studied.

8.1 LOAD DECREASES: ENERGY EFFICIENCY, DEMAND RESPONSE, DEFERRABLE LOADS

The original Scope of Work (SOW) included site visits and ASHRAE Level 1–2 energy audits at up to 10 of the largest energy users, but that effort was interrupted by the Covid-19 pandemic. Even the preliminary customer interviews were halted after just a couple could be completed with sparse results due to the higher priority work in response to the pandemic. Resuming these efforts towards customer outreach and ultimately conducting the Level 1-2 energy audits will yield much more accurate results as to the opportunity for energy efficiency, demand response, and deferrable loads on the island.

8.2 LOAD INCREASES: BUILDING ELECTRIFICATION, VEHICLE ELECTRIFICATION, CRUISE SHIP ELECTRIFICATION

Two main categories for customer electric load growth are building electrification and transportation electrification. Each of these categories were analyzed at a high level, but there is significant need to study further to better plan for the future generation capacity. The reason for this is the same as any system planning process on the mainland, it must take into account reasonable load growth in order to meet the needs of the projected customer base. Without better information as to the number of residential and commercial customers who could electrify their domestic hot water, cooking, and space heating appliances, or the planned deployment of electric golf carts and cruise ship electrification, it is challenging to select the appropriate generation resources and have confidence with a certain renewable energy penetration.

The load increases analysis is a little more complex than simply summing up the potential new load. Similar to the deferrable loads that are to be studied in the load decreases further study, building and transportation electrification could and should be scheduled or managed loads to help stabilize or minimize peak demand increases, even though overall kWh's per year may go up. There are also implications with reduced demand for natural gas and propane on the island, such as reduced demand at the compressor station and reduced emissions from fewer ferry trips that might provide additional benefits in overall emissions reductions. These are just some of the aspects of this adjustment to the load profile that should be studied with this additional scope.

8.3 NREL REOPT PHASE III STUDY

NREL conducted its Phase I and II techno-economic studies for the purposes of repowering Catalina Island. Phase III would incorporate the demand-side options discussed previously and offer a detailed cost benefit analysis to help SCE in selecting a cost-optimal approach to achieving their energy goals at Catalina. These load profile adjustments would also inform the recommended generation portfolio and capacities under various constraint scenarios to aid in structuring subsequent procurement efforts towards generator replacements, renewables deployment, battery storage, and other solutions. Lastly, as SCE is the local water distribution utility in addition to the local electric distribution utility on Catalina, the water energy nexus scenario warrants attention and analysis to provide additional insights for SCE consideration to improve the scheduling, operation and construction of desalination, water treatment, and water distribution assets.

A Phase III techno-economic analysis and modeling of load increases, decreases, and deferrable loads could provide useful information to facilitate decisions on programs, policies, operational practices, and infrastructure investments on Catalina Island to improve the overall effectiveness and efficiency of the energy, water, buildings, and transportation systems.

8.4 RENEWABLE MICROGRID AND ELECTRICAL GRID STUDY

The team began to evaluate various distribution management options including microgrid controllers, DERMS, and a distributed “peer-to-peer” automation system. A next iteration to this investigation would involve a dedicated effort towards understanding the limits and opportunities with the existing Emerson DCS, bidding out multiple controller solutions, and presenting to SCE’s distribution operations some of the options for managing new and distributed generation assets. This effort would also include an assessment of the current telemetering system, its constraints and opportunities. This effort would conclude with a Vision and Goals document stating the SCE’s distribution operators’ desired functionality that would be converted to an ultimate bid package for controller and software vendor solicitation.

More detailed electrical distribution impact studies and facilities studies are recommended to define the scope for potential distribution upgrades needed to interconnect the proposed DER. It is recommended that the preliminary results from this feasibility study be used as informative as to the magnitude of what could cause impacts, why, and what are some appropriate mitigation measures. However the results should not be interpreted as permission to interconnect for any of the proposed project sites. In order to further understand how the grid will respond to the amount of distributed and variable generation as proposed in the renewables and battery storage section, a more in-depth analysis is recommended. It is understood that SCE is engaging in negotiations towards site control with island stakeholders. The results from this effort could inform whether the Team does any restudy of the current list of top ranked sites or other sites that become available.

Lastly, the renewables and battery storage microgrid section recommended a phasing plan to achieve a 60% renewable microgrid over the next 10 years that would support S.B. 100. The next iteration of this study should provide a validation of this phasing plan and develop initial bid documents for SCE to release the low hanging fruit project sites for bid.

8.5 PROJECT DEVELOPMENT SUPPORT

If SCE proceeds with community outreach, CPUC rate case development, permitting, or other jurisdictional engagements, the feasibility study Team would provide the consulting support needed to shepherd the project through each of those stages. This could include meetings with EPA, SCE team members, leadership, or other internal participants; discussions with SCAQMD and other regulatory agencies; participation with Catalina Island Stakeholders for study overview, renewable siting, energy efficiency options, and more; and preparation for public hearings, rate case support, or other professional support services.

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10.0 LIST OF ABBREVIATIONS

°C	Degrees Celsius
A/C	Air Conditioning
AC	Alternating Current
ACF	Area Cost Factor
ACSR	Aluminum Conductor Steel-enforced Cable
AHJ	Authorities Having Jurisdiction
AI	Aluminum
AMI	Advanced Metering Infrastructure
ANSI	American National Standards Institute
ATB	Annual Technology Baseline
AWG	Arbitrary Waveform Generator
AWG	American Wire Gauge
BE	Building Electrification (*e.g.*, conversion of fossil-fueled HVAC and DHW systems to heat pumps and resistance heating)
BEP	Best Efficiency Point of operation for an electric motor or pump
BESS	Battery Energy Storage System
BTU	British Thermal Units
BUG	Back-Up Generator
CA	California
CAISO	California Independent System Operator
CAPEX	Capital Expenditure
CCC	California Coastal Commission
CDP	Conditional Development Permit
CEQA	California Environmental Quality Act
CESA	California Endangered Species Act
CFM	Cubic feet per minute
C LCP	Catalina Local Coastal Plan
COD	Commercial Operation Date
CPUC	California Public Utilities Commission
CUP	Conditional Use Permit
DA	Day Ahead
DC	Direct Current
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DoD	Department of Defense
DR	Demand Response, a form of customer load reduction or deferral managed by the utility or a third party
DSM	Demand-Side Management (i.e., utility-directed EE to reduce customers' energy use)
ECM	Energy Conservation Measure
EDC	Electricity Distribution Company (i.e., non-vertically integrated utility)
EE	Energy Efficiency (i.e., retrofit of existing equipment to reduce energy consumption)
EIA	U.S. Energy Information Association
EIR	Environmental Impact Report
EMD	Electro-Motive Diesel
EPA	Environmental Protection Agency
EPC	Engineer, Procure, Construct
EPS	Electric Power System or utility medium- to low-voltage distribution "grid"

ESA	Energy Services Agreement
ESA Ph1	Environmental Site Assessment Phase 1 (ASTM Practice E 1527-13)
ESCO	Energy Services Company
ESHA	Environmentally Sensitive Habitat Area
ESPC	Energy Savings Performance Contract
EUI	Energy Use Intensity, typically measured in MMBtu/SF
EUL	Expected Useful Life of equipment
FC	Fuel Cell
FF	Fossil Fuel
FF-1	Fossil Fuel Scenario #1
FF-2	Fossil Fuel Scenario #2
FF-3	Fossil Fuel Scenario #3
FF-4	Fossil Fuel Scenario #4
FF-5	Fossil Fuel Scenario #5
FF-6	Fossil Fuel Scenario #6
FF-EE	Fossil Fuel Scenario with Energy Efficiency Sensitivity
FITC	Federal Investment Tax Credit
ft2	Square Foot or Square Feet (see also SF)
gal	Gallons
GE	General Electric
GHG	Greenhouse Gas
GIS	Geographical Information System
gm	Gram
GWh	Gigawatt-hours
HBGS	Huntington Beach Generating Station
HDD	Horizontal Directional Drill
HP	Horsepower
hr	Hour
HVAC	Heating, Ventilation and Air Conditioning
ICE	Instrumentation and Control Electrical
IEEE	Institute of Electrical and Electronics Engineers
IFB	Issue for Bid
IOU	Investor Owned Utility
IRP	Integrated Resource Plan
ISD	In Service Date
ITC	Investment Tax Credit
Kcmil	Thousands of circular mils
kV	Kilovolts
kVA	Kilovolt-amps
kW	kilowatts
kWh or KWh	Kilowatt-hours of energy production or consumption
LARWQCB	Los Angeles Regional Water Quality Control Board
LC-1	Minimize lifecycle cost scenario #1
LCC	Lifecycle Costs
LC-CAP	Minimize Lifecycle Cost Scenario with lower PV/BESS capital cost sensitivity
LED	Light-Emitting Diode (see also SSL)
Li-ion	Lithium ion
LMI	Low- to Moderate Income
LNG	Liquefied Natural Gas

LoD	Limit of Disturbance
M	Million
MACRS	Modified Accelerated Cost Recovery System
MERRA	Modern-Era Retrospective analysis for Research and Applications
MFH	Multi-Family Housing (see also MUD)
MMBTU	Million British Thermal Units
MMPA	Marine Mammal Protection Act
MPPT	Maximum Power Point Tracker
MTU	Maximum Transmission Unit
MUD	Multi-Unit Dwelling (see also MFH)
MW	MegaWatt or one million Watts
MWh	MegaWatt-hour
MV	Medium Voltage
NaS	Sodium Sulfur
NASA	National Aeronautics and Space Administration
NEM	Net Energy Metering
NEPA	National Environmental Policy Act
NESHAP	National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Engines
NOx	Nitrogen Oxide
NREL	National Renewable Energy Laboratory
NSRDB	National Solar Radiation Database
O&M	Operations & Maintenance
OBF	On-Bill Financing
OH	Overhead
OTEC	Ocean Thermal Energy Conversion
PBGS	Pebbly Beach Generation Station
PCC	Point of Common Coupling
PCH	Pacific Coast Highway
PEP	Project Execution Plan
PF	Power Factor
PHS	Pumped Hydro Storage
POI	Point of Interconnection
PPA	Power Purchase Agreement
ppmv	Parts per million of exhaust volume
PTC	Permit to Construct
PU/p.u/pu	Per Unit
PV	Solar Photovoltaic Power
PVC	Polyvinyl chloride
PVRR	Present Value of Revenue Required
R/O	Reverse Osmosis membrane filtration used in desalination
RE	Renewable Energy
RE100-1	100% renewable energy scenario #1
RE100-CAP	100% renewable energy scenario with lower PV/BESS capital cost sensitivity
RE60-1	60% renewable energy scenario #1
RE60-2	60% renewable energy scenario #2
RE60-3	60% renewable energy scenario #3
RE60-CAP	60% renewable energy scenario with lower PV/BESS capital cost sensitivity
RE60-EE	60% renewable energy scenario with energy efficiency sensitivity

REopt	Renewable Energy Optimization and Integration tool
RFP	Request For Proposal
ROM	Rough Order of Magnitude
ROW	Right of Way
RPM	Revolutions Per Minute
SAM	System Advisor Model
S.B.	Senate Bill
SCADA	Supervisory Control and Data Acquisition
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
SCI	Santa Catalina Island
SF	Square Foot or Square Feet
SLP	Slim Line Power
SOC	State of Charge
SOO	Sequence Of Operations
SSL	Solid-State Lighting technology (see also LED)
SWM	Storm Water Management
SWPPP	Storm Water Pollution Prevention Plan
TELF	Tax Exempt Lease Financing
TELP	Tax Exempt Lease Purchase
TMY	Typical Meteorological Year
TTM	Trailing Twelve Months
UC	Undersea Cable
UC-1	Undersea Cable Scenario #1
UG	Underground
USACE	United States Army Corp of Engineers
USC	University of Southern California
USDA	United States Department of Agriculture
USFWS	US Fish and Wildlife Service
V	Volt
VFD	Variable Frequency Drive
W	Watts
WIND Toolkit	Wind Integration National Database Toolkit
WWTF	Waste Water Treatment Facility

11.0 APPENDIX

The Appendix appears in a separate file: [Catalina Island Feasibility Study Appendix]

The Appendix includes the following:

A	Power Plant Generation Cost Estimates
B	Fossil Fuel Generation Electrical Drawings
C	Renewable Energy Site Matrix
D	CPUC Fire Threat Map and SCE Overhead Distribution Line Standards
E	Grid Upgrades Cost Estimate
F	60% Renewable Microgrid Single-Line Diagram
G	Undersea Cable ROM OPC
H	Undersea Cable Schedule
I	Undersea Cable – Miscellaneous
J	NREL Phases I & II Summary Report
K	Domestic (Residential) Cost Estimates
L	Water Systems Cost Estimates
M	Received Items Log
N	Additional Permitting Information