Catalina Island Final Grid Stability Study

(09/29/2023)

I. Executive Summary

As part of its multi-year effort to modernize its aging Pebbly Beach Generating Station (PBGS) on Santa Catalina Island (Catalina), Southern California Edison (SCE) commissioned a comprehensive grid stability study to identify feasible renewable generation options that, if implemented, would enable SCE to continue to provide safe, reliable, clean, and affordable electric power to its customers on Catalina. This report summarizes the results of the analyses conducted by SCE and two consultants, POWER Engineers (POWER) and Mitsubishi Electric Power Products Inc. (MEPPI), of the viability of 22 generation scenarios. The key findings are:[1]

- A minimum of three U.S. EPA Tier 4 Final-certified (T4F) diesel generators must be present to provide resource adequacy, allow for planned maintenance activities, and supply sufficient system inertia to maintain grid stability during routine generation-to-load imbalances and unplanned outages.
- SCE must retain existing diesel generators to serve as backup units to ensure resource adequacy during planned maintenance activities overlapping with unplanned contingency events.
- The maximum annual amount of propane available for PBGS power generation (after allocation for gas utility service) will be limited to 400,000 gallons because of fire suppression regulations and with the assumption that the existing microturbines will have been replaced with a different propane technology. The current maximum amount that can be used is approximately 250,000 gallons annually[2] because of the physical and operating conditions of the aging microturbines as well as the need to cap inverter-based generation for grid stability concerns. Fire- and safety-related objections raised by the City of Avalon Fire Chief prevent increasing the amount of propane storage by using the fourth PBGS tank.[3]

[1] This report relates only to generation resource adequacy and grid stability. SCE will provide emissions estimates separately.

[2] PBGS used approximately 268,000 gallons of propane for power production in 2022. It is important to note that 200,000 gallons is more representative of typical annual propane consumption for power production because the PBGS NaS battery is generally dispatched in favor of the microturbines because it is a zero-emission resource. The amount of propane consumed in 2022 was higher because the PBGS battery was out of service for a large portion of the year, thereby allowing for the increased use of the propane-based microturbines. Achieving the target of 250,000 gallons of propane annually is largely dependent on the installation of the T4F diesel generators because their greater operating range allows for increased propane use.

[3] Letter from City of Avalon Fire Chief to SCE (09/06/2023) (attached as Exhibit K).

- If found to be feasible and commercially available in the future, propane-fueled inverter-based resources[4] could potentially supply up to approximately 14 percent of annual energy production.
- Only two of the 22 scenarios provide sufficient generation and appear to be feasible from a grid stability perspective.
- Inverter-based resources must meet or exceed requirements identified in IEEE Standard 1547-2018 and Hawaiian Electric Company's Source Requirements Document (Version 2.0) for frequency ride-through requirements[5] as well as be able to accommodate rate-of-change-of frequency (RoCoF) settings of equal to or greater than 4.1 Hz per second.
- Should solar generation be made available at the Middle Ranch site, it may be able to contribute significantly to annual energy production (particularly when paired with energy storage) reducing fossil fuel use.

This study provides critical guidance on generation scenarios SCE may be able to implement to minimize emissions and maximize renewable energy generation on Catalina. Once information becomes available regarding proposals from the Clean Energy RFO and if SCE's recommended ride-through and RoCoF requirements can be met, it may be possible to increase Catalina renewable generation up to nearly 30 percent annually and approximately 70 percent instantaneously.[6]

II. Background

Catalina is located 26 miles off the coast of Southern California. SCE's PBGS is the sole provider of electricity, water, and gas utility services for more than 4,100 residents and over one million annual tourists. Reliable electrical service is the backbone of the utility infrastructure required to provide reliable electric service promoting the safety and well-being of the residents on the island. Catalina is a unique area within SCE's electrical service territory. The island is

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[4] The term "inverter-based resources" refers to generation resources that produce direct current (DC) and consequently require a device called an "inverter" to convert that output to the alternating current (AC) used by the U.S. grid. National Renewable Energy Laboratory (NREL), Inertia and the Power Grid: A Guide Without the Spin (05/2020) ("NREL 2020"), at p. v (available at https://www.nrel.gov/docs/fy20osti/73856.pdf); *see also* NREL, An Introduction To Inverter-Based Resources on the Bulk Power System (06/2023) (available at https://www.nerc.com/pa/Documents/2023_NERC_Guide_Inverter-Based-Resources.pdf).

[5] SCE Catalina Island Planning Criteria and Guidelines (09/2023), at pp. 4-5 (attached as Exhibit D).

[6] "Instantaneously" means that the renewable generation in total has the potential to meet 70 percent on a moment-by-moment basis and should not be confused with the annual total energy production (GWh) of 30 percent. In reference to nearly 30 percent annual renewable power production, refer to Exhibit H, Table 1, Scenario No. 4b, "Solar PV" (p. 5). In reference to the approximately 70 percent instantaneous renewable production, refer to Exhibit J, Table 3.2-2 (p. 3-6). In this bookend example of maximum renewable generation during maximum loading conditions, the sum of the renewable power production delivered to the Catalina grid from the Middle Ranch solar, [redacted] is 4,350 kW. When this value is divided by the peak island load of roughly 6,000 kW, the result is 72 percent.

isolated from SCE's mainland grid and all utility services must be provided from infrastructure located on the island.

Rules implemented by the South Coast Air Quality Management District (SCAQMD) require SCE to replace the aging diesel engines at the PBGS. As part of its investigation of generation alternatives, SCE commissioned a grid stability study to determine how much renewable generation can be implemented on Catalina while maintaining a reliable and safe grid. Upgrading an existing and operational electrical system, while maintaining service to all customers, can be far more challenging than building a new system and transferring service over to it. When considering potential system scenarios, it is essential to comprehensively evaluate them to determine their feasibility in meeting the stated objectives. Part of this evaluation includes performing a series of electrical system modeling studies (i.e., grid stability studies). The consequences of the failure to evaluate these studies, or of taking shortcuts in performing them, could include the eventual construction of a project that ends up being unreliable, unsafe, or infeasible to operate in the manner necessary to meet the stated objectives.

A. Grid Stability Fundamentals

1. The Importance of Inertia

The electrical grid is a network of interconnected generation sources (such as power plants), transmission and distribution lines, and the customers who receive the generation (and often can provide their own). The North American grid is composed of four separate smaller grids known as "interconnections."[7] The generation sources within an interconnection all rotate at the same frequency, a concept called "synchronous generation." This produces inertia, or the tendency of an object in motion to remain in motion.[8] System inertia is necessary to mitigate system instability and potential system collapse (i.e., blackouts) during instances of generation-to-load mismatches which result from the loss of generation, loss of load, or sudden increases in load. Operators can rely on the energy from the spinning generators' inertia to compensate temporarily for lost generation, which affords them time to increase generation elsewhere. The amount of inertia available also depends on the grid's size. The greater the number of connected generators there are, the more inertia is produced. This provides the grid operator with more time to respond to instability events.

2. Frequency

The U.S. electrical grid uses alternating current, which means that as electric current flows from generation sources to customers, it changes direction rapidly. The term "frequency" refers to the rate of this change. For the U.S. grid, the default frequency is 60 Hertz (Hz).[9] In order to maintain a functioning grid, operators must ensure that its frequency stays as constant as possible; deviations too far below or above 60 Hz cause disruptions. In most of the mainland U.S., when grid frequency drops below 59.5 Hz, actions known as "frequency control" are taken to restore it

[7] NREL 2020, at pp. 2-3. Three interconnections are in the United States (Eastern, Western, and ERCOT (Texas); the fourth, Quebec, is in Canada.

[8] *Id*. at p. 2.

[9] *Id*.

to 60 Hz, such as forced load shedding (i.e., disconnecting customers) (known as an underfrequency load-shedding event, or UFLS).[10] Similarly, when grid frequency jumps above 60.5 Hz, the operator must shut down some generation to compensate.[11] In either scenario, if the required actions do not occur in time, widespread outages could result, as illustrated below:

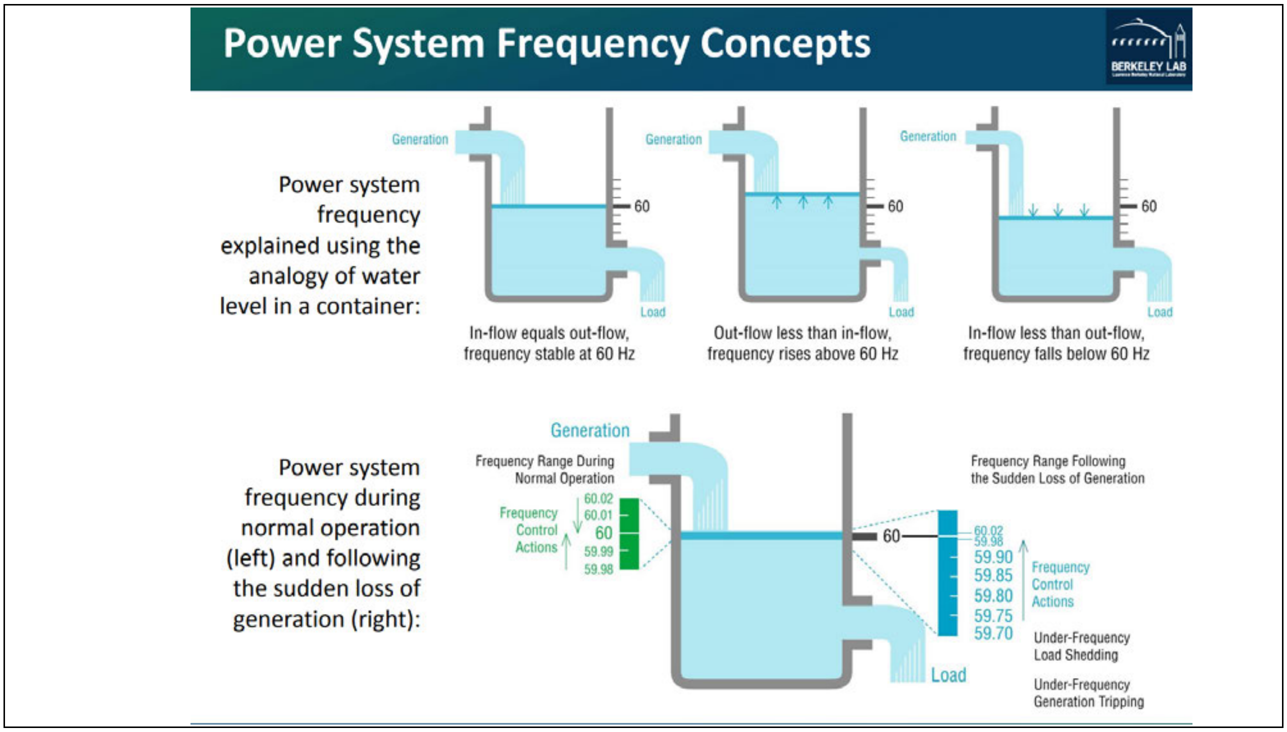

Figure 1 *(Source: Lawrence Berkeley National Laboratory)*[12]

a) Frequency Stability: RoCoF

The term "frequency stability" refers to the electrical system's ability to maintain an almost constant frequency under normal conditions and to quickly recover from any imbalances.[13] System operators use the rate of change of frequency (RoCoF) of generation resources as a means of evaluating frequency stability. Factors that affect RoCoF include the amount of inertia in a system, how quickly generation equipment can respond to a contingency event (e.g., an unplanned outage of a generation resource), the magnitude of the response, and the size of the contingency.[14] Each

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[10] International Renewable Energy Agency, Transforming Small-Island Power Systems (2018), §§ 1.3 (available at Transforming small-island power systems (irena.org)).

[11] NREL 2020 at p. 4.

[12] Lawrence Berkeley National Laboratory, BNL's Frequency Response Study for FERC (available at https://www.energy.gov/sites/prod/files/2018/07/f53/2.1.1%20Frequency%20Response%20Panel%20-%20Eto%2C%20LBNL_1.pdf).

[13] *Id*. at p. 2.

[14] North American Electric Reliability Corporation (NERC), Fast Frequency Response Concepts and Bulk Power System Reliability Needs (03/2020), at p. iv (available at https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf).

of these characteristics were included in the system modeling performed in the grid stability studies.

b) Primary Frequency Response

The term "primary frequency response" (PFR) refers to a system's ability to react or respond to a change in system frequency.[15] A form of "cruise control," it can be accomplished mechanically inside a power plant via control devices that can speed up or slow down individual generators as needed.[16] The following figure illustrates a system recovering from a contingency event:

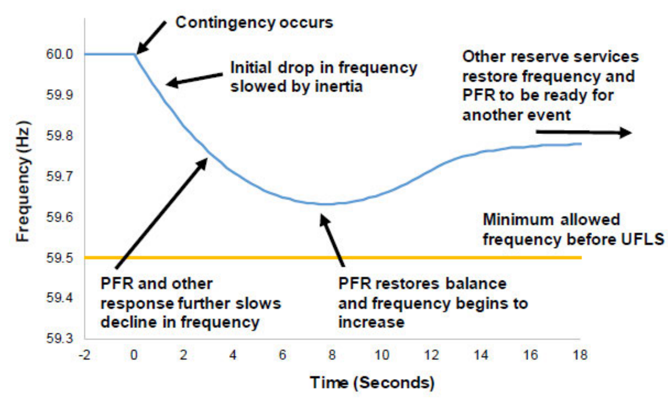

Figure 4. A successful recovery from a contingency event

Figure 2 *(Source: NREL)*[17]

The X axis of the graph depicts the passage of time in seconds and the Y axis depicts the change in frequency. The orange line represents the minimum frequency threshold to avoid UFLS. Before the contingency event occurs, frequency is stable at 60 Hz. At zero seconds, the contingency event occurs and frequency begins to drop; after eight seconds, it reaches a nadir of approximately 59.6 Hz. During the first eight seconds of the contingency event, PFR (i.e., inertia provided by the remaining generators) slows the decline in frequency, avoiding the threshold that would trigger UFLS. At this point, the system operators engage other reserve services to restore balance and increase frequency back towards 60 Hz.

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[15] NERC Glossary of Terms (available at https://www nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf).

[16] NREL 2020 at p. 5.

[17] *Id*. at p. 7.

The following factors contribute to frequency stability:

Factor	Impact of Greater Amount[a]
Generator inertia	Slows down frequency decline
Load inertia and load damping	Slows down frequency decline
Contingency size	Increases frequency decline
Underfrequency limits (UFLS settings)	Lower UFLS settings provides more time for overall response
Frequency response speed	Responds faster to a decline in frequency
[a] Assumes no other factors change	

Figure 3 *(Source: NREL)*[18]

The first factor listed in Figure 4, generator inertia, is described above (section II.A.1.). The second factor, load inertia/load damping, results from the tendency of some motors to continue spinning even after the electricity supply is terminated. This reduces load, which in turn reduces the frequency decline that otherwise is inevitable after loss of generation. The third factor is contingency size; the larger the contingency, the faster the frequency drops. The fourth factor relates to the relevant underfrequency limit in a particular system, which is the point at which circuit breakers will initiate load shedding. In Figure 3 above, the UFLS limit is set at 59.5 Hz. Reducing that limit even slightly allows the system operator more time to respond to a contingency and try to keep the frequency level from dipping below the UFLS limit. The final factor, frequency response speed, is the rate at which remaining online generation can temporarily increase its output to arrest the decline in frequency while other generation resources can be brought online to compensate for the contingency.

B. Electrical System Planning

1. *Resource Adequacy*

When assembling a generation resource portfolio, it is essential to ensure that enough power is available constantly to meet demand. The term "resource adequacy" refers to the evaluation of available resources that includes regularly planned generator maintenance downtime and accounts for contingency events where a generation resource is unexpectedly offline.[19] This is especially important in an isolated grid like Catalina. Studies are performed to evaluate the adequacy of generation to meet load requirements during all hours of the year for both planned and unplanned outages of generation units. Outages of generation units can occur simultaneously or overlap (e.g., one unit can be offline for planned maintenance and then a concurrent unplanned outage of an additional unit occurs)."[20]

[18] *Id*.

[19] NERC defines "adequacy" as "The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements." NERC Glossary of Terms, *supra* note 15. *See also* California Independent System Operator, Resource Adequacy: The Need for Sufficient Energy Supplies (available at https://www.caiso.com/Documents/Resource-Adequacy-Fact-Sheet.pdf).

[20] SCE Catalina Island Planning Criteria and Guidelines (09/2023), at pp. 4-5 (attached as Exhibit D).

SCE's planning criteria account for the required redundancy of generating units, which is expressed as follows: the letter N represents the number of online and operational generating units required to meet load requirements at any given time. The redundancy is expressed by adding numbers to N. For example, in an N+1 scenario, there is enough generation to cover demand when the largest generation unit is offline. In an N+2 scenario, there is enough generation to cover demand when the two largest generation units are offline.

2. Operating Reserve

The term "operating reserve" refers to surplus operating capacity that can instantly respond to a sudden increase in electric load or a sudden decrease in generation output. Operating reserve provides a safety margin that helps ensure reliable electricity supply despite variability in the electric load and renewable power supply. In the context of this document, the term "operating reserve" is used to reflect both the reserve of online synchronous generators (i.e., diesel generators) as well as that of any frequency-responsive inverter-based resources (e.g., grid-following energy storage).[21]

C. System Protection

SCE monitors and manages grid stability by using protection devices that sense, control, and isolate problems. Sensing devices (e.g., voltage transformers and current transformers) monitor electrical system parameters such as voltage, current, and frequency. Control devices (e.g., relays) receive input from the sensing devices and based on the programmed settings, act when a parameter is exceeded by sending a signal to a sectionalizing device. When a sectionalizing device (e.g., circuit breaker) receives a signal, it opens or closes depending on the intended operation. Coordinated protection from generation to the end-of-line of the distribution circuits is essential to minimize power system disruptions and to quickly de-energize electrical facilities for public safety during fault conditions.

D. Special Considerations

1. Island Systems

SCE developed unique standards for Catalina due to its isolation from the mainland grid.[22] Unlike the mainland, on Catalina a single generator or single load feeder can amount to approximately 40 percent of the total load connected to the system. The operation, protection, and control of the Catalina Island power system must recognize that events such as the tripping offline of a generator or a load feeder will commonly cause more severe deviations in voltage and frequency than are seen in large, interconnected mainland power systems. Of particular concern for islanded power systems is maintaining frequency stability following relatively large steps in generation and load (e.g., loss of a generator, loss of a load feeder, or the startup of large motors/load blocks). To maintain frequency stability, the power system needs sufficient primary

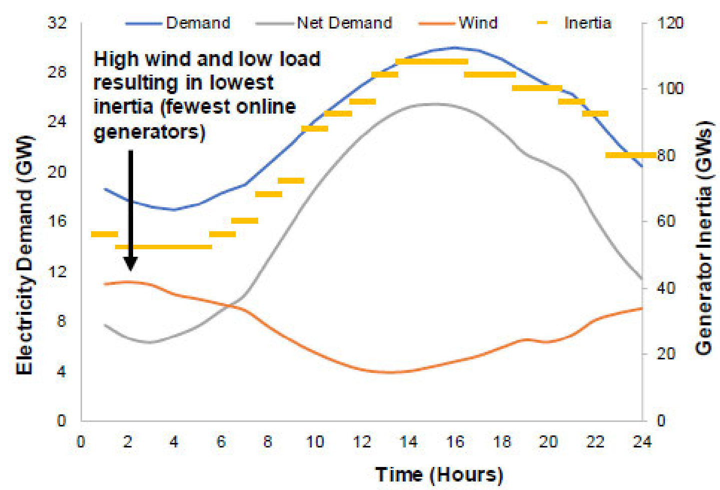
[21] *Id*. at p. 5.

[22] *Id*. at p. 3.

frequency response to arrest the deviation in frequency before the widespread loss of generation or load can occur.[23]

2. Inverter-Based Resources

Unlike synchronous generators, alternative energy sources such as wind, solar photovoltaic (solar PV), and battery storage lack inherent inertia. Known as "inverter-based resources," their use in large quantities can cause inertia to decline, as illustrated below:



a) Dispatch and resulting inertia

Figure 4 *(Source: NREL)*[24]

System operators mitigate this tendency by using newer electronic-based PFR mechanisms; if customers voluntarily agree to forced load-shedding to compensate for the lower inertia generated by inverter-based alternative energy sources, the system operator can use electronic sensors to accomplish this quickly. This practice is known as "load response." Reducing UFLS settings can buy more time for system operators to find alternative generation to compensate during contingency events, as described above (section II.A.2.b.).[25] For the purposes of the system stability studies described below (section III), any new inverter-based resources located at PBGS were assumed to be grid-forming.[26]

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[23] *Id*. at pp. 7-8.

[24] *Id*. at p. 20.

[25] *Id.* at pp. 26-27.

[26] Grid-forming inverters can operate independently of the main electrical grid and can provide voltage and frequency support to the grid. *See* https://energycentral.com/c/iu/grid-forming-vs-grid-following.

III. SCE's Grid Stability Study Process

To perform the grid stability studies (also described as system stability studies), SCE contracted with POWER and MEPPI due to their experience working with islanded power systems and performing grid stability studies. The studies are extensive and include evaluating generation dispatch, resource adequacy, protection, and system stability. Various industry-accepted software programs were used to model the electrical distribution system (e.g., the distribution circuits) and the potential generation scenarios including resources within PBGS as well as those that may be considered elsewhere on Catalina.

A. Summary of Studies

1. July 2022: SCE PBGS Action Plan

SCE's initial efforts to evaluate grid stability focused on its current practice of limiting inverter-based generation (from the microturbines and battery) to the greater of approximately 30 percent of total generation output or up to the amount of operating reserve of the online diesel units.[27] This limit is necessary because the microturbines' protection relays (which detect electric fault events by measuring RoCoF) are set at 1 Hz per second. This means that if the relays detect a frequency change at a rate greater than 1 Hz per second, they will force the microturbines to cease generating as a self-protection mechanism. Such frequency changes can be caused by sudden spikes in load (such as when a large motor load starts up at the Catalina rock quarry). SCE's July 2022 report affirmed the appropriateness of the 30 percent limit on inverter-based resources at PBGS because the microturbines' protection settings could not be adjusted without violating the Underwriters Laboratories (UL) 1741 standard.

2. September 2022: Initial System Stability Study

In its next study, SCE evaluated possible ways to increase the 30 percent limit on inverter-based resources by testing different forms of grid-stability mitigation.[28] The analysis concluded that frequency stability was not linked to the amount of microturbine generation, but rather to the amount of inertia on the system (provided by the diesel generators).[29] SCE evaluated whether improved controls on the microturbines would increase grid stability and concluded they would not.

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[27] SCE, Pebbly Beach Alternatives Study: Revised Final Action Plan (07/14/2022), at 16-17 (attached as Exhibit A).

[28] SCE & POWER Engineers, Pebbly Beach Generating Station: System Stability Study (09/30/2022) (attached as Exhibit C).

[29] *Id*. at p. 15.

3. September 2023: Final System Stability Study

In 2023, SCE worked with POWER and MEPPI on a comprehensive, multiphase study of the feasibility of future generation scenarios and their resulting impact on grid stability.[30] The software program HOMER Pro was used to model generation resource dispatch on an hourly time-series basis. This program models generation output to meet electrical demand to determine resource adequacy and fuel consumption, factoring in required maintenance times and contingency events that take generation resources offline. Another software program, CYME, was used to evaluate distribution circuitry for load flow and protection coordination. Load flow and short-circuit studies were performed at selected instantaneous moments in time to reflect various system stress conditions. The results demonstrate how various proposed generation scenarios would affect the existing distribution circuitry and whether upgrades would be required. Finally, the software program PSCAD was used to evaluate the proposed generation scenarios to determine impacts on the system stability during contingency events (e.g., unplanned outages of either a generation resource or a distribution load). These studies were performed at selected instantaneous moments in time to reflect various system stress conditions.

The evaluation process was iterative and includes a feedback loop, which allows refinements in the parameters if a scenario fails to meet one or more input constraints (e.g., fuel consumption, protection, stability, etc.). The initial phase of the grid stability studies evaluated proposed generation scenarios using HOMER Pro to screen out any scenarios that cannot meet resource adequacy. For those scenarios initially determined feasible through the HOMER Pro analysis, PSCAD was then used to study system stability only within PBGS (i.e., within the plant and excluding contingency events occurring on the distribution circuits).

Scenarios identified as being feasible were then assessed through CYME. This phase of the study evaluated the performance of the protection devices both at PBGS and along the distribution circuitry. Through the CYME assessments, any areas of concern were identified (e.g., if inadequate short-circuit current adversely affected the ability to detect and isolate fault conditions or miscoordination between protection devices). At this point, scenarios with areas of concern were evaluated to determine whether refinements were possible (e.g., modifying the generation resource mix to provide more short-circuit current, adjusting the relay settings of protection devices, or replacing protection devices). In the case of modifying the generation resource mix, this included reassessing the scenario within HOMER Pro and adjusting the dispatch. Once adjustments were made, and if the scenarios successfully passed the HOMER Pro analysis again, the scenarios followed a similar path of study as before and were reevaluated with CYME to determine if original issues had been remedied. Scenarios determined to be feasible through the aforementioned analyses were again studied using PSCAD, but this time assessing contingency events occurring on the distribution circuitry using an island-wide model of the electrical system (i.e., both PBGS and distribution circuitry). The study process can be depicted visually as follows:

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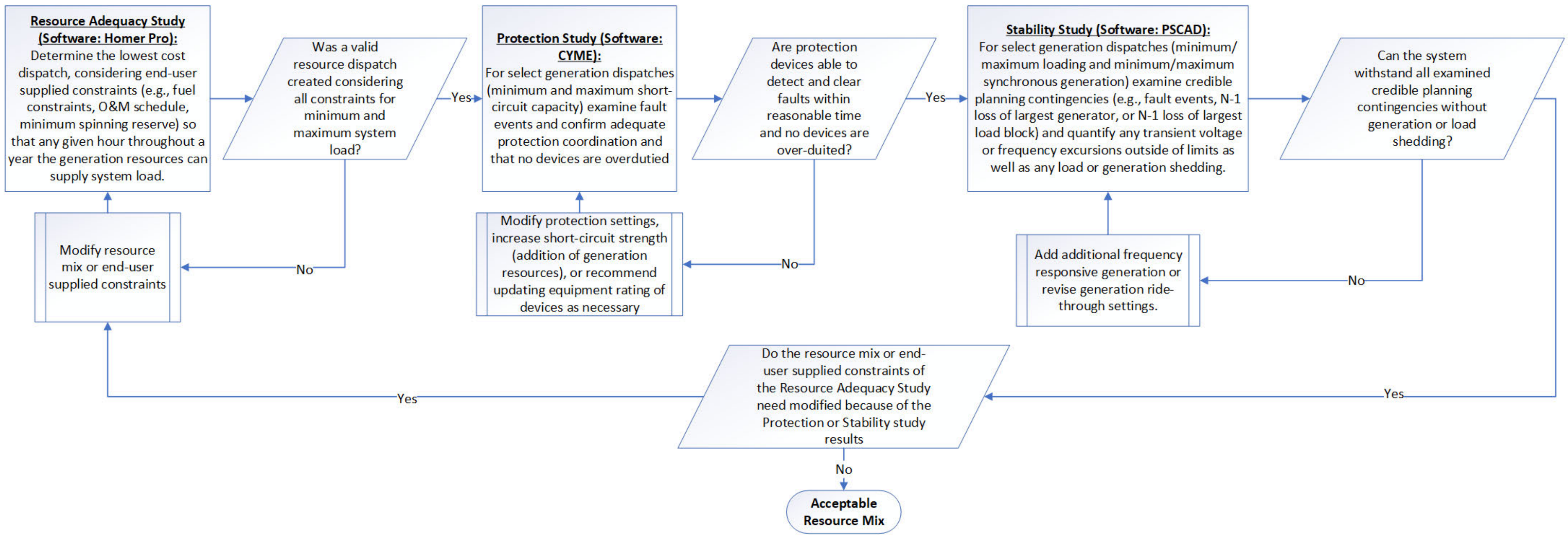
[30] The study built on an April 2023 report by SCE and POWER that evaluated two scenarios: (A) three T4F units, Units 7, 12, and 14 as backup only, the existing PBGS battery, and the existing microturbines; and (B) two T4F units, Units 7, 12, and 14 as backup only, and one 2.097 MW prime-rated propane reciprocating generator. The report concluded that Scenario A was feasible but not recommended due to lack of redundancy and that Scenario B was infeasible. SCE & POWER, PBGS Technical Assessment: Configurations A and B Report (04/28/2023) (see Exhibit B, Letter from SCE to SCAQMD (attaching the report as Exhibit C).



Resource Adequacy Study (Software: Homer Pro):
Determine the lowest cost dispatch, considering end-user supplied constraints (e.g., fuel constraints, O&M schedule, minimum spinning reserve) so that any given hour throughout a year the generation resources can supply system load.
Was a valid resource dispatch created considering all constraints for minimum and maximum system load?
Yes
No
Modify resource mix or end-user supplied constraints
Protection Study (Software: CYME):
For select generation dispatches (minimum and maximum short-circuit capacity) examine fault events and confirm adequate protection coordination and that no devices are overdutied
Are protection devices able to detect and clear faults within reasonable time and no devices are over-duited?
Yes
No
Modify protection settings, increase short-circuit strength (addition of generation resources), or recommend updating equipment rating of devices as necessary
Stability Study (Software: PSCAD):
For select generation dispatches (minimum/ maximum loading and minimum/maximum synchronous generation) examine credible planning contingencies (e.g., fault events, N-1 loss of largest generator, or N-1 loss of largest load block) and quantify any transient voltage or frequency excursions outside of limits as well as any load or generation shedding.
Can the system withstand all examined credible planning contingencies without generation or load shedding?
No
Add additional frequency responsive generation or revise generation ride-through settings.
Yes
Do the resource mix or end-user supplied constraints of the Resource Adequacy Study need modified because of the Protection or Stability study results
Yes
No
Acceptable Resource Mix

B. September 29, 2023 System Stability Final Study Results

1. *HOMER Pro Analysis*

a) Explanation

HOMER Pro evaluates system resource adequacy; in other words, whether a configuration provides sufficient generation supply to meet electrical demand. As an example, when a generation scenario successfully passes the HOMER Pro stage, the program produces a table displaying the relative share of generation that each element of the scenario provided along with the number of gallons of fuel consumed by each fuel type as shown below:

SCENARIO 3			
DG Unit 7	106,442.42	Diesel	3.82%
DG Unit 12	10,159.78	Diesel	0.37%
DG Unit 14	65,499.46	Diesel	2.35%
T4F Unit A	451,745.98	Diesel	18.90%
T4F Unit B	908,039.62	Diesel	41.70%
T4F Unit C	426,766.30	Diesel	18.80%
Linear Generator	399,999.86	Propane	14.10%

Figure 5: *HOMER Pro Result for Scenario 3 (Source: Exhibit H)*

In contrast, when a scenario cannot provide sufficient generation, HOMER Pro produces an error message as shown below:

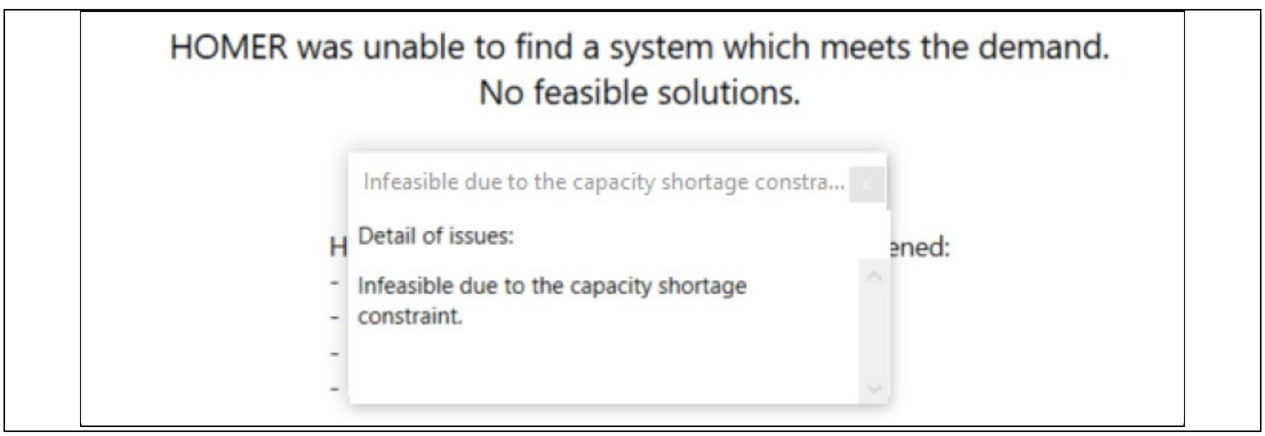


Figure 6: *HOMER Pro Result for SCAQMD Scenario 1 (Source: Exhibit F)*

b) SCE Scenarios

SCE identified 20 different scenarios that included a mix of T4F diesel generators, solar, battery storage, and propane technology.[31] Each scenario listed below included the following elements:

- Three T4F diesel generators; and
- Retain Units 7, 12, and 14 as backup generation.

POWER included numerous assumptions when performing the HOMER Pro analyses, the most important of which are:

- Load demand forecasted data for 2026 reflecting a peak of 6 MW and approximately 31 GWh annual loading;
- One T4F diesel unit receiving one three-month-long maintenance outage;
- Two T4F diesel units each receiving one month-long maintenance outage; and
- One biweekly planned maintenance activity per T4F diesel unit with 10 hours of downtime.

(1) Scenarios Evaluated Using HOMER Pro

Eight scenarios were considered in the HOMER Pro evaluation. The following chart provides a high-level summary of the differences between the scenarios (a detailed version is included in Exhibit H):

[31] Detailed explanations of the scenarios are provided in Exhibits F (the SCAQMD's scenarios) and G (SCE's scenarios).

#	Details	Outcome
1	• Retain existing battery at PBGS • One 2.097 MW prime-rated propane reciprocating generator (with 400,000-gallon annual supply)	Completed HOMER but excluded from further analysis
2	• Retain existing battery at PBGS • One 2.097 MW prime-rated propane reciprocating generator (with 400,000-gallon annual supply) • Solar farm (no battery)	Modified and rerun as No. 2(a)
2a	• Retain existing battery at PBGS • One 2.097 MW prime-rated propane reciprocating generator (with 400,000-gallon annual supply) • Solar farm with battery	Modified and rerun as No. 2(b)
2b	• Upgrade battery at PBGS • One 2.097 MW prime-rated propane reciprocating generator (with 400,000-gallon annual supply) • Solar farm with battery	Completed HOMER but excluded from further analysis
3	• Retain existing battery at PBGS • Five 250 kW propane linear generators (with 400,000-gallon annual supply)	Completed HOMER and advanced to PSCAD & CYME analysis
4	• Retain existing battery at PBGS • Five 250 kW propane linear generators (with 400,000-gallon annual supply) • Solar farm (no battery)	Modified and rerun as No. 4(a)
4a	• Retain existing battery at PBGS • Five 250 kW propane linear generators (with 400,000-gallon annual supply) • Solar farm with battery	Modified and rerun as No. 4(b)
4b	• Upgrade battery at PBGS • Five 250 kW propane linear generators (with 400,000-gallon annual supply) • Solar farm with battery	Completed HOMER and advanced to PSCAD & CYME analysis

Although Scenario Nos. 1 and 2(b) passed HOMER Pro analysis, they were not carried forward to the stability and protection study stage. One of SCE's overarching priorities is to maximize the use of near-zero emission and zero-emission technologies while meeting our obligation to provide safe, reliable, and affordable utility services to customers. As a result, higher priority was given to the propane-fueled technology that provided the greatest potential to maximize propane fuel use while also providing the greatest operational flexibility in generation dispatch. The key consideration associated with the selection of propane linear generators for further grid stability modeling is that the propane reciprocating generator would have an operating range of between 75 and 100 percent of its prime output rating of 2.097 MW (where this is the derated value due to propane fuel use). This equates to an operating range of 1.573 MW to 2.097 MW and leads to many instances where the minimum loading of the propane reciprocating generator would be greater than the needed capacity and therefore would not be dispatched. This would hamstring SCE's ability to maximize the use of propane. In contrast, with respect to the propane linear generators, the smaller unit size and consequential ability to dispatch any number of units results in a much greater and more flexible operating range (between the minimum output of a single unit up through the maximum output of 1.25 MW) that would allow operators to bring the linear generators online as needed in smaller increments. While these grid stability studies included linear generators in the models for evaluation, it is noted that this technology (specifically the 250 kW grid-forming model) is nascent and still evolving. Currently, none have been permitted for use by SCAQMD and none have been commercially deployed.

Of the scenarios that passed the HOMER Pro analysis stage, only two provided sufficient generation and maximized propane use to warrant PSCAD and CYME modeling (grid stability and protection studies). Both scenarios share the following elements:

- Three T4F generators (replacing existing Units 8, 10, and 15);
- Retain Units 7, 12, and 14 as backup generation;[32] and
- Five 250 kW propane linear generators (with 400,000-gallon annual supply).

The remaining elements of the two successful scenarios differ as follows:

The remaining elements of the two successful scenarios differ as follows: **Scenario 3**	**Scenario 4(b)**
• Retain existing battery at PBGS	• Upgrade existing battery at PBGS • Solar farm with battery

Scenario Nos. 3 and 4(b) were carried forward for PSCAD/CYME analysis.

(2) Scenarios Eliminated Without HOMER Pro Analysis

After an initial screening, 12 scenarios were removed from further consideration because they were found to be infeasible. Of the 12 scenarios, eight scenarios[33] were removed because they included a quantity of annual propane use that SCE learned would be impossible to accommodate because the City of Avalon Fire Chief stated that use of the fourth storage tank at PBGS would not be allowed for public safety/fire-suppression reasons. Four other scenarios were removed because one included a propane reciprocating engine (dismissed in favor of the greater operational flexibility of the propane linear generators) and the other three either had no solar farm or a solar farm but without paired energy storage. This allowed POWER and MEPPI to then focus on completing the two newly proposed HOMER Pro scenarios imposed by the SCAQMD Hearing Board[34] by the August 29, 2023 deadline, as well as analysis of Scenario 3 and 4(b) by the September 29, 2023 extended deadline.

[32] Units 7, 12, and 14 each have distinct power production output values that, when coupled with their operating ranges, allow PBGS operators flexibility to dispatch the units when needed. SCE recommends retaining all three units to optimize dispatch to meet electrical demand and minimize emissions from operation of the backup units.

[33] Scenarios 5, 6, 7, 8, 13, 14, 15, and 16.

[34] SCAQMD Hearing Board, Order of Abatement (07/25/2023), Condition No. 4 (p. 11).

#	Details	Outcome
5	• Retain existing battery at PBGS • One 2.097 MW prime-rated propane reciprocating generator (with 750,000-gallon annual supply)	Eliminated
6	• Retain existing battery at PBGS • One 2.097 MW prime-rated propane reciprocating generator (with 750,000-gallon annual supply) • Solar farm (no battery)	Eliminated
7	• Retain existing battery at PBGS • Five 250 kW propane linear generators (with 750,000-gallon annual supply)	Eliminated
8	• Retain existing battery at PBGS • Five 250 kW propane linear generators (with 750,000-gallon annual supply) • Solar farm (no battery)	Eliminated
9	• Upgrade battery at PBGS • One 2.097 MW prime-rated propane reciprocating generator (with 400,000-gallon annual supply)	Eliminated
10	• Upgrade battery at PBGS • One 2.097 MW prime-rated propane reciprocating generator (with 400,000-gallon annual supply) • Solar farm (no battery)	Eliminated
11	• Upgrade battery at PBGS • Five 250 kW propane linear generators (with 400,000-gallon annual supply)	Eliminated
12	• Upgrade battery at PBGS • Five 250 kW propane linear generators (with 400,000-gallon annual supply) • Solar farm (no battery)	Eliminated
13	• Upgrade battery at PBGS • One 2.097 MW prime-rated propane reciprocating generator (with 750,000-gallon annual supply)	Eliminated
14	• Upgrade battery at PBGS • One 2.097 MW prime-rated propane reciprocating generator (with 750,000-gallon annual supply) • Solar farm (no battery)	Eliminated
15	• Upgrade battery at PBGS • Five 250 kW propane linear generators (with 750,000-gallon annual supply)	Eliminated
16	• Upgrade battery at PBGS • Five 250 kW propane linear generators (with 750,000-gallon annual supply) • Solar farm (no battery)	Eliminated

2. SCAQMD-Proposed Scenarios

SCE evaluated two additional scenarios proposed by the SCAQMD staff. Both scenarios share the following assumptions:

- 10% minimum charge on the existing battery system (NaS BESS);
- Load demand forecasted data for 2026 reflecting a peak of 6 megawatts (MW) and approximately 31 gigawatt-hours (GWh) annual loading;
- Existing NaS BESS modeled as 1 MW/7 megawatt-hours (MWh) with a round-trip efficiency of 85%;
- Annual consumption of 500,000 gallons of diesel;
- Annual consumption of 2.1 million gallons of propane; and
- No minimum spinning reserve requirement.

SCAQMD Scenario 1 contains the following elements:

- Utility-scale renewable PV system (30% of annual load);
- Three U.S. EPA Tier 4 Final-certified (T4F) diesel generators (1.825 MW each);
- Existing NaS BESS;
- Five new BESS (1 MW each); and
- Propane near-zero-emission (NZE) technology with a combined rating of at least 2.25 MW (65% of annual load).

SCAQMD Scenario 2 contains the following elements:

- Utility-scale renewable PV system (30% of annual load);
- Three T4F diesel generators (1.825 MW each);
- Existing NaS BESS;
- Five new BESS (1 MW each); and Propane NZE technology with a combined rating of at least 2 MW (50% of annual load).

POWER included the following additional assumptions:

- One T4F diesel unit receiving one three-month-long maintenance outage;
- Two T4F diesel units each receiving one month-long maintenance outage; and
- One biweekly planned maintenance activity per T4F diesel unit with 10 hours of downtime.

The BESS was modeled in aggregate as a 6 MW/27 MWh system (i.e., the existing PBGS NaS BESS at 1 MW/7 MWh plus a renewable solar PV system paired with a BESS at 5 MW/20

MWh). After the parameters for SCAQMD Scenario 1 were entered into HOMER Pro, the program provided the output message shown below:

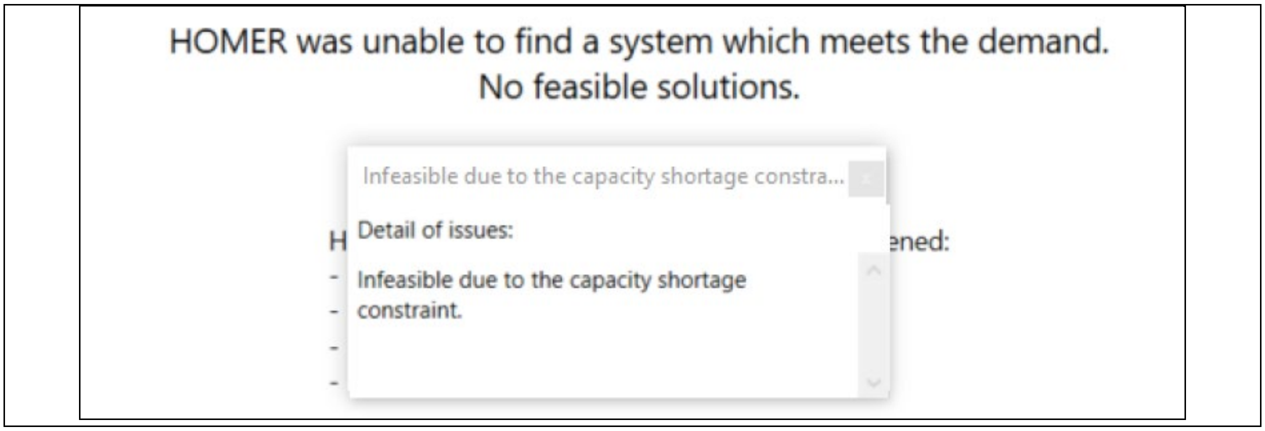


Figure 7: *HOMER Pro Output for SCAQMD Scenario 1 (Source: Exhibit F)*

The HOMER Pro results depicted in Figure 8 indicate that SCAQMD Scenario 1 is infeasible because it fails to provide sufficient capacity to meet all electrical demand at all hours throughout the year. SCAQMD Scenario 2 differs from SCAQMD Scenario 1 by a 250 kW reduction in the generating capacity of the propane NZE technology. Because SCAQMD Scenario 2 provides less generation output capacity than Scenario 1, it also fails to meet demand. Simply put, neither proposed SCAQMD Scenario can meet Catalina's electrical demand requirements at every hour throughout the year.

In order to determine whether the failure to pass the HOMER Pro analysis was due to the propane fuel availability parameters identified in the SCAQMD's proposed scenarios, POWER revised the model to allow the consumption of an unlimited amount of propane before rerunning the first scenario. Again, the outcome was reported as infeasible. SCAQMD Scenario 2 had the same result (failure) because, as mentioned above, it provides less generation output capacity than SCAQMD Scenario 1. Even when all constraints on fuel consumption parameters for both propane and diesel are removed (allowing unlimited consumption), neither scenario would provide the necessary generation resource adequacy to ensure sufficient power supply to meet the requirements of Catalina's customers. This indicates the failure of these two scenarios is due to the lack of generation output capacity rather than fuel availability.

The purpose of modeling generation scenarios using software such as HOMER Pro is to determine whether they will meet the resource adequacy requirements of the electrical system being studied (e.g., Catalina). When an analysis produces a result that demonstrates a scenario is cannot supply the amount of generation required, the consequences (should such a scenario be implemented) can include the following at every instance when a deficiency is identified:

- Required forced load shedding of customer demand to reduce consumption to within the limits of the generation resource mix contemplated; or
- System instability resulting in system collapse (i.e., island blackout) if the aforementioned load shedding does not occur or does not occur quickly enough.

The results from the HOMER Pro analysis of SCAQMD Scenario 1 identified more than 1,000 instances where it was unable to supply the amount of generation required to meet customer demand. The analysis was performed on an hourly basis throughout the year (i.e., all 8,760 hours in one year); the number of instances in which there was insufficient power to supply Catalina customers equates to over 10 percent of the time annually. SCAQMD Scenario 2, which has 250 kW less generation capacity than SCAQMD Scenario 1, is expected to cause even more instances where the system would be unable to supply the amount of generation required to meet customer demand.

The HOMER Pro program evaluates system resource adequacy only and does not reflect system stability issues that may result from insufficient system inertia. System stability was analyzed in the next phase of the study (using software designed for evaluating stability and protection) for those scenarios that pass the HOMER Pro stage. Therefore, only if either scenario above passed the HOMER Pro stage would a PSCAD/CYME system stability and protection analysis be appropriate. Because they failed, no further analysis was conducted of these two scenarios.

C. Conclusions from the HOMER Pro Analysis

Two scenarios advanced to the system stability and protection study phase: Nos. 3 and 4(b). Each scenario requires the installation of three new T4F units as well as keeping Units 7, 12, and 14 as backup generators.

D. Stability & Protection Studies

POWER and MEPPI conducted separate PSCAD analyses of SCE Scenarios Nos. 3 and 4(b). MEPPI also investigated whether under either scenario, and under bookend system dispatches,[35] the Catalina grid could withstand credible planning contingencies without frequency excursions outside the system's operating limits or that triggered significant shedding of generation or load. MEPPI also confirmed that under bookend system dispatches, Catalina's existing protection scheme can adequately detect and clear fault events while remaining within the protective devices' short-circuit rating.

1. POWER: PSCAD Stability Study

To evaluate system stability, POWER measured the RoCoF on the grid from consistent disturbances under different generation dispatches for SCE Scenario Nos. 3 and 4(b). POWER reached four conclusions:

- Having more Tier 4 Final (T4F) units online and powering the system leads to increased system stability.
- The stability benefits of the T4F units are based upon the number of units online regardless of loading levels.

[35] The term "bookend" means that MEPPI studied the minimum and maximum loading and minimum and maximum synchronous generation.

- An inverter-based resource responds more quickly to system disturbances to improve RoCoF than the governor response of a synchronous generator, although the extent is reduced by BESS state-of-charge constraints and limits to fault current contribution.
- Linear generators showed similar improvement in RoCoF to that of adding a second T4F diesel generator. Constraints on propane linear generators include insufficient fuel storage and the lack of proven commercial performance.[36]

Based on the RoCoF levels observed, POWER recommended that SCE operate two T4F generators at all times to maintain sufficient frequency stability. This means that installing a third T4F generator is necessary so that it is available when either of the other two are offline for maintenance or experience an outage. As soon as one of the two T4F generators in operation becomes unavailable, SCE must start up the third T4F unit immediately to prevent load-shedding and/or to maintain system stability. In recognition that each T4F must undergo regular maintenance, during which time it is unavailable for operation, POWER recommends that SCE retain backup diesel generation to replace the unavailable T4F generator.

2. MEPPI: Stability & Protective Device Coordination Studies

MEPPI's study evaluated whether the Catalina grid could successfully handle SCE Scenario Nos. 3 and 4(b) while avoiding any frequency excursions that either exceed the system's limits or would trigger load-shedding.[37] MEPPI analyzed the scenarios' performance when one generating unit (T4F or linear generator) was unavailable due to an outage. MEPPI concluded that two T4F diesel generators must be in operation at all times to provide sufficient inertia and frequency responsive operating reserves. MEPPI also found that custom voltage and frequency ride-through requirements were necessary to avoid unintentional shedding of generation or load during such an outage.[38] The RoCoF exceeded the IEEE Standard 1547-2018 Category III requirement (of 3 Hz) and the frequency nadir dropped below the IEEE Standard 1547-2018 Category III minimum (of 57 Hz). Consequently, SCE will need to incorporate these limits into its frequency ride-through requirements.[39] MEPPI also confirmed that under bookend system dispatches, Catalina's existing protection scheme can adequately detect and clear fault events while remaining within the protective devices' short-circuit rating.

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[36] POWER Engineers, Southern California Edison: Pebbly Beach Generating Station PSCAD Stability Study at p. 1 (09/27/2023) (attached as Exhibit I).

[37] MEPPI's work was limited by the lack of as-built models for the Cummins TF4 generators and future Middle Ranch solar farm and thus relied on a set of generic, reasonable assumptions.

[38] MEPPI, Southern California Edison: Stability and Protection Device Studies – Catalina (09/2023) (attached as Exhibit J).

[39] *Id*. at p. 3-10, pp. 3-13 to 3-14.

IV. Conclusion

With the conclusion of the HOMER Pro, PSCAD, and CYME evaluations, SCE has completed its comprehensive grid stability study and identified feasible generation scenarios that, if implemented, would enable SCE to continue to provide safe, reliable, clean, and affordable electric power to Catalina. The two feasible scenarios that passed the generation resource adequacy, system stability, and protection reviews both include three T4F generators (replacing existing Units 8, 10, and 15); retaining Units 7, 12, and 14 as backup generation; and five 250 kW grid-following propane linear generators[40] (with a 400,000-gallon annual supply). The two scenarios differ in that one would retain the existing PBGS battery (No. 3), while the other includes an upgraded PBGS battery and a solar farm at Middle Ranch paired with energy storage (No. 4(b)).

Upon SCE's receipt of additional information from Cummins relevant to the governor and excitation models of the T4F diesel units, refinements will be made to the CYME and PSCAD studies to identify whether any upgrades to protection devices and/or settings changes may be required. These anticipated refinements are not expected to change the results of the HOMER Pro, PSCAD, and CYME evaluations. The study confirmed the need to install three new T4F diesel generators and to retain three existing diesel units (Units 7, 12, and 14) as backup generators for use only when the new T4F generators are unavailable due to planned or unplanned outages.

SCE will incorporate the study conclusions into the ride-through requirements for future inverter-based resources such as the proposed Middle Ranch solar farm. Additionally, any proposed generation resources that would interconnect to the distribution system outside of PBGS would require power flow studies to determine any necessary distribution system upgrades to accommodate the interconnection(s), as well as stability studies to determine any grid impacts. Finally, SCE will continue to monitor the development and deployment of linear generators (and other grid-forming, propane-fueled inverter-based resources) to see whether the technology matures to the point where it has been demonstrated, in practice, that its use is feasible for power generation and complies with future emissions limits that may be imposed.

[40] Although the two scenarios were identified as being feasible, both included 250 kW grid-forming linear generators. This is evolving technology; to SCE's knowledge, none have been either permitted for use by SCAQMD or commercially deployed.

<u>Exhibits</u>

A. SCE, PBGS Action Plan (07/14/2022)

B. Letter from SCE to SCAQMD (04/28/2023), Exhibit C: PBGS Technical Assessment: Configurations A and B Report

C. SCE and POWER Engineers, System Stability Study (09/30/2022)

D. SCE, Catalina Island Planning Criteria and Guidelines (09/2023)

E. SCE, Grid Stability Study Explanation (08/08/2023)

F. Letter from SCE to SCAQMD (08/30/2023)

G. SCE, Grid Stability Scenarios (9/06/2023)

H. POWER Engineers, Southern California Edison: Pebbly Beach Generating Station Combined HOMER Pro Memos (09/28/2023)

I. POWER Engineers, Southern California Edison: Pebbly Beach Generating Station PSCAD Stability Study (09/28/2023)

J. Mitsubishi Electric Power Products Inc. (MEPPI), Southern California Edison: Stability and Protection Device Studies – Catalina (09/2023)

K. Letter from City of Avalon Fire Chief to SCE (09/06/2023)

July 14, 2022

SOUTHERN CALIFORNIA EDISON

Pebbly Beach Alternatives Study

Revised Final Action Plan

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Revised Final Action Plan

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TABLE OF CONTENTS

I. Executive Summary

Southern California Edison (SCE), with technical support from POWER Engineers (POWER), developed this Final Plan for SCE's Pebbly Beach Generating Station (PBGS) to address the requirements in the Abatement Order issued by the South Coast Air Quality Management District (SCAQMD) Hearing Board on January 4, 2022.[1] SCE and POWER evaluated a range of potential options for alternative electrical generation to reduce particulate matter (PM) emissions associated with Unit 15, a diesel-powered internal combustion engine at PBGS. SCE and POWER also evaluated other generation methods and fuels. Preliminary findings from this evaluation were submitted to SCAQMD on April 1, 2022.

A. Proposed Final Actions

This Final Plan recommends implementing specific improvements at PBGS to bring Unit 15 into compliance with the Rule 1470 PM emissions limit as soon as possible. Two viable options have been identified: (1) replacing the carbon monoxide (CO) catalyst blocks within Unit 15's aftertreatment system with new versions; and (2) if the first option fails, replacing Unit 15 with a U.S. EPA Tier 4 Final-certified (T4F) diesel engine. SCE and POWER also identified other actions, studies, and evaluations to reduce overall emissions at PBGS in both the near-term and over time. SCE's Final Plan includes the following potential equipment modifications/installations and future studies:

1. Equipment modification/installation

- Selected Rule 1470 compliance option: Install Clean Energy Projects Inc. (CEP) catalyst blocks in Unit 15's exhaust aftertreatment system.
    - If the catalyst blocks fail to achieve the required PM emissions reduction, SCE would propose replacing Unit 15 with a new T4F engine.
- Additional emissions reduction options:
    - Pending discussions with SCAQMD staff, possible refurbishment of some microturbines in the near term while SCE evaluates how the space can be used for more efficient alternative generation longer-term.

[1] Appendix A contains a summary of the Abatement Order requirements and how SCE complied with them in its three reports (March 18, 2022; April 1, 2022; and this report).

- New solar photovoltaic (PV) carports and electric vehicle (EV) charging stations.

2. Studies and Evaluations of Additional Emissions-Reduction Options

- Grid stability evaluation: Determine how much inverter-based electrical generation is feasible without compromising grid stability. Use the evaluation results to improve system reliability while increasing the use of inverter-based generation.

- Renewable diesel:[2] Evaluate for potential use in the existing internal combustion engines at PBGS.

- All-Source RFO: By December 2022, issue a solicitation for utility-scale solar PV, other low- or zero-carbon resources, energy storage, and demand response resources on Catalina outside PBGS.

- Propane generator: Evaluate as a replacement for the microturbines. The microturbines are at the end of their useful life, trip offline when there are frequency excursions, and consume about 61% more propane than a similarly sized new propane-fired generator. If feasible, replacing them with one propane generator could lead to notable reductions in criteria pollutants (oxides of nitrogen, CO, and PM) and greenhouse gas (GHG) emissions following a reduction in fuel consumption per kWh generated. It appears that a propane generator equipped with a selective catalytic reduction (SCR) system may be able to meet the requirements of Rule 1110.2, Table 1. SCE is currently working with multiple vendors to assess the size requirements of a single SCR-equipped unit and has requested emissions data from vendor(s).

- Decision-making optimization: SCE is evaluating the installation of an Operator Intelligent Advisory program using the existing plant control system to help manage plant efficiency, emissions, reliability, and fuel availability. The system will also provide predictive information to the operator about the scheduling of fuel deliveries based on a running average of the current consumption rate. The system will be flexible and relatively easily modified as the mix of generating assets changes over time (such as new diesel generators, additional solar PV, clean energy, energy storage changes, microturbine additions/deletions, new propane reciprocating engines, and demand-side resources). Such a diverse resource system can quickly exceed the capabilities of a human to balance the

[2] This fuel is also known as R95 or R99, depending on the percentage of renewable ingredients.

numerous constraints and available generating assets that require complex real-time decisions to be made on a continuous basis.

B. Schedule

Table ES-1 below provides a high-level schedule of the projects relating to the Abatement Order.

Table 1. Abatement Order Action Plan: Schedule Summary

Action	Project Component Initiation/Completion			
	2022	***2023***	***2024***	***Future***
Unit 15: Catalyst Replacement	Start Q3, Finish Q4			
Unit 15: If Needed: Replacement with U.S. EPA Tier 4 Final-certified Engine		Start Q2	Finish Q4[3]	
Microturbine Upgrades (If Selected)	Start Q3	Finish Q2		
Solar PV Carport(s) & EV Charging	Start Q4		Finish Q3	
Renewable Diesel (R99) Evaluation	Start Q4	Finish Q1		
Renewable Diesel (R99) Implementation			Start Q1	Finish

Table ES-2 provides a high-level schedule of the projects and analyses not directly required by the Abatement Order.

Table 2. Post-Abatement Order Action Items: Schedule Summary

Activity	Project Component Initiation/Completion			
	2022	***2023***	***2024***	***Future***
Propane Generator Evaluation	Start Q3	Finish Q2		
Preliminary PBGS Grid Stability Study	Start Q2 Finish Q3			
System Grid Stability Evaluation	Start Q4	Finish Q3		
Decision-Making Optimization	Start Q4	Finish Q4		
Clean Energy All Source RFO solutions (not located at PBGS)	Start Q4			Finish

[3] SCAQMD Rule 1135 (d)(2)(b) prohibits the installation of new diesel combustion engines on Catalina after January 1, 2024. The Rule is expected to be amended this year. SCE may recommend the extension of this deadline if needed.

1. Actions Planned for Achievement of Compliance with Rule 1470

- Planned: Unit 15/New catalyst blocks (Finish Q4 2022): On June 15, 2022, the SCAQMD issued a permit (under Rule 441) to SCE to replace CO catalyst blocks. After the installation, SCE must conduct two separate source tests to verify system performance and PM emission reductions while maintaining compliance with emission limits for other criteria pollutants. The permit expires on March 31, 2023.[4]

- Planned (backup): Unit 15/T4F Replacement (pending results of replacement catalyst block testing): If the preferred option fails to achieve the required PM emissions reduction, SCE proposes to replace Unit 15 with a new T4F engine.

2. Actions Planned/Possible for Future Emissions Reductions at PBGS

- Possible: Microturbine repairs (Finish Q2 2023): With the SCAQMD's concurrence, SCE could refurbish up to 15 microturbines[5] to return them to reliable operating condition (unless SCE and the SCAQMD determine that the space occupied by the microturbines should instead be used for another option, such as a propane-fueled generator).[6]

- Planned: Solar PV carports & EV charging stations (Finish Q3 2023): Add solar PV panels on new carports at two locations at PBGS (the west side of the main building and the east side of the main building over existing parking spaces along the shoreline). This would generate approximately 100 kW at PBGS for EV charging, including SCE's current EV fleet of two SUVs, four golf carts, two forklifts, three hybrid Jeep vehicles, and one hybrid SUV.[7]

- Planned: Renewable diesel/R99 evaluation: SCE will evaluate the potential use of R95/R99 renewable diesel in the existing Unit 8 and Unit 10. If found to be feasible, SCE will evaluate its use in the other units.

[4] Abatement Order Condition No. 3; Appendix B, Facility Permit to Operate, Revision No. 54 (June 15, 2022).
[5] The upgrades would include replacing electronic components that are susceptible to corrosion from exposure to salt air, coating the electronic boards with a corrosion protective film and adding space heaters to reduce condensation in the enclosures.
[6] Abatement Order Condition No. 5.
[7] Abatement Order Condition No. 6(d).

3. Actions Contemplated for Future Emissions Reductions

- Underway: Preliminary PBGS Grid Stability Study (Finish Q3 2022): This study will determine the maximum inverter-based electrical generation level currently feasible at PBGS while maintaining reliable electrical service without compromising grid stability.

- System Grid Stability Evaluation: Using the preliminary study results for PBGS, SCE will evaluate ways to increase inverter-based electrical generation island-wide.

- Single propane generator: Evaluate the installation of a new single reciprocating propane generator with an SCR for exhaust NOx treatment at PBGS to replace the existing microturbines. The study would determine requirements associated with the existing propane storage tanks at PBGS and the delivery cycle required to support the generator as well as any other infrastructure requirements such as fuel storage and required fire suppression water. SCE has gathered information about the anticipated number of fuel deliveries per month and current expected fuel cost per megawatt/hour (MWh). A propane generator appears to have the lowest fuel cost per MWh (based on current island-delivered propane and diesel prices) and the number of fuel deliveries per month would be comparable to those for the new T4F diesel generators. Each 1 MW of continuous propane generation would require about 7.8 barge shipments per month compared to 6.8 shipments per month for the same 1 MW of continuous diesel generation.

- Clean Energy All-Source RFO: In late 2022, SCE will issue an all-source procurement solicitation to obtain offers for renewable energy, near-zero emissions generation, energy storage, demand response, and energy efficiency for Catalina.

II. Introduction

A. Preliminary Action Plan (April 1, 2022)

SCE, with technical support from POWER Engineers (POWER), developed Preliminary and Final Action Plans that present technically feasible approaches to comply with the Abatement Order's requirements. Initial findings were presented in the Preliminary Action Plan submitted to the SCAQMD on April 1, 2022. It evaluated the following options:

- Biodiesel, renewable diesel, and emulsified fuels.
- Retrofit of Unit 15 with a diesel particulate filter (DPF) or other means of filtration.
- Various inverter-based technologies:
    - Fuel cells
    - Solar PV
    - Increased use of microturbines
    - Free piston linear generator
- Reducing PM emissions from the existing engine fleet via operational changes.
- Replacing Unit 15 with a T4F diesel generator.

The options were evaluated using the criteria described below. Although a display of strength in individual criteria can appear promising, a solution cannot be considered realistically viable unless it appears likely to perform well in most or all criteria.

1. <u>Construction/Installation Constraints</u>

This criterion includes an option's ability to:

- Fit within the existing PBGS footprint.
- Provide generating capacity and production comparable to the unit(s) it would replace.
- Avoid compromising existing or new generation equipment and the power distribution system (which includes not interrupting operations during construction).

2. <u>Operational Viability</u>

This criterion relates to an option's ability to:

- Operate at a wide output range while maintaining compliance with emissions limits.
- Integrate with other generation resources at PBGS.
- Have reasonable lifecycle costs compared to other alternatives.
- Not require excessive fuel deliveries per month.

3. Grid Stability & Reliability

This criterion relates to an option's ability to:

- Remain operational (i.e., not enter fault mode and cease generation) after a frequency trip.
    - Reciprocating engines only: Remain online and generating during a frequency excursion of up to 6 Hz for several seconds.
    - Inverter-based technology only: Remain online and generating continuously during a frequency excursion of up to +1.2 Hz and -1.5 Hz.

4. Technical Maturity

This criterion distinguishes between technologies and solutions that are well understood and established in real-world applications from options that are emerging or have not been tested extensively.

5. Environmental Compliance & Emissions Reduction

This criterion relates to an option's ability to meet SCAQMD emissions requirements.

6. Permitting & Timeframe

This criterion relates to SCE's ability to obtain required permits from the SCAQMD and other agencies in a timely fashion (ideally, six months after permit application(s) are submitted).

In the Preliminary Action Plan (April 1, 2022), POWER Engineers and SCE identified two potentially viable pathways to bring Unit 15 into compliance with Rule 1470: (1) installing new CO catalyst blocks; or (2) replacing Unit 15 entirely with a new T4F diesel engine. SCE pursued the first option immediately and received the SCAQMD PTC on June 15, 2022. If the new catalyst blocks fail to function properly and/or bring Unit 15's PM emissions into compliance with Rule 1470 (without raising other noncompliance issues), SCE would then pursue replacing Unit 15 with a new T4F diesel unit.

The Preliminary Action Plan determined that several potential emissions-reduction options were not currently viable at PBGS:

- Alternative Fuels[8]
    - Biodiesel[9]
    - Emulsified fuels[10]

- Inverter-based technologies[11]
    - Fuel cells[12]
    - Solar photovoltaic – large-scale (within the existing plant footprint)[13]
    - Free piston linear generator[14]
    - Increased microturbine use[15]

- Altering operation of existing internal combustion engines to reduce PM emissions.[16]

Two inverter-based technologies may provide some supplemental power generation capacity at PBGS. Small-scale solar PV carports and the possible refurbishment of up to 15 microturbines are evaluated in Sections IV and V below.

[8] Preliminary Action Plan (April 1, 2022), Ch. IV.
[9] *Id*. pp. 13-17. For more information about biodiesel, see U.S. Dept. of Energy, Biodiesel Fuel Basics, https://afdc.energy.gov/fuels/biodiesel_basics.html.
[10] Preliminary Action Plan (April 1, 2022), pp. 20-22.
[11] *Id*., Ch. VI.
[12] *Id*., pp. 28-32.
[13] *Id*., pp. 33-37.
[14] *Id*., pp. 38-39.
[15] *Id*., pp. 39-40.
[16] *Id*., Ch. VII.

III. Selected Option for Rule 1470 Compliance: Catalyst Upgrade

SCE received the PTC for the catalyst upgrade project on June 15, 2022. SCE had previously issued the purchase order on June 1, 2022.[17] The supplier estimates that delivery will occur in August. SCE expects to begin installing the new blocks in early September 2022.

A. Background

The allowable water column exhaust back pressure for Unit 15 is limited to a total of five inches. SCE found a vendor (CEP) who proposed replacing the existing CO catalyst portion with a new catalyst that it believes can keep the total system back pressure within this level (and therefore not require a new housing or induced draft fan). Unit 15's catalyst is composed of five rows, each of which contains 16 blocks in a 4-by-4 configuration. The first four rows contain SCR/NOx catalyst. The last row contains the CO catalyst, which will be replaced with CEP's catalyst. SCE and CEP believe the new catalyst can be installed in the existing housing, which would preserve the current PBGS footprint.[18] Assuming this solution works, SCE anticipates that Unit 15's diesel PM emissions can be brought into compliance with Rule 1470 by late 2022 or early 2023. However, potential impacts on the existing SCR's performance are presently unknown. Although CEP believes the new catalyst will successfully reduce PM emissions within the specified exhaust back pressure margin, there is an inherent risk that it would not lead to sufficient reductions in PM emissions, world negatively affect unit operation, or would negatively affect the emissions of other criteria pollutants.

SCE provided CEP with the latest source test results for Unit 15 to design the new catalyst blocks. Because the contribution of PM control from the existing CO catalyst cell is not presently known, it is difficult to quantify the PM reductions that may be achieved upon installation of the new catalyst. The replacement CO blocks are currently estimated to reduce the PM emissions to less than 1.0 gr/bhp-hour, but testing will be required to confirm this estimate. At optimum temperature the new blocks should achieve the emissions reductions shown in Table 1.

[17] In compliance with Abatement Order Condition No. 10, the purchase order was issued on June 1, 2022.
[18] Appendix C contains product specifications.

Table 3. Emissions-Reduction Effectiveness

Constituent	Effectiveness
CO (Carbon Monoxide)	97-99%
HC (Hydrocarbons)	80-90%
NOx (Nitrogen Oxides)	20-50%
PM10 (particulate matter)	<1.0 gr/hp-hr

CEP designed custom blocks for Unit 15's SCR housing.[19]

B. Schedule

SCE issued a purchase order for the catalyst blocks on June 1, 2022 and anticipates delivery in late August. Once received on site, installation of the new blocks will be performed in parallel with routine cleaning of the existing SCR catalyst blocks. The entire project is expected to take three days to complete (because the existing blocks need to be cooled for two days prior to cleaning or removal). Once the existing blocks are clean, plant staff can see how much incremental back pressure has been caused by the new blocks. SCE will conduct two source tests in accordance with an SCAQMD-approved source test protocol. The first test will be conducted within 90 days of installation and a subsequent test will be conducted within 90 days of the initial test. SCE plans to execute source testing as quickly as possible upon commissioning of the new catalyst. The research permit is valid until March 31, 2023.

C. Cost

The estimated cost of the blocks (including shipping) is approximately $140,000. The estimated installation labor cost (using plant personnel) is approximately $4,000. The testing and final report will be provided by a third party, with an approximate cost of $44,000.

D. Alternative: Replacement of Unit 15 with a T4F Diesel Unit

If the new CO catalyst blocks fail to function properly or to bring Unit 15's PM emissions into compliance with Rule 1470 without causing other noncompliance issues, SCE would pursue the replacement of Unit 15 with a new T4F diesel unit. U.S. EPA Tier 4 Final certification reflects emission performance across a weighted-average duty cycle (partial load through full load) to demonstrate compliance (e.g., 0.67 g of NOx/kWh or 45 ppm applying a 40% fuel efficiency assumption). The Tier 4 Final standard also requires the engines' PM emissions to be less than 0.01 g/bhp-hr (which complies with Rule 1470).

[19] Appendix D is a drawing.

IV. Possible Microturbine Repairs

A. Project Description

PBGS has 23 65-kW Capstone propane-fueled microturbines, each of which produces 56 kW (net). Given their age and the marine environment, they often break down and require frequent and extensive maintenance. If the SCAQMD concurs, SCE may propose to refurbish up to 15[20] microturbines to return them to reliable operating condition.

SCE requested a cost estimate from Capstone's successor (Cal Turbines) for the following scope of work:

- Replacement & upgrade of the existing inverter boards to the current Underwriters Laboratories (UL) 1741-SA standard requirements.
- Application of a protective coating to the electronic circuit boards to help to reduce salt-related corrosion.
- Consideration of other upgrades to help to mitigate the high-humidity environment (which may include enclosure heaters and more weatherproof enclosures).

The microturbines do not provide any rotating mass to help stabilize grid frequency. In fact, the microturbines will trip if the grid frequency rate of change exceeds 1 Hz per second, which is not unusual in a small, isolated grid such as Catalina. A trip of the microturbines adds to system instability and could result in a partial outage if the amount of inverter-based generation exceeds approximately 30 percent. Longer term, and subject to further study as described below, SCE believes the space currently occupied by the microturbines may be more effectively used for a propane-fueled reciprocating engine/generator, which would likely be a more reliable replacement that also contributes to grid stability due to its larger rotating mass. However, limits on propane storage on-site and the need to ensure the supply for the city of Avalon, especially during winter months, are additional constraints that must be considered.

B. Schedule & Cost

Cal Turbines would provide a schedule after the repair plan is finalized, which is expected to take seven weeks. SCE estimates the upgrades can be completed within six months. Cal Turbines estimates the work would cost $0.5 million.

[20] The remaining eight microturbines are beyond repair.

V. Solar Carport EV Charging Stations

A. Description

SCE and POWER investigated the installation of a 100kW-to-400kW solar photovoltaic (PV) system installation at PBGS.[21] POWER evaluated how much PV power can be generated within the site's existing footprint. Existing southern-facing roof slopes, new carports, and entire site coverage scenarios were discussed in the Preliminary Report.[22]

Entire site coverage of PBGS is, of course, infeasible, but provides a useful data point for how much energy such an installation could produce: approximately 24,500 MWh/year or 13.5% of Unit 15's total annual theoretical electrical generation. From a practical standpoint, because of structural constraints, limited facility footprint, and roof-slope-facing azimuths, few spaces exist where PV panels can be economically installed at PBGS.

The evaluation concluded that the best path forward is to provide two new carport areas at the PBGS facility. Rather than inject the electrical generation from the PV arrays into the grid, which could exacerbate the existing grid-instability problem, this additional generation would be used to power electric vehicle (EV) charging stations for PBGS's growing EV fleet. The benefits of this approach are twofold: it reduces the energy demand used by EV charging stations directly connected to the Catalina grid, while also reducing fossil-fuel-powered vehicle emissions.

POWER contacted two companies that specialize in off-grid PV EV charging stations: Paired Power and BEAM. Both companies offer stand-alone, "pop-up" canopy-style carports. Paired Power can also provide traditional carport structure and foundations. The "pop-up" canopy-style carports can be deployed into alternating parking spots. Each canopy can accommodate two chargers.

Paired Power's PV array can generate 100kW of solar power (at peak). BEAM's "pop-up" canopy solution generates 4.3 kW per unit. There are approximately 16 available parking spots to deploy BEAM's solution, which would yield 68.8 kW of solar generation. BEAM also provides a battery energy storage system (BESS) that allows cars to be charged overnight when not being used. Paired Power intends to release a BESS option in early 2023.

[21] This evaluation was required by Abatement Order Condition No. 6(d).
[22] *See* Preliminary Action Plan at pp. 33-37.

The Paired Power traditional carport PV arrays can be connected to inverters to provide excess power to facilities at PBGS, such as lighting in the administration building, further offsetting grid demand.[23]

B. Layouts

POWER evaluated two areas where carports could be installed: on the west side of the main building over existing parking spaces, and on the east side of the main building along the coast where there are additional parking spaces.

The west carport will be adjacent to the west side of the main building and is shown in green in Figure 1. The main building will introduce shade in the morning, limiting electrical output for these solar panels. The east carport will be located over the parking spots along the shore on the east side of the property and is shown in purple. Because this carport would be located closer to the ocean, it will be exposed to ocean spray and waves from storms. As a result, we anticipate accelerated corrosion and deterioration of the PV system (panels, connectors, inverters, etc.).

Figure 1 – Proposed Locations for Solar Carport EV Charging Stations

[23] Appendix E contains details about Paired Power's product. Appendix F contains details about BEAM's product.

C. The PBGS EV Fleet

PBGS has two electric SUVs, four electric golf carts, two electric forklifts, three Jeep Hybrid (electric/gasoline) vehicles, and one Mitsubishi Outlander (electric/gasoline) SUV. In the future, PBGS's entire fleet will likely be electrified and is estimated to consist of approximately 20 electrified cars, golf carts, and heavy equipment units.

The hybrid Jeeps average about 30-50 miles per day. The electric SUVs travel less than 10 miles per day. The golf carts and forklifts average less than five miles per day. The future 100%-electrified fleet will be used for approximately 30-50 miles per day in total.

All the current vehicles use charging stations that are connected to the Catalina grid. Providing an "off-grid" 100% solar-powered EV charging system would decrease grid demand which, in turn, would reduce the need for fossil fuel-powered generation.

D. Schedule

The engineering, specification, and initial procurement tasks for the solar PV carport electric vehicle charging systems can be accomplished within approximately six months. Procurement and materials delivery are estimated to take approximately one year due to current supply chain issues. Delivery to the site and construction are estimated to require four months once the equipment has been shipped.

E. Costs

1. Installation: Paired Power

Paired Power provided unit costs ($/W) for a traditional PV canopy solution and their "pop-up" PV canopy, which can be deployed in one day. Both estimates are considered turnkey and include materials, equipment, engineering, permits, labor, shipping, and installation. The cost of a BESS is not included in Paired Power's price. The pop-up canopy is more cost-effective at the 100kW scale, but the costs are very similar (Table 2).

Table 4 - Paired Power Canopy Solutions

Type	Unit Price ($/W)	kW	Est. Price ($)
Traditional PV Canopy (Fixed)	$7.85	100	$785,000
Pop-Up PV Canopy	$7.77	100	$777,000

2. Installation: BEAM

Beam provided unit costs for a pop-up assembly, including materials, equipment, engineering, shipping, and installation. The cost of a BESS is included in this unit price. It should be noted that BEAM's product does not provide 100kW. Table 3 shows equipment costs and Table 4 shows operating and maintenance costs.

Table 5 - Beam Canopy Solution

Type	Unit Price/ Space	Spaces	kW	Est. Price ($)
EV ARC 2020	$90,000	16	68.8	$1,440,000

3. Annual Operation & Maintenance

The projected annual operations and maintenance costs are summarized below.

Table 6 - Estimated Annual Operating and Maintenance Costs

Location	System Generation				Unit Cost*		Total Cost
Carport – East	122.70	MWh	14.00	kW-yr	$19.00	$/kW-yr	$265.95
Carport – West	47.27	MWh	5.39	kW-yr	$19.00	$/kW-yr	$102.46

*NREL U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark Q1 2020[24]

The cost of solar energy per kWh is only determined by O&M costs because fuel costs are free. The estimated cost of solar energy at PBGS is approximately $0.0019/kWh.

[24] NREL U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark Q1 2020, https://www.nrel.gov/docs/fy21osti/77324.pdf.

VI. Preliminary PBGS Grid Stability Study

It is vital that PBGS, as the only generating source for the entire island of Catalina, remains highly reliable at all times. SCE recently launched a grid stability study to determine the extent to which the use of inverter-based resources (such as microturbines, battery energy storage system (BESS), solar PV (photovoltaic), linear generators, and fuel cells) can be increased at PBGS while maintaining grid stability and reliability. Preliminary study conclusions confirm the validity of SCE's current practice of limiting the maximum amount of inverter-based generation at PBGS to 30 percent of total output to maintain grid stability and reliability. Further subjects of the study are described in Section VIII below.

PBGS's microturbines employ 1 Hz-per-second Rate-of-Change-of-Frequency (RoCoF) protection relays for the purpose of detecting islanding electrical fault events. The original equipment manufacturer (Capstone) told SCE that it cannot change this setting due to IEEE 1547 and UL-1741 standards requirements but indicated it may be willing to eliminate the RoCoF functions if SCE accepts the risk of potential equipment damage. These relays are subject to "nuisance tripping" (a brief disconnection of the microturbine due to large load step changes and short-duration electrical faults that result in fast but short-duration frequency changes). This nuisance tripping occurs when system inertia (primarily provided by the diesel generators) becomes relatively reduced due to the increased presence of inverter-based generation. The study will develop a model capable of testing these grid-stability events with varying levels of inverter-based generation from the microturbines, BESS, and solar PV. With this model, multiple forms of grid-stability mitigation can be tested and compared.

POWER developed a PSCAD model of PBGS generation and circuits. The diesel generators were modeled based on the current configuration of six marine category 2 diesel units). Following SCE's existing practice, Unit 15 was modeled as the primary source of generation. The microturbines were modeled as simple inverter-based resources without grid-support features such as volt/var or frequency/watt support. Upgrading the microturbines with UL 1741 SA inverter control boards would allow volt/var support and over-frequency support. PBGS also has a 1 MW BESS used primarily for load-shifting (that cannot provide frequency support).

Before mitigation could be studied, a baseline model had to be developed and tested. Metered data from PBGS's Hi Line distribution feeder was used to analyze events such as load steps, faults, and trips. This data was used to recreate a three-phase motor load step event on the Hi Line feeder within the developed PSCAD model and served as a form of validation for the model development. Initial results suggest that independent of the number of turbines online, a large load step on the Hi-Line feeder, representative of the one found in the metered data, could cause a RoCoF greater than 1 Hz per second, which could cause a nuisance trip of the microturbines. Detailed information on the existing diesel units' electrical properties is necessary to refine the model and improve its accuracy, but it is unavailable due to the age of the engines. SCE will obtain information about the electrical properties of the T4F units proposed to replace Units 8 and 10.

Nuisance trips of the microturbines resulting from the 1 Hz/sec RoCoF protection (or the over/under frequency protection) are a known issue adversely impacting grid stability at PBGS. If the inverter control boards are refurbished as described above, the updated controls would provide the turbines with volt/var response and over-frequency response functionality, which previously was not available. SCE would retain the RoCoF protection because disabling it would likely cause the microturbines to lose their UL 1741 certification. Conversations with the microturbine OEM are ongoing to determine if the RoCoF protection and over/under frequency protection settings can be adjusted. If possible, this could be a cost-effective means of mitigating nuisance tripping of the microturbines.

Nuisance trips of the BESS resulting from the over/under frequency protection are another known issue that adversely affects grid stability. SCE is investigating the possibility of widening the frequency protection settings. The BESS manufacturer (S&C) is no longer supporting this product, which limits the possibilities for improving its availability.

VII. Alternative Fuels Analysis

SCE has continued its analysis of cost, logistics, storage, and fire-suppression issues for alternative fuels. SCE hired a consultant to undertake a fire protection study that will evaluate the potential for increasing the amount of propane storage at PBGS.

A. Cost Comparison

Table 7 contains a side-by-side comparison of fuel consumption for various generating technologies (for each 1 MW generated).

Table 7 – Fuel Consumption Rates for Each Technology & Fuel Source for 1 MW

Technology	Fuel Consumption[25]		
	Hydrogen (kg/hr)	Propane (gal/hr)	Diesel (gal/hr)
Linear Generator	62.5	158.5	--
Fuel Cell	64.5	--	--
Microturbine	--	187	--
Propane Generator	--	98	--
Diesel Generator	--	--	69.3

Each barge shipment of fuel can deliver 1,250 kg of hydrogen, 9,100 gallons of propane, or 7,450 gallons of diesel.[26] Based on the fuel shipment size and consumption rate for each technology, the following table shows the number of hours of generation for each technology and fuel (based on 1 MW of generation for each technology/fuel). Hydrogen ranks relatively low for the number of hours of generation per shipment and number of shipments required per

[25] Fuel consumption is scaled to a 1-MW power output equivalent to facilitate a direct comparison. The fuel consumption for the linear generator was provided by MainSpring. The fuel cell consumption was provided by Plug Power. The microturbine fuel consumption is based upon the actual fuel consumption and total generation for the year 2021. The propane generator fuel consumption is based upon the Caterpillar G3520 Gas Engine Site Specific Technical Data sheet with pure propane as a fuel source (derated from 2000 kW to 1386 kW due to the use of propane instead of natural gas). The diesel generator fuel consumption is based upon the Cummins EPA T4F DQLH data sheet.

[26] The propane and diesel fuel shipment volumes are based on actual current shipment data. The hydrogen shipment size is based on the largest gaseous hydrogen cylinder trailer that Siren Energy stated could be provided (8 cylinders in a 52-foot-long long trailer). Air Products stated in an email that liquid hydrogen shipments are not possible due to the requirement for cryogenic temperatures (minus 420° Fahrenheit) and hydrogen vaporization losses of 1 percent per day, which would require flaring during transport.

month for a continuous 1 MW power output. Propane and diesel are relatively comparable, with 6.8 shipments per month required for the diesel generator and 7.8 required for the propane generator. The microturbines and linear generator (both consuming propane) are comparable, requiring roughly twice as many shipments per month compared to the diesel or propane generator option (Table 8).

Table 8 – Fuel Shipment Requirements and Equivalent Generating Capacity for Various Technologies at 1 MW Output

	Hours of Generation per Fuel Shipment			Required Shipments per month		
	Hydrogen	Propane	Diesel	Hydrogen	Propane	Diesel
Linear Generator	20	57	--	37	13	--
Fuel Cell	19	--	--	38	--	--
Microturbine	--	49	--	--	15	--
Propane Generator	--	93	--	--	8	--
Diesel Generator	--	--	108	--	--	7

The costs for each fuel are listed below along with the associated cost per MWh for each technology. The cost per MWh is the cost per unit of measure (kg or gallon) multiplied by the fuel consumption from Table 7.

Table 9 – Fuel Costs for 1 MW Output

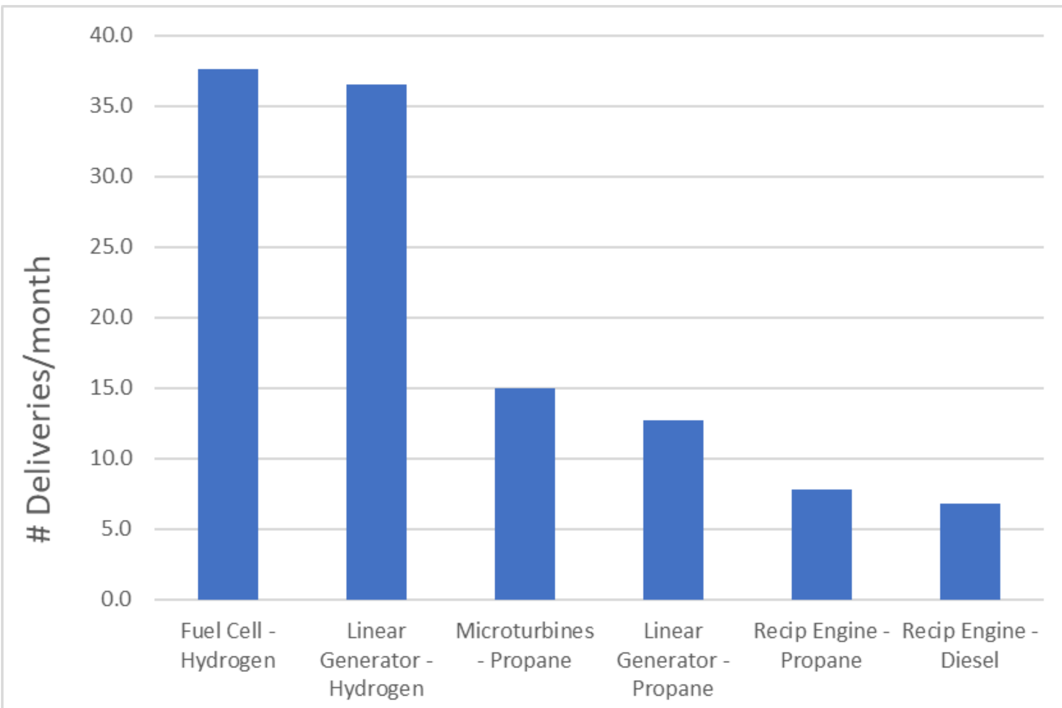
	Cost per Unit of Measure[27]			Cost per MWh		
	Hydrogen ($/kg)	Propane ($/gal)	Diesel ($/gal)	Hydrogen ($/MWh)	Propane ($/MWh)	Diesel ($/MWh)
Linear Generator	6.0	1.97	--	375.0	312.2	--
Fuel Cell	6.0	--	--	387.0	--	--
Microturbine	--	1.97	--	--	368.8	--
Propane Generator	--	1.97	--	--	192.4	--
Diesel Generator	--	--	3.51	--	--	243.2

[27] The propane and diesel fuel costs are based upon actual current shipping invoices. The hydrogen costs are based upon an email from Siren Energy but does not include the additional amount they quoted ($5,600/day) for equipment rental, shipment costs, and barge freight costs. Even without these additional costs, hydrogen is cost prohibitive compared to diesel or propane.

Propane generators have the lowest cost per MWh; diesel generators are the second lowest. However, it should be noted that the diesel generators have a better ability to handle significant frequency excursions compared to propane generators. The inverter-based technologies (linear generator, fuel cells, microturbines) do not significantly contribute to grid frequency support and grid stability. The ongoing Grid Stability Study will evaluate the percentage of propane generation that can be utilized in parallel with diesel generation while still maintaining grid reliability.

Figure 2 summarizes the number of deliveries required per month for each technology and fuel source assuming a constant 1 MW output.

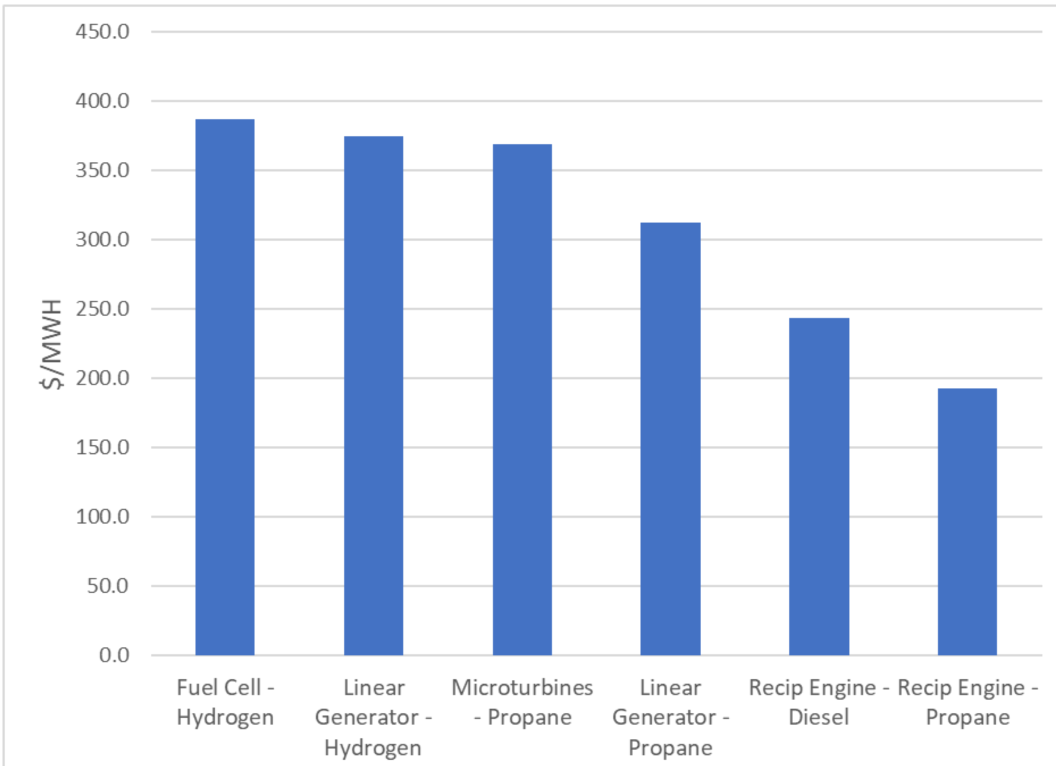
Figure 2 - Estimated Fuel Deliveries Per Month Per 1 MW Continuous Power



Hydrogen appears to be logistically impractical due to the large number of deliveries that would be required per month compared to the other fuel types. Hydrogen would require 5.4 (linear generator) to 5.5 (fuel cell) times as many fuel shipments per month compared to the T4F diesel engine option. Comparing propane to the T4F diesels, the linear generator would require 1.87 times as many shipments, the microturbines 2.12 times as many shipments, and the propane generator 1.15 times as many shipments. The propane generator appears to be the most viable alternative to diesel generators based on the required number of fuel deliveries per month. Again, the maximum amount of propane generation in parallel with diesel generation to support grid stability and reliability must be evaluated.

Figure 3 shows the cost (in dollars per MWh) for each technology and fuel source assuming a constant 1 MW output.

Figure 3 - Estimated Fuel Cost Per MWh Per 1 MW Continuous Power



Hydrogen appears to be cost prohibitive compared to the other technologies and fuels. The cost per MWh of a hydrogen linear generator is 3.79 times that a T4F diesel engine; a hydrogen fuel cell is 3.91 times as much. Propane is less expensive; when compared to a T4F, the linear generator would require 1.28 times the cost per MWh, the microturbines 1.52 times the cost per MWh, and the propane generator 0.79 times the cost per MWh. It is interesting to note that the cost per MWh of a reciprocating propane generator appears less than a T4F, while also contributing to grid stability. However, a diesel generator would have greater contribution to grid stability compared to a propane generator due to its superior ability to quickly pick up load and handle frequency excursions.

B. Storage Constraints/Fire Suppression Requirements

1. Hydrogen

Several issues render hydrogen impractical as a fuel source at PBGS. Hydrogen suppliers have indicated that they can only ship gaseous hydrogen, not liquid hydrogen, because liquid hydrogen must be maintained at cryogenic temperatures (minus 420 degrees Fahrenheit) and about one percent would boil off each day and would have to be vented and flared during transportation. The largest gaseous cylinder truck contains 1,250 kg of hydrogen, which would only provide 20 hours of generation (1 MW). This would require round-the-clock fuel deliveries. According to the Los Angeles County fire marshal, the fuel may not be consumed directly out of the delivery trailer and would need to be cryogenically cooled and pumped into a high-pressure storage vessel on-site. This very cold hydrogen would present a significant freezing hazard to plant personnel when transferring the fuel to the on-site storage vessel. Due to its very small molecular size, hydrogen is highly prone to leakage, easily ignited, and burns with an invisible flame – all contributing to significant worker safety hazards. A liquid cryogenic storage tank on the order of 15,000 to 30,000 gallons would be required. Such a tank would require the following clearance distances: 100 feet to the nearest combustible building or other solids; 75 feet to the nearest air conditioning or air compressor intake; 100 feet to the nearest flammable liquid storage; and 100 feet to any other flammable gas storage.[28] There are no suitable locations available within the PBGS footprint. In addition, there would not be adequate fire water available to cool a hydrogen storage tank in the event of a fire.

2. Propane

Although PBGS has four 30,000-gallon propane tanks, only three can be filled due to the potential for a BLEVE (Boiling Liquid Expanding Vapor Explosion) event and the lack of fire suppression water to manage it. A BLEVE occurs if a fire impinges on a liquid propane (or similar) tank. The propane will begin to boil, building up pressure in the vessel until it fails, catastrophically destroying everything within a large radius of the tank. To prevent a BLEVE, adequate water must be available to be sprayed on the tanks to keep them cool. The quantity of water required for four tanks is not available at PBGS (which is why the fourth tank is kept empty).[29] SCE and POWER are conducting a fire-protection study to determine if propane storage could be increased while still adhering to NFPA requirements. The evaluation will also

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[28] NFPA 2 – Hydrogen Technologies (Table H-4).

[29] In addition to requiring a specified amount and pressure of water, the fire marshal typically requires the water to be potable (i.e., not from the ocean), and gravity-fed (not moved with a pump, which could fail during an emergency).

determine whether buried tanks or other methods could prevent a BLEVE. Vertical (or any other aboveground) storage faces the same storage limitation as the current tanks. If the aboveground tanks were replaced, the city of Avalon's gas supply would be interrupted during the construction period. Additional concerns include soil liquefaction, the proximity of the saltwater table (only 15 feet below grade), and potential soil contamination from a very old industrial site.

The existing propane storage is used for operating the microturbines and to supply the island. In 2018, the microturbines consumed a total of 127,904 gallons of propane (1.42 times the current storage capacity of 90,000 gallons) and generated 700 MWh of electricity. Using this same amount of propane, a 1 MW propane generator would be able to run for 1,305 hours producing 1,305 MWh of electricity.

The total amount of propane storage on-site is 90,000 gallons. This would allow a 1 MW propane generator to run continuously for 918 hours (38.3 days) producing 918 MWh of electricity. This does not consider the propane required to supply the City of Avalon.

Figure 4 illustrates monthly propane consumption on Catalina. On average, the island consumed between 40,000 and 60,000 gallons of propane each month. It is unclear why there was a large jump in propane consumption by the city in March. Propane consumption by the microturbines is relatively low in comparison to the island's utility use.

In 2018, Catalina consumed a total of 518,096 gallons of propane, which is equivalent to 5.76 times the current storage capacity of the existing 90,000 gallons of propane, or 57 barge shipments. If a 1 MW propane generator ran 24/7 for a year (8,760 hours), it would consume 858,480 gallons of propane which is equivalent to 9.54 times the current storage capacity of the existing 90,000 gallons of propane, or about 95 barge shipments. The combined total of the propane supply to Avalon and a 1 MW propane generator would require 1,376,576 gallons of propane. This is equivalent to 15.3 times the current storage capacity of the existing 90,000 gallons of propane storage, or a little over 151 barge shipments.

Figure 5 shows the equivalent number of barge shipments required for the 2018 fuel consumption rates. On average, it requires approximately one to three delivery trips per month to supply the microturbines and four to six trips to supply the utility use.

Figure 4 – Propane Consumption on Catalina Island (2018)

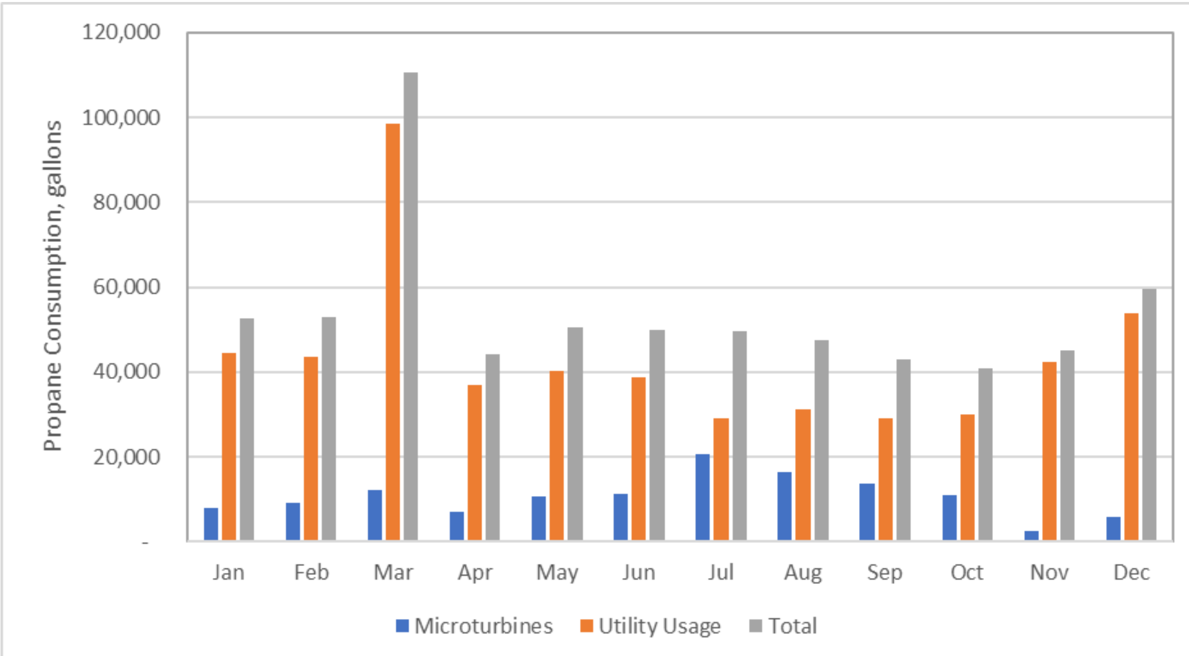

Figure 5 – Equivalent Delivery Trips for 2018 Propane Consumption

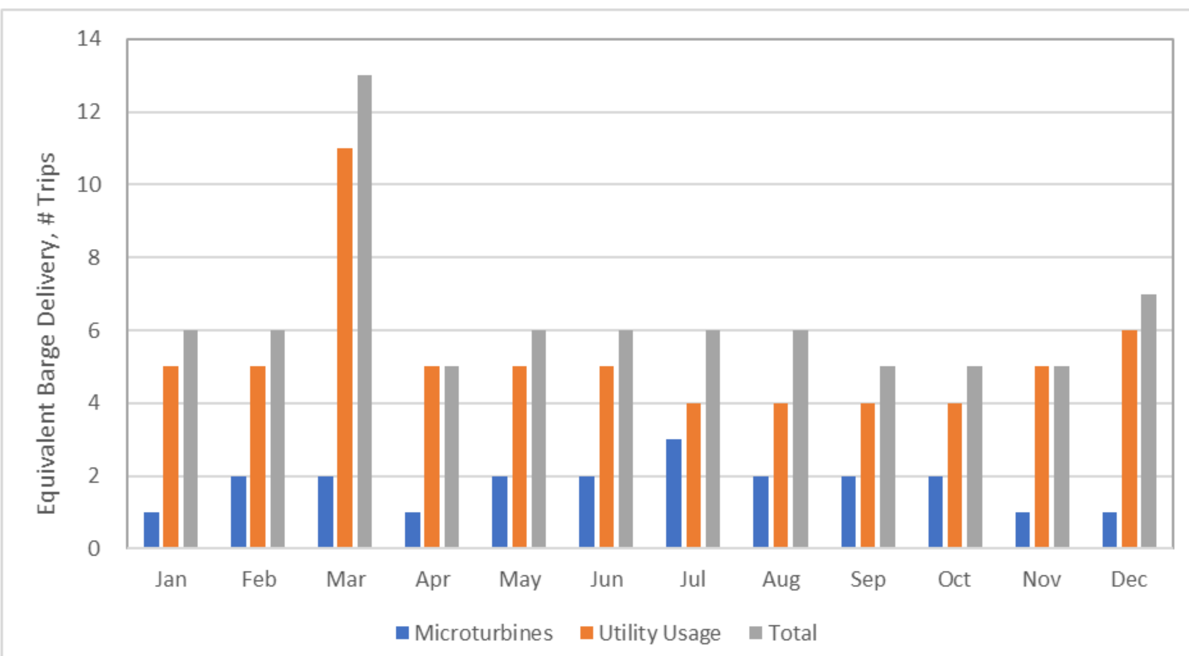

Table 8 summarizes the annual propane use, equivalent existing storage capacity, equivalent barge shipments, and annual MWh of generation.

Table 10 – Fuel Costs and Costs per MWh for Each Technology & Fuel Source

	Annual Propane Usage (gal)	Equivalent Onsite Storage Capacity	Equivalent Barge Shipments	Generation (MWh)
Catalina Island Utility (2018)	518,096	5.76	57	--
Microturbines (2018)	127,904	1.42	14	700
Propane Generator Replacing 2018 Microturbine Consumption	127,904	1.42	14	1,305
1 MW Propane Generator & (2018) Island Utility	1,376,576	15.3	151.3	8,760

C. Renewable Diesel

1. Description

Renewable diesel is derived from agricultural sources and contains less carbon than traditional diesel. The California Air Resources Board (CARB) considers this fuel a "drop-in" equivalent for storage purposes, so no changes to storage practices are required. CARB study shows PM reduction from switching to renewable diesel in comparison to a petroleum-based CARB reference fuel.[30]

R95/R99 is increasing in popularity, particularly in the transportation sector. A study completed by NREL comparing petroleum diesel to renewable diesel indicated a reduction of 4.2% in tailpipe emissions in UPS vehicles.[31] The switch to renewable diesel also has potential to decrease PM emissions. Concerns include supply constraints and delivery logistics, reduced fuel lubricity for engine cylinder linings, compatibility with elastomers (O-rings and seals),

[30] CARB. Low Emission Diesel (LED) Study: Biodiesel and Renewable Diesel Emissions in Legacy and New Technology Diesel Engines. November 2021. Available at: https://ww2.arb.ca.gov/sites/default/files/2021-11/Low_Emission_Diesel_Study_Final_Report.pdf

[31] Kenneth Kelly and Adam Ragatz, National Renewable Energy Laboratory, Economy and Emissions Impacts from Solazyme Fuel in UPS Delivery Vehicles, https://www.nrel.gov/transportation/fleettest-fuels-diesel.html

and chemical elements/contaminants typically present in paraffinic fuels, along with potential effects on catalysts in the exhaust aftertreatment systems.[32]

2. Concerns

A significant concern with R95/R99 is the lack of a lubricating agent, which may result in accelerated engine cylinder liner wear (in petroleum diesel, sulfur enhances lubricity, even the very small amount in the ultra-low-sulfur fuel used at PBGS). Engine wear may consist of scoring or pitting of the engine cylinder liner, accelerated bearing and journal wear, roller bearing surface spalling, leaking gaskets, O-ring failures, fuel pump damage etc. Contaminants in the fuel that could degrade the aftertreatment catalyst include phosphorus, potassium, and alkaline base metals. Care must be taken to ensure limits on these elements. As the front of the SCR catalyst begins to decline, it may allow more NH_3 slip to the CO catalyst, resulting in NOx formation. This could increase overall NOx and CO emissions. Changes in catalyst fouling, engine efficiency, gross or net power output and fuel consumption per MWh will also be evaluated.

3. Supply & Logistics

As R95/R99 becomes more available in the California market, SCE expects to have more options to source this fuel. The product is currently primarily marketed to the over-the-road transportation industry. POWER and SCE met with multiple fuel vendors to discuss the product offering and experience. Each vendor was provided with questions to establish their capacity and reliability of supply as well as their experience using R95/R99 in stationary engines. There has been some use in four-stroke diesel units, and vendors are looking into use in two-stroke diesel engines.

a) California Fuels and Lubricants

California Fuels and Lubricants (CA Fueling) is the current supplier of diesel and propane to PBGS. They were contacted to provide information on what renewable diesel they could supply with existing delivery channels. CA Fueling offers Renewable Energy Group (REG) 9000 Renewable Diesel.[33] The fuel can be incorporated into SCE's existing purchase order at no additional cost over the current ultra-low-sulfur diesel that SCE currently uses. CA Fueling can provide a sample of the fuel for testing in whatever quantity is desired.

[32] Abatement Order Condition No. 6(a).
[33] Specifications and the Safety Data Sheet are provided in Appendix G.

b) World Energy

World Energy met with POWER and SCE to discuss the viability and options of using R99 at PBGS. World Energy has a facility in Paramount, CA which can currently produce 4.5 million gallons per month of neat renewable diesel. When customer demand exceeds production capacity, they use third-party suppliers to fill customer orders. World Energy states they can offer the quantity of fuel required by SCE.

Regarding lubricity concerns, World Energy noted that its product lacks sulfur, a common constituent of diesel that aids in lubricity. World Energy said it has not received any complaints from current users, but this is not directly relevant to PBGS because those users have over-the-road four-stroke diesel engines, not the stationary engines at PBGS. World Energy said that NOx emissions were reduced, which SCE would need to confirm through testing.

4. <u>Testing</u>

The use of renewable diesel in stationary engines is not well documented, so it is unclear how two-stroke units would react to this fuel switch. SCE consulted Metrolink, the commuter rail agency, and inquired about its experience using renewable diesel. During a discussion held on May 16, 2022, Metrolink representatives said that like SCE, they could not obtain concrete information from either fuel vendors or equipment manufacturers prior to making the switch from petroleum diesel to renewable diesel. Metrolink said it was familiar with potential negative consequences from renewable diesel use, such as fouling of the catalyst, causing premature fuel system failures, accelerating engine cylinder wear, uncertain supply reliability, lower power output, and increased fuel consumption leading to higher operating costs. Metrolink initially tested the renewable diesel in their two-cycle locomotives with Caterpillar C27 engines for a period of three months. Metrolink followed with a six-month test in their T4F engines with Caterpillar C125 20-cylinder four-stroke engines. The fuel Metrolink used for testing was either R99 (99% renewable diesel and 1% either biodiesel or #2 diesel) or R95 (95% renewable diesel and 5% either biodiesel or #2 diesel). Metrolink conducted quarterly inspections of their locomotive engines during testing and observed no loss of horsepower or increase in fuel usage. Metrolink did not perform an internal engine inspection, so they could not verify whether cylinder wear in the engine was greater than normal wear using #2 diesel.

SCE has considered comparison testing renewable diesel in one of the existing engines that are scheduled to be replaced by March 2023 with new T4F units. Unit 10 would use renewable diesel as a test unit, and a similar other existing unit would use the current diesel fuel as a control unit. However, the manufacturer (Kirby Corporation/Marine Systems) stated that over 2,000 hours of use on each engine would be required for a reasonable test to assess engine performance. That would require about two years of testing, which would be impractical because it would delay the installation of the new T4F units. Kirby is planning on testing renewable diesel in its factory and expects results in two or three years. It is more practical to let the OEM do this testing in their factory under highly controlled conditions. Based upon the results of the Kirby factory testing, SCE will determine the feasibility of using renewable diesel across the existing diesels in the PBGS fleet. This will include evaluating the impact on performance, emissions, and unit wear. The tests would be scheduled to avoid reliability impacts.

SCE is planning a more limited test of renewable diesel in the existing Unit 10 starting in early 2023 to evaluate operational and emissions performance. The evaluation parameters will include oil dilution, deterioration of fuel system components, SCR catalyst fouling, increased fuel consumption, reduced horsepower, and increases in criteria pollutants. This unit is expected to have enough run hours to gather adequate data on these specific concerns. The testing fuel will be provided from a separate source (a tote or temporary tanker) to avoid contaminating existing fuel storage. SCE plans to compare the results contemporaneously with an engine of similar vintage using the current petroleum-based diesel.

New cylinder and piston assemblies (a.k.a. power packs) will be installed in each unit before the test. A similar other existing unit would be fueled with the current diesel and Unit 10 would be fueled with renewable diesel. After an approximately equal number of hours, both power packs will be sent to the manufacturer for detailed analysis to determine any differences in mechanical degradation. In addition, emissions output and catalyst blocks would be analyzed to identify any adverse effects. SCE will compare the performance of renewable and petroleum diesel using the following criteria:

- Fuel efficiency (i.e., the amount of power produced per unit of fuel);
- Exhaust emissions; and
- Buildup on catalyst aftertreatment blocks.

VIII. Projects Requiring Further Investigation

A. System Grid Stability Evaluation

1. Current Fleet Simulation

The PSCAD model will be refined and validated to reflect the present state of the system. This work includes tuning the existing diesel generators' frequency response to system disturbances. In addition, reasonable load-step changes for the island will be determined. Presently, approximately 30 percent of PBGS generation can be provided by the microturbines before the RoCoF nuisance tripping events occur. The changes will be used to tune and validate the model before investigating system upgrades and potential methods to reduce nuisance trips.

2. New T4F Diesel Engines Simulation

Following the model validation and baseline testing, additional T4F diesel generator upgrades will be incorporated into the system. With a total of two and then three T4F generators operating within the model, the baseline tests will be repeated to determine any impact to acceptable levels of microturbine generation.

3. Grid Stabilization Equipment Simulation

The following topics will be investigated as potential forms of frequency stabilization using the PSCAD model.

a) Microturbine Upgrades

If the microturbines are retained (pending discussions with the SCAQMD), SCE plans to add functionality upgrades to the microturbine models. This would improve the microturbines' ability to operate dynamically at a non-unity power factor. With this ability, the inverters will provide reactive power support for over- and under-voltage conditions. Over-frequency support will also be included in the form of rapid real-power reduction from the microturbines. This is accomplished by installing an internal brake resistor that reduces output.

In addition to the upgrades, discussions would continue about how to desensitize or possibly eliminate the RoCoF relays. If it is determined that this is a realistic possibility, it will be investigated with the use of the PSCAD model.

b) *Flywheel*

A flywheel would be added to the model based upon initial industry findings and quotes. The grid-support abilities of the specified flywheel would be incorporated to analyze its impact on voltage and frequency stabilization. With this, the baseline microturbine tests would be replicated to determine a new microturbine generation level.

B. Decision-Making Optimization

SCE is evaluating the installation of a Operator Intelligent Advisory program using the existing Emerson Ovation Distributed Control System (DCS) to assist in optimizing plant efficiency, emissions, reliability, and fuel availability. The system would be tightly integrated with the Ovation Control Operator Interface. It would provide predictive information to the operator about the scheduling of fuel deliveries based on a running average of the current consumption rate. The system would be flexible and relatively easily modified as the mix of generating assets changes over time (new diesel generators, additional solar PV, BESS changes, microturbine additions/deletions, new propane reciprocating engines, etc.).

The system would project the total island load demand anticipated over the course of a day. This may be based on a running average over the past week, whether a particular day is on a weekday or on a weekend, weather conditions, control operators' manual inputs, etc. The older existing diesels must operate above 80 percent while the new T4F units will be able to operate between 25 to 100 percent load while still meeting emissions limits. The system will take into consideration the maximum amount of inverter-based generation (microturbines, battery storage, or other possible future technologies) that can be allowed at any given time while maintaining grid frequency stability. It would identify as unavailable any units that are out of service for maintenance or other issues.

C. RFO for Large-Scale Renewable Energy Projects

In March 2022, SCE's Energy Procurement and Management (EP&M) unit completed a Request for Information (RFI) to solicit informational submissions for energy solutions that could both complement the new T4F generators and allow SCE to achieve its long-term clean energy strategy. SCE requested information on the following options:

- Third-party Power Purchase Agreements (PPAs);
- California Renewable Portfolio Standard (RPS)-eligible renewable energy resources with or without energy storage;
- Near-zero-emissions energy resources;

- Energy storage (both in front of the meter (IFOM) and behind the meter (BTM));
- Distributed generation (both IFOM and BTM);
- Distributed generation paired with energy storage (both IFOM and BTM);
- Demand response (including energy storage);
- Energy efficiency; and
- Third-party design, construction, and transfer of ownership to SCE of the following project types:
    - Utility-owned renewable generation with or without energy storage; and
    - Utility-owned storage.

The RFI yielded six potential projects:

- Three IFOM renewable-plus-storage projects;
- One low-emissions engine proposal;
- One microgrid proposal (with 60 percent renewable energy); and
- One combined BTM/IFOM renewable-plus-storage project.

Rules issued by the California Public Utilities Commission prohibit SCE from sharing additional details about these projects until the evaluation process has been completed and any award(s) finalized. The goal is to ensure that no participant in the competitive solicitation process has a competitive advantage over another. The next steps in the competitive RFI/RFO competitive solicitation process are expected to follow the estimated timeline below (note that projects may take longer to execute and place into operation).

- July 2022 to November 2022 – RFO launch preparation
- December 2022: RFO launch
- March 2023: Offers due
- April 2023 to October 2023: Offers reviewed and shortlisted
- April 2024: Negotiations complete
- June 2024: Contracts executed
- July 2024 to December 2024: CPUC application filed for contract approval
- July 2026: Anticipated approval of CPUC application (18 months after filing)
- September 2027: Project commences operation

IX. Gantt Chart

Appendix H contains a Gantt chart of the proposed action plan's schedule for implementation, future studies, and other activities described above.

X. Summary and Conclusions

The Preliminary Action Plan (April 1, 2022) outlined and evaluated methods for bringing Unit 15 into compliance with Rule 1470 and explored near- and longer-term alternatives to the use of Unit 15. In this Final Report, SCE proposes to pursue several options concurrently: installing new CO catalyst blocks on Unit 15's aftertreatment system to bring Unit 15 into compliance with Rule 1470, with a backup plan to replace Unit 15 with a T4F engine; evaluating the use of renewable diesel in other existing units (by testing its efficiency, emissions, and potential damage); installing PV carports for EV charging and to help offset PBGS load; and studying Catalina Island's grid stability to support a potential increase in the amount of inverter-based power generation.

SOUTHERN CALIFORNIA
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P.O. Box 5085, Rosemead, CA 91770

April 28, 2023

Mr. Jason Aspell
Deputy Executive Officer
Engineering and Permitting
South Coast Air Quality Management District
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Email: JAspell@aqmd.gov

RE: BACT/LAER Analysis for the Application for Permits to Construct Replacement Generators for Units 8, 10, and 15 – Pebbly Beach Generating Station Repower Project (Facility ID 4477)

Dear Mr. Aspell:

I write this letter in response to the South Coast Air Quality Management District's (SCAQMD) letter regarding Southern California Edison's (SCE) analysis of Best Available Control Technology (BACT) and Lowest Achievable Emission Rate (LAER) provided on February 7, 2023 (**Attachment A**).

As discussed with SCAQMD staff, SCE is actively assessing near-zero emission (NZE) and zero-emission (ZE) technologies for Catalina Island. SCE supports transitioning to a low-carbon future consistent with our Pathway 2045 vision.[1] SCE is committed to providing safe, reliable, and affordable electricity, gas, and water to Catalina's residents and visitors while reducing emissions and maintaining environmental stewardship. SCE is confident that based on the detailed analysis provided, SCAQMD can conclude that BACT and LAER requirements are met by replacing Units 8, 10, and 15 with new U.S. EPA Tier 4 Final-certified (T4F) diesel-fueled internal combustion engines.[2] This is the first step and a critical bridge to transitioning to cleaner technologies at Pebbly Beach Generating Station (PBGS). It is also the quickest path to rapidly reducing emissions of oxides of nitrogen (NOx) at PBGS. Given SCE is the sole provider of electricity, water, and gas services for the island, and considering these services are dependent on isolated systems with no connection to mainland systems, the feasibility assessments for potential technologies to be incorporated at PBGS demonstrate that additional consideration must be given to reliability and resiliency, such as ensuring that the portfolio of generating technologies for PBGS can provide sufficient inertia to the grid to offset PBGS' inability to pull electricity from surrounding grids to avoid "load shedding" and/or blackouts.

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[1] *See* Pathway 2045 | Edison International and Sustainability Report | Edison International.
[2] The T4F generators are model QSK60-G17, manufactured by Cummins.

SCE submitted its Application for Permits to Construct following the recommendation of SCAQMD staff on April 30, 2021. As communicated in previous letters, analyses, and meetings during the subsequent years, SCE remains steadfast in our conclusion that replacing Units 8, 10, and 15 with Cummins QSK60-G17 T4F generators meets the requirements of BACT and LAER at PBGS. The most recent version of this analysis validates this assertion while providing granular details on grid stability and fuel constraints. (*See* **Attachment C**.) SCE's conclusion is based on safety, reliability, resiliency, and environmental considerations. This letter provides a systematic overview of the key considerations and latest findings/data. In **Attachment B,** we respond to each question raised in SCAQMD's February 7, 2023 letter.

SCE appreciates the SCAQMD's ongoing collaboration as we continue to refine and improve the supporting data and analysis results to support this effort. As a measure of good faith, SCE has shared and will continue to share information as it is received. This letter provides an update on recent vendor discussions to clarify: (1) the prime rating of the 4-MW Caterpillar propane reciprocating generator; and (2) Quinn Power's experience with supplying a propane vapor/air mixture to a given propane reciprocating generator skid.

I. AT LEAST THREE T4F GENERATORS ARE NEEDED TO MEET SAFETY AND RELIABILITY REQUIREMENTS

As the sole provider of electricity, water, and gas for the island, SCE must provide safe and reliable service. Catalina's water and gas utility operations rely exclusively on electric power production from PBGS. Without safe and reliable electricity, residents and visitors will experience interruptions of these critical health and safety services. Catalina's electrical distribution system is a self-contained, isolated grid without connections to the mainland's system.

A. What is "System Reliability" and Why is it Important?

State law requires regulated electric utilities like SCE to provide sufficient, safe, and reliable electrical service during both normal and extreme conditions for weather and equipment availability.[3] When designing and operating the generation and distribution systems, one must conduct electric reliability studies to ensure safe and reliable operation of the island-wide system. As the operator of a remote island grid, SCE must study electrical system deficiencies and appropriately plan for future system needs to ensure any upgrades can be completed in advance of the time when they are actually needed.

[3] *See* Public Utilities Code § 451 ("Every public utility shall furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities, including telephone facilities, as defined in Section 54.1 of the Civil Code, as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public.").

To maintain power system reliability, SCE must match its electrical generation output to the electrical load (also known as "demand"). When an imbalance between the two occurs, SCE must immediately remedy it by ramping up or down its generation sources[4] to match the amount of electrical load. This is known as "load following." When generation output can "load follow," the system remains stable. If this cannot be achieved quickly enough, the plant operator is forced to reduce the amount of electrical demand that exceeds the amount of available generation by turning off customers' power. This is known as "load shedding." When significant discrepancies between generation and load occur, the island becomes prone to grid failure and widespread power outages.

The consequences of electrical system outages at Catalina can range from minor inconveniences to serious threats to public safety, such as the loss of electricity for medical facilities and emergency services, water pumping, sewage-treatment facilities, and compression for gas utility services. During severe weather events, electrical outages can pose a public health risk. This is particularly true during heat waves, where extreme temperatures have a greater impact on sensitive individuals (e.g., children and the elderly) by increasing risk for heatstroke, exhaustion, or respiratory difficulties.[5,6,7] Through careful planning, SCE avoids outages to the extent possible.

B. How is System Reliability Measured?

Electric systems are modeled using various software tools such as HOMER PRO® to identify the grid's response to changes in system conditions by simulating both steady-state and transient conditions (e.g., electrical faults), as well as planned and unplanned equipment outages. The simulations are used both in real-time operations and in studying future conditions to identify necessary upgrades to prevent system interruption.

An appropriate assessment of generation resource portfolios must be performed to incorporate all applicable operational conditions and constraints (e.g., fuel availability, planned and unplanned maintenance, emissions limits, space, etc.). System reliability studies inform the electricity providers of the feasibility of various generation

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[4] The current generation sources at PBGS include six diesel-fueled generators, one battery-electric storage system, and 23 propane-fueled microturbines.

[5] Gamble, J.L., B. J. Hurley, P.A. Schultz, W.S. Jaglom, N. Krishnan, and M. Harris. 2013. Climate Change and Older Americans: State of the Science. *Environmental Health Perspectives* 121(1): 15-22.

[6] U.S. Climate Change Science Program. 2008. Analyses of the effects of global change on human health and welfare and human systems. A Report by the U.S. Climate Change Science Program and the Subcommittee on Global Change Research. [Gamble, J.L. (ed.), K.L. Ebi, F.G. Sussman, T.J. Wilbanks (Authors)]. U.S. Environmental Protection Agency, Washington, DC, USA.

[7] Vaidyanathan. A., J. Malilay, P. Schramm, and S. Saha. 2020. Heat-related deaths — United States, 2004–2018. *Morbidity and Mortality Weekly Report* 69(24):729–734.

configurations. The studies are complex, iterative, and absolutely necessary in evaluating various alternatives.

C. Reliability Study for Replacement of Unit 8, 10, and 15 Under BACT and LAER

To support the BACT and LAER analysis for replacement of Units 8, 10, and 15 with three T4F generators, SCE engaged POWER Engineers Inc. (POWER) to model and quantify the reliability of PBGS's electricity generation and Catalina distribution system under two distinct scenarios as part of what has often referred to as the "Grid Stability Study." Using HOMER PRO®, an industry-standard simulation software program, POWER determined the efficacy of each configuration by accounting the following: hourly electricity demand or "load" (forecasted for calendar year 2026); planned and unplanned maintenance downtime for both existing and proposed equipment; electricity contribution from all facility sources applicable to each scenario (e.g., the microturbines); and fuel constraints. POWER compared two scenarios: Configuration A, in which SCE would replace three diesel generators with new T4F generators; and Configuration B, in which SCE would replace two diesel generators with two new T4F generators and would replace the third diesel generator with a 4-MW propane reciprocating generator. POWER concludes that Configuration A appears feasible with carefully planned maintenance, but Configuration B would lead to widespread load shedding and/or blackouts. The key factor is the propane reciprocating generator's lack of operational loading flexibility: it has a minimum operational loading requirement of 75 percent. Even an infinite fuel supply could not lead to a successful run of the configuration. (*See* **Attachment C** for detailed model inputs/assumptions and results.)

The HOMER Pro® program allows POWER to accurately determine whether the various generation configurations proposed by SCAQMD staff can meet all energy[8] and power[9] requirements from the customers. The model accounts for the manufacturer-provided maintenance schedule for the existing (i.e., Units 7, 12, and 14) and proposed (i.e., Cummins QSK60-G17 T4F) generators. The model also includes data from past unplanned maintenance for the existing generators and estimates of unplanned maintenance for the proposed replacements.[10] POWER used 2026 demand forecast data to reflect the expected demand at the time when replacements for Units 8, 10, and 15 are constructed and commissioned. The demand forecast is consistent with CPUC Decision 22-11-007 and

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[8] Energy is measured in kilowatt-hours (kWh).
[9] Power is measured in kilowatts (kW).
[10] The new T4F generators are anticipated to require less-frequent unplanned maintenance than the existing units.

reflects the year 2022 as the baseline load value, on which the 0.5% annual growth was added to calendar year 2026.

The findings and results of the study are presented in the next section. **Attachment C** provides detailed modeling results for Configurations A and B. Below is a summary of model inputs for each configuration, which include the latest data on planned and unplanned maintenance for each technology type.

Configuration A:

- Units 8, 10, and 15 are replaced with three T4F generators.
- Units 7, 12, and 14 remain in place to serve as backup emergency generators.
- The existing sodium-sulfur (NaS) battery remains operational.
- Microturbine efficiency was derived using the historical average energy production, 906,481 kWh, relative to 173,951 gallons of propane per year.[11]

Configuration B:

- Units 8 and 10 are replaced with two T4F generators.
- Units 7, 12, and 14 remain in place to serve as backup emergency generators.
- The existing sodium-sulfur (NaS) battery remains operational.
- Unit 15 is replaced with a 4-MW propane reciprocating generator with a prime rating of 2.097 MW (i.e., Caterpillar Model CG260-16), consuming 400,000 gallons of propane per year.
- The microturbines do not contribute to this configuration because all available propane (i.e., all propane not delivered as gas utility service) would be allocated to the CG260-16 propane reciprocating engine.

Additional Discussion of Propane Model Inputs

In Configuration A, the microturbines' propane consumption (208,689 gallons) is significantly less than the allocatable volume assumed for the CG260-16 propane

[11] The microturbine data include the historical average annual kWh production and propane consumption from calendar years 2019 through 2021 (as requested by the SCAQMD permitting team).

reciprocating engine in Configuration B (400,000 gallons). Annual energy production and fuel consumption totals for the microturbines were derived from historical records for the existing 23 microturbines, of which a portion of the units is consistently down for service as the fleet approaches the end of its useful life. SCE's generation and maintenance staff work diligently to overcome this hinderance to meet and consistently exceed the Title V permit's minimum 635,000 kWh requirement, thereby maximizing the propane consumed by the existing microturbines in an effort to reduce diesel fuel consumption and associated emissions.

SCE recognizes that new propane-fueled electricity generating technologies would likely be more reliable and efficient than the microturbines in operation today, which could provide an opportunity to increase the reliance on propane to produce electricity. SCE performed a fuel analysis to determine the maximum propane consumption for *any* electricity generating technology to apply to the Stage 1 grid stability model based on a 10-day minimum constraint for storage. This resulted in a theoretical maximum of 401,200 gallons of propane per year. *See* Section II and **Attachment D**.

As discussed with the SCAQMD permitting team, SCE's sharing of its study results is an iterative process in which SCE continually learns and gathers more accurate and refined information from prospective vendors. As always, SCE will continue to provide the best available information gathered from vendors and internal analysis. Below is an update on key considerations for the BACT/LAER evaluation for the replacement of Units 8, 10, and 15.

On March 23, 2023, Steven Rodriguez of Quinn Power (who is SCE's main point of contact for the 2- and 4-MW propane-fueled Caterpillar generators) stated that providing an air-propane mixture to propane reciprocating generator skids, rather than pure propane, would not reduce the derating of any of Caterpillar's propane reciprocating generator options. In the early stages of our analysis, SCE speculated that an increase in power output could theoretically be achieved by supplying an air/propane mix to a given propane reciprocating generator and communicated the concept to SCAQMD staff. SCE understands this past discussion may be the reason why the SCAQMD inquired about this approach in its February 7, 2023 letter. In light of Quinn's March 23 response, SCE has determined that this option is no longer viable.

SCE further investigated the derating of the CG260-16 propane reciprocating engine following the SCAQMD's February 7, 2023 letter. Initially, SCE understood the prime rating would be approximately 2 MW after derating from 4 MW. Later, SCE incorrectly assumed the specification sheet's 75% power rating (of 1.573-MW) to be the prime rating. Steven Rodriguez of Quinn Power pointed out this oversight in his March 23, 2023 email.

It turns out that SCE's original approximation of 2 MW was more accurate: the actual prime rating is 2.097 MW for the CG260-16 (**Attachment E**). SCE's Stage 1 grid stability modeling has subsequently been updated. However, the original conclusions remain valid, partly due to the similar electrical and thermal efficiencies at 75 (minimum) and 100 (prime) percent load for the CG260-16 engine, along with its lack of operational load flexibility. In short, installing a CG260-16 propane reciprocating generator in place of Unit 15 is infeasible due to operational flexibility and the resulting grid instability, which would cause frequent interruptions of utilities services, resulting in a significant number of load-shedding/blackout events for the island.

II. THERE IS NOT ENOUGH FUEL AVAILABLE TO OPERATE A PROPANE GENERATOR AS THE THIRD UNIT

A. PBGS's Maximum Annual Propane Throughput for Power Generation is Approximately 400,000 Gallons

As previously indicated by SCE staff, limiting the total propane storage to an approximately five-day supply presents an unacceptable level of risk to our ability to serve our customers. SCE cannot not view past barge obstructions as a failsafe predictor of future fuel reliability, especially given the lack of historical data beyond five years. Unlike on the mainland where electrical or gas utility service system planning would not typically consider procurement logistics given the nearly unlimited opportunities for ground transportation, an isolated island microgrid has neither the ability to receive electricity from adjacent grids nor to bring fuel to the plant solely via roadways. Therefore, if the barge service is obstructed, there is no readily available alternative.

It is SCE's duty to consider both likely factors that could impede the logistics of fuel delivery and less likely but highly impactful events that could reasonably occur within the next 10 to 20 years. As indicated to SCAQMD staff in an August 9, 2022 email, these factors include but are not limited to the following: extreme weather events, tsunami, high winds, fog, roadway erosion, mud slide/erosion from nearby mountain range , labor shortages (e.g., strike among multiple skilled workforces such as refineries or drivers), equipment failure of the tanks and/or fuel unloading stations and delivery systems, fuel supply chain issues, inadequate shipyard space, unavailability due to competing island priorities like food and medical supplies), sabotage, terrorism, and fire.

As a result, SCE elected to calculate fuel availability based on having at least 10 days of storage during both the warmer and cooler seasons. In practice, the amount of propane available for electricity generation would fluctuate based on seasonal demand for gas for utility service and propane volume within tanks, which will also fluctuate based on heat expansion throughout the year.

SCE performed an analysis to determine the maximum annual consumption for propane-fueled electricity generating technology based on 10 storage days and the existing three available tanks (along with comparable calculations for two and four tanks). For this analysis, the generation technology type and frequency of barge deliveries were not relevant because the analysis centers on propane availability for both gas utility service and propane-fueled electricity generating technology in general where efficiency (e.g., gallons per kilowatt-hour of generation) was not a factor. Additionally, the analysis of propane availability was not limited by barge delivery frequency. The overarching goal was to determine how much propane could be allocated to electricity generation per year while providing adequate propane for gas utility service and maintaining 10 days of storage – positioning SCE with reasonably sufficient levels of fuel storage should the barge delivery service halt for any reason. The primary constraint in determining the maximum volume of propane that can be allocated to electricity generating technology is SCE's obligation to deliver up to 650,000 gallons of gas utility propane annually. The analysis concluded that a maximum of 401,200 gallons of propane could theoretically be allocated to electricity generation in a particular year. Detailed calculations are provided in **Attachment D**.

B. The Timeline and Outcome of SCE's Building Electrification Application Remain Uncertain

If approved, SCE's proposed Building Electrification Application at the California Public Utilities Commission could, in the future, reduce utility gas annual throughput and thus allow greater flexibility in allocating propane to electricity generation. However, the application is still pending, so its outcome remains uncertain. Under BACT/LAER requirements, the analysis should be conducted based on the best information available today. Consequently, SCE has not included potential benefits of the Building Electrification Application in its BACT/LAER analysis, which is also in alignment with CPUC Decision 22-11-007.

C. Currently, There is No Compliant Pathway to Bring the Fourth Tank Online Now

SCE remains committed to increasing the amount of propane available for electricity generation, but this is a long-term process. As detailed in **Attachment D**, with four propane tanks in operation, SCE could theoretically allocate approximately 350,000 additional gallons of propane annually to electricity generation without affecting the gas utility service or reducing the nominal number of storage days (10 days) during both the warm and cool seasons at PBGS. Therefore, bringing the fourth tank online theoretically has the potential to increase the total allocatable propane for electricity generation to approximately 751,600 gallons each year. This sharp increase relative to the 401,200 gallons calculated for the first three tanks together is possible because the gas utility service annual throughput is already satisfied in the model when three tanks were considered, leaving the additional propane available for electricity generation. However, it is important to note that with the additional fourth tank, or even an *unlimited* propane supply, the grid reliability study (**Attachment C**) shows that SCE would not be able to meet demand if Unit 15 is replaced with a CG260-16 propane reciprocating engine. Further, this estimate is a theoretical approximation accounting for compliance with reasonable fuel storage levels and gas utility service annual consumption, only. Additional challenges to achieving a 751,600 gallon allocation of propane with the fourth tank online for electricity generation may arise during real-world operation or based on constraints outside of SCE's full control (e.g., propane availability as a commodity, barge deliveries, etc.).

The theoretical maximums for grid stability modeling and discussion purposes are approximately 401,200 gallons for three tanks and 751,600 for four tanks. For any future Title V Permit conditions for minimum annual propane throughput, SCE would need practical flexibility on such a requirement even while recognizing that SCE would strive to exceed the permit minimum when possible. Regardless, the grid stability modeling demonstrates that three T4F generators are needed for the first step of the Repower Project to meet demand. Therefore, any propane estimates should be considered only as a next step after construction and commissioning of the three T4F generators in SCE's pending permit application.

SCE is actively engaging with the Fire Protection Authority Having Jurisdiction (FP-AHJ) to identify how to bring the fourth tank back into operation in the future while complying with all fire-protection requirements. SCE views this as a longer-term effort that, if accomplished, can support our ability to incorporate cleaner ZE and NZE technologies under the timelines proposed for the amendments to Rule 1135. SCE will continue to keep the SCAQMD apprised as more information is provided by the FP-AHJ.

Under BACT/LAER requirements, the analysis should be conducted based on the best information available today. Thus, even though SCE has (for transparency purposes) quantified the additional propane that could theoretically be allocated to electricity generating technology if the fourth tank were brought online (see **Attachment D**), the SCAQMD's BACT/LAER determination should focus on the three currently available propane tanks given the uncertain safety, legal, compliance, logistics, and construction considerations of this ongoing and future effort.

D. Designating Two Tanks for Utility Service is Infeasible Due to Storage and Delivery System Redundancy Requirements

The tank system is not equipped with separate feedlines. The units work as an aggregate to supply fuel, which is critical given the need for redundancy to support service and maintenance. Isolating individual tanks to support specific systems would jeopardize SCE's ability to reliably provide gas utility service. Approximately once every five years, SCE performs maintenance on each tank's pressure relief valves (which takes four days per tank). During these maintenance events, SCE relies on the remaining online tanks, making isolation infeasible. SCE did not perform an analysis of propane allocability for the case of one propane tank designated for electricity generation (i.e., the remaining tank indicated for this SCAQMD proposal) given the lack of redundancy. Further, a complete redesign of the feedlines would be needed, which would affect reliability and resiliency.

E. No Additional Propane Storage Sites Are Available.

SCAQMD staff should not consider additional propane storage constructed on unowned and/or unleased land as part of the evaluation of BACT and LAER because it is not a near-term viable option. As explained above, the BACT/LAER evaluations must rest on the best available information today.

F. The Propane Tanks Cannot be Vertically Aligned.

SCE appreciates the SCAQMD's initiative and creativity on this proposal. However, rotating tanks vertically is not a credible real-world engineering option. The tanks were not designed to hold pressurized and highly flammable fuel when placed vertically. Further, the foundation supporting the tanks was designed to meet seismic requirements for the tanks in their current horizontal configuration. By moving the tanks to a vertical position, the downward normal force of the tanks would be placed on a smaller footprint, which would increase pressure on the pad beyond the level for which it was designed. Moving the tanks to a vertical configuration would trigger a complete redesign of the tanks and pad, causing a long gas utility outage that would be unduly burdensome to residents and visitors.

Furthermore, placing the current tanks vertically would compromise their structural integrity and risk the occurrence of a Boiling Liquid Expanding Vapor Explosion (BLEVE). If the structural integrity of the pressurized propane tank subsequently becomes degraded by being placed vertically, a BLEVE causing catastrophic tank failure could occur in which the tank's contents would be released and projectiles and/or shrapnel may be jettisoned, posing a theoretically lethal safety risk. Finally, orienting the tanks vertically would not enable the installation of additional tanks because of the inability to increase water deluge for fire suppression (which is currently preventing SCE from using its fourth tank).

G. Propane Use in Dual-Fuel Engines is Infeasible Due to High Emissions Levels

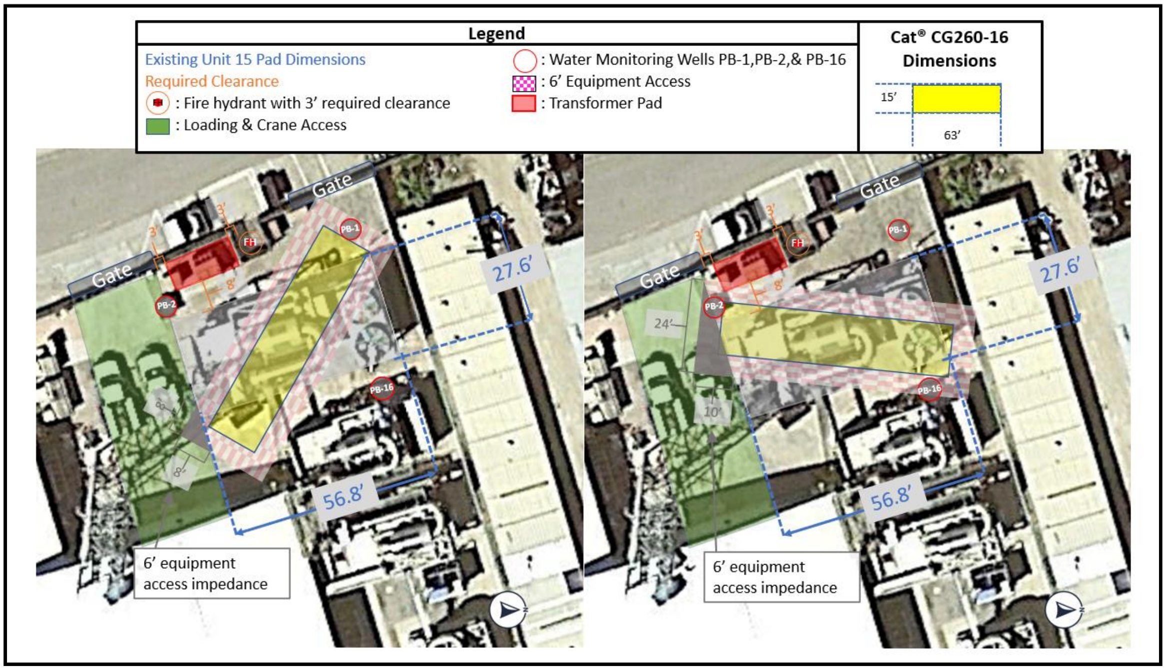
SCE previously assessed the feasibility of incorporating dual-fuel engines at PBGS. One vendor, Marine Systems, Inc. (Marine Systems), theorized that their E23B engine could be retrofitted to run on mostly natural gas with a small percentage of diesel fuel. To SCE's knowledge, this retrofit has never been demonstrated or achieved in practice for a duration of six months or longer as required by Federal LAER for major sources like PBGS. Additionally, as conveyed to SCAQMD permitting staff on September 22, 2022, Marine Systems declined to bid given the complexity associated with meeting SCE's proposed emissions limits. Further, their response was not received by SCE until February 4, 2021, which was after SCE had already submitted its permit applications for the Cummins engines. SCE also investigated an option with Wartsila and determined it would not be possible to permit the units with SCAQMD. SCE appreciates SCAQMD for sharing alternative dual-fuel generation technology (see **Attachment F**).

III. SPATIAL CONSIDERATIONS FOR BACT AND LAER

A. Although One Reciprocating Generator Model Would Physically Fit at Unit 15's Location, Its Use Presents Significant Safety Concerns and Fails to Solve Fuel Limitation and Associated Grid Instability Issues

Even though fuel constraints are the main limiting factor on the replacement of Unit 15 with a propane reciprocating generator, SCE completed an assessment of whether the 4-MW Caterpillar CG260-16 generator/enclosure could fit when positioned at a diagonal compared to existing Unit 15's orientation (Figure 1).

Figure 1. Caterpillar Model CG260-16 Rotated Approximately 45 Degrees Counter-Clockwise (Left) and Approximately 40 Degrees Clockwise (Right) with Respect to Existing Unit 15's Orientation.



As shown in Figure 1, rotating the 4-MW Caterpillar CG260-16 roughly 45 degrees counterclockwise or 40 degrees clockwise with respect to the existing Unit 15 yields a configuration that appears to physically fit the space. However, the required clearances for the transformer pad and designated area for loading and crane access would be impeded. Additionally, the proposed orientation would cover a water monitoring well (PB-2). Moving the well would delay the project because: (1) SCE would need to coordinate with the Los Angeles Regional Water Quality Control Board for approval of the relocation or abandonment of the monitoring well; and (2) significant time would be required to pull the required permits for the installation of a new well and/or destruction of the existing well.

With a 45-degree counterclockwise configuration (right), the unit physically fits the space and complies with basic clearance requirements [e.g., under Occupational Safety and Health Administration Part (OSHA) 1910] compared to the clockwise configuration. However, it would block the northwest gate, which is a key point of egress, thus posing an unacceptable safety risk.

As part of our Injury and Illness Prevention Program (IIPP), SCE prioritizes a robust safety culture and continuously takes regularly cadenced proactive measures to: (1) mitigate risk and eliminate unsafe conditions, (2) reduce near-miss events, and (3) prevent injuries. SCE is continually striving toward low annual Total Recordable Injury Rates across all facilities and empowers employees at every level to exercise their Stop Work Authority if a task appears to be unsafe. In line with SCE's safety prioritization, a key consideration for the overall Repower Project is to reduce risk relative to today by implementing stricter engineering controls and efficient design layouts. When compared to Unit 15's existing configuration, a diagonal configuration would increase the complexity of egress, causing even tighter squeezes for employee foot traffic and forklift/vehicle activity, and generally make for awkward operations of high-risk activities such as crane use. Specifically, Unit 15's northern and eastern edges have very tight clearances adjacent to the neighboring building and generator, respectively. Such configurations generally increase the frequency of slips/trips/falls, forklift/machinery collisions, and crane operation near-misses and failures, across all industries and despite proper training, robust work practices, and the use of applicable personal protective equipment.

In summary, SCE has provided Figure 1 solely to convey why it is an unacceptable option for PBGS. Irrespective of this spatial analysis, replacing Unit 15 with a propane generator is infeasible due to operational flexibility and consequent grid instability, as communicated in the previous sections of this letter.

B. Units 7, 12, and 14 Will Remain in Place as Backup Generation Sources.

The SCAQMD's February 7, 2023 letter contained the following question: "This pad will become available once the Rule 1135 compliance date takes effect on January 1, 2024 (current version of the rule) or July 1, 2025 (proposed amended version of the rule), and the use of those engines is no longer allowed. Has SCE considered this space as an option?"

PAR 1135 does not bar SCE from running Units 7, 12, and 14. However, SCE recognizes that to meet the proposed NOx emission targets, these units can only serve as backups. SCE plans to keep Units 7, 12, and 14 while progressively incorporating cleaner technologies into PBGS. SCE is not considering the space they occupy as part of the permit application for the new T4F generators that would replace Units 8, 10, and 15.

C. PBGS Still Needs at Least Three T4F Generators to Meet Demand

SCE is more than happy to replace the microturbines with new technology during the next phase of the Repower Project. However, to meet current demand and to comply with the interim facility emission target of 45 TPY NOx in 2045, it is critical that SCE receive the permits to replace Units 8, 10, and 15 with T4F engines as soon as possible. Additionally, replacing Unit 15 with a T4F is the quickest way to resolve its noncompliance with Rule 1470(c)(4)(A). It would both reduce facility NOx emissions most expeditiously and provide the necessary backbone of reliability and resiliency for SCE to continue to incorporate zero-emission (ZE) and near-zero-emission (NZE) generation technologies at the facility. Having a third unit is especially important when considering that T4F generators can be out of service for up to four months for normal maintenance that occurs every 20,000 hours of run-time (or every three to four years). SCE also must account for T4F generator downtime due to unforeseen issues (e.g., breakdowns), which we can only estimate at this time. Thus, SCE must assume that only two of the three units will be dispatchable at any given moment. If only Unit 8 and 10 are replaced with T4F generators, SCE would be required to assume that only one unit would be available at times, which would obviously be inadequate to meet demand and comply with emissions limits.

IV. CONCLUSION

SCE has concluded the following:

1. The grid stability analysis is complete for the purposes of BACT and LAER. It demonstrates that at least three T4F generators are necessary to meet demand.

2. Under BACT/LAER requirements, the analysis should be conducted based on the best information available today. Thus, SCE has not included any potential benefits of the Building Electrification Application in its BACT/LAER analysis (specifically, the potential to reduce gas utility throughput and increase the allocation of propane to electricity generating technology), consistent with CPUC Decision 22-11-007.

3. SCE performed a propane fuel analysis to determine the maximum annual consumption for a propane-fueled electricity generating technology based on 10 storage days and the existing three available propane tanks. For this analysis, the generation type and frequency of barge deliveries are irrelevant because the analysis centers on propane availability for both gas utility service and propane-fueled electricity generating technology in general where efficiency was not a factor. Additionally, the analysis of propane availability was not limited by barge delivery frequency.. The results indicate up to approximately 401,200 gallons of propane per year could be allocated to electricity generation.

4. The SCAQMD's assessment and determination of BACT/LAER should focus on the three currently available propane tanks given the uncertain safety, legal, compliance, logistics, and construction considerations described here and in previous letters.

5. If the fourth propane tank was available, SCE could theoretically allocate 751,600 gallons of propane to electricity generation. However, the grid stability analysis demonstrates that PBGS will not be able to meet electricity demand without three T4F generators even with this added allocation of propane. Further, this estimate is a theoretical approximation and additional challenges to achieving a 751,600 gallon

allocation of propane may arise during real-world operation or based on constraints outside of SCE's full control (e.g., propane availability as a commodity, barge deliveries, etc.).

6. SCAQMD staff should not consider additional propane storage constructed on unowned and/or unleased land as part of the evaluation of BACT and LAER because it is not a near-term viable option, and BACT/LAER are required to be evaluated based on the best information available today.

7. SCE is more than happy to replace the microturbines with new technology in the future. It is critical that SCE receive the permits to replace Units 8, 10, and 15 with three T4F engines now to meet demand and reduce emissions.

8. SCE plans to keep Units 7, 12, and 14 to serve as backup generation while progressively incorporating cleaner technologies into PBGS. SCE is not considering the space occupied by these units as part its permit application to replace Units 8, 10, and 15.

9. As requested, SCE has provided diagonal layouts for replacing Unit 15 with a CG260-16 propane reciprocating engine. We caution that this approach not only presents significant safety risks but is not viable due to grid stability constraints that would cause load shedding and/or blackouts.

10. Aligning the propane tanks vertically would require a redesign and reconstruction of the tanks and pad and would risk the occurrence of a BLEVE. Even if the tanks could be placed vertically, this approach would not enable the installation of additional tanks because of the inability to increase water deluge for fire suppression. Therefore, placing the tanks vertically would not provide a mechanism for SCE to increase the allocation of propane to electricity generation.

11. Isolating individual tanks to support specific systems would jeopardize SCE's ability to reliably provide gas utility service, considering required maintenance on each tank's pressure relief valves. This approach is not viable, as it does not conform to SCE's reliability and resiliency requirements.

SCE looks forward to continued coordination with SCAQMD's Permitting Team on the permit applications for three new T4F engines to replace Units 8, 10, and 15. Should you have any questions or concerns, please contact Joy Brooks, Air Quality Senior Manager, at joy.s.brooks@sce.com, (626) 302-8850 and/or myself at Anthony.Hernandez@sce.com, (626) 430-4498.

Sincerely,

DocuSigned by:
Anthony Hernandez
0E235977344E47B...

Anthony Hernandez
Director of Catalina Operations & Strategy, Generation

Attachments

A – SCAQMD BACT/LAER Comment Letter
B – Detailed Response to SCAQMD Comment Letter
C – Reliability Study Summary
D – Propane Availability Analysis
E – Quinn Power Email Communication
F – Wartsila Dual Fuel Generators at Virgin Island Water and Power Authority

CC: Shannon Lee, SCAQMD
Chris Perri, SCAQMD
Michael Morris, SCAQMD
Michael Krause, SCAQMD
Jillian Wong, SCAQMD
Joy Brooks, SCE
Matthew Zents, SCE
Trevor Krasowsky, SCE

A – SCAQMD BACT/LAER Comment Letter

South Coast AQMD staff greatly appreciates the time, effort, and investment that southern California Edison (SCE) has put into the analysis concerning the feasibility of using propane at Pebbly Beach Generating Station (PBGS).

As background, SCE is proposing three new diesel generators which will replace existing generators. Regulation XIII-New Source Review and BACT/LAER requirements are triggered for any new source that results in an increase of air contaminants. The Clean Fuel Policy adopted by the Board in 1988. The BACT Guidelines have been approved by the Board to incorporate the Clean Fuels Policy and have been well established to require natural gas or cleaner burning fuels as part of BACT/LAER requirements. PBGS has existing propane storage onsite. As part of its permitting evaluation, South Coast AQMD staff is required to assess the feasibility of cleaner burning fuels for prime power generation and has requested SCE to provide information regarding the feasibility of a propane-fired generator in lieu of a diesel generator.

South Coast AQMD staff has carefully considered the information provided by SCE, specifically in the following documents:

- Propane Generator Feasibility Report (10/21/2022)
- Propane Storage Fire Protection Report (10/21/2022)
- BACT LAER Letter (12/15/2022)
- BACT-LAER Letter (1/17/2023)
- Santa Catalina Island Repower Feasibility Study (August 2020) (the NV5 report)
- Catalina Repower Feasibility Study: NREL Phases I and II Summary Report (October 2020)

The information has given us a clearer picture into the challenges of integrating propane fueled sources at the facility. We recognize the challenges that propane generators face. However, based on all the information presented thus far, we conclude that the portion of combustion-related power generation on the island supplied by propane fuel can and should be larger than what SCE continues to propose. We recognize the following issues concerning the use of propane fired ICEs at the facility and have included some questions and/or suggestions:

1. Space Limitations

   The information provided in the BACT LAER Letter 1-17-23 showed the graphical representation of the footprint of the 2 propane engines analyzed (the Caterpillar G2520H and the Caterpillar CG260-16) arranged on the pads of existing Unit 8, 10, and 15. The conclusions SCE reached based on this analysis is that neither of these engines would fit on any of the existing pads.

   South Coast AQMD staff's evaluation of the available space and our review of the study raised the following questions:

- Unit 15 pad
  A CG260-16 nearly fits in this area but has a 6.2 ft overhang that impedes on the loading and crane access area, based on Fig 9. However, about 4 feet of this overhang presumably represents a flashback safety clearance, leaving only about 2 feet of physical equipment overhang. Can SCE confirm that this 2' would render the loading/crane area unusable? Or even with this overhang, the trucks and crane would still be able to satisfactorily maneuver in and out of that space? Alternatively, can the manufacturer redesign the unit to reduce the footprint by a

few feet? Or can the CG260-16 be positioned at an angle to better fit in the available space of the Unit 15 pad?

- Unit 8 pad
  The analysis shows that a CG260-16 overhangs the area by about 14.4 ft. This overhang in turn impedes by about 5 ft onto the space needed for an emergency exit. However, there appears to be a possible solution by moving the GC260-16 back towards the Unit 10 pad to provide clearance for the emergency exit. The much smaller Cummins QSK60 (39' L as provided by SCE) designated for Unit 10 replacement will not take up the entire Unit 10 pad, thereby leaving room for a portion of the CG260-16 to extend into the Unit 10 pad. Would this be a possible solution?

- The micro turbine (MT) pad
  SCE has indicated that the MTs have reached the end of their useful life, and SCE has requested to discontinue the use of the MTs (the MTs use is governed by a Settlement Agreement and a Microturbine Site agreement from 2009-10, with a corresponding permit condition reflected the requirements in these agreements in the PBGS permit). The MT pad is large enough to accommodate either (1) CG260-16, or (1) G2520H, or (2) 0.4 MW Caterpillar propane ICEs.

- The space where Units 7, 12, and 14 currently reside
  This pad will become available once the Rule 1135 compliance date takes effect on January 1, 2024 (current version of the rule) or July 1, 2025 (proposed amended version of the rule), and the use of those engines is no longer allowed. Has SCE considered this space as an option?

  For either the MT pad or this space, installation of a propane fired ICE with SCR control designed to meet the NOx level consistence with an NZE as defined in proposed amended Rule 1135 would be consistent with the objectives of Rule 1135.

2. Propane Fuel Delivery/Propane Storage Capacity

SCE currently has four 30,000-gallon propane storage tanks on site. Only three of the tanks are in service due to the limitations of the fire protection system. These tanks are allowed to fill maximumly to 86% of the rated capacity. For years 2020 and 2021, SCE reported that the mean annual propane fill capacity is 67%. SCE also states that the tank liquid level must be maintained at no less than 25%, or 7500 gallons. Thus, SCE maintains that the actual usable volume of propane is between 25% to 67% (about 37,800 gallons) in cooler temperatures, or between 25% and 47% is warmer temperatures (about 19,800 gallons).

SCE supplies up to 650,000 gallons of propane to its customers annually. SCE receives propane deliveries to the island by barge in shipments of about 9,000 gallons.

South Coast AQMD staff's Evaluation of Propane Availability

This new information regarding the reduced propane storage capacity was not provided by SCE prior to January 17, 2023, even though the topic has been discussed previously. South Coast AQMD staff's analysis regarding propane supply capacity has, up to this point, relied on the assumption that there is approximately 90,000 gallons of storage available on PBGS. This number has been used in our working group meetings and SCE has never indicated the error in this assumption. Furthermore, the NV5 Study also relied on a storage tank capacity of 90,000 gallons for its analysis. It is concerning that SCE withheld this important piece of information and waited until the eleventh hour to inform South Coast AQMD staff.

- Option of a 4th tank
  SCE has investigated bringing a 4th propane tank into service by either enhancing the fire protection systems or using a fire retardant material on the tanks themselves. Bringing a 4th tank into service would greatly enhance the ability of the PBGS to move towards cleaner burning propane for its combustion related generating resources. This option should be fully investigated and implemented if possible. SCE has indicated that they had initiated these discussions but never provided complete feedback or communications from the fire authority.

- Designating Two tanks for utility service
  SCE may consider dedicating two tanks to the utility service given that the utility service only requires 1,780 gallons per day on average. This would leave the other one tank (or two, if tank 4 can be brought online) to be use for propane fired generation and permit the tank to be filled to much higher capacity (up to 86%). This would provide 7-14 days of utility service with the two tanks (13,200 gal to 25,200 gallons).

  A propane fired ICE uses about 0.09 gallons of propane per kW of power output at 40% efficiency. PBGS's average daily power output is about 80 MWh/day (based on an average of 3.3 MW/hr). Assuming that 50% of the combustion related power output for the facility is generated through the use of propane, then daily propane use would be about 3600 gallons, or about seven days of supply with a tank capacity of 25,800 gallons.

- Additional propane storage site
  SCE has identified an offsite location where additional propane can be stored. This is the Roaring Canyon location presently used for recreational off road vehicles, about ½ mile southwest of the plant. If obtained by SCE for propane storage, there is space enough for multiple new propane tanks and a water deluge system for fire protection. Expanding the PBGS into this location for additional propane storage would allow much higher propane use (up to 100% of the power plant needs).

- Propane delivery
  Propane is brought to the island by barge. A review of data indicated that disruptions to the barge deliveries are exceedingly rare. Based on the data that we analyzed, the barge was available for at least 96.2% of the days per year (only unavailable on 14 days of the year), and the time between deliveries never exceeded a maximum of five days. Therefore, we have concluded that this is not a valid argument against the feasibility of a propane ICE based on historical data.

- Utility use of propane
  SCE is in the process of transitioning their customers to electricity for heating and cooking needs. As this transition continues the propane supplied through the utility service is expected to decrease, which will result in more propane supply being available for power generation, and while this decrease in propane needs would be offset to some degree by the increase in

electrical load requirements, the reduced need for utility propane would open up storage tank capacity for propane-fired power generation.

To summarize our position, South Coast AQMD staff believes that there are several options that alone, or in combination, can be used to alleviate the issues of propane fuel supply and delivery.

3. ICE Power Generating Capacity

SCE has proposed to replace existing Unit 8, 10, and 15. SCE has indicated that any replacement of these units cannot result in a reduction in the power generating capacity. According to SCE, the propane engines under evaluation for this project, namely the Caterpillar CG260-16 and the Caterpillar G2520H, are derated when fired on liquid propane as opposed to vaporized propane. Specifically, the CG260-16 is derated from a nameplate capacity of 4 MWe to approximately 1.6 MWe, while the G2520H is derated from 2 MWe to about 1.4 MWe. It should be noted that previously SCE had stated that the CG260-16 would only be derated down to 2 MWe.

South Coast AQMD staff's Evaluation

South Coast AQMD staff has considered this limitation in our analysis. With such a significant derating for liquid propane use, SCE could consider what modifications would be necessary to convert the fuel supply to vaporized propane instead, especially since the current vaporization system at the facility is in need of replacement. This would provide a timely opportunity to address a need for vaporized propane to be used for power generation on the island in the very near future.

4. Propane ICE Ramp Rate/Grid Stability

SCE stated in the BACT LAER letter dated 12/15/2022, when referring to propane-fueled reciprocating generators:

> While capable of providing inertia to the grid, these units cannot respond to rapid load fluctuations at the same rate as diesel generators due to the lower energy density of propane compared to diesel. Therefore, the replacement of a diesel engine with a propane reciprocating generator would reduce the facility's ability to reliably produce power

Furthermore, in the BACT LAER letter dated 1/17/2023, SCE provided this:

> On September 30, 2022, SCE provided an initial System Stability Study for PBGS, which included an assessment of propane reciprocating generators. A baseline model of PBGS was built in PSCAD, which is a commonly accepted modeling platform for detailed transient analysis. Initial results indicated that replacing Unit 15 with a propane reciprocating generator would not be as beneficial as replacing Unit 15 with a T4F diesel generator. Although propane reciprocating generators do provide inertia to the grid, the lower energy density of propane compared to diesel fuel causes propane reciprocating generators to respond to fast load fluctuations more slowly than diesel generators, impacting voltage and frequency stability for the island. (See the report dated September 30, 2022.
>
> Presently, SCE has contracted Power Engineers to perform refined analyses of various scenarios, including a mix of T4F diesel generators along with the replacement of Unit 15 with a propane

reciprocating generator. The grid stability analysis will further inform SCE's understanding of whether various technology mixes can provide reliable power considering Catalina's unique isolated microgrid, and the desire to integrate utility-scale zero- and/or near zero-emission generation resources. Power Engineers and SCE will develop "Flexible N-2 Reliability" criteria specific for Catalina's isolated microgrid with the following key considerations:

South Coast AQMD staff's Evaluation

SCE has assessed that replacing a diesel fired ICE with a propane fired ICE would provide the necessary inertia but would result in a reduced load change response time. However, SCE was not specific as to the degree of the reduction in response time. Furthermore, SCE has not yet provided details as to the typical load change characteristics of the Catalina grid, so that an analysis can be made as to the extent of the impact of the slower load response time of the propane generator on grid stability. And finally, this issue should also be looked at through the lens of a hybrid scenario where propane fired capacity is not the only resource online and available to respond to load changes. Presumably these questions will be answered in the upcoming refined grid stability analysis. But up to this point, we do not get the impression that this is an issue that would necessarily eliminate propane fired generation from consideration. In the December 2023 meeting, SCE stated that the integration of a propane fired ICE in support of two diesel ICEs would be feasible for the SCE's inertia needs for the grid. In this scenario, the propane ICE would require even less propane.

5. Conclusion

SCE provided this in the BACT LAER letter dated 1/17/2023 (emphasis added):

Based on SCE's BACT/LAER unit-by-unit analysis, the proposed U.S. EPA Tier 4 Final certified Cummins internal combustion engines meet the requirements of BACT/LAER at PBGS. **However, SCE shares the South Coast AQMD's view that propane technology would significantly reduce emissions and likely be an effective component of the overall strategy to repower PBGS.** Installing new Tier 4 Final-certified diesel engines remains the quickest way to make significant reductions in NOx and other criteria pollutant emissions at PBGS over the next few years. SCE looks forward to continuing to work with SOUTH COAST AQMD to incorporate more near-zero and zero emission inverter-based technologies at PBGS, which would be supported by the clean, inertia-providing Tier 4 Final-certified diesel engines – ensuring SCE can continue to reliably produce electricity for the residents and visitors of Santa Catalina Island.

We believe that SCE is sincere in its statement, and we are willing to collaborate with SCE to achieve this goal. South Coast AQMD staff hopes that SCE concurs with our current position that, at least for the near term, at a minimum, 30% of the combustion related power supply from the facility can transition to cleaner burning propane, for the sake of air quality as well as public health.

Attachments:

Appendix A Propane use scenarios

Appendix B Unit 8 pad illustrations

Appendix A
Propane Use Scenarios

Scenario	Daily Propane Power Output MWh	Daily Diesel Power Output MWh
(A) 50% Propane/ 50% Diesel	40	40
(B) 30% Propane/ 70% Diesel	24	56

	Daily Propane Use, gals						
Scenario	**Power Generation**	**Utility**	**Total**	**Annual Propane Deliveries**	**Daily Diesel Use**	**Annual Diesel Deliveries**	**Total Deliveries**
A	3600	1780	5380	218	2800	142	360
B	2160	1780	3940	160	3920	199	359

The annual propane deliveries could be reduced if shipments larger than 9000 gallons are possible

	Approximate Propane Fuel Supply, days		
Scenario	**With 37,800 Gal**	**With 4 Tanks(1)**	**With 4 Tanks(2)**
A	7.0	9.6	11.5
B	9.6	13.0	16.9

(1) assumes 2 tanks dedicated to power production = 51,600 gals

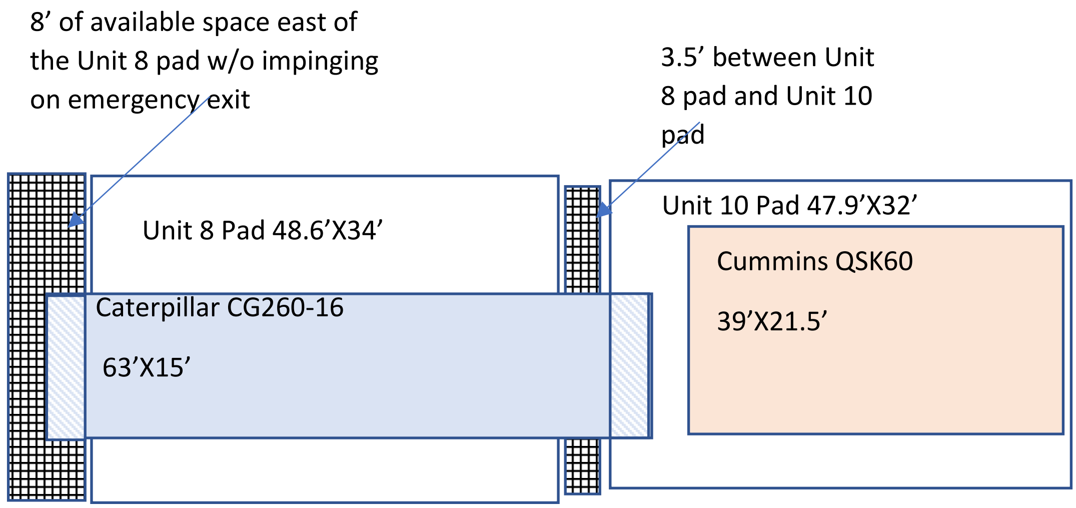
(2) assumes 2 tanks dedicated to power production = 51,600 gals + 50% reduction in utility needs

	Potential Configurations						
Scenario	**1.6 MW Propane ICE CG260-16**	**0.4 MW Propane ICE**	**Total Propane Capacity, MW**	**Required Propane Capacity Factor, %**	**1.8 MW Diesel ICE QSK60-G16**	**Total Diesel Capacity, MW**	**New Engine Capacity, MW**
A1	1	2	2.4	69	2	3.6	6.0
A2	2	0	2.8	60	2	3.6	6.4
B1	1	0	1.6	62.5	2	3.6	5.2
B2	1	1	2.0	50	2	3.6	5.6

Scenario	Propane Engines	Potential Engine Locations
A1	CG260-16 (1) + 0.4 MW (2)	0.4 MW (2) on the MT pad CG260-16 (1) at Unit 15 or Unit 8 location
A2	CG260-16 (2)	CG260-16 (1) on MT pad CG260-16 (1) at Unit 15 or Unit 8 location
B1	CG260-16 (1)	CG260-16 (1) either on MT pad or at Unit 15 or Unit 8 location
B2	CG260-16 (1) + 0.4 MW (1)	CG260-16 (1) at Unit 15 or Unit 8 location 0.4 MW (1) on the MT pad

Note that if it turns out that the Unit 15 or Unit 8 location cannot possibly fit the CG260-16, in scenarios A1 and B2, the locations of the engines can be switched.

Appendix B
Locating a Caterpillar CG260-16 and a Cummins QSK60 at the Unit 8 and Unit 10 location



Scale 1" = 20'


Southern California
Edison Pebbly Beach...
Cummins QSK60
Caterpillar CG260-16

Scale 1” = 36.5’

B – Detailed Response to SCAQMD Comment Letter

Attachment B: SCE Responses to SCAQMD's February 7, 2023 Letter

The following document reproduces the questions posed by the SCAQMD in its February 7, 2023 letter (in *italics*) and provides SCE's responses.

<u>SCAQMD Question 1: Space Limitations</u>

The information provided in the BACT LAER Letter 1-17-23 showed the graphical representation of the footprint of the 2 propane engines analyzed (the Caterpillar G2520H and the Caterpillar CG260-16) arranged on the pads of existing Unit 8, 10, and 15. The conclusions SCE reached based on this analysis is that neither of these engines would fit on any of the existing pads.

South Coast AQMD staff's evaluation of the available space and our review of the study raised the following questions:

<u>Unit 15 pad</u>

A CG260-16 nearly fits in this area but has a 6.2 ft overhang that impedes on the loading and crane access area, based on Fig 9. However, about 4 feet of this overhang presumably represents a flashback safety clearance, leaving only about 2 feet of physical equipment overhang. Can SCE confirm that this 2' would render the loading/crane area unusable? Or even with this overhang, the trucks and crane would still be able to satisfactorily maneuver in and out of that space? Alternatively, can the manufacturer redesign the unit to reduce the footprint by a few feet? Or can the CG260-16 be positioned at an angle to better fit in the available space of the Unit 15 pad?

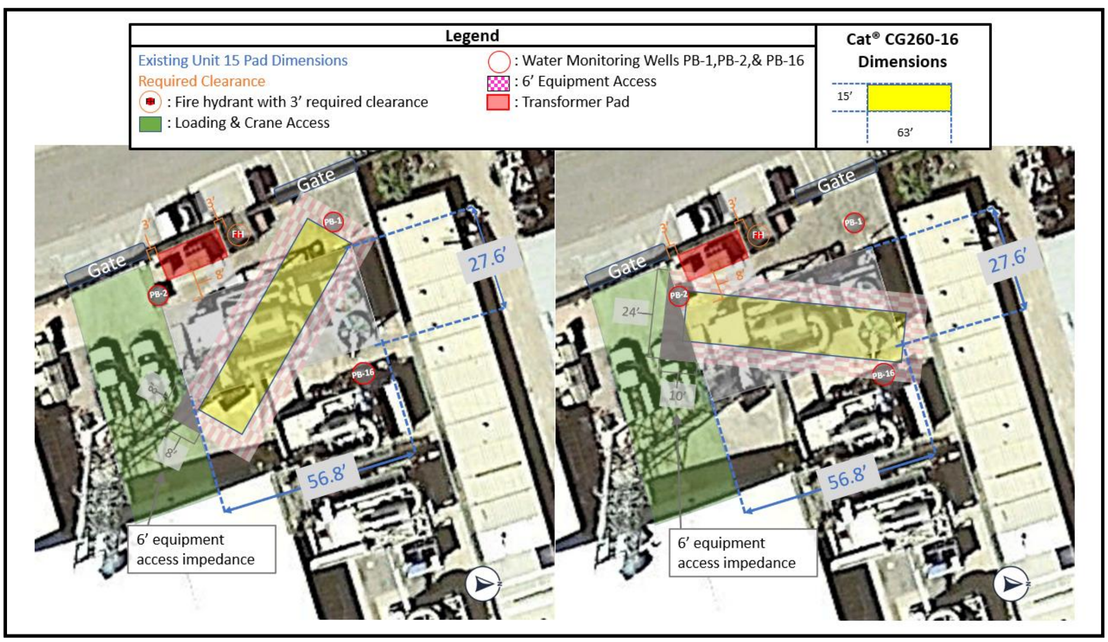
<u>SCE Response to Question 1</u>

<u>Unit 15 pad</u>

The SCAQMD's assumption that 4 feet of the 6.2-foot overhang depicted in Figure 9 represents a flashback safety clearance is incorrect. The 6.2-foot overhang is the physical space of the enclosed CG260-16 unit. SCE acknowledges that the SCAQMD's subsequent questions are based on that incorrect assumption and trusts that the aforementioned information clarifies the space issue. While it may be possible for the vendor to redesign a unit to fit the available footprint, it is simply not a viable option in the near term. Given enough time, resources, and money, a vendor may be able to design a "custom" unit for the Catalina space. However, SCE has learned through the Request for Proposals process that any equipment other than "off the shelf" options will take an additional four to five years to procure. In other words, if SCE is the only market, and the product cannot be scaled, years are added to the process. This is something SCE could have pursued initially with vendors four years ago, but the 2018 amendment of Rule 1135 allowed the installation of six clean U.E. EPA Tier 4 Final-certified (T4F) diesel generators. Given available resources and the need for short-term emission reductions, SCE chose to pursue the T4F replacements. SCE could not have foreseen the current permitting issues or that the SCAQMD would require propane units in 2023. Per the SCAQMD's request, SCE engaged a third-party consultant to complete an arc flash analysis, which would normally be completed by SCE at the time of construction and installation. SCE anticipates receiving the results of the arc flash analysis in early May 2023. Additionally, SCE is fine-tuning the analysis of setback requirements based on all federal and California requirements, regulations, and standards [e.g., Institute of Electrical and Electronics Engineers (IEEE) 1548-2018 standard, National Fire Protection Association (NFPA), National Electrical Code (NEC) Section 110.26, and California Code of Regulations (CCR) Title 8, Sections 2932 and 2340]. However, spatial constraints are only one aspect of feasibility for this analysis.

Fuel constraints are the main limiting factor on the replacement of Unit 15 with a propane reciprocating generator. A propane replacement is infeasible due to fuel limitations that would cause widespread grid failure and a significant number of load/shedding/blackout events. Nevertheless, SCE completed an assessment of whether the 4-MW Caterpillar CG260-16 generator/enclosure could fit when positioned at a diagonal compared to existing Unit 15's orientation (Figure 1).

Figure 1. Caterpillar Model CG260-16 Rotated Approximately 45 Degrees Counterclockwise (Left) and Approximately 40 Degrees Clockwise (Right) with Respect to Existing Unit 15's Orientation.



As shown in Figure 1, rotating the 4-MW Caterpillar CG260-16 roughly 45 degrees counterclockwise or 40 degrees clockwise with respect to the existing Unit 15 yields a configuration that appears to physically fit the space. However, the required clearances for the transformer pad and designated area for loading and crane access would be impeded. Additionally, the proposed orientation would cover a water monitoring well (PB-2). Moving the well would delay the project because: (1) SCE would need to coordinate with the Los Angeles Regional Water Quality Control Board for approval of the relocation or abandonment of the monitoring well; and (2) significant time would be required to pull the required permits for the installation of a new well and/or destruction of the existing well.

With a 45-degree counterclockwise configuration (right), the unit physically fits the space and complies with basic clearance requirements [e.g., under Occupational Safety and Health Administration Part (OSHA) 1910] compared to the clockwise configuration. However, it would block the northwest gate, which is a key point of egress, thus posing an unacceptable safety risk.

As part of our Injury and Illness Prevention Program (IIPP), SCE prioritizes a robust safety culture and continuously takes regularly cadenced proactive measures to: (1) mitigate risk and eliminate unsafe conditions; (2) reduce near-miss events; and (3) prevent injuries. SCE is continually striving toward low annual Total Recordable Injury Rates across all facilities and empowers employees at every level to exercise their Stop Work Authority if a task appears to be unsafe. In line with SCE's safety prioritization, a key consideration for the overall Repower Project is to reduce risk relative to today by implementing stricter engineering controls and efficient design layouts. When compared to Unit 15's existing configuration, a diagonal configuration would increase the complexity of egress, causing even tighter squeezes for employee foot traffic and forklift/vehicle activity, and generally make for operations more difficult, including high-risk activities such as crane use. Specifically, Unit 15's northern and eastern edges have very tight clearances adjacent to the neighboring building and generator, respectively. Across all industries, such tighter squeezes and awkward configurations generally increase the frequency of slips/trips/falls, forklift/machinery collisions, and crane operation near-misses and failures, despite proper training, robust work practices, and the use of applicable personal protective equipment.

In summary, SCE has provided Figure 1 solely to respond to the SCAQMD's question. However, SCE does not recommend a diagonal configuration and trusts that Figure 1 and the above discussion convey why this is not an acceptable option for PBGS.

SCAQMD Question: Unit 8 pad

The analysis shows that a CG260-16 overhangs the area by about 14.4 ft. This overhang in turn impedes by about 5 ft onto the space needed for an emergency exit. However, there appears to be a possible solution by moving the GC260-16 back towards the Unit 10 pad to provide clearance for the emergency exit. The much smaller Cummins QSK60 (39' L as provided by SCE) designated for Unit 10 replacement will not take up the entire Unit 10 pad, thereby leaving room for a portion of the CG260-16 to extend into the Unit 10 pad. Would this be a possible solution?

SCE Response

It appears the SCAQMD staff may have transposed the locations of Units 8 and 10 (*see* the attached Appendix B). SCE acknowledges it may be possible to fit one Cummins QSK60 and one Caterpillar CG260-16 unit in the current locations of Units 8 and 10, but those units would be an alternative to replacing Unit 15, not replacements for Units 8 and 10 themselves. The T4F replacements for Units 8 and 10 have already been delivered to SCE. Replacing Unit 15 with the Cummins and Caterpillar units would not eliminate the suggested option's fuel constraints and associated grid instability.

SCAQMD Question: The micro turbine (MT) pad

SCE has indicated that the MTs have reached the end of their useful life, and SCE has requested to discontinue the use of the MTs (the MTs use is governed by a Settlement Agreement and a Microturbine Site agreement from 2009-10, with a corresponding permit condition reflected the requirements in these agreements in the PBGS permit). The MT pad is large enough to accommodate either (1) CG260-16, or (1) G2520H, or (2) 0.4 MW Caterpillar propane ICEs.

SCE Response

SCE is more than happy to replace the microturbines with new technology during the next phase for the Repower Project. However, in order to meet demand, it is critical that SCE receive the permits to replace Units 8, 10, and 15 with T4F engines as soon as possible. Replacing Units 8 and 10 with T4F engines is necessary to meet the interim facility emission target of 45 TPY NOx in 2045. Additionally, replacing Unit 15 with a T4F is the quickest way to resolve its noncompliance with Rule 1470(c)(4)(A). It would both reduce facility NOx emissions most expeditiously and provide the necessary backbone of reliability and resiliency for SCE to continue to incorporate zero-emission (ZE) and near-zero-emission (NZE) generation technologies at the facility.

SCAQMD Question: The space where Units 7, 12, and 14 currently reside

This pad will become available once the Rule 1135 compliance date takes effect on January 1, 2024 (current version of the rule) or July 1, 2025 (proposed amended version of the rule), and the use of those engines is no longer allowed. Has SCE considered this space as an option? For either the MT pad or this space, installation of a propane fired ICE with SCR control designed to meet the NOx level consistence with an NZE as defined in proposed amended Rule 1135 would be consistent with the objectives of Rule 1135.

SCE Response

PAR 1135 does not bar SCE from running Units 7, 12, and 14. However, SCE recognizes that to meet the proposed NOx emission targets, these units can only serve as backups. SCE plans to keep Units 7, 12, and 14 while progressively incorporating cleaner technologies into PBGS. SCE is not considering the space they occupy as part of the permit application for the new T4F-certified units that would replace Units 8, 10, and 15.

SCAQMD Question 2: Propane Fuel Delivery/Propane Storage Capacity

SCE currently has four 30,000-gallon propane storage tanks on site. Only three of the tanks are in service due to the limitations of the fire protection system. These tanks are allowed to fill maximumly to 86% of the rated capacity. For years 2020 and 2021, SCE reported that the mean annual propane fill capacity is 67%. SCE also states that the tank liquid level must be maintained at no less than 25%, or 7500 gallons. Thus, SCE maintains that the actual usable volume of propane is between 25% to 67% (about 37,800 gallons) in cooler temperatures, or between 25% and 47% is warmer temperatures (about 19,800 gallons).

SCE supplies up to 650,000 gallons of propane to its customers annually. SCE receives propane deliveries to the island by barge in shipments of about 9,000 gallons.

South Coast AQMD staff's Evaluation of Propane Availability

This new information regarding the reduced propane storage capacity was not provided by SCE prior to January 17, 2023, even though the topic has been discussed previously. South Coast AQMD staff's analysis regarding propane supply capacity has, up to this point, relied on the assumption that there is approximately 90,000 gallons of storage available on PBGS. This number has been used in our working group meetings and SCE has never indicated the error in this assumption. Furthermore, the NV5 Study also relied on a storage tank capacity of 90,000 gallons *for its analysis. It is concerning that SCE withheld this important piece of information and waited until the eleventh hour to inform South Coast AQMD staff.*

SCE Response

SCE acknowledges the SCAQMD's concern. Initially, SCE indicated there were significant fuel concerns based on the rated capacity of 90,000 gallons. As we progressed through the most recent analysis, we learned there are additional restrictions on fuel storage, and we raised the issue promptly. SCE acknowledges the SCAQMD's need to receive such information in a timely manner, and SCE will continue to provide the best available information to SCAQMD staff including—as in this case—new information, as it becomes available.

SCAQMD Question: Option of a 4th tank

SCE has investigated bringing a 4th propane tank into service by either enhancing the fire protection systems or using a fire retardant material on the tanks themselves. Bringing a 4th tank into service would greatly enhance the ability of the PBGS to move towards cleaner burning propane for its combustion related generating resources. This option should be fully investigated and implemented if possible. SCE has indicated that they had initiated these discussions but never provided complete feedback or communications from the fire authority.

SCE Response

SCE is actively engaging the Fire Protection Authority Having Jurisdiction (FP-AHJ) to identify how to bring the fourth tank back into operation in the future while complying with all fire protection requirements. This is a longer-term effort that, if successful, can support SCE's ability to incorporate cleaner ZE and NZE technologies under the PAR 1135 timeline. SCE will continue to keep the SCAQMD apprised as more information is provided by the FP-AHJ.

Under BACT/LAER requirements, the analysis should be conducted based on the best information available as of the date of the analysis. Thus, even though SCE has (for transparency purposes) quantified the additional propane that could theoretically be allocated to electricity generating technology if the fourth tank were brought online (*see* below and in Attachment D), the SCAQMD's assessment and determination of BACT/LAER should focus on the three currently available propane tanks given the uncertain safety, legal, compliance, and construction considerations of this ongoing and future effort. Grid stability modeling demonstrates that three T4F generators are needed for the first step of the Repower Project to meet demand, so any propane estimates should be considered as a next step – following construction and commissioning of the first three T4F generators.

SCE remains committed to increasing the amount of propane available for electricity generation, but this is a long-term process. As detailed in Attachment D, with four propane tanks in operation, SCE could theoretically allocate approximately 350,000 additional gallons of propane annually to electricity generation without affecting the gas utility service or reducing the nominal number of storage days (10 days) during both the warm and cool seasons at PBGS. Therefore, bringing the fourth tank online theoretically has the potential to increase the total allocatable propane for electricity generation to approximately 751,600 gallons each year. This sharp increase relative to the 401,200 gallons calculated for the first three tanks together is possible because the gas utility service annual throughput is already satisfied in the model when three tanks were considered, leaving the additional propane available for electricity generation. However, it is important to note that with the additional fourth tank, or even an unlimited propane supply, the grid reliability study (Attachment C) shows that SCE would not be able to meet demand if Unit 15 is replaced with a CG260-16 propane reciprocating engine. Further, this estimate is a theoretical approximation accounting for compliance with reasonable fuel storage levels and gas utility service annual consumption, only. Additional challenges to achieving a 751,600 gallon allocation of propane with the fourth tank online for electricity generation may arise during real-world operation or based on constraints outside of SCE's full control (e.g., propane availability as a commodity, barge deliveries, etc.).

The theoretical maximums for grid stability modeling and discussion purposes are approximately 401,200 gallons for three tanks and 751,600 for four tanks. For any future Title V Permit conditions for minimum annual propane throughput, SCE would need practical flexibility on such a requirement even while recognizing that SCE would strive to exceed the permit minimum when possible. Regardless, the grid stability modeling demonstrates that three T4F generators are needed for the first step of the Repower Project to meet demand. Therefore, any propane estimates should be considered only as a next step after construction and commissioning of the three T4F generators in SCE's pending permit application.

SCAQMD Question: Designating Two tanks for utility service

SCE may consider dedicating two tanks to the utility service given that the utility service only requires 1,780 gallons per day on average. This would leave the other one tank (or two, if tank 4 can be brought online) to be use for propane fired generation and permit the tank to be filled to much higher capacity (up to 86%). This would provide 7-14 days of utility service with the two tanks (13,200 gal to 25,200 gallons).

SCE Response

The tank system is not equipped with separate feedlines. The units work as an aggregate to supply fuel, which is critical given the need for redundancy to support service and maintenance. Isolating individual tanks to support specific systems would jeopardize SCE's ability to reliably provide gas utility service. Approximately once every five years, SCE performs maintenance on each tank's pressure relief valves (which takes four days per tank). During these maintenance events, SCE relies on the remaining online tanks, making isolation infeasible. SCE did not perform an analysis of propane allocability for the case of one propane tank designated for electricity generation (i.e., the remaining tank indicated for this SCAQMD proposal) given the lack of redundancy. Further, a complete redesign of the feedlines would be needed, which would affect reliability and resiliency.

SCAQMD Question

A propane fired ICE uses about 0.09 gallons of propane per kW of power output at 40% efficiency. PBGS's average daily power output is about 80 MWh/day (based on an average of 3.3 MW/hr). Assuming that 50% of the combustion related power output for the facility is generated through the use of propane, then daily propane use would be about 3600 gallons, or about seven days of supply with a tank capacity of 25,800 gallons.

Propane is brought to the island by barge. A review of data indicated that disruptions to the barge deliveries are exceedingly rare. Based on the data that we analyzed, the barge was available for at least 96.2% of the days per year (only unavailable on 14 days of the year), and the time between deliveries never exceeded a maximum of five days. Therefore, we have concluded that this is not a valid argument against the feasibility of a propane ICE based on historical data.

SCE Response

As previously indicated by SCE staff, limiting the total propane storage to an approximately five-day supply presents an unacceptable level of risk. SCE cannot view past barge obstructions as a failsafe predictor of future fuel reliability, especially given the lack of historical data beyond five years. Unlike the mainland, where electrical or gas utility service system planning would not typically consider procurement logistics given the nearly unlimited opportunities for ground transportation, an isolated island microgrid has neither the ability to receive electricity from adjacent grids nor to bring fuel to the plant solely via roadways. Therefore, if the barge service is obstructed, there is no readily available alternative.

It is SCE's duty to consider both likely factors that could impede the logistics of fuel delivery and less likely but highly impactful events that could reasonably occur within the next 10 to 20 years.

As indicated to SCAQMD staff in an August 9, 2022 email, these factors include but are not limited to the following: extreme weather events, tsunami, high winds, fog, roadway erosion, mud slide/erosion from nearby mountain range , labor shortages (e.g., strike among multiple skilled workforces such as refineries or drivers), equipment failure of the tanks and/or fuel unloading stations and delivery systems, fuel supply chain issues, inadequate shipyard space, unavailability due to competing island priorities like food and medical supplies), sabotage, terrorism, and fire.

As a result, SCE elected to calculate fuel availability based on having at least 10 days of storage during both the warmer and cooler seasons. In practice, the amount of propane available for electricity generation would fluctuate based on seasonal demand for gas for utility service and propane volume within tanks, which will also fluctuate based on heat expansion throughout the year.

SCE performed an analysis to determine the maximum annual consumption for propane-fueled electricity generating technology based on 10 storage days and the existing three available tanks (along with comparable calculations for two and four tanks). For this analysis, the generation technology type and frequency of barge deliveries were not relevant because the analysis centers on propane availability for both gas utility service and propane-fueled electricity generating technology in general where efficiency (e.g., gallons per kilowatt-hour of generation) was not a factor. Additionally, the analysis of propane availability was not limited by barge delivery frequency. The overarching goal was to determine how much propane could be allocated to electricity generation per year while providing adequate propane for gas utility service and maintaining 10 days of storage – positioning SCE with reasonably sufficient levels of fuel storage should the barge delivery service halt for any reason. The primary constraint in determining the maximum volume of propane that can be allocated to electricity generating technology is SCE's obligation to deliver up to 650,000 gallons of gas utility propane annually. The analysis concluded that a maximum of 401,200 gallons of propane could theoretically be allocated to electricity generation in a particular year. Detailed calculations are provided in Attachment D.

<u>SCAQMD Question: Additional propane storage site</u>

SCE has identified an offsite location where additional propane can be stored. This is the Roaring Canyon location presently used for recreational off-road vehicles, about ½ mile southwest of the plant. If obtained by SCE for propane storage, there is space enough for multiple new propane tanks and a water deluge system for fire protection. Expanding the PBGS into this location for additional propane storage would allow much higher propane use (up to 100% of the power plant needs).

SCE Response

SCAQMD staff should not consider additional propane storage constructed on land neither owned nor leased by SCE in the BACT/LAER evaluation because it is not a near-term viable option. As explained above, the BACT/LAER evaluations must rest on the best information available today.

SCAQMD Question: Utility use of propane

SCE is in the process of transitioning their customers to electricity for heating and cooking needs. As this transition continues the propane supplied through the utility service is expected to decrease, which will result in more propane supply being available for power generation, and while this decrease in propane needs would be offset to some degree by the increase in electrical load requirements, the reduced need for utility propane would open up storage tank capacity for propane-fired power generation.

To summarize our position, South Coast AQMD staff believes that there are several options that alone, or in combination, can be used to alleviate the issues of propane fuel supply and delivery.

SCE Response

If approved, SCE's proposed Building Electrification Application at the California Public Utilities Commission could, in the future, reduce utility gas annual throughput and thus allow greater flexibility in allocating propane to electricity generation. However, the application is still pending, so its outcome remains uncertain. Under BACT/LAER requirements, the analysis should be conducted based on the best information available today. Consequently, SCE has not included potential benefits of the Building Electrification Application in its BACT/LAER analysis, which is also in alignment with CPUC Decision 22-11-007.

SCAQMD Question* 3: *ICE Power Generating Capacity

SCE has proposed to replace existing Unit 8, 10, and 15. SCE has indicated that any replacement of these units cannot result in a reduction in the power generating capacity. According to SCE, the propane engines under evaluation for this project, namely the Caterpillar CG260-16 and the Caterpillar G2520H, are derated when fired on liquid propane as opposed to vaporized propane. Specifically, the CG260-16 is derated from a nameplate capacity of 4 MWe to approximately 1.6 MWe, while the G2520H is derated from 2 MWe to about 1.4 MWe. It should be noted that previously SCE had stated that the CG260-16 would only be derated down to 2 MWe.

South Coast AQMD staff's Evaluation

South Coast AQMD staff has considered this limitation in our analysis. With such a significant derating for liquid propane use, SCE could consider what modifications would be necessary to convert the fuel supply to vaporized propane instead, especially since the current vaporization system at the facility is in need of replacement. This would provide a timely opportunity to address a need for vaporized propane to be used for power generation on the island in the very near future.

SCE Response

As discussed with the SCAQMD permitting team, SCE's sharing of its study results is an iterative process in which SCE continually learns and gathers more accurate and refined information from prospective vendors. As always, SCE will continue to provide the best available information gathered from vendors and internal analysis. Below is an update on key considerations for the BACT/LAER evaluation for the replacement of Units 8, 10, and 15.

On March 23, 2023, Steven Rodriguez of Quinn Power (who is SCE's main point of contact for the 2- and 4-MW propane-fueled Caterpillar generators) stated that providing an air-propane mixture to propane reciprocating generator skids, rather than pure propane, would not reduce the derating of any of Caterpillar's propane reciprocating generator options. In the early stages of our analysis, SCE speculated that an increase in power output could theoretically be achieved by supplying an air/propane mix to a given propane reciprocating generator and communicated the concept to SCAQMD staff. SCE understands this past discussion may be the reason why the SCAQMD inquired about this approach in its February 7, 2023 letter. In light of Quinn's March 23 response, SCE has determined that this option is no longer viable.

SCE further investigated the derating of the CG260-16 propane reciprocating engine following the SCAQMD's February 7, 2023 letter. Initially, SCE understood the prime rating would be approximately 2 MW after derating from 4 MW. Later, SCE incorrectly assumed the specification sheet's 75% power rating (of 1.573-MW) to be the prime rating. Steven Rodriguez of Quinn Power pointed out this oversight in his March 23, 2023 email. It turns out that SCE's original approximation of 2 MW was more accurate: the actual prime rating is 2.097 MW for the CG260-16 (Attachment E). SCE's Stage 1 grid stability modeling has subsequently been updated. However, the original conclusions remain valid, partly due to the similar electrical and thermal efficiencies at 75 (minimum) and 100 (prime) percent load for the CG260-16 engine, along with its lack of operational load flexibility. In short, installing a CG260-16 propane reciprocating generator in place of Unit 15 is infeasible due to operational flexibility and the resulting grid instability, which would cause frequent interruptions of utilities services, resulting in a significant number of load-shedding/blackout events for the island.

<u>SCAQMD Question 4: Propane ICE Ramp Rate/Grid Stability</u>

SCE stated in the BACT LAER letter dated 12/15/2022, when referring to propane-fueled reciprocating generators:

> While capable of providing inertia to the grid, these units cannot respond to rapid load fluctuations at the same rate as diesel generators due to the lower energy density of propane compared to diesel. Therefore, the replacement of a diesel engine with a propane reciprocating generator would reduce the facility's ability to reliably produce power

Furthermore, in the BACT LAER letter dated 1/17/2023, SCE provided this:

> On September 30, 2022, SCE provided an initial System Stability Study for PBGS, which included an assessment of propane reciprocating generators. A baseline model of PBGS was built in PSCAD, which is a commonly accepted modeling platform for detailed transient analysis. Initial results indicated that replacing Unit 15 with a propane reciprocating generator would not be as beneficial as replacing Unit 15 with a T4F diesel generator. Although propane reciprocating generators do provide inertia to the grid, the lower energy density of propane compared to diesel fuel causes propane reciprocating generators to respond to fast load fluctuations more slowly than diesel generators, impacting voltage and frequency stability for the island. (See the report dated September 30, 2022.
>
> Presently, SCE has contracted Power Engineers to perform refined analyses of various scenarios, including a mix of T4F diesel generators along with the replacement of Unit 15 with a propane reciprocating generator. The grid stability analysis will further inform SCE's understanding of whether various technology mixes can provide reliable power considering Catalina's unique isolated microgrid, and the desire to integrate utility-scale zero- and/or near zero-emission generation resources. Power Engineers and SCE will develop "Flexible N-2 Reliability" criteria specific for Catalina's isolated microgrid with the following key considerations:

<u>South Coast AQMD staff's Evaluation</u>

SCE has assessed that replacing a diesel fired ICE with a propane fired ICE would provide the necessary inertia but would result in a reduced load change response time. However, SCE was not specific as to the degree of the reduction in response time. Furthermore, SCE has not yet provided details as to the typical load change characteristics of the Catalina grid, so that an analysis can be made as to the extent of the impact of the slower load response time of the propane generator on grid stability. And finally, this issue should also be looked at through the lens of a hybrid scenario where propane fired capacity is not the only resource online and available to respond to *load changes. Presumably these questions will be answered in the upcoming refined grid stability analysis. But up to this point, we do not get the impression that this is an issue that would necessarily eliminate propane fired generation from consideration. In the December 2023 meeting, SCE stated that the integration of a propane-fired ICE in support of two diesel ICEs would be feasible for SCE's inertia needs for the grid. In this scenario, the propane ICE would require even less propane.*

SCE Response

The grid stability analysis is complete for BACT/ LAER purposes. The results demonstrate that at least three T4F diesel generators are required to meet Catalina's current electricity demand.

SCAQMD Question 5: Conclusion

SCE provided the following in our January 17, 2023 letter regarding BACT/LAER (emphasis added):

Based on SCE's BACT/LAER unit-by-unit analysis, the proposed U.S. EPA Tier 4 Final certified Cummins internal combustion engines meet the requirements of BACT/LAER at PBGS. **However, SCE shares the South Coast AQMD's view that propane technology would significantly reduce emissions and likely be an effective component of the overall strategy to repower PBGS.** Installing new Tier 4 Final-certified diesel engines remains the quickest way to make significant reductions in NOx and other criteria pollutant emissions at PBGS over the next few years. SCE looks forward to continuing to work with SOUTH COAST AQMD to incorporate more near-zero and zero emission inverter-based technologies at PBGS, which would be supported by the clean, inertia-providing Tier 4 Final-certified diesel engines – ensuring SCE can continue to reliably produce electricity for the residents and visitors of Santa Catalina Island.

We believe that SCE is sincere in its statement, and we are willing to collaborate with SCE to achieve this goal. South Coast AQMD staff hopes that SCE concurs with our current position that, at least for the near term, at a minimum, 30% of the combustion related power supply from the facility can transition to cleaner burning propane, for the sake of air quality as well as public health.

SCE Response

This appears to be a suggestion to require at least 30% of annual output generation from propane sources in the "near term." As indicated above and in previous submittals, limitations on space, fuel, and grid stability must be factored into plans for annual propane generation at PBGS. SCE is committed to addressing these issues and increasing the use of propane or other lower-emitting technology at PBGS, but this must be done after this first phase of the Repower Project (the replacement of Units 8, 10, and 15 with T4F generators) is completed.

SCAQMD Appendix A

Appendix A
Propane Use Scenarios

Scenario	Daily Propane Power Output MWh	Daily Diesel Power Output MWh
(A) 50% Propane/ 50% Diesel	40	40
(B) 30% Propane/ 70% Diesel	24	56

	Daily Propane Use, gals						
Scenario	Power Generation	Utility	Total	Annual Propane Deliveries	Daily Diesel Use	Annual Diesel Deliveries	Total Deliveries
A	3600	1780	5380	218	2800	142	360
B	2160	1780	3940	160	3920	199	359

The annual propane deliveries could be reduced if shipments larger than 9000 gallons are possible

	Approximate Propane Fuel Supply, days		
Scenario	With 37,800 Gal	With 4 Tanks(1)	With 4 Tanks(2)
A	7.0	9.6	11.5
B	9.6	13.0	16.9

(1) assumes 2 tanks dedicated to power production = 51,600 gals
(2) assumes 2 tanks dedicated to power production = 51,600 gals + 50% reduction in utility needs

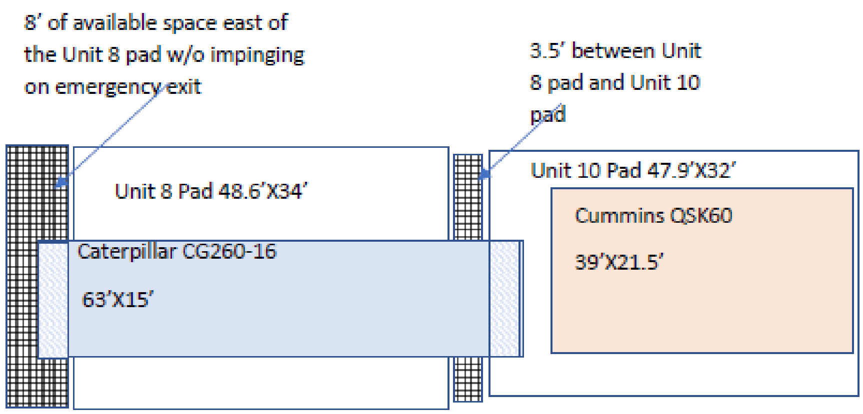
	Potential Configurations						
Scenario	1.6 MW Propane ICE CG260-16	0.4 MW Propane ICE	Total Propane Capacity, MW	Required Propane Capacity Factor, %	1.8 MW Diesel ICE QSK60-G16	Total Diesel Capacity, MW	New Engine Capacity, MW
A1	1	2	2.4	69	2	3.6	6.0
A2	2	0	2.8	60	2	3.6	6.4
B1	1	0	1.6	62.5	2	3.6	5.2
B2	1	1	2.0	50	2	3.6	5.6

Scenario	Propane Engines	Potential Engine Locations
A1	CG260-16 (1) + 0.4 MW (2)	0.4 MW (2) on the MT pad CG260-16 (1) at Unit 15 or Unit 8 location
A2	CG260-16 (2)	CG260-16 (1) on MT pad CG260-16 (1) at Unit 15 or Unit 8 location
B1	CG260-16 (1)	CG260-16 (1) either on MT pad or at Unit 15 or Unit 8 location
B2	CG260-16 (1) + 0.4 MW (1)	CG260-16 (1) at Unit 15 or Unit 8 location 0.4 MW (1) on the MT pad

Note that if it turns out that the Unit 15 or Unit 8 location cannot possibly fit the CG260-16, in scenarios A1 and B2, the locations of the engines can be switched.

Scale 1" = 36.5'

Appendix B
Locating a Caterpillar CG260-16 and a Cummins QSK60 at the Unit 8 and Unit 10 location



Scale 1" = 20'

SCE Response

Under the proposed scenarios below, SCE would not have the ability to service any equipment or bring units offline for maintenance while continuing to provide reliable electrical service to the island. Units 7, 12, and 14 will continue running for several years to ensure customer electrical demand can be met. SCE estimates that approximately once every three to four years, the T4F generators could be out of service for up to four months due to normal maintenance (which occurs every 20,000 hours of run time, which equates to three to four years. Additionally, SCE must account for generator downtime due to unforeseen issues such as breakdowns, which SCE can only estimate for the new generators at this time. Thus, SCE must base its plan on the assumption that only two of the three T4F generators will be dispatchable at any given moment.

SCE believes this discussion should progress with the SCAQMD Planning and Rules Team, with whom considerable progress has already been made on this discussion. It should not be considered as part of the SCAQMD Permitting Team's BACT/LAER evaluation for SCE's permit application to replace Units 8, 10, and 15 with T4F generators. The BACT/LAER analysis is not an appropriate mechanism to expedite the goals of PAR 1135.

C – Reliability Study Summary

April 28, 2023

SOUTHERN CALIFORNIA EDISON

PBGS Technical Assessment

Configurations A and B Report

Revision 1

PROJECT NUMBER:
176291

PROJECT CONTACT:
SAURABH SHAH
EMAIL:
SAURABH.SHAH@POWERENG.COM
PHONE:
509-597-2845

POWER ENGINEERS

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EXECUTIVE SUMMARY

To support the Best Available Control Technology (BACT) and Lowest Achievable Emission Rate (LAER) analysis for Southern California Edison's (SCE) Application for Permits to Construct three Tier 4 Final-certified diesel generators in-place of existing diesel generators, POWER Engineers Inc. (POWER) was contracted by SCE to model and quantify reliability of the Pebbly Beach Generating Station (PBGS) electricity generation and Catalina distribution system under two distinct scenarios. Using HOMER PRO®, an industry-accepted simulation software, POWER determined the efficacy of each configuration by accounting for hourly electricity demand or "load" (forecasted for Calendar year 2026) for the island, planned and unplanned maintenance downtime for both existing and proposed equipment, electricity contribution from all facility sources applicable to each scenario (e.g., the microturbines), and fuel constraints. Power concludes that Configuration A (i.e., if SCE replaces three diesel generators with new Tier 4 Final-certified generators) appears feasible with carefully planned maintenance. In contrast, Configuration B (i.e., when two existing diesel generators are replaced with Tier 4 Final-certified generators and one existing diesel generator is replaced with a 4 MW propane reciprocating generator) would lead to widespread blackouts and periods of "load shedding," where curtailment of electrical demand in excess of available generation must occur.

- **Configuration A is feasible but not advisable**
  - Great care must be given to maintenance scheduling and coordination, or the system will not have enough capacity to meet demand.
  - While Configuration A is shown to be feasible, it is recommended that a level of reliability and resiliency be added to improve confidence in this generation configuration.

- **Configuration B is infeasible**
  - 29% of the hourly loading failed to meet demand.
  - The bottleneck in performance is the 75% minimum loading requirement on the Reciprocating Propane Engine.
  - It is noted that even with a more favorable maintenance schedule than what is shown in this report, Configuration B would still fail to meet the loading of the island.

While previous memos on this subject have been delivered, the models and results described here present the latest and most up-to-date information.

STUDY APPROACH

Description of the configurations

The study compares the performance of a system with three Tier 4 Final-certified (T4F) generators (Configuration A) to one which consists of two T4F units with a Reciprocating Propane Engine (RPE) (Configuration B). The performance of the Catalina generation and distribution systems is modeled as a microgrid because it is not connected to the mainland power system. As such, it is imperative that the sources of generation are designed to be as robust and reliable as possible since the island will not receive any assistance from the mainland power grid in the event of an emergency. To accomplish this, the maximum capacity of the island's generation must meet the projected peak demand and annual hourly demand, with a certain safety factor included as a best practice. In addition to meeting capacity requirements, diversifying fueling resources aids in system resiliency, for example if something were to happen to the propane supply, the island would still have a fall back on diesel generation. This scenario, though not ideal because it could still lead to load shedding, avoids a catastrophic failure of the island's power grid (total blackout). Additionally, the battery bank provides some extra security when the installed generation system encounters demand beyond its capacity for short periods.

Below is a breakdown of Configuration A and B respectively.

<u>Configuration A:</u>

- Units 8, 10 and 15 are replaced with three (3) T4F-certified engines.
- Units 7, 12, and 14 remain in place at PBGS to serve as backup generators.
- The existing sodium sulfur (NaS) battery remains operational
- The microturbines produce 906,481 kWh of energy through consumption of 173,951 gallons of propane.

<u>Configuration B:</u>

- Units 8 and 10 are replaced with two (2) U.S. EPA T4F-certified engines.
- Units 7, 12, and 14 remain in place at PBGS to serve as backup generators.
- Unit 15 is replaced with a 4 MW propane reciprocating generator with a prime-rating of 2.097 MW (i.e., Caterpillar Model CG260-16), consuming 400,000 gallons of propane throughout calendar year 2026.

Model Inputs, Assumptions, and Constraints

Constraints

Robust quantification of variable inputs was critical to ensuring model results were accurate. Each configuration's capability of meeting electricity demand was greatly dependent on fuel availability and maintenance scheduling. Based on historical data provided by SCE the fueling and maintenance requirements included in the model were:

- Annual consumption of 400,000 gallons of propane
- Annual consumption of 2.2 million gallons of diesel
- 6% minimum power reserve requirement
- One (1) T4F unit receiving 4-month long maintenance, representing a 20,000 hours overhaul event (compared to 100,000 hours for the existing marine category 2 engines).
- One (1) T4F units receiving a 5-day maintenance activity
- One (1) 24-hour planned maintenance activity per T4F unit to occur after every 250 hours of run time, representing a routine oil and filter change.
- No maintenance on microturbine units
- 48-hour maintenance on the Backup Diesel Generators every 480 hours
- Propane Reciprocating Engines' maintenance activities match those of the T4F units

The model was run over one year (8760 hours) under the reasonable conditions in which one unit would be receiving the 4-month long maintenance, and another that same year would receive the 5-day maintenance. The 6% minimum power reserve represents a capacity safety factor which is necessary to ensure the system will ride through unforeseen peaks in demand should they arise. Table 1 shows the maintenance scheduling. The maintenance schedule is based upon best estimates and practices working with vendor information and historical performance records.

TABLE 1: MAINTENANCE SCHEDULING

Maintenance Type for Each New T4F Generator	Downtime per Occurrence (Days)	Occurrences Per Year*
One 1-Day Maintenance Event Occurring Every 250 Run-Hours	1	24
One 5-Day Event Occurring Every 10,000 Run-Hours	5	0.6
One 138-Day Maintenance Event ("Overhaul") Occurring Every 20,000 Run-Hours	138	0.3

**Based on target utilization of 6000 run-hours per year or 68.5% utilization.*

Note, it is anticipated that reaching 20,000 run-hours where overhaul is required would occur typically every three to four years. Given that there are three units which require this activity it is known that one unit will be down for four months almost every year in the system's life as the units rotate per the schedule.

Model Inputs and Assumptions

Given that the analysis explores a future configuration, the assumptions in the model pertained to loading and potential future equipment performance based on regulatory requirements and manufacturer data. Additionally, performance metrics on existing systems which are not readily available were also given values based on best estimates and research. As requested by Mike Krause and the District Permitting Team on March 30, 2023, in a meeting with SCE and POWER, below are inputs/assumptions for modeling grid stability in support of the BACT/LAER analysis.

- 75% minimum loading on the Propane Reciprocating Engines
- 10% minimum charge on the existing battery system
- 25% minimum loading on the T4F generators
- Forecasted demand data for 2026 with a peak of 6 MW and 31 GWh annual loading
- Existing NaS BESS modeled as 1 MW / 7 MWH with a round-trip-efficiency of 85%.
- 12 unplanned maintenance activities per T4F and RPE unit with randomized outage durations
- 90% minimum loading on the Backup Diesel Generators
- Backup Diesel Engine operating efficiency of approximately 30% at full load
- T4F unit operating efficiency of approximately 38% operating efficiency at full load
- RPE operating efficiency of approximately 40% at full load
- Microturbine operating efficiency of approximately 20% at full load

The unplanned maintenance activities were modeled using historical data which showed an average occurrence of 12 activities per year with a average total duration of 130 hours. Assuming 12 events annually, the duration of each event was assigned a value using a random number generator but constrained such that the sum equaled 130 hours.
Note: the T4F units do have a Standby rating of 2250 kW, in addition to the Prime unit rating of 1825 kW. However, standby is a short-term operation and not appropriate for long-term planning which is the intent and desired outcome of this study.

RESULTS

Configuration A

Configuration A was shown to be feasible only if SCE staff can perfectly coordinate the required maintenance outages. While on paper there is enough capacity to support the load, precise planning must be taken when scheduling maintenance activities. If generation unit outages are not coordinated properly during certain times of the year or if unexpected disruptions occur to the planned maintenance schedule, there will not be enough generation to support the demand. Table 2 depicts the performance results for Configuration A, and Figures 1 - 3 show the annual output of each T4F unit when modeled as Prime units. Figure 3 shows an overlay of the demand and generation profiles.

TABLE 2: CONFIGURATION A HOMER MODEL RESULTS		
Unit	**Annual Output (kWh) / Annual %**	**Gallons / Fuel Type**
Microturbines	1,053,437 / 3%	208,689 / Propane
Backup Diesel Unit 7	570,118 / 1.85%	50,764 / Diesel
Backup Diesel Unit 12	769,934 / 2.5%	68,359 / Diesel
Backup Diesel Unit 14	1,365,916 / 4.44%	121,849 / Diesel
T4F Unit A	13,539,007 / 44%	948,853 / Diesel
T4F Unit B	9,969,278 / 32.4%	725,492 / Diesel
T4F Unit C	3,519,231 / 11.4%	283,862 / Diesel
Totals	30,786,921 kW Annual Demand	208,689 / Propane 2,199,178 / Diesel

While units A, B, and C are shown with an annual operating percentage of 44%, 32.4%, and 11.4% respectively for modeling purposes, in practice the units will likely operate in a load sharing mode and accumulate a similar number of annual operating hours over time.

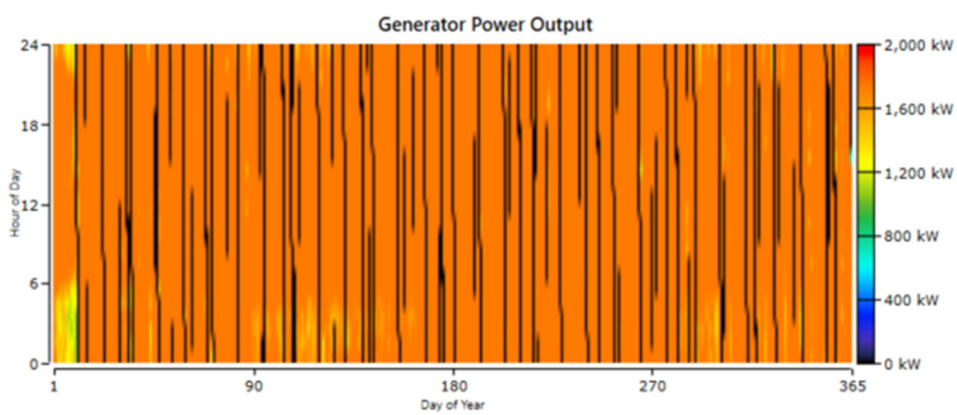

Figure 1: Generation Profile For T4F Unit A With Unscheduled And Bimonthly Maintenance

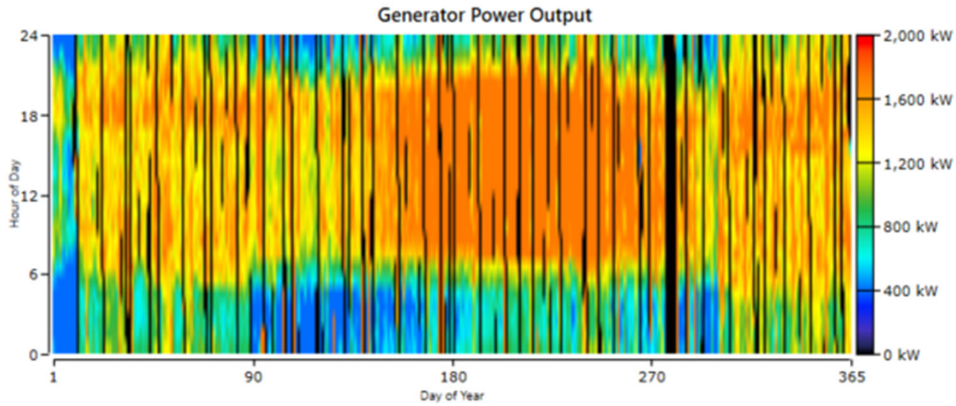

Figure 2: Generation Profile For T4F Unit B With Unscheduled 5-Day Biannual And Bimonthly Maintenance

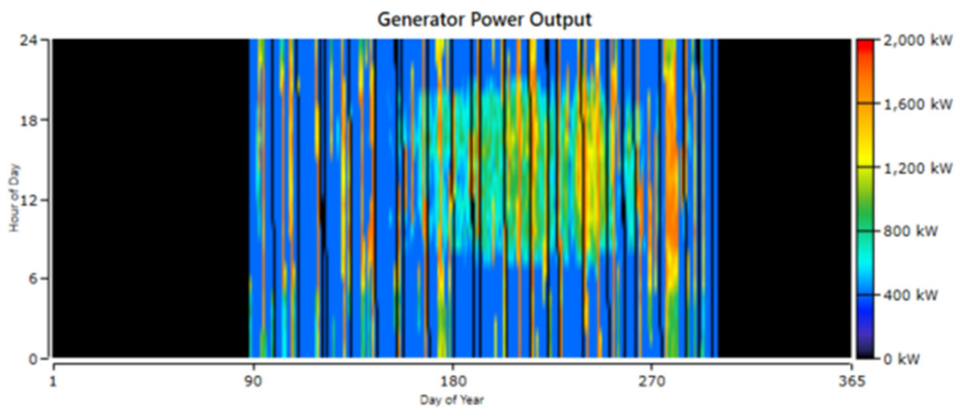

Figure 3: Generation Profile For T4F Unit C With Unscheduled, 4-Month "Overhaul", And Bimonthly Maintenance

Figure 1 shows the T4F unit that is not scheduled to receive any major maintenance events in the represented year. The black lines in the graph represent regular maintenance activities and the unplanned outages inputted to the model. Figure 2 represents the unit undergoing the biannual 5-day maintenance in addition to the regular and unplanned maintenance activities. The 5-day event is represented by the thicker black line shortly after the 270th day timestamp on the horizontal axis. Figure 3 shows the unit undergoing the 4-month-long maintenance event, scheduled during the black boxes in the figure. Figure 4 shows the total capacity of the system overlaying the annual loading. It is clear that this configuration does successfully meet the required loading. In moments where demand still exceeds capacity there is enough charge on the batteries to support the system. It is also noted that unplanned maintenance activities in this model are treated as static events. In real-world operation they will be dynamic and unpredictable in nature.

Configuration B

The analysis of this model shows that Configuration B is infeasible in all conditions. In previous iterations of the model, the propane reciprocating engines was constrained to a minimum load of 25%. Discussions with the vendor led to a revision of this assumption as they advised to set minimum loading to 75%. When updated to 75%, there was no amount of propane supply that would result in a successful run of the configuration. Therefore, Configuration B with the 75% constraint on the RPE leading would result in outages because demand could not be successfully met. It has been shown that a 65% reduction in load would result in a successful run of the configuration. Figure 5 shows an overlay of the Configuration B's demand and generation profiles.

Figure 5 shows the total capacity of the system overlaying the annual loading. For about a third of the year, the system is unable to meet the required demand. This time period corresponds to the 4-month-long maintenance activity modeled on Unit C. Within the time period, the constraints of minimum loading, along with planned and unplanned maintenance, make it impossible for the backup diesel generators and the RPE to support the remaining single T4F unit in carrying the required load. Additionally, the durations of deficiency are so long that the battery is unable to provide support for the entirety of the period and island customers will experience frequent events when they will be without electricity.

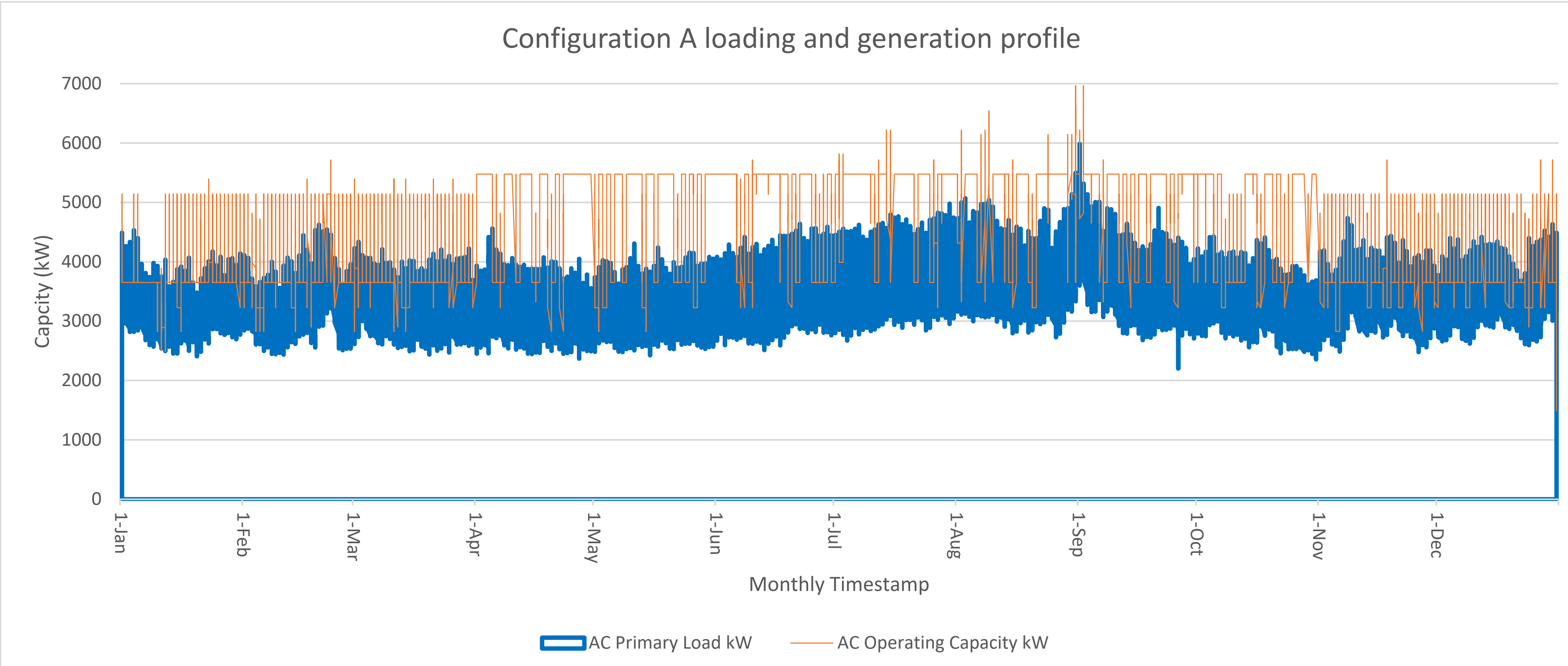

Figure 4: Configuration A Annual Loading And Capacity

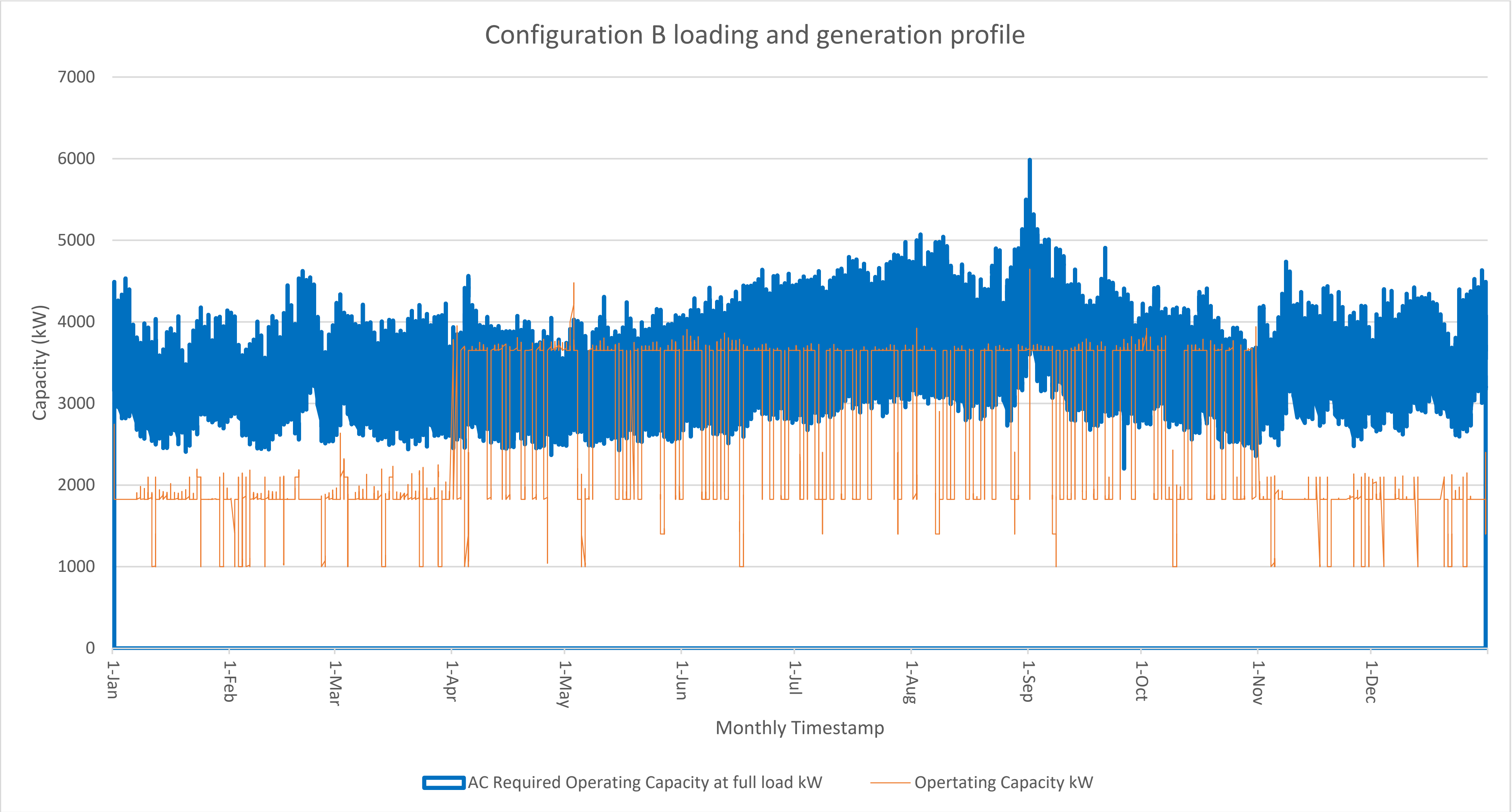

Figure 5: Configuration B Annual Loading And Capacity

D – Propane Availability Analysis

DocuSign Envelope ID: 6CB43FD3-1188-49C7-BF74-C33ECA6EB547

Metric	Description of Propane Metrics	Value			Units	Notes
n	Number of Tanks (n)	2	3	4	Unitless	
S_{Nn}	Nominal Storage Time with n Tanks	10	10	10	Days	*Nominally at least 33.3% of 30 Day Goal with Less Storage (and Risk) when at least 1 Tank Undergoes Maintenance*
S_{Sn}	Summer Storage Time with n Tanks	10	10	10	Days	*Nominally at least 33.3% of 30 Day Goal with Less Storage (and Risk) when at least 1 Tank Undergoes Maintenance*
C	Single Tank Rated Capacity	30,000	30,000	30,000	Gallons	*Actual Physical Volume*
C_n	Total Rated Capacity of Tank System ($C_N = C$ * n)	60,000	90,000	120,000	Gallons	*Actual Physical Volume*
C_{Tn}	Theoretical Maximum Capacity of Tank System ($C_{Tn} = C_n$ * 86%)	51,600	77,400	103,200	Gallons	*Based on MEOP and MAWP*
V_{NMn}	Nominal Maximum Fill Volume of Tank System ($V_{NMn} = C_n$ * 67%)	40,200	60,300	80,400	Gallons	*Based on Mean Historical Tank Levels*
V_{Sn}	Summer Maximum Fill Volume of Tank System ($V_{Sn} = C_n$ * 47%)	28,200	42,300	56,400	Gallons	*Based on Tank P During Heat Events at PBGS*
V_{Ln}	Minimum Volume for Tank System ($V_{Ln} = C_n$ * 25%)	15,000	22,500	30,000	Gallons	*Based on Minimum Tank Level to Support Gas and Electricity Service (Vapor/Liquid)*
V_{NUn}	Nominal Usable Volume of Tank System ($V_{NUn} = V_{NMn} - V_{Ln}$)	25,200	37,800	50,400	Gallons	
V_{SUn}	Summer Usable Volume of Tank System ($V_{SUn} = V_{Sn} - V_{Ln}$)	13,200	19,800	26,400	Gallons	
R_{AUS}	Annual Utility Service Consumption	650,000	650,000	650,000	Gallons per Year	*Fixed Assumption*
R_{DUS}	Average Daily Utility Service Consumption ($R_{DUS} = R_{AUS}$ / 365 Days)	1,781	1,781	1,781	Gallons per Day	
$R_{MDFCNSn}$	Maximum Daily Facility Consumption During Nominal Storage ($R_{MDFCNSn} = V_{NUn} / S_{Nn}$)	2,520	3,780	5,040	Gallons per Day	
$R_{MDECNSn}$	Maximum Daily Electricity Generating Technology Consumption During Nominal Storage ($R_{MDECNSn} = R_{MDFCNSn} - R_{DUS}$)	739	1,999	3,259	Gallons per Day	
R_{6ECNSn}	Maximum 6 Month Projected Electricity Generating Technology Consumption During Nominal Storage ($R_{6ECNSn} = R_{MDECNSn}$ * 365 Days/yr * 0.5 years)	134,900	364,850	594,800	Gallons per 6 Month Period	
$R_{MDFCSSn}$	Maximum Daily Facility Consumption During Summer Storage ($R_{MDFCSSn} = V_{SUn} / S_{Sn}$)	1,320	1,980	2,640	Gallons per Day	*Less propane reserves due to heat expansion in summer*
$R_{MDECSSn}$	Maximum Daily Projected Electricity Generating Technology Consumption During Summer ($R_{MDECSSn} = R_{MDFCSSn} - R_{DUS}$)	(461)	199	859	Gallons per Day	
R_{6ECSSn}	Maximum 6 Month Projected Electricity Generating Technology Consumption During Summer ($R_{6ECSSn} = R_{MDECSSn}$ * 365 Days/yr * 0.5 years)	(84,100)	36,350	156,800	Gallons per 6 Month Period	
$R_{MAEGTCn}$	Maximum Annual Electricity Generating Technology Consumption ($R_{MAEGTCn} = R_{6ECNSn} + R_{6ECSSn}$)	50,800	**401,200**	751,600	Gallons per Year	

E – Quinn Power Email Communication

Trevor S Krasowsky

From: Steven Rodriguez <Steven.Rodriguez@quinnpower.com>
Sent: Wednesday, April 26, 2023 11:55 AM
To: Trevor S Krasowsky
Subject: RE: (External):RE: (External):RE: 4 MW

Hello Trevor,

Thanks for the call just now. We used 75% because of the derate (from 4MW down to 2MW). Generally this derate, and operating on a higher energy value like propane, changes the inlet manifold pressures and other combustion characteristics such that operating below this value may have some undesirable consequences (lean misfire, etc.). I'll look into this with CAT and see if there is a better answer.

Thank you,

Steven Rodriguez
Sales Engineer
Quinn Power Systems
Cell: 559-904-3123
steven.rodriguez@quinnpower.com

From: Trevor S Krasowsky <TREVOR.KRASOWSKY@SCE.COM>
Sent: Monday, April 24, 2023 10:41 AM
To: Steven Rodriguez <Steven.Rodriguez@quinnpower.com>
Cc: Joy Brooks <joy.s.brooks@sce.com>; Matthew Zents <Matthew.Zents@sce.com>; Bethmarie Quiambao <Bethmarie.Quiambao@SCE.com>; Casey Scott <Casey.Scott@sce.com>; John Martin <john.martin@sce.com>; Ronald Hite <Ronald.Hite@sce.com>; Anthony Hernandez <Anthony.Hernandez@sce.com>; Mouw, Chris <chris.mouw@powereng.com>; josef.provatakis@powereng.com; Anthony Hernandez <Anthony.Hernandez@sce.com>
Subject: [External] RE: (External):RE: (External):RE: 4 MW
Importance: High

Hi Steven,

I hope you are well. We are working on finalizing a feasibility report for the District over the next few days (which is time-sensitive), and a question came up.

Can you please elaborate on the minimum operating load of 75% (1573 kW) for CG260-16? What is the driving the minimum? Is it related to SCR control efficiency?

Thank you,
Trevor

Trevor Krasowsky, PhD
Consultant, Air Quality
Operational Excellence| Environmental Services
M: 949-324-2678

2244 Walnut Grove Ave, Rosemead, CA 91770

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(He | Him| His pronouns*)

From: Steven Rodriguez <Steven.Rodriguez@quinnpower.com>
Sent: Thursday, March 23, 2023 3:56 PM
To: Trevor S Krasowsky <TREVOR.KRASOWSKY@SCE.COM>
Cc: Joy Brooks <joy.s.brooks@sce.com>; Matthew Zents <Matthew.Zents@sce.com>; Bethmarie Quiambao <Bethmarie.Quiambao@SCE.com>; Casey Scott <Casey.Scott@sce.com>; John Martin <john.martin@sce.com>; Ronald Hite <Ronald.Hite@sce.com>; Anthony Hernandez <Anthony.Hernandez@sce.com>
Subject: (External):RE: (External):RE: 4 MW

Hello Trevor,

I have been down this road with the factory before and mixing the propane with air does not provide a higher rating. I am happy to talk about it in more detail if you want to schedule a meeting for next week.

I do want to note that the data sheet has us at 2097kW at full load, 1573kW is the minimum operating load.

Thank you,

Steven Rodriguez
Sales Engineer
Quinn Power Systems
Cell: 559-904-3123
steven.rodriguez@quinnpower.com

CENTURY STRONG QUINN 100

From: Trevor S Krasowsky <TREVOR.KRASOWSKY@SCE.COM>
Sent: Thursday, March 23, 2023 10:28 AM
To: Steven Rodriguez <Steven.Rodriguez@quinnpower.com>
Cc: Joy Brooks <joy.s.brooks@sce.com>; Matthew Zents <Matthew.Zents@sce.com>; Bethmarie Quiambao <Bethmarie.Quiambao@SCE.com>; Casey Scott <Casey.Scott@sce.com>; John Martin <john.martin@sce.com>; Ronald

Hite <Ronald.Hite@sce.com>; Anthony Hernandez <Anthony.Hernandez@sce.com>
Subject: [External] RE: (External):RE: 4 MW

From: prvs=24464d5beb=trevor.krasowsky@sce.com - unless you were expecting something from this email - do not reply, click links or open attachments

Hi Steven,

I hope you are well. South Coast AQMD has inquired about the de-rating of the 4 MW CG260-16 unit to 1.573 MW on pure propane. They are specifically asking whether it would be feasible to convert the fuel supply to be a vaporized air/propane mixture to reduce the impact of de-rating.

I would like to arrange a meeting to discuss the following:

1) Whether Quinn could support upgrades to the system;
2) How much this would impact the prime rating;
3) Initial thoughts on the timeline impact of construction/installation.

Can you please let me know your availability next Thursday and Friday morning?

Thank you,
Trevor

Trevor Krasowsky, PhD
Consultant, Air Quality
Operational Excellence| Environmental Services
M: 949-324-2678

2244 Walnut Grove Ave, Rosemead, CA 91770

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(He | Him| His pronouns*)

From: Trevor S Krasowsky
Sent: Wednesday, December 21, 2022 1:08 PM
To: Steven Rodriguez <Steven.Rodriguez@quinnpower.com>
Cc: Joy Brooks <joy.s.brooks@sce.com>; Matthew Zents <Matthew.Zents@sce.com>; Bethmarie Quiambao <Bethmarie.Quiambao@SCE.com>; Casey Scott <Casey.Scott@sce.com>
Subject: RE: (External):RE: 4 MW

Hi Steven,

Thank you for the quick turnaround. This is helpful. (It would be outdoors – not in a building.)

While we are on the topic, I have 7.2' by 25.2' for the 2 MW unit (C3520H). Can you please confirm the estimated size when equipped with the aftermarket SCR?

Much appreciated,
Trevor

Trevor Krasowsky, PhD EnvE
Consultant, Air Quality
Operational Services | Environmental Services
M: 949-324-2678

2244 Walnut Grove Ave, Rosemead, CA 91770

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(He | Him| His pronouns*)

From: Steven Rodriguez <Steven.Rodriguez@quinnpower.com>
Sent: Wednesday, December 21, 2022 12:59 PM
To: Trevor S Krasowsky <TREVOR.KRASOWSKY@SCE.COM>
Cc: Joy Brooks <joy.s.brooks@sce.com>; Matthew Zents <Matthew.Zents@sce.com>; Bethmarie Quiambao <Bethmarie.Quiambao@SCE.com>; Casey Scott <Casey.Scott@sce.com>
Subject: (External):RE: 4 MW

Hello Trevor,

Attached is a preliminary drawing of an enclosed package, estimated size of that is closer to 15' x 55'

However if you are putting it in a building the generator itself is smaller. You can find a CAD file of it at the link below and a version attached here.

https://1drv.ms/u/s!AqcsC2L2gfNdg7xyKueJznlCTHdZsA?e=yuYoKy

Thank you,

Steven Rodriguez
Sales Engineer
Quinn Power Systems
Cell: 559-904-3123
steven.rodriguez@quinnpower.com

CENTURY STRONG QUINN 100

From: Trevor S Krasowsky <TREVOR.KRASOWSKY@SCE.COM>
Sent: Monday, December 19, 2022 11:09 AM

To: Steven Rodriguez <Steven.Rodriguez@quinnpower.com>
Cc: Joy Brooks <joy.s.brooks@sce.com>; Matthew Zents <Matthew.Zents@sce.com>; Bethmarie Quiambao <Bethmarie.Quiambao@SCE.com>; Casey Scott <Casey.Scott@sce.com>
Subject: [External] 4 MW

From: prvs=93529b4daa=trevor.krasowsky@sce.com - unless you were expecting something from this email - do not reply, click links or open attachments

Hi Steven,

As I understand it, the 4 MW propane generator (de-rated to 2097 kW) is roughly 32' x 10'. Can you confirm the size with the aftermarket SCR system?

Can you please provide the actual drawing of the CG260-16?

Thank you,
Trevor

Trevor Krasowsky, PhD EnvE
Consultant, Air Quality
Operational Services | Environmental Services
M: 949-324-2678

2244 Walnut Grove Ave, Rosemead, CA 91770

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F – Wartsila Dual Fuel Generators at Virgin Island Water and Power Authority

DEPARTMENT OF PLANNING AND NATURAL RESOURCES

AIR POLLUTION CONTROL PROGRAM
AUTHORITY TO CONSTRUCT PERMIT

Virgin Islands Water and Power Authority-St. Thomas

EFFECTIVE DATE: January 31, 2018
EXPIRATION DATE: January 31, 2019

PERMIT NUMBER: STT-909-AC-18

THE PERMITTEE IS SUBJECT TO ALL TERMS, CONDITIONS, LIMITATIONS, AND STANDARDS CONTAINED HEREIN. THE CONDITIONS IN THIS PERMIT ARE FEDERALLY ENFORCEABLE AND STATE ENFORCEABLE.

Signed

Director

1/31/18
Date

SECTION 1: FACILITY INFORMATION

PERMITTEE:	Virgin Islands Water and Power Authority
SIC CODE:	4911
PERMIT NUMBER:	STT-901-AC-18
FACILITY ADDRESS:	Randolph Harley Generating Facility Krum Bay, St. Thomas VI 00804
MAILING ADDRESS:	P.O. Box 1450 Charlotte Amalie St. Thomas, VI 00804
ISLAND:	ST. Thomas
RESPONSIBLE OFFICIAL:	Gregory Rhymer Chief Operating Officer (340) 774-3552 ext.2010
FACILITY CONTACT:	Maxwell George Manager, Environmental Affairs (340) 774-3552 ext. 2274

PROJECT SUMMARY

Virgin Island Water and Power Authority is proposing to install four (4) new Wartsila Diesel Reciprocating Internal Combustion Engines (RICE), with dual fuel firing, model number 20V32LG. Each has a generator capacity of 9 MW. This system burns high pressure LPG and less than 5 % ultra-low sulfur pilot fuel.

Wartsila will use Selective Catalytic Reduction (SCR) to minimize NOx emissions from the diesel engines. The SCR can achieve efficiency up to 95%. In addition, a Regenerative Thermal Oxidizer (RTO) burning will be used on each engine to destroy at least 98% of the Volatile Organic Compounds VOCs and 75% of Carbon Monoxide (CO) in the exhaust.

Based on the information submitted in the application and any supporting documents, VIWAPA is subject to the following regulations:

SECTION II: REGULATORY REQUIREMENTS

Table 1 – Applicable Regulations

Virgin Islands Air Pollution Control Act, Rules and Regulations: Title 12, Chapter 9
New Source Performance Standards (NSPS) Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60 Subpart IIII
National Emission Standards for Hazardous Air Pollutants for Stationary RICE (NESHAP) 40 CFR 63 ZZZZ

SECTION III: SPECIFIC CONDITIONS FOR FOUR WARTSILA RICEs

A. OPERATING REQUIREMENTS

1. VIWAPA shall meet the requirement of 40 CFR 60 subpart IIII for the four Wartsila RICEs.

2. VIWAPA shall meet the requirement of 40 CFR 63 subpart ZZZZ for the four Wartsila RICEs.

3. VIWAPA shall install and maintained all units according to manufacturer specification.

4. The four Wartsila RICEs shall be constructed to only combust LPG.

5. VIWAPA shall meet NOx limit by installing and maintaining SCR control.

6. VIWAPA shall install and maintain a RTO on the four Wartsila and spark ignition engines (previously permitted) to ensure compliance with Volatile Organic Compound (VOC) and Carbon Monoxide (CO) requirements under the NSPS- Subpart IIII and JJJJ for the new RICE.

7. To ensure efficiency, the SCR and RTO shall be installed and maintained according to manufacture specification.

8. No additional significant physical change or change in the method of operation shall be made without a PSD applicability review and EPA approval.

9. VIWAPA shall be limited to combust a maximum of 74, 080 Mgallons (1000 gallons) of LPG on a rolling 12-month basis.

10. Sulfur content, by weight, of fuels shall not exceed as follows: LPG- 0.0175%, LNG- 1.2 grains/100 SCF and no. 2 fuel oil- 0.15%. Nitrogen content of fuel oil no. 2 shall not exceed 150 ppm by weight.

11. All other monitoring and measuring requirements of the PSD permits and the Title V permits will continue to apply while burning fuel oil.

12. When water injection is not operating on any turbine and its CEM is inoperative, the NOx and CO emission factors listed in the Emission Factor (EF) Table shall be used to calculate emissions. Note that the use of emission factors to determine compliance with the annual emission limits when water injection system is inoperative is not an approved alternative to the requirements to have and properly operate the water injection system.

13. VIWAPA shall operate LPG, LNG or fuel oil tanks and associated systems according to manufacturers' recommendations and best management practices. All fuel receipts and distribution related records shall be maintained onsite for 5 years. A one-time testing or verification of emissions factors by the methods approved by the permitting authority shall be required.

14. No additional significant physical changes or changes in method of operations shall be made without NSR review and approval from the permitting authorities.

15. VIWAPA shall comply with the following annual emission limits on a rolling 12-month basis:

Table 2 Proposed Annual Facility-Wide Emission Limits

Pollutant (Combustion Turbines)	Proposed Annual Emission Limit
Nitrogen Oxides (NOx)	504.5 tons / 12 months
Sulfur Dioxide (SO2)	332.1 tons / 12 months
Carbon Monoxide (CO)	360.3 tons / 12 months
Volatile Organic Compounds (VOC)	25.3 tons/months
Particulate Matter ($PM/PM_{10}/(PM_{2.5})$	99 tons / 12 months
Greenhouse Gases (GHG) as CO2e	507, 781 tons / 12 months

16. VIWAPA shall calculate turbine actual emissions by multiplying actual fuel use with the following emission factors on weekly basis. If any fuel oil with nitrogen or sulfur content

higher than permitted above is combusted, the NOx and $S0_2$ emission factors shall be revised upwards to calculate actual emissions.

Table 3 Combustion Turbine and RICE LPG Emission Factors

	Combustion Turbine- LPG Tons/1000 gallons	SI RICE Tons/1000 gallons	Diesel RICE Tons/1000 Gallons (Mgal)
NOx	0.007320 (when CEMs not operating)	0.002491 (when CEMs not operating)	0.006810 (when CEMS not operating)
NOx	0.02662 (when water injection and CEMs are not operational)	-	0.1362 (when no SCR and CEMS not operating)
CO	0.0006863 when CEMs not operating	0.01384 (when CEMS not operating)	0.003555 (when CEMS not operating)
CO	-	0.02380 (when no RTO and CEMS not operating)	0.01422 (when no RTO and CEMS not
VOC	0.00009608	0.0004428	0.0006543
VOC	-	0.02188 (when no RTO)	0.032175 (when no RTO)
$PM\text{-}PM_{10}$ and $_{2.5}$	0.0003020	0.0008994	0.001896
SO_2	0.0007526	0.0007526	0.0007526
$C0_{2e}$	6.2115	6.2115	6.2115

Table 4 Combustion Engine Fuel Oil Emission Factors Ton/1000 gal (Mgal)

	Combustion Turbines-14 Tons/1000 gallons	Combustion Turbines-15 Tons/1000 gallons	Combustion Turbines-18 Tons/1000 gallons	Combustion Turbines-23 Tons/1000 gallons	Combustion Turbines-22, 25 and New TM 2500 + Tons/1000 gallons
NOx	0.0612	0.0147 when CEMs inoperative	0.0112 when CEMs inoperative	0.0114 when CEMs inoperative	0.0112 when CEMs inoperative
NOx	N/A	0.021 when CEMs & water injection inoperative	0.016 when CEMs & water injection inoperative	0.016 when CEMs & water injection inoperative	0.016 when CEMs & water injection inoperative
CO	0.000231	0.00277 when CEMs inoperative	0.0112 when CEMs inoperative	0.0117 when CEMs inoperative	0.00288 when CEMs inoperative
VOC	0.0000287	0.000425	0.000428	0.00217	0.000151
$PM\text{-}PM_{10}$ and $_{2.5}$	0.000840	0.00107	0.00102	0.00444	0.000776
SO_2	0.00924	0.00925	0.00925	0.00925	0.00924
CO_{2e}	11.45	11.45	11.45	11.45	11.45

B. MONITORING REQUIREMENTS

1. A fuel flow meter shall be installed and used to determine LPG for the Wartsila RICEs.

2. For the purpose of determining compliance with the PSD non-applicability annual emission limits, VIWAPA shall use fuel use data, emission factors in the Emissions Factor (EF) Tables, and CEMs data where applicable, to calculate emissions on a daily basis. Whenever a CEM is not operating, NOx and CO emission factors as listed in the EF Tables shall be used to calculate actual emissions. Note that the use of emission factors to determine compliance with the annual emission limits when a CEM is not working is not an approved alternative to the requirements to have and properly operate CEMs.

3. VIWAPA shall demonstrate compliance with these sulfur and nitrogen weight content limits by maintaining the fuel supplier's certifications for each delivery. VIWAPA shall ensure that all fuels received at the plant meet sulfur and nitrogen content limits.

C. NOTIFICATION AND RECORDKEEPING REQUIREMENTS

1. VIWAPA shall submit a written notification of the date of commencement of construction for the Wartsila RICEs. The notifications shall be postmarked no later than 30 days after such time.

2. VIWAPA shall maintain the fuel supplier certification for each delivery as the means to demonstrate compliance with the sulfur and nitrogen concentration weight limits.

3. All fuel certificates and daily records of fuel use shall be maintained on site for five years.

D. REPORTING REQUIREMENTS

VIWAPA shall report all upsets/malfunctions of units by telephone within 24 hours to DPNR-DEP. A follow-up letter describing the incident, the amount of down time and the corresponding action taken must be submitted within 5 calendar days to DPNR-DEP and to the Director, Caribbean Environmental Protection Division, EPA, Region 2 Office.

E. TESTING REQUIREMENTS

1. VIWAPA will determine the emission factors for the four Wartsila RICEs through stack testing.
2. VIWAPA shall obtain approval of all performance test protocols prior to conducting any performance test. The protocol shall be submitted to EPA and VIDPNR-DEP no later than 120 days before the test for review and approval.
3. VIWAPA shall submit copies of the performance test report no later than 60 days after completion of the performance test.

4. As part of the initial test program, VIWAPA shall conduct a one-time testing or verification of the emission factors. The test methods for verification shall be identified and approved as part of the test protocol.

IV: FACILITY WIDE CONDITIONS

1. This Authority to Construct shall be valid for a period of a year beginning on the date this permit becomes effective and ending one (1) year later.

2. Each Authority to Construct Permit shall automatically become invalid one (1) year after the date of its issuance, unless the construction or modification has commenced or application for extension, in the form of a letter to the Commissioner, is made thirty (30) days prior to the expiration date of the permit. The permit may only be extended for one (1) additional year later.

3. Any revisions to the conditions upon which an Authority to Construct Permit has been granted must be approved by the Commissioner prior to submission of an application for a Permit to Operate.

4. In the case that this Permit is subject to any challenge by third parties, the effectiveness of the Permit stands until any judicial court decides the contrary.

5. Failure of the Commissioner to act on a permit application shall not be deemed issuance by default.

6. Where an applicable requirement of the Clean Air Act, as amended 42 USC 7401 (Act), is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, the permit incorporates both provisions into the permit and the Commissioner or the Administrator will enforce the most stringent.

7. VIWAPA must construct and/or install the equipment, control apparatus and emission monitoring equipment within the design limitations. VIWAPA shall maintain all equipment in proper working condition at all times.

8. VIWAPA shall not cause or permit any materials to be handled, transported, or stored in a building, its appurtenances, or cause a road to be used, constructed, altered, repaired or demolished without taking the necessary precautions to prevent particulate matter from becoming airborne [V.I.R.R. Title 12, Ch.9, § 204-25(a)(1) through (9)]

9. VIWAPA shall not cause or permit the discharge of quantities of air contaminants or other material which cause injury, detriment, nuisance, annoyance to person or to the public or which endanger the comfort, repose, health, or safety of any such persons or the public or which cause or have tendency to cause injury or

damage to business or property. [V.I.R.R. Title 12, Ch.9, § 204- 27(a)]

10. The Commissioner may require other reasonable measures as may be necessary to prevent particulate matter from becoming airborne.

11. VIWAPA shall not cause or permit the discharge of visible emissions of fugitive dust beyond the boundary line of the property on which their emissions originate.

12. VIWAPA must maintain the following records of monitoring information as required by this permit:
    a. The date, location and time of sampling or measurements
    b. The date(s) analyses performed
    c. The company or entity performing the analyses
    d. The analytical techniques or methods used
    e. The result of such analyses
    f. The facility's status at the time of sampling or measurements.

13. VIWAPA must retain the records of all required monitoring data and support information for at least five (5) years from the date of the monitoring sample, measurement, report or application. Support information includes all calibration and maintenance records and all chart/data recordings for continuous monitoring instrumentation and copies of all reports required by this permit.

14. VIWAPA shall submit all testing reports required under this permit to EPA and DPNR official addressed below:

    Chief
    Multi-Media Permits and Compliance Branch
    Caribbean Environmental Protection Division, USEPA Region 2
    City View Plaza II
    #48 Rd 165, km 1.2, STE 7000
    Guaynabo, PR 00968-8069

    And

    Director
    Division of Environmental Protection
    Department of Planning and Natural Resources
    8100 Lindberg Bay, Suite # 61
    Cyril E King Airport
    St. Thomas USVI 00802

15. VIWAPA shall report any deviation that poses an imminent and substantial

danger to public health, safety, or the environment, or results in the increase of emissions within 24 hours of the deviation. The VIWAPA shall also submit within 7 days a written report which shall contain the probable cause of the deviation(s), duration of the deviation(s), and may corrective actions or preventive measures taken. [V.I.R.R. Title 12, Ch.9, § 206-71 (a)(5)(B)(ii)]

V: GENERAL PROVISIONS

1. This Authority to Construct Permit is not a Permit to Operate. This is a permit to construct only.

2. The VIWAPA must comply with all conditions of this Authority to Construct Permit. Any permit noncompliance constitutes a violation and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

3. All terms and conditions contained herein shall be enforceable by the EPA and citizens of the United States under the Clean Air Act, as amended , 42 U.S.C. 7401, et seq.

4. Nothing in this Permit shall alter or affect the authority of the EPA to obtain information pursuant to 42 U.S.C. 7414, "Inspections, Monitoring, and Entry".

5. VIWAPA shall not claim as a defense in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

6. The Department may modify, revoke, reopen and reissue the permit or terminate the permit for cause. The filing of a request by the source for a permit modification, revocation and reissuance, or termination or the filing of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

7. This permit does not convey any property rights of any sort, or any exclusive privilege.

8. Issuance of this Permit does not relieve VIWAPA from the responsibility of obtaining and complying with any other permits, licenses, or approvals required by the Department or any other federal, territorial, or local agency.

9. Nothing in this Permit shall alter or affect the liability of VIWAPA for any violation of applicable requirements prior to or at the time of Permit issuance.

10. Any condition or portion of this Permit which is challenged becomes suspended

or is ruled invalid as a result of any legal or other action shall not invalidate any other portion or condition of this Permit.

11. Compliance with the terms of this Permit shall be deemed compliance with all applicable requirements as of the date of Permit issuance provided that all applicable requirements are included and specifically identified in the Permit.

12. The Department shall allow certain defined changes at permitted facilities that contravene permit terms or conditions or make them inapplicable without requiring a permit revision. Such changes may not include changes that violate applicable requirements or contravene permit terms and conditions that are monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements.

13. If, after notification as described in Condition 12 above, the Department deems that the change implemented by the source does not qualify under V.I.R.R. Title 12, Ch.9, § 206-65(b), the original terms of the permit remain fully enforceable.

14. Provisions for operational flexibility do not preclude a source's obligation to comply with all applicable requirements.

15. Any application forms, all reports, or compliance certifications submitted pursuant to this Permit shall contain a certification of truth, accuracy and completeness signed by a responsible official of the facility. Any certification submitted by the facility shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

16. Information contained in permit applications shall be public except that which is confidential in accordance with the Virgin Islands Air Pollution Control Act. The contents of the Permit itself are not entitled to confidentiality. [V.I.R.R. Title 12, Ch.9, § 206-62(d)]

17. VIWAPA must allow any authorized representatives of the Department, upon presentation of credentials, to perform the following:

    a. Enter upon VIWAPA 's premises where the permitted source is located, or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

    b. Have access to and copy, at reasonable times, any records required under the conditions of this Permit;

    c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this Permit; and

d. As authorized by the Act, sample or monitor at reasonable times substances or parameters for assuring compliance with this Permit or applicable requirements.

18. VIWAPA shall furnish to the Division, in writing, information that the Division may request to determine whether cause exists for modifying, revoking and reissuing, or terminating the Permit, or to determine compliance with the Permit.

19. VIWAPA shall report to the Commissioner, in writing, within thirty days of the permanent discontinuance or dismantlement of fuel burning, combustion or process equipment or device coming under the jurisdiction of this Permit.

20. A person who has been granted a permit under the provisions of V.I.R.R. Title 12, Ch.9, § 206-20(a) (1995), shall firmly affix such Authority to Construct Permit, an approved facsimile, or other approved identification bearing the permit number upon the article, machine, equipment, or other contrivance in such a manner as to be clearly visible and accessible. In the event that the article, machine, equipment, or other contrivance is constructed or operated in such a manner that the Authority to Construct Permit cannot be so placed, the permit should be maintained so as to be readily available at all times on the premises.

21. The Permittee is required to be in compliance with V.I.R.R. Title 12, Ch.9, § 206.26 (1995).

September 30, 2022

SOUTHERN CALIFORNIA EDISON

Pebbly Beach Generating Station

System Stability Study

PROJECT NUMBER:
176291

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POWER ENGINEERS

SOUTHERN CALIFORNIA EDISON

SYSTEM STABILITY STUDY

PREPARED FOR:

SOUTHERN CALIFORNIA EDISON

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EXECUTIVE SUMMARY

Pebbly Beach Generation Station (PBGS) on Catalina Island, California presently experiences power quality issues specifically with the island frequency. Large load step changes and/or faults can cause the island microturbines (MTs) and the battery energy storage system (BESS) to trip offline on frequency-related protection settings. This type of realistic cascading event can lead to under frequency load shedding (UFLS) on the island. UFLS is a protection scheme that removes feeder load based on a reduction in the grid frequency typically from power generation shortage.

POWER Engineers, Inc. (POWER) was retained by Southern California Edison (SCE) to assist in a system stability analysis of the existing system configuration at PBGS, pursuant to an abatement order issued by the SCAQMD. The driving theory for this work was that frequency stability on the island could be maintained if less than 30% of the load was served by MTs on a minute-by-minute basis. The study's goal is to determine the maximum currently feasible inverter-based electrical generation level for the present state/configuration of PBGS, while maintaining reliable electrical service (e.g., without compromising grid stability). The present state of PBGS consists of six (6) diesel generators (including Unit 15, which is the focus of the Abatement Order), a BESS, and twenty-three (23) MTs. In the current configuration, all inverter-based generation is derived from the MTs. A model of PBGS was built specifically for this study in PSCAD™ which is a common industry accepted modeling platform for detailed transient power systems electromagnetic transients (EMT) simulations. While SCE is reviewing broader options for the integration of more inverter-based electrical generation on the island system while maintaining island grid stability, the focus of this study is on the present state of PBGS as an effort to provide immediate and useful information to guide next steps.

There is a significant point to make regarding the origins and purpose of this study. It was originally thought that the amount of MT generation on the system is what would lead to system instability. This study reveals information disproving this initial thinking. In summary, it is <u>not</u> the extra MT generation that leads to system instability but rather the reduction in diesel generation usage. The reduction in system inertia, which is presently only provided by the diesel generators, is the real driving factor that can lead to system instability. The study supports this conclusion and provides useful information for improved system studies and future planning for evaluating different electricity generating mixes including various inverter-based technologies.

Below are the key findings:

- The MTs were found to nuisance trip on Rate-of-Change-of-Frequency (RoCoF), which is a protection setting designed to detect and mitigate unintentional electrical tripping. This tripping is described as 'nuisance' since it should instead be riding through the type of short-lived frequency deviations occurring on Catalina. Nuisance tripping can potentially lead to a cascading loss to the system as the MT fleet trips offline, overloading and tripping the diesel generator fleet resulting in an island blackout. To avoid a cascading loss to the system, PBGS has adopted an operational rule of thumb to maintain the output of the MT generation to less than 30% of the total generation output. However, the results of this study demonstrate this rule of thumb does not fully encapsulate the minute-by-minute maximum allowable inverter-based electricity (i.e., currently produced via the MTs, only, at PBGS) generation for all operational situations encountered at the facility. Having discussed this issue with the manufacturer, it is noted that the MTs rely on external system inertia to mitigate this issue.

- Grid frequency stability is not linked to the amount of MT generation. Rather, it is linked to the amount of inertia on the system, which is presently produced solely through diesel generators. Having more diesel generators online improves grid frequency regulation given that diesel generators add inertia to the grid. When the MTs are operational, less power is produced by the diesel generators leading to a reduction in system inertia and thus reduced frequency stability.

- The study investigated the benefits associated with upgrading the MTs to allow for improved controls for grid support. This upgrade was found to not improve grid frequency stability and should not be considered as viable option for reducing the reliance on Unit 15 (i.e., or a method to mitigate emissions from Unit 15).

- For present implementation, it is recommended that the power generated from the MTs and the BESS at any given point in time should not exceed the spinning reserves available from the online diesel generator. This is to reduce the risk of UFLS events from cascading losses of the MTs and the BESS.

- SCE is currently testing a novel catalyst that will potentially reduce the diesel particulate matter (DPM) emissions from Unit 15 to comply with the Rule 1470 emission limit (0.01 g PM/bhp-hr). If the catalyst does not work, SCE will replace Unit 15 with a Tier 4 Final-Certified diesel generator that would comply with Rule 1470. The Tier 4 Final-Certified engine would be capable of operating at lower loads than Unit 15; however, the increased operational range will not necessarily solve the issue of grid inertia or allow for a greater reliance on MT electricity generation due to their current physical state and capacity.

- Propane reciprocating generator(s) are being considered as a replacement for the existing MTs. The study finds:

  - Elimination of the MTs removes the issue of the MTs nuisance tripping on frequency instability.

  - When considering installation of a propane reciprocating generator at PBGS, the change to grid stability is dependent on the source of electricity generation [i.e., the unit(s) or technology] that is being replaced. Replacing the MTs with a propane reciprocating generator would lead to an improvement in grid stability given the MTs provide no grid inertia; however, if Unit 15, a diesel generator, was replaced by a propane reciprocating generator, then grid stability would be reduced. Even though propane reciprocating generators may provide similar (or slightly less) grid inertia, the lower energy density of the fuel reduces their effectiveness in responding to fast load fluctuations.

In addition to these findings, potential options to reduce the reliance on Unit 15 (thereby mitigating PM emissions) over the longer term are briefly discussed within this report. Per the findings of this report, mitigation options, which add inertia or fast-frequency response to the system would be the most likely candidates for further study. The flywheel and synchronous condensers offer more promise over the fuel cell or linear generator options.

STUDY APPROACH

Background

PBGS's electricity generation portfolio includes inverter-based MTs [i.e., consisting of twenty-two (22) 65 kW units and one (1) 60 kW unit, for a total of 1.49 MW]. Standard operating procedures have been to limit the percentage of MT generation from PBGS to less than 30% of the overall plant output at any moment in time. The MTs employ one (1) Hz-per-second RoCoF protection relays for the purpose of detecting "islanding events". The term "islanding event" refers to an instance when a distributed generation resource continues to operate even though it has become disconnected from the larger grid. These events can lead to abnormal frequencies and voltages unless strict controls, such as the RoCoF relays, are present. For this reason, the microturbine manufacturer states that the relays cannot be removed without violating requirements as described in the Institute of Electrical and Electronics Engineers (IEEE) standard for Interconnecting Distributed Resources with Electric Power Systems (IEEE 1547) and the UL standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources (UL-1741). These relays are subject to nuisance tripping during non-islanding events such as large load step changes and short-duration faults when the system inertia (primarily provided by the diesel generators at PBGS currently), becomes relatively reduced due to the increased use of the inverter-based generation.

The purpose of this study is to develop a model capable of testing these grid-stability events with varying levels of inverter-based generation. With this model, different forms of grid-stability mitigation can be tested and compared. Because the microturbines are the primary inverter-based technology currently used at PBGS, they were used as the basis for this study even though SCE plans to remove and replace them with other yet-to-be-determined technology.

Modeling Approach

POWER developed a PSCAD™ model of PBGS generation and lumped load equivalents for the feeder circuits. Circuit impedances and equipment locations were based upon the CYME model titled "Catalina Network (all circuits).sxst." Feeder loading distribution and power factor were also based upon this model and scaled based upon the desired loading case. According to PBGS operators, the facility has a minimum load of 2.3 MW, typical load of 3 MW, and the maximum load of 6 MW. Three of the most heavily used diesel generators were modeled based upon current facility configuration, which includes six (6) Marine Category 2 diesel generators (see Table 1). Unit 15 was modeled as the primary source of generation with Unit 10 and 14 next in line for PBGS as is the current practice. The MTs are modeled as simple inverter-based resources without grid--support features such as volt/var or over-frequency support. In addition to primary power generation, PBGS has a 1-MW BESS used primarily for peak shaving; however, it does not provide dynamic support to the grid.

TABLE 1: DIESEL GENERATORS		
UNIT	**VOLTAGE (KV)**	**POWER (KW/KVA)**
7	2.4	1000/1250
8	2.4	1500/3250
10	2.4	1125/1250
12	2.4	1500/3125
14	12	1400/1750
15	2.4	2800/3500

Microturbines

The twenty-three (23) propane-fueled MTs at PBGS were placed in service in 2009 and twenty-two (22) of the units received software upgrades in 2011 to increase their capacity from 60 to 65 kW. All units are in relatively poor condition, approaching the end of their useful life and will require overhaul or replacement per an assessment performed in January 2022.

In contrast to diesel generators that contribute to grid frequency stability via their rotating mass, MTs are an inverter-based technology and cannot contribute to grid frequency stability. The MTs spin at 90,000 RPM, and their attached generators output a high frequency alternating current (AC), which is converted to direct current (DC) that is then converted to 60 Hz AC. In addition, the MTs are highly sensitive to frequency disturbances. Capstone has stated that the MTs will trip if the grid's RoCoF exceeds one (1) Hz per second, which is a common occurrence on the Catalina microgrid.

A change of load demand that might be considered minor on the mainland becomes a major load change in a microgrid environment. A sudden load change causes any connected synchronous generators (the diesel generators) to slow down or speed up to support the change in demand (similar to a car in cruise control mode that speeds up or slows down when traversing steep hills). Capstone has stated that due to this issue, no more than 50 percent of the plant output can be carried by the MTs at any moment in time. However, plant experience has shown that no more than 30 percent of the plant load should be carried by the MTs in order to avoid a "cascading trip." In the case of PBGS, a cascading trip could occur if the entire MT fleet tripped offline, overloading and tripping the diesel generator fleet resulting in an island blackout.

TABLE 2: CURRENT MICROTURBINE PROTECTION SETTINGS

RELAY	PICKUP	DELAY
Over-Frequency	60.5 Hz	0.09 sec
Under-Frequency	59.3 Hz	0.09 sec
Over-Voltage	1.25 pu	0.03 sec
Over-Voltage	1.09 pu	1.9 sec
Under-Voltage	0.89 pu	1.9 sec
Under-Voltage	0.55 pu	0.09 sec
ROCOF	1 Hz/s	0 ms

Diesel Generators

Three (3) diesel generators (Units 15, 14, and 10) were modeled using PSCAD's built-in synchronous machine block, excitation system, and a simplified governor and engine block. The generators were set to control voltage and frequency with droops of 4% and 5%, respectively. Due to the age of these units, electrical properties were unavailable; therefore, typical values were applied to the model. Inertia constants for each unit were estimated and further refined to improve alignment with the responses found in the metered data. Per SCE, these units are required to operate at a high enough temperature to ensure full operation of the SCRs (corresponding to approximately 80% load). This load level ensures optimal emission control performance whereby SCE remains in compliance with emissions requirements.

BESS

PBGS has a 480V, 1000kW/1250kVA BESS that utilizes inverter technology. Operators dispatch it at unity power factor to shave peak demand and maintain the diesel generators above 80% loading. The BESS was modeled as a generic inverter-based resource operating at its dispatched real and reactive power references with the protection settings found in Table 3.

TABLE 3: BESS PROTECTION SETTINGS

RELAY	PICKUP	DELAY
Over-Frequency	60.4 Hz	0.145 sec
Under-Frequency	59.5 Hz	0.145 sec
Over-Voltage	1.1 pu	0.995 sec
Under-Voltage	0.9 pu	1.995 sec

Baseline

Before mitigation can be studied, a baseline model had to be developed and tested. Metered data acquired by POWER from 7/21/22 to 8/04/22 from PBGS's "Hi Line" distribution feeder was used to analyze significant load step events. These data were used to re-create a representative load step event on the Hi Line feeder within the developed PSCAD™ model and refine the diesel generator models. This served as a form of validation for the diesel generator model development.

Baseline + Microturbine Upgrade

Nuisance trips of the MTs resulting from the one (1) Hz/sec RoCoF protection, or the over/under frequency protection, is a known issue adversely impacting grid stability at PBGS. A refurbishment of the MTs is being considered in the near-term which will include an update to the control board for the turbines. The updated controls will provide the MTs with UL 1741 SA grid support functions. This includes Volt/Volt-Amps Reactive (volt/var) response and over-frequency response functionality that previously was not available, but the RoCoF protection will still exist. If it was disabled, the microturbines would likely lose their UL 1741 certification.

Frequency response available in the updated controls is summarized in Figure 1 and only applies to over-frequency events. The linear decline in power output versus frequency is controlled using an internal brake resistor. The function uses the actual output power at the time of activation (measured frequency > minimum frequency) as the basis for the percent power reduction gradient. This essentially operates as droop control for over-frequency events. According to Capstone, the minimum frequency should provide enough flexibility to avoid continuous activation of the brake resistor. Parameters used for this study are found in Table 4 and were selected to respond before the BESS trips on over-frequency (60.4 Hz) and with the maximum allowed response gradient.

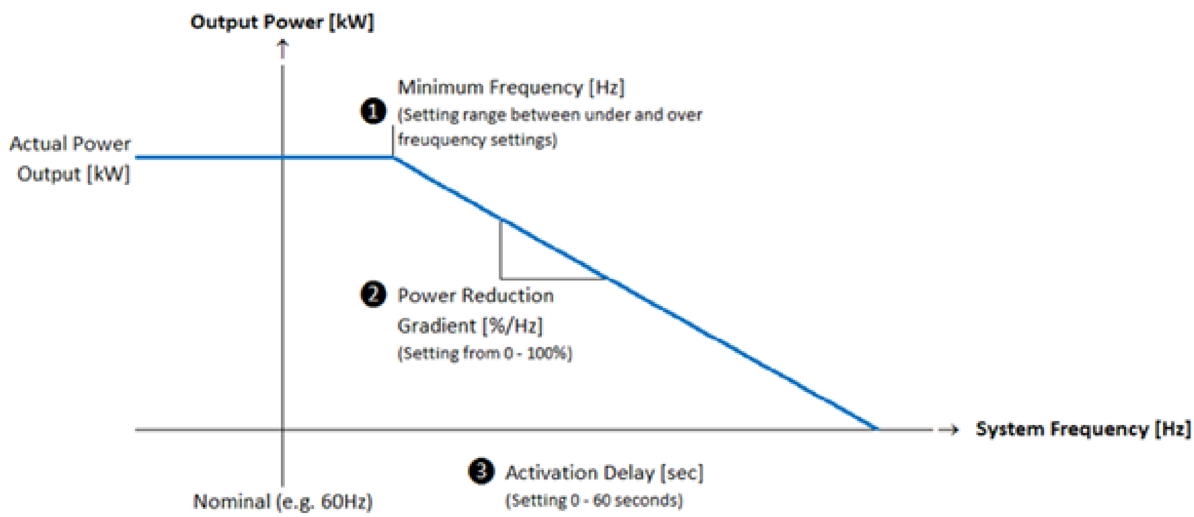


FIGURE 1: REFURBISHED MT FREQUENCY RESPONSE.

TABLE 4: FREQUENCY-WATT SETTINGS	
SETTING	**VALUE**
Min-Frequency	60.2 Hz
Activation Delay	0 sec
Gradient	100 %/sec

Volt-var response available in the updated controls is summarized in Figure 2, which demonstrates there is no activation delay and V2 and V3 can be set to the same values making it similar to traditional droop control. According to Capstone, the best use of this function occurs when operating the MTs at unity power factor. This is the current operating condition for the MTs and is how they were dispatched in the study. Parameters used for this study are found in Table 5 and were selected to provide a maximum response before voltage protection in the turbines and BESS would be reached.

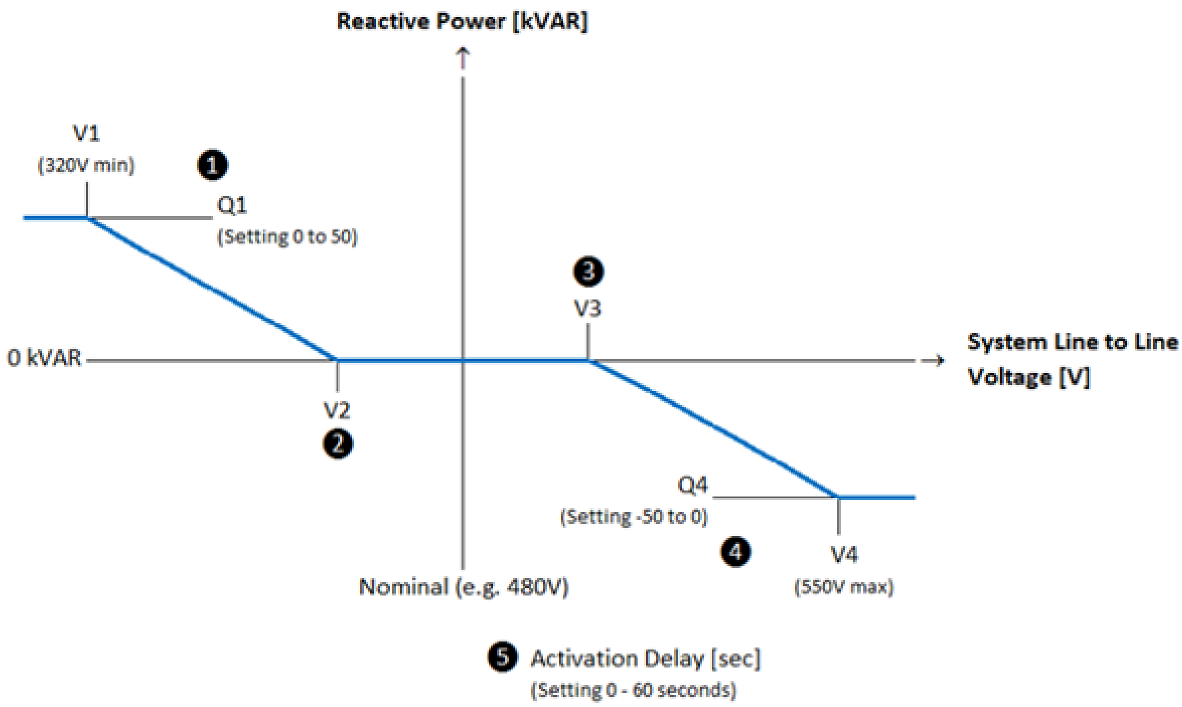


FIGURE 2: REFURBISHED MT VOLT-VAR RESPONSE.

TABLE 5: VOLT-VAR SETTINGS	
SETTING	**VALUE**
V1	432 V
V2	477.6 V
V3	482.4 V
V4	528 V
Q1	50 kVAR
Q4	-50 kVAR

Frequency ride through is also available with the upgraded controls and is summarized in Figure 3. The function requires the MT to continue providing power as long as the frequency remains in the highlighted regions. The updated protection sections used in this study are found in Table 6. These protection settings were selected to align with IEEE 1547-2018 Category 1 defaults.

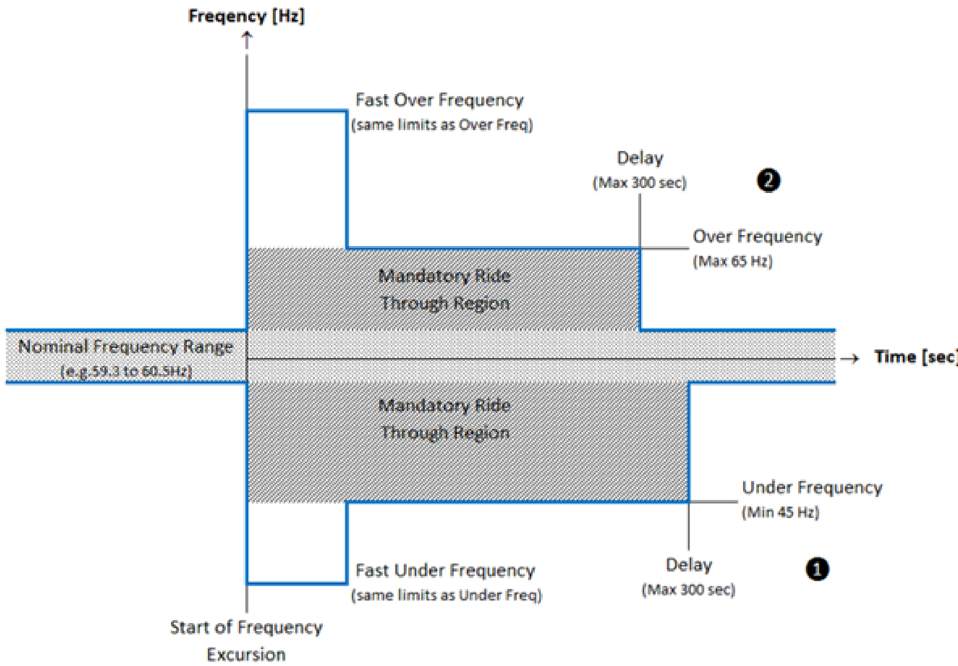


FIGURE 3: REFURBISHED MT FREQUENCY RIDE THROUGH.

TABLE 6: REFURBISHED MICROTURBINE PROTECTION SETTINGS		
RELAY	**PICKUP**	**DELAY**
Fast Over-Frequency	62 Hz	0.16 sec
Over-Frequency	62 Hz	0.16 sec
Under-Frequency	56.5 Hz	0.16 sec
Fast Under-Frequency	56.5 Hz	0.16 sec
Fast Over-Voltage	1.2 pu	0.16 sec
Over-Voltage	1.1 pu	2 sec
Under-Voltage	0.7 pu	2 sec
Under-Voltage	0.45 pu	0.16 sec
RoCoF	1 Hz/s	0 ms

Baseline + Tier 4 Generator Upgrade

For these scenarios, the model assumes Unit 15 was replaced with a Tier 4 Final-Certified Cummins QSK60 series diesel generator with a prime rating of 1825 kW/2281 kVA, which can be operated at 25 percent loads, providing a larger range of dispatch and more flexibility for PBGS operators. This diesel generator was modeled with similar parameters and droop gains as Unit 15 with the primary differences being power and current ratings.

Propane Generator

Incorporating one or two propane generators into the generation fleet is being considered at PBGS. One option being considered is a 2000 kW unit from Caterpillar de-rated to 1386 kW when fueled by pure liquid propane. Smaller and larger models are also a possibility. The propane generator(s) would replace the existing MT generation and get placed in the same physical location.

Assumptions

- Feeder load lumped as constant impedance (R-L)
- Hi-Line loads are the largest and most dynamic
- Diesel generator units 15, 10, and 14 are the most frequently dispatched units; therefore, they were the only units modeled in detail
- MTs are dispatched at 55 kW which is a result of the weather conditions at PBGS

RESULTS

Baseline

Load step tests (pick up and remove) with a 125-kW fixed impedance (R-L) load were conducted with the baseline model under two loading scenarios (min and max). For the minimum load scenario, the feeder load was adjusted to a total of 2.3 MW with the load being supported solely by operation of Unit 15. For the maximum load scenario, the feeder load was adjusted to a total of 5.5 MW with Units 15, 14, and 10 operating and sharing the load[1]. For both loading scenarios, the number of turbines operating was varied from 0 to 15 of the 23 total units along with the BESS being dispatched to maintain the loading on the units at or above 80%. The turbines were each dispatched at 55 kW, which is the typical production for the conditions found at PBGS.

Figure 4 shows the maximum frequency deviation relative to the percentage of MT load contribution. For the minimum load case, the maximum frequency deviation (in reference to the pre-load stop frequency) varied from 0.175 Hz to 0.18 Hz while the maximum frequency deviation for the maximum

[1] The historical maximum load between 2019 – 2021 was 5.5 MW, which was applied to the model. Based on the September 2022 extreme heat event, SCE notes the maximum load can exceed 6.3 MW.

load case varied from 0.09 Hz to 0.1 Hz. The maximum RoCoF for the minimum load case varied from 0.21 to 0.22 Hz/s compared to the maximum RoCoF for the maximum load case that held consistently at 0.11 Hz/s.

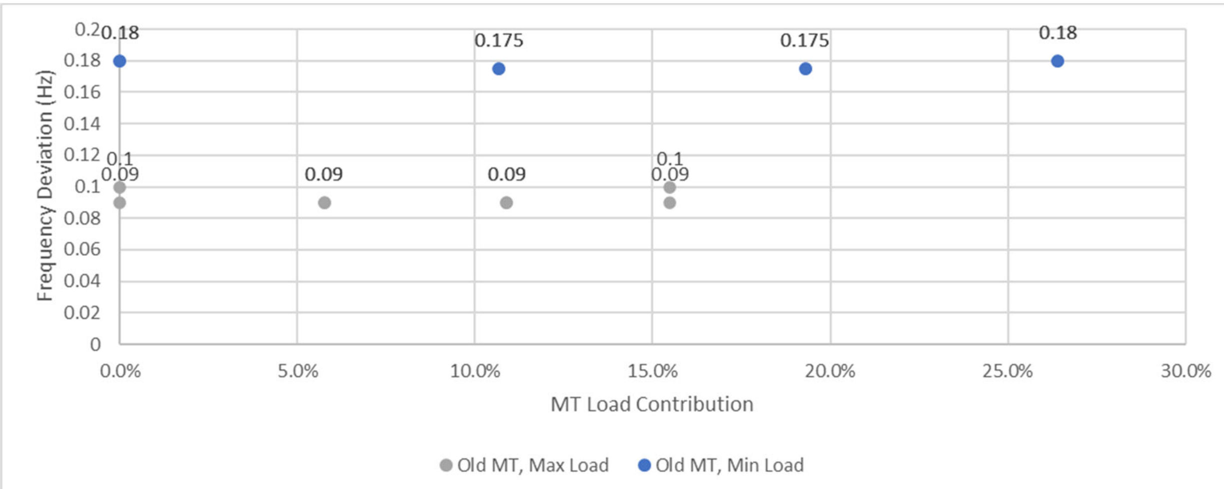


FIGURE 4: BASELINE MAXIMUM FREQUENCY DEVIATION.

Baseline + Microturbine Upgrade

Load step tests (pick up and remove) with a 125-kW fixed impedance (R-L) load were conducted with the upgraded MT model integrated into the baseline model. This upgraded MT model had updated protection settings along with grid support functions (volt/var and frequency response) active. The same tests that were performed in the baseline section were repeated.

Figure 5 shows the maximum frequency deviation relative to the percentage the MT generation is in relation to the load. For the minimum load case, the maximum frequency deviation (in reference to the pre-load stop frequency) varied from 0.18 Hz to 0.19 Hz while maximum frequency deviation for the maximum load case varied from 0.09 Hz to 0.1 Hz. The maximum RoCoF for the minimum load case varied from 0.21 to 0.22 Hz/s while for the maximum load case the maximum RoCoF was consistently 0.11 Hz/s.

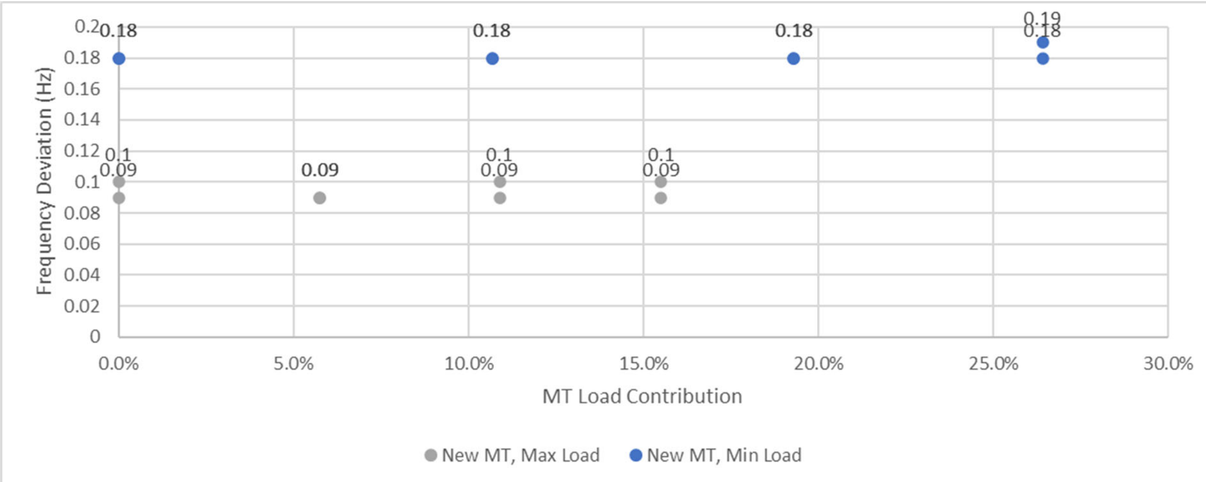


FIGURE 5: REFURBISHED MT MAXIMUM FREQUENCY DEVIATION.

Baseline + Tier 4 Generator Upgrade

Two 125 kW R-L load step tests were performed with the Tier 4 Final-Certified diesel generator substituted into the baseline model for Unit 15. The first test was with the Tier 4 Final-Certified unit online with the minimum system load of 2.3 MW and the BESS dispatched (discharging 840 kW) to bring the load on the Tier 4 Final-Certified unit down to 80% (~1.46 MW). The second load step again contained the same minimum system load of 2.3 MW and the BESS discharging 840 kW but now included operation of ten (10) MTs, which brought the effective load on the Tier 4 Final-Certified unit down to 50%. This test provides a comparison of handling a load step under 80% loading of the Tier 4 Final-Certified unit compared to 50% loading. Figures 6 and 7 show the Tier 4 Final-Certified unit loading along with the frequency and RoCoF on the 12 kV bus at PBGS. When comparing the two tests, the only notable difference is the load level on the machine. The frequency deviation and RoCoF is unchanged and not impacted by the lower loading level. Based on this, the grid stability is not expected to improve or worsen by changing the loading level on a Tier 4 Final-Certified unit.

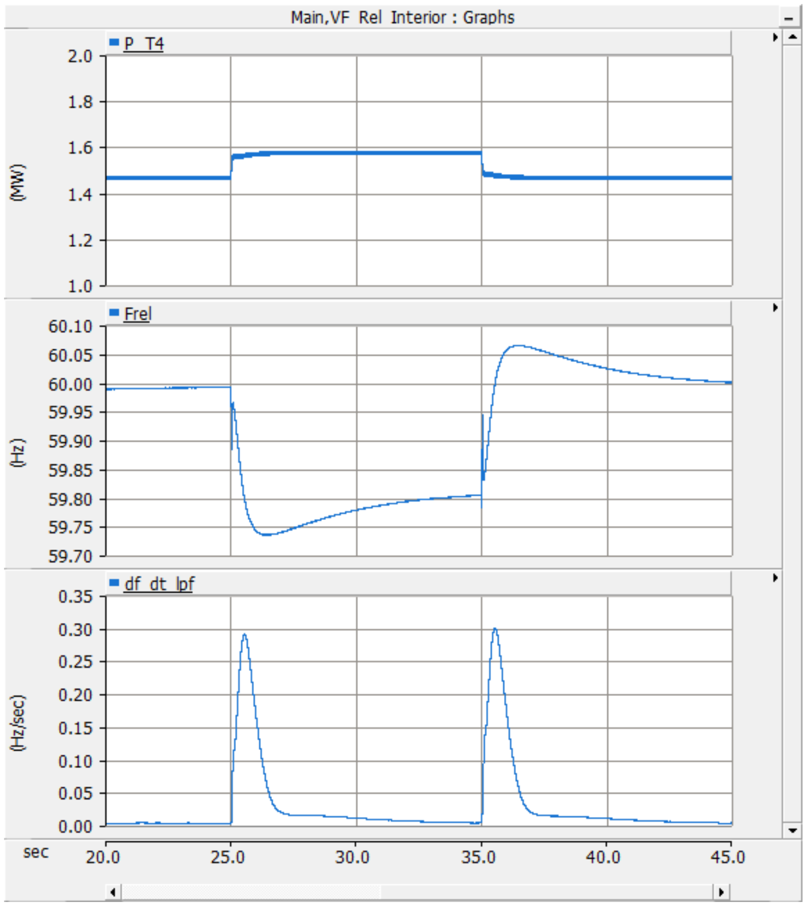


FIGURE 6: T4 LOAD STEP, 80% LOADING

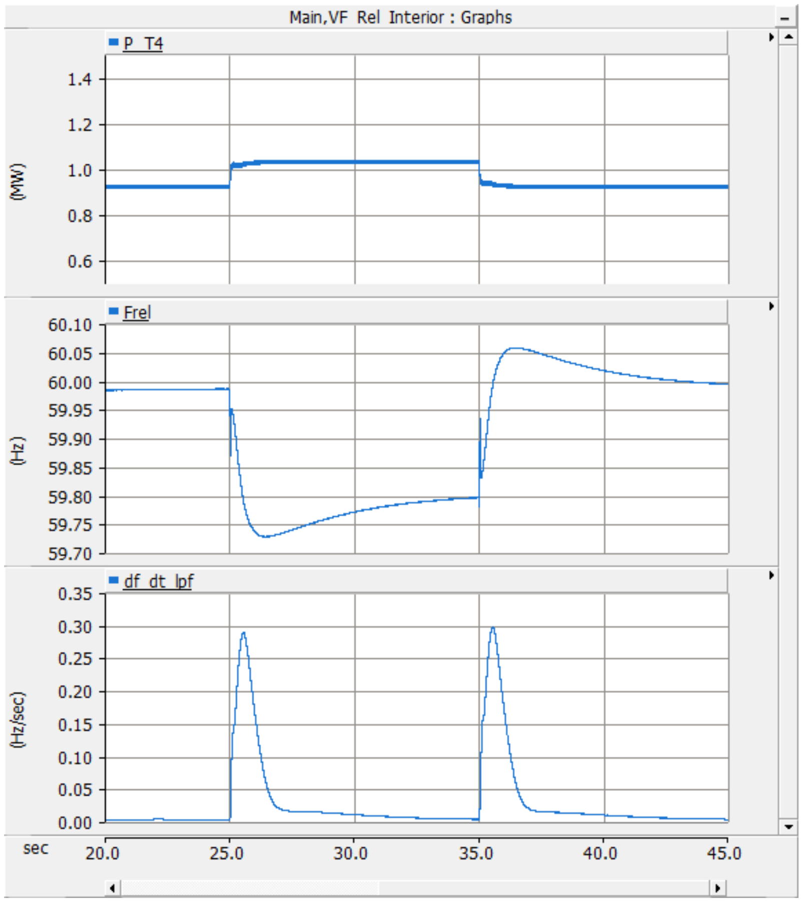


FIGURE 7: T4 LOAD STEP, 50% LOADING

Propane Generator

While the exact electrical parameters for the propane generator(s) proposed for PBGS are still unknown, the following general statements can be made:

- Replacing the MTs with a propane generator would remove a generation asset that does not contribute to the system inertia and has a known history of nuisance trips due their internal RoCoF protection and narrow frequency protection settings.
- When considering installation of a propane reciprocating generator at PBGS, the change to grid stability is dependent on the source of electricity generation [i.e., the unit(s) or technology] that is being replaced. Replacing the MTs with a propane reciprocating generator would lead to an improvement in grid stability given the MTs provide no grid inertia; however, if Unit 15, a diesel generator, was replaced by a propane reciprocating generator, then grid stability would be reduced. Even though propane reciprocating generators may provide similar (or slightly less) grid inertia, the lower energy density of the fuel reduces their effectiveness in responding to fast load fluctuations.

ANALYSIS & RECOMMENDATIONS

Below are the key findings:

- Grid frequency stability is not linked to the amount of MT generation. Rather, it is linked to the amount of inertia on the system which is only found presently through the diesel generators. Having more diesel generators online is what improves grid frequency regulation. The use of MTs has allowed less diesel generators to be online which leads to a reduction in system inertia and thus reduced frequency stability.
- The study investigated the benefits associated with upgrading the MTs to allow for improved controls for grid support. This upgrade was found to not improve grid frequency stability and should not be considered as a viable mitigation strategy to reduce the reliance on Unit 15 or other diesel generators within the PBGS electricity generation portfolio.
- For present implementation, it is recommended that the power generated from the MTs and the BESS at any given point in time should not exceed the spinning reserves available from the online diesel generator. This is to reduce the risk of UFLS events from cascading losses of the MTs and the BESS.
- SCE is currently testing a novel catalyst that will potentially reduce the diesel particulate matter (DPM) emissions. If the catalyst does not work, SCE will replace Unit 15 with a Tier 4 Final-Certified diesel generator in order to bring the facility into compliance with the Rule 1470 diesel particulate matter emission limit (0.01 g PM/bhp-hr). Replacing Unit 15 with a Tier 4 Final-Certified engine will allow for a greater operational range, which would potentially allow for an additional diesel generator to be online under higher system load conditions. The additional diesel generator would increase inertia and therefore grid stability. This increased inertia may provide a pathway to increase usage of the MTs.
- Propane generation is being considered as a replacement for the existing MTs. The study finds:
    - Elimination of the MTs removes the issue of the MTs nuisance tripping on frequency instability.
    - Replacing the MTs with one or more propane generator(s) adds a new source of inertia to the system which would improve grid frequency stability.
    - Replacing Unit 15 with a propane generator would not be as beneficial as replacing the MTs at PBGS because propane generator(s) are slower than a diesel generator in responding to rapid load fluctuations. There is increased improvement to grid stability by replacing the MTs versus Unit 15. Propane reciprocating generators provide inertia whereas the MTs do not provide inertia and therefore are more effective at improving grid stability.

FUTURE WORK

SCE and POWER plan to continue analyzing additional options for improving grid frequency stability. Scenarios being considered include the following: (1) a flywheel; (2) fuel cells; (3) linear generator(s); (4) and a synchronous condenser. Based on the findings of the current report, mitigating solutions will likely need to demonstrate the ability to add inertia to the system. For inverter-based resources, the solution likely would need to have fast-frequency response to both under-frequency and over-frequency conditions to be an effective solution for PBGS. SCE and POWER will be considering these options along with potential additional options in the coming weeks.

APPENDIX A – PSCAD MODEL

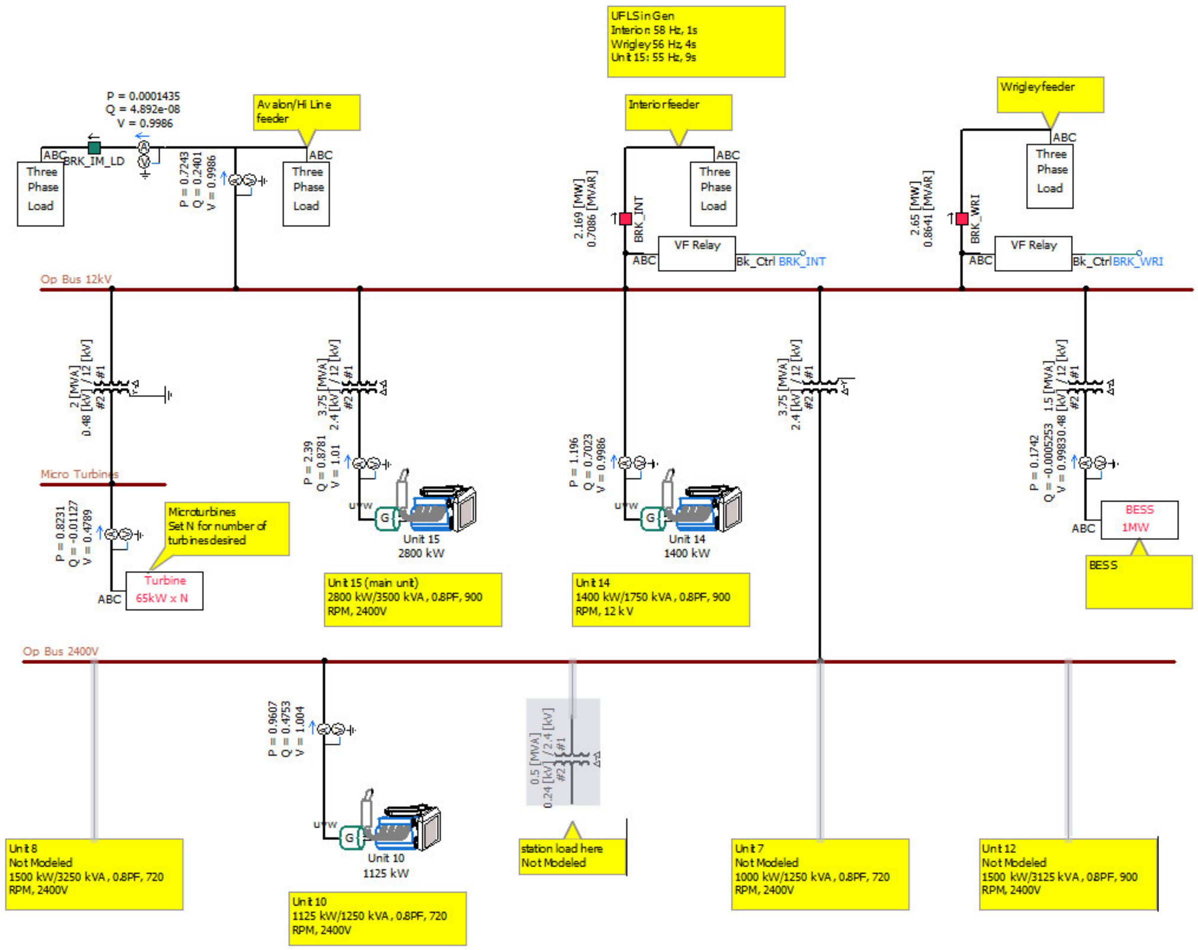
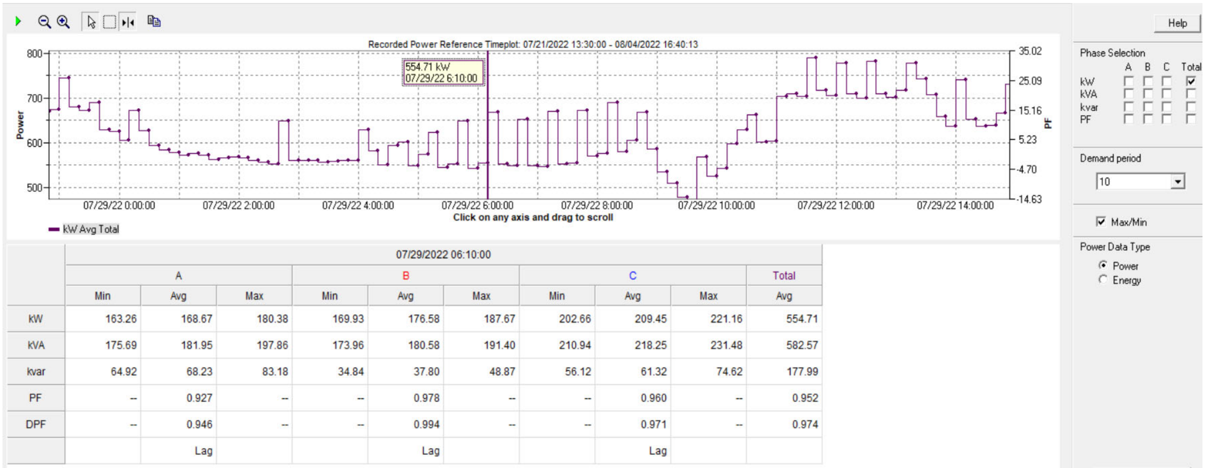


FIGURE 8: PBGS PSCAD MODEL

APPENDIX B – HI LINE PQM LOAD STEPS



	07/29/2022 06:10:00									
	A			B			C			Total
	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max	Avg
kW	163.26	168.67	180.38	169.93	176.58	187.67	202.66	209.45	221.16	554.71
kVA	175.69	181.95	197.86	173.96	180.58	191.40	210.94	218.25	231.48	582.57
kvar	64.92	68.23	83.18	34.84	37.80	48.87	56.12	61.32	74.62	177.99
PF	--	0.927	--	--	0.978	--	--	0.960	--	0.952
DPF	--	0.946	--	--	0.994	--	--	0.971	--	0.974
		Lag			Lag			Lag		

FIGURE 9: HI LINE KW LOAD STEPS

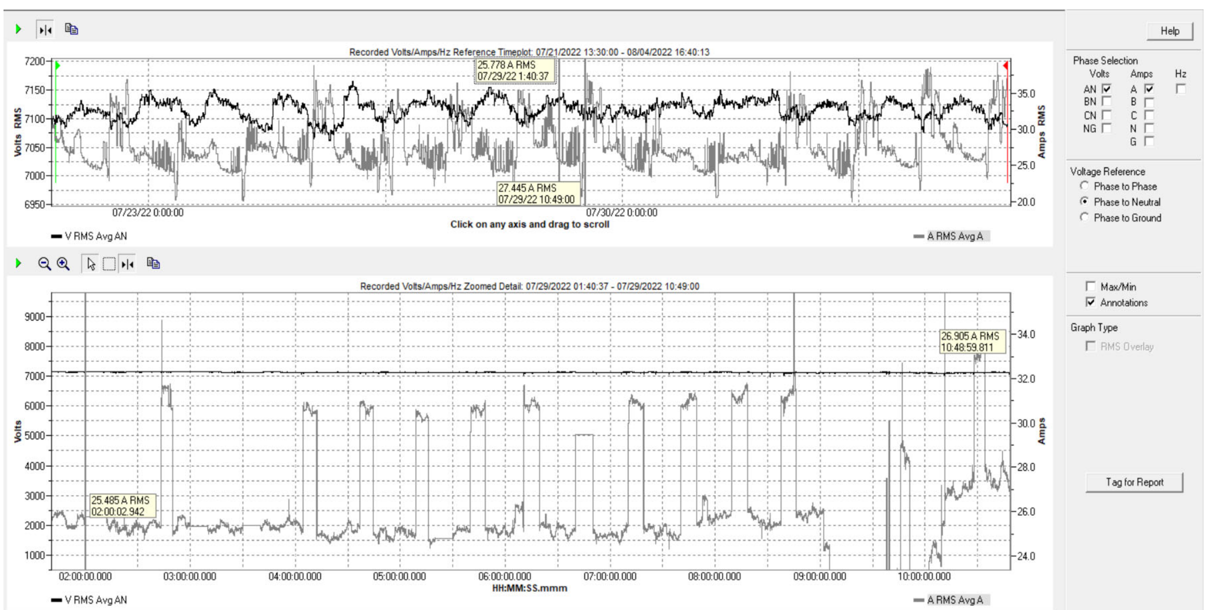


FIGURE 10: HI LINE KA LOAD STEPS

APPENDIX C –REPRESENTATIVE LOAD STEP RESPONSES

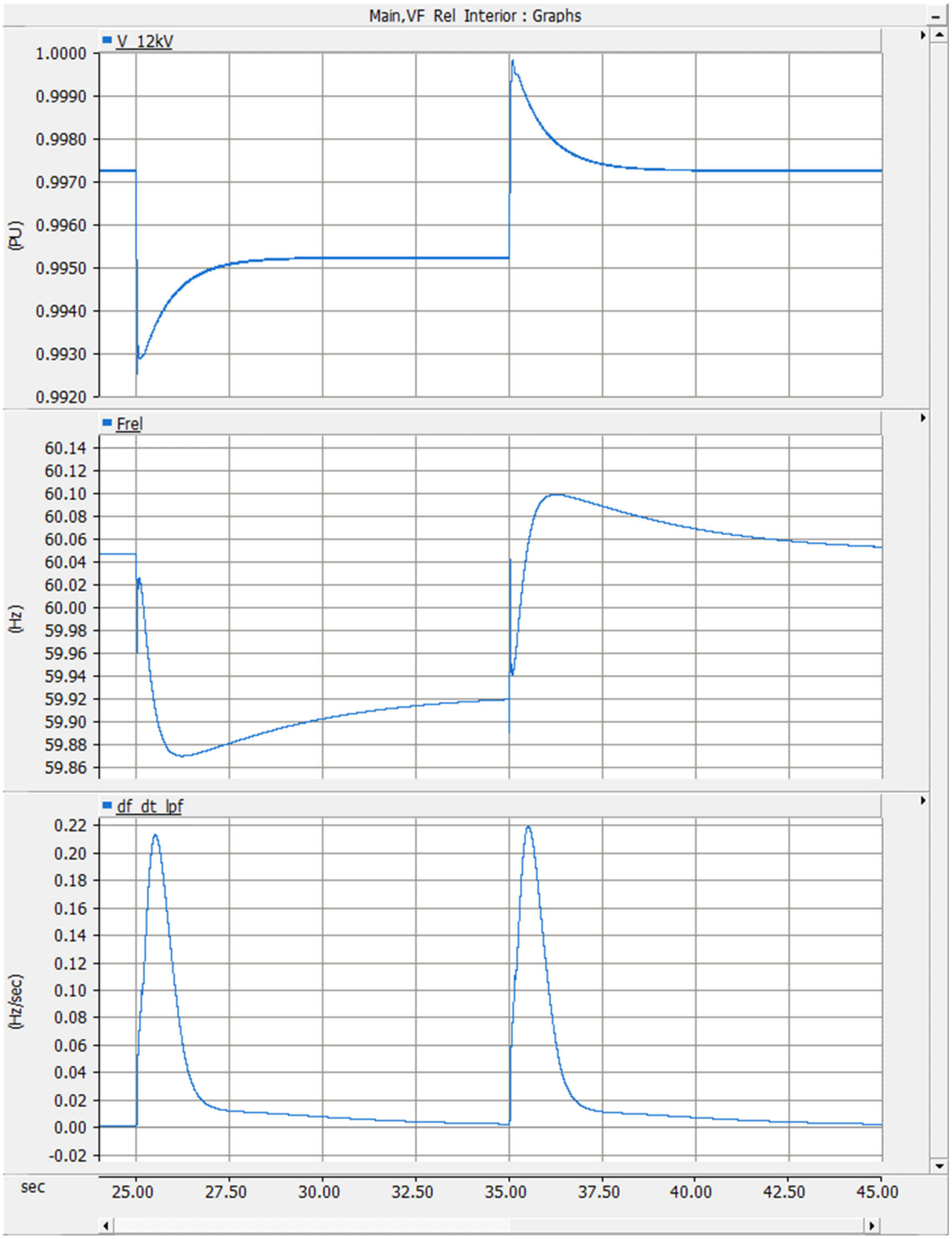


FIGURE 11: REPRESENTATIVE 12 KV VOLTAGE, FREQUENCY, AND DF/DT FOR MINIMUM LOAD CASE.

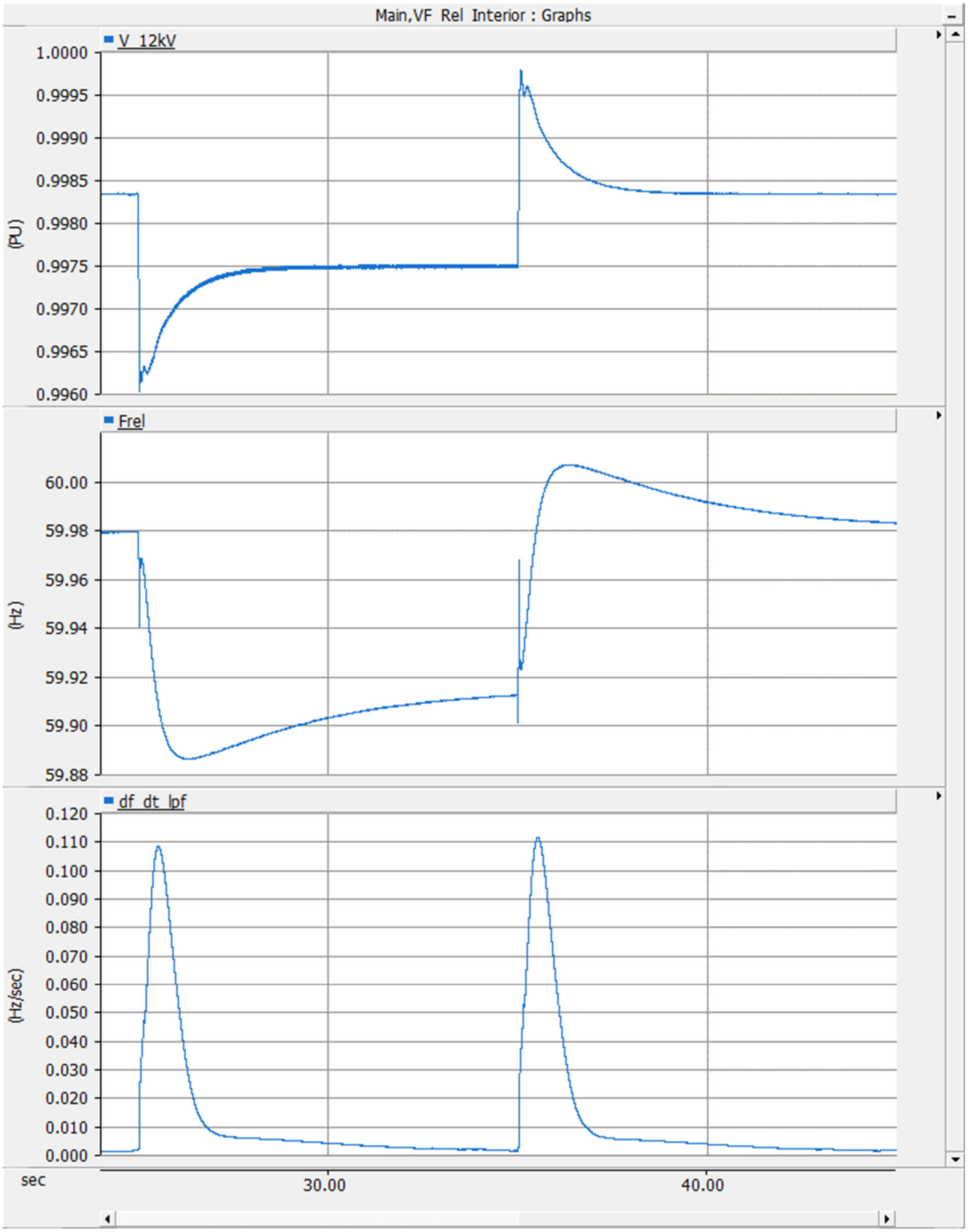


FIGURE 12: REPRESENTATIVE 12 KV VOLTAGE, FREQUENCY, AND DF/DT FOR MAXIMUM LOAD CASE.

CATALINA ISLAND

PLANNING CRITERIA AND GUIDELINES

SOUTHERN CALIFORNIA EDISON

SOUTHERN CALIFORNIA EDISON
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Contents

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SECTION 1 – INTRODUCTION

Santa Catalina Island (Catalina Island) is located 26 miles off the coast of Southern California. Southern California Edison (SCE) operates the Pebbly Beach Generating Station (PBGS), which is the sole provider of electricity, water, and gas utility services for more than 4,000 residents and over one million annual tourists. SCE is currently developing a long-term strategy for electricity generation on the island to cost-effectively reduce air pollution emissions and improve reliability and resiliency for Catalina Island.

This document provides a framework for planning metrics and criteria and guidelines for Catalina Island. Historically, the primary planning criteria used for Catalina Island mirrored the planning criteria used for the mainland; however, with increasingly stringent emissions requirements, technological advancements in various generation resources, heightened focus on wildfire risk, reliability, and resilience, SCE determined it was necessary to develop a Catalina Island specific criteria document.

Therefore, this document provides support and technical guidance focusing on two key analytical areas:

1. Catalina Island-specific performance and planning metrics and criteria to be used in annual electrical planning assessments by various organizations within SCE to ensure adequate, safe, and reliable electrical service throughout Catalina Island. These metrics and criteria have been developed based on comprehensive review of SCE's existing mainland criteria and other island electrical systems (similar to Catalina) whereby SCE determined its mainland criteria to be inadequate for Catalina Island planning activities.
2. Technical constraints and considerations associated with electrical system (i.e., generation and distribution) operation on Catalina Island, include but are not limited to the following:
    a. resource availability (e.g., fuel availability/deliverability, land availability, conformance to fire suppression requirements, technical safety regulations and standards – other power plant operational considerations, etc.).
    b. minimizing and/or mitigating environmental impacts during both construction/installation and operation/maintenance;
    c. incorporating "zero" or "near-zero" emission sources of electrical generation;
    d. ensuring adequate capacity, reliability, and resilience; and,
    e. balancing cost-effectiveness in consideration of rate payers.

The following sections are included in this report:

- Section 2: Background on Island Power Systems
- Section 3: Catalina Island Power System Planning Requirements

SECTION 2 – BACKGROUND ON ISLAND POWER SYSTEMS

This section provides background on island power systems and uses planning and design criteria consistent with those used on islanded power systems around the world with similar power consumption to Catalina Island.

2.1 BACKGROUND

Traditionally, islanded power systems (both physically and/or electrically) have predominantly depended on fossil fuels for electricity generation. The fuel is typically burned by reciprocating internal combustion engines (ICEs), which convert the chemical energy of the fuel into kinetic energy. This kinetic energy is then used to spin the rotor of a synchronous generator producing electrical energy. In these islanded power systems, diesel-fueled ICEs are one of the most common electricity generation methods given diesel engines provide required inertia for system stability, have relatively low capital costs, fast response times, quick start-up capability, and are easy to install, maintain, and operate. Figure 2.1-1 illustrates a simplified conventional islanded power system based on diesel generation.

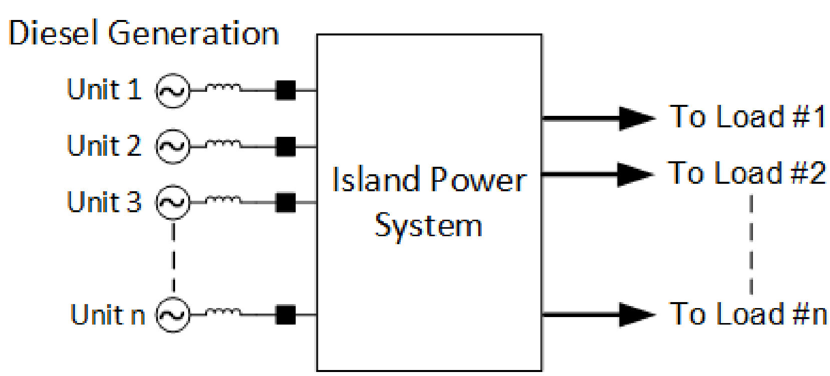


Figure 2.1-1. Conventional Islanded Power System Based on Diesel Generation

While diesel is one of the most common fuels used for electricity generation for islanded power systems, other fuels, such as propane, gasoline, and natural gas are used as well. However, with technological advancements and increased availability of a variety of renewable generation resources (e.g., solar photovoltaic, wind, battery energy storage, etc.), integration of renewable generation resources is becoming significantly more common.

When evaluating potential generation resource portfolios for islanded power systems, the number of generation units[1] is based on the desired redundancy such as N+1 or N+2, where N is the number of online and operational generating units required to meet load requirements at

[1] Generating units for consideration can be of any technology and fuel type that can be accommodated given the Catalina Island specific constraints such as fuel availability, space limitations, environmental regulations (including emission requirements), fire-suppression regulations, etc.

any given time. N+1 redundancy requires that if the largest generation unit is offline during the peak load, then the remaining generation must be adequate to still cover demand. Similarly, N+2[2] redundancy requires that if the two largest generation units are offline during the peak load, then the remaining generation must still cover demand. Studies are performed to evaluate adequacy of generation to meet load requirements both during on-peak and off-peak load conditions for both planned and unplanned outages of generation units. Outages to generation units can occur simultaneously or overlapping (e.g., one unit is offline for planned maintenance and then a concurrent unplanned outage of an additional unit occurs).

Should inverter-based resources (IBRs) become a significant source of generation (e.g., equal to or greater than the sum of the operating reserve[3] of the online inertia-based generation resources), simulations would be required to be to study the impacts of the loss of IBR generation in a manner similar to the N+1 and N+2 studies performed for the inertia-based generation resources (e.g., diesel, propane, etc.).

Because of technological developments and price reductions in renewable energy technologies and energy storage within the past decade, as well as increasing prices for fossil fuels and increasingly strict air emissions requirements, there are now many islanded power systems operational in the world combining traditional generation with renewable energy sources. Many of these hybrid islanded power systems are located in Alaska, Australia, Hawaii, and the Caribbean.

Typical challenges that arise when integrating renewable energy sources (especially intermittent sources such as solar and wind) to these islanded power systems are often related to the following factors [2-1]:

1. **Resource Adequacy:** Non-intermittent generation should still be able to reliably supply all electrical load at all times.

2. **Flexibility:** Generation should be capable of accommodating the intraday variations (from seconds to minutes to hours) of the net load (i.e., load minus intermittent renewable energy) with the generation system. This challenge is driven mostly by the variability and uncertainty of the variable renewable energy sources.

[2] The use of "N+2" redundancy throughout this document reflects conditions where two generating units are concurrently inoperable. The term is technology and fuel type agnostic and can also be called "Flexible N+2" redundancy.

[3] Operating reserve is surplus operating capacity that can instantly respond to a sudden increase in the electric load or a sudden decrease in the power output. Operating reserve provides a safety margin that helps ensure reliable electricity supply despite variability in the electric load and renewable power supply. In the context of this document, the term "operating reserve" is used to reflect both the reserve of online synchronous generators as well as that of any frequency-responsive inverter-based resources.

3. **System Stability:** Since the electro-mechanical characteristics of small power systems often change significantly with a high penetration of inverter-based renewable energy sources, the response of the electrical system to disturbances also changes, which could affect system operation, reliability, and resilience.

4. **Thermal and Voltage Limits:** The thermal capacity of lines, cables, transformers, and other network elements must be considered. Integrating a large amount of renewable energy sources (or other power plant technologies) into the network (at the transmission or distribution level) can lead to power flows for which the system was not initially designed. There is a risk of exceeding the thermal capacity of network elements either in normal operating conditions or following an outage when some network elements become unavailable.

5. **Protection:** Protection systems are designed to detect and initiate response to short circuits on the grid. Renewable energy sources that connect to the grid through power electronics-based inverters have limited short-circuit current contribution compared to conventional power plants equipped with synchronous generators. High penetration of renewable energy sources may therefore lead to reduced short-circuit current values. Protection systems are generally set and coordinated to isolate faults for high short-circuit current values. As the contribution of generation from inverter-based resources increases, if the available short-circuit current falls below the minimum required to detect and isolate faults, the protection systems may not operate properly.

6. **Power Quality:** Especially in weak power systems,[4] the integration of power electronics based renewable energy sources [e.g., solar photovoltaic (PV)] can lead to power quality issues (e.g., flicker) due to the characteristics of these devices.

Planning and designing islanded power systems are challenging tasks because of the limited primary resources available for new generation, the environmental constraints on grid expansion, the uncertainty in load growth, and the typically small size of the system (meaning that any change to the system has a greater impact on its overall performance and reliability relative to the typically larger mainland systems). For example, in a large electrical system peaking at 50,000 megawatts (MW), an unplanned outage of a large 1,000 MW generation unit results in a 2% loss of resources whereas in a small, islanded power system of 5 MW, the loss of a 1 MW generation unit results in a 20% loss of resources. Several studies need to be performed to understand and quantify the potential challenges of planning and designing

[4] Power systems can be categorized by their "system strength" (i.e., being either "strong" or "weak"). "A weak grid is commonly defined as a power grid with a low short-circuit ratio (SCR), i.e., high impedance, and a low inertia constant (H), which are typical features of microgrids. As a result, the voltage and frequency can be distorted in weak grids." [2-2]

islanded power systems including [2-1]:

- Load and Generation Balance
    - Resource Adequacy
    - Sizing of Operating Reserves
    - Generation Scheduling (including regular maintenance and major overhauls)
- Network Studies
    - Static Network Analysis
        - Load Flow Studies
        - Static Security Assessment
        - Short-Circuit Current Studies
    - System Stability Analysis
        - Transient Stability Analysis
        - Frequency Stability Analysis
        - Voltage Stability Analysis
    - Special Network Analysis
    - Special Protection Schemes
    - Grid Connection Studies

2.2 SECTION 2 REFERENCES

[2-1] IRENA, "Transforming small-island power systems: Technical planning studies for the integration of variable renewables", Abu Dhabi, 2018.

[2-2] Aswad Adib, et. al., "On Stability of Voltage Source Inverters in Weak Grids", IEEE Access, Volume 6, 2018.

SECTION 3 – CATALINA ISLAND POWER SYSTEM PLANNING REQUIREMENTS

This section provides the performance, planning, and reliability requirements for the Catalina Island power system.

3.1 ISLANDED POWER SYSTEM PLANNING REQUIREMENTS

3.1.1 Power System Size and Configuration

3.1.1.1 Relative size of system components

All power systems are isolated. Some, like the interconnections on the mainland, are very large in relation to the individual generating units and load feeders that make them up; others, like the Catalina Island power system are small in that individual components are large in relation to the total capacity of the system. The Catalina Island power system is small in that a single generator or single load feeder can be approximately 40% of the total load connected to the system. The operation, protection, and control of the Catalina Island power system must recognize that events such as tripping of a generator or a load feeder, will commonly cause more severe deviations in voltage and frequency than are seen in large, interconnected mainland power systems. Of particular concern, for an islanded power system such as Catalina, is maintaining frequency stability following relatively large steps in generation and load (e.g., loss of a generator, loss of a load feeder, or the start-up of large motors/load blocks). To maintain frequency stability the power system needs sufficient primary frequency response to arrest deviation in frequency before widespread loss of generation or load occurs. This will be determined through stability studies performed prior to proposed changes to generation resources [3-16]. Figure 3.1-1 below shows simulation results for a small island power system demonstrating the detrimental impact on the system frequency performance when under frequency clearing times of distributed energy resources (DERs) are too short [3-1]. System response like this is uncommon in relatively strong mainland power systems; however, it is a major concern for weak islanded power systems. Figure 3.1-1 below models system frequency dips as low as 57.5 Hz when DERs are unable to ride through a disturbance and they trip offline in less than 1 second.

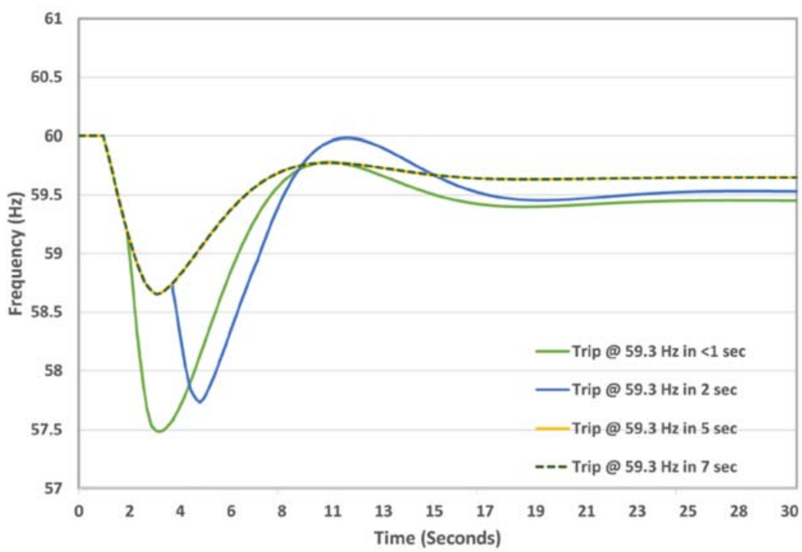


Figure 3.1-1. Modeling results illustrating the impact of trip function delay times on frequency performance (here: for a small island power system) [3-2].

3.1.1.2 Catalina Island power system

The recommendations included within this document assume that the Catalina Island power system will retain the following main characteristics as it is upgraded:

- There will be no electrical connections to the SCE mainland electrical system.
- The electrical distribution system will continue to be served by several 12 kilovolt (kV) distribution feeders originating from the PBGS.

- Adequate allocation of power production (determined based on resource adequacy[5] studies) supplied to the island will be produced by inertia-based reciprocating engines driving synchronous generators located at the PBGS to ensure system stability and provide safe, reliable, and resilient power at all times.
- The balance of power production (beyond the minimum allocation required for system stability) may be provided by other resources including near-zero or zero emission inverter-based resources (e.g., battery energy storage, PV, etc.).

3.1.2 Operation and Control

Voltage in the Catalina Island power system is, and will continue to be, controlled mainly by control of voltages at the PBGS. The voltage of the 12 kV distribution system close to PBGS will be determined principally by the actions of the synchronous generators at PBGS. The voltage at the remote ends of the 12 kV feeders will be influenced by voltage control actions taken at PBGS and affected by the use of reactive power and voltage control elements located on the 12 kV feeders.

Frequency control on the power system is implemented by the controls of the PBGS inertia-based reciprocating engines. The existing battery energy storage (BESS) at PBGS will continue to operate at operator-specified power output or input values and will not be frequency responsive, and the battery energy storage operation will occur as follows:

- Slowly in accordance with commands from the PBGS supervisory control system; or
- Instantaneously by switching on or off in response to signals raised by electrical protection elements.

Future upgrades to the PBGS BESS may include the addition of control devices that allow the BESS to provide frequency and voltage support and at such time, the dispatch of the BESS will be analyzed accordingly.

3.1.3 Power System Studies

Proposed power system changes (i.e., new generation or distribution lines) to the Catalina Island power system should be evaluated by the same analytical studies that are used for evaluating proposed changes to large mainland power systems. That is; the behavior of any proposed modifications to the Catalina Island power system should be evaluated by simulations which will provide input on the following items to:

- Ensure that the main elements of the upgraded system work in ways that are compatible with one another, are responsive to changing load and operational requirements, and are stable in response to anticipated unpredictable events;

[5] "Resource adequacy ensures there is enough capacity and reserves for the grid operator to maintain a balanced supply and demand across the electric system." https://www.caiso.com/Documents/Resource-Adequacy-Fact-Sheet.pdf

- Provide insight into the settings of protective relays; and
- Provide insight into setting operating limits and parameters regarding the number and types of generators that must be operational to maintain grid stability at all times.

For comprehensive coverage of the issues that should be expected to arise, the suite of studies outlined below should be undertaken for any proposed configuration modifications [3-3].

3.1.3.1 Power flow and dynamic simulation

A master base case power flow model should be set up to represent the proposed system. At a minimum, the power flow base case and associated dynamic modeling should represent the system at the following level of detail:

- Buses, lines, and loads: All 2.4 kV and 12 kV buses at the PBGS and throughout the system should be represented explicitly. Each of the 12 kV feeders should be represented with a level of detail that allows explicit recognition of significant individual loads, such as medical facilities, large buildings, feeder-connected PV generation, and voltage control elements (shunt capacitors). All 2.4 kV and 12 kV transformers should be represented in detail, including tap changers (if present) and grounding provisions.

- Synchronous generators: All synchronous generators and their excitation systems should be represented individually and in detail. For each generator, the excitation system including series current compensation should be represented in detail. Over-excitation and under-excitation limiters should be represented.

- Engines and engine primary controls: The engines and engine controls should be represented individually and in detail.

- PBGS controller: The supervisory controller of the PBGS must be recognized and represented in detail with the dynamic simulation program selected for the study tasks.

- IBRs: For system configurations that include IBRs (e.g., PV generation, wind generation, battery energy storage systems, etc.), the generating source, electrical interface controls, and any associated reactive power control elements should be represented by dynamic models at the level of the Western Electricity Coordinating Council (WECC) "list of approved dynamic models."

3.1.3.2 Electromagnetic transients simulation

As penetration of inverter-based resources increases, simulations may be required to be undertaken at the electromagnetic transient (EMT) level. While the need for such simulation can be anticipated, the details of the IBRs cannot. A phasor domain tool representation of IBR generation should be used in the modeling outlined above as a "placeholder" to facilitate the use of EMT simulation if and when the need arises. General industry guidance and experience [3-4], [3-5], [3-6] has stated that EMT modeling and simulation is necessary for systems with high penetration of IBRs (e.g., equal to or greater than the sum of the operating reserve of online inertia-based generation resources). One of the best practices for such modeling is to begin collecting models as soon as possible. As such, any new IBR plants connected to the Catalina Island power system should be required to provide EMT models in accordance with California Independent System Operator (CAISO) EMT modeling requirements [3-7].

3.1.3.3 Generation scheduling

Dynamic simulations using the modeling outlined in Section 3.1.3.1 will develop guidance in relation to the amount of reserve generating capacity (headroom between actual power and maximum power of online generators) that must be present at all times. This guidance will be used as input to a generation scheduling program. The scheduling program should recognize each individual generation source. If IBR generation is to be connected into the system via load-serving feeders, the scheduling simulation should have the ability to recognize the effect of IBR production on feeder flows.

3.1.4 Dynamic performance issues and performance expectations

3.1.4.1 Defining contingencies

The Catalina Island power system should be designed and operated in a way such that it can withstand reasonably considered contingency events at any time (e.g., N-1 for the distribution feeder system and N-2 for the generation system). Contingency events that must be considered include:

- The tripping of the synchronous generator making the largest contribution to power production (may not be the largest generation contributor).
- The tripping of any inverter-based resources when contributing equal to or greater than the available operating reserve of the frequency-responsive generation resources producing power on the grid at any time.
- The outage of any distribution feeder while it is serving load.
- The failure or misoperation of automatic voltage control devices, such as tap changers or shunt capacitors.

3.1.4.2 Loss of largest generation contribution

An unplanned outage of the generation source contributing the greatest percentage of power supply should not result in power supply levels below those required to meet the electrical demand at all times. Proposed changes to the generation resource portfolio should ensure that sufficient inertia-based operating reserve, or other technologies (e.g., fast-response energy storage) is maintained to arrest the decline of frequency and maintain continuity of supply to all loads. Stability studies are required to determine the minimum operating reserve of frequency-responsive generation resources to avoid forced load shedding to prevent system collapse.

- The behavior of the PBGS BESS should be modeled with regard to:
  - Its response, if any, to normal variations of frequency and voltage.
  - Its ability to quickly cease charging when low frequency is sensed.
  - Its ability to quickly cease discharging when high frequency is sensed.
  - Its ability to vary its reactive power consumption or delivery in response to changes in voltage.
- As penetration of inverter-based resources increases, the operation of IBR equipment shall meet or exceed the frequency-droop parameters identified in the Hawaiian Electric Source Requirements Document (SRD) V2.0 [3-8] such that it can recognize both:
  - Variations of electrical output in accordance with the intended (droop) relationship between frequency and electrical power
  - Variations, cessations, or resumptions, of electrical power whose occurrence and purpose are to protect the IBR equipment

The table below represents the frequency-droop parameters from the Hawaiian Electric SRD V2.0.

IEEE 1547-2018 Table 24
Parameters of frequency-droop (frequency-power) operation for DER of abnormal operating performance
Category III

Parameter	Ranges of allowable settings [a]	
	1547-2018 Category III	SRD V2.0
dbOF, dbUF (Hz)	0.017[b]–1.0	0.017 -1.0
kOF, kUF	0.02–0.05	0.02 - 0.07
$T_{response}$ (small-signal) (s)	0.2–10	0.2-10

3.1.4.3 Loss of loaded distribution feeder

The opening of a distribution feeder circuit breaker (or other sectionalizing device) will subject the power system to a sudden unbalance of load versus generation. In some instances, this may be as severe as resulting in the sudden loss of the largest contributing generation source, but in the opposite case where the load of a feeder was lost, engine speeds would rise very quickly. Currently, the only control actions available to restrain the increase in frequency would be those that may be available from PBGS. Should the generation resource mix on Catalina Island change and if frequency-responsive generation resources are incorporated, then the control actions to restrain over-frequency events may include actions that occur outside of PBGS. It is possible that generation would have to be tripped, with the generator tripping being controlled by over-frequency relays or a centralized load-balancing controller. It will be necessary to match (to the extent possible) the amount of generation that is tripped to the amount of load that is interrupted, and to achieve the matching quickly so as to avoid tripping of engines by their overspeed protections.

The modeling and system representation points noted in Section 3.1.4.2 are applicable to the consideration of sudden load loss.

3.1.4.4 Industrial power experience

An industrial power system that has been disconnected suddenly from its connection to a large grid faces the same operating and control issues as the Catalina Island power system. There is extensive experience in the industrial power sector with the fast and managed control of on-site generation in response to sudden imbalances of load and generation. A significant aspect of industrial practice for fast management of load and generation imbalances is that such control requires that communication between sensors, computers, and actuators be achieved with minimal latency. Low-latency communication between all generation resources and load sectionalizing devices shall be provided.

3.1.4.5 Loss of load with fault clearance

The normal consideration of rotor angle stability following electrical faults will be implicit but not the main concern of system simulations; the main concern will be the behavior of the electrical load after clearance of a fault. It is important to base the modeling of load in both static power flows and dynamic simulations. Known loads should be represented as closely as available factual data allows. Where information is unavailable, the analytical load composition modeling practices used throughout the WECC should be used.

3.1.4.6 Voltage controls

Depending on whether voltage control devices are connected to the 2.4 kV or 12 kV bus directly or through transformers, the voltage regulators of the synchronous generators should be set up with series current compensation and included in the modeling of the PBGS.

3.1.5 Load Requirements

Based on the historical data (and similarly observed in modeling simulations), the Catalina Island power system generation shall be designed to accommodate unbalanced load currents of up to 10%.

In addition, the Catalina Island power system generation shall be designed to accommodate the inrush current associated with starting existing large motor loads without causing any system stability issues on the island and to limit the rapid voltage changes per IEEE Standard 1453 Table 3 [3-9].

3.1.6 Voltage Requirements

The Catalina Island power system shall be designed in compliance with SCE's Rule 2 filed with the California Public Utilities Commission (CPUC). It shall also meet American National Standards Institute (ANSI) C84.1 [3-10] and SCE's Distribution and Subtransmission Planning Criteria and Guidelines [3-11] voltage requirements during peak load and light load conditions based on the load requirements provided in Section 3.1.5.

3.1.7 Reliability Requirements

Since the Catalina Island power system is isolated from any other electrical power supply, and because island-wide operation of both gas and water utility service rely on electricity, the existing power generation on the island must have N+2 redundancy to ensure system reliability and sufficient operating reserve. N+2 redundancy requires that if the two largest generation units are offline (for any combination of planned or unplanned outages), then the remaining generation (any combination of synchronous generation or frequency-responsive inverter-based resources) must still be sufficient to cover the peak load.

3.1.8 Fuel Storage Requirements

The island currently receives on average five trips per week from two vessels combined which bring fuel to the island for generation use at PBGS [3-12]. Under normal operating conditions, a 10-day fuel supply for PBGS generation must be maintained to address fuel shipment delays, interruptions, or other limitations.

3.1.9 Data Communication Requirements

The Catalina Island power system generation shall provide real-time data (voltage, frequency, real and reactive power flow values, etc.) of all generation units and energy storage resources (if applicable).

3.1.10 Interconnection Requirements

Existing and any proposed generation, including fossil fuel-based resource and any near-zero or zero-emission resources, shall meet the interconnection requirements of SCE's Interconnection Handbook [3-13]. Additionally, since the Catalina Island power system is a weak power system compared to the mainland, any proposed inverter-based generation, at a minimum, shall meet the Hawaiian Electric SRD V2.0 frequency ride-through requirements [3-15] and the IEEE 1547 rate-of-change-of-frequency (ROCOF) requirements [3-14]. The proposed inverter-based generation, at a minimum, shall also meet IEEE 1547 Category III voltage ride-through and Category B voltage and reactive power capability. Stability studies are required for interconnection of proposed inverter-based generation and results may determine that settings which exceed those included in the above referenced standards would be required. Additionally, proposed inverter-based generation shall not include ROCOF protection settings. The table below represents the frequency ride-through requirements from the Hawaiian Electric SRD V2.0.

IEEE 1547-2018 Table 19
Frequency ride-through requirements for DER of abnormal operating performance Category III
(see Figure H.10 from IEEE 1547-2018)

Frequency range (Hz)		Operating mode		Minimum time (s) (design criteria)	
1547-2018	**SRD V2.0**	**1547-2018**	**SRD V2.0**	**1547-2018**	**SRD V2.0**
f > 62.0	f > 65.0	No ride-through requirements apply to this range			
61.2 < f ≤ 61.8	63.0 < f ≤ 65.0	Mandatory Operation[a]	Mandatory Operation[a]	299	299
58.8 ≤ f ≤ 61.2	57.0 ≤ f ≤ 63.0	Continuous Operation[a,b]	Continuous Operation[a,b]	Infinite[c]	Indefinite
57.0 ≤ f < 58.8	50.0 ≤ f < 57.0	Mandatory Operation[a]	Mandatory Operation[a]	299	299
f < 57.0	f < 50.0	No ride-through requirements apply to this range			

3.1.11 Protection Requirements

Existing and proposed generation and energy storage shall provide the minimum short-circuit current as determined by a protection study to ensure the protection system can detect and isolate faults in the Catalina Island power system. Proposed system configuration changes may necessitate protection settings changes, upgrades, or may indicate generation resource portfolios that are infeasible in providing the minimum required short-circuit current for protection.

A comprehensive island-wide (PBGS to end-of-line for each circuit feeder) coordination study shall be performed to ensure safe, reliable, and resilient operation. This study shall be performed as needed as changes are proposed to the generation resource mix and/or distribution electrical topology of the island.

3.2 SECTION 3 REFERENCES

[3-1] EPRI, "Impact of Variable Generation on Voltage and Frequency Performance of the Bulk System: Case Studies and Lessons Learned", 2014.

[3-2] EPRI, "Recommended Settings for Voltage and Frequency Ride-Through of Distributed Energy Resources", 2015.

[3-3] IRENA, "Transforming small-island power systems: Technical planning studies for the integration of variable renewables", Abu Dhabi, 2018.

[3-4] NERC, "Odessa Disturbance", September 2021.

[3-5] NERC, "900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report", February 2018.

[3-6] NERC, "April and May 2018 Fault Induced Solar Photovoltaic Resource Interruption Disturbances Report", January 2019.

[3-7] CAISO, "Electromagnetic Transient Modeling Requirements", April 2021.

[3-8] Hawaiian Electric, "Source Requirements Document Version 2.0", July 2020.

[3-9] IEEE Standard 1453, "Analysis of Fluctuating Installations on Power Systems", 2015.

[3-10] ANSI C84.1-2020, "Electric Power Systems and Equipment - Voltage Ratings (60 Hz)."

[3-11] Southern California Edison Company, "Subtransmission Planning Criteria and Guidelines", December 2021.

[3-12] NREL, "Catalina Repower Feasibility Study: NREL Phases I & II Summary Report", October 2020.

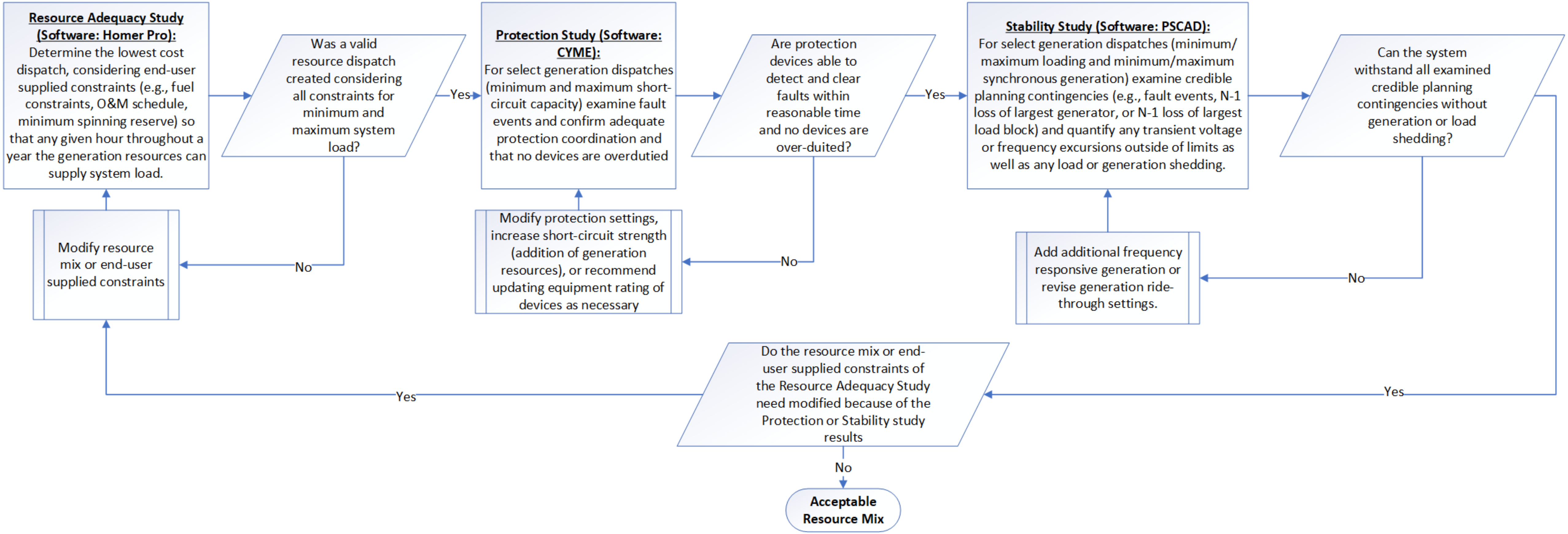
[3-13] Southern California Edison Company, "The Interconnection Handbook", Revision 10.

[3-14] IEEE Standard 1547, "Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces", 2018.

[3-15] Hawaiian Electric, "Source Requirements Document Version 2.0", July 2020.

[3-16] John Undrill, "Primary Frequency Response and Control of Power System Frequency", February 2018.

SCE Catalina Island Grid Stability Study Process



Step 1: HOMER

- Initial screening tool that identifies which generation scenarios can meet the annual and hourly peak demand under normal conditions and assuming typical maintenance outage frequency
- Started with 8 scenarios; 4 passed
- SCE will complete analysis of the two AO scenarios by August 30

Step 2a: CYME

- For scenarios that pass HOMER
- Models distribution circuitry exiting generating station and delivering electricity to customers
    - Evaluates system response to distribution circuit faults including coordination of protective devices (e.g., circuit breakers, fuses, etc.) to safely delivery of power
    - Determines if generation scenarios produce the necessary short-circuit current to ensure protective devices will operate properly and within required response time to avoid system collapse or blackouts

Step 2b: PSCAD

- Ideally run for scenarios that pass HOMER & CYME analysis, however time constraints cause work to be evaluated in parallel in an iterative process
- Models system stability on a minute-by-minute basis monitoring voltage and frequency response
    - Incorporates generator outages, load changes, and the resulting frequency and voltage deviations
    - Determines generation response and those events in which load-shedding or system collapse would be expected (e.g., blackouts)

Feedback Loop

- As scenarios fail in PSCAD or CYME:
  1. Cycle back to HOMER to adjust generation resource mix to address the failures
  2. Adjust HOMER model, then run through PSCAD to ensure generation stability
  3. If revised scenario passes both HOMER & PSCAD again, re-study with CYME to ensure the initial failure cause is remedied
- Scenarios that pass HOMER, PSCAD, & CYME are then considered electrically feasible for further consideration

Appendix: Background Information

Background: Studies Needed to Integrate Renewables to Island Power Systems

Table ES2: The main types of studies to support VRE integration

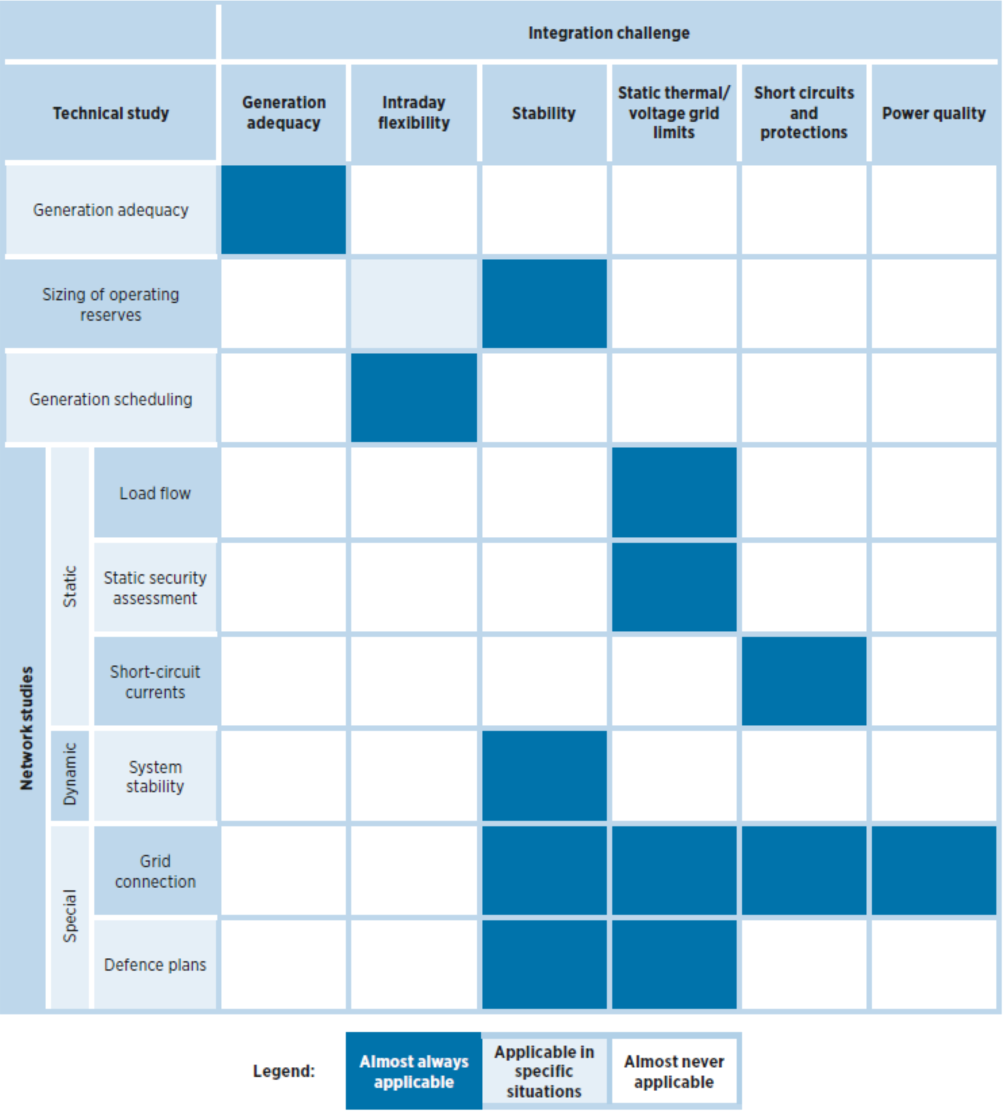
			Typical time horizon		Parts of the power system represented		
			Long-/mid-term planning (month to years ahead)	Operational planning (day to week ahead)	Load and generation	Transmission	Distribution
		Generation adequacy	Almost always applicable	Almost never applicable	Almost always applicable	Applicable in specific situations	Almost never applicable
		Sizing of operating reserves	Almost always applicable	Applicable in specific situations	Almost always applicable	Almost never applicable	Almost never applicable
		Generation scheduling	Almost always applicable	Almost always applicable	Almost always applicable	Applicable in specific situations	Almost never applicable
Network studies	Static	Load flow	Almost always applicable	Almost always applicable	Almost always applicable	Almost always applicable	Almost always applicable
Network studies	Static	Static security assessment	Almost always applicable	Almost always applicable	Almost always applicable	Almost always applicable	Applicable in specific situations
Network studies	Static	Short-circuit currents	Almost always applicable	Almost always applicable	Almost always applicable	Almost always applicable	Almost always applicable
Network studies	Dynamic	System stability	Almost always applicable	Almost always applicable	Almost always applicable	Almost always applicable	Applicable in specific situations
Network studies	Special	Grid connection	Almost always applicable	Almost never applicable	Almost always applicable	Almost always applicable	Applicable in specific situations
Network studies	Special	Defence plans	Almost always applicable	Almost never applicable	Almost always applicable	Almost always applicable	Applicable in specific situations (UFLS & UVLS)

Legend: Almost always applicable | Applicable in specific situations | Almost never applicable

Source: IRENA (2018), Transforming small-island power systems: Technical planning studies for the integration of variable renewables, International Renewable Energy Agency, Abu Dhabi

Background: Challenges Each Study Addresses

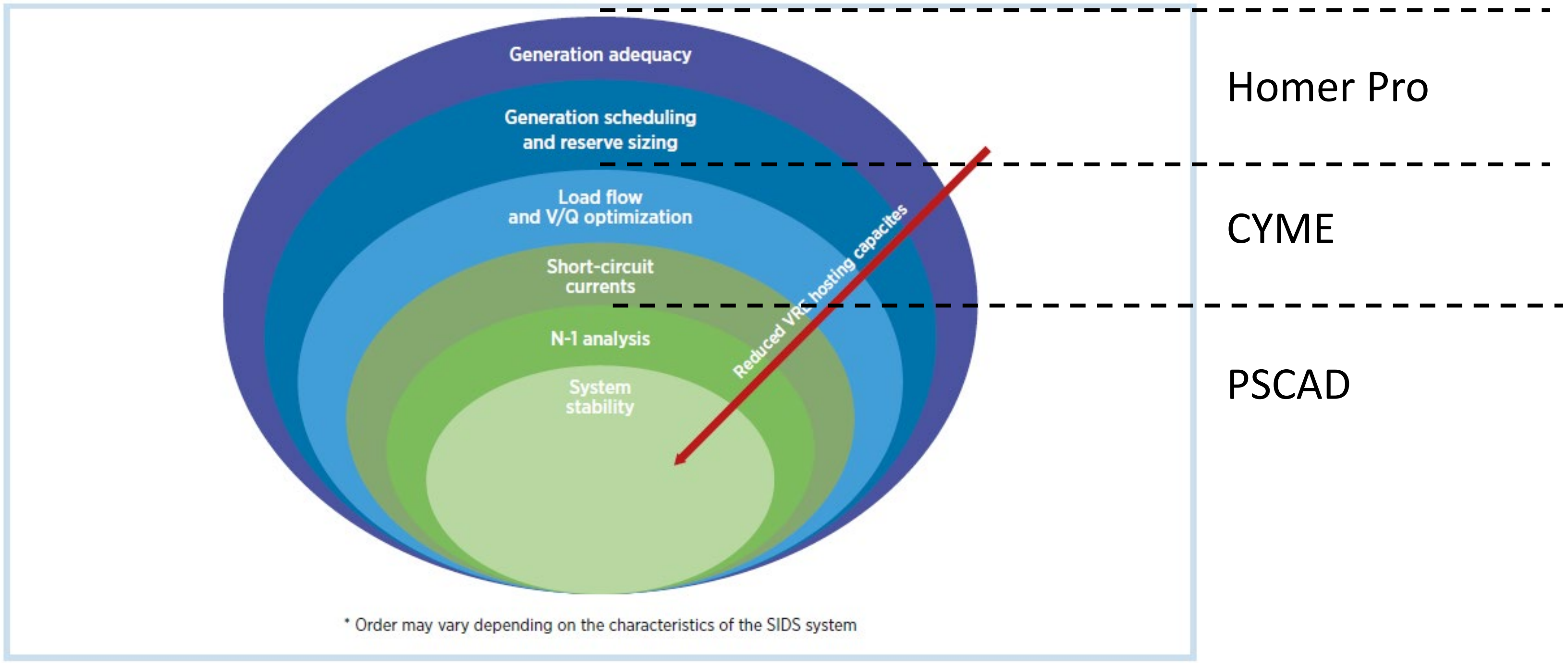
Table ES3: Technical studies and how they address key VRE integration challenges



Source: IRENA (2018), Transforming small-island power systems: Technical planning studies for the integration of variable renewables, International Renewable Energy Agency, Abu Dhabi

Background: Study Process for Renewable Integration

Figure ES2: Limitations for VRE integration resulting from different technical studies



Source: IRENA (2018), Transforming small-island power systems: Technical planning studies for the integration of variable renewables, International Renewable Energy Agency, Abu Dhabi

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August 30, 2023

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RE: Grid Stability Study, Order of Abatement (Case #1262-115), Pebbly Beach Generating Station Repower Project (Facility ID 4477)

Dear Ms. Reichert:

In compliance with Condition Nos. 3 and 4 of the Order for Abatement issued on July 25, 2023 by the South Coast Air Quality Management District (SCAQMD) Hearing Board, Southern California Edison (SCE) hereby provides the results for the two SCAQMD-proposed configurations that were evaluated using HOMER (Hybrid Optimization of Multiple Energy Resources) Pro software by the consultant POWER Engineers (POWER).[1]

Both configurations share the following assumptions:

- 10% minimum charge on the existing battery system (NaS BESS);
- Load demand forecasted data for 2026 reflecting a peak of 6 megawatts (MW) and approximately 31 gigawatt-hours (GWh) annual loading;
- Existing NaS BESS modeled as 1 MW/7 megawatt-hours (MWh) with a round-trip efficiency of 85%;
- Annual consumption of 500,000 gallons of diesel;
- Annual consumption of 2.1 million gallons of propane; and
- No minimum spinning reserve requirement.

SCAQMD Configuration 1 contains the following elements:

- Utility-scale renewable PV system (30% of annual load);
- Three U.S. EPA Tier 4 Final-certified (T4F) diesel generators (1.825 MW each);
- Existing NaS BESS;
- Five new BESS (1 MW each); and
- Propane near-zero-emission (NZE) technology with a combined rating of at least 2.25 MW (65% of annual load).

[1] SCE will provide a report summarizing the remainder of the study by September 29, 2023, pursuant to the extension granted by the SCAQMD.

SCAQMD Configuration 2 contains the following elements:

- Utility-scale renewable PV system (30% of annual load);
- Three T4F diesel generators (1.825 MW each);
- Existing NaS BESS;
- Five new BESS (1 MW each); and
- Propane NZE technology with a combined rating of at least 2 MW (50% of annual load).

POWER included the following additional assumptions:

- Load demand forecasted data for 2026 reflecting a peak of 6 MW and approximately 31 GWh annual energy consumption;
- One T4F diesel unit receiving one three-month-long maintenance outage;
- Two T4F diesel units each receiving one month-long maintenance outage; and
- One biweekly planned maintenance activity per T4F diesel unit with 10 hours of downtime.

The BESS was modeled in aggregate as a 6 MW/27 MWh system (i.e., the existing PBGS NaS BESS at 1 MW/7 MWh plus a renewable photovoltaic (PV) system paired with a BESS at 5 MW/20 MWh). The HOMER Pro program evaluates system resource adequacy; in other words, whether a configuration provides sufficient generation supply to meet electrical demand. However, the analysis do not reflect system stability issues that may result from insufficient system inertia. System stability is analyzed in Stage 2b of the study (using software designed for evaluating stability and protection) for those configurations that pass the HOMER Pro stage. Therefore, only if either configuration above passes the HOMER Pro stage would a Stage 2b system stability analysis be appropriate.

After the parameters for Configuration 1 were entered into HOMER Pro, the program provided the output message shown below:

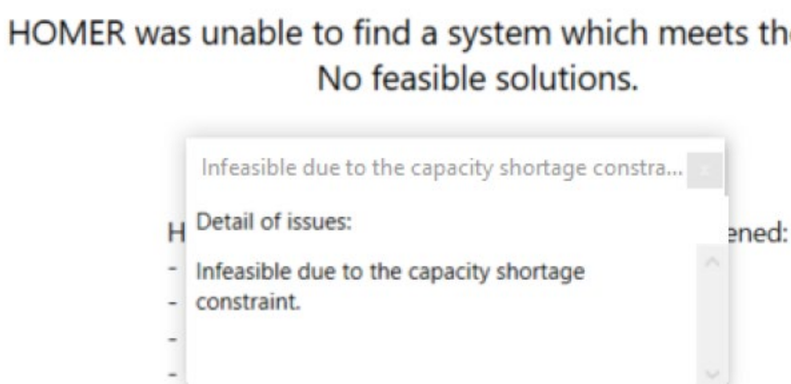

Figure 1: HOMER Pro Output for Configuration 1

The HOMER Pro results depicted in Figure 1 indicate that Configuration 1 is infeasible because it fails to provide sufficient capacity to meet all electrical demand. Configuration 2 differs from Configuration 1 by a 250-kW reduction in the generating capacity of the propane NZE technology. Because Configuration 2 provides less generation output capacity than Configuration 1, it also would fail to meet demand.[2] Simply put, both proposed configurations would be unable to meet Catalina Island's electrical demand requirements at every hour throughout the year.

In order to determine whether the failure to pass the HOMER Pro analysis was due to the propane fuel availability parameters identified in the SCAQMD's proposed configurations, POWER revised the model to allow the consumption of an unlimited amount of propane before rerunning the configuration. Again, the outcome was reported as infeasible. Configuration 2 would have the same result (failure) because, as mentioned above, it provides less generation output capacity than Configuration 1. Even when all constraints on fuel consumption parameters for both propane and diesel are removed (allowing unlimited consumption), neither configuration provides the necessary generation resource adequacy to ensure sufficient power supply to meet the requirements of Catalina Island customers. This indicates the failure of these two configurations is due to the lack of generation output capacity rather than fuel availability.

The purpose of modeling generation scenarios using software such as HOMER Pro is to determine whether they will meet the generation resource adequacy requirements of the electrical system being studied (e.g., Catalina Island). When an analysis produces a result that demonstrates the studied scenario is unable to supply the amount of generation required, the consequences (should such a scenario be implemented) can include the following at every instance when a deficiency is identified:

- Required forced load shedding[3] of customer demand to reduce consumption to within the limits of the generation resource mix contemplated; or
- System instability resulting in system collapse (i.e., island blackout) if the aforementioned load shedding does not occur or does not occur quickly enough.

The results from the HOMER Pro analysis of Configuration 1 identified over 1,000 instances where it was unable to supply the amount of generation required to meet customer demand. The analysis was performed on an hourly basis throughout the year (i.e., all 8,760 hours in one year); the number of instances in which there was insufficient power to supply Catalina customers equates to over 10% of the time annually. Configuration 2, which has 250 kW less generation capacity than Configuration 1, would be expected to cause even more instances where the system would be unable to supply the amount of generation required to meet customer demand.

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[2] POWER did not run Configuration 2 through HOMER Pro because the failure of Configuration 1, which provides more generation capacity, shows that Configuration 2 would fail as well.

[3] Forced load shedding refers to manual intervention by system operators to reduce loading by turning power off to customers. Typically, this would take the form of rotating outages for a specified duration and amount until the imbalance of generation to load can be remedied.

Had Configuration 1 passed the HOMER Pro stage, the program would have generated a table displaying the relative share of generation that each element of the configuration provided along with number of gallons of fuel consumed by each fuel type as shown in Figure 2 below (which was previously provided in Exhibit C to SCE's April 28, 2023 letter):

TABLE 2: CONFIGURATION A HOMER MODEL RESULTS		
Unit	**Annual Output (kWh) / Annual %**	**Gallons / Fuel Type**
Microturbines	1,053,437 / 3%	208,689 / Propane
Backup Diesel Unit 7	570,118 / 1.85%	50,764 / Diesel
Backup Diesel Unit 12	769,934 / 2.5%	68,359 / Diesel
Backup Diesel Unit 14	1,365,916 / 4.44%	121,849 / Diesel
T4F Unit A	13,539,007 / 44%	948,853 / Diesel
T4F Unit B	9,969,278 / 32.4%	725,492 / Diesel
T4F Unit C	3,519,231 / 11.4%	283,862 / Diesel
Totals	30,786,921 kW Annual Demand	208,689 / Propane 2,199,178 / Diesel

Figure 1. Example of Successful HOMER Pro Configuration

However, since Configuration 1 failed (as would Configuration 2), the model could not produce similar results (only the error message shown in Figure 1 above).

In conclusion, both SCAQMD-requested configurations were found to be infeasible to meet the electrical demand and maintain a stable electrical system. No further analysis will be conducted of these two scenarios. SCE will continue to assess the remaining scenarios in the Grid Stability Study to determine which will ensure safe, reliable, and affordable electricity production while reducing emissions and maintaining environmental stewardship.

I appreciate the opportunity to collaborate with the SCAQMD to bring alternative cleaner power generation solutions to Catalina Island. If you have questions or concerns regarding the HOMER Pro analysis, please contact me at (626) 302-4411 or kelly.henderson@sce.com.

Sincerely,

Kelly Henderson

Kelly Henderson, Esq.
Senior Attorney

cc: Michael Krause
Chris Perri

September 6, 2023

Catalina Grid Stability Study Scenarios

1. ***Scenarios That Passed HOMER Pro***

Of the scenarios that passed the HOMER Pro analysis stage (which evaluates whether a configuration provides sufficient generation supply to meet electrical demand), only two provided sufficient generation supply and maximized propane use to warrant PSCAD & CYME modeling (grid stability and protection studies): Nos. 3 and 4(b). For definitions of and details about HOMER Pro, PSCAD & CYME, please see the presentation SCE provided on August 8, 2023.

#	Scenario	Considerations
1	• Three Tier 4 Final-certified diesel generators (A, B, and C) • Retain Units 7, 12, and 14 • Retain existing sodium sulfur (NaS) battery (1 MW/7 MWh) • One 4 MW propane reciprocating generator (2.097 MW prime) w/ propane stored in 3 tanks (400,000 gallons per year)	Completed HOMER but did not proceed to PSCAD & CYME analysis; due to the operational limitations of propane reciprocating generators, this technology did not maximize the use of limited propane fuel. See the explanation at the end of this table.
2	• Three T4F generators (A, B, and C) • Retain Units 7, 12, and 14 • Retain existing NaS battery (1 MW/7 MWh) • One 4 MW propane reciprocating generator (2.097 MW prime) w/ propane stored in 3 tanks (400,000 gallons per year) • Solar farm (4.5 MWac, 5.6 MWdc, no battery)	Modified to become Condition 2(a) to pair the solar farm with battery storage.
2a	***Added in early July.*** • Three T4F generators (A, B, and C) • Retain Units 7, 12, and 14 • Retain existing NaS battery (1 MW/7 MWh) • One 4 MW propane reciprocating generator (2.097 MW prime) w/ propane stored in 3 tanks (400,000 gallons per year) • Solar farm **paired with battery (4.5 MWac, 5.6 MWdc with a 2 MW/8 MWh battery)**	Modified once more to become Condition 2(b) to upgrade the existing NaS battery from 1 MW to 1.5 MW.

#	Scenario	Considerations
2b	***Added in late July.*** • Three T4F generators (A, B, and C) • Retain Units 7, 12, and 14 • **Upgrade existing PBGS NaS battery (1.5 MW/7 MWh)** • One 4 MW propane reciprocating generator (2.097 MW prime) w/ propane stored in 3 tanks (400,000 gallons per year) • Solar farm **paired with battery (4.5 MWac, 5.6 MWdc with a 2 MW/8 MWh battery)**	Completed HOMER but did not proceed to PSCAD & CYME analysis; due to the operational limitations of propane reciprocating generators, this technology did not maximize/optimize the use of limited propane fuel. See the explanation at the end of this table.
3	• Three T4F generators (A, B, and C) • Retain Units 7, 12, and 14 • Retain existing NaS battery (1 MW/7 MWh) • Five 250 kW propane linear generators (1.25 MW total) w/ propane stored in 3 tanks (400,000 gallons per year)	Completed HOMER and currently under PSCAD & CYME analysis.
4	• Three T4F generators (A, B, and C) • Retain Units 7, 12, and 14 • Retain existing NaS battery (1 MW/7 MWh) • Five 250 kW propane linear generators (1.25 MW total) w/ propane stored in 3 tanks (400,000 gallons per year) • Solar farm (4.5 MWac, 5.6 MWdc, no battery)	Modified to become Condition 4(a) to pair the solar farm with battery storage.
4a	***Added in early July.*** • Three T4F generators (A, B, and C) • Retain Units 7, 12, and 14 • Retain existing NaS battery (1 MW/7 MWh) • Five 250 kW propane linear generators (1.25 MW total) w/ propane stored in 3 tanks (400,000 gallons per year) • Solar farm **paired with battery (4.5 MWac, 5.6 MWdc with a 2 MW/8 MWh battery)**	Modified once more to become Condition 4(b) to upgrade the existing NaS battery from 1 MW to 1.5 MW.

#	Scenario	Considerations
4b	***Added in late July.*** • Three T4F generators (A, B, and C) • Retain Units 7, 12, and 14 • **Upgrade existing PBGS NaS battery (1.5 MW/7 MWh)** • Five 250 kW propane linear generators (1.25 MW total) w/ propane stored in 3 tanks (400,000 gallons per year) • Solar farm **paired with battery (4.5 MWac, 5.6 MWdc with a 2 MW/8 MWh battery)**	Completed HOMER and currently under PSCAD & CYME analysis.

<u>Explanation for De-prioritization of Scenarios With Propane Reciprocating Generators (Nos. 1, 2, 2a, & 2b)</u>

One of SCE's overarching priorities is to maximize the use of near-zero emission and zero-emission technologies while meeting our obligation to provide safe, reliable, and affordable utility services to our customers. As a result, higher priority was given to the propane-fueled technology that provided the greatest potential to maximize propane fuel use while also providing the greatest operational flexibility in generation dispatch. The key consideration associated with the selection of linear propane generators for further grid stability modeling is that the propane reciprocating generator has an operating range of between 75% and 100% of its prime output rating of 2.097 MW (where this is the derated value due to propane fuel use). This equates to an operating range of 1.573 MW to 2.097 MW leading to many instances where the minimum loading of the propane reciprocating generator would be greater than the needed capacity and therefore it would not be dispatched. This would result in adversely impacting the ability to maximize the use of propane fuel. In contrast, with respect to the linear generators, the smaller unit size and consequential ability to dispatch any number of units results in a much greater and flexible operating range. The operating range would be between the minimum output of a single unit up through the maximum output of 1.25 MW. This would allow operators to bring the linear generators online as needed in smaller increments to produce power.

2. ***Scenarios Eliminated Without HOMER Pro Analysis***

#	Scenario	Considerations
5	• Three T4F generators (A, B, and C) • Retain Units 7, 12, and 14 • Retain existing NaS battery (1 MW/7 MWh) • One 4 MW propane reciprocating generator (2.097 MW prime) w/ propane stored in 4 tanks (750,000 gallons per year)	Eliminated from further grid stability modeling. The AHJ (City of Avalon Fire Department) has deemed the use of a fourth propane storage tank at PBGS infeasible due to insufficient fire suppression, current clearance distances, and the need for increased deliveries.
6	• Three T4F generators (A, B, and C) • Retain Units 7, 12, and 14 • Retain existing NaS battery (1 MW/7 MWh) • One 4 MW propane reciprocating generator (2.097 MW prime) w/ propane stored in 4 tanks (750,000 gallons per year) • Solar farm (4.5 MWac, 5.6 MWdc, no battery)	Same as #5.
7	• Three T4F generators (A, B, and C) • Retain Units 7, 12, and 14 • Retain existing NaS battery (1 MW/7 MWh) • Five 250 kW “grid-forming” propane linear generators (1.25 MW total) w/ propane stored in 4 tanks (750,000 gallons per year)	Same as #5.
8	• Three T4F generators (A, B, and C) • Retain Units 7, 12, and 14 • Retain existing NaS battery (1 MW/7 MWh) • Five 250 kW “grid-forming” propane linear generators (1.25 MW total) w/ propane stored in 4 tanks (750,000 gallons per year) • Solar farm (4.5 MWac, 5.6 MWdc, no battery)	Same as #5.

#	Scenario	Considerations
9	• Three T4F generators (A, B, and C) • Retain Units 7, 12, and 14 • **Upgrade existing PBGS NaS battery (1.5 MW/7 MWh)** • One 4 MW propane reciprocating generator (2.097 MW prime) w/ propane stored in 3 tanks (400,000 gallons per year)	Removed this scenario due to timeline constraints and the need to prioritize efforts on #4b.
10	• Three T4F generators (A, B, and C) • Retain Units 7, 12, and 14 • **Upgrade existing PBGS NaS battery (1.5 MW/7 MWh)** • One 4 MW propane reciprocating generator (2.097 MW prime) w/ propane stored in 3 tanks (400,000 gallons per year) • Solar farm (4.5 MWac, 5.6MWdc, no battery)	Same as #9.
11	• Three T4F generators (A, B, and C) • Retain Units 7, 12, and 14 • **Upgrade existing PBGS NaS battery (1.5 MW/7 MWh)** • Five 250 kW propane linear generators (1.25 MW total) w/ propane stored in 3 tanks (400,000 gallons per year)	Same as #9.
12	• Three T4F generators (A, B, and C) • Retain Units 7, 12, and 14 • **Upgrade existing PBGS NaS battery (1.5 MW/7 MWh)** • Five 250 kW propane linear generators (1.25 MW total) w/ propane stored in 3 tanks (400,000 gallons per year) • Solar farm (4.5-MWac, 5.6 MWdc, no battery)	Same as #9.

#	Scenario	Considerations
13	• Three T4F generators (A, B, and C) • Retain Units 7, 12, and 14 • **Upgrade existing PBGS NaS battery (1.5 MW/7 MWh)** • One 4 MW propane reciprocating generator (2.097 MW prime) w/ propane stored in 4 tanks (750,000 gallons per year)	Same as #5.
14	• Three T4F generators (A, B, and C) • Retain Units 7, 12, and 14 • **Upgrade existing PBGS NaS battery (1.5 MW/7 MWh)** • One 4 MW propane reciprocating generator (2.097 MW prime) w/ propane stored in 4 tanks (750,000 gallons per year) • Solar farm (4.5 MWac, 5.6 MWdc, no battery)	Same as #5.
15	• Three T4F generators (A, B, and C) • Retain Units 7, 12, and 14 • **Upgrade existing PBGS NaS battery (1.5 MW/7 MWh)** • Five 250 kW propane linear generators (1.25 MW total) w/ propane stored in 4 tanks (750,000 gallons per year)	Same as #5.
16	• Three T4F generators (A, B, and C) • Retain Units 7, 12, and 14 • **Upgrade existing PBGS NaS battery (1.5 MW/7 MWh)** • Five 250 kW propane linear generators (1.25 MW total) w/ propane stored in 4 tanks (750,000 gallons per year) • Solar farm (4.5 MWac, 5.6 MWdc, no battery)	Same as #5.

September 27, 2023

SOUTHERN CALIFORNIA EDISON

Pebbly Beach Generating Station

Combined HOMER Pro Memos

Revision 0

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176291

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POWER ENGINEERS

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SCENARIO DESCRIPTION

The scenario analyses for the Pebbly Beach Generation Station (PBGS) were performed using HOMER Pro software. Scenarios 1 through 4b and SCAQMD Configurations 1 & 2 shown below were evaluated to consider their comparative performance. All generators were modeled with maintenance scheduling and extrapolated loading data for 2026.

Scenario 1:

- Three (3) Tier 4 Finals (A, B, and C)
- Existing Unit 7, 12, and 14
- Existing NaS Battery
- One (1) 4 MW Propane Reciprocating Generator (PRG) (2.097 MW Prime) limited to 400k gallons of propane

Scenario 2:

- Three (3) Tier 4 Finals (A, B, and C)
- Existing Unit 7, 12, and 14
- Existing NaS Battery
- One (1) 4 MW Propane Reciprocating Generator (2.097 MW Prime) limited to 400k gallons of propane
- 4.5 MW Solar Photovoltaic (PV) farm

Scenario 2a:

- Three (3) Tier 4 Finals (A, B, and C)
- Existing Unit 7, 12, and 14
- Existing NaS Battery
- One (1) 4 MW Propane Reciprocating Generator (2.097 MW Prime) limited to 400k gallons of propane
- 4.5MW Solar PV farm paired with a 2MW/8MWh BESS

Scenario 2b:

- Three (3) Tier 4 Finals (A, B, and C)
- Existing Unit 7, 12, and 14
- Upgraded existing 1.5/7MWh NaS Battery
- One (1) 4 MW Propane Reciprocating Generator (2.097 MW Prime) limited to 400k gallons of propane
- 4.5MW Solar PV farm paired with a 2MW/8MWh BESS

Scenario 3:

- Three (3) Tier 4 Finals (A, B, and C)
- Existing Unit 7, 12, and 14
- Existing NaS Battery
- 5, 250 kW “Grid-Forming” Propane-Fuel Linear Generators (1.25 MW, total) limited to 400k gallons of propane

Scenario 4:

- Three (3) Tier 4 Finals (A, B, and C)
- Existing Unit 7, 12, and 14
- Existing NaS Battery
- 5, 250 kW "Grid-Forming" Propane-Fuel Linear Generators (1.25 MW, total) limited to 400k gallons of propane
- 4.5MW Solar PV farm

Scenario 4a:

- Three (3) Tier 4 Finals (A, B, and C)
- Existing Unit 7, 12, and 14
- Existing NaS Battery
- 5, 250 kW "Grid-Forming" Propane-Fuel Linear Generators (1.25 MW, total) limited to 400k gallons of propane
- 4.5MW Solar PV farm paired with a 2MW/8MWh BESS

Scenario 4b:

- Three (3) Tier 4 Finals (A, B, and C)
- Existing Unit 7, 12, and 14
- Upgraded existing 1.5/7MWh NaS Battery
- 5, 250 kW "Grid-Forming" Propane-Fuel Linear Generators (1.25 MW, total) limited to 400k gallons of propane
- 4.5MW Solar PV farm paired with a 2MW/8MWh BESS

SCAQMD Configuration 1:

- Utility Scale Renewable Photovoltaic (PV) System (30% of annual load)
- Three Tier 4 Final Diesel Generators (1.825 MW each)
- Existing NaS Battery System
- Five new battery systems (1 MW each)
- Propane near zero emission (NZE) technology with a combined rating of at least 2.25 MW (65% of annual load)

SCAQMD Configuration 2:

- Utility Scale Renewable PV System (30% of annual load)
- Three Tier 4 Final Diesel Generators (1.825 MW each)
- Existing NaS Battery System
- Five new battery systems (1 MW each)
- Propane NZE technology with a combined rating of at least 2 MW (50% of annual load)

ASSUMPTIONS IN THE MODELS INCLUDE THE FOLLOWING:

- 75% minimum loading on the Propane Reciprocating Engines
- Propane Reciprocating Engines' maintenance activities match those of the T4 units
- 10% minimum charge on the existing battery system
- Load demand forecasted data for 2026 reflecting a peak of 6 MW and approximately 31 GWh annual loading
- Existing NaS BESS modeled with a round-trip efficiency of 85% in all cases
- Annual consumption of 400,000 gallons of propane
- 6% minimum power reserve requirement
- 12 unplanned maintenance activities per T4 unit with randomized outage durations
- 1 Tier 4 Final unit receiving 3-month long maintenance
- 2 Tier 4 Final units receiving a month-long maintenance activity
- 1 biweekly planned maintenance activity per Tier 4 Final unit with a 10 hour downtime
- Scheduled maintenance on the Emergency Diesel Generators every 480 hours, 48 hour downtime
    - The Emergency Diesel Generators were excluded from the SCAQMD Configurations 1 & 2
- 90% minimum loading on the Emergency Diesel Generators
    - The Emergency Diesel Generators were excluded from the SCAQMD Configurations 1 & 2
- The BESS was modeled in aggregate as:
    - Scenarios 2a and 4a: 3MW/15MWh system (i.e., the existing PBGS NaS BESS at 1MW/7MWh plus a renewable PV system paired with a BESS at 2MW/8MWh)
    - Scenarios 2b and 4b: 3.5MW/15MWh system (i.e., the existing PBGS NaS BESS at 1.5MW/7MWh plus a renewable PV system paired with a BESS at 2MW/8MWh)
    - SCAQMD Configurations 1 & 2: 6MW/27MWh system (i.e., the existing PBGS NaS BESS at 1MW/7MWh plus a renewable PV system paired with a BESS at 5MW/20MWh)
- Does not yet consider potential stability concerns from insufficient inertia
- Proposed 2MW/8MWh BESS may prove infeasible due to fire suppression concerns
- All scenarios are for potential future island configurations and are subject to change

The results of the models are shown in Table 1 which presents a comparison of fuel consumption and percent of electrical generation for each source across the scenarios. Figures 1 and 2 provide a graphical depiction of the data shown in Table 1. Note: due to the constraints of 400k gallons of propane and 4.5 MW of rated Solar PV being held constant, diesel is the only uncontrolled variable system thus Figure 1 only presents a comparison of diesel consumption.

HOMER Pro was unable to produce a result for SQAMD Configuration 1 due to unmet capacity requirements which is shown in Figure 3. This result implies that SQAMD Configuration 2 will also fail as the generation capacity for this configuration is reduced from the first configuration by 250 kW. The model was then permitted to consume an unlimited amount of propane; this also did not yield a result. Next the restrictions on diesel were removed, this also did not produce a feasible result. Given that unrestricted fuel consumption does not suffice, it is determined that these configurations are outside of the Pebbly Beach Generating Station's operational capabilities.

Table 1: Comparison of generation configurations

SCENARIO 1			
Unit	**Gallons**	**Fuel Type**	**% Load Served**
DG Unit 7	144,981.41	Diesel	5.21%
DG Unit 12	15,008.66	Diesel	0.539%
DG Unit 14	79,720.08	Diesel	2.86%
T4F Unit A	470,835.55	Diesel	19.6%
T4F Unit B	877,733.21	Diesel	40.1%
T4F Unit C	430,816.58	Diesel	19%
PRG	399,478.20	Propane	12.7%
SCENARIO 2			
DG Unit 7	50,400.80	Diesel	1.83%
DG Unit 12	1,814.21	Diesel	0.07%
DG Unit 14	34,539.91	Diesel	1.24%
T4F Unit A	288,225.70	Diesel	11.59%
T4F Unit B	765,532.68	Diesel	34.32%
T4F Unit C	315,039.38	Diesel	12.99%
PRE	399,999.86	Propane	12.66%
Solar PV	-	-	25.31%
SCENARIO 2a			
DG Unit 7	64,661.78	Diesel	2.32%
DG Unit 12	7,377.22	Diesel	0.26%
DG Unit 14	43,683.02	Diesel	1.57%
T4F Unit A	293,340.96	Diesel	11.85%
T4F Unit B	686,806.82	Diesel	30.25%
T4F Unit C	298,155.79	Diesel	12.12%
PRE	399,999.86	Propane	12.66%
Solar PV	-	-	28.97%
SCENARIO 2b			
DG Unit 7	64,581.00	Diesel	2.32%
DG Unit 12	7,377.22	Diesel	0.26%
DG Unit 14	43,457.30	Diesel	1.56%
T4F Unit A	293,480.35	Diesel	11.85%
T4F Unit B	687,687.79	Diesel	30.29%
T4F Unit C	298,353.53	Diesel	12.13%
PRE	398,601.98	Propane	12.62%
Solar PV	-	-	28.97%

SCENARIO 3			
DG Unit 7	106,442.42	Diesel	3.82%
DG Unit 12	10,159.78	Diesel	0.37%
DG Unit 14	65,499.46	Diesel	2.35%
T4F Unit A	451,745.98	Diesel	18.90%
T4F Unit B	908,039.62	Diesel	41.70%
T4F Unit C	426,766.30	Diesel	18.80%
Linear Generator	399,999.86	Propane	14.10%
SCENARIO 4			
DG Unit 7	44,666.69	Diesel	1.60%
DG Unit 12	1,451.21	Diesel	0.05%
DG Unit 14	26,299.94	Diesel	0.94%
T4F Unit A	265,013.23	Diesel	10.52%
T4F Unit B	791,505.00	Diesel	35.66%
T4F Unit C	296,835.00	Diesel	12.05%
Linear Generator	399,999.86	Propane	14.14%
Solar PV	-	-	25.03%
SCENARIO 4a			
DG Unit 7	49,826.57	Diesel	1.79%
DG Unit 12	4,837.54	Diesel	0.17%
DG Unit 14	37,474.80	Diesel	1.35%
T4F Unit A	282,793.90	Diesel	11.30%
T4F Unit B	686,547.58	Diesel	30.23%
T4F Unit C	297,180.31	Diesel	12.07%
Linear Generator	399,995.11	Propane	14.09%
Solar PV	-	-	29.00%
SCENARIO 4b			
DG Unit 7	49,826.57	Diesel	1.79%
DG Unit 12	4,837.54	Diesel	0.17%
DG Unit 14	37,474.80	Diesel	1.35%
T4F Unit A	282,761.69	Diesel	11.30%
T4F Unit B	686,906.62	Diesel	30.25%
T4F Unit C	297,226.51	Diesel	12.07%
Linear Generator	399,455.23	Propane	14.07%
Solar PV	-	-	29.00%

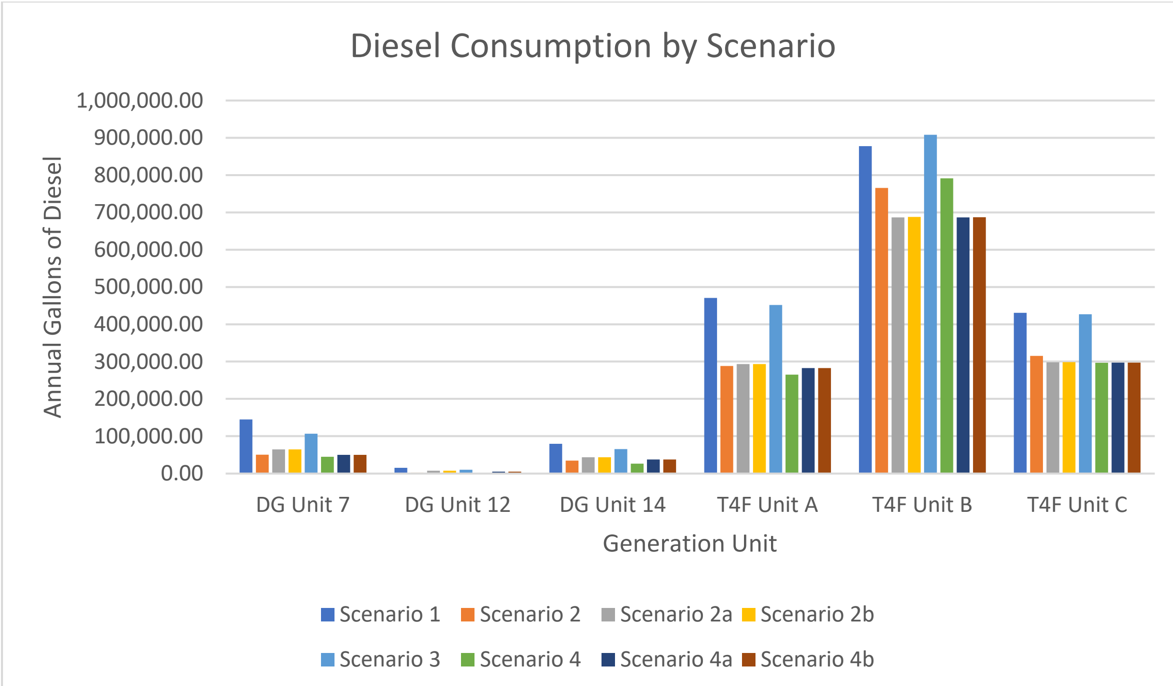

Figure 1: Diesel Consumption by Scenario

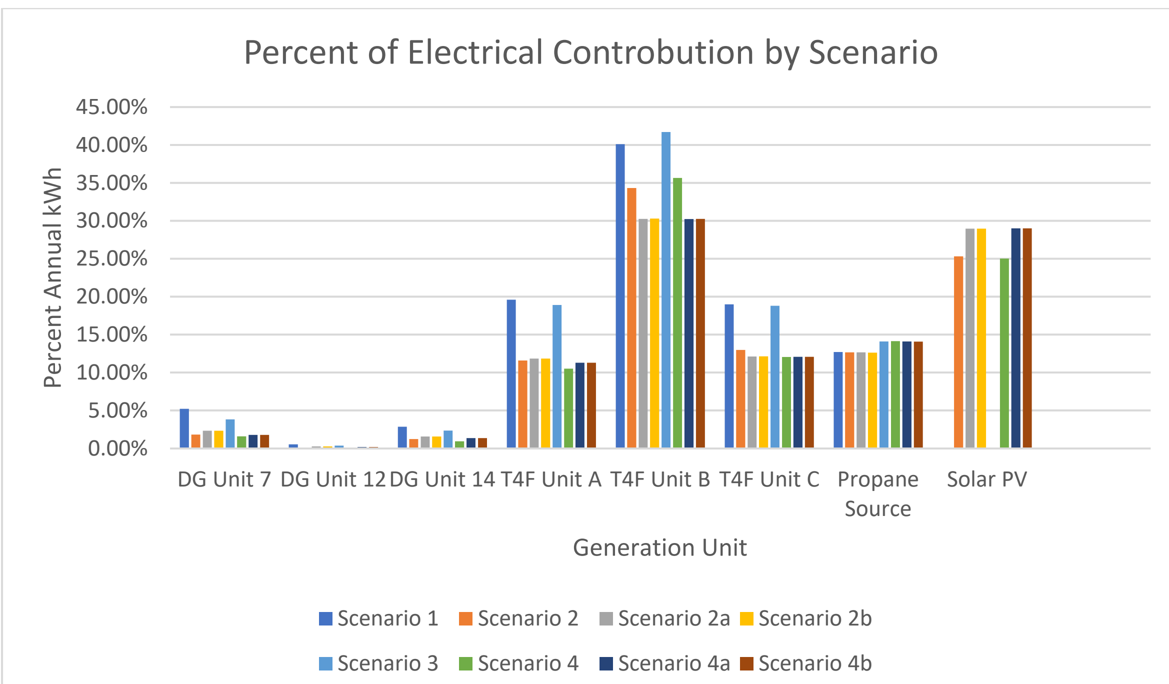

Figure 2: Percent Electrical Contribution by Scenario

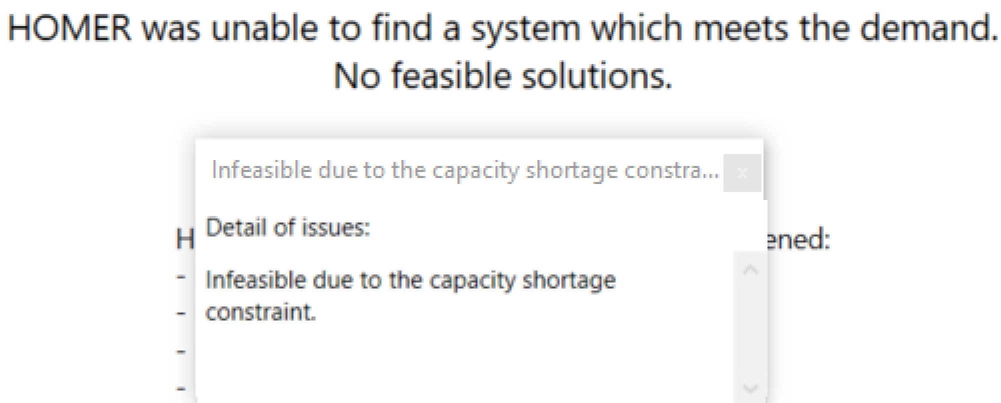

Figure 3: HOMER Pro output for SCAQMD Configuration 1

September 27, 2023

SOUTHERN CALIFORNIA EDISON

Pebbly Beach Generating Station

PSCAD Stability Study

Revision 0

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EXECUTIVE SUMMARY

POWER Engineers (POWER) developed a PSCAD model representation of the Pebbly Beach Generation Station (PBGS) in which various proposed mixes of generation are considered. The purpose of this study is to assess how the various generation mixes and dispatches can affect the stability of the Catalina grid. For these tests, the measured Rate of Change of Frequency (ROCOF) on the grid from consistent disturbances under different generation dispatches is used to compare these effects.

The study makes the following conclusions:

- Having more Tier 4 Final (T4F) units online and powering the system leads to increased system stability.
- The stability benefits of the T4F units are based upon the number of units online regardless of loading levels.
- An Inverter-Based Resource (IBR) responds more quickly to system disturbances than the governor response of a synchronous generator which can improve ROCOF. However, ROCOF response is limited by BESS state-of-charge constraints. There are additional limitations with IBR technology such as limitations on fault current contribution. In addition, traditional IBRs provide no inertia to system stability which is something that is provided with synchronous generators.
- The grid-forming (GFM) linear generator (LG) showed similar improvement in ROCOF to that of adding a 2nd T4F diesel generator regarding reducing ROCOF. While this technology can be a useful asset in providing stability to the grid, limited reliance should be placed upon it based upon the newness of this technology as well as the constraints on propane availability at PBGS.

It is recommended that two (2) T4F diesel generators be planned for spinning operations at all times to maintain sufficient frequency stability for the island of Catalina. During contingencies when only one (1) T4F unit is available, then an emergency backup diesel generator must be available and brought online, as such it is recommended that Units 7, 12, and 14 remain on site. The adoption of the GFM LG is also recommended to further enhance the stability of the grid. It should be noted that this recommendation is specifically for the GFM version of the LGs. Grid-following (GFL) versions of this product exist and would not provide the same benefits noted here.

BACKGROUND

SCE has observed system stability issues with the present-day generation configurations on the island of Catalina. Energy to the island is primarily provided by the PBGS which presently consists of a mix of diesel generators, microturbines, and an existing Battery Energy Storage System (BESS). The microturbines and the existing BESS, each an IBR, were susceptible to nuisance tripping on common system disturbances like large load steps or faults. ROCOF was the primary culprit in these nuisance trips and represented a risk to reliability for the system. Present-day mitigation is to keep the generation contribution from these IBRs to approximately 30% or less of the loading with the remainder provided by the diesel generators. It should be noted that the microturbines are being considered for replacement with LG and that the existing BESS may be a candidate for refurbishment and upgrade. A study was requested by SCE to evaluate the system stability under proposed generation changes.

Additionally, it should be noted that stability for this study is focused on system frequency. Presently, the biggest indication of the system losing stability would be if an under-frequency load shedding (UFLS) scheme needed to be tripped. This would be a loss in power to a large section of the grid with the purpose of reducing the load for the PBGS plant. The idea is that some of the load could be tripped offline to save the rest of the grid. This is typically a last resort to save the grid from a total collapse. An UFLS event can be trigged by a sufficiently large drop in frequency in both amplitude and duration. Therefore, it is pivotal to the energy security and reliability for the island that a sufficiently stable frequency be provided. Presently, a ROCOF of 1.0 Hz/sec could cause the microturbines and existing BESS on the island to trip offline. A loss of this generation under the wrong conditions could lead to an UFLS event.

Frequency stability is traditionally associated with forms of spinning generation like diesel generators. These typically involve synchronous generators which have a spinning mass and provide a mechanical inertia. This inertia helps to stabilize the grid during a transient event like a large load step or a fault. In contrast, IBRs do not inherently provide inertia. They typically operate in a GFL mode of operation which relies upon the stability and frequency provided by other components of the grid. This is true for the present condition of PBGS where all IBRs are grid-following. As part of this study, a new form of IBR control is introduced which is known as GFM. In general, GFM provides more support to the system that aims to add increased stability to system frequency and thus provides support to the broader electrical grid. This is a newer technology that is advancing but not yet deployed at the utility-scale, and has typically been deployed in smaller electrical systems like microgrids.

This frequency stability study builds off a generation feasibility study conducted using the HOMER Pro software. In this study, multiple sources of generation were evaluated in various combinations against the projected peak power and annual energy demands for 2026. The results of the generation feasibility study indicate that four (4) scenarios (two of which are broken into sub scenarios A and B) have the potential to meet the island's loading demand. This data informs this frequency stability study as to which generation sources and combinations are to be evaluated. The scenarios are presented in Table 1.

TABLE 1: SCENARIOS BEING CONSIDERED			
SCENARIO 3	**SCENARIO 4**	**SCENARIO 4A**	**SCENARIO 4B**
3 Tier 4 Finals (A, B, and C)	3 Tier 4 Finals (A, B, and C)	3 Tier 4 Finals (A, B, and C)	3 Tier 4 Finals (A, B, and C)
Existing Unit 7, 12, and 14	Existing Unit 7, 12, and 14	Existing Unit 7, 12, and 14	Existing Unit 7, 12, and 14
Existing NaS Battery	Existing NaS Battery	Existing NaS Battery	Upgraded existing 1.5/7MWh NaS Battery
5, 250 kW "Grid-Forming" Propane-Fuel Linear Generators (1.25-MW, total) limited to 400k gallons of propane	5, 250 kW "Grid-Forming" Propane-Fuel Linear Generators (1.25-MW, total) limited to 400k gallons of propane	5, 250 kW "Grid-Forming" Propane-Fuel Linear Generators (1.25-MW, total) limited to 400k gallons of propane	5, 250 kW "Grid-Forming" Propane-Fuel Linear Generators (1.25-MW, total) limited to 400k gallons of propane
	4.5MW Solar PV farm	4.5MW Solar PV farm paired with a 2MW/8MWh BESS	4.5MW Solar PV farm paired with a 2MW/8MWh BESS

PROCEDURE

POWER's work builds upon a PSCAD model previously developed with modifications to the latest generation considerations. System stability was tested by observing ROCOF during 150 kVA load step changes under varying generation dispatches and loading conditions. This test does not represent the largest type of transient the system could incur, such as a three-phase fault, but represents a good repeatable and representative test by which to compare different generation dispatches. The philosophy is that lower ROCOF correlates with higher stability for system frequency.

Loading was updated to be representative of the year 2026 load forecast provided by SCE with maximum loading being 5.98 MVA and minimum loading being 2.20 MVA. Table 2 summarizes the generation components considered when performing the stability analysis. The minimum and maximum power ranges are given for when the units produce power. The units are all also capable of producing 0 MVA by being completely offline. Three of the existing generating units (Units 8, 10, and 15) are slated to be replaced with T4F diesel generators. Existing diesel generating Units 7, 12, and 14 are to remain as-is. The before-mention microturbines may be replaced with propane LGs. Finally, a proposed PV+BESS site is introduced which are co-located located outside of the PBGS facility (e.g, Middle Ranch) and would be connected to the 12 kV distribution circuit of the island.

The controls of the generating units are based upon typical generation control models with slight adjustments made based upon known settings such as voltage and frequency droop control gains on the synchronous generating units. All diesel generators are on a shared droop control scheme. The PV and BESS inverters are all generic operating as simple constant-power sources. Only the LG have detailed control from a manufacturer-provided model. Knowing that the controls are somewhat generic, a simpler load-step test approach was utilized. This type of test relies less heavily upon the details of a tuned generator control system as opposed to a more aggressive fault test. Using this testing method will allow for quality comparisons between the different generation resources. It is noted that more aggressive fault disturbances will result in higher ROCOFs that the results presented here. A separate study investigates these types of disturbances.

TABLE 2: GENERATION COMPONENTS CONSIDERED		
TYPE	**MINIMUM (MVA)**	**MAXIMUM (MVA)**
THREE (3) T4F DIESEL GENERATORS (UNITS 15, 8, AND 10)	0.570	2.281
UNIT 14 EXISTING DIESEL GENERATOR	1.4	1.75
UNIT 7 EXISTING DIESEL GENERATOR	1	1.25
UNIT 12 EXISTING DIESEL GENERATOR	1.575	3.125
LG	0	1.25
EXISTING PBGS BESS	-1	1
NEW SOLAR AT MIDDLE RANCH	0	4.5
NEW BESS AT MIDDLE RANCH	-2	2

The PBGS system is illustrated in Figure 1. Primary generation includes T4F diesel generation Unit 15 on the 12 kV op bus, followed by Units 8 and 10 (also T4F diesel units) on the 2.4 kV op bus. Backup generation units include diesel generation Units 14, Unit 7, and Unit 12. Also inserted to the 12 kV bus is the existing 1 MW BESS unit, the LG units, and the new Solar and BESS units, which will physically be connected on the distribution circuit but are shown modeled as having an electrical connection to the 12 kV bus for the purposes of this study. Feeder loading consisting of Avalon/Hi Line, Interior, and Wrigley are identified. Lastly, the switched 150 kVA test load is identified and used to study and analyze ROCOF during transient load events.

[redacted]

Figure 1: PSCAD Model of PBGS

Various dispatches of generation were used to meet varying loads with the purpose of measuring ROCOF under a consistent 150 kVA load step. The generation dispatch included the three (3) T4F units, the two BESS (existing and new), the new PV, and the LG. The existing diesel generators (Units 7, 12, and 14) were not included in the dispatch as their use will be to serve as backup for the proposed T4F units.

The primary purpose of the study is to identify the number of T4F units which should be providing power to the system at any given time and/or the amount of power that should be coming from the T4F generators. While it is anticipated that the GFM LG technology should offer improvements to system stability, the newness of the technology comes with risks. Specific examples of this include the fact that GFM IBRs have not yet seen widespread adoption into the grid. There are usually unforeseen consequences with new technology incorporation into the grid. Additionally, propane fuel limitations to the LG limit the annual generation capacity. Therefore, the T4F diesel units provide the most secure, safe, and reliable form of generation to provide stability to the island. Other anticipated findings from this study aim to identify which other forms of generation impact system stability as well as the impact on loading of the units compared to the impacts on ROCOF.

RESULTS AND ANALYSIS

Appendix A contains tables of the results in full. The subsections here will focus on comparative analysis from the tests performed to determine what planning guidance can be taken from these numbers.

Example of Tested System Disturbance

Illustrated in Figure 2 is the per-unitized (pu) grid voltage, frequency, and measured ROCOF for Dispatch 1. The switched load is picked up at 15 sec and dropped at 20 sec. This leads to a transient in the voltage and frequency measurements as well as a maximum ROCOF of 0.836. Figure 3 shows the total real and reactive power draw of all loading, while Figure 4 illustrates the active and reactive power provided from Unit 15 during the test.

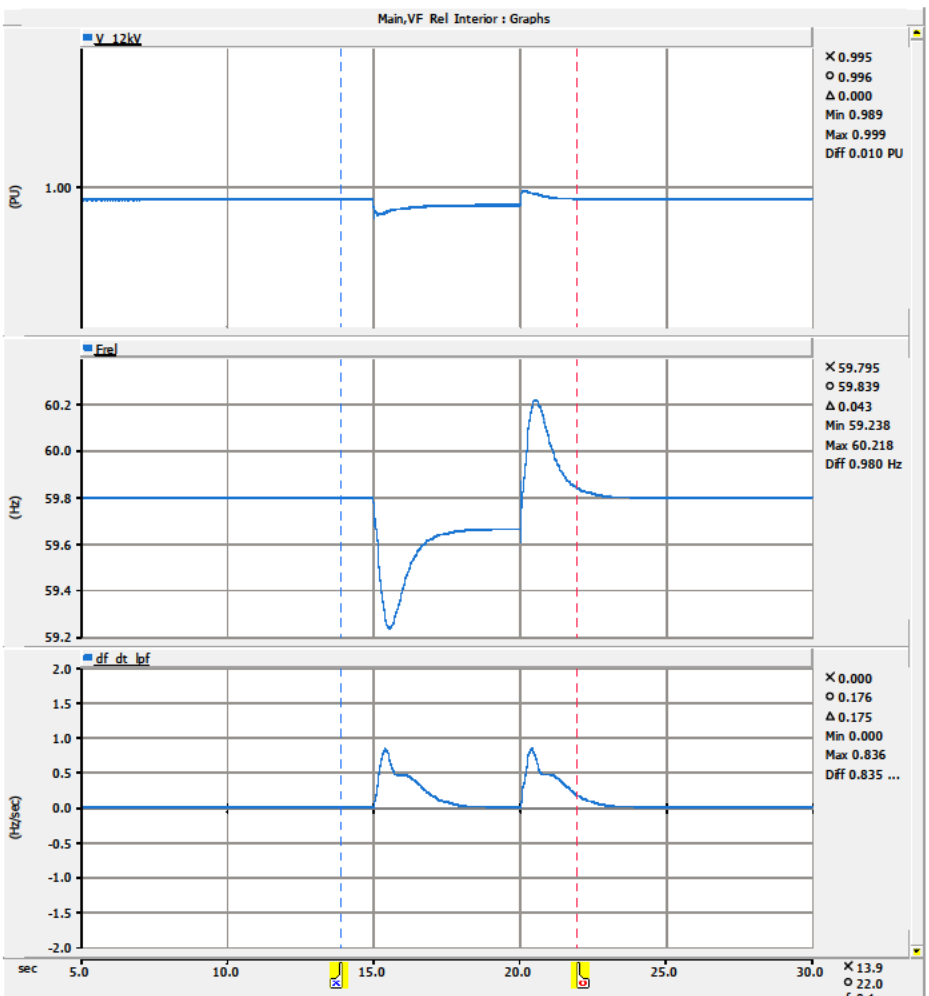

Figure 2: Grid voltage, frequency, and ROCOF during Dispatch 1.

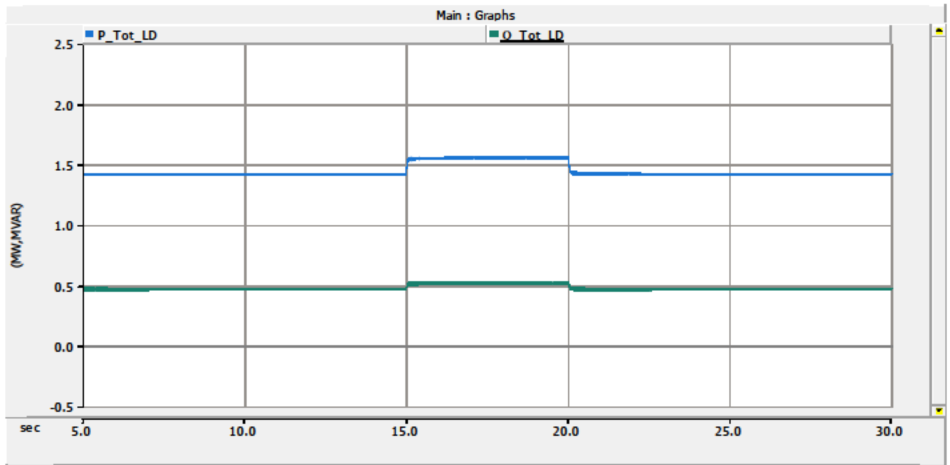

Figure 3: Total load active and reactive power draw during Dispatch 1.

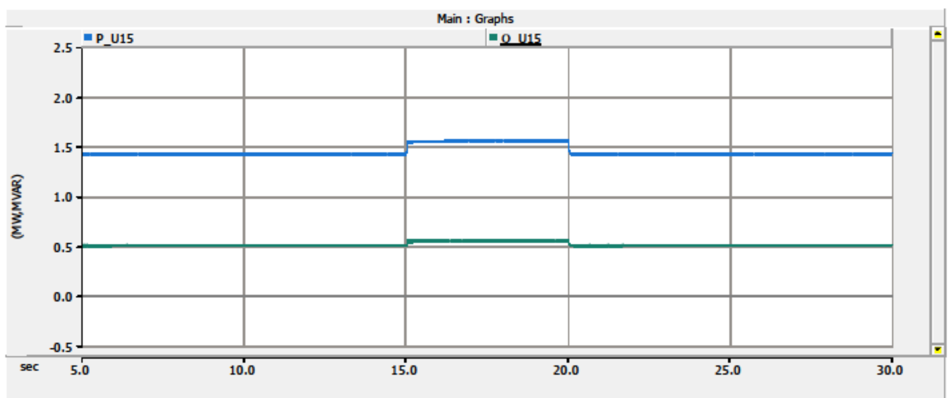

Figure 4: Active and reactive power from T4F diesel generation Unit 15 during Dispatch 1.

Specific Generation Dispatch Analysis

As noted, the entirety of the results can be viewed in the appendix as Table 8. The same data can also be viewed in Table 9 sorted from lowest ROCOF to highest. In these tables and the following, the same color formatting has been used to highlight the relative values of ROCOF. In all tests, the largest ROCOF of 0.839 Hz/sec occurred in Dispatch 16 while the lowest ROCOF occurred for Dispatch 9 which resulted in a peak ROCOF of 0.178 Hz/sec. In each of these ROCOF tables, as well as the subset tables which will follow, the generating units which were providing power during the scenario have their power outputs highlighted to more easily see which units were online and contributing power during each dispatch test. It is also noted that there can be small discrepancies between the sum of the generation and the loading. This is due to transformer power losses in the system and are expected.

The results in Table 3 illustrate how ROCOF changes with the number of T4F units. In all tests, the load was held constant to 1.5 MVA. This loading is below the system minimum loading and is not intended to represent a real loading scenario, rather it helps to illustrate the point being made. Specifically, it demonstrates the relative performance of the dispatches to each other under a consistent loading event. With one T4F unit providing all the power to the island, the ROCOF had an elevated value of 0.836 Hz/sec. When a second T4F unit was brought online to meet the same load, the ROCOF was reduced to 0.351 Hz/sec. Adding the third T4F dropped ROCOF further to 0.228 Hz/sec. This shows that as additional T4F units were brought online to meet the same load, then system stability would increase.

TABLE 3: NUMBER OF T4F VS ROCOF

DISPATCH	LOAD (MVA)	UNIT 15 (MVA)	UNIT 8 (MVA)	UNIT 10 (MVA)	EX BESS (MVA)	SOLAR (MVA)	BESS (MVA)	LG (MVA)	PERCENT T4F	PEAK ROCOF
1	1.50	1.52	0.00	0.00	0.00	0.00	0.00	0.00	100%	0.836
2	1.50	0.78	0.76	0.00	0.00	0.00	0.00	0.00	100%	0.351
3	1.50	0.54	0.51	0.51	0.00	0.00	0.00	0.00	100%	0.228

Having noted the results of Table 3, it would be fair to question whether adding additional T4F units lead to the reduction in ROCOF or if it were due to the fact that the loading on each individual T4F unit was lessened by the addition of more units. The results of Table 4 clarify this. Dispatches 15 – 17 show the change to ROCOF when the loading on a single T4F unit is varied. Similarly, Dispatches 18 – 20 show the same for two T4F units. In each of these groups of tests, the sensitivity of ROCOF changes from varying loading on a fixed number of T4F units is less than when the number of T4F units changed. This demonstrates that the improvement to ROCOF is directly related to the number of T4F units online (regardless of their loading percentage) as opposed to just the amount of load served by T4F units as observed in Table 3.

TABLE 4: ONE OR TWO T4F AND LOADING VS ROCOF

DISPATCH	LOAD (MVA)	UNIT 15 (MVA)	UNIT 8 (MVA)	UNIT 10 (MVA)	EX BESS (MVA)	SOLAR (MVA)	BESS (MVA)	LG (MVA)	PERCENT T4F	PEAK ROCOF
15	0.75	0.77	0.00	0.00	0.00	0.00	0.00	0.00	100%	0.832
16	1.25	1.27	0.00	0.00	0.00	0.00	0.00	0.00	100%	0.839
17	1.75	1.75	0.00	0.00	0.00	0.00	0.00	0.00	100%	0.838
18	1.50	0.78	0.76	0.00	0.00	0.00	0.00	0.00	100%	0.351
19	2.50	1.29	1.24	0.00	0.00	0.00	0.00	0.00	100%	0.335
20	3.50	1.78	1.71	0.00	0.00	0.00	0.00	0.00	100%	0.328

Next, we have the results of Table 5. Here, we see system minimum loading (2.20 MVA) and maximum loading (5.98 MVA) scenarios. For each loading, the dispatch is setup to have either 1, 2, or 3 T4F units providing power. The remainder of the generation is met through a combination of existing BESS, New Solar PV, and New BESS. The ROCOF results show that Dispatch 4 had an elevated ROCOF while the others were smaller. Dispatch 4 being elevated lines up with the thinking that using only a single T4F unit leads to increased ROCOF. Dispatch 7 also has only a single T4F unit but showed reduced ROCOF. The key difference here was the inclusion of the Solar PV along with using both BESS to help meet the loading. The key difference here is in how the IBR BESS and PV operate. Inverters can change their operational output more quickly than a spinning generator which is limited to a slower governor response. In this specific way, IBRs can respond more quickly to dynamic disturbances. This operational difference between IBR and synchronous machine can lead to quicker responses which can help improve ROCOF. However, it must be noted that limitations with IBRs still make it difficult to rely too heavily upon them for system power. For example, inverters cannot contribute significantly to system fault currents the way that synchronous generation can. For this reason, significant synchronous generation, in this case T4F diesel generators, are needed to provide the fault current necessary for safe and reliable protection operation of the electrical system.

TABLE 5: MIN AND MAX LOAD EXAMPLE DISPATCHES VS. ROCOF

DISPATCH	LOAD (MVA)	UNIT 15 (MVA)	UNIT 8 (MVA)	UNIT 10 (MVA)	EX BESS (MVA)	SOLAR (MVA)	BESS (MVA)	LG (MVA)	PERCENT T4F	PEAK ROCOF
4	2.20	1.33	0.00	0.00	0.98	0.00	0.00	0.00	58%	0.727
5	2.20	1.13	1.09	0.00	0.00	0.00	0.00	0.00	100%	0.338
6	2.20	0.78	0.73	0.73	0.00	0.00	0.00	0.00	100%	0.222
7	5.98	0.94	0.00	0.00	0.70	2.93	1.80	0.00	15%	0.309
8	5.98	1.67	1.48	0.00	0.98	0.00	2.00	0.00	51%	0.250
9	5.98	1.25	1.01	1.01	0.98	0.00	2.00	0.00	52%	0.178

The results of Table 6 illustrate how varying penetration levels of Solar PV under consistent loading conditions for either one or two T4F units can affect ROCOF. Dispatches 10 – 12 have loading of 5.98 MVA with two T4F units providing power. Solar PV production ranged from 2.02 – 3.82 MVA. During these tests, the ROCOF decreased slightly with the increased solar contribution. This supports the findings that IBRs can provide frequency response. Similar results are shown in Dispatches 13 and 14 although with elevated ROCOF due to the reducing in T4F units from two to one.

TABLE 6: T4F OFFSET BY PV VS. ROCOF

DISPATCH	LOAD (MVA)	UNIT 15 (MVA)	UNIT 8 (MVA)	UNIT 10 (MVA)	EX BESS (MVA)	SOLAR (MVA)	BESS (MVA)	LG (MVA)	PERCENT T4F	PEAK ROCOF
10	5.98	2.04	1.88	0.00	0.00	2.02	0.00	0.00	66%	0.267
11	5.98	1.68	1.51	0.00	0.00	2.93	0.00	0.00	52%	0.253
12	5.98	1.35	1.14	0.00	0.00	3.82	0.00	0.00	40%	0.239
13	4.50	1.91	0.00	0.00	0.00	2.51	0.00	0.00	43%	0.485
14	4.50	1.23	0.00	0.00	0.00	3.40	0.00	0.00	27%	0.432

The last dispatch tests compiled for analysis in Table 7 focus on the impacts of the GFM LGs. In Dispatches 21 and 22, a single T4F generator provides approximately 50% of the 2 MVA load. The other half of the load is met by either the GFM LG or the GFL BESS. Observing the ROCOF results of Dispatches 21 and 22, we observe that the GFM LG reduced system ROCOF similarly to the effect of adding a second T4F generator. We see similar findings in Dispatches 23 and 24 where two T4F units are each loaded to ~1 MVA each under a 3 MVA load. This leaves the remaining ~1 MVA to fall to either the BESS or the LG. Again, the LG performed better than the BESS in reducing ROCOF. This demonstrates that the LG can be an asset to improving system stability. It is noted that limitations on power production (1.25 MW max) and propane availability at PBGS limit the reliance that can be placed upon the LG technology. In addition, GFM controls are a newer technology that is only recently seeing exploratory adoption into the grid. A measured approach is recommended to incorporating such new technology into the grid until it has become more established in the power systems industry.

TABLE 7: ONE OR TWO T4F AND LG VS. ROCOF

DISPATCH	LOAD (MVA)	UNIT 15 (MVA)	UNIT 8 (MVA)	UNIT 10 (MVA)	EX BESS (MVA)	SOLAR (MVA)	BESS (MVA)	LG (MVA)	PERCENT T4F	PEAK ROCOF
21	2.00	1.04	0.00	0.00	0.00	0.00	0.00	0.99	51%	0.295
22	2.00	1.11	0.00	0.00	0.00	0.00	0.95	0.00	54%	0.722
23	3.00	1.05	1.00	0.00	0.00	0.00	0.00	0.98	68%	0.209
24	3.00	1.05	1.00	0.00	0.00	0.00	1.00	0.00	67%	0.304

CONCLUSION

Based on the results and analysis noted, the following conclusions are made:

- Having more Tier 4 Final (T4F) units online and powering the system leads to increased system stability.
- The stability benefits of the T4F units are based upon the number of units online regardless of loading levels.
- An Inverter-Based Resource (IBR) responds more quickly to system disturbances than the governor response of a synchronous generator which can improve ROCOF. However, ROCOF response is limited by BESS state-of-charge constraints. There are additional limitations with IBR technology such as limitations on fault current contribution. In addition, traditional IBRs provide no inertia to system stability which is something that is provided with synchronous generators.
- The grid-forming (GFM) linear generator (LG) showed similar improvement in ROCOF to that of adding a 2nd T4F diesel generator regarding reducing ROCOF. While this technology can be a useful asset in providing stability to the grid, limited reliance should be placed upon it based upon the newness of this technology as well as the constraints on propane availability at PBGS.

It is recommended that two (2) T4F diesel generators be planned for spinning operations at all times to maintain sufficient frequency stability for the island of Catalina. During contingencies when only one (1) T4F unit is available, then an emergency backup diesel generator must be available and brought online, as such it is recommended that Units 7, 12, and 14 remain on site. The adoption of the GFM LG is also recommended to further enhance the stability of the grid. It should be noted that this recommendation is specifically for the GFM version of the LGs. Grid-following (GFL) versions of this product exist and would not provide the same benefits noted here.

Future work in this area could expand upon the use of grid-support features of the IBRs like volt-var and frequency-watt features for the potential to provide additional stability to the system. Additionally, more detailed and vendor-supplied generation models could be incorporated and allow for more aggressive fault-response tests to be performed.

APPENDIX A

Included below are the stability study test results for Dispatches 1 – 24. The color coding of Peak ROCOF is meant to highlight the relative risk impacts different dispatches represent to frequency stability. Relatively larger numbers represent higher risk to the system and are shaded red while lower numbers represent less risk and are shaded green. In addition, the dispatches are correlated with the applicable scenarios from Table 1: Scenarios Being Consideredto showcase under which scenarios the given dispatch could theoretically occur.

TABLE 8: STABILITY STUDY TEST DATA

DISPATCH	LOAD (MVA)	UNIT 15 (MVA)	UNIT 8 (MVA)	UNIT 10 (MVA)	EX BESS (MVA)	SOLAR (MVA)	BESS (MVA)	LG (MVA)	PERCENT T4F	PEAK ROCOF	APPLICABE SCENARIO
1	1.50	1.52	0.00	0.00	0.00	0.00	0.00	0.00	100%	0.836	3, 4, 4A, 4B
2	1.50	0.78	0.76	0.00	0.00	0.00	0.00	0.00	100%	0.351	3, 4, 4A, 4B
3	1.50	0.54	0.51	0.51	0.00	0.00	0.00	0.00	100%	0.228	3, 4, 4A, 4B
4	2.20	1.33	0.00	0.00	0.98	0.00	0.00	0.00	58%	0.727	3, 4, 4A, 4B
5	2.20	1.13	1.09	0.00	0.00	0.00	0.00	0.00	100%	0.338	3, 4, 4A, 4B
6	2.20	0.78	0.73	0.73	0.00	0.00	0.00	0.00	100%	0.222	3, 4, 4A, 4B
7	5.98	0.94	0.00	0.00	0.70	2.93	1.80	0.00	15%	0.309	4A, 4B
8	5.98	1.67	1.48	0.00	0.98	0.00	2.00	0.00	51%	0.250	4A, 4B
9	5.98	1.25	1.01	1.01	0.98	0.00	2.00	0.00	52%	0.178	4A, 4B
10	5.98	2.04	1.88	0.00	0.00	2.02	0.00	0.00	66%	0.267	4, 4A, 4B
11	5.98	1.68	1.51	0.00	0.00	2.93	0.00	0.00	52%	0.253	4, 4A, 4B
12	5.98	1.35	1.14	0.00	0.00	3.82	0.00	0.00	40%	0.239	4, 4A, 4B
13	4.50	1.91	0.00	0.00	0.00	2.51	0.00	0.00	43%	0.485	4, 4A, 4B
14	4.50	1.23	0.00	0.00	0.00	3.40	0.00	0.00	27%	0.432	4, 4A, 4B
15	0.75	0.77	0.00	0.00	0.00	0.00	0.00	0.00	100%	0.832	3, 4, 4A, 4B
16	1.25	1.27	0.00	0.00	0.00	0.00	0.00	0.00	100%	0.839	3, 4, 4A, 4B
17	1.75	1.75	0.00	0.00	0.00	0.00	0.00	0.00	100%	0.838	3, 4, 4A, 4B
18	1.50	0.78	0.76	0.00	0.00	0.00	0.00	0.00	100%	0.351	3, 4, 4A, 4B
19	2.50	1.29	1.24	0.00	0.00	0.00	0.00	0.00	100%	0.335	3, 4, 4A, 4B
20	3.50	1.78	1.71	0.00	0.00	0.00	0.00	0.00	100%	0.328	3, 4, 4A, 4B
21	2.00	1.04	0.00	0.00	0.00	0.00	0.00	0.99	51%	0.295	3, 4, 4A, 4B
22	2.00	1.11	0.00	0.00	0.00	0.00	0.95	0.00	54%	0.722	4A, 4B
23	3.00	1.05	1.00	0.00	0.00	0.00	0.00	0.98	68%	0.209	3, 4, 4A, 4B
24	3.00	1.05	1.00	0.00	0.00	0.00	1.00	0.00	67%	0.304	4A, 4B

TABLE 9: STABILITY STUDY TEST DATA (ROCOF SORTED)											
DISPATCH	**LOAD (MVA)**	**UNIT 15 (MVA)**	**UNIT 8 (MVA)**	**UNIT 10 (MVA)**	**EX BESS (MVA)**	**SOLAR (MVA)**	**BESS (MVA)**	**LG (MVA)**	**PERCENT T4F**	**PEAK ROCOF**	APPLICABE SCENARIO
9	5.98	1.25	1.01	1.01	0.98	0.00	2.00	0.00	52%	0.178	4A, 4B
23	3.00	1.05	1.00	0.00	0.00	0.00	0.00	0.98	68%	0.209	3, 4, 4A, 4B
6	2.20	0.78	0.73	0.73	0.00	0.00	0.00	0.00	100%	0.222	3, 4, 4A, 4B
3	1.50	0.54	0.51	0.51	0.00	0.00	0.00	0.00	100%	0.228	3, 4, 4A, 4B
12	5.98	1.35	1.14	0.00	0.00	3.82	0.00	0.00	40%	0.239	4, 4A, 4B
8	5.98	1.67	1.48	0.00	0.98	0.00	2.00	0.00	51%	0.250	4A, 4B
11	5.98	1.68	1.51	0.00	0.00	2.93	0.00	0.00	52%	0.253	4, 4A, 4B
10	5.98	2.04	1.88	0.00	0.00	2.02	0.00	0.00	66%	0.267	4, 4A, 4B
21	2.00	1.04	0.00	0.00	0.00	0.00	0.00	0.99	51%	0.295	3, 4, 4A, 4B
24	3.00	1.05	1.00	0.00	0.00	0.00	1.00	0.00	67%	0.304	4A, 4B
7	5.98	0.94	0.00	0.00	0.70	2.93	1.80	0.00	15%	0.309	4A, 4B
20	3.50	1.78	1.71	0.00	0.00	0.00	0.00	0.00	100%	0.328	3, 4, 4A, 4B
19	2.50	1.29	1.24	0.00	0.00	0.00	0.00	0.00	100%	0.335	3, 4, 4A, 4B
5	2.20	1.13	1.09	0.00	0.00	0.00	0.00	0.00	100%	0.338	3, 4, 4A, 4B
2	1.50	0.78	0.76	0.00	0.00	0.00	0.00	0.00	100%	0.351	3, 4, 4A, 4B
18	1.50	0.78	0.76	0.00	0.00	0.00	0.00	0.00	100%	0.351	3, 4, 4A, 4B
14	4.50	1.23	0.00	0.00	0.00	3.40	0.00	0.00	27%	0.432	4, 4A, 4B
13	4.50	1.91	0.00	0.00	0.00	2.51	0.00	0.00	43%	0.485	4, 4A, 4B
22	2.00	1.11	0.00	0.00	0.00	0.00	0.95	0.00	54%	0.722	4A, 4B
4	2.20	1.33	0.00	0.00	0.98	0.00	0.00	0.00	58%	0.727	3, 4, 4A, 4B
15	0.75	0.77	0.00	0.00	0.00	0.00	0.00	0.00	100%	0.832	3, 4, 4A, 4B
1	1.50	1.52	0.00	0.00	0.00	0.00	0.00	0.00	100%	0.836	3, 4, 4A, 4B
17	1.75	1.75	0.00	0.00	0.00	0.00	0.00	0.00	100%	0.838	3, 4, 4A, 4B
16	1.25	1.27	0.00	0.00	0.00	0.00	0.00	0.00	100%	0.839	3, 4, 4A, 4B

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Southern California Edison

Stability and Protective Device Coordination Studies – Catalina

Technical Report

REP-1684
Revision #2

September 2023

Submitted By:
Mitsubishi Electric Power Products, Inc. (MEPPI)
Power Systems Engineering Division (PSED)
Warrendale, PA

EXECUTIVE SUMMARY

INTRODUCTION

Santa Catalina Island, often referred to as "Catalina", sits 26 miles off the coast of Southern California and has a population of over 4,000. Southern California Edison's (SCE's) Generation Side is currently working on determining a strategy for electricity generation on the island that results in reduced air emissions, improved reliability, and improved resilience. California regulators have directed SCE to develop a flexible N+2 planning criteria specific to Catalina Island. SCE has commissioned preliminary studies to analyze the performance of system protection and stability, in accordance with recommended industry best practices, to confirm that proposed resource mix configurations for Catalina will meet the minimum requirements of the SCE's Catalina Island Planning Criteria and Guidelines. These studies will also provide input on the recommended interconnection requirements, such as voltage and frequency ride-through requirements and rate-of-change of frequency requirements.

The analysis included within this report addresses the following objectives:

- Confirmation that for book-end system dispatches (minimum/maximum loading and minimum/maximum synchronous generation) with the planned generation at Pebbly Beach Generating Station (PBGS) as well as along the three (3) main 12 kV feeders for the island (e.g., [redacted] and potential Middle Ranch renewable facility), the system can withstand credible planning contingencies (e.g., fault events, N-1 loss of largest generator, or N-1 loss of largest load block) without any transient voltage or frequency excursions outside of system operating limits or any significant generation or load shedding.
- Confirmation that for book-end system dispatches (minimum/maximum loading and minimum/maximum synchronous generation) with the planned generation, the existing protection scheme on the island can adequately detect and clear fault events and that no protective devices short-circuit ratings are exceeded.

OVERALL SUMMARY

Key Assumptions

This study provides high level operational, system requirements, and interconnection guidance for the Catalina Island Power System. At the time this feasibility study was performed, "as-built" models for key generation resources including the Cummins Tier 4 Diesel Gensets, the existing PBGS sodium sulfur (NaS) Battery Energy Storage System (BESS), and the proposed Middle Ranch Renewable Plant did not exist. As such, MEPPI and SCE made assumptions regarding the capabilities and performance of these facilities. Where relevant, MEPPI has made note of these key assumptions and their potential impact on study results throughout the report. As a high-level summary, the following are key assumptions for this analysis:

- Synchronous machine parameters used for the Tier 4 Diesel gensets were directly from the Cummins generators datasheet. As such, it's assumed that the initial response to a large disturbance event, i.e., first few hundred milliseconds (ms), should be reasonably accurate.
    - The actual inertia constant, H, of these generators wasn't known at the time of the study. As such, a reasonable assumption of 1 second was used, based on generators of similar type and size.
- Generic assumptions were made for the remainder of the Cummins Tier 4 Diesel gensets parameters. As such, the response and performance of the excitation and governor controls of the real units that SCE recently purchase may vary from what is studied within this report. In particular, the response of the actual generators may be different than the simulation results 300 to 400 ms after a large disturbance event.
- It was assumed that the existing NaS BESS as well as the proposed Middle Ranch Renewable Plant utilize inverters operating in grid following (GFL) mode (current industry standard) and do not have fast frequency response capabilities. Meaning that these devices will not automatically respond to deviations in grid frequency and require external operator intervention to change dispatch.
    - It has been observed that the existing NaS BESS has a 1 Hz/sec rate of change of frequency (ROCOF) limit.
- It was assumed that all generation on the island (existing and proposed) is able to ride-through the simulated voltage excursions, frequency excursions, and observed high ROCOF.
    - These protections were purposely ignored such that the study results could inform ride through requirements by understanding the extremes of what existing and future equipment will experience.
- The peak load and minimum loads were based on Year 2026 loading estimates.
- It was assumed that any distribution system upgrades will be performed before queued Distributed Energy Resources (DERs) i.e., [redacted] and Middle Ranch renewable plant are installed.

- Additional interconnection studies will need to be completed to evaluate the distribution and interconnection facilities upgrades required for these DERs. This was not evaluated as part of this scope.

Electromagnetic Transients (EMT) Model Development and Validation

An Electromagnetic Transients (EMT) model representation of the three (3) main 12 kV Catalina Island feeders was created using the EMT software PSCAD/EMTDC version 4.6.3. The model included the three 12 kV feeders in the island (namely, Hi Line, Interior, and Wrigley), the proposed large DERs, and a simplified representation of the Rock Quarry motors.

The developed PSCAD feeder models were benchmarked by comparing the power flow between the developed PSCAD model and the reference CYME model. Based on the verification, it was determined that the developed PSCAD feeder models were adequate representations of the Catalina Island feeders for the purposes of this analysis.

Following development and validation of the PSCAD models for the three 12 kV feeders, they were added to a detailed PSCAD model representation of the Pebbly Beach Generating Station (PBGS) which was provided by SCE. This detailed representation of PBGS included dynamic representations of the following resources:

- 1250 kW Linear Generator
- 1825 kW Cummins Tier-4 Diesel Generator (Unit 8)
- 1825 kW Cummins Tier-4 Diesel Generator (Unit 10)
- 1825 kW Cummins Tier-4 Diesel Generator (Unit 15)

This final combined model of the Catalina Island Power System was used for the System Stability Study.

System Stability Study

The stability study was performed to quantify the impact of various N-1 outage scenarios where one of the generating units is tripped. In accordance with standard industry practice, the stability study is focused on limiting "book-end" operating conditions. The study scenarios were chosen to minimize the amount of instantaneous frequency responsive generation on-line at a given time. The following scenarios were studied:

- Overall minimum system loading with 0% instantaneous renewable energy penetration (e.g., nighttime).
- Overall maximum system loading with maximum renewable energy penetration (e.g., clear sunny day) while maintaining enough frequency responsive operating reserves to cover tripping of the largest single generating unit.

Specifically, the objective of this study was to evaluate if custom voltage and frequency ride-through requirements are needed for Catalina Island or if IEEE Std 1547 Category III ride-trough requirements are sufficient for future Inverter-Based Resource (IBR) Facilities to operate as intended and support reliable system operation. Based on the studied scenarios, it was observed that:

- The system was able to ride through the examined generator N-1 trip events with generation protections disabled and reach a new steady-state operating point within a reasonable time frame.
- The measured rate of change of frequency (ROCOF) is a cause for concern as it exceeds the IEEE Std 1547 Category III ROCOF requirement of 3.0 Hz/sec. As such, IBR facilities may trip off-line during such events.
- The frequency nadir (i.e., the point of maximum frequency excursion) dropped below the IEEE Std 1547 Category III mandatory operation frequency range of 57.0 Hz. As such, IBR facilities designed to the requirements outlined in IEEE 1547 may cease to inject current during such events resulting in a potential loss of generation during the critical part of system frequency recovery.

<u>Short Circuit and Protective Device Coordination Study</u>

Short-circuit analysis was performed to calculate the short-circuit currents produced by balanced three-phase and unbalanced faults at each bus consistent with industry standard practices of studying faulted conditions. The results of the analysis were used to determine if the anticipated short-current currents are within or exceed the interrupting ratings of the protection equipment and to verify if the short-circuit currents seen by the protective devices are sufficient to exceed the minimum pickup setting of the existing protective devices.

Based on the maximum short-circuit case device evaluation results, the short-circuit currents are within the interrupting rating of all of the protective devices.

For the three-phase bolted faults in the system, the minimum fault currents seen by the protective devices are at least two times higher than their pickup rating.

For the single-line-to-ground faults with a 30-ohm fault impedance, the minimum fault currents seen by the protective devices are at least two times higher than their pickup rating excluding three fuses (two of them located along the Hi Line feeder and one located along the Interior feeder). While the downstream sections of these three fuses are still protected, the clearing times for high impedance faults (e.g., 30-ohm or higher) may be significantly longer (or may not clear) for these three fuses protection zones.

OVERALL RECOMMENDATIONS

Based on the analysis results, the following is recommended:

(1) It is necessary that a minimum amount of frequency responsive operating reserves is always maintained on-line such that the system can survive the loss of the single largest generating resource and continue to supply system load.
   a. For the Catalina Power System as studied, this necessitates that at minimum, two diesel generators are always on-line to ensure sufficient operating reserves of frequency responsive generation.
   b. Going forward, if additional frequency responsive inverter-based resources are added to the system, then system stability and protective device coordination studies should be performed to confirm the ability of the studied resource to adequately support reliable system operation.
   c. While adding generation resources to the Catalina Power System, SCE should continue to monitor the single largest N-1 outage element. Future stability studies should consider the impact of the loss of the single largest generating element. For example:
      i. The kW size of each individual plant/unit
      ii. The total kW of installed generation on a given feeder

(2) It is recommended that SCE requires frequency ride-through requirements that exceed IEEE 1547 Category III similar to Hawaiian Electric's Source Requirements Document Version 2.0.
   a. It is recommended that the inverter-based generation in the island should be able to operate at 56.5 Hz or below.
   b. It is recommended that the inverter-based generation in the island should be able to ride through for ROCOFs of 4.1 Hz/s or above.
   c. It is recommended that SCE works with DER inverter Original Equipment Manufacturers (OEMs) to obtain information or models on ROCOF-related behavior.

(3) It is recommended that SCE perform additional analysis to confirm the specific voltage ride-through requirements for the Catalina Island Power System. This future study will potentially require adjusting the protection coordination for the island to minimize clearing times.

(4) It is recommended that future analysis is performed considering the impact of maximum duration fault clearing events (faults occurring at the edge of a zone of protection) to ensure the ability of the island power system to successfully ride through such events and provide guidance regarding voltage ride through requirements for future generation resources.
   a. Note, that while the three-phase bolted faults and single phase-to-ground impedance faults at the feeder end or the end of the substation breaker zone of protection were not studied in this analysis, it is recommended to study these

scenarios once accurate OEM PSCAD models are obtained. These scenarios will not impact the minimum required diesel generation to be online, however, it may impact the minimum clearing times required for the substation breakers or may necessitate the need for additional protective devices (e.g., reclosers along the feeders) under these different fault scenarios.

(5) It is recommended that SCE re-performs key cases from the analysis outlined in this document as well as the recommended fault studies from recommendation (4) after obtaining OEM models of the Cummins Tier 4 diesel generators to confirm the impact of the devices actual excitation and governor control systems on the stability phenomena under examination in this report.

(6) It is recommended that SCE requires OEM PSCAD models for any future large generation in the island such as Tier 4 diesel generators' exciter and governor models and DERs over 100 kW.

  a. Once OEM PSCAD models are obtained for the DERs on the island, it is recommended to study the impact of IEEE 1547-2018-compliant DERs on stability. These DERs will be capable of bidirectional frequency droop response and will typically (but not always) have headroom for up regulation since most are now being installed with batteries.

(7) It is recommended that SCE performs an island-wide protective device coordination study based on the final PBGS generation option selected.

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SECTION 1
INTRODUCTION

Santa Catalina Island, often referred to as "Catalina", sits 26 miles off the coast of Southern California and has a population of over 4,000. Southern California Edison's (SCE's) Generation Side is currently working on determining a strategy for electricity generation on the island that results in reduced air emissions, improved reliability, and improved resilience. California regulators have directed SCE to develop a flexible N+2 planning criteria specific to Catalina Island. SCE has commissioned preliminary studies to analyze the performance of system protection and stability, in accordance with recommended industry best practices, to confirm that proposed resource mix configurations for Catalina will meet the minimum requirements of SCE's Catalina Island Planning Criteria and Guidelines. These studies will also provide input on the recommended interconnection requirements, such as voltage and frequency ride-through requirements and rate-of-change of frequency requirements.

The analysis included within this report satisfies the following objectives:

- Confirmation that for book-end system dispatches (minimum/maximum loading and minimum/maximum synchronous generation) with the planned generation at Pebbly Beach Generating Station (PBGS) as well as along the three (3) main 12 kV feeders for the island (e.g., [redacted] and potential Middle Ranch renewable facility), the system can withstand credible planning contingencies (e.g., fault events, N-1 loss of largest generator, or N-1 loss of largest load block) without any transient voltage or frequency excursions outside of system operating limits or any significant generation or load shedding.
  - The analysis included in "Section 2: Electromagnetic Transients (EMT) Model Development and Validation" and "Section 3: System Stability Study" satisfy this objective.
- Confirmation that for book-end system dispatches (minimum/maximum loading and minimum/maximum synchronous generation) with the planned generation, the existing protection scheme on the island can adequately detect and clear fault events and that no protective devices short-circuit ratings are exceeded.
  - The analysis included in "Section 4: Short Circuit and Protective Device Coordination Study" satisfy this objective.

SECTION 2
ELECTROMAGNETIC TRANSIENTS (EMT) MODEL DEVELOPMENT AND VALIDATION

This report section describes the approach, input parameters, and validation for the Electromagnetic Transients (EMT) model developed for the Catalina Island 12 kV feeders. The model developed here will be used to evaluate the stability of the Catalina Island Power System for credible planning contingencies.

2.1 APPROACH FOR THE SYSTEM TRANSIENTS MODEL DEVELOPMENT

For the stability analysis included in this report, it was important to explicitly model key loads (Rock Quarry) and generation ([redacted] and Middle Ranch renewable plant) along the three (3) 12 kV feeders. The following describes the approach taken to develop a detailed representation of these three feeders:

(1) Develop 12 kV feeder models of Catalina Island, namely, Hi Line, Interior, and Wrigley in the EMT software (PSCAD/EMTDC version 4.6.3) based on the CYME feeder models provided by SCE.
    a. The CYME models used to develop the feeder models were provided by SCE with the file names "Catalina Island_Pebbly Beach_Gen CYME Model_As_Is - Circuit Model with MicroGrid" and "Catalina Island_Pebbly Beach_Gen CYME Model_As_Is - MIN Load_Protection Settings_Circuit Model".
(2) Adjust loads in the PSCAD model to match the peak load and minimum load CYME cases as provided above.
(3) Benchmark the PSCAD model of the distribution feeders to the CYME model.
    a. The developed model of the distribution feeders was benchmarked to the CYME model by verifying that the power flows were within 10% of the CYME Electric model.
(4) Add dynamic model representations for large distributed energy resources (DERs) in the queue including [redacted] Middle Ranch, and [redacted]
(5) Add large motor load Rock Quarry.
(6) Integrate the feeder models developed to the Pebbly Beach Generating Station (PBGS) PSCAD model provided by SCE.

The following sections describe the data used to develop the system transients model, the DER models, and the motor load model. Furthermore, any assumptions made in situations where data that was not provided by SCE are identified.

2.2 DISTRIBUTION SYSTEM DATA

The data used to model SCE's 12 kV feeders for this analysis was obtained from the CYME model provided by SCE with the following filename:

- "Catalina Island_Pebbly Beach_Gen CYME Model_As_Is - Circuit Model with MicroGrid"

This model was based on the peak load scenario. Using this model, all the main branch lines from the PBGS were modeled in detail, whereas the lateral branches were represented as unbalanced loads based on the values obtained from the CYME model load flow results. The voltages at the PBGS were adjusted to match the CYME model voltage setting (1.023 p.u. on a 12 kV base). All the lines were represented as PI section models in PSCAD with the line impedances obtained from the CYME model (i.e., under "Info Tab" for each line). All loads were modeled as constant power loads to match the load representation in the CYME model and load values (kW and kvar) were obtained from the CYME model as well. Refer to Figure 2.2-1 for a snapshot of the distribution system model in PSCAD. The model was developed to the appropriate level of detail for a transients analysis with transient overvoltages and currents in the frequency range of 60 Hz to several kHz.

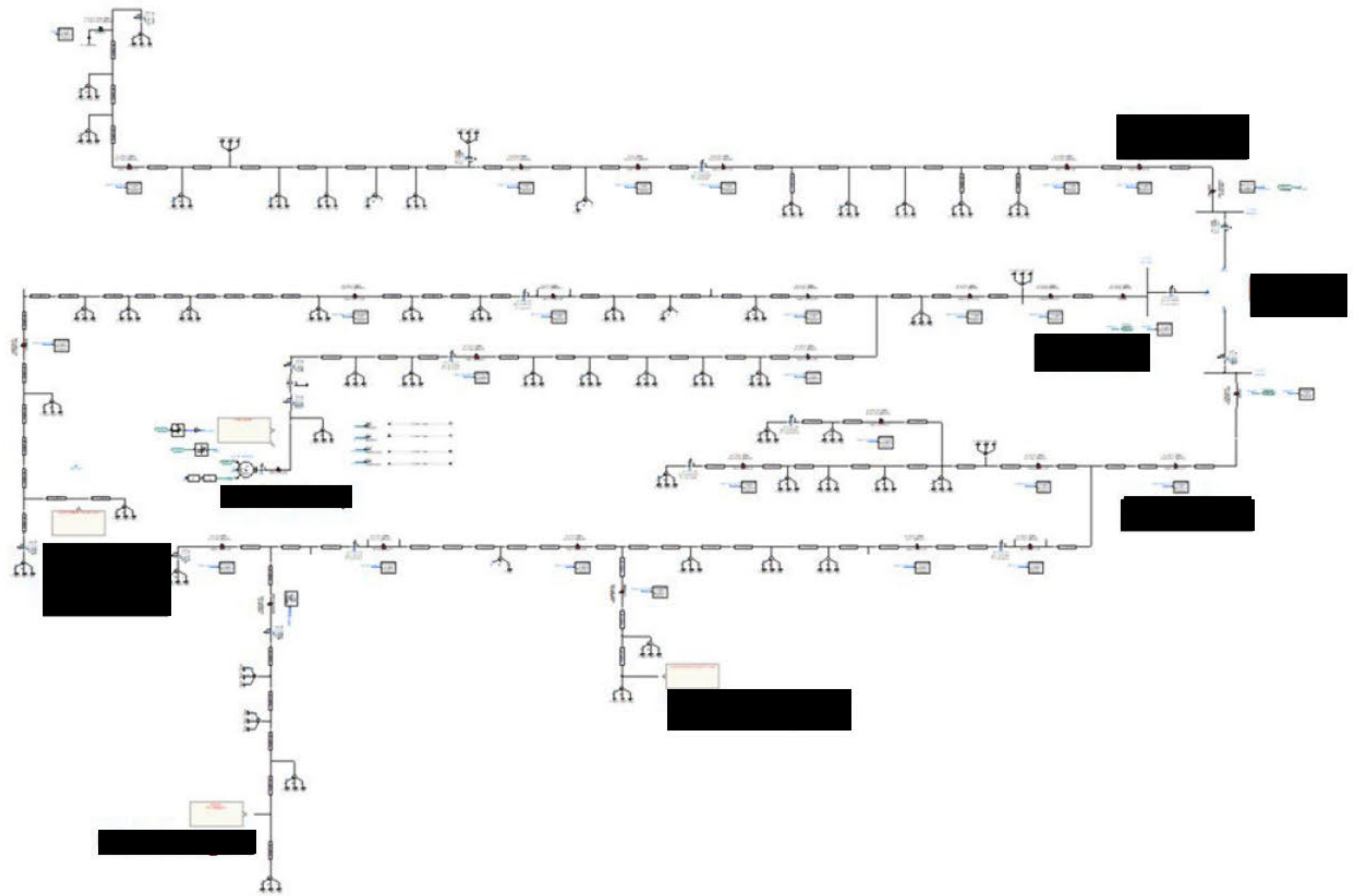

Figure 2.2-1. Illustration of the feeder models developed in PSCAD for use in this analysis.

The following sections provide a list for all of the data used to develop the system transients model used for this analysis. Furthermore, any assumptions used for data that was not provided by SCE are included as well.

2.2.1 Distribution Lines

The distribution lines were modeled as "lumped pi-equivalent" based on their positive and zero sequence self-impedance. The short sections of bus work connecting the distribution lines to the bus were neglected (unless otherwise noted) because their relative length to the total line is negligible. Refer to Table 2.2-1 for a list of line types used in the model with their respective positive and zero sequence self-impedance.

Table 2.2-1
Impedance Data for the Distribution Lines in the System Transients Model Developed

Ref. No.	Cable ID	Voltage (kV)	R1 (ohm/mi)	X1 (ohm/mi)	B1 (µS/mi)	R0 (ohm/mi)	X0 (ohm/mi)	B0 (µS/mi)
1	1000_JCN_3PH_12KV	12	0.2515	0.3059	0.5000	1.3390	0.3824	0.5000
2	336_ACSR_3PH_12KV	12	0.5308	1.0810	8.0470	0.9907	4.7180	8.0470
3	1/0_ACSR_3PH_12KV	12	1.8350	1.3030	8.0470	2.2950	4.9400	8.0470
4	350_CLP_3PH_12KV	12	0.5727	0.3331	0.5000	2.4290	0.8480	0.5000
5	4_ACSR_3PH_12KV	12	4.4870	1.4530	8.0470	4.9470	5.0890	8.0470
6	2_CLP_3PH_12KV	12	2.8740	0.4427	0.5000	5.1410	1.2970	0.5000

2.2.2 Short-Circuit Equivalents

For the purposes of benchmarking the 12 kV feeders, PBGS was modeled by short-circuit equivalents. The short-circuit equivalents were modeled as an ideal voltage source behind a positive and zero sequence impedance to obtain the appropriate response (60 Hz) of Catalina Island. Table 2.2-2 lists the data used for modeling the short-circuit equivalents that were obtained from the CYME model. These short-circuit equivalents were replaced with detailed dynamic representations of the PBGS generation provided by SCE for the Stability Study outlined in Section 3 of this report.

Table 2.2-2
Impedance Data for Short-Circuit Equivalents in the System Transients Model Developed

Ref No.	Bus Name	Voltage (kV)	MVA Base	R1 (ohms)	X1 (ohms)	R0 (ohms)	X0 (ohms)
1	[redacted]	12	100	0.0380	3.5370	0.0750	0.7960
2	[redacted]	12	100	0.0380	3.5370	0.0750	0.7960
3	[redacted]	12	100	0.0380	3.5370	0.0750	0.7960

2.3 BENCHMARKING THE TRANSIENTS MODEL TO THE CYME MODEL

The developed PSCAD model was benchmarked to the SCE provided CYME model to ensure that the 12 kV feeders provide an appropriate representation of the primary study area. Load flow analysis was performed to verify the power flows are within 10% of the CYME model.

2.3.1 Power Flow Verification

To verify that the developed PSCAD model of the 12 kV feeders is an accurate representation of the data included within the reference CYME model, power flows at the 12 kV feeder heads from both models were compared. Due to differences in equipment modeling techniques between the load-flow model and the system transients model, the power flows are not expected to be identical. For the purposes of a transients analysis, power flows within 10% of those in the load-flow model are acceptable based on industry practice. Table 2.3-1 lists the power flows at the buses considered in the primary study area for the peak load conditions. Table 2.3-2 lists the power flows at the buses considered in the primary study area for the minimum load conditions. It is seen that the percent difference is less than 1% for real power flow and 10% for reactive power flow between the two models. Also, the measured absolute difference in reactive power flow is less than 0.01 Mvar (10 kvar).

Table 2.3-1
Power Flow Comparison for Peak Load Scenario

Ref. No.	Bus Name	Voltage (kV)	Power Flow				Percent Difference(1)	
			CYME		PSCAD Model		CYME vs PSCAD Model	
			MW	Mvar	MW	Mvar	MW	Mvar
1	[redacted]	12	[redacted]	0.23	[redacted]	0.23	[redacted]	1.30%
2	[redacted]	12	[redacted]	0.42	[redacted]	0.42	[redacted]	0.59%
3	[redacted]	12	[redacted]	0.33	[redacted]	0.32	[redacted]	3.13%
						Overall Highest Percent Difference →	**0.28%**	**3.13%**
						Average Percent Difference →	**0.20%**	**1.67%**

(1) Percent Difference (%) calculated as [(CYME - PSCAD)/ CYME]*100

Table 2.3-2
Power Flow Comparison for Minimum Load Scenario

Ref. No.	Bus Name	Voltage (kV)	Power Flow				Percent Difference(1)	
			CYME		PSCAD Model		CYME vs PSCAD Model	
			MW	Mvar	MW	Mvar	MW	Mvar
1	[redacted]	12	[redacted]	-0.08	[redacted]	-0.08	[redacted]	1.27%
2	[redacted]	12	[redacted]	0.07	[redacted]	0.07	[redacted]	8.19%
3	[redacted]	12	[redacted]	-0.01	[redacted]	-0.01	[redacted]	9.09%
						Overall Highest Percent Difference →	0.16%	9.09%
						Average Percent Difference →	0.13%	6.18%

(1) Percent Difference (%) calculated as [(CYME - PSCAD)/ CYME]*100

2.4 GENERIC PHOTOVOLTAIC INVERTER MODEL

To model the large DERs i.e., [redacted] Middle Ranch Solar, and [redacted] for this study, a generic grid-following inverter model that is publicly available from NREL was used (https://github.com/NREL/PyPSCAD). The details about this model can be found in the following NREL publication: "Open-Source PSCAD Grid-Following and Grid-Forming Inverters and A Benchmark for Zero-Inertia Power System Simulations" [2-1]. This generic model is not representative of any manufacturers PV inverter and as such, the results of this analysis are intended for informational purposes only and SCE should utilize them at their own risk. Refer to Figure 2.4-1 for a snapshot of the [redacted] inverter model in PSCAD.

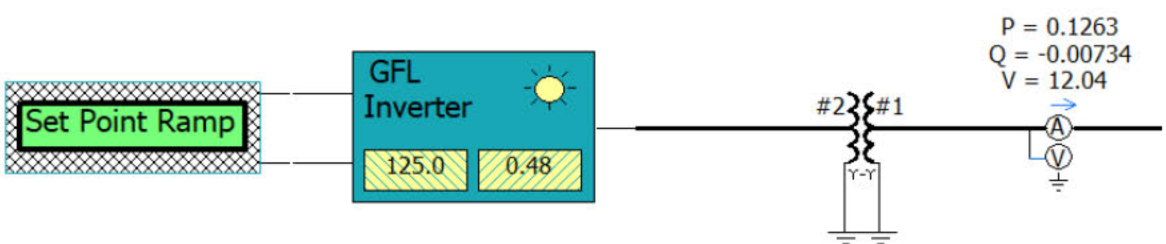

Figure 2.4-1. PV Inverter Model in PSCAD.

2.5 MOTOR MODEL

To model the Rock Quarry motor loads in PSCAD, the "Typical" data entry format was used in the PSCAD squirrel cage induction machine model. Since detailed motor parameters or operation sequence of the motors were not available, it was assumed that two of the largest motors can start direct on-line at the same time with a combined horsepower of 350. Refer to Figure 2.5-1 for the motor model in PSCAD. Figure 2.5-2 shows the motor model parameters entered into PSCAD.

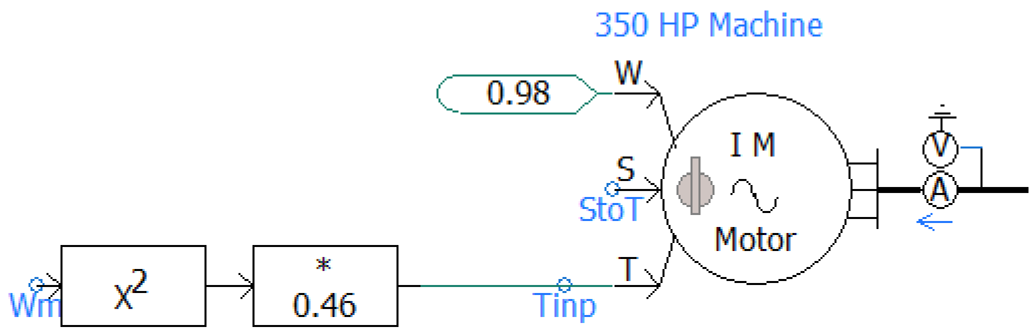

Figure 2.5-1. Motor Model in PSCAD.

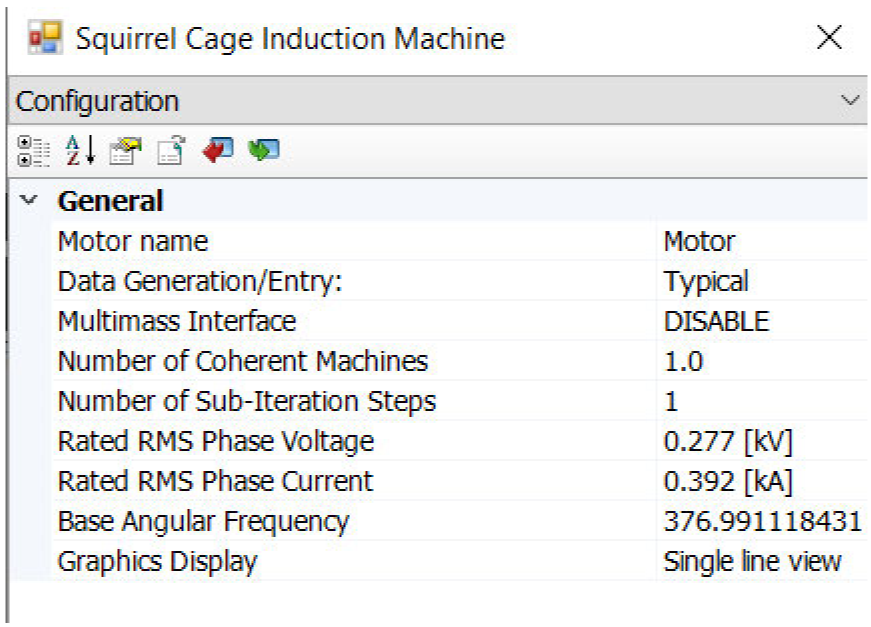

Figure 2.5-2. Motor Model parameters in PSCAD.

2.6 OVERALL SUMMARY

An Electromagnetic Transients (EMT) model representation of the three (3) main 12 kV Catalina Island feeders was created using the transients software PSCAD/EMTDC version 4.6.3. The model included the three 12 kV feeders, the proposed large DERs, and a simplified representation of the Rock Quarry motors.

The developed PSCAD feeder models were benchmarked by comparing the power flow between the developed PSCAD model and the reference CYME model. Based on the verification, it was determined that the developed PSCAD feeder models were adequate representations of the Catalina Island feeders for the purposes of this analysis.

Following development and validation of the PSCAD models for the three 12 kV feeders, they were added to a detailed PSCAD model representation of the Pebbly Beach Generating Station (PBGS) which was provided by SCE. This detailed representation of PBGS included dynamic representations of the following resources:

- 1250 kW Linear Generator
- 1825 kW Cummins Tier-4 Diesel Generator (Unit 8)
- 1825 kW Cummins Tier-4 Diesel Generator (Unit 10)
- 1825 kW Cummins Tier-4 Diesel Generator (Unit 15)

This final combined model of the Catalina Island Power System was used for performance of the Stability Study outlined in Section 3 of this report.

2.7 REFERENCES

[2-1] R. Kenyon, "Open-Source PSCAD Grid-Following and Grid-Forming Inverters and A Benchmark for Zero-Inertia Power System Simulations," 2021 Kansas Power and Energy Conference, April 19–20, 2021.

SECTION 3
SYSTEM STABILITY STUDY

The overall goal of the "System Stability Study" was to assess the ability of the Catalina Island Power System to withstand credible planning contingencies (e.g., fault events, N-1 loss of largest generator, or N-1 loss of largest load block) without any transient voltage or frequency excursions outside of system operating limits or any significant generation or load shedding. This evaluation was performed considering book-end system dispatches (minimum/maximum loading and minimum/maximum renewable penetration) with the planned generation at Pebbly Beach Generating Station (PGBS) as well as along the three (3) main 12 kV feeders for the island (e.g., [redacted] and Middle Ranch renewable plant).

The results of this analysis were used to evaluate if custom voltage and frequency ride-through requirements are needed for Catalina Island or if IEEE Std 1547 [3-1] Category III ride-trough requirements are sufficient for future Inverter-Based Resource (IBR) facilities to operate as intended and support reliable system operation.

3.1 BACKGROUND ON POWER SYSTEM STABILITY FOR ISLAND POWER SYSTEMS

Power system stability is defined as the ability of an electric power system to regain a state of operating equilibrium after being subjected to a physical disturbance [3-2]. Power system stability is a single, fundamental problem. However, to simplify analysis and evaluation of stability issues, it is broken up into categories considering:

- The physical nature or main system variable in which instability can be observed
- The size of the disturbance, which impacts how it is studied
- The devices and time span of the event

Historically, the study of power system stability and the dynamic behavior of power systems has been dictated by synchronous machines, their control systems, and the dynamics of loads. As such, the analysis of power system stability has focused on relatively slow electromechanical phenomena. However, with higher penetrations of power electronic coupled loads and IBRs, the dynamic behavior of power systems is becoming faster. These devices have nested controls loops and power electronic switching that operate at frequencies from a few Hz up to kHz. As such, modern power system stability phenomenon needs to consider the impacts of electromagnetic and wave phenomena on overall power system stability as well [3-2].

For an island power system such as Santa Catalina Island, the primary power system stability concern will be short term frequency stability. Frequency stability is defined as the ability of a power system to maintain frequency following a severe disturbance resulting in a significant imbalance between generation and load. Adequate frequency stability is the ability to maintain/restore equilibrium between generation and load with minimal unintended loss of load. Instability may manifest in sustained frequency swings resulting in tripping of generation or load. Frequency stability issues are associated with lack of system inertia, poor governor response capabilities of generators, or insufficient generation reserves. For short term frequency stability, which is the primary focus of this study, the time frame of interest is within seconds of a disturbance. Of primary concern is the ability of the system and its inherent inertial and fast frequency response to arrest the rate-of-change-of-frequency (ROCOF) and the frequency nadir (point of maximum frequency excursion) immediately following system disturbances (within a few seconds). The initial ROCOF (neglecting the impact of fast frequency response or control action) can be estimated as follows:

$$ROCOF = \frac{\Delta P_{loss}}{2 * (KE_{sys} - KE_{loss})} * 60$$

Where KE_{sys} is the total system kinetic energy from on-line synchronous generators calculated as follows:

$$KE_{sys} = \sum H_i * MVA_i$$

Where H_i is the inertia constant (units of seconds) of the "i^{th}" synchronous machine generator and MVA_i is the rated MVA of the "i^{th}" synchronous machine generator [3-3].

Key system characteristics that impact the frequency nadir and the rate of change of frequency (ROCOF) include [3-3]:

- The size of the contingency (i.e., loss of generation)
- Overall system inertia of synchronously connected machines, including generation and motor loads
- Speed of response and magnitude of energy injection provided by generation in response to the observed deviation in frequency
- Speed of response and magnitude of load tripping or load response to the observed deviation in frequency (e.g., underfrequency load shedding)

As island power systems continue to transition towards higher penetration of inverter-based renewable energy resources, it is expected that the system synchronous inertia will decrease which will impact frequency nadir and ROCOF. This section describes the approach and results obtained from the system stability study performed in PSCAD.

3.2 APPROACH

Using the Electromagnetic Transients (EMT) model developed in Section 2, a stability study was performed quantifying the impact of various N-1 outage scenarios where one of the generating units is tripped. In accordance with standard industry practice, the stability study is focused on limiting "book-end" operating conditions. The study scenarios were chosen to minimize the amount of instantaneous frequency responsive generation on-line at a given time. The following scenarios were studied:

- Overall minimum system loading with 0% instantaneous renewable energy penetration (e.g., nighttime).
- Overall maximum system loading with maximum renewable energy penetration (e.g., clear sunny day) while maintaining enough frequency responsive operating reserves to cover tripping of the largest single generating unit.

The following is the approach used for the stability study:

(1) Using the combined PSCAD model of Catalina Island described in Section 2 of this report which includes detailed dynamic representation of both the distribution connected generation and load as well as the central generation resources at Pebbly Beach Generating Station (PBGS). Note the detailed model of the PBGS generation was provided to MEPPI by SCE for use in this study. Figure 3.2-1 provides a screenshot of the combined PSCAD model.
   - Because the intent of this study is to provide high level operational and interconnection guidance for the Catalina Island Power System, the analysis was performed without final or as-built models for the PBGS generation. For the purpose of this feasibility study, the PBGS generation excitation and governor control systems were represented with generic assumptions provided by SCE. As such, the actual response and performance of the excitation and governor controls of the real Cummins Tier 4 Diesel gensets that SCE recently purchased may vary from what is studied within this report. In particular, the response of the actual generators may be different than the simulation results 300 to 400 ms after a large disturbance event. The synchronous machine parameters used for the Tier 4 Diesel gensets were direct from the Cummins generators datasheet. As such, it is assumed that the initial response to a large disturbance event, i.e., first few hundred ms, should be reasonably accurate.

(2) Adjust generators settings related to control of voltage and frequency at PBGS as agreed with SCE.
   - Generators real power – frequency droop settings: 3%
   - Generators reactive power – voltage droop settings: 2%
   - Generators voltage set point: 1.02 p.u.
   - Generators speed set point: 1.01 p.u.

(3) Run N-1 scenarios by tripping select generating units (one at a time) during steady-state conditions for the minimum load – no renewables scenario. Table 3.2-1 shows the scenarios studied.

(4) Run N-1 scenarios by tripping select generating units (one at a time) during steady-state conditions for the peak load – maximum renewables scenario. Table 3.2-2 shows the scenarios studied.

[redacted]

Figure 3.2-1. Final PSCAD model combining the feeders and the PBGS.

Table 3.2-1
Minimum Load – No Renewables Scenarios Simulated

Generation Name	Frequency Responsive Generation?	Unit Ratings			Scenario 1 Initial Conditions		Scenario 2 Initial Conditions	
		Pmax (kW)	Pmin (kW)	Unit Rating (KVA)	Pgen (kW)	Available Spinning Reserves for Up Regulation (kW)	Pgen (kW)	Available Spinning Reserves for Up Regulation (kW)
Unit 7	Yes	1000	800	1250	Offline	--	Offline	--
Unit 12	Yes	1575	1260	3125	Offline	--	Offline	--
Unit 14	Yes	1400	1120	1750	Offline	--	Offline	--
Unit 8	Yes	1825	456	2281	Offline	--	Offline	--
Unit 10	Yes	1825	456	2281	495	1330	495	1330
Unit 15	Yes	1825	456	2281	495	1330	495	1330
Linear Generator	Yes	1250	125	5x250	1250	0	1250	0
Solar + BESS at Hi Line (Middle Ranch)*	No	4500	-2000	6500	Offline	--	Offline	--
Existing PBGS BESS	No	1000	-1000	1000	Offline	--	Offline	--
[redacted]		[redacted]					[redacted]	-
					Sum (kW) →			
				Sum (kW) →	2240	2660	2240	2660
				Simulated N-1 →	Linear Generator		Unit 10	
				Case notes →	No renewables		No renewables	

Note: For the scenarios studied, it was required that the available spinning reserve exceeds the size of the single largest generation output.
(*): Third Party Owned Generation

Table 3.2-2
Peak Load – Maximum Renewables Scenarios Simulated

Generation Name	Frequency Responsive Generation?	Unit Ratings			Scenario 1 Initial Conditions		Scenario 2 Initial Conditions	
		Pmax (kW)	Pmin (kW)	Unit Rating (KVA)	Pgen (kW)	Available Spinning Reserves for Up Regulation (kW)	Pgen (kW)	Available Spinning Reserves for Up Regulation (kW)
Unit 7	Yes	1000	800	1250	Offline	--	Offline	--
Unit 12	Yes	1575	1260	3125	Offline	--	Offline	--
Unit 14	Yes	1400	1120	1750	Offline	--	Offline	--
Unit 8	Yes	1825	456	2281	560	1265	560	1265
Unit 10	Yes	1825	456	2281	560	1265	560	1265
Unit 15	Yes	1825	456	2281	560	1265	560	1265
Linear Generator	Yes	1250	125	5x250	Offline	--	Offline	--
Solar + BESS at Hi Line (Middle Ranch)*	No	4500	-2000	6500	3750	N/A	3750	N/A
Existing PBGS BESS	No	1000	-1000	1000	Offline	--	Offline	--
[redacted]		[redacted]						
				Sum (kW) →	6030	3795	6030	3795
				Simulated N-1 →	Solar at Hi Line		Unit 10	
				Case notes →	Max Renewables		Max Renewables	

Note: For the scenarios studied, it was required that the available spinning reserve exceeds the size of the single largest generation output.
(*): Third Party Owned Generation

3.3 STABILITY STUDY RESULTS

The stability study results for the minimum load and the peak load scenarios are provided below.

3.3.1 Minimum Load – No Renewables Results

Table 3.3-1 provides a summary of the Minimum Load – No Renewables Scenarios results. The following are key observations based on the results in Table 3.3-1:

- The system was able to ride through the examined generator N-1 trip events with generation protections disabled and reach a new steady-state operating point within a reasonable time frame.
- The measured rate of change of frequency (ROCOF) is a cause for concern as it exceeds the IEEE Std 1547-2018 Category III ROCOF requirement of 3.0 Hz/sec. As such, IBR facilities may trip off-line during such events.

Figures 3.3-1 and 3.3-2 provide simulation results for the two cases studied.

Table 3.3-1
Summary of Results from the Minimum Load – No Renewables Scenarios

Ref No.	Case Description	Frequency Nadir (Hz)	ROCOF (Hz/sec)
1	Linear generator trips at 25th second	58.41	4.07
2	Unit 10 trips at 25th second	58.26	3.11

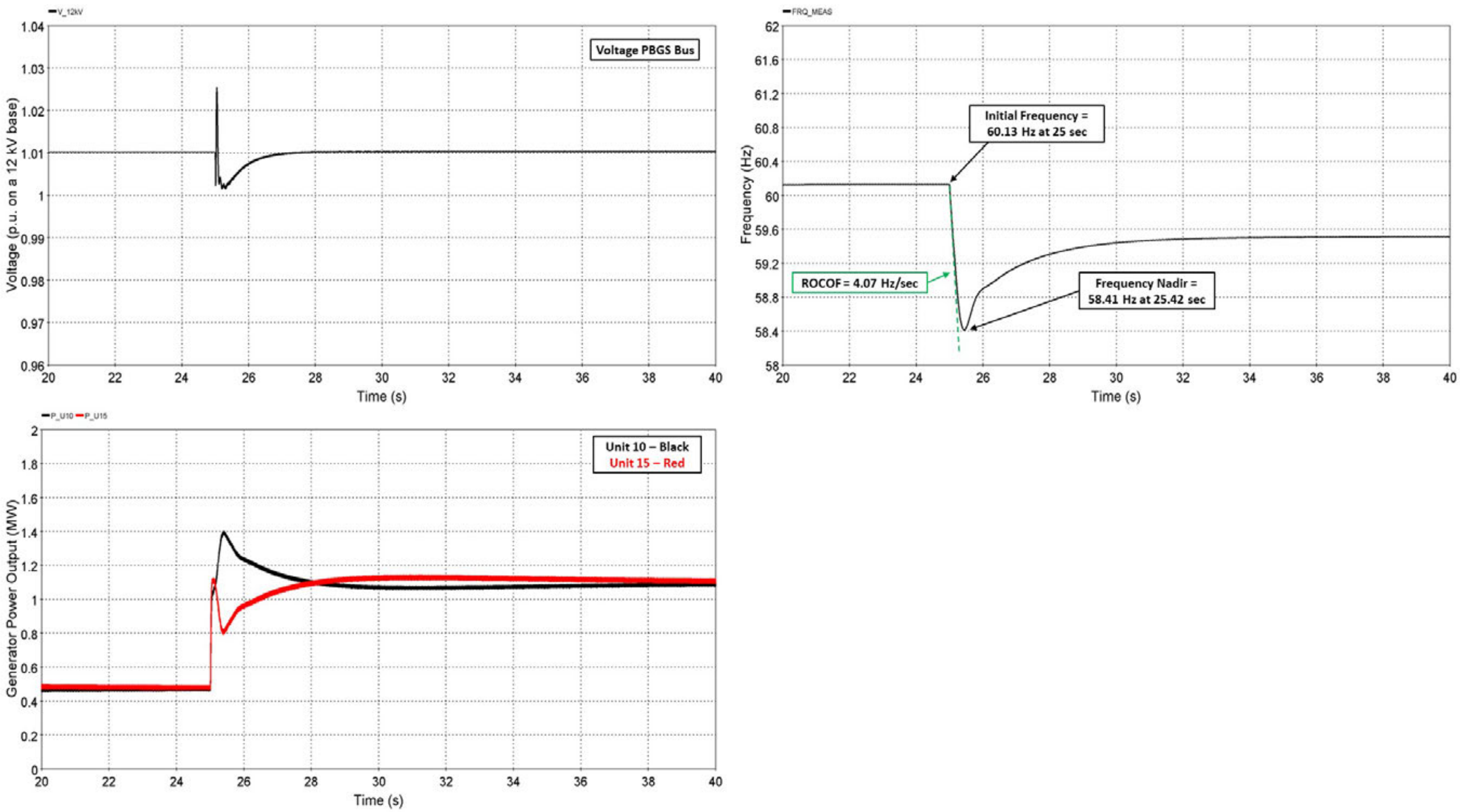

Figure 3.3-1. Tripping of 1.25 MW Linear Generator Under Minimum Load and No Renewables Dispatch (Ref. No. 1)

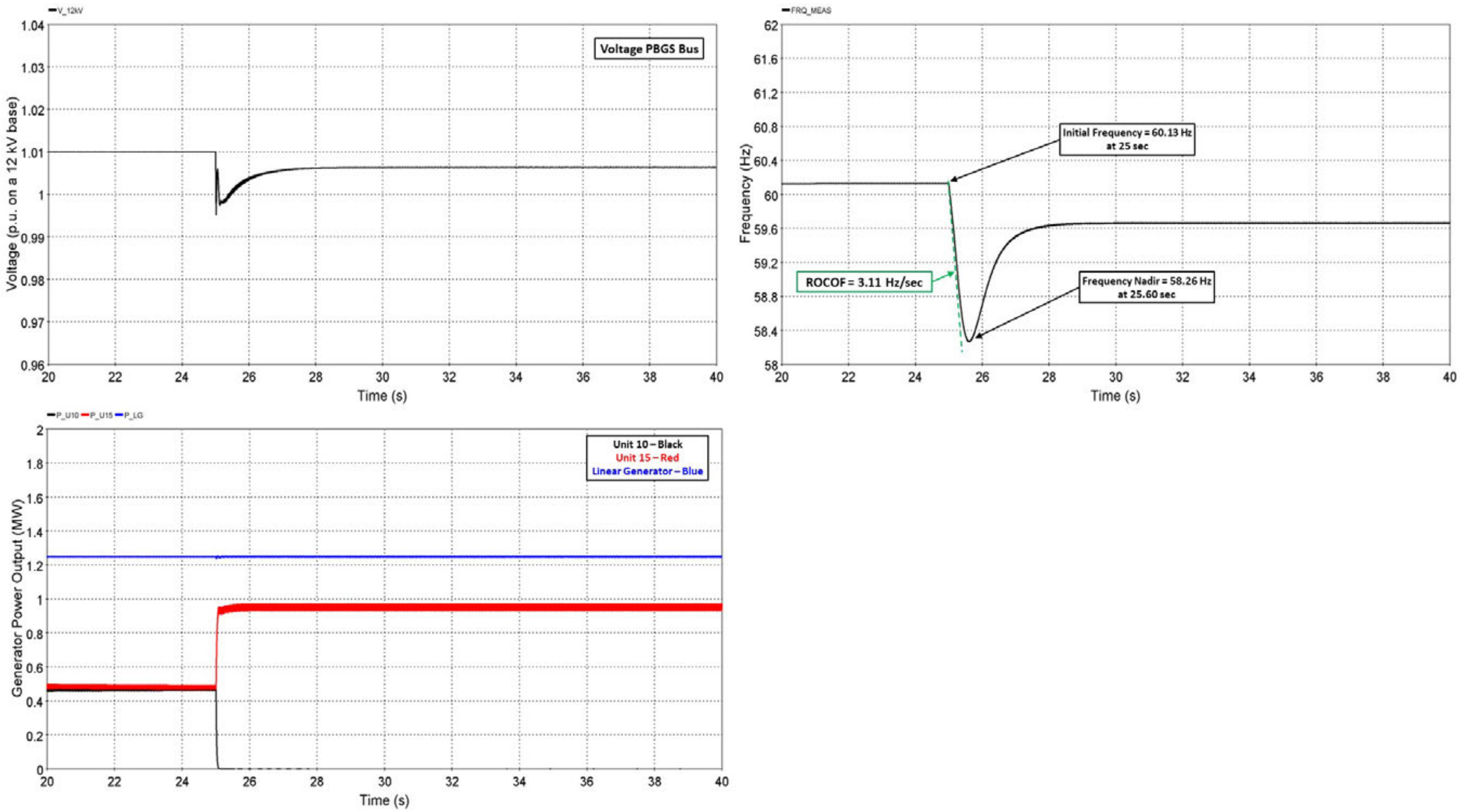

Figure 3.3-2. Tripping of 1.825 MW Diesel Generator Under Minimum Load and No Renewables Dispatch (Ref. No. 2)

3.3.2 Peak Load – Maximum Renewables Results

Table 3.3-2 provides a summary of the Peak Load – Maximum Renewables Scenarios results. The following are key observations based on the results in Table 3.3-2:

- The system was able to ride through the examined generator N-1 trip events with generation protections disabled and reach a new steady-state operating point within a reasonable time frame.
- The measured rate of change of frequency (ROCOF) is a cause for concern as it exceeds the IEEE Std 1547-2018 Category III ROCOF requirement of 3.0 Hz/sec. As such, IBR facilities may trip off-line during such events.
- The frequency nadir dropped below the IEEE Std 1547-2018 Category III mandatory operation frequency range of 57.0 Hz. As such, IBR facilities designed to the requirements outlined in IEEE 1547-2018 may cease to inject current during such events resulting in a potential loss of generation during the critical part of system frequency recovery.

Figures 3.3-3 and 3.3-4 provide simulation results for the two cases studied.

Table 3.3-2
Summary of Results from the Peak Load – Maximum Renewables Scenarios

Ref No.	Case Description	Frequency Nadir (Hz)	ROCOF (Hz/sec)
1	Solar at Hi Line trips at 36th second	56.54	4.06
2	Unit 10 trips at 36th second	58.73	2.58

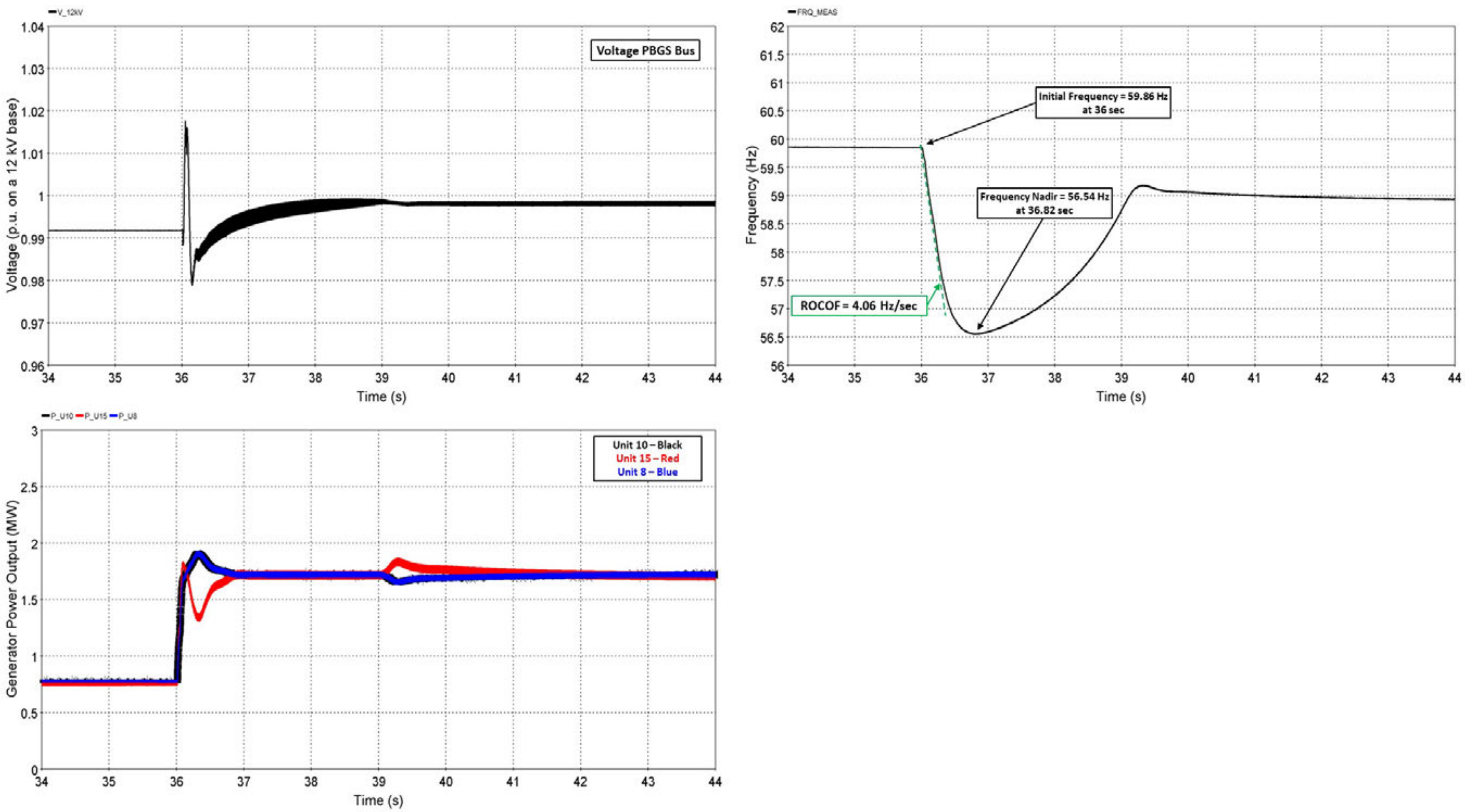

Figure 3.3-3. Tripping of 3.75 MW Solar Under Peak Load and Maximum Renewables Dispatch (Ref. No. 1)

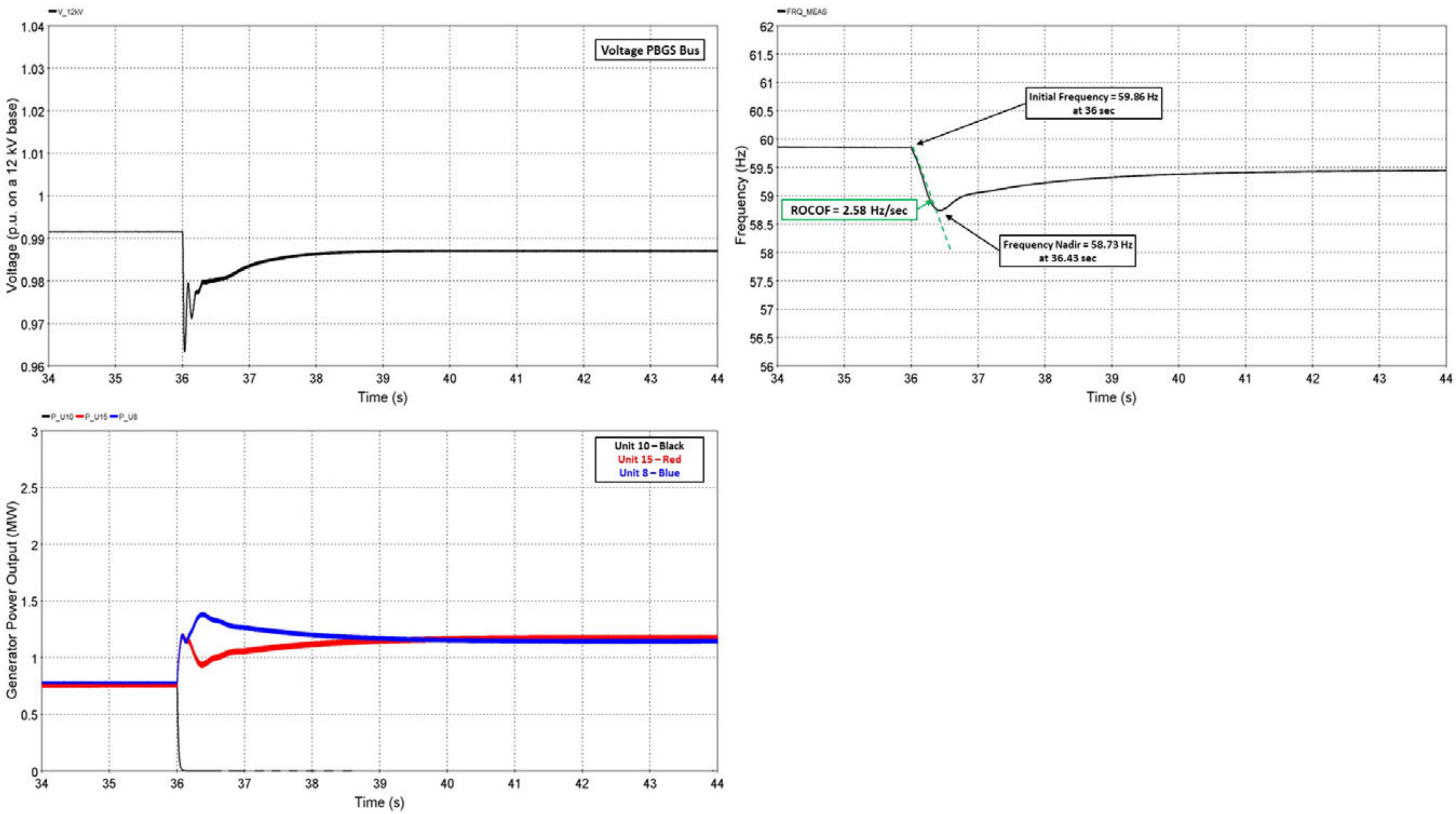

Figure 3.3-4. Tripping of 1.825 MW Diesel Generator Under Peak Load and Maximum Renewables Dispatch (Ref. No. 2)

3.4 OVERALL SUMMARY AND RECOMMENDATIONS

3.4.1 Overall Summary

The stability study was performed to quantify the impact of various N-1 outage scenarios where one of the generating units is tripped. In accordance with standard industry practice, the stability study is focused on limiting “book-end” operating conditions. The study scenarios were chosen to minimize the amount of instantaneous frequency responsive generation on-line at a given time. The following scenarios were studied:

- Overall minimum system loading with 0% instantaneous renewable energy penetration (e.g., nighttime).
- Overall maximum system loading with maximum renewable energy penetration (e.g., clear sunny day) while maintaining enough frequency responsive operating reserves to cover tripping of the largest single generating unit.

The objective of this study was to evaluate if custom voltage and frequency ride-through requirements are needed for Catalina Island or if IEEE Std 1547-2018 Category III ride-trough requirements are sufficient for future Inverter-Based Resource (IBR) Facilities to operate as intended and support reliable system operation. Based on the studied scenarios, it was observed that:

- The system was able to ride through the examined generator N-1 trip events with generation protections disabled and reach a new steady-state operating point within a reasonable time frame.
- The measured rate of change of frequency (ROCOF) is a cause for concern as it exceeds the IEEE Std 1547-2018 Category III ROCOF requirement of 3.0 Hz/sec. As such, IBR facilities may trip off-line during such events.
- The frequency nadir dropped below the IEEE Std 1547-2018 Category III mandatory operation frequency range of 57.0 Hz. As such, IBR facilities designed to the requirements outlined in IEEE 1547-2018 may cease to inject current during such events resulting in a potential loss of generation during the critical part of system frequency recovery.

3.4.2 Overall Recommendations

The following are key study recommendations as a result of the Stability Study:

(1) It is necessary that a minimum amount of frequency responsive operating reserves are maintained on-line at all times such that the system can survive the loss of the single largest generating resource and continue to supply system load.

a. For the Catalina Power System as studied, this necessitates that at minimum, two diesel generators are one-line at all times to ensure sufficient operating reserves of frequency responsive generation.
b. Going forward, if additional frequency responsive inverter-based resources are added to the system, then system stability and protective device coordination studies should be performed to confirm the ability of the studied resource to adequately support reliable system operation.
c. While adding generation resources to the Catalina Power System, SCE should continue to monitor the single largest N-1 outage element. Future stability studies should always consider the impact of the loss of the single largest generating element. For example:
    i. The kW size of each individual plant/unit
    ii. The total kW of installed generation on a given feeder

(2) It is recommended that SCE requires frequency ride-through requirements that exceed IEEE 1547-2018 Category III similar to Hawaiian Electric's Source Requirements Document Version 2.0 [3-4].
   a. It is recommended that the inverter-based generation on the island should be able to operate at 56.5 Hz or below
   b. It is recommended that the inverter-based generation on the island should be able to ride through for ROCOFs of 4.1 Hz/s or above
   c. It is recommended that SCE works with distributed energy resource (DER) inverter original equipment manufacturers (OEM) to obtain information or models on ROCOF-related behavior

(3) It is recommended that SCE perform additional analysis to confirm the specific voltage ride-through requirements for the Catalina Island Power System. This future study will potentially require adjusting the protection coordination for the island to minimize fault clearing times.

(4) It is recommended that future analysis is performed considering the impact of maximum duration fault clearing events (faults occurring at the edge of a zone of protection) to ensure the ability of the island power system to successfully ride through such events and provide guidance regarding voltage ride through requirements for future generation resources.
   a. Note, that while the three-phase bolted faults and single phase-to-ground impedance faults at the feeder end or the end of the substation breaker zone of protection were not studied in this analysis, it is recommended to study these scenarios once accurate OEM PSCAD models are obtained. These scenarios will not impact the minimum required diesel generation to be online, however, it may impact the minimum clearing times required for the substation breakers or may necessitate the need for additional protective devices (e.g., reclosers along the feeders) under these different fault scenarios.

(5) It is recommended that SCE re-performs key cases from the analysis outlined in this document as well as the recommended fault studies from recommendation (4) after obtaining OEM models of the Cummins Tier 4 diesel generators to confirm the impact of

the devices actual excitation and governor control systems on the stability phenomena under examination in this report.

(6) It is recommended that SCE requires OEM PSCAD models for any future large generation on the island (e.g., Tier 4 diesel generators' exciter and governor models, DERs over 100 kW).

   a. Once OEM PSCAD models are obtained for the DERs on the island, it is recommended to study the impact of IEEE 1547-2018-compliant DERs on stability. These DERs will be capable of bidirectional frequency droop response and will typically, but not always, have headroom for up regulation since most are now being installed with batteries.

3.5 REFERENCES

[3-1] IEEE Std 1547-2018, "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces."

[3-2] N. Hatziargyriou et. al, "Definition and Classification of Power System Stability – Revisited & Extended", IEEE Trans. Power Systems, July 2021.

[3-3] NERC, "Fast Frequency Response Concepts and Bulk Power System Reliability Needs", March 2020.

[3-4] Hawaiian Electric, "Source Requirements Document Version 2.0", July 2020.

SECTION 4
SHORT-CIRCUIT AND PROTECTIVE DEVICE COORDINATION STUDY

The electrical distribution system will occasionally experience short-circuits. Overcurrent protective devices such as fuses and circuit breakers should isolate the fault current at desired locations safely with minimal equipment damage and minimal disruption to customers. Other components of the distribution system, such as transformers, cables, and disconnect switches, must be able to withstand the mechanical and thermal stresses produced by the fault current flowing through them.

A short circuit analysis is required to ensure that existing and new equipment ratings are adequate to withstand the available short circuit current at each point in the power system. The magnitudes of short-circuit currents are determined by calculation, and electrical equipment ratings are selected based upon these calculation results.

This section describes the approach and results obtained from the short-circuit analysis performed in CYME and addresses considerations for the Catalina Island Power System where short-circuit current magnitudes are lower as compared to the mainland SCE power system.

4.1 APPROACH

The objective of this analysis is to confirm that for book-end system dispatches (i.e., minimum/maximum synchronous generation) with the planned generation, the existing protection scheme on the island is able to adequately detect and clear fault events. The results will be used to determine if the anticipated short-circuit currents are within or exceed the interrupting ratings of protective devices and to verify there is sufficient short-circuit current for the minimum pickup setting (i.e., the minimum amount of short-circuit current that can be clearly distinguished from normal condition load current) of the existing protective devices. The following is the approach used for the short-circuit analysis:

(1) Add the proposed generation scenarios to represent the minimum short-circuit and the maximum short-circuit capacity cases to the CYME model provided by SCE named "Catalina Island_Pebbly Beach_Gen CYME Model_As_Is - MIN Load_Protection Settings_Circuit Model".
(2) Run "Minimum Fault" analysis [4-1] in CYME for the minimum short-circuit capacity case to determine if the short-circuit currents seen by the protective devices are larger than their pickup settings (ideally twice or more). The minimum fault protection analysis is an algorithm which allows to verify if the protective devices modeled in CYME can adequately detect and clear the minimum faults seen in their respective protection zones. The analysis will begin by identifying the protection zones based on user defined zone delimiters. It will then determine the minimum fault currents in each zone and evaluate if the protective device protecting the zone can effectively address this fault. If the primary

protective device fails to address the minimum fault current, the secondary protection will then be verified. If both devices fail to address the minimum fault current in the zone, the analysis will then attempt to locate a sectionalizing device that could isolate the uncovered area.

(3) Run "Equipment Rating Verification" analysis [4-2] in CYME for the maximum short-circuit capacity case to determine if the short-circuit currents are within the interrupting rating of the existing protective devices.

For the analysis performed, short-circuit currents were calculated for a three-phase bolted fault and a single-line-to-ground fault with a 30-ohm fault impedance [4-3] at each bus. The generation options considered for the minimum short-circuit case and the maximum short-circuit case is shown in Table 4.1-1. These specific dispatches were chosen to represent the worst case (minimum and maximum short-circuit capacity) instantaneous generation dispatch that would be able to serve the minimum and maximum system load while allowing for N-1 redundancy (loss of a single generator does not result in the inability to serve system load). The modified CYME model to represent the minimum short circuit-case is shown in Figure 4.1-1.

Table 4.1-1
Generation Options Considered

Generation Name	Minimum Short-Circuit Case	Maximum Short-Circuit Case
Unit 7	Offline	Offline
Unit 12	Offline	Offline
Unit 14	Offline	Offline
Unit 8	Offline	Online
Unit 10	Online	Online
Unit 15	Online	Online
Linear Generator	Online	Online
Solar at Hi Line (Middle Ranch)	Offline	Online
BESS 1 MW	Offline	Online
[redacted]		
[redacted]		

[redacted]

Figure 4.1-1. PBGS model for the minimum short-circuit case in CYME.

The impedance data for the PBGS transformers are presented in Table 4.1-2 and the impedance data used for the generators obtained from the Cummins datasheets in CYME are shown in Figures 4.1-2 and 4.1-3, respectively. It was assumed that the linear generator (and any other inverter-based generation) can contribute 120% of its nominal current during a fault as shown in Figure 4.1-4.

Table 4.1-2
PBGS Transformers Data

Ref. No.	Bus 1 Name	Bus 2 Name	MVA Base	V1 (kV)	V2 (kV)	Winding Configuration	R1 (p.u.)	X1 (p.u.)	Neutral Impedance (ohms)
1	PBGS 2.4 kV	PBGS 12 kV	3.75	2.4	12	D-Y, delta lags	0.0066	0.0504	0+0i
2	LIN GEN	PBGS 12 kV	2	0.48	12	Y-D, delta lags	0.0070	0.0503	0+0i

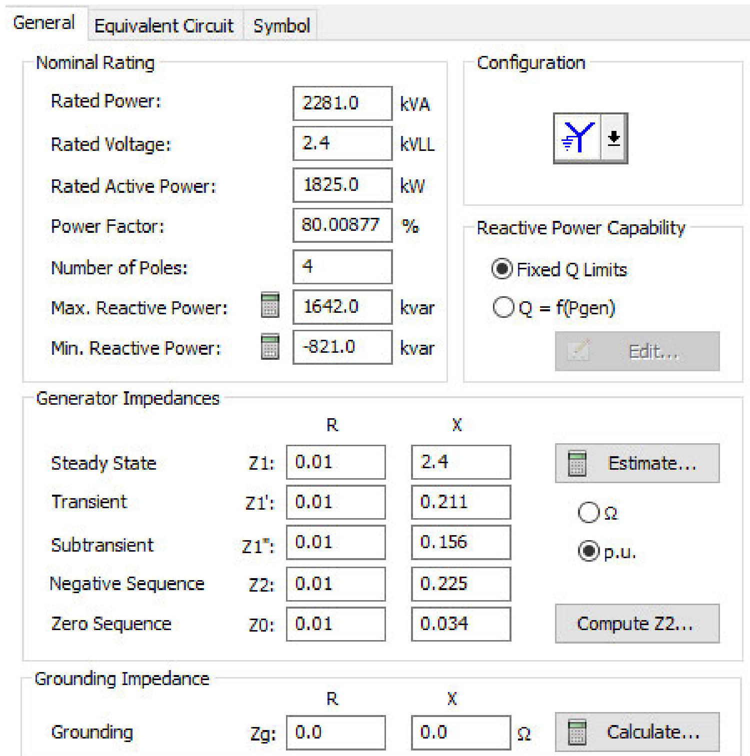

Figure 4.1-2. Unit 8 or Unit 10 Generator parameters in CYME.

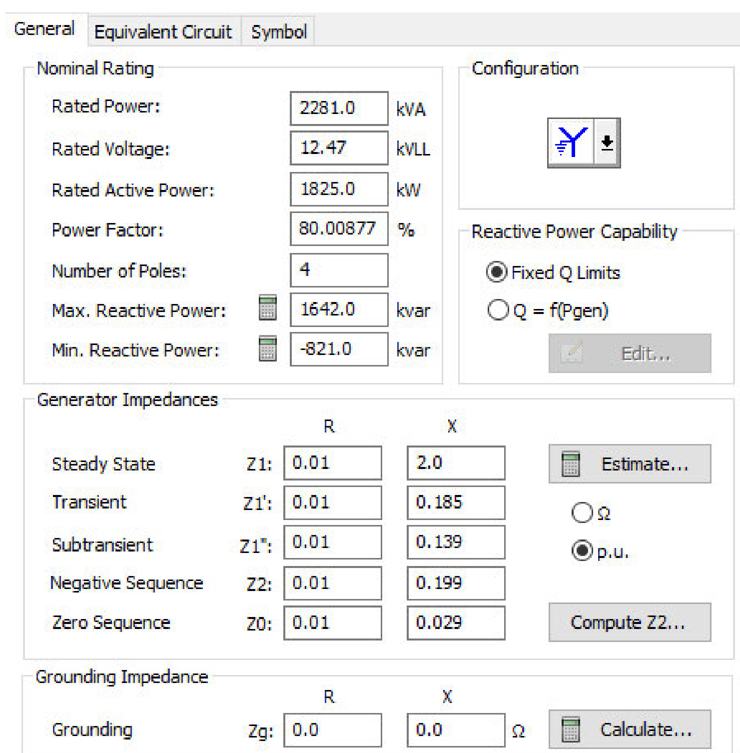

Figure 4.1-3. Unit 15 Generator parameters in CYME.

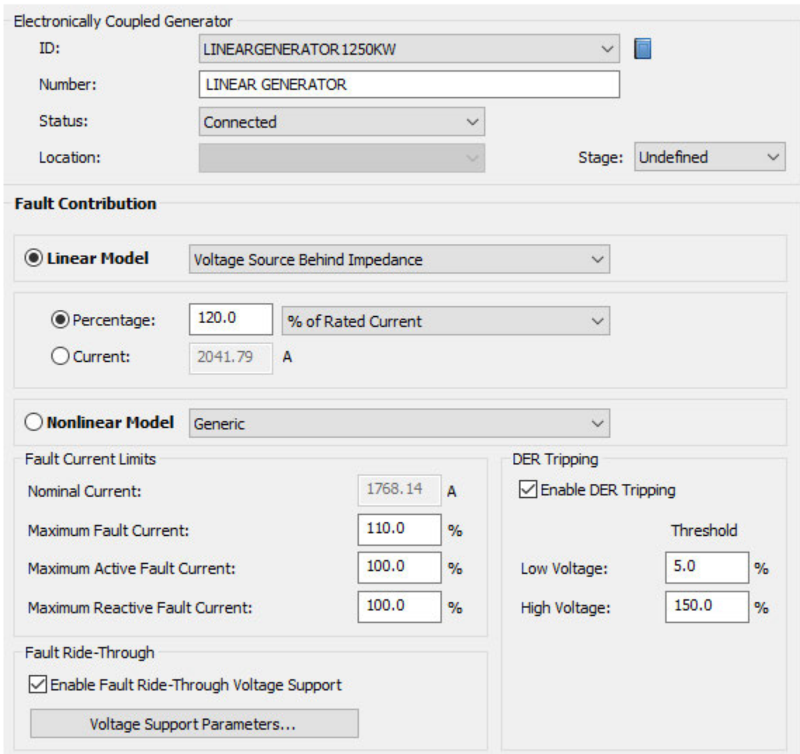

Figure 4.1-4. Linear Generator parameters in CYME.

4.2 SHORT-CIRCUIT ANALYSIS RESULTS

The short-circuit analysis results for the minimum short-circuit case and the maximum short-circuit case are provided below.

4.2.1 Minimum Short-Circuit Case Results

The fault currents seen at Pebbly Beach Generating Station (PBGS) 12 kV bus for the minimum short-circuit case in shown in Table 4.2.1. Based on the three-phase fault current, the short circuit capacity at PBGS 12 kV bus is 30 MVA.

Table 4.2-1
Fault Currents seen at PBGS 12 kV

PBGS 12 kV Short Circuit Currents (A)				
LLL	LLG	LL	LG	LG min (with 30 Ohm)
1445	2046	1009	1616	235

Table 4.2-2 and Table 4.2-3 summarize the minimum fault analysis results for the three-phase bolted fault and a single-line-to-ground fault with a 30-ohm fault impedance, respectively.

For the three-phase bolted faults in the system, the minimum fault currents seen by the protective devices are at least two times higher than their pickup rating as shown in Table 4.2-2.

For the single-line-to-ground faults with a 30-ohm fault impedance in the system, the minimum fault currents seen by the protective devices are at least two times higher than their pickup rating as shown in Table 4.2-3 excluding three fuses (Ref. No. 27, 29, and 30). While the downstream sections of these three fuses are still protected, the clearing times for high impedance faults (e.g., 30-ohm or higher) may be significantly longer (or may not clear) for these three fuses protection zones.

Table 4.2-2
Minimum Fault Analysis Results – Three-Phase Bolted Fault

Ref. No	Critical Location	Fault Type	Prot. Dev. Type	Prot. Dev. Number	Setting (A)	Pickup	Fault Current seen by Prot. Dev. (A)	Fault Current (A)	Protected	Is fault current at least twice the pickup setting?
1	[redacted]	LLL	Relay-Controlled Breaker	[redacted]	204	Phase	864	864	Yes	Yes
2	[redacted]	LLL	Relay-Controlled Breaker	[redacted]	360	Phase	809	809	Yes	Yes
3	[redacted]	LLL	Relay-Controlled Breaker	[redacted]	198	Phase	1010	1010	Yes	Yes
4	[redacted]	LLL	Recloser	[redacted]	100	Phase	200	200	Yes	Yes
5	[redacted]	LLL	Recloser	[redacted]	105	Phase	340	340	Yes	Yes
6	[redacted]	LLL	Recloser	[redacted]	75	Phase	289	289	Yes	Yes
7	[redacted]	LLL	Recloser	[redacted]	50	Phase	288	288	Yes	Yes
8	[redacted]	LLL	Recloser	[redacted]	50	Phase	248	248	Yes	Yes
9	[redacted]	LLL	Fuse	[redacted]	15	Phase	540	540	Yes	Yes
10	[redacted]	LLL	Fuse	[redacted]	25	Phase	268	268	Yes	Yes
11	[redacted]	LLL	Fuse	[redacted]	80	Phase	778	778	Yes	Yes
12	[redacted]	LLL	Fuse	[redacted]	40	Phase	1033	1033	Yes	Yes
13	[redacted]	LLL	Fuse	[redacted]	25	Phase	845	845	Yes	Yes
14	[redacted]	LLL	Fuse	[redacted]	80	Phase	765	765	Yes	Yes
15	[redacted]	LLL	Fuse	[redacted]	30	Phase	938	938	Yes	Yes
16	[redacted]	LLL	Fuse	[redacted]	25	Phase	863	863	Yes	Yes
17	[redacted]	LLL	Fuse	[redacted]	80	Phase	1062	1062	Yes	Yes
18	[redacted]	LLL	Fuse	[redacted]	15	Phase	289	289	Yes	Yes
19	[redacted]	LLL	Fuse	[redacted]	18	Phase	1333	1333	Yes	Yes
20	[redacted]	LLL	Fuse	[redacted]	30	Phase	929	929	Yes	Yes
21	[redacted]	LLL	Fuse	[redacted]	15	Phase	530	530	Yes	Yes
22	[redacted]	LLL	Fuse	[redacted]	6	Phase	264	264	Yes	Yes
23	[redacted]	LLL	Fuse	[redacted]	7	Phase	454	454	Yes	Yes
24	[redacted]	LLL	Fuse	[redacted]	6	Phase	283	283	Yes	Yes
25	[redacted]	LLL	Fuse	[redacted]	15	Phase	354	354	Yes	Yes
26	[redacted]	LLL	Fuse	[redacted]	80	Phase	291	291	Yes	Yes
27	[redacted]	LLL	Fuse	[redacted]	50	Phase	600	899	Yes	Yes
28	[redacted]	LLL	Fuse	[redacted]	50	Phase	300	899	Yes	Yes
29	[redacted]	LLL	Fuse	[redacted]	8	Phase	1140	1140	Yes	Yes
30	[redacted]	LLL	Fuse	[redacted]	18	Phase	1381	1381	Yes	Yes
31	[redacted]	LLL	Fuse	[redacted]	30	Phase	595	595	Yes	Yes
32	[redacted]	LLL	Fuse	[redacted]	50	Phase	864	864	Yes	Yes
33	[redacted]	LLL	Fuse	[redacted]	40	Phase	204	204	Yes	Yes
34	[redacted]	LLL	Fuse	[redacted]	10	Phase	1156	1156	Yes	Yes
35	[redacted]	LLL	Fuse	[redacted]	10	Phase	249	249	Yes	Yes
36	[redacted]	LLL	Fuse	[redacted]	20	Phase	289	289	Yes	Yes
37	[redacted]	LLL	Fuse	[redacted]	50	Phase	1440	1440	Yes	Yes

Table 4.2-3
Minimum Fault Analysis Results – Single-Line-to-Ground Fault with a 30-ohm Fault Impedance

Ref. No	Critical Location	Fault Type	Prot. Dev. Type	Prot. Dev. Number	Setting (A)	Pickup	Fault Current seen by Prot. Dev. (A)	Fault Current (A)	Protected	Is fault current at least twice the pickup setting?
1	[redacted]	LG	Relay-Controlled Breaker	[redacted]	60	Ground	198	198	Yes	Yes
2	[redacted]	LG	Relay-Controlled Breaker	[redacted]	60	Ground	200	200	Yes	Yes
3	[redacted]	LG	Relay-Controlled Breaker	[redacted]	60	Ground	214	214	Yes	Yes
4	[redacted]	LG	Recloser	[redacted]	35	Ground	100	99	Yes	Yes
5	[redacted]	LG	Recloser	[redacted]	35	Ground	135	134	Yes	Yes
6	[redacted]	LG	Recloser	[redacted]	25	Ground	121	121	Yes	Yes
7	[redacted]	LG	Recloser	[redacted]	25	Ground	120	120	Yes	Yes
8	[redacted]	LG	Recloser	[redacted]	6	Ground	106	106	Yes	Yes
9	[redacted]	LG	Fuse	[redacted]	15	Phase	170	170	Yes	Yes
10	[redacted]	LG	Fuse	[redacted]	25	Phase	120	120	Yes	Yes
11	[redacted]	LG	Fuse	[redacted]	80	Phase	198	198	Yes	Yes
12	[redacted]	LG	Fuse	[redacted]	40	Phase	216	216	Yes	Yes
13	[redacted]	LG	Fuse	[redacted]	25	Phase	205	205	Yes	Yes
14	[redacted]	LG	Fuse	[redacted]	80	Phase	192	192	Yes	Yes
15	[redacted]	LG	Fuse	[redacted]	30	Phase	211	211	Yes	Yes
16	[redacted]	LG	Fuse	[redacted]	25	Phase	207	207	Yes	Yes
17	[redacted]	LG	Fuse	[redacted]	80	Phase	218	218	Yes	Yes
18	[redacted]	LG	Fuse	[redacted]	30	Phase	146	146	Yes	Yes
19	[redacted]	LG	Fuse	[redacted]	15	Phase	121	121	Yes	Yes
20	[redacted]	LG	Fuse	[redacted]	18	Phase	225	225	Yes	Yes
21	[redacted]	LG	Fuse	[redacted]	30	Phase	209	209	Yes	Yes
22	[redacted]	LG	Fuse	[redacted]	15	Phase	172	172	Yes	Yes
23	[redacted]	LG	Fuse	[redacted]	6	Phase	119	119	Yes	Yes
24	[redacted]	LG	Fuse	[redacted]	7	Phase	160	160	Yes	Yes
25	[redacted]	LG	Fuse	[redacted]	6	Phase	124	124	Yes	Yes
26	[redacted]	LG	Fuse	[redacted]	15	Phase	141	141	Yes	Yes
27	[redacted]	LG	Fuse	[redacted]	80	Phase	121	121	Yes	No
28	[redacted]	LG	Fuse	[redacted]	50	Phase	134	201	Yes	Yes
29	[redacted]	LG	Fuse	[redacted]	50	Phase	67	201	Yes	No
30	[redacted]	LG	Fuse	[redacted]	80	Phase	148	148	Yes	No
31	[redacted]	LG	Fuse	[redacted]	8	Phase	223	223	Yes	Yes
32	[redacted]	LG	Fuse	[redacted]	18	Phase	230	230	Yes	Yes
33	[redacted]	LG	Fuse	[redacted]	50	Phase	198	198	Yes	Yes
34	[redacted]	LG	Fuse	[redacted]	40	Phase	100	100	Yes	Yes
35	[redacted]	LG	Fuse	[redacted]	10	Phase	223	223	Yes	Yes
36	[redacted]	LG	Fuse	[redacted]	10	Phase	115	115	Yes	Yes
37	[redacted]	LG	Fuse	[redacted]	20	Phase	121	121	Yes	Yes
38	[redacted]	LG	Fuse	[redacted]	15	Phase	106	106	Yes	Yes
39	[redacted]	LG	Fuse	[redacted]	50	Phase	234	234	Yes	Yes

4.2.2 Maximum Short-Circuit Case Results

The fault currents seen at PBGS 12 kV bus for the maximum short-circuit case are shown in Table 4.2-4. Based on the three-phase fault current, the short circuit capacity at PBGS 12 kV bus is 42 MVA.

Table 4.2-4
Fault Currents seen at PBGS 12 kV

PBGS 12 kV Short Circuit Currents (A)				
LLL	LLG	LL	LG	LG min (with 30 Ohm)
2018	2689	1386	2159	236

Table 4.2-5 summarizes the device evaluation results for the protective devices. It is seen that the short-circuit currents are within the interrupting rating of all of the protective devices.

Table 4.2-5
Device Evaluation Results

Ref. No	Protective Device Number	Type	Manufacturer	Status	Calculated Short Circuit Current (kA)	Interrupting Rating (kA)	Rating (%)
1	[redacted]	Breaker		Pass	2.15	25	8.61
2	[redacted]	Breaker		Pass	2.16	25	8.62
3	[redacted]	Breaker		Pass	2.15	25	8.61
4	[redacted]	Breaker		Pass	2.54	25	10.16
5	[redacted]	Fuse	S&C	Pass	1.05	14	7.48
6	[redacted]	Fuse	HI-TECH	Pass	1.05	50	2.09
7	[redacted]	Fuse	HI-TECH	Pass	0.99	50	1.99
8	[redacted]	Fuse	HI-TECH	Pass	1.03	50	2.06
9	[redacted]	Fuse	COOPER	Pass	0.55	6.3	8.70
10	[redacted]	Fuse	S&C	Pass	0.35	14	2.52
11	[redacted]	Fuse	HI-TECH	Pass	1.06	50	2.11
12	[redacted]	Fuse	HI-TECH	Pass	1.49	50	2.98
13	[redacted]	Fuse	HI-TECH	Pass	1.92	50	3.84
14	[redacted]	Fuse	HI-TECH	Pass	1.29	50	2.57
15	[redacted]	Fuse	S&C	Pass	1.34	14	9.60
16	[redacted]	Fuse	HI-TECH	Pass	1.79	50	3.58
17	[redacted]	Fuse	HI-TECH	Pass	0.22	50	0.43
18	[redacted]	Fuse	HI-TECH	Pass	2.14	50	4.28
19	[redacted]	Fuse	S&C	Pass	0.54	14	3.89
20	[redacted]	Fuse	S&C	Pass	1.23	14	8.80
21	[redacted]	Fuse	S&C	Pass	0.97	14	6.96
22	[redacted]	Fuse	S&C	Pass	0.38	12	3.14
23	[redacted]	Fuse	S&C	Pass	0.38	14	2.71
24	[redacted]	Fuse	S&C	Pass	0.30	14	2.14
25	[redacted]	Fuse	S&C	Pass	0.31	14	2.21
26	[redacted]	Fuse	S&C	Pass	0.59	14	4.20
27	[redacted]	Fuse	HI-TECH	Pass	0.26	50	0.52
28	[redacted]	Fuse	S&C	Pass	1.46	14	10.44
29	[redacted]	Fuse	S&C	Pass	0.15	14	1.05
30	[redacted]	Fuse	S&C	Pass	0.28	14	1.98
31	[redacted]	Fuse	S&C	Pass	0.73	14	5.24
32	[redacted]	Fuse	HI-TECH	Pass	1.12	50	2.25
33	[redacted]	Fuse	S&C	Pass	0.37	14	2.64
34	[redacted]	Fuse	S&C	Pass	0.68	12	5.70
35	[redacted]	Fuse	HI-TECH	Pass	1.05	50	2.09
36	[redacted]	Recloser		Pass	0.38	0.6	63.29
37	[redacted]	Recloser		Pass	1.30	12.5	10.40
38	[redacted]	Recloser		Pass	0.36	12.5	2.89
39	[redacted]	Recloser		Pass	1.24	12.5	9.92
40	[redacted]	Recloser		Pass	0.42	12.5	3.40
41	[redacted]	Recloser		Pass	0.00	12.5	0.00

4.3 OVERALL SUMMARY

Short-circuit analysis was performed to calculate the short-circuit currents produced by balanced three-phase and unbalanced faults at each bus. The results of the analysis were used to determine if the anticipated short-current currents are within or exceed the interrupting ratings of the protection equipment and to verify if the short-circuit currents seen by the protective devices are sufficient to exceed the minimum pickup setting of the existing protective devices.

Based on the maximum short-circuit case device evaluation results, the short-circuit currents are within the interrupting rating of all of the protective devices.

For the three-phase bolted faults in the system, the minimum fault currents seen by the protective devices are at least two times or higher than their pickup rating.

For the single-line-to-ground faults with a 30-ohm fault impedance, the minimum fault currents seen by the protective devices are at least two times or higher than their pickup rating excluding three fuses (Ref. No. 27, 29, and 30 on Table 4.2-3). While the downstream sections of these three fuses are still protected, the clearing times for high impedance faults (e.g., 30-ohm or higher) may be significantly longer (or may not clear) for these three fuses protection zones. Hence, MEPPI recommends replacing these three fuses with smaller sizes to clear high-impedance faults faster.

4.4 REFERENCES

[4-1] https://www.cyme.com/software/cymecymtcc/
[4-2] https://www.cyme.com/software/faultanalyses/
[4-3] Tom Guttormson, "40 Ohm Ground Fault Resistance – Still Applicable?", MN Power Systems Conference, November 2016.

CITY OF AVALON

September 6, 2023

SCAQMD
21865 Copley Dr.
Diamond Bar, CA. 91765

RE: Southern California Edison Pebbly Beach Generating Station Site Visit

To Whom It May Concern:

On behalf of the City of Avalon Fire Department ("AFD") I wanted to identify a few fire and safety concerns with regard to increasing propane storage and deliveries at the Pebbly Beach Generating Station ("PBGS"):

NFPA Standard 15 specifies the required water flow rate in a water deluge system to protect fixed structures such as storage tanks in the case of a fire. The amount of required water depends on the size of the area protected. The AFD calculated that the deluge system must be capable of supplying 3,000 gallons per minute (gpm) to control a fire in the propane tank farm for PBGS to comply with NFPA 15. PBGS's water flow system is 1,800 gpm, or 60% of the NFPA 15 required flow rate.

Even if the fourth tank were relocated elsewhere within the facility, SCE does not have sufficient water storage or delivery systems for fire suppression. At this time, SCE does not have enough space to install a new water tank within its property.

There is also an inherent risk associated with propane transportation and unloading. As such, increasing the number of deliveries increases the overall fire and safety risk.

PBGS propane storage tanks are located in the center of the facility. The propane tank relief valve vents and the propane loading area (locations where incidental propane emissions can occur) are located approximately 50 feet from the 12-kV and 2.4-kV switch yard fences. Due to the close spacing between the two propane venting locations and the two switchyards, PBGS is unable to meet the National Fire Protection Association (NFPA) Standard 59 (Utility Liquid Propone-Gas Plant Code) that establishes a minimum offset distance required between a transfer point of a flammable substance (i.e., a vent location) and an uncontrolled source of ignition (switchyard). The offset distance required by NFPA-59 is 75 feet, but site constraints limit the available offset to 60 feet. The AFD granted PBGS a variance from the NFPA-59 standard, allowing a 60-foot offset. A second variance further reducing the offset distance would not be possible.

Please feel free to reach out to me with any other questions.

Michael Alegria
Fire Chief, City of Avalon